Association of Irritated Residents ▪ California Environmental Justice Alliance
Center for Climate Protection ▪ Center for Food Safety
Center on Race, Poverty & the Environment
Central California Asthma Collaborative ▪ Central California Environmental Justice Network
Central Valley Air Quality Coalition ▪ Clean Water and Air Matter
Comité Residentes Organizados al Servicio del Ambiente Sano (Comité ROSAS)
Committee for a Better Shafter ▪ Committee for a Better Arvin ▪ Community Science Institute
Communities for a Better Environment ▪ Delano Guardians ▪ Environmental Health Coalition
Food & Water Watch ▪ Greenfield Walking Group ▪ Institute for Agriculture and Trade Policy
Leadership Counsel for Justice and Accountability ▪ Medical Advocates for Healthy Air
Merced Bicycle Coalition ▪ Bruce Meyers ▪ North Carolina Environmental Justice Network ▪
Vianey Nunez ▪ Physicians for Social Responsibility – Los Angeles ▪ Public Justice
San Joaquin Valley Sustainable Ag Collaborative ▪ Sierra Club California
Socially Responsible Agricultural Project ▪ Valley Improvement Projects

May 26, 2016

Via Online Submission

Ryan McCarthy
Craig Segall
California Air Resources Board
1001 I Street
Sacramento, CA 95814
ryan.mccarthy@arb.ca.gov
craig.segall@arb.ca.gov

Re: Comments on Proposed Short Lived Climate Pollutant Reduction Strategy

Dear Mr. McCarthy and Mr. Segall:

Pursuant to Senate Bill 605 (Lara), the Air Resources Board has released the Proposed Short-Lived Climate Pollutant Reduction Strategy (hereafter “Proposed Strategy”). These comments on the Proposed Strategy are submitted on behalf of the Association of Irritated Residents, California Environmental Justice Alliance, Center for Climate Protection, Center for Food Safety, Center on Race, Poverty & the Environment, Central California Asthma Collaborative, Central California Environmental Justice Network, Central Valley Air Quality Coalition, Clean Water and Air Matter, Comité Residentes Organizados al Servicio del Ambiente Sano (Comité ROSAS), Committee for a Better Shafter, Committee for a Better Arvin, Community Science Institute, Communities for a Better Environment, Delano Guardians, Environmental Health Coalition, Food & Water Watch, Greenfield Walking Group, Institute for Agriculture and Trade Policy, Leadership Counsel for Justice and Accountability, Medical

Advocates for Healthy Air, Merced Bicycle Coalition, Bruce Meyers, North Carolina Environmental Justice Network, Vianey Nunez, Physicians for Social Responsibility – Los Angeles, Public Justice, San Joaquin Valley Sustainable Ag Collaborative, Sierra Club California, Socially Responsible Agricultural Project, and Valley Improvement Projects.

The Proposed Strategy calls for mandatory methane controls for manure management systems, with the regulatory development process to begin in 2017 at existing industrialized factory dairies (operations with no pasture utilizing flushed lagoon manure management systems). We applaud Board staff for shifting this strategy from voluntary performance to mandatory regulations. Given the urgent need to reduce Short-Lived Climate Pollutants, and the substantial contribution of dairy methane to California's total greenhouse gas inventory, the Board should adopt the proposed methane strategy for manure management at industrialized factory dairies as soon as possible. The Board should amend the Proposed Strategy, which inappropriately calls for voluntary reductions from enteric emissions, to instead adopt and implement mandatory enteric emissions reduction strategies.

We call on the Board to move quickly during the regulatory process because of the short-term impact of methane, which has a current IPCC 20-year methane global warming potential of 84 (the Proposed Strategy relies on the IPCC 4th Assessment which assigns a 20-year methane global warming potential of 72), and prioritize regulatory strategies to provide co-benefits for disadvantaged communities and environmental co-benefits, especially those offered by pasture-based dairy systems. To the extent that the State Board uses financial incentives to achieve methane reductions (e.g. the Greenhouse Gas Reduction Fund), such incentives should be directed towards pasture-based systems that reduce methane emissions and act as a carbon sink rather than to subsidize the use of polluting anaerobic digesters in the San Joaquin Valley and the South Coast air basins. Anaerobic digesters do not offer co-benefits to disadvantaged communities, and rather negatively impact disadvantaged communities.

Introduction

The Proposed Strategy states that the "science unequivocally underscores the need to *immediately* reduce emissions of Short-Lived Climate Pollutants[.]"[1] Consistent with this acknowledgement, the Proposed Strategy should require *mandatory* controls for existing and new dairies' methane emissions, the largest uncontrolled sector of the greenhouse gas inventory.[2]

California's 2014 Gross Domestic Product was $2.13 trillion,[3] with 2014 California milk production accounting for $9.4 billion.[4] Accordingly, dairy accounts for 0.44 percent of California's economy, yet livestock manure management at dairies and enteric methane

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[1] Proposed Strategy at 1 (emphasis added).

[2] Proposed Strategy at 64-71.

[3] California Legislative Analyst Office, July 1, 2015, available at http://www.lao.ca.gov/LAOEconTax/Article/Detail/90, attached as Exhibit 1.

[4] California Department of Food and Agriculture, available at https://www.cdfa.ca.gov/statistics/, attached as Exhibit 2.

emissions represent 5.2 percent of California's 2013 greenhouse gas emission inventory.[5] Dairy thus contributes a vastly disproportionate share of greenhouse gas emissions compared to its overall contribution to the economy, especially when modifying the inventory data to account for methane's higher global warming potential in the short term 20-year period. The 2013 emissions inventory demonstrates that California dairies account for 45 percent of California's methane emissions, with manure management and enteric emissions accounting for 25 and 20 percent of total methane emissions, respectively.[6] In the San Joaquin Valley, which hosts the majority of industrialized factory dairies, *at least* eighty-seven percent of methane emissions are from dairy (and other cattle) operations.[7] Compared to the Aliso Canyon (Porter Ranch) natural gas storage leak, California dairies emit on average 2.3 times more per day than Aliso Canyon, and 1.45 times more per day at the Aliso Canyon's peak emissions rate.[8] This Board and other state leaders have called for abating Aliso Canyon and mitigating that impact, and no reason exists for why industrialized factory dairies should continue to avoid mandatory reductions. Accordingly, the State Board should ensure that dairies do their fair share to reduce methane emissions by adopting a mandatory methane reduction strategy for existing and new dairies.

The Legislature has directed the ARB to, *inter alia*, (1) identify existing and potential new control measures for Short-Lived Climate Pollutants; and (2) prioritize development of new measures that offer co-benefits for water quality and air pollution reductions that benefit disadvantaged communities.

> In developing the strategy, the state board shall do all of the following:
>
> (1) Complete an inventory of sources and emissions of short-lived climate pollutants in the state based on available data;
> (2) Identify research needs to address any data gaps;
> (3) Identify existing and potential new control measures to reduce emissions;
> (4) Prioritize the development of new measures for short-lived climate pollutants that offer co-benefits by improving water quality or reducing other air pollutants that impact community health and benefit disadvantaged communities, as identified pursuant to Section 39711; and
> (5) Coordinate with other state agencies and districts to develop measures identified as part of the comprehensive strategy.

Health & Safety Code § 39730(a).

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[5] Proposed Strategy at 58; California Greenhouse Gas Inventory 2000-2013 (100 year GWP), available at http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_2000-13_20150831.pdf, attached as Exhibit 3.

[6] Proposed Strategy at 58.

[7] D.R. Genter, et al., Emissions of organic carbon and methane from petroleum and dairy operations in California's San Joaquin Valley, Atmos. Chem. Phys., 14, 4955–4978 (2014), attached as Exhibit 4.

[8] *See* Memorandum from Jonathan Sha to Brent Newell, February 9, 2016, attached as Exhibit 5. This memorandum relies on the IPCC's 4th Assessment methane global warming potential of 72 because that is the global warming potential the Board uses for this Proposed Strategy.

The Strategy Should Include Mandatory Regulations for Manure Management and Enteric Emissions

In May 2015, the Board released the Concept Paper, which discussed anaerobic digesters (covered liquid manure lagoons that capture methane emissions) and manure scraping as strategies for reducing manure-based methane emissions. The Concept Paper also briefly addressed breeding and dietary strategies for controlling enteric methane emissions, which account for twenty percent of total methane emissions. The Concept Paper called for voluntary controls for the entire dairy sector.

In September 2015, the Board released the Draft Strategy and proposed to continue *voluntary* manure management controls, proposed no enteric emissions controls, and simultaneously failed to investigate the environmental, economic, and other co-benefits of pasture-based systems. At the public workshop in Fresno on October 19, 2015, ARB staff indicated that staff would perform a cost-effectiveness and co-benefits analysis to accompany the next draft of the strategy.

The Proposed Strategy, released in April 2016, marks a paradigm shift. It proposes to do what no other state or the federal government has done: develop and implement mandatory regulations to reduce methane from manure management in the animal agriculture industry. For that we applaud the Board and encourage the Board to move forward with all deliberate speed. The Proposed Strategy, however, continues to call for dairies to voluntarily control enteric emissions. We thus call on the Board to move forward with the same urgency and adopt and implement a mandatory regulation requiring reductions from enteric processes.

The Strategy Should Prioritize Pasture-Based Dairy Systems and Should Not Rely on Anaerobic Digesters.

The Proposed Strategy focuses on the economic benefits of biogas from anaerobic digesters without acknowledging significant negative impacts on disadvantaged communities in the San Joaquin Valley. At the same time, the Strategy attempts to find fault with pasture-based systems without recognizing several co-benefits such operations achieve. This explicit bias violates Senate Bill 605.

The Proposed Strategy does not prioritize measures which provide co-benefits to air and water quality, and which benefit disadvantaged communities. The combustion of methane from anaerobic digestion adds oxides of nitrogen, an ozone and fine particulate matter (PM2.5) precursor, to the severely polluted San Joaquin Valley air basin where most liquefied manure dairy systems are located. Many disadvantaged communities in the Valley suffer from poor air quality and other social and environmental impacts as demonstrated by CalEnviroScreen 2.0.[9] Before the Board claims that combustion of biogas to produce electricity provides a co-benefit, it should investigate and demonstrate that electricity generation at a dairy-based anaerobic digester operates more efficiently and produces less GHGs and criteria pollutants than a natural gas

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[9] Available at http://oehha.ca.gov/calenviroscreen/report/calenviroscreen-version-20.

combined cycle (NGCC) power plant. The use of electricity from dairy biogas will displace electricity produced at NGCC plants under the Renewable Portfolio Standard, and thus generate more emissions in the air basin when internal combustion engines operate less efficiently than a NGCC power plant. The Proposed Strategy has failed to consider this important impact on the health and well-being of disadvantaged communities in the San Joaquin Valley. Health & Safety Code § 39730(a)(4). This is especially important when the Strategy refers to manure management controls at 500 dairies, which would potentially mean 500 separate internal combustion engines producing air pollution.[10] California should end its reliance on dirty energy sources like anaerobic digesters and power plants, and replace them with truly renewable, clean sources of energy such as wind and distributed generation solar power.

The Board has failed to perform a meaningful assessment of the relative co-benefits of pasture-based systems, including an assessment of carbon sequestration in healthy grassland soil, reduced volatile organic compound (VOC) and oxides of nitrogen (NOx) emissions from corn silage, reduced threats to groundwater contamination, and overall reductions in methane from both manure management and enteric emissions. SB 605 requires the Board to prioritize measures that attain these co-benefits when developing this Strategy. *Id*. The Proposed Strategy briefly discusses pasture-based systems and states that "[P]asture-based systems are a viable option that is appropriate in some cases, but likely challenging to implement at many existing, larger dairies in the Central Valley."[11] However, the single paragraph in the Proposed Strategy discussing pasture-based systems dismisses the benefits of pasture with conclusory statements unsupported by any analysis by the State Board.[12] Chapter VIII briefly recognizes the co-benefits of reduced air pollution and reduction of groundwater pollution, and that 25 dairies could convert to pasture without reducing herd sizes or procuring additional land.[13] The Proposed Strategy, when fairly read in its entirety, celebrates the benefits of energy produced by anaerobic digesters without considering adverse impacts on air quality, yet criticizes the viability of pasture-based systems without considering several significant co-benefits offered by pasture-based systems. This kind of bias does not comport with SB 605.

The Proposed Strategy fails to support its assertion that pasture-based systems are not a widely viable methane reduction strategy because they allegedly would require more land, "pose feed production and animal welfare concerns due to heat exposure," may face nutrient management issues, have reduced milk production efficiencies, and have higher enteric fermentation per unit of milk produced.[14] The objective of Senate Bill 605 is not to achieve low levels of GHG *per unit of milk*, but rather to achieve *net* methane reductions. The Strategy has not identified any social or environmental imperative to continue industrialized factory dairies' current milk production levels along with concomitant, massive methane emissions, so even if pasture-based systems result in lower herd sizes and less milk production, the Board should

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[10] Proposed Strategy at 66

[11] *Id*.

[12] Proposed Strategy at 65-66.

[13] Proposed Strategy at 124.

[14] Proposed Strategy at 65-66.

identify the co-benefits of such systems as well as the opportunity to reduce methane and sequester carbon in healthy grassland soil.

The Proposed Strategy speciously claims that pasture-based systems implicate animal welfare concerns. A "happy cow" living on pasture and grazing enjoys a far more natural life with high animal welfare than a cow confined in a freestall barn or manure-filled corral with no access to pasture. The fact that irrigated pasture-based dairy and beef cattle farms operate, and have operated, in the San Joaquin Valley exposes the Proposed Strategy's fallacy. Pasture-based systems avoid anaerobic methane emissions, sequester carbon, avoid corn silage VOC and NOx emissions, and lead to less enteric emissions because pasture-based systems stock fewer cows per acre than industrialized systems. Moreover, the Proposed Strategy improperly focuses on methane emissions per unit of milk rather than overall methane reductions needed from the dairy sector. The Strategy required by SB 605 should yield overall methane reductions from actual "happy cows," and not misleadingly "low" GHG milk from industrialized factory dairies. Furthermore, the Proposed Strategy has failed to consider whether water consumption may be lower in pasture-based systems than confinement-based dairies. This analysis could be done – and the Proposed Strategy has not stated the analysis is not feasible – using existing data from industrialized factory dairies and pasture-based systems in the San Joaquin Valley, where irrigated pasture is a demonstrated practice. Given pasture's promising co-benefits and methane reductions, including the benefits of reduced herd sizes' enteric emissions, the State Board should fully investigate, prioritize, and rely on pasture as a viable methane control strategy and should revise the Proposed Strategy to include pasture as a priority measure pursuant to SB 605. Furthermore, the Board should provide *tangible support,* through grants and financial incentive programs, for existing pasture-based dairies and industrialized factory dairies interested in transitioning their operation to a pasture-based system.

Localized Impacts of Anaerobic Digesters.

San Joaquin Valley communities rank among the most disadvantaged communities in California because of social, economic, and environmental exposures to pesticides, air pollution, and groundwater contamination, among other factors. Close proximity of industrialized factory dairies to disadvantaged communities and location in the San Joaquin Valley air basin both contribute to localized and regional impacts. We are concerned that anaerobic digesters at these facilities will harm, rather than benefit, disadvantaged communities in the Valley.

Digesters have been and could be placed in already overburdened communities, with unhealthy air and contaminated drinking water. Dairy digesters will only exacerbate conditions in disadvantaged communities and further degrade the water and air quality in these communities by emitting air pollutants and through unlined liquefied manure storage lagoons and application to feed crops. Placing these facilities in these communities will bring in heavy-duty vehicle traffic and increase noise levels. Digesters increase vehicle miles traveled as well as levels of harmful short-lived climate pollutants such as black carbon from diesel truck emissions. Fresno County, for example, ranks second in the nation for short-term fine particle pollution (PM2.5), with asthma rates more than three times the national average.[15] Bakersfield ranks as the worst for both short-term and long-term PM2.5 exposure.[16]

Other issues that arise with the placement of dairy digesters in disadvantaged communities, include degraded transportation infrastructure, contamination of groundwater supplies, and increased levels of harmful air pollutants. Rural communities already lack the services and funding to improve transportation infrastructure, and the placement of these digesters would lead to an overuse of already substandard road infrastructure and further deteriorate the roads and highways of disadvantaged, underfunded communities. Furthermore, the operation of dairy digesters results in nitrogen-rich digestate that negatively affects groundwater through unlined lagoons, over-application of nitrogen to crop fields, and volatized ammonia gas, which acts as a precursor to ammonium nitrate, the most prevalent form of PM2.5 in the Valley. Many nearby disadvantaged communities rely on groundwater for their water needs, and nitrate groundwater levels can reach unhealthy levels, causing such impacts as methemoglobinemia or "blue baby syndrome."

Because of these localized impacts on disadvantaged communities in the Valley, we urge the Board to not adopt a Strategy that relies on anaerobic digesters. Instead, as the Legislature directed, the strategy should prioritize "the development of new measures for short-lived climate pollutants that offer co-benefits by improving water quality or reducing other air pollutants that impact community health and benefit disadvantaged communities." Health & Safety Code § 39730(a)(4).

The Proposed Strategy's Economic, Public Health, and Environmental Justice Analysis Suffer from Significant Shortcomings.

The Proposed Strategy emphasizes the economic benefits to the dairy industry for utilizing anaerobic digesters to produce electricity and biomethane for use as a transportation fuel. The Proposed Strategy relies on the economic benefits to dairy producers for these strategies, and calls for the heavy use of subsidies to support anaerobic digesters for early adopters prior to the imposition of regulations. The Legislature, however, explicitly did not direct the Board to prioritize measures based on economic considerations or financial benefits to the industry. *See* Health & Safety Code § 39730. Rather, the Legislature specifically directed prioritization of those measures that "that offer cobenefits by improving water quality or reducing other air pollutants that impact community health and benefit disadvantaged communities, as identified pursuant to Section 39711." Health & Safety Code § 39730(a)(4).

The economic analysis fails to consider the social cost of carbon[17] as part of the economic analysis, or an analysis of pasture-based systems' carbon sequestration co-benefits.

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[15] American Lung Association, State of the Air 2016, available at http://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/most-polluted-cities.html, attached as Exhibit 6.

[16] *Id.*

[17] *See* EPA Fact Sheet, The Social Cost of Carbon, attached as Exhibit 7. Given the global warming potential of methane is 84, the Board should estimate the social costs of unabated methane from the dairy industry, the social costs of fugitive methane emissions at anaerobic

Such negative costs to society caused by dairy methane emissions (as well as CO_2 and co-pollutants from combusted methane) should be considered as part of the economic analysis. Moreover, the cost to society for methane emissions warrants regulations implemented quickly. We note that the social cost of carbon has been criticized as being too low and not accounting for the cost of all societal impacts.

The public health analysis briefly recognizes air quality co-benefits of pasture,[18] but fails to discuss or analyze the co-benefits of reduced VOC and NOx emissions from corn silage produced and consumed by industrialized factory dairies when such operations convert to pasture based systems. Corn silage emits massive amounts of VOC in the San Joaquin Valley, with dairy corn silage VOC emissions forming more ozone than the VOC emitted by passenger vehicles.[19] As the Board is aware, corn silage also emits NOx, and mitigation of VOC and NOx emissions remain a challenge at industrialized factor dairies.[20]

The Proposed Strategy includes a less than three-page environmental justice analysis. This section of the Proposed Strategy fails to assess the impacts of anaerobic digesters on air quality or groundwater quality and how that implicates an environmental justice issue or how air and water quality impacts will affect disadvantaged communities in the San Joaquin Valley.[21] This woefully inadequate environmental justice analysis should be amended prior to the final hearing before the Board.

The environmental analysis in Appendix C states that:

> Generally, digesters may also displace some criteria air pollutant emissions associated with the use of fossil fuels by using the captured dairy biogas as a substitute source for generating electricity, fueling vehicles, or cooking and space heating as well as other natural gas combustion uses. Depending on end-use and other factors, emissions could fall below current conditions.[22]

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digesters, the social costs of CO_2 emitted during methane combustion, the social benefits of avoided methane emissions from pasture-based operation (includes avoided manure management emissions from aerobic manure decomposition on pasture and reduced enteric emissions from lower herd sizes), as well as the social cost benefits of carbon sequestration at pasture-based systems.

[18] Proposed Strategy at 123.

[19] Cody J. Howard, et al., Reactive Organic Gas Emissions from Livestock Feed Contribute Significantly to Ozone production in Central California, Environ. Sci. Technol. (2010), 44, 2309–2314, attached as Exhibit 8; San Joaquin Valley Unified Air Pollution Control District Air Pollution Control Officer's Revision of the Dairy VOC Emission Factors at 34-35 (2012), attached as Exhibit 9.

[20] Frank Mitloehner, et al., Quantification of the Emission Reduction Benefits of Mitigation Strategies for Dairy Silage (2016), attached as Exhibit 10.

[21] Proposed Strategy at 125-127.

[22] Appendix C at 4-29.

Combusting biogas in internal combustion engines yields significant NOx, SOx, VOC, and particulate matter emissions that negatively affect air quality.[23] The current permitting of digesters by the San Joaquin Valley Unified Air Pollution Control District only requires internal combustion engines as Best Available Control Technology.[24] For example, a single dairy digester project with two IC engines producing 1,059 kw of electricity emits air pollution (approximately 5 tons per year of NOx, for example) for which the facility does not need to purchase offsetting emission reduction credits.[25] This means that the digester adds pollution to the air basin.

One can reasonably extrapolate the impact from the 500 dairies the Strategy identifies,[26] each emitting approximately 5 tons per year of NOx without obtaining any offsets. Considering the proposed 600 megawatt NGCC Avenal Power Center's maximum NOx emissions of 99.4 tons/year,[27] it would only take 20 digesters the size of the Lakeview Dairy's digester to emit the equivalent NOx from the Avenal Power Center, yet the Avenal Power Center had to buy offsets and the Lakeview Dairy did not.[28] Moreover, those 25 dairies would have only produced 25 megawatts of electricity (1,059 kilowatts each). Five hundred dairies with digesters emitting 2,500 tons per year of NOx would equal approximately 25 Avenal Power Centers *with no offsets*. This example and analysis also applies with equal force to emissions of VOC, SOx, and PM2.5. Yet the Proposed Strategy neither analyzes nor mitigates this huge impact.

Such analysis is reasonable, given the report prepared in 2015 for the Board on such impacts.[29] This report studied the effects of burning biogas and found that internal combustion engines result in criteria pollutant increases, but the environmental analysis here does not provide that analysis or propose mitigation for the impacts of combustion of methane in IC engines other than referring to the District's permitting authority. As demonstrated above, that permitting authority yields massive cumulative air pollution with no offsets required. Further, the Proposed Strategy and the Environmental Analysis (Appendix C) fails to consider the health impacts on disadvantaged communities or environmental justice impacts of an anaerobic digester strategy. As a whole, the Proposed Strategy and the Environmental Analysis fail to perform a meaningful assessment of the impacts of anaerobic digesters.

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[23] Assessment of the Emissions and Energy Impacts of Biomass and Biogas Use in California (2015) ("Biogas Impact Assessment"), attached as Exhibit 11.

[24] *See, e.g.*, Notice of Preliminary Decision – Authority to Construct, Lakeview Dairy Biogas at 7, attached as Exhibit 12.

[25] *Id*. at 1, 20.

[26] Proposed Strategy at 66.

[27] Notice of Final Determination of Compliance, Avenal Power Center at 3, 27, attached as Exhibit 13.

[28] *Id.* at 38.

[29] Assessment of the Emissions and Energy Impacts of Biomass and Biogas Use in California (2015).

Conclusion.

Reducing methane emissions to achieve immediate methane reductions requires a paradigm shift in California milk production from highly polluting, confined industrialized factory systems to high animal welfare, environmentally beneficial, pasture-based systems that achieve multiple co-benefits. The Board should not allow such a large component of the total statewide GHG inventory to escape mandatory controls, especially when the dairy industry has thus far failed to reduce emissions voluntarily. To the extent that the State Board uses financial incentives to achieve methane reductions (e.g. the Greenhouse Gas Reduction Fund), such incentives should be directed towards pasture-based systems that reduce methane emissions, reduce corn silage emissions, and act as a carbon sink rather than to subsidize the use of polluting anaerobic digesters in the San Joaquin Valley and the South Coast air basins. Thank you for your work to date and we look forward to working with you and other Board staff to ensure significant, equitable methane reductions from California dairies.

Sincerely,

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Center on Race, Poverty & the Environment

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Leadership Counsel for Justice and Accountability

Tom Frantz
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Amy Vanderwarker
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Woody Hastings
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Central California Asthma Collaborative
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Dolores Weller
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Diana Vazquez
Sierra Club California

Danielle Diamond
Socially Responsible Agricultural Project

Thomas Helme
Valley Improvement Projects

Exhibit 1

LAO 75 YEARS OF SERVICE

California Economy & Taxes

All Articles

2014 GDP: California Ranks 7th or 8th in the World

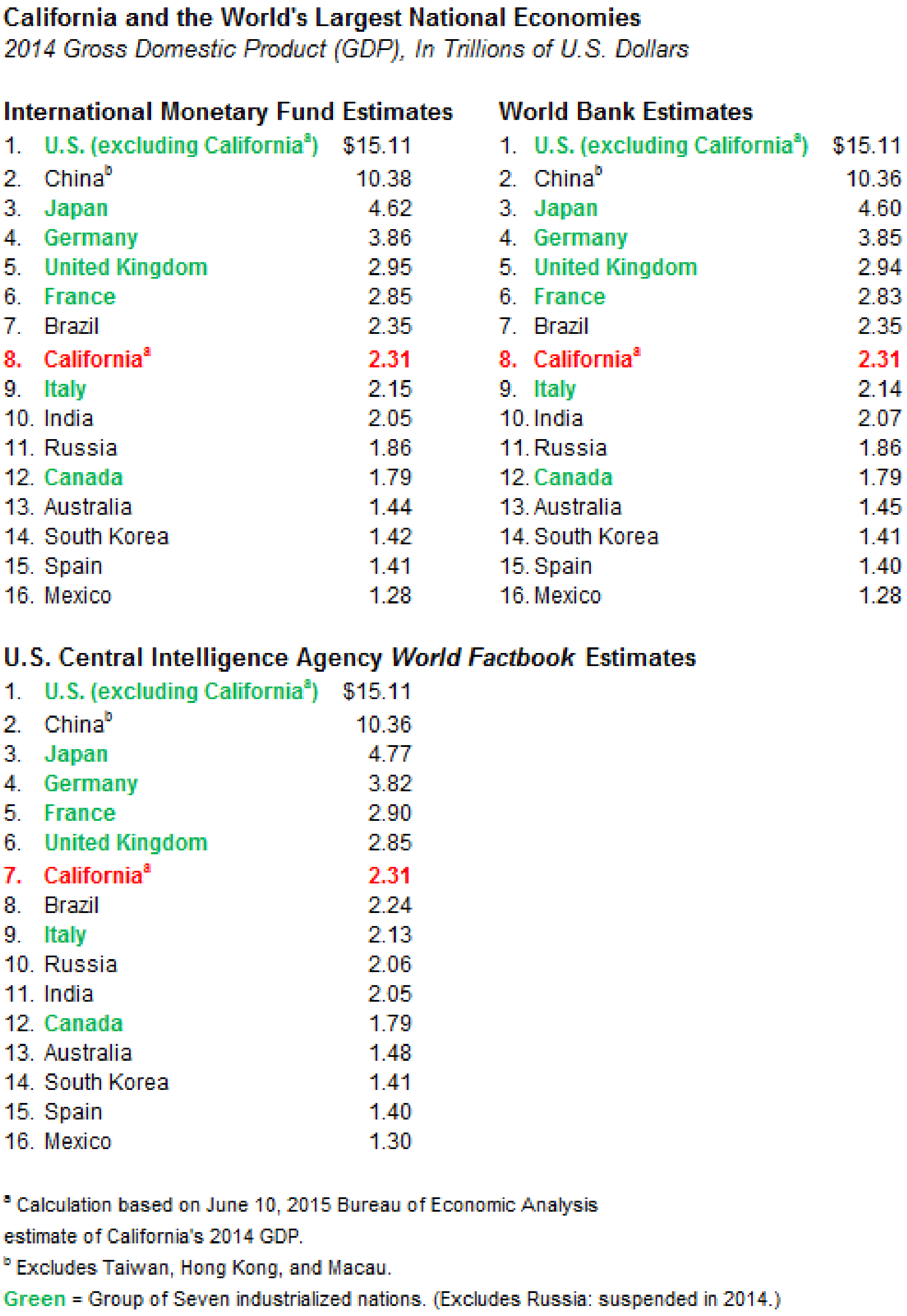
July 1, 2015

Jason Sisney Justin Garosi

On June 10, the U.S. Bureau of Economic Analysis released its preliminary estimates of state gross domestic product (GDP) for 2014, as we described in a blog post last week. California's 2014 GDP—the value of all goods and services produced here—was estimated at $2.31 trillion. In this blog post, we discuss one of the most common questions we are asked—how California's economy compares with that of major countries around the world—based on the preliminary 2014 GDP data.

Traditional GDP Ranking—U.S. Dollar Comparison

California Was the 7th or 8th Largest Economy in World in 2014, Based on Traditional Measure. There are different estimates of countries' GDP. Based on three estimates now available, the 2014 GDP of California ranked either as the 7th or 8th largest—based on international GDP estimates converted to U.S. dollars. The figure below shows how California ranks based on estimates from the International Monetary Fund (IMF), the World Bank, and the U.S. Central Intelligence Agency (CIA) *World Factbook* publication. This exercise essentially treats California as if it were a separate nation-state. Because the difference between California and Brazil is very small in the IMF and World Bank data, it is possible that later revisions could result in California rising to #7 on these lists as well. (The state Department of Finance [DOF] shows the GDP comparison on its website using IMF data.)



California and the World's Largest National Economies

2014 Gross Domestic Product (GDP), In Trillions of U.S. Dollars

International Monetary Fund Estimates

1.	U.S. (excluding California[a])	$15.11
2.	China[b]	10.38
3.	Japan	4.62
4.	Germany	3.86
5.	United Kingdom	2.95
6.	France	2.85
7.	Brazil	2.35
8.	California[a]	2.31
9.	Italy	2.15
10.	India	2.05
11.	Russia	1.86
12.	Canada	1.79
13.	Australia	1.44
14.	South Korea	1.42
15.	Spain	1.41
16.	Mexico	1.28

World Bank Estimates

1.	U.S. (excluding California[a])	$15.11
2.	China[b]	10.36
3.	Japan	4.60
4.	Germany	3.85
5.	United Kingdom	2.94
6.	France	2.83
7.	Brazil	2.35
8.	California[a]	2.31
9.	Italy	2.14
10.	India	2.07
11.	Russia	1.86
12.	Canada	1.79
13.	Australia	1.45
14.	South Korea	1.41
15.	Spain	1.40
16.	Mexico	1.28

U.S. Central Intelligence Agency *World Factbook* Estimates

1.	U.S. (excluding California[a])	$15.11
2.	China[b]	10.36
3.	Japan	4.77
4.	Germany	3.82
5.	France	2.90
6.	United Kingdom	2.85
7.	California[a]	2.31
8.	Brazil	2.24
9.	Italy	2.13
10.	Russia	2.06
11.	India	2.05
12.	Canada	1.79
13.	Australia	1.48
14.	South Korea	1.41
15.	Spain	1.40
16.	Mexico	1.30

[a] Calculation based on June 10, 2015 Bureau of Economic Analysis estimate of California's 2014 GDP.

[b] Excludes Taiwan, Hong Kong, and Macau.

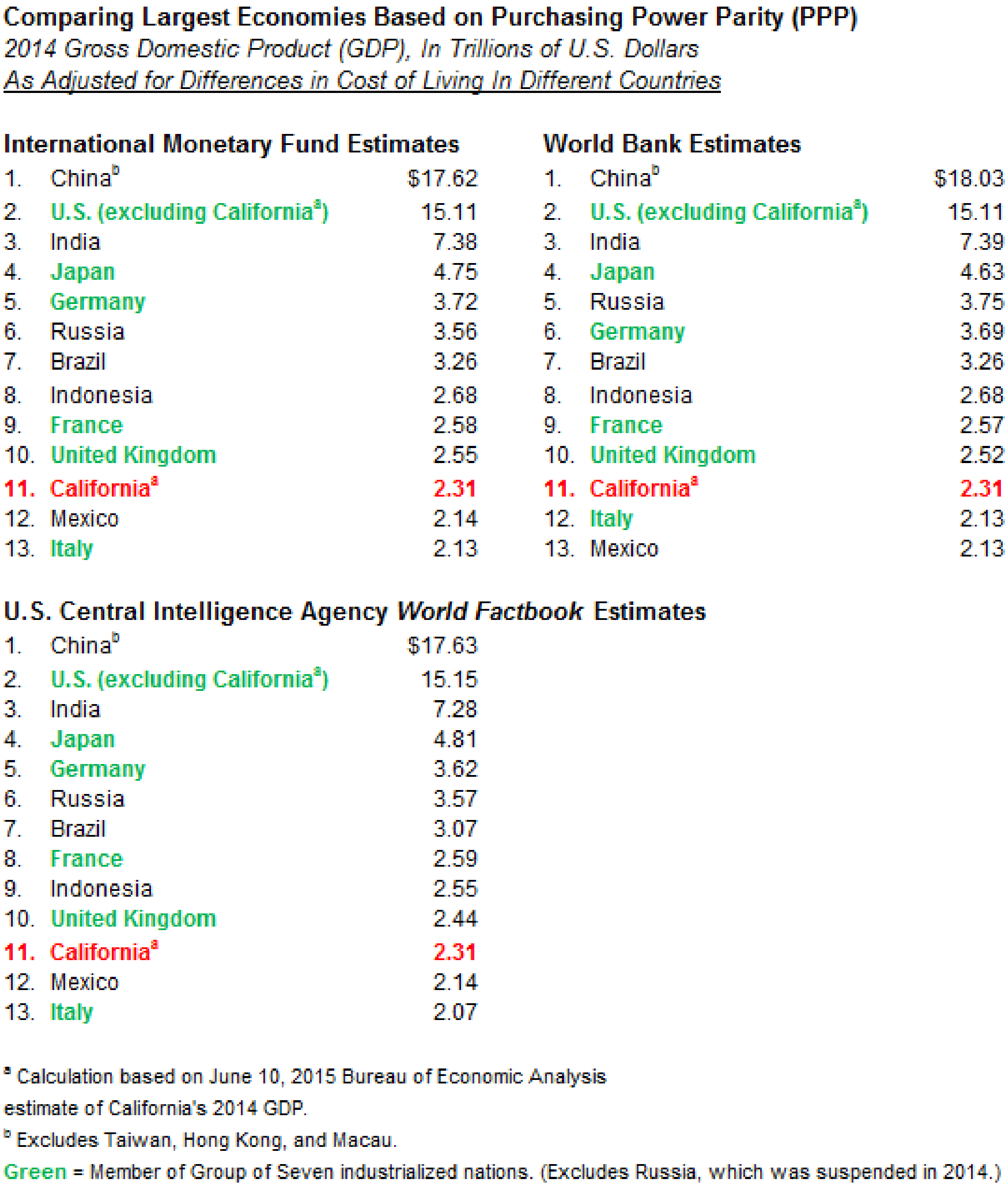
Green = Group of Seven industrialized nations. (Excludes Russia: suspended in 2014.)

As shown above, California's economy is of a size that would justify its inclusion in the Group of Seven (or Eight) industrialized nations, were it independent. This is because California's economy is larger than that of two "G7" members: Italy and Canada. The international estimates above convert GDP in countries' home currencies to dollars based on exchange rates that prevailed in 2014. As such, changes in currency exchange rates can affect these rankings noticeably from year to year.

Changes Since 2013. There has been little change in California's GDP ranking in 2014, based on the estimates available to date. In our blog post on GDP rankings late last year, we highlighted the World Bank's GDP data, which would have ranked California 8th at the time. We also noted that, using CIA or IMF data, California would have ranked 7th or 8th, respectively, for 2013.

Alternative GDP Rankings

Adjusted for Cost of Living, California's Economy Could Be Viewed as Ranking #11. An alternative international GDP comparison uses purchasing power parity (PPP) instead of exchange rates to attempt to adjust for differences in living costs across countries. Using PPP, California's economy—adjusted for cost of living—can be viewed as ranking eleventh in the world, as shown below.



Comparing Largest Economies Based on Purchasing Power Parity (PPP)
2014 Gross Domestic Product (GDP), In Trillions of U.S. Dollars
As Adjusted for Differences in Cost of Living In Different Countries

International Monetary Fund Estimates

1.	China[b]	$17.62
2.	U.S. (excluding California[a])	15.11
3.	India	7.38
4.	Japan	4.75
5.	Germany	3.72
6.	Russia	3.56
7.	Brazil	3.26
8.	Indonesia	2.68
9.	France	2.58
10.	United Kingdom	2.55
11.	**California[a]**	**2.31**
12.	Mexico	2.14
13.	Italy	2.13

World Bank Estimates

1.	China[b]	$18.03
2.	U.S. (excluding California[a])	15.11
3.	India	7.39
4.	Japan	4.63
5.	Russia	3.75
6.	Germany	3.69
7.	Brazil	3.26
8.	Indonesia	2.68
9.	France	2.57
10.	United Kingdom	2.52
11.	**California[a]**	**2.31**
12.	Italy	2.13
13.	Mexico	2.13

U.S. Central Intelligence Agency *World Factbook* Estimates

1.	China[b]	$17.63
2.	U.S. (excluding California[a])	15.15
3.	India	7.28
4.	Japan	4.81
5.	Germany	3.62
6.	Russia	3.57
7.	Brazil	3.07
8.	France	2.59
9.	Indonesia	2.55
10.	United Kingdom	2.44
11.	**California[a]**	**2.31**
12.	Mexico	2.14
13.	Italy	2.07

[a] Calculation based on June 10, 2015 Bureau of Economic Analysis estimate of California's 2014 GDP.

[b] Excludes Taiwan, Hong Kong, and Macau.

Green = Member of Group of Seven industrialized nations. (Excludes Russia, which was suspended in 2014.)

This dataset essentially assumes that the cost of living is uniform across the entire U.S. California's cost of living is higher than the U.S. in several key categories, such that a more refined PPP estimate, if it were available, might adjust California's GDP down somewhat, compared to the data in the table above.

Using the PPP measure, China's economy is now larger than that of the entire U.S. As the CIA *World Factbook* explains, "because China's exchange rate is determine[d] by fiat, rather than by market forces, the official exchange rate measure of GDP [that is, the traditional measure described earlier in this post] is not an accurate measure of China's input," as it "substantially understate's the actual level of China's output vis-a-vis the rest of the world." The *World Factbook* opines that the GDP measurement under the PPP method "provides the best measure for comparing output across countries," including China. Both India and Indonesia's economies also are larger than California's by this measure due to their lower costs of living. (Wikipedia has useful entries that list various international GDP rankings, including PPP rankings.)

Per Capita GDP: California Ranks Very Highly Internationally. As shown below, California, if it were a separate country from the rest of the U.S., could be viewed as ranking #7 in GDP per capita (per person), according to IMF data. (Several other U.S. states with higher GDP per capita, including some with substantial oil and gas production, are not shown in this ranking list but are mentioned in its footnotes.)

Per Capita Gross Domestic Product (GDP)
Using 2014 Gross Domestic Product (GDP), In U.S. Dollars

International Monetary Fund Estimates

1.	Luxembourg	$111,716
2.	Norway	97,013
3.	Qatar	93,965
4.	Switzerland	87,475
5.	Australia	61,219
6.	Denmark	60,564
7.	**California**	**59,574**
8.	Sweden	58,491
9.	San Marino	56,820
10.	Singapore	56,319
11.	U.S. (including California)	54,597

Note: California is the only state shown separately in the list above. Eleven U.S. states, plus the District of Columbia, have higher per capita GDP levels than California, as of 2014.

These other U.S. jurisdictions include the District (around $175,000) and the highest-ranked state, Alaska (around $77,000). Following Alaska were Wyoming, North Dakota, New York, Connecticut, Massachusetts, Delaware, New Jersey, Texas, Washington, Nebraska, and then California. Per capita GDP estimates for states were derived by converting Bureau of Economic Analysis real per capita GDP estimates to 2014 dollars based on the ratio of 2014 current-dollar GDP for each state to the 2009 chained-dollar real GDP for that state.

GDP per capita rankings can vary based on which countries are included. For example, the IMF data above excludes some small territories (Monaco, Liechtenstein, Macau, and Bermuda) that likely would outrank California. If included, Jersey, the Falkland Islands, and the Cayman Islands could rank lower than California, but above the U.S. as a whole.

Comparisons to Other U.S. States

#1 California GDP 40% Bigger Than #2 Texas. With an estimated $2.31 trillion of GDP in 2014, California has the largest state-level economy in the U.S. due largely to its population, which ranks 1st among U.S. states. Texas ranks 2nd at $1.65 trillion. This means that California's 2014 GDP was 40% bigger than that of Texas. In 2014, Texas GDP grew at 5.2% (2nd highest growth rate among states), versus California's 2.8% growth rate (9th highest growth rate). Texas was one of the oil and gas states that had significant GDP growth in 2014. Because the price of oil and its production have declined, GDP growth in Texas and some other states may be significantly less in 2015.

(This post was edited on July 2 primarily to reflect newly released World Bank data.)

GDP International State Comparisons

Legislative Analyst's Office | The California Legislature's Nonpartisan Fiscal and Policy Advisor
925 L Street, Suite 1000 Sacramento, CA 95814 | (916) 445-4656

Exhibit 2

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CDFA Home > California Agricultural Production Statistics

cdfa
CALIFORNIA DEPARTMENT OF FOOD & AGRICULTURE

CALIFORNIA AGRICULTURAL PRODUCTION STATISTICS

2014 Crop Year Report

In 2014, the most recent year for which a full crop-year **report** is available, California's 76,400 farms and ranches received approximately $54 billion for their output. This represents an increase of 5.1 percent over 2013. California is the leading US state in cash farm receipts with combined commodities representing nearly 13 percent of the US total.

California's Agricultural Exports

In 2014, California's agricultural **exports** amounted to $21.59 billion in value. As a percentage of the total US agricultural exports for 2014, California's share represents 14.3 percent—slightly less than the 14.9 percent share reported the previous year. California's top 10 export destinations—European Union, Canada, China/Hong Kong, Japan, Mexico, Korea, India, United Arab Emirates, Turkey, and Vietnam—accounted for 69 percent of the 2014 export value. For 2014, India showed the largest growth in total export value compared to the previous year at 19.1 percent.

California's agricultural abundance includes more than 400 commodities. Over a third of the country's vegetables and two-thirds of the country's fruits and nuts are grown in California. The dairy industry, California's leading commodity in cash receipts, generated a record $9.36 billion for milk production in 2014, up 23 percent from 2013 and 22 percent above the record year of 2011.

California's top—ten valued commodities for 2014 are:

Milk — $9.4 billion
Almonds — $5.9 billion
Grapes — $5.2 billion
Cattle, Calves — $3.7 billion
Strawberries — $2.5 billion
Lettuce — $2 billion
Walnuts — $1.8 billion
Tomatoes — $1.6 billion
Pistachios — $1.6 billion
Hay — $1.3 billion

Statistics

California agricultural statistics derive primarily from the United States Department of Agriculture/National Agricultural Statistics Services (USDA/NASS) reports. The California Department of Food and Agriculture also publishes statistics related to California dairy production and, in cooperation with the University of California at Davis, statistics for California agricultural exports. For most timely research into California dairy statistics, please see our dairy pages under Division of Marketing Services. Please see also links in the right hand column for USDA National Agricultural Statistics and Economic Research Service reporting. For county-level reporting please see the CDFA **County Liaison site**.

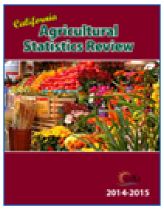
Annual crop year reports have been reproduced below for your convenience. Export reports are typically published within the corresponding crop year report. While data is made available throughout the year, crop year and export reports are published typically about one year following the given crop year.

SELECT COVERS BELOW TO VIEW NASS/CDFA AGRICULTURAL RESOURCE REPORTS:

MORE RESOURCES

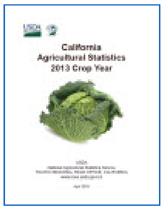
- CA County Ag Commissioners' Reports (NASS)
- CA County Crop Reports
- CA Crop Progress & Condition (NASS)
- CA Crop Year Reports (2014-1993 CDFA & USDA NASS)
- Cal Ag Export Data (UC Davis, Ag Issues Center)
- NASS/RSS: Cal News Feed
- USDA Census of Agriculture (2012)
- USDA/ERS Commodity Data Available by Query by State
- USDA/NASS Cal Office
- USDA/NASS Cal Publications

- Report a Pest App
- Report: Improving Food Access
- California & 2014 Farm Bill
- Strategic Plan for CDFA: 2013-2018
- Planting Seeds: The CDFA Blog
- California Agricultural Vision 2030

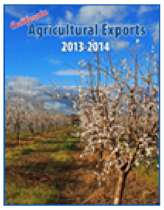


2015
REPORT

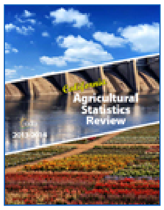
2015
EXPORTS REPORT



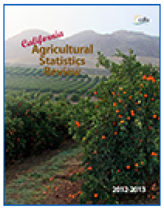
2014 REPORT
(NASS)



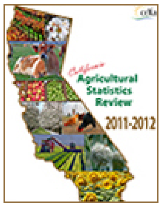
2014
EXPORTS REPORT



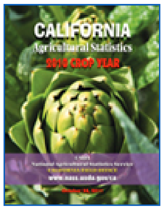
2013
REPORT



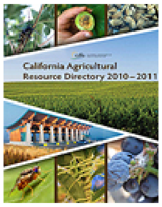
2012 REPORT



2011 REPORT



2010 Report
(NASS)



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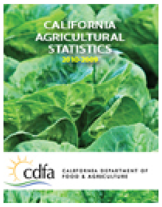
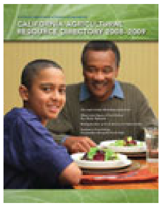
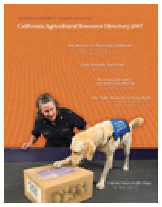


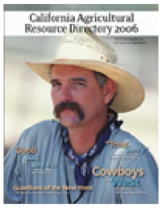
2008 REPORT



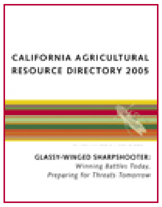
2007 REPORT



2006 REPORT



2005 REPORT



2004 REPORT

CALIFORNIA DEPARTMENT OF FOOD AND AGRICULTURE

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Exhibit 3

California Environmental Protection Agency
Air Resources Board

California Greenhouse Gas Inventory for 2000-2013
— by Category as Defined in the 2008 Scoping Plan

million tonnes of CO2 equivalent - (based upon IPCC Fourth Assessment Report's Global Warming Potentials)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Transportation	176.08	176.38	183.47	183.25	186.68	188.76	188.84	188.96	177.77	171.19	170.27	168.00	167.36	169.02
On Road	162.64	163.12	169.25	168.52	171.30	172.42	172.12	172.15	162.77	158.20	157.22	154.80	153.96	155.24
Passenger Vehicles	126.06	126.69	131.58	130.77	131.73	131.89	131.12	130.45	124.31	122.90	122.25	120.10	119.92	120.23
Heavy Duty Trucks	36.58	36.43	37.67	37.74	39.57	40.53	41.00	41.70	38.45	35.31	34.97	34.70	34.04	35.02
Ships & Commercial Boats	3.50	3.32	3.63	3.80	3.81	4.06	4.11	4.27	4.02	3.66	3.68	3.70	3.88	3.96
Aviation (Intrastate)	4.15	4.07	4.12	4.25	4.50	4.50	4.57	4.98	4.51	4.04	3.85	3.75	3.73	3.88
Rail	1.88	1.89	2.50	2.70	2.91	3.34	3.53	3.17	2.38	1.94	2.33	2.49	2.48	2.48
Off Road [1]	2.63	2.79	2.77	2.84	3.03	3.22	3.32	3.18	2.82	2.25	2.03	2.13	2.23	2.33
Unspecified	1.28	1.19	1.21	1.13	1.13	1.22	1.20	1.22	1.27	1.10	1.16	1.14	1.08	1.13
Industrial	97.87	96.35	97.27	96.08	98.02	96.01	94.13	90.81	91.36	88.79	92.12	91.97	92.52	92.68
Refineries and Hydrogen Production	28.52	29.10	29.25	29.89	29.13	29.80	29.70	29.26	28.47	28.34	30.39	30.12	29.88	29.27
General Fuel Use	20.25	19.09	20.32	16.54	17.07	16.05	16.01	14.81	16.05	15.60	18.03	19.18	19.07	19.01
Natural Gas	16.82	14.62	15.18	11.97	12.80	12.72	12.38	11.56	12.37	11.46	13.46	14.48	14.46	14.38
Other Fuels	3.43	4.46	5.14	4.57	4.27	3.33	3.63	3.25	3.67	4.14	4.57	4.70	4.60	4.63
Oil & Gas Extraction [2]	19.81	20.18	18.91	21.39	21.07	19.74	18.07	18.18	19.43	18.34	17.44	17.37	18.06	19.65
Fuel Use	17.53	17.76	16.51	19.03	19.20	17.91	15.75	15.78	17.03	15.92	15.01	14.91	15.50	16.99
Fugitive Emissions	2.29	2.41	2.40	2.36	1.87	1.83	2.32	2.39	2.40	2.42	2.44	2.46	2.56	2.67
Cement Plants	9.41	9.52	9.62	9.71	9.81	9.91	9.74	9.14	8.63	5.72	5.56	6.14	6.92	7.20
Clinker Production	5.43	5.52	5.60	5.68	5.77	5.85	5.80	5.55	5.28	3.60	3.46	4.08	4.65	4.93
Fuel Use	3.98	4.00	4.01	4.03	4.05	4.06	3.95	3.59	3.34	2.12	2.10	2.06	2.26	2.28
Cogeneration Heat Output	11.73	10.48	10.65	10.59	12.92	12.41	12.16	11.15	10.40	12.55	12.60	11.14	10.81	9.82
Other Fugitive and Process Emissions	8.15	7.99	8.52	7.96	8.02	8.09	8.44	8.26	8.38	8.23	8.10	8.02	7.78	7.73
Pipelines	3.60	3.68	4.30	3.76	3.85	3.88	4.11	4.00	4.13	4.20	4.04	4.03	3.84	3.82
Manufacturing	0.30	0.32	0.26	0.27	0.28	0.28	0.27	0.25	0.24	0.22	0.22	0.24	0.23	0.20
Wastewater Treatment	2.41	2.37	2.39	2.37	2.38	2.40	2.39	2.41	2.38	2.29	2.33	2.32	2.31	2.34
Other	1.85	1.62	1.57	1.56	1.51	1.53	1.67	1.60	1.63	1.52	1.50	1.43	1.40	1.37
Electric Power	104.85	122.00	108.64	112.61	115.20	107.85	104.53	113.93	120.14	101.32	90.30	88.04	95.09	90.45
In-State Generation	58.95	62.98	49.68	48.05	49.15	45.05	49.85	54.12	54.32	53.27	46.70	41.18	51.02	50.46
Natural Gas	50.92	55.46	42.17	40.92	42.40	38.11	43.07	47.12	48.02	46.08	40.59	35.92	45.77	47.04
Other Fuels	6.84	6.36	6.36	5.98	5.59	5.77	5.63	5.85	5.15	5.85	5.01	4.01	4.44	2.49
Fugitive and Process Emissions	1.18	1.16	1.15	1.15	1.16	1.16	1.15	1.16	1.14	1.34	1.10	1.25	0.82	0.92
Imported Electricity	45.90	59.02	58.96	64.56	66.04	62.80	54.68	59.81	65.82	48.04	43.59	46.86	44.07	39.99
Unspecified Imports	14.27	25.42	26.92	32.05	32.92	30.01	27.95	32.73	37.92	14.99	13.45	15.52	17.48	11.53
Specified Imports	31.64	33.59	32.04	32.51	33.13	32.79	26.73	27.08	27.90	33.05	30.14	31.34	26.59	28.46

California Greenhouse Gas Inventory for 2000-2013
— by Category as Defined in the 2008 Scoping Plan

million tonnes of CO2 equivalent - (based upon IPCC Fourth Assessment Report's Global Warming Potentials)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Commercial and Residential	**43.18**	**42.08**	**44.06**	**42.43**	**43.80**	**42.25**	**42.94**	**43.15**	**43.47**	**43.70**	**44.88**	**45.40**	**42.88**	**43.54**
Residential Fuel Use	***29.38***	***28.47***	***28.62***	***28.14***	***29.17***	***27.98***	***28.36***	***28.50***	***28.82***	***28.45***	***29.18***	***29.64***	***27.34***	***28.11***
Natural Gas	27.98	27.38	27.49	26.62	27.33	25.93	26.55	26.68	26.62	26.26	26.99	27.51	25.76	26.52
Other Fuels	1.41	1.09	1.13	1.52	1.84	2.06	1.81	1.82	2.20	2.19	2.20	2.13	1.58	1.59
Commercial Fuel Use	***11.47***	***11.31***	***13.11***	***12.74***	***12.70***	***12.56***	***12.84***	***12.83***	***12.94***	***12.99***	***13.42***	***13.61***	***13.41***	***13.31***
Natural Gas	10.05	10.08	11.88	11.36	11.14	10.92	11.60	11.47	11.14	11.00	11.17	11.33	11.24	11.28
Other Fuels	1.42	1.22	1.23	1.38	1.56	1.64	1.24	1.36	1.80	1.98	2.25	2.28	2.16	2.03
Commercial Cogeneration Heat Output	***1.09***	***1.05***	***1.06***	***0.26***	***0.62***	***0.40***	***0.42***	***0.49***	***0.37***	***0.92***	***0.92***	***0.78***	***0.76***	***0.72***
Other Commercial and Residential	***1.24***	***1.26***	***1.27***	***1.29***	***1.30***	***1.31***	***1.32***	***1.33***	***1.34***	***1.35***	***1.36***	***1.37***	***1.38***	***1.39***
Agriculture	**32.10**	**32.57**	**34.07**	**34.63**	**34.34**	**35.08**	**36.30**	**36.04**	**36.48**	**34.86**	**34.50**	**35.68**	**36.43**	**36.21**
Livestock	***19.66***	***20.44***	***21.06***	***21.63***	***21.06***	***21.81***	***22.22***	***23.73***	***24.09***	***23.88***	***23.35***	***23.38***	***23.92***	***23.92***
Enteric Fermentation (Digestive Process)	10.26	10.45	10.74	10.89	10.78	11.14	11.24	11.93	11.89	11.71	11.51	11.49	11.78	11.78
Manure Management	9.40	10.00	10.32	10.75	10.28	10.67	10.98	11.80	12.20	12.17	11.84	11.89	12.14	12.14
Crop Growing & Harvesting	***8.63***	***8.31***	***8.63***	***8.63***	***8.76***	***8.65***	***8.76***	***8.51***	***8.48***	***8.33***	***8.35***	***8.65***	***8.71***	***8.46***
Fertilizers	6.59	6.55	6.66	6.70	6.58	6.63	6.57	6.50	6.55	6.33	6.36	6.59	6.63	6.45
Soil Preparation and Disturbances	1.96	1.69	1.91	1.86	2.11	1.95	2.12	1.94	1.86	1.92	1.91	1.98	1.99	1.93
Crop Residue Burning	0.08	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
General Fuel Use	***3.81***	***3.82***	***4.38***	***4.37***	***4.52***	***4.62***	***5.32***	***3.79***	***3.91***	***2.65***	***2.81***	***3.66***	***3.80***	***3.83***
Diesel	2.52	2.69	3.04	3.10	3.17	3.40	3.86	2.68	2.99	1.78	1.98	2.37	2.47	2.51
Natural Gas	0.98	0.75	0.94	0.85	0.82	0.70	0.88	0.79	0.75	0.69	0.65	0.66	0.70	0.69
Gasoline	0.31	0.38	0.41	0.41	0.52	0.52	0.57	0.32	0.17	0.17	0.17	0.63	0.62	0.63
Other Fuels	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High GWP	**7.24**	**7.55**	**8.06**	**8.79**	**9.57**	**10.34**	**10.93**	**11.60**	**12.61**	**13.83**	**15.49**	**16.78**	**17.77**	**18.50**
Ozone Depleting Substance (ODS) Substitutes	***6.35***	***6.82***	***7.37***	***8.10***	***8.95***	***9.75***	***10.33***	***11.04***	***12.05***	***13.38***	***15.01***	***16.11***	***17.16***	***18.02***
Electricity Grid SF6 Losses [4]	***0.33***	***0.32***	***0.30***	***0.29***	***0.30***	***0.29***	***0.28***	***0.26***	***0.27***	***0.26***	***0.24***	***0.24***	***0.23***	***0.19***
Semiconductor Manufacturing [3]	***0.57***	***0.41***	***0.38***	***0.39***	***0.32***	***0.30***	***0.32***	***0.30***	***0.30***	***0.19***	***0.24***	***0.43***	***0.37***	***0.30***
Recycling and Waste	**7.45**	**7.62**	**7.59**	**7.73**	**7.74**	**7.93**	**8.03**	**8.10**	**8.27**	**8.39**	**8.46**	**8.75**	**8.77**	**8.87**
Landfills [3]	***7.21***	***7.36***	***7.30***	***7.42***	***7.40***	***7.58***	***7.65***	***7.70***	***7.84***	***7.94***	***7.99***	***8.25***	***8.25***	***8.32***
Composting	***0.24***	***0.26***	***0.29***	***0.31***	***0.33***	***0.36***	***0.38***	***0.40***	***0.43***	***0.45***	***0.47***	***0.50***	***0.52***	***0.54***
Total Emissions	***468.77***	***484.56***	***483.16***	***485.52***	***495.34***	***488.23***	***485.69***	***492.60***	***490.10***	***462.07***	***456.02***	***454.61***	***460.82***	***459.28***

[1] Includes equipment used in construction, mining, oil drilling, industrial and airport ground operations. [2] Reflects emissions from combustion of natural gas, diesel, and lease fuel plus fugitive emissions. [3] These categories are listed in the Industrial sector of ARB's GHG Emission Inventory sectors. [4] This category is listed in the Electric Power sector of ARB's GHG Emission Inventory sectors

Exhibit 4

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Emissions of organic carbon and methane from petroleum and dairy operations in California's San Joaquin Valley

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Abstract. Petroleum and dairy operations are prominent sources of gas-phase organic compounds in California's San Joaquin Valley. It is essential to understand the emissions and air quality impacts of these relatively understudied sources, especially for oil/gas operations in light of increasing US production. Ground site measurements in Bakersfield and regional aircraft measurements of reactive gas-phase organic compounds and methane were part of the CalNex (California Research at the Nexus of Air Quality and Climate Change) project to determine the sources contributing to regional gas-phase organic carbon emissions. Using a combination of near-source and downwind data, we assess the composition and magnitude of emissions, and provide average source profiles. To examine the spatial distribution of emissions in the San Joaquin Valley, we developed a statistical modeling method using ground-based data and the FLEXPART-WRF transport and meteorological model. We present evidence for large sources of paraffinic hydrocarbons from petroleum operations and oxygenated compounds from dairy (and other cattle) operations. In addition to the small straight-chain alkanes typically associated with petroleum operations, we observed a wide range of branched and cyclic alkanes, most of which have limited previous in situ measurements or characterization in petroleum operation emissions. Observed dairy emissions were dominated by ethanol, methanol, acetic acid, and methane. Dairy operations were responsible for the vast majority of methane emissions in the San Joaquin Valley; observations of methane were well correlated with non-vehicular ethanol, and multiple assessments of the spatial distribution of emissions in the San Joaquin Valley highlight the dominance of dairy operations for methane emissions. The petroleum operations source profile was developed using the composition of non-methane hydrocarbons in unrefined natural gas associated with crude oil. The observed source profile is consistent with fugitive emissions of condensate during storage or processing of associated gas following extraction and methane separation. Aircraft observations of concentration hotspots near oil wells and dairies are consistent with the statistical source footprint determined via our FLEXPART-WRF-based modeling method and ground-based data. We quantitatively compared our observations at Bakersfield to the California Air Resources Board emission inventory and find consistency for relative emission rates of reactive organic gases between the aforementioned sources and motor vehicles in the region. We estimate that petroleum and dairy operations each comprised 22 % of anthropogenic non-methane organic carbon at Bakersfield and were each responsible for 8–13 % of potential precursors to ozone. Yet, their direct impacts as potential secondary organic aerosol (SOA) precursors were estimated to be minor for the source profiles observed in the San Joaquin Valley.

1 Introduction

California's San Joaquin Valley contains a large density of dairy farms and is an important region for oil and natural gas production in the United States. Both sources are prominent in the California Air Resources Board (CARB) emission inventory of reactive organic gases (ROG) in the San Joaquin Valley (California Air Resources Board, 2010). Recent work has described large emissions and impacts from new oil/gas operations with increased US production (Petron et al., 2012; Gilman et al., 2013; Carter and Seinfeld, 2012; Schnell et al., 2009; Kemball-Cook et al., 2010; Pacsi et al., 2013). Petroleum operations include extraction, storage, transport, and processing; all of which can have varying degrees of fugitive emissions of methane and other gas-phase organic carbon, such as volatile organic compounds (VOCs) (Leuchner and Rappengluck, 2010; Buzcu and Fraser, 2006, Katzenstein et al., 2003; Petron et al., 2012; Gilman et al., 2013). Crude oil and unrefined natural gas are composed of a suite of organic compounds that span a range of vapor pressures, and are either produced by thermogenic or biogenic processes in the reservoirs (Lillis et al., 2007; Ryerson et al., 2011). Thermogenic gas is geochemically produced via the cracking of larger compounds in oil and can either be termed associated or non-associated depending on the presence of oil (Lillis et al., 2007). The vast majority of wells in the San Joaquin Valley are oil wells and most have associated gas, also known as wet thermogenic gas (Lillis et al., 2007). Thermogenic wet gas is predominately found in oil wells and contains substantial amounts of non-methane hydrocarbons ranging from 3 to 40 % C_2 and greater content (e.g., Table 1) (Lillis et al., 2007). The San Joaquin Valley has historically been an active region for oil/gas production. In 2010, crude oil production in Kern County, located at the southern end of the San Joaquin Valley, was 450 000 barrels day^{-1}, which represents 69 % of production within California and 8 % of national production (US EIA, 2010; Sheridan, 2006).

There have been several studies on fugitive emissions from oil and gas operations, including emissions from isolated facilities at oil or gas fields, extraction facilities using advanced recovery methods (i.e., hydraulic fracturing), and urban areas with industrial storage and processing facilities (Leuchner and Rappengluck, 2010; Buzcu and Fraser, 2006; Katzenstein et al., 2003; Petron et al., 2012; Gilman et al., 2013). These studies all provide important advances in the characterization of emissions from petroleum operations, but there is considerable variability between regions due to differences in reservoirs and production methods. The specific equipment/processes, state/county regulations, and regional composition of crude oil and natural gas are critical for determining the potential emission pathways and composition of fugitive emissions. So, regional studies remain important to effectively characterize petroleum operation sources.

Previous research on dairy farms and livestock operations has reported emissions of methane, alcohols, carbonyls, esters, acids, and other organic hydrocarbons. Among these, emissions are dominated by methane, methanol, ethanol, and acetic acid (Alanis et al., 2010; Chung et al., 2010; Hafner et al., 2013; Howard et al., 2010a, b; Malkina et al., 2011; Sun et al., 2008; Shaw et al., 2007). Howard et al. (2010b) recently concluded that emissions from dairy operations are dominant contributors to ozone production in California's Central Valley (comprised of the San Joaquin Valley and the Sacramento Valley to the north), but modeling studies suggest a larger role for VOC emissions from motor vehicles (Hu et al., 2012). Methane and oxygenated organic compounds are emitted via several pathways and sources, all co-located at dairies (and their farms). Silage processing/fermentation, bovine enteric fermentation, and animal waste are among the most dominant sources (Alanis et al., 2010; Chung et al., 2010; Hafner et al., 2013; Malkina et al., 2011; Sun et al., 2008; Shaw et al., 2007). The composition of emissions from each of these sources is different and varies widely depending on factors such as feed composition. The animal feed, also known as total mixed rations, is typically comprised of corn and other grains (i.e., silage), with corn being the abundant type in the US (Hafner et al., 2013). The silage is fermented on-site in large piles and mixed with various adjuncts

Table 1. Unrefined natural gas composition for thermogenic wet wells in the San Joaquin Valley from USGS samples ($N = 49$ wells) (Lillis et al., 2007).

	wtC %	Std. Dev.	k_{OH}	MIR
methane	82.3	9.2	0.0064	0.014
ethane	5.33	3.46	0.248	0.28
propane	4.42	3.50	1.09	0.49
isobutane	0.920	0.837	2.12	1.23
n-butane	1.55	2.17	2.36	1.15
isopentane	0.223	0.401	3.6	1.45
n-pentane	0.273	0.405	3.80	1.31
neopentane	0.061	0.182	0.825	0.67
n-hexane	0.105	0.108	5.20	1.24
n-heptane	0.049	0.041	6.76	1.07

Notes:
– k_{OH} is in $\mathrm{cm}^3\ \mathrm{s}^{-1}$ $\mathrm{molecules}^{-1} \times 10^{12}$ from Atkinson and Arey, (2003).
– MIR is in $\mathrm{gO}_3\ \mathrm{g}^{-1}$ from Carter 2007.
– The observed source profile for petroleum gas emissions at the Bakersfield site is well represented by the composition of non-methane organic carbon shown here.

(e.g., almond shells, fruit, fat). The site-by-site heterogeneity in feed composition and the processing of both animal feed and waste leads to variability in the source profile and emission ratios of organic compounds from dairy operations. This work aims to reduce this uncertainty by estimating the average source profile for dairy operation emissions in the San Joaquin Valley.

The objectives of this work are to examine the magnitude, chemical composition, and spatial distribution of organic carbon emissions from petroleum and dairy operations in the San Joaquin Valley. This is accomplished using multiple gas-phase organic carbon data sets from stationary ground sites and aircraft platforms. Our approach includes the development of a method to assess the spatial distribution of sources (i.e., a statistical source footprint) via ground site measurements and meteorological modeling. We examine the relative abundance of emissions from petroleum and dairy operations against other prominent anthropogenic sources in the San Joaquin Valley, and evaluate their potential to impact air quality. We also provide a quantitative assessment of petroleum and dairy operations emissions relative to motor vehicle emissions in the CARB emission inventory.

2 Materials and methods

2.1 Measurement sites and instrumentation

Gas-phase organics and other gases were measured 18 May–30 June 2010 in Bakersfield, CA during the CalNex (California Research at the Nexus of Air Quality and Climate Change) project. The ground supersite (35.3463° N, 118.9654° W) was located in southeast Bakersfield, a city in the southern San Joaquin Valley. With the exception of gas-sampling canisters and ion chromatography to measure acids, measurements were made from the top of an 18 m tower. Measurements of a few light VOCs are included from canister measurements at ground level to further characterize the observed sources. Canisters were taken as 3 h averages in the morning (05:00–08:00 PST) and analyzed via US Environmental Protection Agency (EPA) methods for an array of organic compounds (Klouda et al., 2002). Supporting methane measurements were made using integrated cavity output spectroscopy (Los Gatos Research, Fast Greenhouse Gas Analyzer) with 1 min time resolution. Acetic acid and other acids were measured using both chemical ionization mass spectrometry (CIMS) and ambient ion monitor–ion chromatography (AIM-IC). These two instruments were located at different heights on the sampling tower in Bakersfield and had different measurement frequencies. With both sets of data averaged to hourly resolution, the acetic acid data were well correlated to each other ($r = 0.84$) with a slope near unity. Details on their sampling and measurement methods have been published previously (Crounse et al., 2006; Markovic et al., 2012).

As part of the CalNex project, measurements were also made from the National Oceanic and Atmospheric Administration (NOAA) WD-P3 research aircraft. VOC canister samples were collected on the aircraft and analyzed offline (Barletta et al., 2013). High time resolution data on selected organic compounds and methane were collected on the aircraft using proton transfer reaction mass spectrometry (PTR-MS) and a Picarro flight-ready greenhouse gas analyzer (model 1301 m), respectively (de Gouw and Warneke, 2007; Peischl et al., 2012). High-resolution data were averaged to 1 min intervals and select flights in the Central Valley were used to evaluate the spatial distribution of methane concentrations (flight dates: 5/7, 5/11, 5/12, 6/14, 6/16, 6/18, 2010).

2.2 Source apportionment methods

2.2.1 Petroleum operations

Using six weeks of in situ VOC data from the Bakersfield ground site, we assessed emissions from petroleum operations during spring and summer 2010. Contributions to observed VOC concentrations at the site from petroleum operations were determined (along with other motor vehicle-related sources) using a source receptor model with chemical mass balancing and effective variance weighting focused on hydrocarbon emissions from petroleum-related sources (Gentner et al., 2012). The model used 10 compounds emitted from the sources of interest (petroleum operations, non-tailpipe gasoline emissions, gasoline exhaust, and diesel exhaust) along with reliable information on the fractional composition of the 10 compounds from each of the sources (i.e., source profiles). The 10 compounds used were dependent species, but the model also calculated the predicted concentrations of all the independent compounds not included in the model, but emitted by the petroleum-related sources and measured at the site.

The compounds used in the over-constrained (i.e., more tracer compounds than sources) source receptor model were propane, n-butane, n-pentane, isopentane, m/p-xylene, o-xylene, isooctane, n-nonane, n-undecane, and n-dodecane to model motor vehicle and petroleum operation sources. Due to high background concentrations, measurements of propane and n-butane were corrected by local background values of 500 and 100 pptv, respectively. The 10 tracer compounds were carefully selected because together they captured the dynamics of all four petroleum-related sources. The atmospheric lifetimes of the more reactive species did not bias the model since the vast majority of contributions (i.e., emissions) were within short transport times to the site. The petroleum operations source had the longest transport times (up to 6 h) from source to field site, which did not present a problem because that source was represented and modeled by the least reactive species that had negligible degradation during transport. Extensive details on these methods and model validation are described in detail in Gentner et al. (2012).

A priori source profile information for the model was constructed using US Geological Survey data on associated thermogenic natural gas composition from wells in the San Joaquin Valley (Table 1) (Lillis et al., 2007) and regional gasoline/diesel fuel composition data (Gentner et al., 2012). There was substantial variability between wells and sampling methods in the data compiled by the USGS, so standard deviations for the petroleum operations source profile were ±80–300 %. Due to this large uncertainty, we represented the uncertainty for all the source profiles in the model by standard errors (similar to the US EPA CMB 8.2 model), defined as the standard deviation divided by the square root of the sample size ($N = 49$).

The source receptor model effectively modeled the compounds included in the initial petroleum operations source profile (Table 1), but there were an array of hydrocarbons (not among the compounds used in the model) that episodically exceed predicted concentrations based on emissions from motor vehicles. Many of the excess hydrocarbon concentrations were well correlated with each other and the petroleum operations source factor, likely indicating emissions from the petroleum operations source. Emissions of additional compounds from petroleum operations (not present in the initial limited petroleum gas profile) are derived from the residual mass that is well correlated with the petroleum operations source. The residuals, or excess concentrations beyond contributions from motor vehicles, were filtered for values that exceeded the uncertainties of model calculations, which are determined in part by the 10–20 % variability in gasoline and diesel fuel.

Similarly, we calculated the expected ethanol emissions from gasoline vehicles for hourly data. Taking the difference between these predicted concentrations and total observed ethanol results in non-vehicular ethanol concentrations that must be attributed to other ethanol sources, but were not correlated with the petroleum operations source.

2.2.2 Dairy operations

A reliable source profile for dairy operations in the San Joaquin Valley was not available in the literature for all the compounds of interest in this study, so the source profile was established using a mix of aircraft and ground measurements. The emission ratios of organic compounds to methane were calculated using flight and ground data for compounds that had evident, quantifiable emissions from dairy operations to construct the source profile. The ratio of methanol to methane in dairy operation emissions was determined using 1 min aircraft data points sampled in the plumes from farms and facilities in the San Joaquin Valley. Acetic acid and ethanol ratios could not be determined using the flight data due to a lack of measurements and spatial incongruence of canister to methane data, respectively. Ratios of these two compounds to methane were determined using ground site data from Bakersfield. Dairies have been shown in previous studies to be major sources of methane, methanol, ethanol, acetic acid, and other oxygenated species; and there is a large concentration of dairies in the San Joaquin Valley (Alanis et al., 2010; Chung et al., 2010; Howard et al., 2010a, b; Malkina et al., 2011; Sun et al., 2008; Shaw et al., 2007). So each compound is compared to methane via regression with close attention to enhancements from other sources that may skew the observed dairy operations emission ratio.

Predicted concentrations in Bakersfield of methanol, ethanol, and acetic acid from dairy operations were estimated using the determined emission ratios to methane and measurements of methane at the Bakersfield ground site. A local background methane concentration of 1.87 ppmv was subtracted prior to multiplication by the emission ratio. These predicted concentrations were compared with observed concentrations to determine the fraction of each compound emitted from dairy operations.

OH reactivities and ozone formation potentials reported in this paper are from literature on OH reaction constants and maximum incremental reactivities (MIRs), respectively (Carter, 2007; Atkinson and Arey, 2003).

2.3 Methods to determine spatial distribution of emissions

Several methods are used in this work to assess the spatial distribution of organic carbon sources. In addition to the use of aircraft data collected from the NOAA WD-P3 mobile platform during the CalNex campaign, we developed a method that uses a Lagrangian transport and meteorological model (FLEXPART-WRF) to calculate the distribution of air parcels (i.e., back-trajectory footprints) for each hourly sample prior to measurement at a ground site. We combine these footprints with ambient compound data from the CalNex site to assess the spatial distribution of emissions for a given compound in a region. Our method builds upon previous techniques (i.e., TrajStat) to estimate source location(s) using ground site data and the Hybrid Single Particle Lagrangian Integrated Trajectory Model (HYSPLIT) (Wang et al., 2009).

We generated 6 and 12 h back-trajectory footprints with 4×4 km resolution for each hourly sample using the FLEXPART Lagrangian transport model with WRF meteorological modeling (Fig. 1). Simulations were initiated from the top of the 18 m tower using WRF runs EM4N in Angevine et al. (2012); further details on FLEXPART and WRF modeling can also be found in Brioude et al. (2012) and Metcalf et al. (2012). Here, we integrate this transport/meteorological model with statistical back-trajectory analysis to explore the distribution and relative magnitude of gas-phase organic carbon sources at ground level.

The back-trajectory footprint produced by FLEXPART-WRF represents the area where the air parcel(s) of interest (i.e., a 30 min VOC sample) contacts the surface layer. The statistical source footprint (the final output) represents the calculated distribution of ground-level emissions. Utilizing this concentration-weighted trajectory analysis allows us to find the emissions potential of every point in a region, which is represented by the average concentration of a compound in each cell ($\bar{C_{ij}}$) on a gridded map with i and j representing the axes:

$$\bar{C_{ij}} = \frac{1}{\sum_0^t (\tau_{ijt})} \sum\nolimits_0^t (c_t \cdot \tau_{ijt}), \tag{1}$$

where τ_{ijt} is the time each back-trajectory footprint spends at ground level (< 100 m) in the 2-dimensional cell ij for the VOC sample at time t, and c_t is the measured concentration of a compound at the ground site. Each cell has a corresponding n_{ij} value, representing the number of individual footprints included in each cell, which was determined as the number of samples contributing to a cell's average ($\bar{C_{ij}}$) (Seibert et al., 1994). To reduce bias from cells with few samples (i.e., low n_{ij} values), a weighting function multiplies the ($\bar{C_{ij}}$) result by a factor of 1, 0.7, 0.4, or 0.05 for cells with n_{ij} values above the Q_{90}, Q_{75}, Q_{50} or below the Q_{50} percentiles, respectively (Polissar et al., 2001). Contour maps were then plotted using these final values and shown with a 1 arcsec elevation map obtained from the USGS National Map Seamless Server (http://viewer.nationalmap.gov/viewer/). It is insufficient to only consider the distribution of wind directions against compound concentrations when complex meteorology affects the transport of air masses. This is the case in California's Central Valley. Similarly, basic single HYSPLIT back-trajectory analysis can oversimplify the footprint of measurements into one single path and not accurately represent the distribution of ground-level residence times for an air parcel (Fig. 2).

3 Results and discussion

Figure 3 shows measurements of a selection of compounds plotted against carbon monoxide, a common technique to assess contributions from anthropogenic emissions (after filtering for biomass burning events). Some compounds have ratios to CO consistent with measurements from the Los Angeles air basin during the same time period (Borbon et al., 2013). However, there are several compounds with frequent enhancements above the Los Angeles slope, indicating additional sources of these compounds that are not abundant in LA. Most of the compounds shown in Fig. 3 have been previously linked to petroleum and dairy operations (e.g., Gilman et al., 2013 and Shaw et al., 2007), and their enhancements here are evidence for substantial emissions in the San Joaquin Valley.

3.1 Emissions from petroleum operations

Petroleum operations emit a significant mass of numerous hydrocarbons, which have a distribution of molecular weights smaller than emissions from gasoline sources. The 25th percentiles for propane and n-butane are similar to other urban ground sites during the summer, but higher concentrations were observed for the 50th and 75th percentiles, by up to a factor of 2 compared to Pittsburgh, PA (2002) (Millet et al., 2005). The 75th percentiles in the San Joaquin Valley are also higher by 25–50 % compared to measurements from 2005 in Riverside, CA, a much more populated region (Gentner et al., 2009). Between the CalNex field sites at Bakersfield and Pasadena, median and smaller values (10th and 25th percentiles) were similar and lower at Bakersfield, respectively. Yet, 75th percentile concentrations were greater at Bakersfield by 53 % for propane (5.6 vs. 3.7 ppbv) and 16 % for n-butane (5.6 vs. 3.7 ppbv). Previous work in the South Coast air basin has also reported emissions of light alkanes from oil/gas operations, but there is a lesser prevalence of oil/gas fields in that air basin compared to the San Joaquin Valley (Peischl et al., 2013).

The source receptor model with chemical mass balancing used in Gentner et al. (2012) effectively modeled emissions of most compounds in a motor vehicle emissions study at the Caldecott tunnel and many of the compounds that are most prevalent in gasoline and diesel emissions at Bakersfield. We used the non-methane composition of thermogenic wet gas reported by the USGS (Table 1) to construct the initial petroleum operations source profile in our source receptor model. The composition of unrefined natural gas has substantial variability among all the wells sampled, but the average composition was very effective for modeling the in situ data from Bakersfield. In many cases, ratios in ambient data can be impacted by differences in the rates of chemical reaction in the atmosphere; as is the case in Los Angeles (Borbon et al., 2013). At Bakersfield, the timescales for transport from source to measurement site are much shorter than the

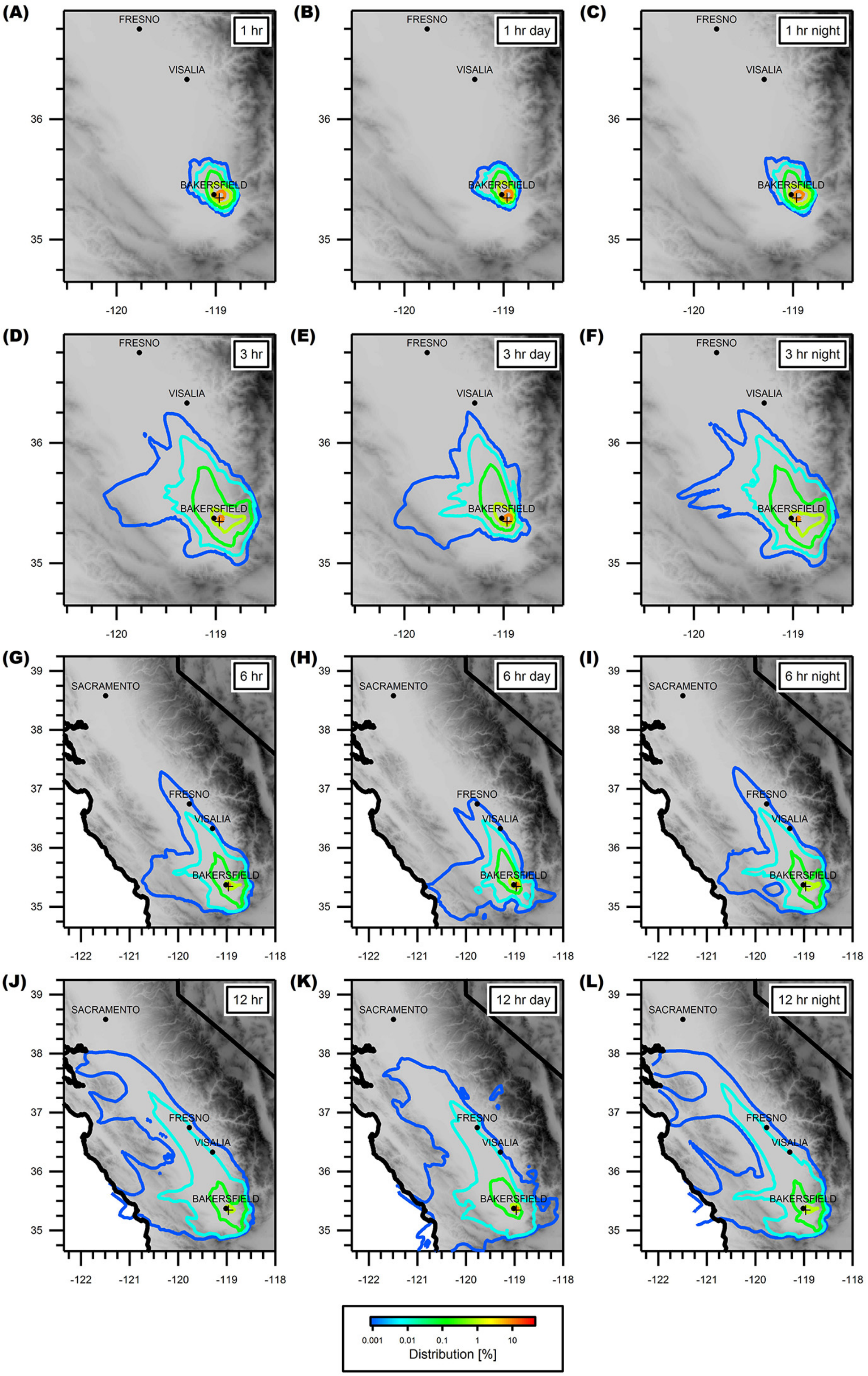

Figure 1. 1, 3, 6 and 12 h statistical footprints for the Bakersfield ground site (marked by +) averaged across the entire CalNex campaign (y and x axes represent latitude and longitude, respectively). Daytime **(B, E, H, K)** and nighttime **(C, F, I, L)** averages are filtered for 08:00–20:00 PST and 21:00–06:00 PST, respectively, and are shown with overall averages **(A, D, G, J)**.

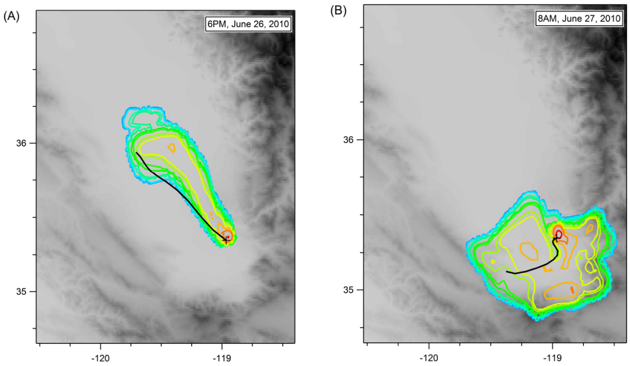

Figure 2. Examples of individual probability distribution back-trajectory footprints produced using FLEXPART-WRF (contours with log color scale – red: max, blue: min) for the southern San Joaquin Valley with air parcels arriving at the CalNex-Bakersfield ground site. Two examples show results for the previous 6 h with air parcels coming **(A)** along a concentrated northwest flowpath and **(B)** a more dispersed footprint from the southern tip of the valley. Dates and arrival times are superimposed on the panels. Also shown are comparisons of single-path HYSPLIT back-trajectories (black lines) and FLEXPART-WRF footprints.

timescales of reaction for the species considered here. So, variability due to chemical processing is negligible for all but the most reactive primary emitted compounds in our Bakersfield data (Gentner et al., 2012).

In addition to the compounds known to be in thermogenic wet gas (Table 1), the model under-predicted the observed concentrations of numerous alkanes. These compounds are summarized in Table 2 and Fig. 4, which show their average unexplained concentrations and the percent of total mass that is unexplained (determined by the residuals in the chemical mass balance source receptor model). Most of the unexplained concentrations of these alkanes were well correlated ($r \geq 0.75$) with the petroleum operations source contribution from the model and are attributed to this source. The presence of the branched and cyclic alkanes in unrefined petroleum gas is not surprising as there are significant amounts of C_{5-7} straight chain alkanes in the reported composition (Table 1) and a select few have been measured in other studies (Gilman et al., 2013; Ryerson et al., 2011). Yet, there are limited previous in situ measurements for many of the compounds reported here, especially many of the cyclic alkanes. Concentrations of aromatics observed at Bakersfield matched predicted concentrations from motor vehicle sources in our model, but other studies have observed aromatic emissions from petroleum operations (e.g., Gilman et al., 2013).

The additional compounds attributed here to the petroleum operations source profile increase the mass of emissions by 10.6 % as shown by the regression of the correlated "unexplained" compounds with the petroleum gas source ($r = 0.95$) (Fig. 5). The weight fraction of each correlated compound in the "unexplained" mass is given in Table 2 with similar fractions in the overall source profile as the known C_{5-7} compounds in thermogenic wet gas (Table 1). In all, the interquartile range of the unrefined petroleum gas source contribution was 7.6–89 ppbC, with a diurnal pattern that was strongly dependent on meteorological dilution (Supplement Fig. S3). This source represented a substantial fraction of anthropogenic emissions. For comparison, the mass concentration of compounds emitted by the observed petroleum operations source ranged from 30–40 % to 100–150 % of the sum of compounds from motor vehicles during the afternoon and nighttime, respectively (Supplement Fig. S4).

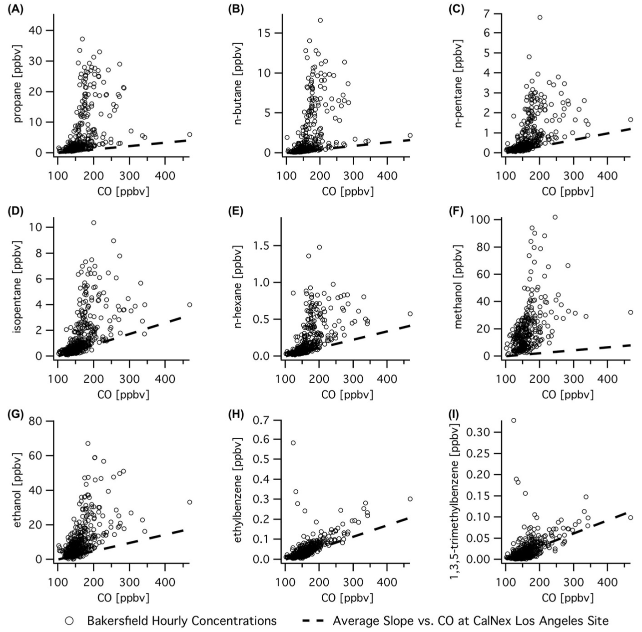

Figure 3. Concentrations of several compounds from Bakersfield, CA shown against carbon monoxide with the average slope of compounds vs. CO during the same time period at the CalNex-LA site in Pasadena, CA (Bourbon et al., 2013). Concentration enhancements above VOC/CO line are due to emissions from **(A–E)** petroleum operations and **(F–G)** dairy operations, neither of which emit CO. **(H–I)** are shown as examples of compounds that largely agree between Bakersfield and Los Angeles.

The remaining branched and cyclic compounds that were not highly correlated with the petroleum gas source represent a relatively small amount of mass and we could not confidently infer a specific source for these compounds. The excess C_{13-16} branched alkanes were well correlated ($r \geq 0.80$) with each other, but not with any other compounds. The excess concentrations of C_{10-11} branched alkanes were correlated with each other, and one of the compounds, 2,6-dimethyloctane, was well correlated ($r \geq 0.80$) with the three C_9 cycloalkanes that do not correlate well with the petroleum operations source. These remaining compounds have ozone formation potentials similar to other observed compounds,

Table 2. Interquartile ranges and MIRs for alkanes discussed in this work.

Compound name	# in Fig. 4	Interquartile range [pptv]	WtC % of unexplained mass	MIR [$gO_3\ g^{-1}$]
propane	–	1133–5602		0.49
n-butane	–	230–6397		1.15
n-pentane	–	221–2127		1.31
2-2-dimethylbutane	1	28.0–76.6		1.17
2-methylpentane & 2,3-dimethylbutane	2	121.6–501.0	9.92	1.2
3-methylpentane	3	50.1–253.9	7.67	1.80
2,4- & 2,2-dimethylpentane	4	13.7–54.7		1.3
3,3-dimethylpentane	5	4.0–16.6		1.20
2,3-dimethylpentane	6	19.7–93.0		1.34
2-methylhexane	7	23.2–90.3	2.73	1.19
3-methylhexane	8	28.0–124.6	3.48	1.61
2,2-dimethylhexane	9	1.0–4.0		1.02
2,5-dimethylhexane	10	6.2–35.8	1.44	1.46
2,4-dimethylhexane	11	7.4–32.0	0.84	1.73
2,2,3-trimethylpentane	12	2.7–12.1		1.22
isooctane	13	39.1–115.3		1.26
2,3,4-trimethylpentane & ctc-1,2,3-trimethylcyclopentane	14	31.6–160.2	7.38	1.3
2,3,3-trimethylpentane & 2,3-dimethylhexane	15	11.3–32.8		1.1
2-methylheptane	16	10.2–48.8	1.29	1.07
4-methylheptane	17	4.3–20.7		1.25
3-methylheptane	18	9.3–43.6	1.79	1.24
2,2,5-trimethylhexane	19	5.4–16.3		1.13
2,6-dimethylheptane	20	5.4–30.7	1.86	1.04
3,5-dimetylheptane	21	2.2–10.3		1.56
2,3-dimethylheptane	22	0.9–4.7		1.09
2- & 4-methyloctane	23	2.9–12.7		0.9
3-methyloctane & 4-ethylheptane	24	3.1–12.9		1.1
2,2,5-trimethylheptane	25	0.7–1.7		1.26
2,2,4-trimethylheptane	26	0.8–2.6		1.16
C10 branched alkanes (5 unknown isomers)	27	3.0–11.5		0.94
2,6-dimethyloctane	28	0.7–3.2		1.08
2- & 3- & 4-methylnonane & 3- & 4-ethyloctane & 2,3-dimetyloctane	29	6.9–24.6		0.94
C11 branched alkanes (3 unknown isomers)	30	0.7–2.6		0.73
C11 branched alkanes (10 unknown isomers)	31	5.4–17.5		0.73
dimethylundecane isomer #1	32	0.8–3.3		0.6
dimethylundecane isomer #2	33	0.8–2.6		0.6
C13 branched alkanes (2 unknown isomers)	34	2.3–5.8		0.6
C14 branched alkanes (6 unknown isomers)	35	4.4–11.3		0.55
C16 branched alkane (unknown)	36	1.3–3.1		0.47
cyclopentane	37	36.7–164.5	4.14	2.39
methylcyclopentane	38	57.4–315.3	9.24	2.19
cis-1,3-dimethylcyclopentane	39	14.8–100.1	5.09	1.94
trans-1,3-dimethylcyclopentane	40	16.4–177.7	7.70	1.94
ethylcyclopentane	41	7.9–44.4	1.89	2.01
ctc-1,2,4-trimethylcyclopentane	42	5.4–52.2	4.09	1.53
ctt-1,2,4-trimethylcyclopentane	43	1.7–15.5	1.29	1.53
Unknown methylethylcyclopentane	44	0.7–4.3		1.6
iso-propylcyclopentane	45	1.1–5.9	0.35	1.69
n-propylcyclopentane	46	2.1–10.0	0.56	1.69
cyclohexane	47	27.5–154.0	6.10	1.25
methylcyclohexane	48	20.4–147.0	7.17	1.70
cis-1,3- & 1,1-dimethylcyclohexane	49	4.6–38.4	2.91	1.4
trans-1,2-dimethylcyclohexane	50	4.6–42.4	3.27	1.41
trans-1,3-dimethylcyclohexane	51	2.9–17.8	0.91	1.52
cis-1,2-dimethylcyclohexane	52	1.9–9.8	0.51	1.41
ethylcyclohexane	53	4.8–31.9	2.31	1.47
ccc-1,3,5-trimethylcyclohexane	54	1.0–6.6		1.15
1,1,3-trimethylcyclohexane	55	2.0–20.4	2.26	1.19
1,1,4-trimethylcyclohexane	56	1.1–8.8		1.2
ctt-1,2,4- & cct-1,3,5-trimethylcyclohexane	57	0.7–3.9		1.2
ctc-1,2,4-trimethylcyclohexane	58	1.2–9.6		1.2
1,1,2-trimethylcyclohexane and isobutylcyclopentane	59	0.7–2.0		1.3
methylethylcyclohexane isomer #1	60	0.8–4.5	0.32	1.4
methylethylcyclohexane isomer #2	61	0.7–3.7	0.27	1.4
iso-propylcyclohexane	62	0.9–5.2		1.3
n-propylcyclohexane	63	2.9–15.5		1.29
unidentified C10 cyclohexane	64	2.5–7.8		1.07
unidentified C10 cyclohexanes	65	0.7–2.7		1.07
unidentified C9 cycloalkane	66	1.2–11.0	1.23	1.36

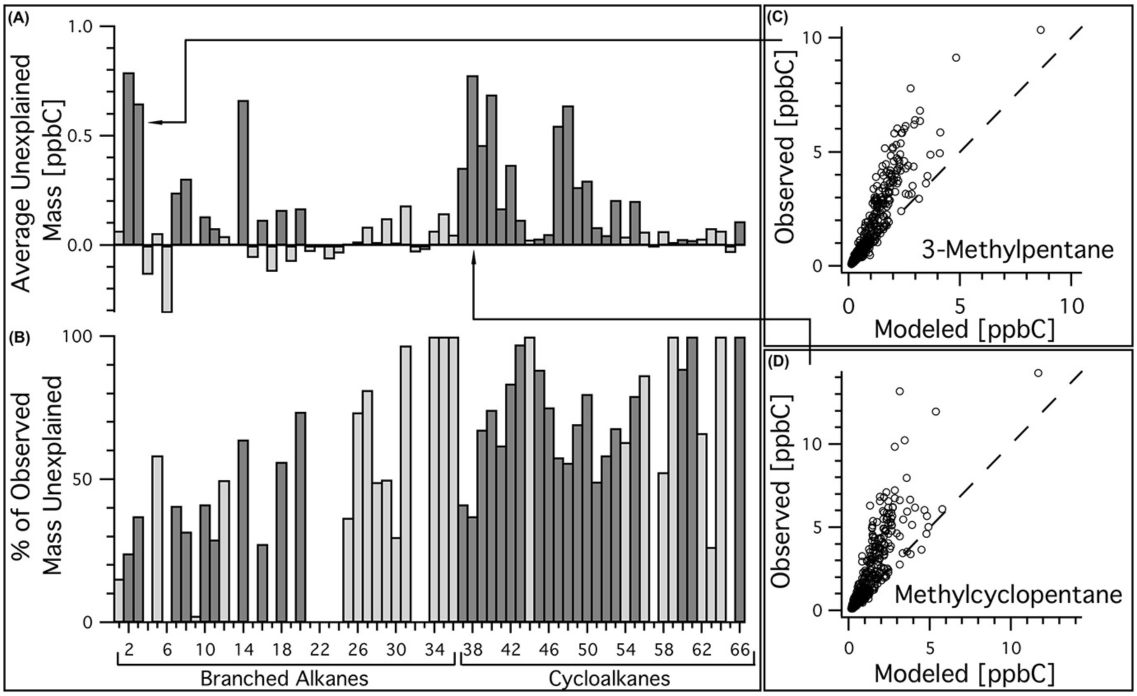

Figure 4. Many branched and cyclic alkanes exceeded predicted concentrations based on source profiles for motor vehicles. **(A–B)** the average unexplained concentration of each compound and the percentage of unexplained mass out of total observed mass. Compounds that are well correlated ($r \geq 0.75$) with the petroleum gas source are shown with shaded bars. A few compounds have negative residuals. **(C–D)** Examples of exceedances of observed over-predicted values are shown with a 1 : 1 line.

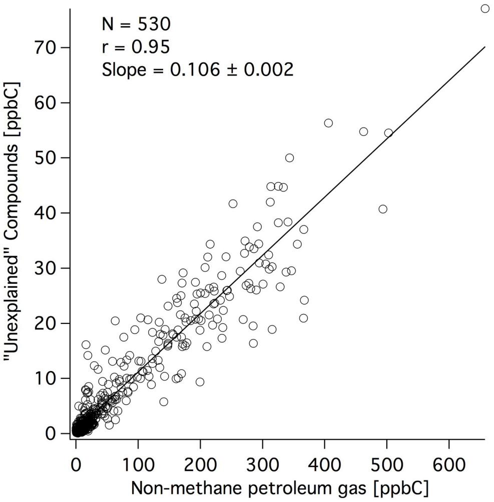

Figure 5. The sum of unexplained compounds was very well correlated with gas-phase emissions from the modeled petroleum operations source with a slope of 0.106. This increases emissions by 10.6 % from the original profile.

ranging from 0.6 to 1.6 $gO_3\,g^{-1}$, but their excess concentrations after modeling were minimal – average values from 0 to 0.15 ppbC each (Fig. 4). Work by Liu et al. (2012) and Chan et al. (2013) at CalNex-Bakersfield inferred a source of higher molecular weight organic carbon, potentially from petroleum operations, but we did not observe any significant correlation with their data.

Unrefined thermogenic wet gas is largely comprised of methane when extracted at the wells. Yet, at the Bakersfield ground site observations of methane and contributions from the petroleum operations source were not well correlated (Supplement Fig. S5). Additionally, the potential methane emissions expected based on the thermogenic wet gas source profile (Table 1) would exceed all of the observed methane enhancements above background concentrations by over 30 %. Despite the absent methane emissions, the large source of hydrocarbons is well modeled by the source profile from unrefined thermogenic wet gas in the San Joaquin Valley when using propane and larger compounds.

We compared the relative ratios of hydrocarbons in the thermogenic wet gas profile data to regression slopes of in situ data and canister data to further explore emissions from petroleum operations using ethane and isobutane, which were not available in our in situ data. The light alkanes discussed here were very well correlated in measurements from Bakersfield. Regressions with C_5 and larger compounds have more scatter due to emissions from gasoline-related sources, so they are excluded here and addressed using the source receptor model (example in Supplement Fig. S2). For the light alkanes, which have relatively minimal contributions from

Table 3. Observed light alkane ratios ($\mathrm{gC\,gC^{-1}}$) from this and other studies.

	Data Source	ethane/ propane	propane/ n-butane	n-butane/ isobutane	ethane/ n-butane	Sample size (N)
Unrefined SJV thermogenic wet gas [±std. err. (±std. dev.)]	This study/USGS	1.2 ± 0.2 (± 1.2)	2.9 ± 0.7 (± 4.6)	1.7 ± 0.4 (± 2.8)	3.4 ± 0.8 (± 5.3)	49
Bakersfield ambient canister measurements [±std. dev. (r)]	This study	0.6 ± 0.03 ($r = 0.93$)	1.8 ± 0.1 ($r = 0.98$)	1.7 ± 0.04 ($r = 0.99$)	1.1 ± 0.1 ($r = 0.90$)	46
Bakersfield ambient in situ measurements [±std. dev. (r)][a]	This study	–	1.9 ± 0.01 ($r = 0.98$)	–	–	693
Colorado Front Range ambient in situ measurements [±std. err. (±std. dev.)][c,d]	Gilman et al. (2013)	0.86 ± 0.06 (± 1.41)	1.5 ± 0.1 (± 2.6)	2.3 ± 0.2 (± 4.6)	1.3 ± 0.1 (± 2.2)	554
Colorado Front Range ambient canister measurements [range (±std. dev.) (r)][b,d]	Petron et al. (2012)	–	1.5-1.7 (± 0.01) ($r \sim 1$)	–	–	25+[b]
SW US (fall) ambient canister measurements [±std. err.][c,d]	Katzenstein et al. (2003)	1.1 ± 0.2	1.7 ± 0.4	2.2 ± 0.5	1.9 ± 0.4	85
SW U.S. (spring) ambient canister measurements [±std. err.][c,d]	Katzenstein et al. (2003)	1.4 ± 0.1	2.0 ± 0.3	2.0 ± 0.3	2.9 ± 0.4	261
East Texas Condensate Tanks [±std. err. (±std. dev.)]	Hendler et al. (2009)	0.64 ± 0.04 (± 0.20)	1.3 ± 0.1 (± 0.4)	1.9 ± 0.2 (± 0.8)	0.78 ± 0.07 (± 0.33)	24

Notes:
– Comparison done using C_4 alkanes and smaller as there are large contributions/interference from motor vehicle sources for C_5 and larger compounds at Bakersfield.
– Standard error (aka standard deviation of the mean) is reported as the primary uncertainty for the unrefined natural gas profile and others where appropriate, and represents the variability of the average within large highly variable data sets. Further information on statistical definitions/differences can be found in Altman and Bland (2005). Both the standard error and deviation are provided so the reader can judge the uncertainty and variability.
– Results of positive matrix factorization (PMF), and similar studies are excluded from this comparison (Peischl et al., 2013; Buzcu and Fraser, 2006; Leuchner and Rappengluck, 2010).
[a] Measurements of ethane and isobutane were unavailable from Bakersfield in situ data.
[b] Range of 5 data regressions, each with 25 or more samples and very small uncertainty. Other regressions were not reported in Petron et al. (2012).
[c] Ratios calculated from mean mixing ratios and their standard deviations, with propagation of uncertainty.
[d] Studies focused on regions with large oil and gas operations.

motor vehicles at the site, we compare ratios between atmospheric data and the source profile expected for petroleum operations (Table 1) with the results summarized in Table 3. Ratios of n-butane to isobutane strongly support the conclusion of a petroleum operations source, as they are identical with 1.7 ± 0.4 and 1.7 ± 0.04 ($r = 0.99$) in the oil well data and in canister measurements from Bakersfield, respectively. The process of methane separation from the associated petroleum gas can remove a fraction of very light alkanes (i.e., C_{2-3}) and affect their relative composition to other hydrocarbons in the condensate (Armendariz, 2009; Hendler et al., 2009). This is consistent with our observations of ratios involving C_{2-3} alkanes. The ethane to propane ratio ($\mathrm{gC\,gC^{-1}}$) observed via canister measurements at the Bakersfield site (0.6 ± 0.06, $r = 0.93$) (Supplement Fig. S1) is significantly lower than expected based on the thermogenic wet well composition in the San Joaquin Valley (1.2 ± 0.2). Similarly, the ethane to n-butane ratio is significantly lower in the canister data (1.1 ± 0.1) relative to the unrefined gas data (3.4 ± 0.8). The propane to n-butane ratios in the in situ and canister data (1.9 ± 0.01 ($r = 0.98$) & 1.8 ± 0.1 ($r = 0.98$)) were slightly lower than in the oil well data (2.9 ± 0.7). The selective removal of ethane and propane along with methane changes the overall petroleum operations source profile observed at Bakersfield, primarily for ethane, which was not used in our source receptor model. This also results in a 33 % decrease in the propane weight fraction of the source profile. A revised source profile is shown in Table 4 with the addition of the previously "unexplained" compounds. We modified the propane content of the source profile to reflect this slight change in the propane composition relative to n-butane, and it resulted in very minor changes to the source receptor model outputs and maintained the same robust model diagnostics. The results reported throughout the paper reflect this minor change. The new source profile (Table 4) does affect the overall ozone formation potential. Including

Table 4. Observed petroleum operations source profile at Bakersfield.

Compound	wtC %
ethane	19.72
propane	34.02
n-butane	17.87
n-pentane	3.15
n-hexane	1.21
n-heptane	0.57
isobutane	10.61
isopentane	2.57
neopentane	0.70
2-methylpentane & 2,3-dimethylbutane	0.95
3-methylpentane	0.73
2-methylhexane	0.26
3-methylhexane	0.33
2,5-dimethylhexane	0.14
2,4-dimethylhexane	0.08
2,3,4-trimethylpentane & ctc-1,2,3-trimethylcyclopentane	0.71
2-methylheptane	0.12
3-methylheptane	0.17
2,6-dimethylheptane	0.18
cyclopentane	0.40
methylcyclopentane	0.89
cis-1,3-dimethylcyclopentane	0.49
trans-1,3-dimethylcyclopentane	0.74
ethylcyclopentane	0.18
ctc-1,2,4-trimethylcyclopentane	0.39
ctt-1,2,4-trimethylcyclopentane	0.12
iso-propylcyclopentane	0.03
n-propylcyclopentane	0.05
cyclohexane	0.58
methylcyclohexane	0.69
cis-1,3- & 1,1-dimethylcyclohexane	0.28
trans-1,2-dimethylcyclohexane	0.31
trans-1,3-dimethylcyclohexane	0.09
cis-1,2-dimethylcyclohexane	0.05
ethylcyclohexane	0.22
1,1,3-trimethylcyclohexane	0.22
methylethylcyclohexane isomer #1	0.03
methylethylcyclohexane isomer #2	0.03
unidentified C9 cycloalkane	0.12

Notes:
– Source profile carbon fraction is 0.82.
– Uncertainties are defined as standard errors and conservatively (±20 %) mainly due to the variability in the oil well data.

these "new" compounds increases the ozone forming potential of the reported petroleum operations source profile to 0.82 $gO_3\,g^{-1}$, due to the addition of more reactive cycloalkanes and branched alkanes to the initial source profile (Table 1).

The successful modeling of these emissions using the source profile constructed from well data and the consistency of hydrocarbon ratios between wells and Bakersfield measurements (canisters and in situ data) contributes to the strong evidence of emissions from petroleum operations. Overall, our results infer that the VOC source characterized and classified as petroleum operations in this analysis is not a major source of methane in this region. In many cases, methane emissions are coincident with emissions of non-methane hydrocarbons at petroleum extraction or processing sites due to either co-emission from the same equipment/reservoir or co-located emission pathways at the same facility (Katzenstein et al., 2003; Petron et al., 2012; Gilman et al., 2013). For comparison, we include light hydrocarbon ratios from other relevant studies in Table 3. Given regional variability in oil/gas deposit composition, direct extrapolation between regions should only be done with careful attention to compositional differences in wells and other fuels, especially in urban areas where there are numerous sources of light hydrocarbons. Despite this expected heterogeneity, ratios are similar between most of the studies within the calculated uncertainties. The consistency between ratios of ethane to propane and n-butane between our ambient measurements and condensate tank samples in Hendler et al. (2009) supports the case for emissions from condensate storage tanks or associated equipment. Our observation of a major petroleum operations source with minimal coincident methane is consistent with composition measurements of condensate storage tank emissions in two Texas-based studies. The tanks contain the separated non-methane liquids and emissions were dominated by non-methane hydrocarbons (Armendariz, 2009; Hendler et al., 2006). The studies demonstrated that condensate tanks emit 4–6 times more VOCs than methane, whereas all other emission pathways emit 3–15 times more methane than VOCs, and methane was on average only 15 ± 11 wt % of 20 vent gas samples from condensate tanks (Armendariz, 2009; Hendler et al., 2009).

Similar results can also be found in positive matrix factorization (PMF) studies in the urban area of Houston, a prominent region for petroleum imports and refining. They reported considerable emissions attributed to oil/gas operations and petrochemical production of other chemicals (Leuchner and Rappengluck, 2010; Buzcu and Fraser, 2006). One evident source, termed oil/natural gas evaporation from refineries, was comprised of C_{2-7} straight and branched alkanes, as well as cyclopentane, cyclohexane, and methylcyclopentane. In Leuchner and Rappengluck (2010), a similar source accounted for 27 % of observed VOC mass at the urban site outside of the Houston shipping channel, and resulted in atmospheric concentrations ranging from 10–40 ppbC diurnally from that source.

The good agreement of the observed non-methane hydrocarbon source profile with the measured composition of associated gas in oil wells (accounting for the selective reduction of C_{2-3} alkanes) suggests that emissions occurs via a pathway involving volatile non-methane components separated from thermogenic wet gas. This is very likely a fugitive emission pathway(s), occurring predominantly after methane separation, during the extraction, storage, or processing of crude oil, associated gas, or condensate. In 2012 and 2013, California issued targeted standards to reduce emissions of VOCs and methane from oil and natural gas operations.

Table 5. Interquartile range ($Q_{25} - Q_{75}$) at Bakersfield shown with the source profile of dairy operations (determined using ground site Bakersfield data and aircraft measurements in the San Joaquin Valley), and the ozone formation potential (MIR) of individual components.

Compound	IQR [ppbv]	wt %	MIR [$gO_3\ g^{-1}$]	% of Observed concentrations from dairy operations during CalNex-Bakersfield [avg. (range)]
Methane	1950–2380	93.3	0.014	–
Methanol	9.5–25.5	1.4	0.67	27 % (22–37 %)
Ethanol	3.9–14.3	4.9	1.57	45 % (18–67 %)
Acetic acid	0.79–2.5	0.45	0.68	28 % (11–44 %)

Note:
There are potential contributions from other organic compounds (e.g., carbonyls, larger alcohols, acids, alkenes). Based on our data, they are either minor or much more reactive than measured species, as they could not be apportioned with significance in ambient measurements. Nevertheless, there are potentially other compounds emitted from dairy operations that have high ozone formation potential.

These efforts to control VOCs are primarily directed at storage tanks and other relevant equipment, with a focus on emissions during production and transmission from equipment that stores and handles crude oil or condensate, and effective control technologies (California Air Resources Board, 2012, 2013). Spatial mapping of emissions in Sect. 3.3 suggests an area source with a similar distribution to oil wells in the San Joaquin Valley.

The results of this section along with the following sections form and augment the conclusion that the vast majority of methane enhancements observed in the San Joaquin Valley are due to emissions from dairy operations. In particular, Sect. 3.3 shows the statistical source footprint of emissions from petroleum operations in stark contrast to both the statistical source footprint of methane emissions and the spatial distribution of methane concentrations measured via aircraft in California's Central Valley with large spikes over areas with high concentrations of dairies. It is very possible that there are emissions of methane in the San Joaquin Valley from other petroleum operations that are downstream from our observed source, perhaps related to natural gas marketing. The results of this study infer that these emissions are minor compared to dairy operations, and are predominantly not co-located with our characterized petroleum operations source.

3.2 Emissions from dairy operations

We observed evidence for substantial emissions from dairy operations in the San Joaquin Valley. These emissions, unlike the petroleum operations source, were dominated by small alcohols, acetic acid, and methane. Concentrations of the major non-methane organic compounds – methanol, ethanol, and acetic acid (average and interquartile range concentrations in Table 5) – are higher than previous measurements at other locations. Compared to another urban ground site in Pittsburgh during summer 2002 (Millet et al., 2005), the ethanol and methanol interquartile ranges and geometric means were greater in Bakersfield, by approximately 300 % and 50 %, respectively. Despite the larger human population of the South Coast air basin, nighttime geometric means were 70 % and 240 % greater in Bakersfield compared to coincident measurements at Pasadena, CA (CalNex) for ethanol and methanol, respectively. The mean and median ethanol concentrations at the urban Bakersfield site were 12.8 and 7.6 ppbv, respectively. These values are several times greater than observations of urban and continental ethanol mixing ratios globally, as reported by Kirstine et al. (2012). However, a comparison of methanol concentrations is within the typical range of observed values globally (Heikes et al., 2002).

The methanol to methane emission ratio in dairy operation plumes measured on the aircraft was 7.4 ± 0.6 mmol mol^{-1}

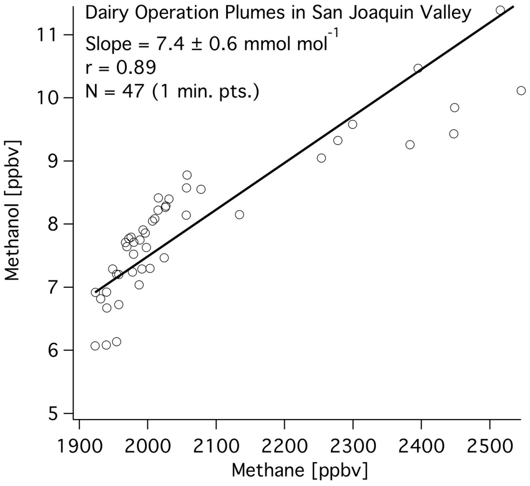

Figure 6. Methanol and methane concentrations are well correlated in dairy operation plumes sampled via aircraft (flight dates: 5/7, 6/14, 2010). Ratios of methanol to methane average 7.4 ± 0.6 mmol mol^{-1} and range up to 16 mol mol^{-1} due to the heterogeneity in emission pathways at dairy operations. Note: the data shown here represent a subset of dairies in the valley.

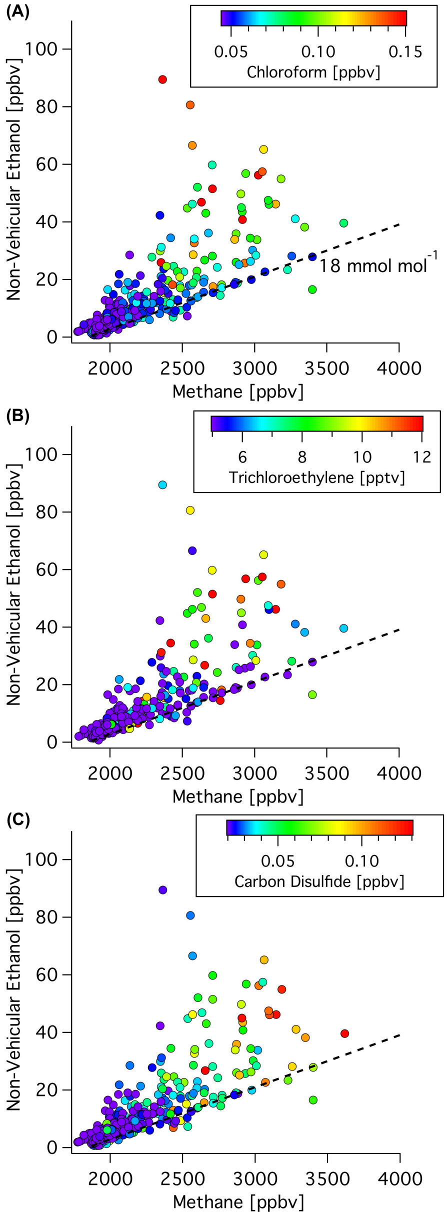

Figure 7. Observations of non-vehicular ethanol vs. methane are correlated and shown with the inferred emission ratio from dairy operations. Enhancements of ethanol from a source other than the dominant source of methane and ethanol are shown by enhancements in **(A)** chloroform, **(B)** trichloroethylene, and **(C)** carbon disulfide. No major enhancements of methane are observed beyond the inferred slope with non-vehicular ethanol.

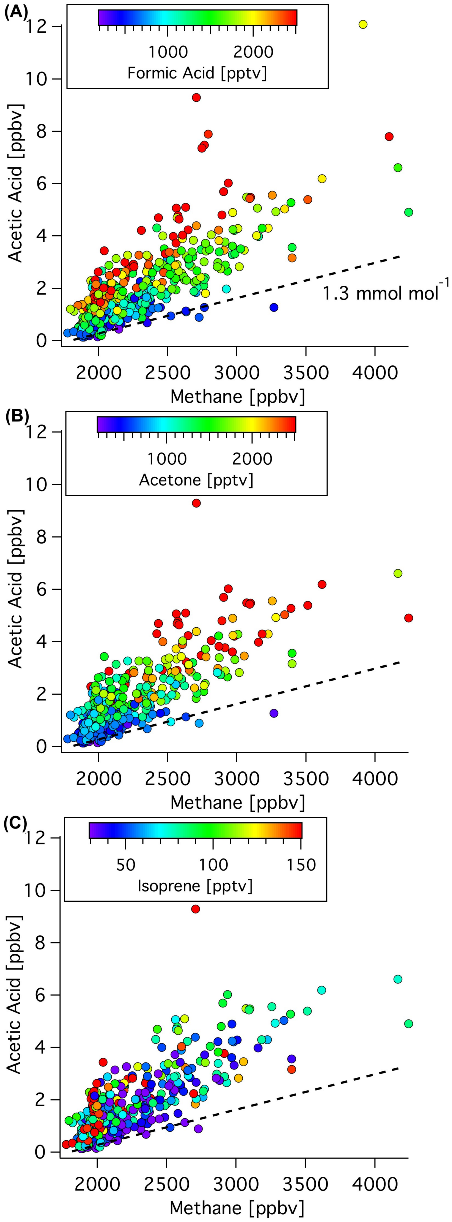

Figure 8. Acetic acid vs. methane shown with the inferred acetic acid : methane emission ratio from dairy operations. Acetic acid exceedances above the emission ratio are due to other sources of acetic acid coincident with emissions of **(A)** formic acid, **(B)** acetone, and **(C)** isoprene.

(aka ppbv ppmv^{-1}); this slope of the regression ($r = 0.89$) is nearer to the lower limit of the 7–16 mmol mol^{-1} range in the plumes (Fig. 6). This ratio was constructed from multiple transects and shows a range of ratios indicating some near-source variability in emissions from the different pathways of emissions. This ratio could be improved by collecting a larger sample size of data from more locations in future source characterization studies.

Ground site ethanol and acetic acid data were compared to methane to determine their emission ratios with close attention to enhancements from other sources. For ethanol and somewhat for acetic acid, there is a clear slope that emerges (Figs. 7–8) against methane with occasional enhancements in ethanol or acetic acid that are coincident with high concentrations of tracers for other sources. In contrast, there were no enhancements in methane concentrations past these baseline slopes in the data. This is indicative of a singular major source of methane that is clearly related to ethanol and acetic acid. This result, along with the results of Sect. 3.3 showing the agreement of dairy locations with the spatial distribution of concentrations (measured via aircraft) and the statistical source footprint of both methane and ethanol, supports the conclusion that dairies are the predominant source of methane in the San Joaquin Valley and emissions from petroleum are minor in comparison. To calculate emission ratios, data points with enhancements due to other sources (determined and shown by correlation with other tracer compounds) were not considered in the emission ratio assessment. Thus isolating the ethanol and acetic acid associated with dairy operations. With dairy (and other cattle) operations responsible for the vast majority of methane emissions observed at the Bakersfield site, the emission ratios of ethanol and acetic acid to methane are effectively the lower limit of slopes versus methane when enhancements from other sources of ethanol or acetic acid are at their minimum.

At the Bakersfield ground site, concentrations of non-vehicular ethanol (calculated via the source receptor model) were well correlated with methane, except for outliers with enhancements in ethanol that were coincident with large enhancements in tracers of other ethanol sources (Fig. 7). Other potential sources of alcohols and oxygenated gas-phase organic carbon are wastewater treatment, vegetation, soil processes, motor vehicles, and landfill/composting facilities. At low concentrations of these tracers, non-vehicular ethanol and methane are very well correlated with a slope of 18 mmol mol^{-1}. Chloroform, trichloroethylene, and carbon disulfide correlate with different points that deviate from the emission ratio, suggesting multiple other minor sources of ethanol.

The results of the acetic acid versus methane assessment (Fig. 8) at the Bakersfield ground site produced similar results to that of non-vehicular ethanol versus methane. The enhancements of acetic acid above the emission ratio slope coincided with tracers of other primary and secondary sources. We calculated an emission ratio for acetic acid to methane of 1.3 mmol mol^{-1}. This value represents a lower limit of acetic acid emissions associated with dairy operations. There is remaining uncertainty in this emission ratio and, based on the data shown in Fig. 8, the ratio of acetic acid to methane could be up to 50 % greater. The diurnal profile of acetic acid also suggests emissions from local/regional sources since concentrations are at their maxima during the night when emissions accumulate in the nocturnal boundary layer with minimal horizontal or vertical dilution. The results of our study show that there are high concentrations of acetic acid that are associated with methane, formic acid, acetone, or isoprene. This indicates that there are multiple major biogenic and anthropogenic sources of acetic acid in the San Joaquin Valley.

Rice cultivation could also be an important source of light alcohols and methane (Peischl et al., 2012), but there is little rice cultivation in the San Joaquin Valley. The bulk of Californian rice cultivation is located in the Sacramento Valley – the northern portion of California's Central Valley. In the San Joaquin Valley, emissions from dairy operations should far outweigh those from rice cultivation. This work is focused on sources in the San Joaquin Valley, but data from aircraft canister measurements suggest that dairy operations and rice cultivation have different emission ratios of ethanol to methanol (Supplement Fig. S6). In general, observations between the two valleys are heavily influenced by the major source that dominates in each air basin (Figs. 13, S11).

Constructing an overall source profile for dairy operations is difficult since methane, light alcohols, and acetic acid all have different emission rates from specific source pathways at dairies. Previous studies report that methane emissions are minimal from animal waste and greatest from enteric fermentation in cows, whereas emissions of non-methane gas-phase organic carbon come predominately from animal feed, followed by waste, with minor contributions from the animals themselves (Chung et al., 2010; Howard et al., 2010b; Shaw et al., 2007; Sun et al., 2008). Further variability is introduced by factors such as feed composition, temperature, and specifics of feed and waste handling. Table 5 summarizes the average regional source profile for dairy operations, determined via downwind sampling of a large collection of individual farms/feedlots in the San Joaquin Valley. Comparison against other studies is limited by the lack of a similar set of compounds. Previous studies report high emission rates for a selection of the primary compounds in Table 5, but there is no full set for comparison, and other work is focused on singular emission pathways rather than the overall source profile. Extrapolation to other regions must be done with caution, as the emission ratios reported here are region specific. So here we compare our results to other studies to the extent that it is possible.

In this and other studies, emissions of ethanol are typically greater than methanol, ranging 1.3–2.4 mol mol^{-1}. Based on the literature and our results, it is apparent that the ratios of the two main alcohols to methane can vary depending on the relative amount of animals versus feed and waste, and the specifics of feed/waste storage and processing. Our reported ratios represent the average for the region; the ratio of ethanol to methane reported by Sun et al. (2008) for lactating cows and waste (24 mmol mol^{-1}) is slightly higher than our value (18 mmol mol^{-1}). Their ratio of methanol to methane (19 mmol mol^{-1}) was greater by 150 %, but is within the range observed in our analysis of aircraft data. The differences between results can potentially be attributed to the absence of feed, which will increase alcohol emissions. Measurements of acetic acid are less common so there are few studies to compare emission ratios. Shaw et al. (2007) reported ratios of acetic acid to methanol ranging from 0.05 to 0.94 mol mol^{-1} for cows and their waste. In this work, we observed a ratio of 0.18 mol mol^{-1}.

Emissions of other compounds have been reported from dairy and other livestock operations, most in relatively minor quantities compared to the dominant compounds presented in this work. There are likely small emissions of low molecular weight aldehydes (e.g., propanal, butanal), ketones (e.g., acetone), other alcohols (e.g., propanol, phenols), alkenes, and esters (e.g., propyl acetate, propyl propionate) from dairy operations (Chung et al., 2010; Howard et al., 2010b; Malkina et al., 2011). In general, a major source of many oxygenated species is secondary production from the chemical oxidation of other compounds. The measurements used in this study similarly suggest substantial contributions from secondary production for many of the measured carbonyls and acids. At the ground site and from the aircraft, emissions of many of these carbonyls from dairy operations could not be detected due to the magnitude of other sources, and there were no measurements of esters or larger alcohols. In this study, dairy operation emissions of these minor compounds (acetone, methyl ethyl ketone, propanal, butanal, and other oxygenated VOCs measured at the Bakersfield site) make only minimal contributions to total emissions of these compounds on a valley-wide basis. One potential exception is acetaldehyde; previous work reported emissions equivalent to 20–110 % of ethanol emissions from feed and relatively minor emissions from cows and their manure (Makina et al., 2007; Shaw et al., 2007). In this study, no significant correlation was observed between acetaldehyde and methane in the dairy plumes measured by aircraft, and insufficient data exist from the ground site to check for emissions of acetaldehyde. Also, neither methyl ethyl ketone nor acetone were well correlated ($r = 0.55$–0.65) with methane in the dairy plumes measured by the aircraft. Other studies on volatile organic acids have also reported emissions of propanoic acid and butanoic acid with relative emission rates ranging from an order of magnitude below acetic acid to the same order of magnitude as acetic acid (Alanis et al., 2010; Shaw et al., 2007; Sun et al., 2008). We did not measure propanoic or butanoic acid, but we did not observe any correlation between measured concentrations of either formic or oxalic acid and the prominent compounds emitted from dairies at the Bakersfield ground site. Based on our work and the literature, acetic acid appears to be the most prominent acid emitted by dairy operations.

One of the objectives of this study was to provide a basic source profile, averaged over the bulk of dairy operations in the San Joaquin Valley with the understanding that the profile can potentially vary between individual operations. Methanol, ethanol, and acetic acid were the predominant non-methane compounds emitted from dairy operations. Figure 9 shows comparisons of the concentrations of these compounds attributed to dairy operations versus the total observed concentrations for each hourly sample in Bakersfield. The percentage of each compound from dairies ranged widely with some significant diurnal patterns (Supplement Fig. S8). On average, 27 % of observed methanol was from dairies with hourly averages ranging diurnally 22–37 %. 28 % of observed acetic acid was from dairies with a diurnal range of 11–44 %. As mentioned previously, the emission ratios for methanol and acetic acid are conservative estimates that may tend towards lower limits. In this case, the fraction of methanol and acetic acid from dairy operations will increase slightly, but since ethanol makes up a dominant fraction of the non-methane source profile (Table 5) these changes will have a negligible impact on the overall source profile and implications of dairy operations on air quality in the valley (Sect. 3.4). Due to the increased use of gasoline, 9.6 ± 5.8 % of ethanol was emitted by gasoline-related sources. Of the remainder, 48 % was from dairy operations on average with a diurnal range of 30–71 %.

The diurnal average of the percent contribution from dairy sources (Supplement Fig. S8) shows minima during the daytime for acetic acid and non-vehicular ethanol. These ratios vary widely with time of day and meteorology. This daytime minimum can be attributed in part to biogenic emissions of ethanol when emissions from natural vegetation and agriculture are likely highest. For acetic acid, the minimum is likely due to secondary production from the oxidation of isoprene and other reactive precursors. Methanol did not have a strong diurnal pattern, since other major day and nighttime sources have similar emission patterns (e.g., vegetation). The remaining methanol observed at the Bakersfield site can be attributed to a mix of emissions from anthropogenic urban sources, natural vegetation, and biogenic emissions from agriculture. A recent study by Hu et al. (2011) found that 90 % of methanol was biogenic during the summer in the Midwestern US, with the remainder being anthropogenic. Heikes et al. (2002) reports a similar value with primary biogenic emissions responsible for 81 % of non-oceanic emissions. Dairies are an important source of methanol in the San Joaquin Valley along with emissions from agriculture and natural vegetation. The methods used in these studies to allocate emissions will determine whether dairy (and other cattle) operations are categorized as biogenic or anthropogenic sources. In this work we consider emissions from dairy operations to be anthropogenic, similar to the CARB inventory.

Pusede et al. (2014) found that daytime average concentrations of light alcohols, aldehydes, and acids at the Bakersfield site increased with daily maximum temperature. It is possible that increases in ambient temperature could lead to increases in silage emissions due to enhanced volatilization of some compounds (e.g., alcohols), which would change the reported source profiles slightly. Yet, ethanol was the most prominent non-methane compound in our source profile and results from Pusede et al. (2014, Table A2) show that daytime averages of ethanol did not increase between moderate and high temperatures. So, we do not expect major changes with temperature for the dairy source profile reported in this work and recommend further research to identify other high-temperature sources of oxygenated compounds.

Table 6. Quartiles [ppbC] for ambient concentrations from major petroleum-based sources measured at the Bakersfield site (does not include methane emissions) shown with average maximum incremental reactivity (MIR) values and secondary organic aerosol (SOA) yields for each source.

	Q_{25}	Q_{50}	Q_{75}	MIR [$gO_3\ g^{-1}$]	SOA yield [gSOA g^{-1}]
Gasoline exhaust	12	21	35	4.5	0.023 ± 0.007
Diesel exhaust	15	28	54	2.5	0.15 ± 0.05
Non-tailpipe gasoline	4.1	8.1	18	2.0	0.0024 ± 0.0001
Petroleum gas source	7.6	20	89	0.82	~ 0
Dairy operations	5.7	11	26	1.3	~ 0

Note:
– Gasoline and diesel exhaust include both emissions of unburned fuel and products of incomplete combustion. MIR and SOA yield values for motor vehicle sources shown for comparison from Gentner et al. (2013) and Gentner et al. (2012) for comparison.
– Dairy operations include other cattle farming in the San Joaquin Valley, and the MIR value is for the NMOC fraction of the source profile.
– The average ozone formation potential (MIR) value is potentially an underestimate due to other organic compounds emitted, which may also impact the SOA formation potential (see Table 5 note).

3.3 Spatial distribution of sources

Using FLEXPART-WRF meteorological data and methods, distributions of back-trajectories were calculated for 6 and 12 h prior to arrival and measurement at the Bakersfield site. Overall averages, as well as day and nighttime averages, are shown for the entire campaign in Fig. 1. The influence of local emissions near the site is important at all times. Daytime measurements are largely impacted by transport from the north-northwest due to consistent up-valley flows during the day. In contrast, at night the wind speeds and direction are more variable and irregular with flows that arrive from all directions, but originate as up-valley flows from the north-northwest. Extensive reviews of meteorology and flow patterns in the San Joaquin Valley found elsewhere are consistent with the results presented in this work (Bao et al., 2007; Beaver and Palazoglu, 2009). The footprint analysis used in this study provides a good representation of the distribution of surface-level areas that influence parcels' contact with the surface layer and associated sources, but potentially has some uncertainty given the complexities of Bakersfield meteorology (Angevine et al., 2013).

Statistical meteorological modeling using ground site data resulted in a spatial distribution of petroleum gas emissions similar to that of oil wells in the southern San Joaquin Valley (Fig. 10). Additionally, canister samples taken via aircraft in the region show higher propane (a major component of the source profile) concentrations for some points in the southern part of the valley (Fig. 10c). Given the co-location of oil wells in the region and the spatial distribution of elevated concentrations of petroleum gas compounds, it is probable that the observed emissions occur at or near the wells during extraction, storage, and initial processing.

The statistical distribution of emissions of non-vehicular ethanol and methane were similar for both 6 and 12 h back-trajectories. The map of emissions is consistent with the distribution of dairies in the San Joaquin Valley (Figs. 11, 12) and aircraft measurements of ethanol and methane (Figs. 13, 14). While there are dairy operations within the 12 h footprint and the emitted methane and light alcohols have long atmospheric lifetimes, the dairies within the 6 h footprint are much more influential on elevated concentrations, especially at night. The spatial distributions of petroleum and dairy operation emissions clearly show that they are coming from different parts of the valley. The maps in this section provide strong supporting evidence that the vast majority of methane is emitted from dairy (and other cattle) operations.

The statistical emissions mapping method developed in this paper is a useful integration of concentration-weighting trajectory methods with the FLEXPART-WRF modeling platform. This emissions mapping tool is effective at locating point and area sources, especially for prominent sources in the San Joaquin Valley. The analyses of the spatial distribution of emissions from petroleum and dairy operations shown in this work are two applications of this technique. For these purposes, either concentration data or modeling outputs (e.g., source receptor models) can be used, both of which appear in this work. Further development of this approach will continue to improve its utility and quantitative outputs, but caution must be given to the transport timescales and tracer lifetime. There is one limitation to the current version of the statistical source footprint analysis. The area of analysis is limited to the distribution of sample footprints across all runs, and there is likely insufficient data to assess areas outside that total footprint. Nevertheless, the current method is excellent for looking at the most important sources that impact an area, such as Bakersfield in this study. Coverage could be improved in other studies by using data from multiple sites in a region, but care must be exercised to ensure the data is properly weighted. Overall, this work demonstrates the efficacy and usefulness of this tool, warrants further development, and future work should apply it on regional and continental scales, as appropriate, to locate primary sources of pollution.

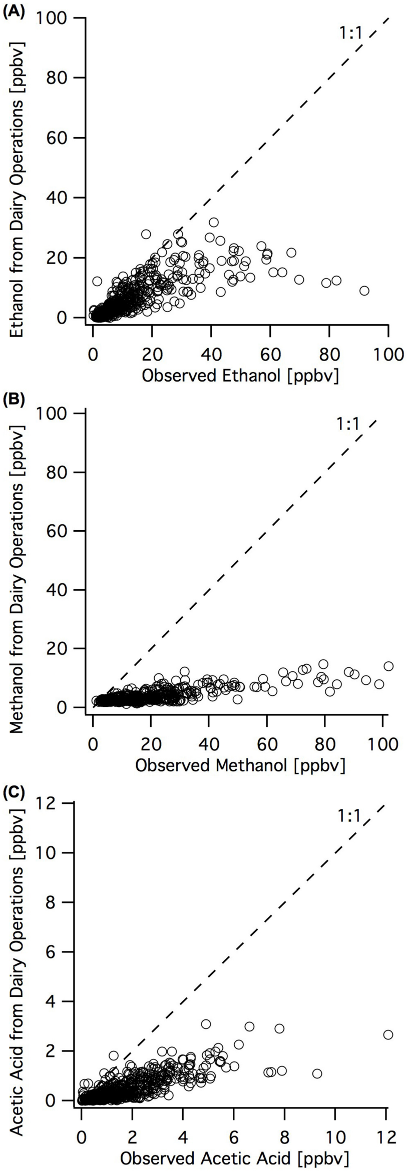

Figure 9. Estimated concentrations of non-methane organic compounds emitted by dairy operations shown against ambient observations at the Bakersfield ground site. Emissions are apportioned to dairy operations using the emission ratios of methane determined using aircraft and ground site measurements. On average, 45 % of observed **(A)** ethanol is from dairies, whereas, smaller fractions of **(B)** methanol (27 %) and **(C)** acetic acid (28 %) are from dairy operations. These fractions vary with time of day and source strength. Diurnal patterns of percent contributions from dairy operations are shown in Supplement Fig. S8.

3.4 Implications for air quality and emissions inventories

Both petroleum and dairy (and other cattle) operations are important sources of reactive organic carbon in the San Joaquin Valley. On a mass basis, observed VOC concentrations from petroleum extraction/processing were on the same order as emissions from motor vehicles. Yet, they represent a relatively minor contribution to potential ozone formation, as the average MIR value for the source ($0.82\,gO_3\,g^{-1}$) is $\sim$3–6 times less than that of motor vehicle sources. Direct contributions to secondary organic aerosol (SOA) from the petroleum operations source profile in this study are likely to be minimal, given that the yields for all of the alkanes with eight or less carbon atoms will be $0.002\,gSOA\,g^{-1}$ at most, with an organic particle loading of $10\,\mu g\,m^{-3}$ (Gentner et al., 2012). The potential ozone and SOA implications of petroleum operation emissions will depend greatly upon composition, which varies between regions. We did not observe any aromatic content, but other studies have observed aromatic and other larger compound fractions (Carter and Seinfeld, 2012; Gilman et al., 2013). Aromatics have been shown to be very effective precursors to SOA and ozone (Gentner et al., 2012; Carter, 2007). So, their presence in oil/gas emissions will have further implications for air quality.

Dairy operations in the San Joaquin Valley are largely responsible for the higher than typical ethanol concentrations in the San Joaquin Valley. Based on the primary compounds observed from dairy operations (ethanol, methanol, acetic acid), we infer that emissions have minor impacts on SOA formation, but have a greater potential to impact ozone formation with an MIR of $1.3\,gO_3\,g^{-1}$. The inclusion of other oxygenated compounds previously observed from dairy operations (e.g., Hafner et al., 2013) to the basic source profile in Table 5 may increase the ozone and SOA formation potential. Yet, in this study they were minor and not significantly correlated with other dairy emissions (see Sect. 3.2).

In Bakersfield during spring/summer, dairy operations were responsible for 22 % of anthropogenic non-methane organic carbon emissions and 13 % of potential anthropogenic ozone formation. Similarly, petroleum operations were responsible for 22 % of anthropogenic emissions and 8 % of potential ozone. Motor vehicles were responsible for the remaining 56 % of anthropogenic emissions, 79 % of anthropogenic potential ozone formation, and essentially all of the potential anthropogenic SOA formation. It is important to note that emissions from petroleum and dairy operations have substantial potential to impact the atmospheric chemistry leading to secondary pollution, but they themselves are not a major source of SOA precursors (note: does not consider aqueous chemical processing). These results apply to the emissions of VOCs from petroleum operations observed and characterized in this work; other recent work on petroleum operations has reported emissions of larger hydrocarbons that have higher SOA yields (Chan et al., 2013; Gilman et al., 2013). These five main sources are summarized in Fig. 15 and are very important sources for the San Joaquin Valley. There are other anthropogenic sources that likely contribute emissions on smaller urban scales that are

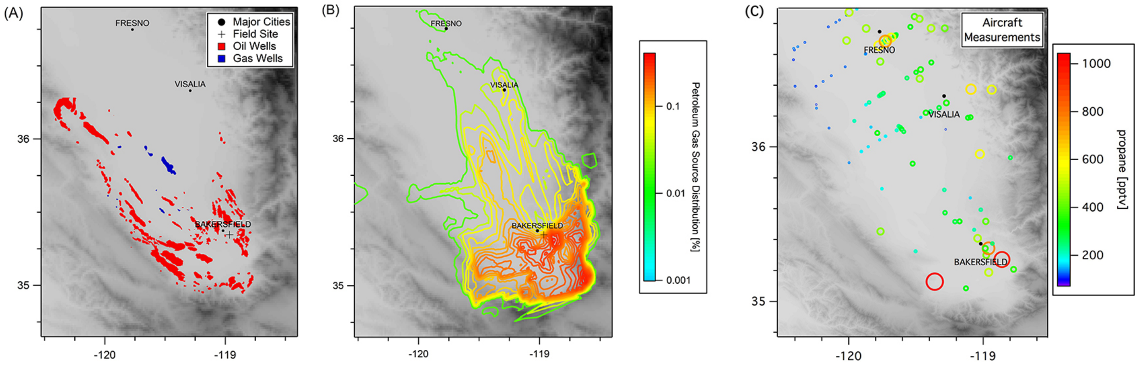

Figure 10. Maps of the southern part of the San Joaquin Valley with **(A)** the location of oil and gas wells, **(B)** the spatial distribution of petroleum gas emissions determined using statistical footprint analysis (6 h), and **(C)** aircraft canister measurements of propane, sized and colored by concentration. Together the maps show a similar distribution of wells and emissions in the region. Note: meteorological conditions, altitude, and local dilution varies between canister measurements.

Table 7. Comparison of the relative abundance of VOC emissions from each source observed in Bakersfield to CARB inventory for the San Joaquin Valley (SJV) and the portion of Kern County in the San Joaquin Valley including Bakersfield (SJV-Kern).

	Relative mass abundance in Bakersfield (this study)	Fraction of emissions [%] in inventory (absolute emission rate [tons day^{-1}])	
		SJV inventory	SJV-Kern inventory
Petroleum operations	22 %	15 % (28)	53 % (26)
Dairy operations	22 %	30 % (57)	9 % (4.5)
On- & off-road motor vehicles	56 %	55 % (104)	38 % (19)

Notes:
– Motor vehicle emissions are sum of on- and off-road since ambient source apportionment cannot discern between them; includes gasoline and diesel exhaust, and non-tailpipe gasoline emissions.
– Comparison is limited to discussed sources, biogenic emissions and other potentially important sources are excluded (for biogenic emissions from agriculture see Gentner et al., 2014).

not enumerated in this work. Such as the contributions of biogenic sources, which are another major factor for air quality in California's Central Valley.

In the comparison of the sources discussed in this work, the percent contribution of vehicular sources is larger in Bakersfield than it would be most places in the region. In non-urban areas of the San Joaquin Valley, motor vehicle emissions will still be important, but emissions from petroleum and dairy operations will make up a greater fraction of non-methane organic carbon in the atmosphere and will be responsible for a greater fraction of potential ozone formation. The results from Bakersfield in this study confirm the transport and importance of emissions from dairy operations throughout the San Joaquin Valley. Our results for potential ozone give a 3.5 : 1 ratio of potential ozone from gasoline vehicles to dairy operations in Bakersfield. When considering that there is a greater prevalence of motor vehicles around our measurement site and most dairy emissions are outside the county (Table 7), the ratio is similar to the valley-wide ratio of 3 : 2 for light-duty vehicles to livestock feed modeled by Hu et al. (2012). Overall, this, and other recent work (Howard et al., 2010a; Hu et al., 2012), demonstrates that motor vehicles and multiple source pathways at dairy operations are major emitters of reactive ozone precursors throughout the San Joaquin Valley. Elevated concentrations of non-vehicular ethanol that are largely linked to dairy operations warrants further evaluation of emission processes involving livestock silage, as ethanol has been demonstrated as a primary component of those emissions (Hafner et al., 2013; Howard et al., 2010a; Malkina et al., 2011).

Our results on the relative contributions from each source indicate a mix of influential sources. Given our location in an urban area in the southern San Joaquin Valley, where oil wells are concentrated, emissions from motor vehicles and petroleum operations are likely higher than other parts of the valley. The San Joaquin Valley has an abundance of

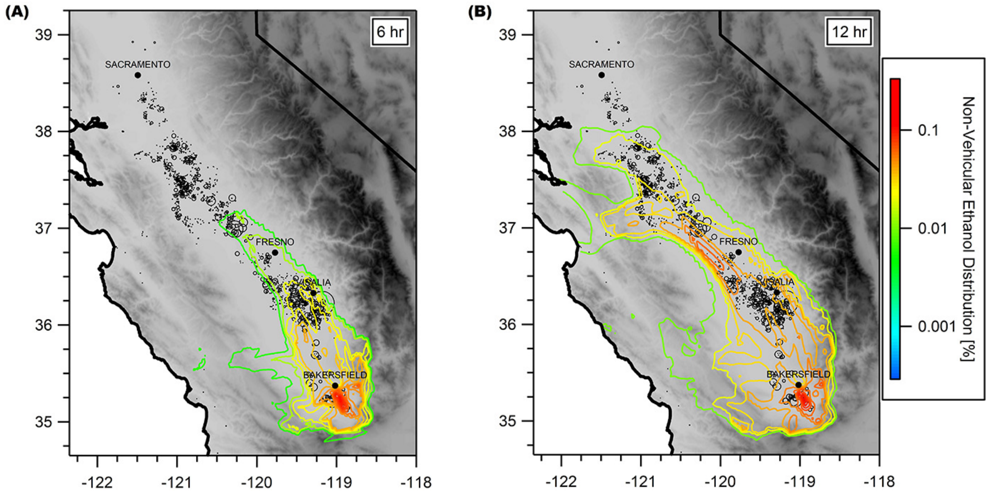

Figure 11. Statistical distribution of emissions of non-vehicular ethanol in the San Joaquin Valley shown as colored contours for 6 and 12 h footprints. Modeling results shown with the location of dairies as markers (o) scaled by the size of each dairy.

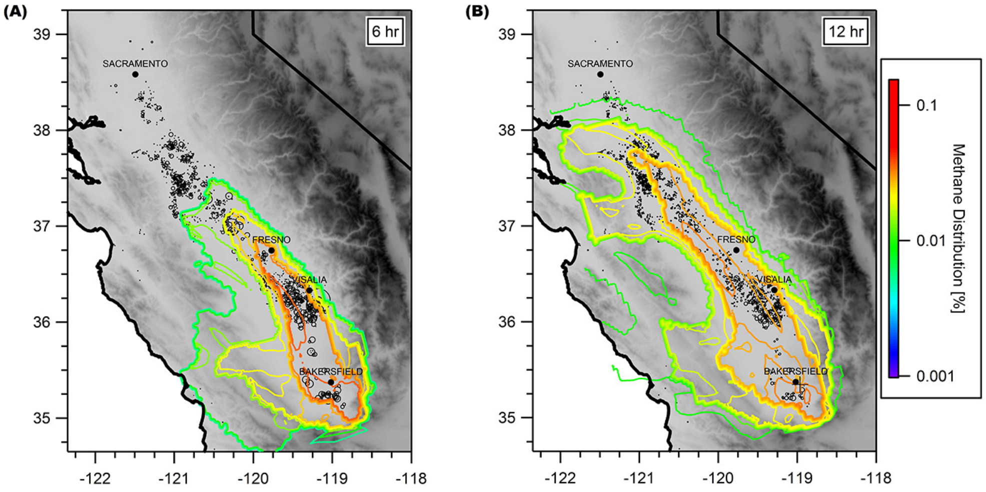

Figure 12. Statistical distribution of emissions of methane in the San Joaquin Valley shown as colored contours for 6 and 12 h footprints. Modeling results shown with the location of dairies as markers (o) scaled by the size of each dairy.

agriculture and is surrounded by natural vegetation that represents a large potential source of emissions following transport to other parts of the valley. Comprehensive modeling assessments need to evaluate the sources discussed here along with biogenic emissions of reactive organic gases from both agriculture and natural vegetation.

Comparing different assessments for emissions from multiple sources presents challenges relating to the definition of sources and spatial boundaries. Here, we provide a comparison of our relative emission magnitudes at the Bakersfield site to the CARB emission inventory for the San Joaquin Valley (Table 7). To promote consistency with our observed sources, we compare our petroleum operations source to emissions from oil/gas production and refining, and exclude petroleum marketing (and combustion from petroleum operations) since our observed source is clearly related to unrefined petroleum. While there are likely some differences in emissions, it is difficult to separate dairy cattle from other cattle, so we have assumed that we are observing all cattle in this study and include them with dairy operations. Although in the CARB inventory, dairy cattle represent almost 80 % of cattle-related emissions in the San Joaquin Valley. Similarly, we compare these sources to on- and off-road mobile sources as that is the best representation of the observed motor vehicle sources in our source apportionment.

There are potential seasonal effects among the 5 sources shown in Tables 6 and 7 and Fig. 15. The composition of gasoline fuel changes seasonally to reduce volatility by varying formulation, which affects the composition and magnitude of emissions. In the CARB almanac, VOC emissions

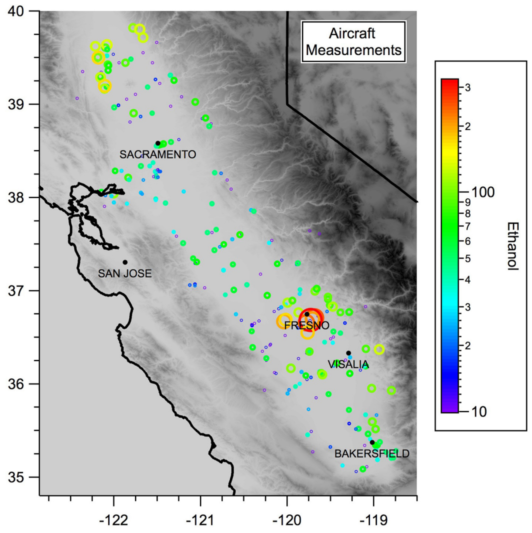

Figure 13. Aircraft canister measurements of ethanol in California's Central Valley shown as individual circles, sized and colored by ethanol concentration. Data were taken at varying altitudes above and below the boundary layer with a general filter for below 1000 m. Vertical gradients are responsible for some variability, but aircraft data support conclusions of other analyses showing large ethanol sources in the Central Valley: dairy operations in the San Joaquin Valley and rice cultivation in the Sacramento Valley. Note: meteorological conditions and local dilution varies between canister measurements. Also, alcohol measurements made using the canisters were prone to significant losses, so their use is only relative.

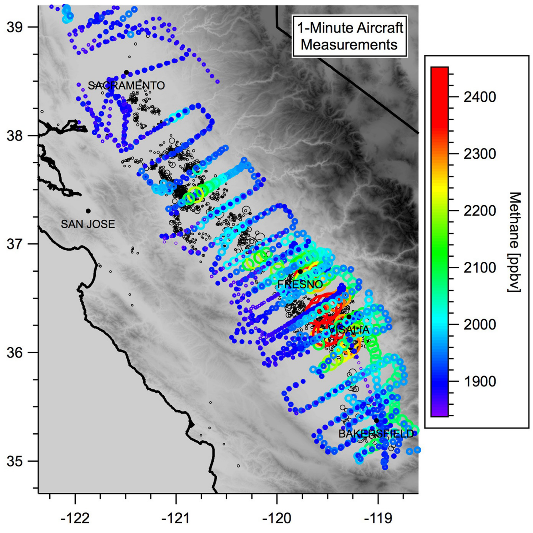

Figure 14. Map of observed methane concentrations over 7 flights in California's Central Valley shown as individual circles, sized and colored by methane concentration. Data were taken at varying altitudes above and below the boundary layer with general filter for below 1000 m. Vertical gradients and multiple flights are responsible for some variability, but methane enhancements in aircraft data show good correlation with the location of dairy operations (open black circles sized by bovine population). A map including the entire Sacramento Valley can be found in the Supplement (Fig. S11).

from dairy operations and petroleum production and refining have no seasonal change between summer and winter. The emissions we observe from both sources could be hypothesized to volatilize more in warmer weather, but we have insufficient data to assess seasonal changes and effects other than temperature may potentially play a role.

The CARB emissions inventory for the San Joaquin Valley reports an average of 28 tons ROG per day from petroleum operations (production and refining), which is equal to 27 % of on-and off-road mobile source emissions (72+32 tons per day) in the air basin (California Air Resources Board, 2010). This value is consistent with daytime ratios (18–51 %) observed at the Bakersfield site (Supplement Fig. S4) when vehicular emissions are greatest, but is smaller than nighttime ratios (62–120 %) and the overall ratio (39 %). Bakersfield is in much closer proximity to potential petroleum operations sources compared to other parts of the air basin, so nighttime ratios are significantly higher with relatively less vehicular traffic and local emissions play a larger role when there is less atmospheric dilution. A comparison on a smaller scale for the portion of Kern County in the San Joaquin Valley demonstrates the local importance of petroleum operations, as much of the San Joaquin Valley's petroleum operation emissions are in this county. For this area, petroleum production/refining emissions in the CARB inventory are equivalent to 139 % of on- and off-road mobile sources (California Air Resources Board, 2010). These observations are consistent with the statistical footprints shown in this work as daytime footprints encompass a larger area that stretches into other counties, while nighttime footprints are more heavily influenced by local emissions.

According to the CARB emission inventory, dairy and other cattle operations in the San Joaquin Valley emit 57 tons ROG per day, which is 80 % of non-vegetation farming-related emissions (California Air Resources Board, 2010). These emissions from dairy and cattle operations are equivalent to 55 % of on- and off-road motor vehicle emissions in the inventory, which is higher than the average non-methane organic carbon (NMOC) mass comparison at the Bakersfield measurement site (40 %). The CARB inventory for the San Joaquin Valley states that emissions from dairy operations are twice those from petroleum operations (dairy & other cattle operations ROG emissions = 2.0 × oil/gas production and refining ROG emissions). The average measured contributions from petroleum and dairy sources were equivalent at the Bakersfield site (Fig. 15). This is largely dependent on the distribution of petroleum operations relative to dairy operations, which is greatest in the southern part of the San Joaquin Valley (e.g., Bakersfield) where the oil wells and related operations are concentrated. Thus, the ratio of petroleum to dairy operation contributions goes up by several factors with decreased dilution and a greater influence of local sources

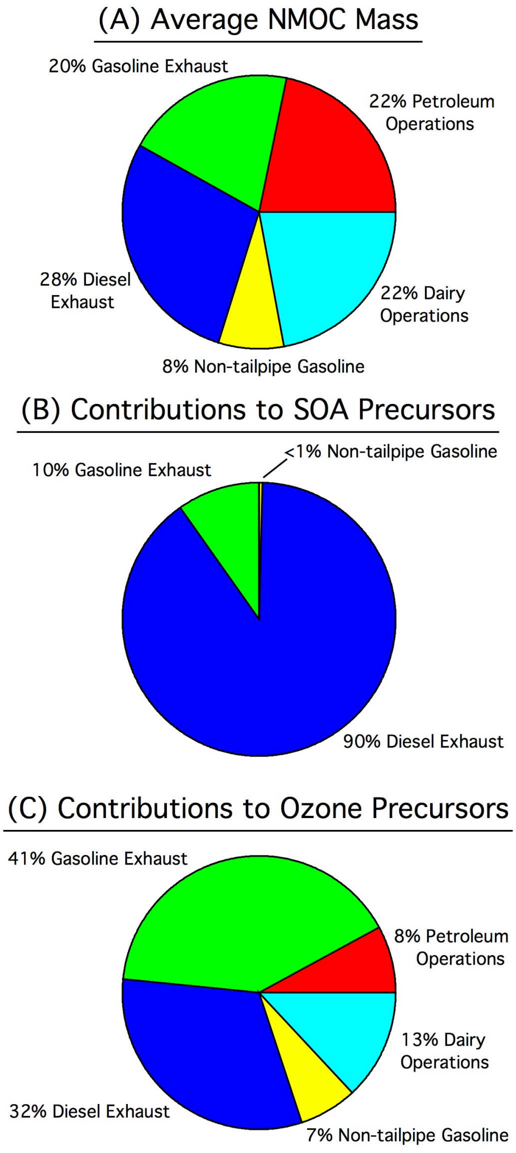

Figure 15. Breakdown of the contributions of prominent anthropogenic sources in Bakersfield for **(A)** total non-methane organic carbon (NMOC) mass (g), **(B)** precursors to secondary organic aerosol (SOA), and **(C)** precursors to ozone. Other sources/compounds may impact SOA formation indirectly via changes in photochemistry. The exhaust values here include unburned fuel emissions and products of incomplete combustion, and dairy operations include other cattle farming. Biogenic emissions from natural vegetation are excluded, but are likely to have important contributions to emissions and air quality in the San Joaquin Valley, but less so in the urban core of Bakersfield, CA. Note: the NMOC mass comparison in panel A is in terms of mass (similar to inventories), so ratios of sources will be slightly different from Table 5 where they are in mol carbon.

(Table 6). This is likely also the reason for the greater contribution from motor vehicles relative to dairy operations at the Bakersfield site versus the inventory. The greater prevalence of motor vehicles near the site increases its impact relative to the whole valley.

A comparison of the dairy operations source profile (Table 5) with the CARB emission inventory reveals that the ratio of methane to NMOC is consistent between our results and the inventory, 93 % vs. 92 % methane. Additionally, the existing CARB inventory for the San Joaquin Valley reflects the difference in the magnitude of methane emissions between the two sources, with total methane emissions from dairy (and other cattle) operations being an order of magnitude greater than petroleum production operations, and responsible for at least 87 % of methane emissions. Furthermore, for petroleum operations, the majority (81 %) of fugitive methane (and ethane by inventory definition) emissions are from oil/gas marketing rather than production/refining (California Air Resources Board, 2010). Overall, these intercomparisons, while rough, provide validation of the CARB emission inventory for relative emission rates of dairy and petroleum operations in the San Joaquin Valley.

The San Joaquin Valley, and the Central Valley as a whole, contains a complex mixture of both anthropogenic and biogenic sources of reactive gas-phase organic carbon on both regional and urban scales. Our focus in this paper has been quantifying regional emissions from petroleum and dairy operations, comparing their emission rates to other anthropogenic sources, and evaluating their importance for air quality in the urban area of Bakersfield and the San Joaquin Valley. The dairy and petroleum sources are clearly relevant to air quality on both local and regional scales for ozone formation, but are likely not as important as sources of precursors to SOA. This study provides important new information, expanding knowledge on the suite of compounds emitted from these sources and providing new useful information on their sources profiles.

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Exhibit 5

MEMORANDUM

TO: Brent Newell
FROM: Jonathan Sha
DATE: February 9, 2016
RE: Porter Ranch and Dairy Industry Methane Emissions Comparison

On October 23, 2016, a natural gas leak was discovered coming from a well within the Aliso Canyon Underground Storage Field in Los Angeles County.[1] The Southern California Gas Company, which owns and maintains the well, has so far been unable to stop the leak.[2] The resulting leak has garnered much attention from the public and media for its adverse effects on the environment and public health. Since the leak was discovered the California Air Resource Board has estimated that the leak has cumulatively emitted 100,353 tons of CH_4 into the air.[3]

What is perhaps more alarming, however, is that a far greater source of methane gas has been allowed to emit its GHG pollution unabated since the inception of AB 32.[4] In 2013, the ARB estimates California dairy enteric emissions of 362,000 tons of CH_4* and dairy liquefied manure management emissions of an additional 452,000 tons of CH_4*.[5] Since 2006, when AB 32 became law, until 2013, the ARB estimates California dairy enteric emissions of approximately 2.84 million tons of CH_4* and dairy liquefied manure management emissions of approximately 3.53 million tons of CH_4*.[6] California dairy emissions are projected to remain constant for the next 20 years, meaning, for the next 20 years, California dairy enteric and liquefied manure management will continue to emit approximately 814,000 tons of $CH_{4,}$* annually.[7] The ARB has not promulgated regulations to require methane reductions at dairies, despite having the authority to do so under AB 32.

While the Porter Ranch gas leakage rate has fluctuated over time, since its announcement the leak has emitted an average of 955 tons of CH_4 per day.[8] Comparatively, California dairies emit an average of 2,230 tons of CH_4 per day.[9] Over the course of the Porter Ranch gas leak between October 23 and February 4, California dairies emitted a total of 234,164 tons of CH_4, more than double the amount emitted by the Porter Ranch leak. Even its peak flow of 58,000 kilograms of methane per hour as measured on November 28, the Porter Ranch leak emitted 1,534 tons of CH_4 per day, well below that of California dairies.[10]

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[1] http://www.caloes.ca.gov/ICESite/Pages/Aliso-Canyon.aspx
[2] http://www.caloes.ca.gov/ICESite/Pages/Aliso-Canyon.aspx
[3] http://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_natural_gas_leak_updates-sa_flights_thru_feb_4_2016.pdf (As of February 4, 2016)
[4] http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf
[5] http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_ipcc_all_2000-13_20150831.pdf
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[7] http://www.arb.ca.gov/cc/shortlived/2015appendixa.pdf
[8] http://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_natural_gas_leak_updates-sa_flights_thru_feb_4_2016.pdf (As of February 4, 2016)
[9] http://www.arb.ca.gov/cc/shortlived/2015appendixa.pdf
[10] http://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_natural_gas_leak_updates-sa_flights_thru_feb_4_2016.pdf (As of February 4, 2016)

Though California seeks to fix the Porter Ranch leak, it is now time to also address the massive amount of unregulated methane emitted from the dairy industry that has escaped regulation for far too long.

* Figure calculated by converting MMTCO2e to CH_4 using an IPCC 100-year GWP for CH_4. An IPCC 100-year GWP for CH_4 was selected according to California inventory tracking methodology from 2002-2014 outlined in http://www.arb.ca.gov/cc/inventory/data/misc/ghg_inventory_trends_00-12_2014-05-13.pdf. IPCC 100-year GWP for CH4 located at https://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html.

Exhibit 6

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Most Polluted Cities

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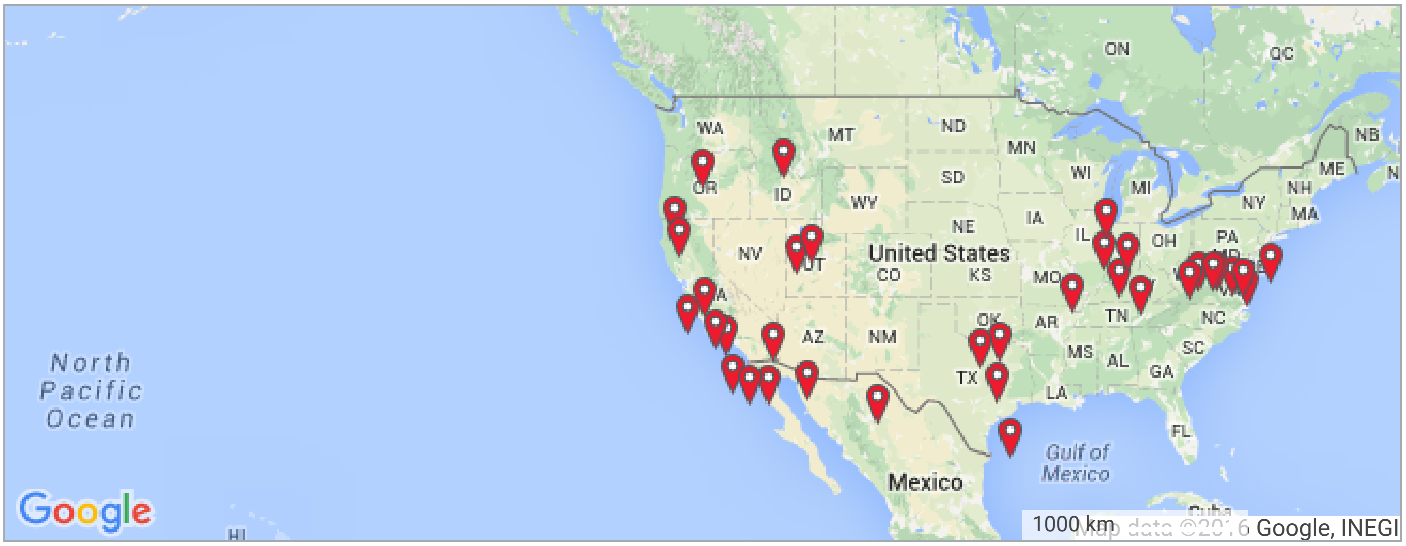

By Ozone

#1: Los Angeles-Long Beach, CA
#2: Bakersfield, CA
#3: Visalia-Porterville-Hanford, CA

#4: Fresno-Madera, CA

#5: Phoenix-Mesa-Scottsdale, AZ

#6: Sacramento-Roseville, CA

#7: Modesto-Merced, CA

#8: Denver-Aurora, CO

#9: Las Vegas-Henderson, NV-AZ

#10: Fort Collins, CO

#11: Dallas-Fort Worth, TX-OK

#12: El Centro, CA

#13: San Diego-Carlsbad, CA

#14: New York-Newark, NY-NJ-CT-PA

#15: Houston-The Woodlands, TX

#16: San Jose-San Francisco-Oakland, CA

#16: El Paso-Las Cruces, TX-NM

#18: St. Louis-St. Charles-Farmington, MO-IL

#18: Tulsa-Muskogee-Bartlesville, OK

#18: Grand Rapids-Wyoming-Muskegon, MI

#21: Chicago-Naperville, IL-IN-WI

#22: Sheboygan, WI

#23: San Luis Obispo-Paso Robles-Arroyo Grande, CA

#24: Oklahoma City-Shawnee, OK

#25: Edwards-Glenwood Springs, CO

By Year Round Particle Pollution

#1: Bakersfield, CA

#2: Visalia-Porterville-Hanford, CA

#3: Fresno-Madera, CA

#4: Los Angeles-Long Beach, CA

#5: El Centro, CA

#6: San Jose-San Francisco-Oakland, CA

#6: Modesto-Merced, CA

#8: Pittsburgh-New Castle-Weirton, PA-OH-WV

#9: Harrisburg-York-Lebanon, PA

#10: Louisville/Jefferson County--Elizabethtown--Madison, KY-IN

#11: Cleveland-Akron-Canton, OH

#12: Philadelphia-Reading-Camden, PA-NJ-DE-MD

#13: Indianapolis-Carmel-Muncie, IN

#14: Cincinnati-Wilmington-Maysville, OH-KY-IN

#14: Altoona, PA

#16: Houston-The Woodlands, TX

#16: Lancaster, PA

#16: Johnstown-Somerset, PA

#16: San Luis Obispo-Paso Robles-Arroyo Grande, CA

#20: Detroit-Warren-Ann Arbor, MI

#21: Erie-Meadville, PA

#22: Birmingham-Hoover-Talladega, AL

#23: Fairbanks, AK

#23: Wheeling, WV-OH

#23: Little Rock-North Little Rock, AR

By Short-Term Particle Pollution

#1: Bakersfield, CA

#2: Fresno-Madera, CA

#3: Visalia-Porterville-Hanford, CA

#4: Modesto-Merced, CA

#5: Fairbanks, AK

#6: Salt Lake City-Provo-Orem, UT

#7: Logan, UT-ID

#8: San Jose-San Francisco-Oakland, CA

#9: Los Angeles-Long Beach, CA

#10: Missoula, MT

#11: Reno-Carson City-Fernley, NV

#11: Lancaster, PA

#13: El Centro, CA

#14: Pittsburgh-New Castle-Weirton, PA-OH-WV

#15: Yakima, WA

#16: Anchorage, AK

#17: Sacramento-Roseville, CA

#18: Harrisburg-York-Lebanon, PA

#18: Philadelphia-Reading-Camden, PA-NJ-DE-MD

#20: El Paso-Las Cruces, TX-NM

#21: South Bend-Elkhart-Mishawaka, IN-MI

#21: Phoenix-Mesa-Scottsdale, AZ

#21: Eugene, OR

#24: New York-Newark, NY-NJ-CT-PA

#25: Medford-Grants Pass, OR

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Breathing ozone irritates the lungs, resulting in something like a bad sunburn within the lungs.

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Exhibit 7

EPA FACT SHEET

SOCIAL COST OF CARBON

Background

EPA and other federal agencies use the social cost of carbon (SC-CO_2) to estimate the climate benefits of rulemakings. The SC-CO_2 is an estimate of the economic damages associated with a small increase in carbon dioxide (CO_2) emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO_2 reduction).

The SC-CO_2 is meant to be a comprehensive estimate of climate change damages and includes, among other things, changes in net agricultural productivity, human health, property damages from increased flood risk and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. However, it does not currently include all important damages. The IPCC Fifth Assessment report observed that SC-CO_2 estimates omit various impacts that would likely increase damages. The models used to develop SC-CO_2 estimates do not currently include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models naturally lags behind the most recent research. Nonetheless, the SC-CO_2 is a useful measure to assess the benefits of CO_2 reductions.

The timing of the emission release (or reduction) is key to estimation of the SC-CO_2, which is based on a present value calculation. The integrated assessment models first estimate damages occurring after the emission release and into the future, often as far out as the year 2300. The models then discount the value of those damages over the entire time span back to present value to arrive at the SC-CO_2. For example, the SC-CO_2 for the year 2020 represents the present value of climate change damages that occur between the years 2020 and 2300 (assuming 2300 is the final year of the model run); these damages are associated with the release of one ton of carbon dioxide in the year 2020. The SC-CO_2 will vary based on the year of emissions for multiple reasons. In model runs where the last year is fixed (e.g., 2300), the time span covered in the present value calculation will be smaller for later emission years—the SC-CO_2 in 2050 will include 40 fewer years of damages than the 2010 SC-CO_2 estimates. This modeling choice—selection of a fixed end year—will place downward pressure on the SC-CO_2 estimates for later emission years. Alternatively, the SC-CO_2 should increase over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater levels of climatic change.

One of the most important factors influencing SC-CO_2 estimates is the discount rate. A large portion of climate change damages are expected to occur many decades into the future and the present value of those damages (the value at present of damages that occur in the future) is highly dependent on the discount rate. To understand the effect that the discount rate has on present value calculations, consider the following example. Let’s say that you have been promised that in 50 years you will receive $1 billion. In “present value” terms, that sum of money is worth $291 million today with a 2.5 percent discount rate. In other words, if you invested $291 million today at 2.5 percent and let it compound, it would be worth $1 billion in 50 years. A higher discount rate of 3 percent would decrease the value today to $228 million, and the value would be even lower—$87 million-- with a 5 percent rate. This effect is even more pronounced when looking at the present value of damages further out in time. The value of $1 billion in 100 years is $85 million, $52 million, and $8 million, for discount rates of 2.5 percent, 3 percent, and 5 percent, respectively. Similarly, the selection of a 2.5 percent discount rate would result in higher SC-CO_2 estimates than would the selection of 3 and 5 percent rates, all else equal.

Process Used to Develop the Social Cost of Carbon

An interagency working group was convened by the Council of Economic Advisers and the Office of Management and Budget in 2009-2010 to design an SC-CO_2 modeling exercise and develop estimates for use in rulemakings. The interagency group was comprised of scientific and economic experts from the White House and federal agencies, including: Council on Environmental Quality, National Economic Council, Office of Energy and Climate Change, and Office of Science and Technology Policy, EPA, and the Departments of Agriculture, Commerce, Energy, Transportation, and Treasury. The interagency group identified a variety of assumptions, which EPA then used to estimate the SC-CO_2 using three integrated assessment models, which each combine climate processes, economic growth, and interactions between the two in a single modeling framework.

Social Cost of Carbon Values

The 2009-2010 interagency group recommended a set of four SC-CO_2 estimates for use in regulatory analyses. The first three values are based on the average SC-CO_2 from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent. SC-CO_2 estimates based on several discount rates are included because the literature shows that the SC-CO_2 is highly sensitive to the discount rate and because no consensus exists on the appropriate rate to use for analyses spanning multiple generations. The fourth value is the 95th percentile of the SC-CO_2 from all three models at a 3 percent discount rate, and is intended to represent the potential for higher-than-average damages. See the 2010 SC-CO_2 Technical Support Document (PDF, 51pp, 854K) for a complete discussion about the methodology and resulting estimates.

The interagency group updated these estimates, using new versions of each integrated assessment model and published them in May 2013. The 2013 interagency process did not revisit the 2009-2010 interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios or equilibrium climate sensitivity). Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and as used in the peer-reviewed literature. The 2010 SC-CO_2 Technical Support Document (PDF, 51pp, 854K) provides a complete discussion of the methods used to develop these estimates and the current SC-CO_2 TSD presents and discusses the 2013 update (including minor technical corrections to the estimates published in July 2015).[1]

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[1] Both the 2010 SC-CO2 TSD and the current TSD are available at: https://www.whitehouse.gov/omb/oira/social-cost-of-carbon.

The four SC-CO_2 estimates are: $14, $46, $68, and $138 per metric ton of CO_2 emissions in the year 2025 (2007 dollars).[2]

The table below summarizes the four SC-CO_2 estimates in certain years.

Social Cost of CO_2, 2015-2050 [a] (in 2007 Dollars per metric ton CO_2)

Source: Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)

	Discount Rate and Statistic			
Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th percentile**
2015	$11	$36	$56	$105
2020	$12	$42	$62	$123
2025	$14	$46	$68	$138
2030	$16	$50	$73	$152
2035	$18	$55	$78	$168
2040	$21	$60	$84	$183
2045	$23	$64	$89	$197
2050	$26	$69	$95	$212

[a] The SC-CO_2 values are dollar-year and emissions-year specific.

Examples of Applications to Rulemakings

EPA has used the SC-CO_2 to analyze the carbon dioxide impacts of various rulemakings since the interagency group first published estimates in 2010. Examples of these rulemakings include:

- The Joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards (2012-2016)
- Amendments to the National Emission Standards for Hazardous Air Pollutants and New Source Performance Standards (NSPS) for the Portland Cement Manufacturing Industry
- Regulatory Impact Results for the Reconsideration Proposal for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Source

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[2] The current version of the SCC TSD is available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. The TSDs present SC-CO2 in $2007.

- Proposed National Emission Standards for Hazardous Air Pollutants (NESHAP) for Mercury Emissions from Mercury Cell Chlor Alkali Plants
- Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units Standards
- Final Mercury and Air Toxics Standards
- Joint EPA/Department of Transportation Rulemaking to establish Medium- and Heavy -Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards
- Proposed Carbon Pollution Standard for Future Power Plants
- Joint EPA/Department of Transportation Rulemaking to establish 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards

Limitations

The interagency group noted a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Additional details are discussed in the Technical Support Documents. [3]

Next Steps

In addition, the Office of Management and Budget (OMB) has issued a response to the public comments received through its solicitation for comments on the SC-CO_2 estimates. In this response, OMB announced plans to obtain expert, independent advice from the National Academies of Sciences, Engineering, and Medicine on how to approach future updates to the SC-CO_2 estimates. To help synthesize the technical information and input reflected in the comments, and to add additional rigor to the next update of the SC-CO_2, the interagency working group plans to seek independent expert advice on technical opportunities to improve the SC-CO_2 estimates from the Academies. The Academies' review will help to ensure that the SC-CO_2 estimates used by the federal government continue to reflect the best available science and methodologies.

After careful evaluation of the full range of comments, the interagency working group continues to recommend the use of the current SC-CO_2 estimates in regulatory impact analysis until further updates can be incorporated into the estimates.

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[3] Both the 2010 SC-CO_2 TSD and the current TSD are available at: https://www.whitehouse.gov/omb/oira/social-cost-of-carbon.

Exhibit 8

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Reactive Organic Gas Emissions from Livestock Feed Contribute Significantly to Ozone Production in Central California

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The San Joaquin Valley (SJV) in California currently experiences some of the highest surface ozone (O_3) concentrations in the United States even though it has a population density that is an order of magnitude lower than many urban areas with similar ozone problems. Previously unrecognized agricultural emissions may explain why O_3 concentrations in the SJV have not responded to traditional emissions control programs. In the present study, the ozone formation potentials (OFP) of livestock feed emissions were measured on representative field samples using a transportable smog chamber. Seven feeds were considered: cereal silage (wheat grain and oat grain), alfalfa silage, corn silage, high moisture ground corn (HMGC), almond shells, almond hulls, and total mixed ration (TMR = 55% corn silage, 16% corn grain, 8% almond hulls, 7% hay, 7% bran + seeds, and 5% protein + vitamins + minerals). The measured short-term OFP for each gram of reactive organic gas (ROG) emissions from all livestock feed was 0.17−0.41 g-O_3 per g-ROG. For reference, OFP of exhaust from light duty gasoline powered cars under the same conditions is 0.69 ± 0.15 g-O_3 per g-ROG. Model calculations were able to reproduce the ozone formation from animal feeds indicating that the measured ROG compounds account for the observed ozone formation (i.e., ozone closure was achieved). Ethanol and other alcohol species accounted for more than 50% of the ozone formation for most types of feed. Aldehydes were also significant contributors for cereal silage, high moisture ground corn, and total mixed ration. Ozone production calculations based on feed consumption rates, ROG emissions rates, and OFP predict that animal feed emissions dominate the ROG contributions to ozone formation in the SJV with total production of 25 ± 10 t O_3 day^{-1}. The next most significant ROG source of ozone production in the SJV is estimated to be light duty vehicles with total production of 14.3 ± 1.4 t O_3 day^{-1}. The majority of the animal feed ozone formation is attributed to corn silage. Future work should be conducted to reduce the uncertainty of ROG emissions from animal feeds in the SJV and to include this significant source of ozone formation in regional airshed models.

1. Introduction

Ozone (O_3) is a persistent public health problem with serious economic consequences in the United States. In the years 2005−2007, more than 400 counties had 8 h average O_3 concentrations higher than 75 ppb (the most recent health-based National Ambient Air Quality Standard) (*1*). Three of six counties with the highest O_3 concentrations were located in California's San Joaquin Valley (SJV), while the remaining "top six" counties were located in Southern California (*2*). The severity of the O_3 problem in the SJV counties is puzzling given that they have a combined population of only 2.1 M compared to 14 M residents in the top Southern California counties. Higher temperatures, less summer cloud cover, and longer periods of stagnation in the SJV explain part of this trend, but even the most sophisticated computer models that account for all of these effects predict that O_3 concentrations in the SJV should be decreasing faster than currently observed in response to emissions control programs.

Ozone is produced by the photochemical reaction of oxides of nitrogen (NO_x) and reactive organic gases (ROGs). Lower ozone concentrations generally result from reductions in ROG emissions in urban areas. NO_x control is a more effective means to decrease ozone concentrations in regions where biogenic and other natural sources account for the majority of the ROG emissions. Photochemical model results based on current emissions inventories predict that NO_x control is a more efficient method for ozone reduction in the SJV, but that conclusion is subject to review as new ROG emissions sources are discovered. One possible cause for unexpected O_3 formation in the SJV is missing ROG emissions associated with the intensity of agricultural activities in the region. Almost 10% of the agricultural output for the entire United States comes from the SJV (*3*). The California Air Resources Board recently estimated that reactive organic gas (ROG) emissions from dairy cattle waste are the second largest source of O_3 formation in the SJV (with motor vehicle exhaust being the largest source) (*4*). Direct testing suggests that this initial estimate for dairy cattle waste is overstated since animal emissions do not contain ROGs with high ozone formation potential (OFP) (*5, 6*). Nevertheless, the OFPs of many other agricultural ROGs have not yet been tested, making agricultural emissions a high priority for further analysis.

Recent studies have identified animal feeds as one possible ROG source of agricultural OFP (*7, 8*). The ROG flux measured from silage and total mixed ration (TMR) was 2 orders of magnitude higher than comparable fluxes from animal waste (*7*). Chamber measurements confirm that animal feed ROG emissions are significantly higher than animal waste emissions and several of the animal feed ROG compounds have potentially high OFP (*8*). Neither of these previous studies directly quantified the OFP from animal feed or performed total ozone closure experiments, leaving the contribution of this source to regional ozone formation unknown.

The purpose of the present study is to directly measure the OFP of commonly used animal feeds and to estimate the importance of this ROG source for O_3 formation relative to other common ROG sources. A transportable smog chamber was used to measure OFP from seven feed types including one feed mixture under realistic agricultural conditions. Measured ROG emissions from feed placed into an envi-

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ronmental chamber were used to initialize model calculations of O_3 formation that were compared to measured values (ozone closure experiments). Finally, total emissions rates of ROGs from animal feeding operations were estimated for the SJV so that the importance of this source could be judged relative to other common ROG sources that contribute to O_3 production.

2. Materials and Methods

2.1. Field Experiments. The OFP of sources too complicated to reproduce in the laboratory can be measured directly in the field using transportable smog chambers (*5, 9*). Ozone formation is measured by introducing a source gas into a well mixed chamber that contains background NO_x and reactive organic gases (ROG) that represents conditions in the region of interest. The background NO_x and ROG produce ozone when it is exposed to ultraviolet (UV) radiation. The OFP for the target source is defined to be the additional ozone that is formed when emissions from that source are added to the background mixture. The one drawback to transportable chambers is that they are usually smaller than laboratory chambers. The reduced size limits experiments to shorter times and the larger surface to volume ratios require extra care when accounting for wall effects. The benefits of making ozone measurements directly from complex sources far outweigh these limitations.

In the present study, a mobile ozone chamber assay (MOChA) was used to directly measure OFP from livestock feeds. The MOChA consists of a 1 m^3 Teflon film reaction chamber housed within a wooden enclosure sitting on top of a modified trailer. The inner surface of the enclosure is covered with highly reflective aluminum sheeting, which helps to maximize UV irradiation of the reaction chamber. The UV irradiation is supplied by up to 26 UV lamps (model no. F40BL, Sylvania) with peak intensity at a wavelength of 350 nm. The lamps are mounted approximately 50 cm from the reaction chamber. The number of lamps was adjusted to produce ~50 ± 2 W/m^2 of UV output, which is typical for conditions in Central California during the summer months. The intensity of UV irradiation was measured before and after each experiment using a photometer (model no. PMA-2111, Solar Light Co. Inc., Glenside, PA).

During a typical experiment, the reaction chamber was filled with source air using a Teflon diaphragm pump. The target concentration of background NO_x was added from a high pressure cylinder as a 95% NO_2/5% NO mixture by volume. The background ROG used in the present study consisted of a 55 ± 1% ethene, 33 ± 1% *n*-hexane, and 12 ± 1% xylenes mixture by volume that was designed to simulate background ROG concentrations in the SJV during stagnation events. The composition of the background ROG was chosen to represent diluted urban plumes based on the "mini-surrogate" developed by Carter et al. (*10*). A grab canister sample (*11*) of the ROG concentrations was collected, the lights were turned on, and a three-hour ozone formation experiment was performed. Ozone, NO_x, relative humidity, and temperature measurements were made at regular intervals and logged to a computer. A second grab sample of ROG concentrations was collected at the end of the experiment, the lights were turned off, and the bag was evacuated and flushed using a clean air generator (model no. ZA-750−12, Perma Pure Inc., Toms River, NJ). Further details of the MOChA standard operating procedures and initial validation experiments are provided elsewhere (*5*).

Ozone formation experiments were performed on seven different types of feed obtained from a commercial local dairy. Those tested feeds included cereal silage (wheat grain and oat grain), alfalfa silage, corn silage, high moisture ground corn (HMGC), almond shells, almond hulls, and total mixed ration (TMR = 55% corn silage, 16% corn grain, 8% almond hulls, 7% hay, 7% bran+seeds, and 5% protein + vitamins + minerals on a as-fed basis). Alfalfa silage was tested under two conditions: <1 week of fermentation and ~1 month of fermentation.

Feed samples were collected from trench silos on the dairy farm and moved to the testing facility in large double wrapped plastic bags. For cereal, alfalfa, and corn silage, a section of the silage face was removed so that the entire feed sample was collected from the anaerobic region. Air was removed from the plastic bags and they were sealed for transportation to the UC Davis Department of Animal Science where experiments were conducted. The test chamber was a 4.4 × 2.8 × 10.5 m sealed room with mechanically controlled ventilation. A detailed description of this facility can be found elsewhere (*6*). Feed samples were weighed and then placed in a circular bin that set on the floor of the chamber. The circular bin ensured that each feed type had the same exposed surface area (2.63 m^2) during an experiment. The effective density of each of the feed types in kg per m^3 was: corn silage (300 ± 40), alfalfa silage (260 ± 30), cereal silage (300 ± 35), HMGC (640 ± 70), almond shells (150 ± 20), and almond hulls (160 ± 20). After six minutes (the air residence time in the chamber), MOChA air samples were drawn from the ventilation outlet of the testing room through a 10 m Teflon tube. Canister samples, DNPH-silica cartridges (model no. 037500, Waters Corp, MA), and sorbent tube (model no. 226−119, SKC Inc., Eighty-Four, PA) samples were also collected inside the testing facility for supplemental ROG analysis. DNPH cartridges were eluted with acetonitrile and analyzed using high performance liquid chromatography (HPLC), while sorbent tube and canister samples were analyzed using gas-chromatography mass-spectrometry (GC-MS) (*11–14*). The ozone formation of each feed type was measured under two background ROG conditions: with background ROG added to the system and without background ROG. Initial NO_x concentrations were 50 ± 5 ppb.

2.2. Model Calculations. Model calculations were used to perform ozone closure experiments and to estimate OFP under ROG/NO_x ratios other than those tested during experiments. Ozone closure experiments attempt to reconcile ozone measurements at the end of an experiment with ozone predictions made using only the ROG and NO_x concentrations measured at the beginning of an experiment. Extensive under-predictions of ozone formation would suggest the presence of unidentified ROG compounds with significant OFP (no such under-predictions were detected in the current study). Simulations were carried out using a modified version of the Caltech Atmospheric Chemistry Mechanism (CACM) (*15*). Modifications were made to CACM in order to accurately represent ethanol and acetaldehyde chemistry in rural conditions and to better simulate the spectrum of UV radiation emitted by the MOChA lamps (*5*). Model predictions for OFP were found to be in good agreement with previous OFP measurements for animal waste sources (*5, 9*). Likewise, in the present study model predictions are able to reproduce OFP for animal feed sources (see the Supporting Information (SI)).

3. Results and Discussion

A detailed list of the chemical species measured across all feed types and their lumped model category is provided in the SI. Alkanes (ALKL + ALKH), alkenes (OLEL + OLEH), and ketones (KETL + KETH) are lumped into two categories based on the number of carbon atoms in each molecule. Esters are lumped into one of the two ketone categories. Alcohols (ALCH) are represented with a single lumped category with the exception of explicit treatment for ethanol (ETOH). Acetaldehyde (ALD1) is also represented explicitly, while the rest of the aldehydes are grouped into two lumped categories representing higher molecular weight aldehydes (ALD2) and

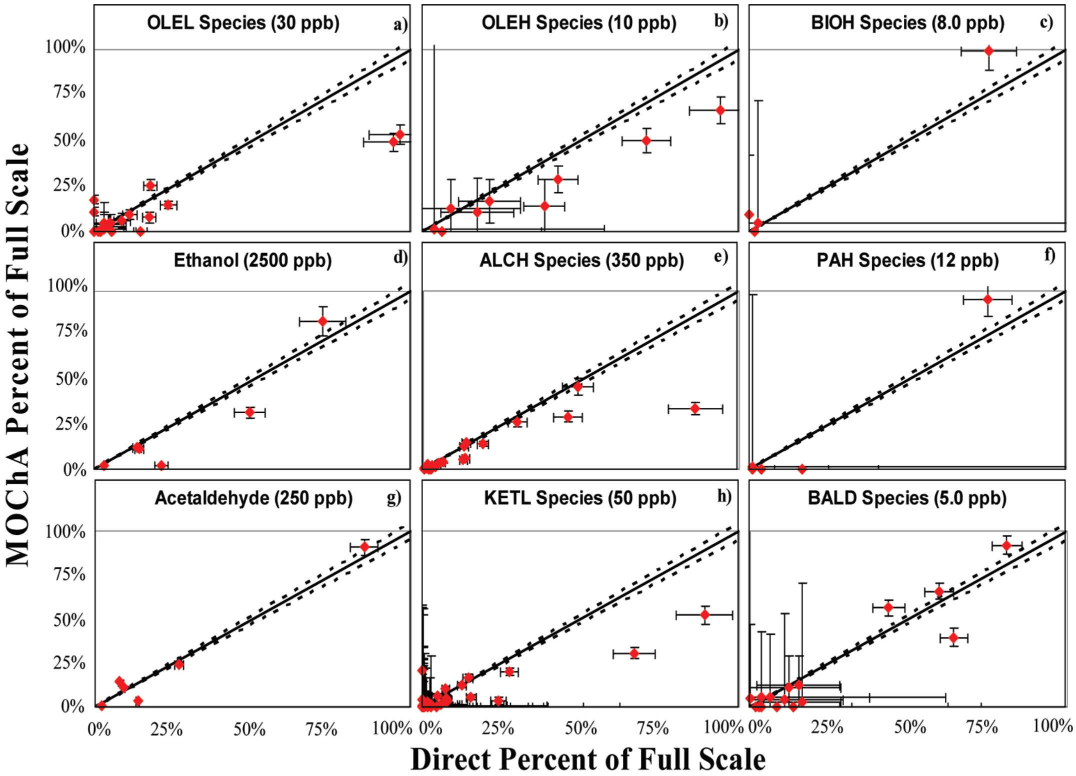

FIGURE 1. MOChA ROG canisters sample concentrations vs Direct ROG (from the test chamber) canister sample concentration for each lumped chemical species (concentrations in ppb). Note that each graph is from 0 to 100% of the maximum concentration, which is displayed in parentheses next to the species type.

cyclic aldehydes (BALD). Biogenics (BIOL + BIOH) and aromatic species (AROL + AROH) are lumped according to their SOA yield, whereas phenol (PHEN) is represented explicitly. A more detailed description of the CACM lumping scheme is provided elsewhere (*5, 15*), as are emissions rates for each of the chemical species (*8*).

Figure 1 depicts the differences between ROG species concentrations measured in the MOChA vs direct measurements in the feed testing facility. Each graph represents either an individual chemical species or a lumped chemical species category tracked by model calculations (see SI Table S1) with direct measurements of ROG on the *x*-axis and MOChA measurements of ROG on the *y*-axis. Regression analysis (see SI Table S2) was performed on MOChA vs direct measurements and the results show that those lumped species with average concentrations greater than 2 ppb had R^2 values above 0.84. The two species with the highest average concentration, ethanol (650 ppb) and acetaldehyde (60 ppb), had R^2 values of 0.91 and 0.98 respectively and the regression slope fell within one standard deviation of the 1:1 line (0.94 ± 0.27 and 1.04 ± 0.13, respectively). Four of the eight lumped categories with average concentrations above 2 ppb (ALCH, OLEL, OLEH, and KETL) had regression slopes <0.68 with 95% confidence intervals below the 1:1 line consistent with losses to surfaces in the ventilation ducts and sampling lines. The two lumped species right at the 2 ppb threshold (BIOH and PAH) had regression slopes >1.21 but closer inspection shows that this result was driven by a single data point in each case. The corresponding 95% confidence intervals for the regression slopes are therefore very broad. Likewise, there was significant scatter for lumped species measured at concentrations <2 ppb, which resulted in lower correlation coefficients and broader confidence intervals for the regression slopes. The lower detectable concentration of the ROG measurement method was 1 ppb which explains the scattered behavior of measurements approaching this limit.

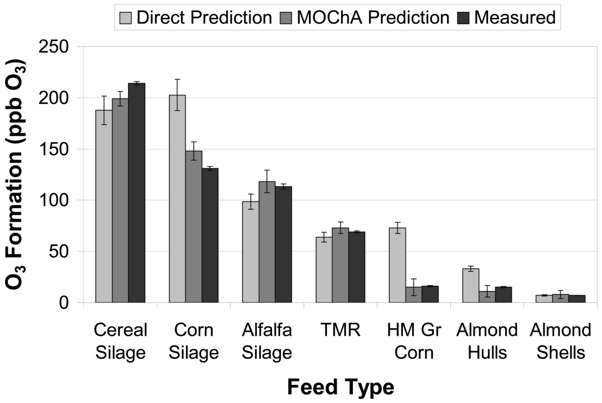

FIGURE 2. Ozone formation (ppb O_3) measured in each experiment vs model predictions using ROG samples from MOChA and Direct ROG samples from the feed testing facility.

Figure 2 illustrates the ozone formation (ppb-O_3) due to emissions from each animal feed vs the ozone formation predicted using CACM (ozone closure experiment). The figure depicts ozone formation under controlled conditions, where surface area of feed, ventilation rate in the chamber, and volume sampled remain constant across all feed types. By controlling these variables, the emissions from a feed type can be attributed to the actual flux from that feed. Simulations were conducted using the ROG profiles measured in the MOChA and the ROG profiles measured directly from the feed testing facility. For almost every feed type, the model predictions for ozone formation based on the MOChA ROG profiles are within uncertainty estimates to measured ozone formation in the MOChA. Ozone formation from corn silage, high moisture ground corn (HMGC), and almond hulls predicted using ROG profiles measured directly from the feed testing facility are higher than predictions based on

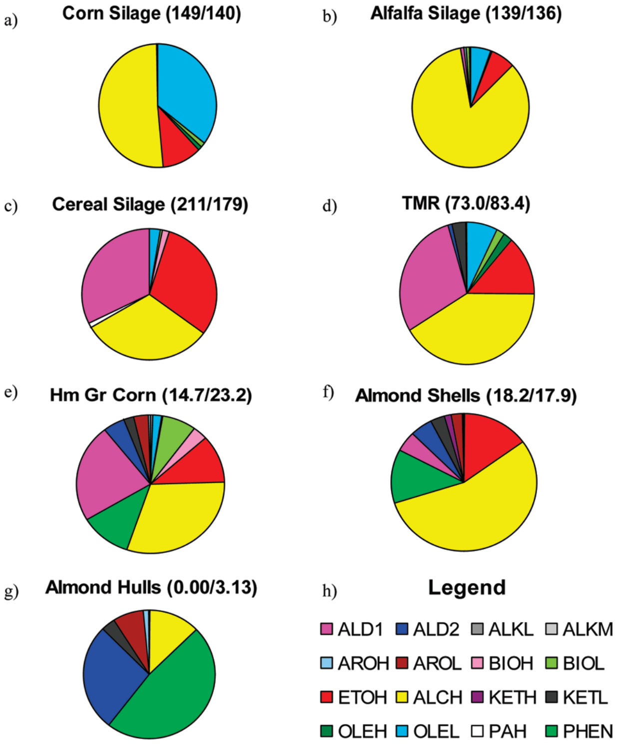

FIGURE 3. Contribution to total ozone formation from each lumped model species assuming additive behavior. Ozone formation associated with each species is calculated by removing that species from the ROG profile and observing the net reduction in ozone formation. The amount of ozone produced under the experimental conditions is listed after each subtitle (ppb O_3). The first value represents the measured total ozone formation, while the second value represents the predicted total O_3 formation using the sum from individual ROG subfractions. See the Supporting Information for an explanation of lumped model species codes.

MOChA ROG measurements. Concentrations of alcohol species were higher in the direct sample than the MOChA sample by a factor of 1.5, 5, and 10 for corn silage, almond hulls, and HMGC, respectively. Alcohol concentrations (ALCH + ETOH) account for roughly half of the ozone formation for these feed types. Multiplying the increased alcohol concentration by the expected ozone formation yields the difference in ozone formation between direct and MOChA samples for these three feed types (25% increase for corn silage, 300% for almond hulls, and 500% for HMGC). The influence of sampling line losses on these compounds must be considered when predicting the atmospheric ozone formation associated with these feeds.

Figure 3 illustrates the contribution that each lumped ROG category makes to ozone formation for each of the feeds. ROG contributions to ozone formation were calculated by removing the ROG from the feed profile and observing the reduction in predicted ozone production. This method assumes simple additive behavior (linear approximation) that does not completely describe the nonlinear photochemical system. The measured ozone formation and predicted ozone formation (sum of the individual ROG contributions) are displayed after the subtitle for each feed to convey the uncertainty introduced by the linear approximation. The relative error introduced by the linear approximation is <20% for feeds that produce >50 ppb O_3 under the experimental conditions (corn, alfalfa, cereal, TMR) with larger errors for feeds that produce <50 ppb of O_3 under the study conditions (HMGC, almond shells, almond hulls). Ethanol and especially larger alcohol species (ALCH) account for >50% of the ozone formation for most types of feed. Alkene species (OLEL) were significant contributors for corn silage and important in alfalfa silage and TMR. Acetaldehyde accounts for 25−30% of the ozone formation in cereal silage, TMR, and HMGC. Phenols account for significant ozone production for HMGC, almond shells, and almond hulls. Other important contributors to total ozone formation include the second lumped aldehyde category (ALD2), biogenic species, and aromatic species.

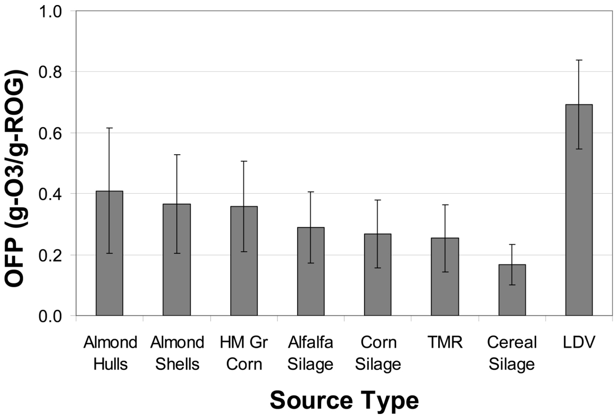

FIGURE 4. Calculated average O_3 formation potential (OFP) of the ROG emissions from animal feed sources and light duty gasoline-powered vehicles (LDV) expressed as g-O_3 produced per g-ROG emitted based on background NO_x and ROG concentrations. Uncertainty bars represent the range of conditions considered (see text).

Model simulations were conducted to explore OFP of animal feeds under pollutant conditions expected in the SJV. Figure 4 displays the calculated ozone formation potential for feed in grams of ozone produced per gram of ROG emitted using the emissions measured in the current study. These values can be compared to the OFP of light duty gasoline-powered vehicle exhaust (LDV). The error bars in Figure 4 represent the range of conditions considered for each feed type, while the large bar represents the average between the estimates. The upper estimate represents urban concentrations in the SJV (NO_x = 75 ppb, ROG = 125 ppb), while the lower estimate represents rural conditions in the SJV (NO_x = 25 ppb, ROG = 62.5 ppb) (*2*). OFP is typically calculated using incremental reactivity, which compares the ozone formation of a reference mixture to the ozone formation of the reference mixture plus a small concentration of source ROG. Incremental reactivity can be defined for any point on an ozone isopleth, but at low NO_x and ROG conditions it is best to use the equal benefit incremental reactivity (EBIR), which is the point on the ozone isopleth where ROG and NO_x controls contribute equally to ozone reduction (*16*). Fortunately, the reference estimates for the SJV fall along this EBIR line for the NO_x conditions considered. The three silage feed types used in the experiments had OFP ranging from 0.17 to 0.29 g-O_3 per g-ROG. Total mixed ration, which contains both silage and other feeds, had the sixth highest OFP at 0.26 ± 0.11 g-O_3 per g-ROG. High moisture ground corn had the third highest OFP (0.36 ± 0.15 g-O_3 per g-ROG), almond shells had the second highest OFP (0.37 ± 0.16 g-O_3 per g-ROG), and almond hulls had the highest OFP (0.41 ± 0.21 g-O_3 per g-ROG). The OFP of LDV at EBIR conditions was calculated using CACM to be 0.69 ± 0.15 g-O_3 per g-ROG using published ROG emission estimates (*17*). These results demonstrate that under representative NO_x conditions, the OFP of feed sources are potentially important compared to LDV OFP.

Ozone formation potential quantifies the reactivity of each gram of ROG, but total emission estimates are needed to calculate total ozone formation within a region. Animal feed ROG emissions originate from storage silos and from feed placed in front of animals for their consumption. ROG emission rates from the exposed face of storage silos and from feed placed in front of animals are calculated based on exposed feed surface area and measured flux rates (g ROG day^{-1} m^{-2}). SI Table S3 summarizes the flux emissions rates for different feeds inferred from test chamber measurements in the current study. Test chamber measurements were converted to flux rates using the following equation:

$$\mathrm{flux} = \frac{CV}{\tau A} \tag{1}$$

where C is the measured concentration in the chamber, V is the chamber volume, τ is the time scale for air exchange in the room, and A is the surface area of exposed feed. Chamber measurements made at time $= \tau$ were still increasing to steady state values (achieved after time $= 3\tau$) and so the flux values are approximately 37% lower than the true initial emissions rates from the animal feeds. Continuous emissions flux measurements for corn silage made over a 24 h period indicate that steady state emissions decreases over time (*18*). A decrease of 37% from the initial emissions rate is achieved after approximately 4−5 h have passed. Hence, the emissions flux measurements are appropriate for an exposure time of 4−5 h. The corn silage emissions flux rates in the current study (1.66 ± 0.18 ROG g hr^{-1} m^{-2}) are in excellent agreement with direct flux rate measurements described by other investigators (1.8 ± 0.1 g ROG hr^{-1} m^{-2}) (*7*).

Total corn silage ROG emissions in the SJV were calculated assuming that almost all of the corn silage used in California is fed to dairy cattle and that most of the corn silage is kept in trench silos (not tower silos). The total daily feed consumption was estimated using statistics from the U.S. Department of Agriculture (*19*) (see SI Table S1).

ROG emissions from the exposed face of the trench silo (E_{face}) were calculated using the following equation:

$$E_{\mathrm{face}} = \frac{M_{\mathrm{feed}} A_{\mathrm{face}}(\mathrm{flux})}{\rho V_{\mathrm{pile}}} \tag{2}$$

where M_{feed} is the total mass of silage feed consumed in the SJV each year ($1.0 \times 10^{10} \pm 5.0 \times 10^{8}$ kg) (*19*), ρ is the density of silage in the pile (300 ± 40 kg m^{-3}) (*20*), V_{pile} is the volume of a representative silage pile ($1.0 \times 10^{4} \pm 100$ m^{3}) (*20*), A_{face} is the representative area of the silage pile face (90 ± 4.5 m^{2}) (*20*), and flux is the ROG emissions flux appropriate for 4−5 h of exposure time (40 ± 2 g ROG day^{-1} m^{-2}) (measured this study).

Fugitive ROG emissions from corn silos (E_{spoilage}) were calculated assuming that all of the ROG contained in the spoiled silage is released to the atmosphere using the following equation:

$$E_{\mathrm{spoilage}} = \frac{M_{\mathrm{spoil}} \mathrm{DM} f_{\mathrm{ETOH\_DM}}}{f_{\mathrm{ETOH\_ROG}}} \tag{3}$$

where M_{spoil} is the total amount of feed lost in the silo due to air spoilage (10% of total mass $= 1.0 \times 10^{9} \pm 5.0 \times 10^{7}$ kg yr^{-1}) (*21*), DM is the fraction of the silage that is dry matter (30%) (*22*), $f_{\mathrm{EtOH\_DM}}$ is the ratio of ethanol to dry matter in the feed (1.2%) (*22*), and $f_{\mathrm{EtOH\_ROG}}$ is the fraction of the ROG attributed to ethanol (EtOH) (55%) (*8*). This methodology predicts that fugitive ROG emissions can be calculated as 0.65% of the spoiled silage mass.

The ROG emission rate from feed placed in front of the animals (E_{manger}) was calculated assuming that the feed is available to the cows twenty-four hours a day using the equation:

$$E_{\mathrm{manger}} = S_{\mathrm{cow}} N_{\mathrm{cow}} f_{\mathrm{silage}} \mathrm{flux} \tag{4}$$

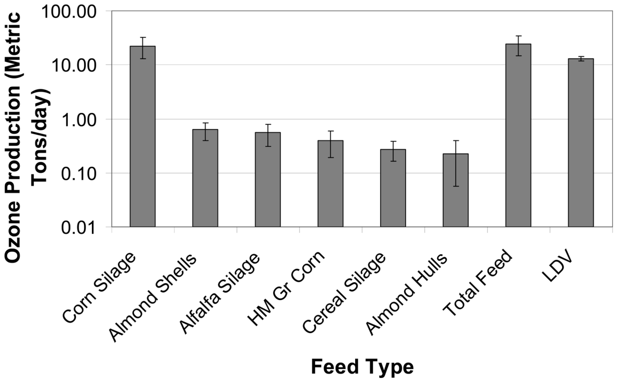

FIGURE 5. Total ozone production in metric tons per day for the various animal basic feed types vs light duty vehicles (LDV) in the SJV. Note that the *y*-axis is log scale. Calculations are based on OFP and total ROG emissions (see SI Table S1 for a summary of corn silage calculations).

where S_{cow} is the representative surface area of feed in front of each cow, N_{cow} is the number of cows in the SJV ($1.9 \times 10^{6} \pm 1.9 \times 10^{4}$) (*7*), f_{silage} is the fraction of the feed composed of silage (50%) (see previous discussion of TMR composition), and flux is the ROG emissions flux appropriate for 4−5 h of exposure time (40 ± 2 g ROG day^{-1} m^{-2}) (measured this study). The E_{manger} was calculated using measurements from a typical dairy in the SJV (1200 cows, two barns each housing 600 cows, total length of feed line is 750 m, and effective cross-sectional width of feed line is 2.2 m). The result gives the average exposed feed surface area of 1650 m^{2} for 1200 cows or 2.7×10^{6} m^{2} for 1.9 million cows in the SJV (*23*). Again, f_{silage} reduces the resulting surface area by half to account for approximately 50% corn silage used in TMR. All of the values needed to apply eqs 2−4 are summarized in SI Table S6 along with references for data sources.

The total ROG emissions from corn silage calculated using eqs 2−4 were 12.3 ± 1.9 t day^{-1} (storage face) + 18.4 ± 1.8 t day^{-1} (fugitive emission) + 53.1 ± 6.0 t day^{-1} (feed in front of animals) yielding a total emissions rate of 83.8 ± 6.6 t day^{-1}. Multiplying ROG emissions by the OFP of corn silage (0.27 ± 0.11 g-O_3 per g-ROG) gives total ozone production in the SJV as 23 ± 9.5 t day^{-1}. Similar calculations of ozone production from the other feed sources were performed and the result is summarized in Figure 5. The estimated ozone formation from LDVs is also displayed in Figure 5 using published emissions estimates for this source (*4*). Traditional emissions inventory estimates have identified LDVs as the largest anthropogenic ROG source of ozone production in the SJV. The present calculations suggest that ozone production from animal feed ROG (25 ± 10 t day^{-1}) is nearly two times larger than ozone production from LDV ROG (14.3 ± 1.4 t day^{-1}) in this heavily polluted region. Corn silage accounts for 93% of the feed ozone production in the SJV. The next most significant category of feed is alfalfa silage contributing 2% to the SJV total.

All of the calculations described above are preliminary. Further refinements are needed to account for meteorological variables such as temperature, wind speed, and humidity. The relative importance of NO_x vs ROG control on ozone formation in the SJV must also be considered. The natural approach to evaluate these factors is the application of a regional air quality model that includes the newly recognized animal feed ROG emissions and then perturbs the system to consider the effectiveness of NO_x vs ROG emissions controls. The preliminary calculations shown in the present study clearly indicate that animal feed emissions are a significant source of ozone precursors in the SJV at current NO_x levels. Ozone control strategies in the SJV currently focus on NO_x control because previous calculations (without animal feed

ROG emissions) predicted this to be the most efficient strategy. If some measure of ROG control is deemed to be worthwhile when these new emissions are recognized, then future research should study how ROG emissions can be reduced from these essential animal feeds.

Acknowledgments

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Supporting Information Available

Table S1 describes the assignment of individual ROG species to lumped CACM species, Table S2 summarizes regressions between MOChA vs Direct ROG measurements, Table S3 displays the emission flux rates for the various feed types in the test chamber, Table S4 lists the mass of feed used in chamber experiments, Table S5 lists the pH and total solids content of corn and alfalfa silage, Table S6 summarizes the data needed to calculate corn silage ROG emissions in the SJV, Figure S1 illustrates agreement between CACM predictions and MOChA measurements, Figure S2 illustrates calculated O$_3$ isopleths, Figure S3 illustrates the amount of each feed type used in California each year, Figure S4 displays measured concentrations of ROG species at or below the quantification threshold, and Figure S5 illustrates a picture of the MOChA apparatus. This material is available free of charge via the Internet at http://pubs.acs.org.

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Exhibit 9

San Joaquin Valley
Unified Air Pollution Control District

San Joaquin Valley
Air Pollution Control District

Air Pollution Control Officer's Revision of the Dairy VOC Emission Factors

February 2012

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Reviewed by:
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Note: The revised dairy VOC emission factors that are set forth in this document are based on the best scientific data that were available. As with other emission factors, the dairy VOC emission factors will be periodically updated if new scientific information indicates that revisions may be necessary.

Introduction

This report provides the bases for the District's revision to the District's Volatile Organic Compound (VOC) emission factors for dairies, which were previously established on August 1, 2005 in the report, entitled "*Air Pollution Control Officer's Determination of VOC Emission Factors for Dairies*"[1]. The emission factors set forth in this document will be used for permitting dairies in the San Joaquin Valley.

This document lists some of the previous studies that were analyzed to develop the previous dairy VOC emission factors and reviews the more recent studies that were not available to the District during the previous process. It includes a summary of the analyses performed by the District that resulted in the determination of the District's Dairy VOC emission factors, as well as general recommendations for further research necessary to continue to improve our understanding of VOC emissions from dairy operations.

Accurate dairy emission factors are required for the proper implementation of applicable air quality regulations and also for the evaluation of appropriate technologies and practices to reduce emissions. Dairy VOC emission factors are needed to implement the requirements of State law. Under State law (SB 700, Florez 2003) agricultural operations, including dairies, that have emissions greater than ½ of any of the major source thresholds are required to obtain air district permits. In order to determine which operations exceed this level of emissions, accurate VOC emission factors are needed. Emission factors for the specific processes at dairies are also needed to evaluate and revise Best Available Retrofit Control Technology (BARCT) for existing dairies as required under the District's attainment plan and to evaluate and establish Best Available Control Technology (BACT) for new and expanding dairies to comply with the requirements of New and modified Source Review (NSR). The magnitude of the emission factor will be one of the several factors that are considered when establishing the final BARCT and BACT requirements. The District, through a public process, will also fully examine the technological feasibility, availability, and cost of possible control measures that may be required.

San Joaquin Valley Air District staff members have gained a great deal of experience in the evaluation of emissions from agricultural sources through collaborative efforts with other institutions, agencies, and interested stakeholders. Technical methodologies for determining agricultural emissions that were compiled and developed by Valley Air District engineers and specialists are currently being used by air quality agencies throughout California to establish permitting requirements for agricultural sources, determine the applicability of requirements under Title V of the Federal Clean Air Act, and

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[1] San Joaquin Valley Air Pollution Control District (APCO), August 1, 2005. Air Pollution Control Officer's Determination of VOC Emission Factors for Dairies

develop air quality attainment plans. Additionally, members of the Valley Air District have been thoroughly involved with recent and ongoing collaborative scientific research efforts to evaluate emissions from agricultural sources. This is particularly true of the agricultural emissions research efforts that have been ongoing in California. The extent of Valley Air District involvement in agricultural research efforts includes providing recommendations on the allocation of funds; evaluating test methods and protocols to quantify emissions from agricultural sources; identifying important areas in which further research is needed; evaluating and commenting on study proposals; working with other parties to lead research projects; and interpretation of the data obtained. These research efforts require coordination between air quality agencies, research institutions, independent researchers, and agriculture. The Valley Air District plays an important role in these essential coordination efforts through the San Joaquin Valleywide Air Pollution Study Agency (Study Agency) and the Study Agency's Agricultural Air Quality Research Committee (AgTech).

The revised Dairy VOC emission factors proposed in this report is based on a detailed review of the available science. There has been significant additional scientific research conducted since the development of the previous emission factor in the report by the APCO, dated August 1, 2005. These additional studies have been conducted with greater focus on processes and compounds of interest and were also designed to be more reflective of conditions found at California dairies. The District has compared some of these recent studies with the studies that were used to develop the previous emission factor. As would be the case with emission factors for other sources, the District's dairy emission factors will be revised to reflect the latest scientific information that is currently available.

In revising the dairy emission factors, the District continued to adhere to the sound guiding principles which were used to establish the District's original dairy emission factor. Continued adherence to these principles ensures that the revised dairy emission factors are supported by best available science.

In evaluating the latest research studies, studies performed on California dairies and in conditions representative of California conditions were always given preference. The revised dairy emission factors are entirely based on results from studies of California researchers at California dairies. The District's previous emission factor was also predominantly based on California research. However, because at the time there was not adequate California research to quantify emissions of volatile fatty acids (VFAs), studies from outside of California (Hobbs et al and Koziel et al) were previously used to calculate emissions of these compounds from dairy manure. In establishing the revised dairy emission factor, these studies have been replaced with more recent studies on enteric VFA emissions from dairy cattle conducted by Dr. Frank Mitloehner from UC Davis and studies on total VOC emissions from various dairy processes conducted by Dr. Charles Schmidt, a private consultant based in California. This report also uses California emission studies to quantify emissions from dairy feed, an important emissions source for which there was previously insufficient research.

The District's Dairy Emission Factors are summarized in the tables below.

The District continues to support continued and ongoing research at California dairies to further refine and supplement these emission factors.

Summary of Dairy Emission Factors

Dairies Subject to Phase I of District Rule 4570 (≥ 1,000 milk cows)

Per Cow Dairy VOC Emission Factors	
Process or Constituent	**Emissions (lb/hd-yr)**
1. Enteric Emissions from Cows	4.1
2. Milking Parlor(s)	0.03
3. Freestall Barns	1.8
4. Corrals/Pens	6.6
5. Liquid Manure Handling (Lagoons, Storage Ponds, Basins)	1.3
6. Liquid Manure Land Application	1.4
7. Solid Manure Land Application	0.33
8. Separated Solids Piles	0.06
9. Solid Manure Storage	0.15
Total not including Feed	**15.8**

Dairies not Implementing Phase I of District Rule 4570 (< 1,000 milk cows)

Uncontrolled Per Cow Dairy VOC Emission Factors	
Process or Constituent	**Emissions (lb/hd-yr)**
1. Enteric Emissions from Cows	4.3
2. Milking Parlor(s)	0.04
3. Freestall Barns	1.9
4. Corrals/Pens	10.0
5. Liquid Manure Handling (Lagoons, Storage Ponds, Basins)	1.5
6. Liquid Manure Land Application	1.6
7. Solid Manure Land Application	0.39
8. Separated Solids Piles	0.06
9. Solid Manure Storage	0.16
Total not including Feed	**20.0**

VOC Emissions from Dairy Feed Sources

Silage Pile VOC Emissions Flux*	
10. Silage Piles	**Emissions Flux (lb/ft^2-day)**
1. Corn Silage	1.02E-02
2. Alfalfa Silage	5.15E-03
3. Wheat silage	1.29E-02

*Assuming silage piles are completely covered except for the “face” from where feed can be removed

Average Total Mixed Ration (TMR) VOC Emissions Flux	
11. Average TMR	**Emissions Flux (lb/ft^2-day)**
TMR	3.85E-03

Background

The San Joaquin Valley Air Basin has an inland Mediterranean climate characterized by hot, dry summers and cool, foggy winters. The San Joaquin Valley is surrounded by mountains on the east, west, and south sides. This creates stagnant air patterns that trap pollution, particularly in the south of the San Joaquin Valley. Additionally, the sunshine and hot weather, which are prevalent in the summer, lead to the formation of ozone (photochemical smog). Because of the San Joaquin Valley's geographic and meteorological conditions, it is extremely sensitive to increases in emissions and experiences some of the worst air quality in the nation.

The San Joaquin Valley Air Basin was previously classified as a serious non-attainment area for the health-based, Federal eight-hour ozone standard. However, EPA recently reclassified the air basin as an extreme non-attainment area for the eight-hour ozone standard because of the inability to reach attainment of the standard by the earlier serious and severe classification attainment dates using currently available technologies. The air basin is also classified as a non-attainment area for the Federal PM-2.5 (ultra-fine particulate matter) standard.

Purpose of the San Joaquin Valley Air Pollution Control District

The San Joaquin Valley Air District is a public health agency whose mission is to improve the health and quality of life for all Valley residents through efficient, effective and entrepreneurial air quality management strategies. To protect the health of Valley residents, the District works toward achieving attainment with health-based ambient air quality standards as required under State and Federal law. To achieve this goal, the District develops and adopts air quality attainment plans that include control measures aimed at further reducing emissions from a broad range of sources, including agriculture.

As mandated by Federal Law, the San Joaquin Valley Air District adopted its 2007 ozone attainment plan to demonstrate how the Valley would reach attainment with the Federal eight-hour ozone standard. In developing the ozone attainment plan every feasible measure to reduce emissions of ozone precursors (VOC and NOx) was explored. However, even though the District will be requiring every practical VOC and NOx control, and will be relying on the state and federal governments to significantly reduce emissions from mobile sources of pollution, the San Joaquin Valley will still need the development and adoption of future, not-yet-developed, clean air technologies to reach attainment by the 2023 deadline. Achieving the goal of attainment with air quality standards will require continued contributions from all industries, businesses, and individuals in the San Joaquin Valley.

Permitting Requirements

A critical tool that the air districts use to limit increases in emissions of air pollutants and to assure compliance with air quality regulations is the issuance of conditional construction and operating permits to commercial and industrial sources of air pollution. Since the 1970s, the San Joaquin Valley Air Pollution Control District and its predecessors have issued tens of thousands of conditional permits that are being used to assure compliance with air pollution control requirements throughout the Valley. District permits address the requirements of federal standards, state regulations, and District rules that specifically apply to a source of air pollution. New and modified sources of air pollution are also subject to the more protective requirements of “New Source Review”, which are determined on a case-by-case basis and are also included in the permit. Permit holders, District Inspectors, and others use these District permits, rather than directly reference the complex and voluminous underlying regulations, to verify compliance with applicable air quality requirements.

Removal of the Agricultural Exemption from Permitting

Under California state law, agricultural sources of air pollution, including dairies, were previously exempt from air district permitting requirements and new source review emissions limitations. This exemption was removed effective January 1, 2004, when Senate Bill 700 (Florez) amended the California Health and Safety Code to eliminate the longstanding permit exemption for agricultural operations that grow crops or raise animals. With the elimination of the agricultural permit exemption, San Joaquin Valley dairies also became subject to “New Source Review” requirements, including the requirement to apply Best Available Control Technology (BACT) to new and expanding operations.

San Joaquin Valley Dairies and Air Quality

Dairies are significant sources of smog-forming Volatile Organic Compounds (VOCs) and fine particulate matter in the San Joaquin Valley. Volatile Organic Compounds are emitted directly from the Valley’s approximately 2.5 million dairy cows[2], from the fermentation and decomposition of cattle feed, and from the decomposition of the manure generated each day from dairy cows in the San Joaquin Valley. Dairies are among the largest sources of VOCs in the Valley, and these smog-forming VOC emissions can have an adverse impact on efforts to achieve attainment with health-based air quality standards.

VOC Emission Factors for Dairies

When agricultural sources in California first became subject to air district permitting requirements on January 1, 2004, there was very little data available

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[2] USDA, National Agricultural Statistics Service. 2007 Census of Agriculture – County Data, Table 11 – Cows and heifers that had calved

that could be used to quantify Volatile Organic Compounds (VOC) emissions from confined animal facilities, such as dairies. To calculate VOC emissions from dairies, EPA and the California Air Resources Board (ARB) used a VOC emission factor of 12.8 lb/head-year based on the very limited information that was available. Subsequently, California air districts, including the San Joaquin Valley Air Pollution Control District, adopted this VOC emission factor for dairy permitting and emissions inventory purposes. However, the basis for the 12.8 lb/head-year VOC emission factor was an older study performed in the 1930s that only measured methane emissions from dairy cows in environmental chamber tests. Volatile Organic Compounds emissions were not directly determined in the tests but were estimated using an assumed ratio of VOCs to total organic gasses with the methane emission measurement values used as total organic gas emissions. Additionally, the 1930 chamber tests did not represent the majority of dairy processes. Because of the age of the original study and the many assumptions that were needed to derive the dairy VOC emission factor, there was a great deal of uncertainty as to whether the 12.8 lb/head-year emission factor accurately reflected VOC emissions from dairy cows and dairy processes and was scientifically defensible.

As such, the District revised the dairy emission factor in its report entitled, "*Air Pollution Control Officer's Determination of VOC Emission Factors for Dairies*"[1] which was released on August 1, 2005 and resulted in the District's previous dairy VOC emission factor of 19.3 lb/head-yr. This is the emission factor that the District used for permitting dairy operations in the San Joaquin Valley. This emission factor was based on a thorough review of the scientific research available and represents a significant improvement compared to the previous value of 12.8 lb/head-year. However, the emission factor report identified several dairy processes and compounds for which additional research was needed to accurately quantify emissions. This second revision is brought about because of an accumulation of significant additional scientific research on the majority of sources of emission at a dairy, specifically at those sources where no data were available during the initial revision.

Deferral of Permit Requirements for Some Smaller Operations

Under SB 700, permitting requirements were deferred for smaller agricultural operations with emissions less than one-half of the major source thresholds. Based on the original dairy VOC emission factor of 12.8 lb/head-year, existing dairies with 1,954 cows[3] were estimated to have VOC emissions equal to or greater than one-half of the District major source threshold, and were required to apply for District permits by June 30, 2004. Dairies with less than 1,954 cows were determined to have emissions less than one-half of the major source

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[3] The 1,954 number is an estimated threshold assuming all cows on the dairy emit VOCs at the same rate as milk cows, which is not the case. The actual threshold (generally above 1,954) must be determined on a case-by-case basis and varies with the number of milk cows, dry cows, heifers, and calves on the dairy.

threshold; therefore, District permitting for these smaller dairy operations was not initially required. However, on August 1, 2005 the District revised the Dairy VOC emission factor from 12.8 lb/head-year to 19.3 lb/head-year using the best available science. As a result of the revised emission factor, dairies with more than 1,190 milk cow (or an equivalent mix including support stock) became subject to District permits after August 1, 2005.

Additionally, under the provisions of SB 700, an air district may permit smaller sources by making the following findings in a public hearing:

> 1) A permit is necessary to impose or enforce reductions in emissions of air pollutants that the district shows causes or contributes to a violation of a state or federal ambient air quality standard.
>
> 2) The requirement for a source or category of sources to obtain a permit would not impose a burden on those sources that is significantly more burdensome than permits required for other similar sources of air pollution.

The District did, in fact, make these findings during its adoption of District Rule 4570 – Confined Animal Facilities (CAF). The District determined that to ensure enforceability of the VOC mitigation measures required by state law and the District's attainment plans, agricultural facilities subject to the rule required District permits. As determined by the California Air Resources Board (ARB), a dairy with 1,000 milk cows or more is defined as a large CAF. Therefore, any dairy with 1,000 or more milk cows became subject to District permits.

It should be noted that agricultural sources of air pollution do not become subject to District permitting, "New Source Review" (NSR), or Best Available Control Technology (BACT) requirements until the emissions from these sources exceed one-half of the major source threshold values, which was previously 12.5 tons (25,000 lbs) of NOx or VOC, but was recently reduced to 5 tons (10,000 lbs) of NOx or VOC after EPA approved the re-designation of the San Joaquin Valley as an Extreme Nonattainment area for the Federal 8 hour ozone standard. For non-agricultural source categories, District permits and BACT are generally required at the far lower emissions rate of anything greater than 2 lb/day. For numerous years, permits and significant air pollution controls have been required for much smaller sources of emissions such as print shops, autobody shops, gasoline stations, and dry cleaners.

Authority to Construct Permitting Requirements for Dairies Constructed or Modified after 1/1/2004

As well as requiring operating permits for existing dairies, SB 700 also required dairies with emissions greater than one-half the major source thresholds that were constructed or modified on or after 1/1/2004 to obtain Authority to Construct permits from the District prior to commencing construction. These new and modified dairies, like all other new and modified sources of air pollution, are subject to the requirements of the District's New and Modified Stationary Source Review Rule (District Rule 2201), including the requirement to apply BACT, and may potentially be required to offset emission increases once protocols are in place to allow agricultural sources to bank Emission Reduction Credits from qualified emission reductions.

Large CAF Rule for Existing Dairies

In addition to the Air District permitting requirements described above that resulted from the elimination of the agricultural exemption, Section 40724.6 of the Health and Safety Code required the California Air Resources Board (ARB) to develop a definition for the source category of "large" Confined Animal Facilities (CAF) that would be subject to VOC control requirements. In developing the large CAF definition, ARB was required to review relevant scientific information, including potential air quality impacts, the effects that confined animal facilities may have on the attainment and maintenance of air quality standards, and applicable livestock emission factors. This section of the Health and Safety Code also required the District to adopt a rule establishing VOC control requirements for large CAFs, including dairies.

On June 23, 2005, at the conclusion of a public hearing, ARB adopted Resolution 05-35, which established the definition of large Confined Animal Facilities. The definition adopted by ARB specifies that dairies with 1,000 or more milk cows that are in a region designated as a federal ozone nonattainment area as of January 1, 2004 are large CAFs and that dairies in all other areas with 2,000 or more milk cows are large CAFs. Because of the San Joaquin Valley Air Basin's status as a federal ozone nonattainment area, dairies in the Valley with 1,000 or more milk cows are large CAFs. On June 15 2006, the District adopted Rule 4570 – Confined Animal Facilities to require existing large CAFs to begin to implement VOC control requirements that are suitable to each particular operation. District Rule 4570 included various options and management practices that could be used to achieve the required emission reductions from different sources at confined animal facilities, such as feed storage and handling, animal housing, manure handling and storage, and lagoons. The District issued Authority to Construct permits to over 600 confined animal facilities, including over 500 dairies, to implement various mitigation measures and practices to reduce VOC emissions from these facilities.

The District recently amended the existing version of Rule 4570 to achieve further reductions from existing confined animal facilities in order to attain compliance with applicable health-based ambient air quality standards. The amendments resulted in lowering the applicable threshold and requiring Phase II mitigation measures. The Phase II mitigation measures include additional practices to reduce VOC emissions from feed sources at dairies, which are now known to be a significant source of VOC emissions. During the District's process to amend Rule 4570 it was critical to use the most accurate emissions information available. The use of the revised dairy emission factors from this document allowed for a more accurate assessment of sources that contribute to emissions at a dairy and allowed these emission sources to be targeted for cost-effective emission control strategies. Implementation of the recently adopted Phase II mitigation measures of District Rule 4570 is expected to result in significant reductions of smog-forming VOCs in the San Joaquin Valley that will be in addition to the VOC reductions that have already been achieved by the implementation of Phase I of District Rule 4570.

Important Findings from Latest Dairy Emissions Research

Recent dairy emission research studies performed under the direction of California air quality agencies and stakeholders have significantly increased knowledge of dairy emissions and also shed some light on potential strategies to reduce these emissions. Recently completed California dairy emission studies of note include:

- A study at UC Davis, led by Dr. Frank Mitloehner, entitled "*Volatile Fatty Acids, Amine, Phenol, and Alcohol Emissions from Dairy Cows and Fresh Waste*".[4] This study measured emissions of alcohols, volatile fatty acids, and amines directly from lactating and dry cows and also from their fresh manure. This study provides valuable information on enteric emissions from cattle as well as emissions from freshly excreted manure.
    - The original study led by Dr. Mitloehner (May 2006) was found to have incorrect data due to the lack of an ammonia filter in the INNOVA measurement device. The lack of an ammonia filter resulted in significant interference when measuring alcohols; therefore, readings of ammonia emissions were incorrectly reported as alcohol emissions. In order to obtain accurate data; Dr. Mitloehner repeated the study with the proper filters in place. The study was completed in October 2009.[5] At the request of District staff, Dr. MItloehner provided the resulting preliminary data, minimal but sufficient, to the District so that emissions could be estimated using this data.
- Two studies conducted by Dr. Charles Schmidt and Thomas Card (Dairy emissions using flux chambers, 2006 - Phase III[6] and 2009 - Phase IV[7]),

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[4] Mitloehner, F. Trabue, S. Koziel, J.A. (2006) Volatile Fatty Acids, Amine, Phenol, and Alcohol Emissions from Dairy Cows and Fresh Waste (May 31, 2006). Final Report to California Air Resource Board (ARB)

[5] Mitloehner, Frank, 2009. Revision of May 2006 Study- Alcohol Emissions from Dairy Cows and Fresh Waste from Environmental Chambers (data set only)

[6] Schmidt, C. Card, T. (2006) Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures (May 2006). Final Report to California Air Resource Board (ARB)

[7] Schmidt, C. Card, T. (2009) 2008 Dairy Emissions Study: Summary of Dairy Emission Factors and Emission Estimation Procedures. August 2009. Final Report to San Joaquin Valley Air Pollution Control District

which measured various emission compounds along with total VOCs from dairy manure and feed. The emission measurements were taken from silage piles, bunker feed (Total Mixed Ration (TMR)), lagoons, manure piles, corrals, flush lanes, solid manure application and liquid manure application. This information will be used to develop estimates of annual emissions from important sources such as corrals, silage piles, and total mixed ration.

- A series of studies in which flux chambers were used to evaluate VOC emissions from sources at six dairies in the San Joaquin Valley; the field sampling program was led by Dr. Charles Krauter of CSU Fresno and the corresponding analytical program was headed by Dr. Donald Blake at UC Irvine.[8] The emission measurements were taken from many sources at the dairy including the corrals, flush lanes, lagoons, feed storage areas, and Total Mixed Ration (TMR). Seasonal and diurnal data were also taken for certain sources during the flux chamber studies.
- An ARB research project led by Dr. Ruihong Zhang of UC Davis in which a team of researchers identified and quantified significant VOC compounds emitted from thin layers of loose silage, cows and manure in environmental chambers, and dairy manure storage for the purpose of developing VOC emissions models to quantify emissions from dairy processes.[9] Flux chambers were used to measure emissions from samples of loose silage. The emissions were evaluated using Proton Transfer Reaction Mass Spectroscopy (PTRMS) and an INNOVA photo-acoustic analyzer to measure alcohols. A wind-tunnel was used to evaluate the effect of wind speed on VOC emissions from silage and the information gathered was used to create a preliminary model to estimate ethanol emissions from thin layers of loose silage given the initial ethanol concentration. A preliminary model was also generated to estimate acetic acid emissions from manure storage depending on the characteristics of the manure in storage (i.e. acetic acid concentration, pH, temperature, solids content, etc.). This ARB project was supported by UC Davis, UC Berkley, and USDA Agricultural Research Service (ARS). A large number of researchers contributed to the project including: Dr. Ruihong Zhang, Dr. Frank Mitloehner, Dr. Hamed El-Mashad, Dr. Irina Malkina, Dr. Huawei Sun, Dr. Peter Green, Dr. Baoning Zhu, Dr. Yongjing Zhao, Ms. Veronica Arteaga, Mr. Kameron Chun, Ms. Sara Place, and Ms. Yuee Pan, Dr. Allen Goldstein, Dr. Daniel Matross, Dr. Sasha Hafner, Dr. Felipe Montes, and Dr. C. Alan Rotz. This project greatly increased the available data regarding the speciation of VOC compounds emitted from sources at dairy operations and provides a strong foundation for the continued

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[8] Krauter, C. Blake, D. (2009) Dairy Operations: An Evaluation and Comparison of Baseline and Potential Mitigation Practices for Emissions Reductions in the San Joaquin Valley (May 01, 2009). Final Report for California Air Resource Board (ARB)

[9] Zhang, Ruihong. (2010) Process-Based Farm Emission Model for Estimating Volatile Organic Compound Emissions from California Dairies. May 2010. Final Report for California Air Resource Board (ARB)

development of emission models to estimate VOC emission models from dairies and is expected to become a useful tool for identifying and evaluating measures that have the potential to reduce emissions from important sources at dairy operations.

Important findings of the latest dairy research studies include:

- Manure storage ponds and lagoons, which were previously thought to be one of the largest sources of VOC emissions at dairies (approximately 8.1 lb/head-year of the District's previous dairy VOC emission factor of 19.3 lb/head-year was attributed to lagoons and volatile fatty acids from wet processes), now appear to emit a comparatively small fraction of the overall dairy VOC emissions;
- Feed at dairies is a significant source of VOC emissions. The exposed faces of silage piles that are used to store and preserve silage to be fed to the cattle and the total mixed ration placed in lanes for cattle consumption emit significant amounts of VOCs, particularly alcohols.
- Emissions of alcohols (primarily ethanol) from feed, fresh manure, and directly from cows appear to comprise a significant fraction of dairy VOC emissions;
- Manure deposited in open corrals appears to be an important source of VOC emissions on some dairies;
- Emissions of volatile fatty acids (VFAs) from non-feed sources, which comprised 15.5 lb/head-year (over 80%) of the District's previous dairy VOC emission factor of 19.3 lb/head-year, are not as significant as previously estimated;
- The practice of flushing freestall barns more frequently has the potential to reduce VOC emissions from cow housing areas.
- Several of the compounds that have been identified as important components of dairy emissions, such as alcohols and volatile fatty acids, are highly soluble in aqueous solutions. This property may be important when developing potential mitigation strategies.
- Land application of solid and liquid dairy manure appears to contribute a relatively small amount to total VOC emissions at dairy.
- Seasonal variation in emissions may be an important factor to consider when developing annual emission estimates. The seasonal variation in emission rates was observed to be more pronounced with ammonia emissions than VOC emissions.

This additional research, which has been completed since the August 1, 2005 revision to the dairy emission factors, will be evaluated to update the dairy VOC emission factors that are used to permit dairies in the San Joaquin Valley.

The Purpose of this Revision to the Dairy VOC Emission Factors

The District is charged with the responsibility of adopting emission factors for various sources of air pollution in order to establish accurate emissions inventories for the San Joaquin Valley air basin and to develop rules and standards to efficiently allocate resources to reduce emissions in the most cost-effective way. For sources, such as agriculture, that have only recently become subject to air quality regulations, there can be a lack of consensus as to the emission factors that are most suitable. In these cases the District must use its expert judgment to evaluate the scientific information available to establish an appropriate emission factors. This District did exactly this during the previous revision to the dairy VOC emission factor. However, as stated earlier, dairy emissions research that better reflects the conditions at California dairies has recently been completed. These studies have greatly improved our knowledge of the emissions of compounds, such as alcohols and volatile fatty acids. These studies have also given us valuable, new information on emissions from important sources, such as dairy feed and land application, which had not previously been measured. The District has determined that the new information on dairy emissions that is contained in the latest studies must be included in the District's dairy VOC emission factors in order to accurately quantify emissions and assess potential mitigation strategies that may be required by BACT and the revised version of District Rule 4570. As with the previous revision to the dairy VOC emission factor, the contents of this report went through a public process in which comments on the proposed emission factor were addressed.

Guiding Principles Used by the APCO for Determining Appropriate Emission Factors

Dairies are fairly complex emissions sources that emit several types of VOCs from the different dairy processes. Because of this, it is difficult to design and carry out a single research effort that would measure all of the VOCs emitted. Therefore, in order to determine appropriate dairy emission factors, the District reviewed several different studies in the previous revision to the dairy VOC emission factor. This current revision will reevaluate the dairy VOC emission factor in light of the recently completed California dairy emissions studies. The results of these studies will be used to augment or replace values in the previous dairy emission factor for categories of dairy processes or compounds emitted for which better emissions research is now available.

The following principles were utilized to evaluate studies and select appropriate data for revision of the dairy emission factor:

1. Emissions data from research studies provided by scientists, information of dairy emissions research, and data from available scientific literature were used to determine the emission factor.
2. The methods used to collect the data were reviewed. Data were considered invalid if any of the following problems are found, unless an appropriate way to correct the data is available:
    a) Indications that samples may have been contaminated.

b) Evidence that sample collection procedures may have resulted in the potential for significant loss of analyte.
c) Evidence that sample storage procedures may have resulted in the potential for significant loss of analyte.
d) Sample loss determined to have occurred in the analytical process (e.g. low laboratory spike recovery due to matrix effects)
e) Indications of mis-calibration or excessive calibration drift.
f) Appropriate laboratory protocols were not followed.
g) Other uncorrectable errors were identified.

3. When VOC data for a process or compound is available from more than one source, the following steps are to be followed to select the best available data for use in developing an emission factor:

   a) Valid data from recent tests performed at California dairies was given preference over data from other sources. The District will carefully consider specific process conditions (such as meteorological conditions, season, manure moisture content, available information on feed, etc.) in evaluating the transferability of out-of-state data.
   b) Data representing a specific constituent or process are to be given preference over data that represents a broad range of constituents or processes.
   c) Where test results from more than one source are deemed equivalent, an average emission factor is to be determined.

4. Non-quantitative or anecdotal evidence of emissions such as compound concentrations measured near dairies or feedlots that could not be related to process parameters, or the presence of varying levels of odors near dairy processes, will not be used to determine emission factors.

5. When no valid source of quantitative VOC data that could be linked to dairy processes is found, no emission factor is to be determined, and the constituent or process emission factor is to be reported as “NA” or not available and further research is to be recommended.

6. When evidence indicates that significant quantities of VOC compounds are emitted, but the emissions cannot be quantified based on available data, the constituent or process emission factor is to be reported as “TBD, >0”, meaning To Be Determined, but known to be greater than zero, and further research is to be recommended.

Analysis

Category 1: Enteric Emissions

Basis of Previous VOC Emission Factor

Basis of the Previous Dairy VOC Emission Factor – Enteric Emissions		
Process or Constituent	**Emission Factors (lb/hd-yr)**	**Basis for Previous Emission Factors**
Previous Category 1: Emissions from Cows and Feed in Environmental Chamber		
Emissions from Cows and Feed	1.4	Emissions from Cows and Feed in Environmental Chamber with analysis by PTR/MS (Mitloehner, 2005)[10]
From Previous Category 5: VFA Emissions from Cows and Feed in Environmental Chamber		
Enteric VFA Emissions	8.3	Measurement of airborne volatile fatty acids emitted from dairy cows and their manure using sorbent tubes with GC/MS analysis (Estimated based on preliminary unpublished data from Trabue, Koziel, & Mitloehner, 2005)

VOC emissions from cows, feed, and fresh manure were measured in environmental chambers by Dr. Mitloehner and other researchers using Proton Transfer Reaction Mass Spectroscopy (PTRMS). VOC emissions were estimated to be 1.6 lb/head-year. Because other VOC tests by Dr. Mitloehner using EPA Method TO-15 had shown that emissions from fresh manure in the test chamber represented approximately 10% of emissions, the value for enteric and feed emissions without the excreta was calculated to be to 1.4 lb/head-year.

Enteric Volatile Fatty Acid (VFA) emissions in the District's previous dairy emission factor were estimated based on preliminary unpublished information from an environmental chamber study conducted by Dr. Mitloehner, Dr. Steven Trabue and Dr. Jack Koziel. The purpose of the study was to determine the relative concentration of VFA components. The VFA samples were collected from the environmental chamber using sorbent tubes. Preliminary data indicated high levels of VFAs in the exhaust from the environmental chamber but the inlet concentrations of VFAs were not measured and there was a high amount of variation in the concentration data. Further analysis of the data and the subsequent performance of similar studies have measured enteric VFA emissions that are significantly less than the estimate used in the District's

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[10] Study conducted in 2005, but published in 2007: *Shaw, S.L. Mitloehner, F.M. Jackson, W.A. DePeters, E. Holzinger, R., Fadel, J. Robinson, P. and Goldstein, A.H. "Volatile Organic Compound Emissions from Dairy Cows and Their Waste as Measured by Proton Transfer-Reaction Mass Spectrometry", Environmental Science and Technology. VOL. 41, NO. 4, 2007, 1310-1316*

previous dairy emission factor. This may be related to the lack of VFA inlet data. It also may be possible that the type of feed that was used during the preliminary chamber studies may have influenced VFA measurements since it is now known that silage-based feed is a significant source of VOC emissions. It is not known what type of feed was used during the preliminary measurements but the subsequent environmental chamber studies used grain-based feed.

Recent VOC Emissions Studies

Recent Studies – Enteric Emissions		
Recent Studies	**Emission Factors from Recent Studies (lb/hd-yr)**	**Notes**
Emissions from Cows and Feed in Environmental Chambers with analysis by TDS/GC-MS, NIOSH 2010, alcohols by INNOVA photoacoustic analyzers (Mitloehner, 2006)[4]	**Milk Cows** VFAs: 0.015 Phenols/Cresols: 0.08	The alcohol measurements were performed using INNOVA photoacoustic analyzers with no ammonia filters. It was later shown that ammonia present in the mixture of gases being measured results in inferences that cause measured alcohol concentrations to be greater than the true values.
Alcohol Emissions from Cows and Feed in Environmental Chambers by INNOVA photoacoustic analyzers with ammonia filters (unpublished data Mitloehner, 2009)[7]	**Milk Cows** Ethanol: 2.6 Methanol: 0.03	Unpublished Data for Period before Manure Accumulates in the Environmental Chamber

Evaluation

The California research that is currently available to quantify enteric emissions from dairy cows is from a series of studies conducted at UC Davis led by Dr. Mitloehner, including a recent study that has not yet been published. Dairy cows were placed in controlled environmental chambers and various methodologies were used to quantify VOC emissions from cows and the manure deposited in the chambers.

In the first environmental chamber study conducted in 2005 (published in 2007), Proton-Transfer-Reaction Mass Spectrometry (PTRMS) was used to quantify emissions from dairy cattle and fresh manure. PTRMS detected a number of oxygenated compounds and some volatile fatty acids. However, ethanol emissions were not quantified in this study because the measurement process converts much of the ethanol to ethane, which has a low proton affinity, and is, therefore, undetectable by PTRMS. Several other studies have shown that large quantities of ethanol are emitted from the various processes at dairies; therefore, the inability to measure ethanol is a significant weakness in the PTRMS data. However, the PTRMS measurements were used to quantify emissions for the

August 2005 revision to the dairy emission factor because it was the best information available at the time.

In the second environmental chamber study completed in 2006, INNOVA photoacoustic analyzers were used to quantify ethanol and methanol emissions from dairy cattle and fresh manure and emissions of VFAs and phenolic compounds were sampled using a modified sorbent tube method and quantified using thermal desorption and gas chromatography (EPA TO-17). The instrumentation was calibrated to measure the following VFAs: acetic, propionic, isobutyric, butyric, isovaleric, valeric, isocaproic, caproic, and heptanoic acids and was calibrated to measure the following phenol and cresol compounds: phenol, 2-methylphenol, 2-ethylphenol, 3-methylphenol, 4-methylphenol, indole, and 3-methylindole. The results of this study indicated very high emissions of alcohols from cows and their fresh manure. However, subsequent research by Dr. Mitloehner has confirmed that when using the INNOVA analyzer without an ammonia filter, significant interference occurs when measuring alcohols. Because the INNOVA analyzer in this study did not include an ammonia filter, ammonia present in the chamber was incorrectly identified as alcohols. Therefore, the alcohol measurements from this study are not reliable. The study results showed very low levels of VFAs and phenol and cresol compounds. The only VFAs that were detected in measurable quantities were acetic, propionic, and butyric acid. Acetic acid was the only VFA that was consistently above the Limit of Quantification and the only VFA found to measurably contribute to enteric VOC emissions from milk cows but this contribution was very small. The VFA emissions measured in this study were lower than the acetic acid values measured in the earlier study using PTRMS.

The third environmental chamber study was completed by Dr. Mitloehner in late 2009. The experimental setup was as described in the California EPA, ARB project led by Dr. Zhang (May 2010), Section 6.0 - Measurement and Modeling of Volatile Organic Compound Emissions from Free Stall and Corral Housing. However, the information used to estimate enteric emissions from cows is based on unpublished data from the study for the period when cows are initially introduced into the environmental chamber and manure had not begun to accumulate. This unpublished data was provided by Dr. Mitloehner. This study is intended to replace the alcohol data from the previous 2006 study. In this study INNOVA photoacoustic analyzers with ammonia filters were used to quantify ethanol and methanol emissions from dairy cattle and fresh manure. The alcohol measurements from this study are considered to be much more reliable than the measurements from the earlier study, in which INNOVA analyzers without ammonia filters were used. This study resulted in significantly lower alcohol emissions. Enteric ethanol emissions from milk cows were significantly lower and enteric methanol emissions from milk cows were nearly zero. The methanol emissions measured in this study were lower than the value measured in the earlier study using PTRMS.

Conclusion

The APCO has chosen to continue to use the 1.4 lb/head-yr from PTRMS to quantify emissions of methanol, acetic acid, and other compounds in this category due to the conservative nature of the PTRMS measurement and sample loss. The storage and transport loss was less likely than with the sorbent tube method used to measure VFAs in the second chamber study. Additionally, 0.08 lb/head-year will be added to represent the measured value for enteric emissions of phenols and cresols from the second chamber study and 2.6 lb/head-year will be added to account for the ethanol emissions measured in the third chamber study. Therefore, enteric VOC emissions from milk cows are determined to be 4.1 lb/head-year.

Category 2: Milking Parlor (manure emissions)

California VOC Emissions Studies

Milking Parlor (manure emissions)		
Process or Constituent	**Emission Factor (lb/hd-yr)**	**Basis for Previous Emission Factor**
VOCs from Milking parlors	VOCs by TO-15: 0.02 lb/hd-yr Amines: 0.01 lb/hd-yr	Flux chambers with analysis by EPA TO-15, & EPA TO-11 (Schmidt, 2004)[11]

Dr. Charles Schmidt and Thomas Card measured VOC emissions from a dairy milking parlor at one Merced County dairy using flux chambers in conjunction with EPA method TO-15 and EPA method TO-11. The emission measurements were performed in 2004. The TO-15 measurements resulted in a total VOC measurement of 0.02 lb/head-year and amines were found to contribute an additional 0.01 lb/head-year. Therefore, total VOCs from the milking parlor were 0.03 lb/head-year based on this study.

Evaluation

The VOC emissions measured from the milking parlor were found to be very low. This is likely the result of the high solubility of the VOCs that would be emitted. Milking parlors are constantly flushed with fresh water so these compounds are likely to remain in solution in the water rather than being emitted to the atmosphere.

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[11] Schmidt, C.E. April 2005. Results of the Dairy Emissions Evaluation Using Flux Chambers Merced Dairy- Summer Testing Event. Final Report to the Central California Ozone Study (CCOS) group

Conclusion

The only California data available to calculate non-enteric VOC emissions from milking parlors are from Schmidt and Card's 2004 study; therefore, the APCO proposes an emission factor of 0.03 lb/head-year for milking parlors. Because of the high solubility of VOCs emitted at dairies and the relatively small surface area of milking parlors, this source does not contribute significantly to total VOC emissions at a dairy.

Category 3: Freestall Barns (manure emissions)

Recent VOC Emissions Studies

Recent Studies – Freestall Barns (bedding and flush lanes)

Recent Studies	Emission Factors from Recent Studies (lb/hd-yr)	Notes
Flux chamber sampling of barns (flush lanes and stalls) with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2006 - Phase III)[6]	**1.8 lb/hd-yr** Average pre-flushed flush lane flux of 131 μg/m^2-min (Dairy 1: 158 μg/m^2-min; Dairy 2: 104 μg/m^2-min) Average bedding solids flux of 246 μg/m^2-min	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3
Flux chamber sampling of ROG from flush lanes with analysis by GC/MS (Krauter, 2009)[7]	Average flush lane flux of 187 μg/m^2-min (pre-flush/scrape: 353 μg/m^2-min; post-flush/scrape: 21 μg/m^2-min) Average flush lane flux excluding outlier: 111 - 131 μg/m^2-min (pre-flush/scrape: 200 - 241 μg/m^2-min; post-flush/scrape: 21 μg/m^2-min)	Analysis and speciation by GC/MS 1st average includes single outlier with higher ROG primarily due to refrigerant CFC-12, which was removed from second average flux value

Evaluation

The recent California research that is currently available to quantify emissions from dairy freestall barns is from two studies conducted at dairies in the San Joaquin Valley.

The first study was performed in 2005 (report completed in 2006) by Dr. Charles Schmidt and Thomas Card and used flux chambers to quantify emissions at two dairies located in Merced County and Kings County. Flux chambers were used to collect samples and SCAQMD Method 25.3 was used to quantify total VOC flux. Several other methods were also used to quantify emissions during this study, including EPA TO-11, EPA TO-13, EPA TO-8, BAAQMD 29, EPA TO-14, and EPA TO-15. SCAQMD Method 25.3, which quantifies total carbon atoms from VOCs excluding methane and ethane, consistently resulted in higher mass values of VOC as methane than the sum of the other methods when the total carbon measured by these methods was also converted to methane. The measured flux values and the surface areas of specific processes at the dairies were used to determine the emissions rate. The emissions rates were then divided by the number of cows at the dairies to arrive at the emission factors for the dairies. VOC emissions measured from the flush lanes prior to flushing were low and the emissions flux was similar at both dairies. The original study report calculated an emission factor based on the total head at the dairies. The measured flux and process surface areas for only the milk cow areas and estimated number of milk cows at the dairies in 2005 were used to calculate the VOC emission factors based only on milk cows. The resulting VOC emission factors were 0.8 lb/head-year for the flush lanes and 1.0 lb/head-year for the stall bedding, for a total of 1.8 lb/head-year from the freestall barns.

A recently completed study, in which the field sampling program was led by Dr. Charles Krauter with sample analysis headed by Dr. Donald Blake, measured VOC flux from six dairies in the San Joaquin Valley using flux chambers. Flux chambers were used to collect samples and GC/MS was used to quantify VOC flux. Sampling occurred during the winter, early summer, and fall. The report did not provide the surface areas of specific processes at the dairy, which are needed to calculate the total mass emissions rates. However, the average flux values from this study can be compared to the flux values obtained in the Schmidt and Card study. This study measured higher average VOC flux values for the flush lanes prior to flush/scrape than Dr. Schmidt’s 2005 study, but also measured very low VOC flux from the lanes after flushing/scraping. Therefore, the overall averages were similar. There was one flux measurement at Dairy A that had several times the flux value of the next highest measurement, primarily due to the refrigerant CFC-12, which was not found in more than trace amounts in the other samples. When this measurement is removed, the overall average for VOC flux from the flush lanes is nearly the same as Dr. Schmidt’s 2005 dairy study. Although the study report did not provide sufficient information to calculate an emission factor for the individual dairies sampled, the study did contain an example of emissions that could be expected from a fictitious dairy based on the information gathered in the study. The fictitious dairy in the report had a VOC emission factor of 1.0 lb/head-year for the flush lanes, which is very close to the value of 0.8 lb/head-year from the Dr. Schmidt’s 2005 dairy study.

Conclusion

The APCO has determined that the total VOC measurements from Schmidt and Card’s 2005 study provide the best available data to quantify VOC emissions from dairy freestall barns. Dr. Schmidt's 2005 dairy study measured total VOC emissions from both flush lanes and stalls in the freestall barns and provided the information needed to calculate specific emission factors for these processes. The study by Krauter and Blake resulted in similar average VOC flux from the freestall flush lanes. If the one potentially anomalous measurement is removed from the Krauter and Blake study, the average VOC flux from the freestall is equivalent or less than the average flux determined in the Schmidt and Card study using a different analytical method. Both studies indicated that VOC emissions from flush lanes are low because of the high solubility of many of the compounds. The flush lane VOC emission factor from the data in the Schmidt and Card study and the VOC emission factor for the fictitious dairy described in the report for the Krauter and Blake study are nearly the same. Therefore, both studies clearly support each other. However, it is more defensible to base the emission factor on the data from Dr. Schmidt's study because the surface areas used to calculate the emission factor in this report were based on the processes observed at the dairies studied rather than approximations based on a fictitious dairy. Therefore, the APCO proposes an emission factor of 1.8 lb/head-year for non-enteric emissions from freestall barns.

Category 4: Exercise Pens and Corrals (manure emissions)

Recent VOC Emissions Studies

Recent Studies – Exercise Pens and Corrals (manure emissions)

New Studies	Emission Factors from Recent Studies (lb/hd-yr)	Notes
Flux chamber sampling of corrals/ pens with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2006 - Phase III)[6]	Turnout Average: **8.3 lb/hd-yr** (Average flux of 243 µg/m^2-min) Seasonally Adjusted Turnout Average based on 2008 Study: **6.8 lb/hd-yr** (Average flux of 195 µg/m^2-min)	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3
Flux chamber sampling of corrals/ pens during summer and winter seasons with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2009 – Phase IV)[7]	Seasonally Adjusted Turnout Average: **6.5 lb/hd-yr** (Average flux of 207 µg/m^2-min)	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3
Flux chamber sampling of ROG from open lots with analysis by GC/MS (Krauter, 2009)[8]	Average flux of 173 µg/m^2-min from open lots	Analysis and speciation by GC/MS

Evaluation

The recent California research that is available to quantify emissions from corrals and exercise pens at dairies is from three studies conducted at dairies in the San Joaquin Valley.

As mentioned above, Dr. Schmidt and Card performed a study in 2005 using flux chambers and SCAQMD Method 25.3 to quantify emissions at two dairies located in Merced County and Kings County. Dr. Schmidt and T. Card performed a follow-up study in 2008 using flux chambers and SCAQMD Method 25.3 to quantify emissions at the same two dairies. However, the first study measured emissions only during the summer season while the 2008 study collected some samples during the winter season to characterize seasonal effects on the VOC emissions rates. The study results showed that winter VOC emissions rates from the corrals were lower than the summer rates. This information was used to adjust the summer data from the 2005 and 2008 studies to arrive at an annual average considering seasonal variability. The original study reports calculated emission factors based on total head at the dairies. The measured flux and process surface areas for only the milk cow areas and estimated number of milk cows at the dairies in 2005 and the reported number of milk cows at the dairies in 2008 were used to calculate the VOC emission factor based only on milk cows. This resulted in an annual VOC emission factor of 6.6 lb/head-year for the exercise pens and corrals.

The Krauter and Blake study also measured VOC flux from six dairies in the San Joaquin Valley using flux chambers to collect samples. GC/MS was used to quantify VOC flux. Sampling occurred during the winter, early summer, and fall. The average flux values from this study can be compared to the flux values obtained in Dr. Schmidt’s study. This study resulted in average VOC flux values for the corrals that were similar but slightly less than the seasonal-adjusted averages from Dr. Schmidt’s 2005 and 2008 dairy studies. The study report states that emissions from the corrals were found to vary with surface temperature and season. Like the Schmidt and Card dairy studies, emissions from the corrals were found to be higher in the summer than the winter. As previously mentioned, the report contained an example of emissions that could be expected from a fictitious dairy based on the information gathered in the study. The fictitious dairy in the report had a VOC emission factor of 3.2 lb/head-year for the corrals/pens, which is approximately half the annual average value from Dr. Schmidt’s dairy study.

Conclusion

The APCO has determined that the total VOC measurements from Dr. Schmidt’s 2005 and 2008 studies provide the best available data to quantify VOC emissions from corrals and exercise pens at dairies. The study by Krauter and Blake resulted in similar average VOC flux rates from corrals but the study estimated a lower overall emissions rate for the fictitious dairy presented in the report. It appears that the dairy VOC compound profile used for the GC/MS captured a large portion of the mass of VOC emissions from corrals since the average flux measurements were similar to Dr. Schmidt's study. Based on this, it appears that the corral area needed for the fictitious dairy was possibly underestimated, thereby resulting in lower VOC emissions. As stated above, it is more appropriate to base the emission factor on the actual data from Dr. Schmidt's study because the surface areas used to calculate the emission factor in this report were based on the processes observed at the dairies studied rather than approximations based on a fictitious dairy. Therefore, the APCO proposes an emission factor of 6.6 lb/head-year for the corrals and exercise pens.

Category 5: Lagoons, Storage Ponds, and Settling Basins

Basis of Previous VOC Emission Factor

Basis of the Previous Dairy VOC Emission Factor		
Process or Constituent	**Emission Factors (lb/hd-yr)**	**Basis for Previous Emission Factors**
Previous Category 4: VOCs from lagoons and storage ponds		
VOCs (except VFAs and Amines) from settling basins, lagoons, and storage ponds	1.0	Flux chambers with analysis by EPA TO-15, & EPA TO-11 (Schmidt, 2004)[11] Concentration analysis by EPA TO-15 and Emissions Modeling by ISCST3 (Krauter, 2005)[12]
From Previous Category 5: VFAs from Wet Processes		
VFAs from wet processes (settling basins, lagoons, storage ponds, etc.)	7.14	Estimated based on laboratory manure slurry study and a correlation between ammonia and VOC emissions from manure (Hobbs, P.J. Webb, J. Mottram, T.T. Grant, B. and Misselbrook. T.M. 2004)

Dr. Schmidt and Card measured VOC emissions from a dairy lagoon at one Merced County dairy using flux chambers in conjunction with EPA method TO-15 and EPA method TO-11. In a study led by Dr. Krauter VOC emissions from lagoons and storage ponds at two San Joaquin Valley dairies were estimated using TO-15 measurements of upwind and downwind concentrations in conjunction with inverse dispersion modeling techniques.

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[12] Krauter Presentation to DPAG on March 8, 2005 at the San Joaquin Valley Air Pollution Control District Central Office, Fresno, CA - Concentration analysis by EPA TO-15 and Emissions by Inverse Dispersion Modeling using ISCST3

At the time of the previous revision to the District's dairy VOC emission factor, no California studies were available to estimate VFA emissions from wet processes, such as lagoons. Therefore, VFA emissions from wet processes were estimated based on the Hobbs et al study, in which VFA emissions were measured from manure slurry in a laboratory. The lb/head-year VFA emission factor was calculated based on a correlation between ammonia emissions and VOC emissions from manure and assuming that 60% of the manure on a typical San Joaquin Valley dairy is handled in a wet process.

Recent VOC Emissions Studies

Recent Studies – Lagoons, Storage Ponds, and Settling Basins		
New Studies	**Emission Factors from Recent Studies (lb/hd-yr)**	**Notes**
Flux chamber sampling of lagoons with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2006 - Phase III)[6]	1.3	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3

Evaluation

Dr. Schmidt's 2005 study used flux chambers to collect samples at two dairies located in Merced County and Kings County and SCAQMD Method 25.3 was used to quantify total VOC flux. The original study reports calculated emission factors based on total head at the dairies. The measured flux, process surface areas, and estimated number of milk cows at the dairies in 2005 were used to calculate an emission factor based only on milk cows. This resulted in an annual VOC emission factor of 1.3 lb/head-year for the liquid manure handling system.

Conclusion

The District has determined that the VOC measurements taken in the study led by Dr. Krauter in 2005 and the total VOC measurements from Dr. Schmidt's 2005 study provide the best available data to quantify VOC emissions from dairy lagoons, storage ponds, and settling basins. Each of these studies resulted in a VOC emission factor of 1.3 lb/head-year. Therefore, the APCO proposes an emission factor of 1.3 lb/head-year for the lagoons, storage ponds, and settling basins. Dr. Schmidt's earlier 2004 study reported lower emissions but only focused on a very limited number of compounds. SCAQMD Method 25.3, which was used in Dr. Schmidt's later studies, is able to measure total VOCs and captures a greater proportion of the VOCs emitted at dairies, including volatile fatty acids and amines. Recent studies that are available have indicated that VOC emissions from lagoons were relatively low; therefore, VFA emissions from this source are not as significant as previously thought.

Category 6: Liquid Manure Land Application

Recent VOC Emissions Studies

Recent Studies – Liquid Manure Land Application		
New Studies	**Emission Factors from Recent Studies (lb/hd-yr)**	**Notes**
Flux chamber sampling of lagoons with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2009 – Phase IV)[7]	1.4	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3

Evaluation

The only VOC emissions data that were available for liquid manure land application at a California dairy were from Schmidt and Card's Phase IV flux chamber study at a dairy located in Merced County. Total VOCs (as methane) were measured from the dry soil prior to land application and following application of liquid manure. VOC flux measurements from land application of chemical fertilizer at a different site were also performed for comparison purposes. Emissions were measured immediately after irrigation and at three hours, eight hours, and 21 hours after irrigation. The net VOC flux from liquid manure land application was found to be very low and was near the detection limits of the instrumentation. Therefore, the contribution of land application to VOC emissions at the dairy was primarily the result of the very large land application area (2,500 acres) being irrigated with liquid manure three times per year. The land application area was shared with an adjacent dairy. The land application emission factor given in the study report was based on the total number of milk cows at both dairies and resulted in an annual VOC emission factor of 1.4 lb/head-year for liquid manure land application.

Conclusion

The only California data that were available to calculate VOC emissions from liquid manure land application are from Dr. Schmidt's Phase IV study; therefore, this data will be used to quantify VOC emissions from this source. Therefore, the APCO proposes an emission factor of 1.4 lb/head-year for liquid manure land application.

The study resulted in very low total VOC flux near the quantification limit. Additionally, there was an extremely low correlation for the estimated curve fit that was used to calculate overall emissions. Therefore, in future studies additional measurements are needed to better quantify the low net flux value to calculate emissions with greater accuracy. Because of the low flux value, the mass of emissions is primarily the result of the very large surface area for this process. Therefore, to more accurately assess VOC emissions from this source, additional information is needed regarding the number of times liquid manure is applied to land, the number of acres irrigated for each event, and the total land application area at dairies in relation to the number of milk cows and total herd size.

Category 7: Solid Manure Land Application

Recent VOC Emissions Studies

Recent Studies – Solid Manure Land Application		
New Studies	**Emission Factors from Recent Studies (lb/hd-yr)**	**Notes**
Flux chamber sampling of solid manure land application with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2009-Phase IV)[7]	0.33	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3

Evaluation

The only VOC emissions data that were located for solid manure land application at a California dairy were from Dr. Schmidt and Card's 2008 flux chamber study at a Merced County dairy. Total VOCs (as methane) were measured from the soil prior to land application of solid manure and following the application of solid manure. Initial emission measurements were performed for both incorporated and unincorporated solid manure. Incorporation of solid manure was found to significantly reduce ammonia emissions; however, no significant differences were found in the VOC emissions from incorporated and unincorporated solid manure. VOC emissions were measured for incorporated manure at one hour, three hours, and seven hours after application. The net VOC flux from solid manure land application was found to be very low and was near the detection limits of the instrumentation. The net VOC flux dropped back to background levels at approximately four hours after application. The contribution of solid manure land application to VOC emissions at the dairy was the result of solid manure being applied to the very large application area (2,500 acres) twice per year. The annual VOC emission factor from the study for solid manure land application based only on milk cows was 0.33 lb/head-year.

Conclusion

The only California data that were available to calculate VOC emissions from solid manure land application are from Dr. Schmidt's Phase IV study; therefore, the data in that study will be used to quantify VOC emissions from this source. Therefore, the APCO proposes an emission factor of 0.33 lb/head-year for solid manure land application.

The study resulted in very low total VOC flux near the quantification limit and the mass of emissions is primarily the result of the very large surface area for this process. To more accurately assess VOC emissions from this source, additional information is needed regarding the number of times solid manure is applied to land and the total land application area at dairies in relation to the number of milk cows and total herd size.

Category 8: Separated Solids Piles

Recent VOC Emissions Studies

Recent Studies – Separated Solids Piles

New Studies	Emission Factors from Recent Studies (lb/hd-yr)	Notes
Flux chamber sampling of separated solids piles with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2006 - Phase III)[6]	0.06	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3

Evaluation

The only California data that were available to calculate VOC emissions from separated solids plies are from Dr. Schmidt and Card’s 2005 study. Flux chambers were used to measure emissions at a dairy located in Merced County and SCAQMD Method 25.3 was used to quantify total VOC flux. Dr. Schmidt also measured this source in 2004 using TO-15 to quantify emissions. The total VOC emissions measured using SCAQMD Method 25.3 were approximately twice the emissions measured using TO-15. But the overall emissions quantified with either method were very low, possibly because of the high solubility of the volatile compounds emitted from dairies, which may have resulted in many of these compounds remaining in the liquid manure when solids were removed. The annual VOC emission factor for separated solids resulting from the 2005 study using SCAQMD Method 25.3 adjusted for only milk cows is 0.06 lb/head-year.

Conclusion

The APCO has determined that the total VOC measurements from Dr. Schmidt’s Phase III study provide the best available data to quantify VOC emissions from separated solids. All available studies indicate that VOC emissions from separated solids are very low. However, the earlier 2005 study used only TO-15 and focused on a very limited number of compounds. SCAQMD Method 25.3, which was used in Dr. Schmidt's later studies, captures a more complete range of compounds, including volatile fatty acids and amines. Therefore, the APCO proposes an emission factor of 0.06 lb/head-year for manure separated solids. Given the very low emissions measured, future dairy emission studies do not need to focus on VOC emissions from this source.

Category 9: Solid Manure Storage

Dairies in the San Joaquin Valley will typically have stockpiles of solid manure consisting of stored separated solids that can be used as bedding in freestalls or applied to cropland and scrapings from exercise pens and corrals that are applied to the dairy's cropland or transported offsite to be applied to the cropland of other farms.

Recent VOC Emissions Studies

Recent Studies – Solid Manure Storage

New Studies	Emission Factors from New Studies (lb/hd-yr)	Notes
Flux chamber sampling of lagoons with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2006 – Phase III)[6]	0.15	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3

Evaluation

The only recent California data that were available to calculate VOC emissions from stored solid manure are from Dr. Schmidt and Card's 2005 study. Flux chambers were used to measure emissions at two dairies located in Merced County and Kings County. The annual VOC emission factor from the study for solid manure storage adjusted for only milk cows is 0.15 lb/head-year.

Conclusion

The only California data that were available to calculate VOC emissions from separated solids are from Dr. Schmidt's 2005 study; therefore, the data from this study will be used to quantify VOC emissions from this source. Therefore, the APCO proposes an emission factor of 0.15 lb/head-year for solid manure storage.

Category 10: Silage Piles

Recent VOC Emissions Studies

Recent Studies –Silage Piles		
New Studies	**Average VOC Flux from Recent Studies ($\mu g/m^2$-min)**	**Notes**
Flux chamber sampling with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2006 – Phase III)[6]	Silage Pile Average Flux: 29,335 $\mu g/m^2$-min (8.65 x 10^{-3} lb/ft^2-day) Seasonally and Time Adjusted Average Flux based on 2008 Study: 21,435 $\mu g/m^2$-min (6.32 x 10^{-3} lb/ft^2-day)	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3 Highest reported flux from freshly disturbed silage: 49,329 $\mu g/m^2$
Flux chamber sampling during summer and winter seasons with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2009 – Phase IV)[7]	Seasonally and Time Adjusted Average Flux: 39,405 $\mu g/m^2$-min (1.16 x 10^{-2} lb/ft^2-day)	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3 Highest reported flux from freshly disturbed silage: 85,240 $\mu g/m^2$ and 81,374 $\mu g/m^2$ Although higher average flux was measured in 2008, the higher per head EF in the report is also due to an additional silage pile being open at each dairy during the Phase IV study.
Flux chamber sampling of ROG from with analysis by GC/MS (Krauter, 2009)[8]	Average flux Disturbed silage: 19,170 $\mu g/m^2$-min (5.65 x 10^{-3} lb/ft^2-day); Undisturbed silage: 4,229 $\mu g/m^2$-min (1.25 x 10^{-3} lb/ft^2-day)	Analysis and speciation by GC/MS Time dependent data not provided but highest reported flux from freshly disturbed silage (75,977 $\mu g/m^2$ and 72,698 $\mu g/m^2$) is very similar to highest flux reported in Schmidt Phase IV study.

Recent Study for Comparison Purposes – Thin Layers of Loose Silage		
New Studies	**Average VOC Flux ($\mu g/m^2$-min)**	**Notes**
Flux chamber sampling with analysis of VOC by PTRMS and INNOVA photoacoustic analyzer (Zhang, 2010)[9]	Loose Corn Silage*: Ave. Flux: 1.17 g/m^2-hr (~ 19,400 $\mu g/m^2$-min) Loose Alfalfa Silage*: Ave. Flux: 1.00 g/m^2-hr (~ 16,700 $\mu g/m^2$-min)	Major VOC measured by PTRMS: methanol, acetic acid, and acetaldehyde. INNOVA analyzer measured ethanol and methanol. Based on Cumulative Emissions measured over 12 hours

*For total VOC flux the methanol values by PTRMS and the INNOVA analyzer were averaged

Evaluation

The recent California research that is available to quantify emissions from silage piles at dairies is based on three studies conducted at dairies in the San Joaquin Valley. In addition, the average flux rates measured for loose silage from the ARB research project led by Dr. Ruihong Zhang of UC Davis will also be briefly discussed for comparison purposes.

Dr. Schmidt and Card's Phase III study used flux chambers and SCAQMD Method 25.3 to quantify emissions at two dairies located in Merced County and Kings County. As previously mentioned, Schmidt and Card performed a follow-up study in 2008 (Phase IV) using flux chambers to quantify emissions at the same two dairies. In the Phase IV study, some samples were collected during the winter season to characterize seasonal effects on the VOC emissions rates. The study showed that winter VOC emissions rates from the feed sources were lower than the summer rates. This information was used to adjust the summer data from the Phase III and Phase IV studies to arrive at an annual average considering seasonal variability. Additionally, measurements were taken at one of the dairies throughout the day to characterize how emissions changed with time. The VOC emissions from the silage piles were the highest when the silage was initially disturbed to remove feed for the TMR but declined with time. The silage that had not been disturbed had much lower emissions. The operational practices observed at the dairy were used to simulate emissions and arrive at an average annual VOC emission factor. The adjustment factors from the Phase IV study were also used to adjust the emissions measurements from the Phase III study. The following average flux values were derived from these studies: corn silage: 1.02E-02 lb/ft^2-day (34,681 μg/m^2-min); alfalfa silage: 5.15E-03 lb/ft^2-day (17,458 μg/m^2-min); and wheat silage: 1.29E-02 lb/ft^2-day (43,844 μg/m^2-min).

For reference purposes, the measured flux and process surface areas for the open faces of the silage piles can also be used to calculate the seasonally adjusted VOC emission factor based on the number of milk cows at the dairies. This would result in an average VOC emission factor of approximately 6.5 lb/head-year for the uncovered faces of the silage piles. However, the lb/head-year emission factor may overestimate VOC emissions from silage since the silage piles at the Merced dairy also served other dairies with additional milk cows that were not counted when determining this value. Additionally, because emissions from this source are more dependent on the exposed area of the silage piles than the number of cows at the dairy, using the average flux values to calculate VOC emissions is more appropriate for this source. This is illustrated by the fact that a significant portion of the increased lb/head-year silage pile VOC emission factor reported in the Phase IV study conducted in 2008 as compared to the Phase III study conducted in 2005 can be attributed to an additional silage pile being open and utilized at each dairy during the Phase IV study.

The study by Dr. Krauter and Dr. Blake also used flux chambers to measure VOC emissions from the silage piles at six dairies in the San Joaquin Valley. GC/MS was used to analyze and quantify VOC flux. Sampling occurred during the winter, early summer, and fall but no seasonal effects were found for VOC emissions from feed sources. This study reported maximum VOC flux values for freshly disturbed silage that were similar to the maximum VOC flux values for freshly disturbed silage reported in Dr. Schmidt's Phase III and Phase IV dairy studies, particularly the higher values in the Phase IV study report. However, the average VOC flux values reported for silage piles were significantly less than the seasonally-adjusted averages from Dr. Schmidt's Phase III and Phase IV dairy studies. The reason for this difference is not known at this time but may be related to the time measurements were taken after initial disturbance of the silage and how these values were averaged. Additional time-dependent emissions data for dairy feed sources would be useful for better characterizing emissions from this source and determining representative emission values. There was also a great deal of variability in the flux measured from the silage at the dairies. The variability may be related to the types of silage used or silage compaction; however, the study report does not provide all of this information but states that an upcoming report may contain at least some of this information.

During the Krauter and Blake study INNOVA analyzers were also used to quantify alcohol emissions from sources at the dairies. The INNOVA analyzer measurements were taken at the same source within 10 minutes of the canister samples analyzed with GC/MS. In the report to ARB for the Krauter and Blake study it was noted that the INNOVA analyzer alcohol measurements for silage were consistently three to four times the values obtained with the canister samples analyzed by GC/MS and that Dr. Donald Blake of UC Irvine and other project collaborators had questioned the ability of the GC/MS system to extract all of the water soluble gasses, such as alcohols, from the canisters when they are analyzed. However, the results in the report indicating higher alcohol emissions measured with the INNOVA analyzer as compared to GC/MS were based on preliminary information from an earlier progress report submitted to ARB in April 2007. Later measurements performed by the researchers indicated general agreement between the GC/MS alcohol measurements and the INNOVA analyzer alcohol measurements.[13] Researchers at CSU Fresno that were involved in the project were contacted and they indicated that the apparent difference between the two methods occurred in the first year (2006) and possibly the early part of the second year (2007) of the monitoring study while the methodology was still being developed and the field collection and lab analysis techniques were still being modified. Dr. Krauter and other researchers involved with the project stated that the data from the later years, 2007- 2009, including the measurement values in the main body of the final report to ARB, showed much better agreement and are more reliable than their preliminary work

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[13] Chung M., Beene M., Ashkan S., Krauter C., Hasson A. (2009) Evaluation of non-enteric sources of non-methane volatile organic compound (NMVOC) emissions from dairies. Atmospheric Environment 44, 786-794.

that indicated differences between the GC/MS alcohol measurements and the INNOVA analyzer alcohol measurements.

The primary purpose of the study led by Dr. Ruihong Zhang was to identify and quantify significant VOC compounds emitted from silage and dairy manure storage for the purpose of developing process-based models to quantify emissions from dairy sources. As part of the study, samples of corn and alfalfa silage were spread in thin layers and flux chambers were used to measure emissions using PTRMS and an INNOVA photoacoustic analyzer to measure alcohols. Four major compounds were detected with high certainty by PTRMS: methanol, acetic acid, acetaldehyde, and acetone (an exempt compound). The INNOVA analyzer was used to measure ethanol and methanol. Emissions from the loose silage samples were measured over a twelve-hour period. The average VOC flux rates from the main compounds reported in this study are presented for comparison purposes only since the thin layers of loose silage samples that were measured are not representative of the condition of the majority of silage in silage piles, which is densely compacted to slow aerobic spoilage and preserve nutritional value. The average flux measurements for the major VOCs reported for thin layers of loose corn and alfalfa silage are generally similar to the average silage pile emission numbers reported by Dr. Krauter and Dr. Blake. These average flux values were less than the seasonally-adjusted average flux for corn silage from Dr. Schmidt's Phase III and Phase IV dairy studies and similar to the seasonally-adjusted average flux for alfalfa silage. This is likely because of the limited number of compounds for which the flux rates were reported since emissions are known to increase with increased porosity and loose silage samples would be expected to have a higher average flux rate than silage in silage piles, most of which would be densely compacted.

Conclusion

The APCO has determined that the total VOC flux measurements from Dr. Schmidt's Phase III and Phase IV studies provided the best available data to quantify VOC emissions from silage piles at dairies. Because emissions from this source are more directly related to the exposed area of the silage piles, the measured flux will be used to calculate emissions on a per area basis rather than a per cow basis. The APCO proposes that the following average flux values be used to calculate emissions from the silage piles at a dairy on a per area basis: corn silage: 1.02E-02 lb/ft^2-day; alfalfa silage: 5.15E-03 lb/ft^2-day; and wheat silage: 1.29E-02 lb/ft^2-day.

The study by Krauter and Blake resulted in very similar maximum VOC flux rates but lower average VOC flux using GC/MS. Additional time-dependent emissions data for dairy feed sources would be useful to better characterize emissions from this source and determine representative emission values. The difference in the average flux values may also be related to the types of silage used or other factors. The study report states that some of this information may be provided in another report. As mentioned above, preliminary results of the Krauter and Blake study had initially indicated higher alcohol flux using INNOVA analyzers; however these preliminary results were based on measurements that were taken while the field and lab procedures were still being developed. Later measurements demonstrated general agreement between the values obtained by GC/MS and the INNOVA analyzer and the researchers involved with the project state that these later results are more reliable. Dr. Schmidt's Phase IV study found seasonal variation that was not found in the Krauter and Blake study but the winter data set from Dr. Schmidt's Phase IV study was very limited. Therefore, additional data may need to be collected in the winter and/or fall seasons to better quantify seasonal variability of VOC emissions from this source.

The average flux rates of major VOCs emitted from thin layers of loose silage that were identified in the study led by Dr. Zhang were presented for comparison purposes. The average VOC flux rates from this study were similar to the average flux rates for silage piles in the Krauter and Blake study and less than the average flux rates for silage piles from the Schmidt and Card Studies. This is likely because of the limited number of major compounds for which flux rates were reported since loose silage will generally have higher emission fluxes than densely compacted silage piles.

Category 11: Total Mixed Ration

Recent VOC Emissions Studies

Recent Studies – Total Mixed Ration (TMR) (feed placed in front of cows)		
New Studies	**Average VOC Flux from Recent Studies ($\mu g/m^2$-min)**	**Notes**
Flux chamber sampling with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2006 – Phase III)[6]	TMR Average Flux: 40,061 $\mu g/m^2$-min (1.18×10^{-2} lb/ft^2-day) Seasonally and Time Adjusted Average Flux based on 2008 Study: 15,415 $\mu g/m^2$-min (4.55×10^{-3} lb/ft^2-day)	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3
Flux chamber sampling during summer and winter seasons with analysis of Total ROG by SCAQMD 25.3 (Schmidt, 2009 – Phase IV)[7]	Seasonally and Time Adjusted Average Flux: 10,696 $\mu g/m^2$-min (3.15×10^{-3} lb/ft^2-day)	Total non-methane, non-ethane VOC as methane determined by SCAQMD 25.3
Flux chamber sampling of ROG from TMR with analysis by GC/MS (Krauter, 2009)[8]	TMR Average flux: 8,260 $\mu g/m^2$-min (2.44×10^{-3} lb/ft^2-day)	Analysis and speciation by GC/MS

Evaluation

The recent California research that is available to quantify emissions from Total Mixed Ration (TMR) at dairies is based on three studies conducted at dairies in the San Joaquin Valley.

Schmidt and Card's Phase III study used flux chambers and SCAQMD Method 25.3 to quantify emissions at two dairies located in Merced County and Kings County. The later Phase IV study used the same methodologies but with a focus on seasonal and temporal variability from important emission sources. The VOC emissions from the TMR, the feed placed to be consumed by the cows, were the highest when the feed was first placed but declined with time. The TMR was the largest source of VOC emissions at the dairies and also had the most variability. The maximum flux measured from the TMR at the Kings County dairy was significantly higher than the flux measured from the TMR at the Merced County dairy. The operational practices observed at the dairies were used to simulate emissions and arrive at an average annual VOC emission factor. However, the original exponential curve fit used in the report to calculate VOC emissions from the milk cow TMR had a very low correlation value - so low that it could be argued that there was no true correlation between the data set and the exponential equation used. Therefore, the emission factor for the TMR used in this report is based on a slightly more conservative linear curve fit of the 2008 data set that had a higher correlation value. The adjustment factors derived from the 2008 study were also used to adjust the emissions measurements from the 2005 study for both temporal and seasonal variability. For reference purposes, the measured flux and process surface areas for the TMR can be used to calculate the seasonally adjusted VOC emission factor based on the number of milk cows at the dairies, which results in an average VOC emission factor of approximately 11.8 lb/head-year for the TMR. However, as with silage piles, the other feed emission source, it has been determined that using the average flux value and the area of the TMR placed for the cows to calculate VOC emissions is more appropriate for determining emissions from this source. The following average flux value derived from Schmidt and Card's Phase III and Phase IV dairy studies can be used to calculate emissions from the TMR on a per area basis: 3.85E-03 lb/ft^2-day (13,056 μg/m^2-min).

The Krauter and Blake study (2009) also used flux chambers to measure VOC emissions from the TMR at six dairies in the San Joaquin Valley. Sampling occurred during the winter, early summer, and fall. No seasonal effects were found for VOC emissions from feed sources. However, as in Schmidt and Card's studies, emissions from the TMR were found to decrease with time after placement of the feed. The average flux values reported for this study can be compared to the average flux values reported for the studies by Schmidt and Card. This study resulted in average VOC flux values for the TMR that were less than the values reported by Schmidt and Card but were more similar to the average flux values reported by Schmidt and Card after they had been adjusted to account for temporal and seasonal variability in VOC emissions from feed. The study also resulted in lower emissions from the TMR for the fictitious dairy described in the report. As mentioned earlier, preliminary results of the Krauter and Blake study had initially indicated higher alcohol flux using INNOVA analyzers compared to the values obtained by GC/MS; however these preliminary results were based on measurements that were taken while the field and lab procedures were still being developed. Later measurements demonstrated general agreement between the values obtained by GC/MS and the INNOVA analyzer[13] and the researchers involved with the project state that these later results, including the values contained in the main body of the final project report to ARB, are more reliable. More data were collected on TMR emissions at two of the dairies but these data were not presented in the current project report. The report states that these data will be presented in a forthcoming report.

Conclusion

The APCO has determined that the total VOC measurements from the Schmidt and Card Phase III and Phase IV studies provide the best available data to quantify VOC emissions from TMR at dairies. Therefore, the APCO proposes that the following average flux value be used to calculate emissions from the TMR on a per area basis: 3.85E-03 lb/ft^2-day.

The Krauter and Blake study resulted in a slightly lower average VOC flux than the values reported by Schmidt and Card, once these values had been adjusted to account for temporal and seasonable variability. Additional data may need to be collected in the winter and/or fall seasons to better quantify seasonal variability of VOC emissions from this source. Additionally, the correlations for the curve fits that were examined to calculate emissions from TMR based on data from the Phase IV Schmidt Study were all low. Additional time-dependent emissions data are needed to better characterize changes in emissions from dairy feed sources over time and determine representative emission values.

Category 12: Composting

Composting		
Process or Constituent	**Emission Factor (lb/hd-yr)**	**Basis for Emission Factor**
Composting	TBD, > 0	N/A

Although unknown quantities of VOCs may be emitted during composting of dairy manure solids, no California emissions data could be located that were representative of this source. Therefore, the APCO will consider the emissions from this source to be of the category to be determined but greater than zero. Further research is recommended to quantify emissions from this source.

Summary of Dairy Emission Factors

In summary, the tables below show the dairy emission factors that were developed based on the best information available to the APCO and will be used for each source and constituent:

Dairy Emission Factors based on Studies Summarized in this Document

Per Cow Dairy VOC Emission Factors	
Process or Constituent	**Emissions (lb/hd-yr)**
1. Enteric Emissions from Cows	4.1
2. Milking Parlor(s)	0.03
3. Freestall Barns	1.8
4. Corrals/Pens	6.6
5. Liquid Manure Handling (Lagoons, Storage Ponds, Basins)	1.3
6. Liquid Manure Land Application	1.4
7. Solid Manure Land Application	0.33
8. Separated Solids Piles	0.06
9. Solid Manure Storage	0.15
12. Composting & Manure Disturbance	TBD, >0
Total not including Feed	**15.8**

The dairy emission factors that are summarized in the table above were developed based on the studies reviewed and summarized in this document; however, the APCO has determined that during the time that the majority of these studies were performed, measures were being implemented that would reduce VOC emissions below the levels that would otherwise have been measured. In order to calculate the uncontrolled dairy emission factors for the period when no controls/mitigation measures were implemented (i.e. prior to District Rule 4570), the dairy emission factors developed in this document were adjusted to remove control efficiencies for certain practices that reduced emissions. Details of how this calculation was performed can be found in Appendix 8 and the uncontrolled dairy VOC emission factors to be used for dairies that are not required to implement measures from Phase I of District Rule 4570 are summarized in the table below.

Dairies not Implementing Phase I of District Rule 4570 (< 1,000 milk cows)

Uncontrolled Per Cow Dairy VOC Emission Factors	
Process or Constituent	**Emissions (lb/hd-yr)**
1. Enteric Emissions from Cows	4.3
2. Milking Parlor(s)	0.04
3. Freestall Barns	1.9
4. Corrals/Pens	10.0
5. Liquid Manure Handling (Lagoons, Storage Ponds, Basins)	1.5
6. Liquid Manure Land Application	1.6
7. Solid Manure Land Application	0.39
8. Separated Solids Piles	0.06
9. Solid Manure Storage	0.16
12. Composting & Manure Disturbance	TBD, >0
Total not including Feed	**20.0**

VOC Emissions from Dairy Feed Sources

Silage Pile VOC Emissions Flux*	
10. Silage Piles	**Emissions Flux (lb/ft^2-day)**
1. Corn Silage	1.02E-02
2. Alfalfa Silage	5.15E-03
3. Wheat silage	1.29E-02

*Assuming silage piles are completely covered except for the “face” from where feed can be removed

Average Total Mixed Ration (TMR) VOC Emissions Flux	
11. Average TMR	**Emissions Flux (lb/ft^2-day)**
TMR	3.85E-03

Previous Dairy VOC Emission Factor for Reference

For comparison purposes only, the District's previous dairy emission factor (adopted August 1, 2005) is provided in the table below. The District's revised dairy emission factors represent a significant improvement because it specifically addresses many areas of the previous dairy emission factor for which there was a need for additional research to better quantify emissions under California dairy conditions.

District's Previous Dairy Emission Factors (Adopted August 1, 2005)	
Process or Constituent	**Emissions (lb/hd-yr)**
1. Emissions from Cows and Feed in Environmental Chamber	1.4
2. Ethylamines from specific dairy processes	0.2
3. VOCs (except VFAs and Amines) from miscellaneous dairy processes	1.2
4. VOCs (except VFAs and Amines) from lagoons and storage ponds	1.0
5. Volatile Fatty Acids	15.5
6. Phenols (from dairy processes)	TBD, > 0
7. Land Application	TBD, > 0
8. Feed storage, settling basins, composting, & manure disturbance	TBD, > 0
Total not including Feed	**19.3**

Summary of Future Research Recommendations

The APCO believes that future research will continue to improve the quality of dairy emission factors and recommends future research on the following items:

- Additional data are needed on different process emissions and effects of management practices on emissions to develop practical measures to mitigate emissions from important sources at dairies.
- Additional data need to be collected using real-time emission measurement techniques to better characterize changes in emissions from dairy feed sources over time and to compare these values with total VOC and other canister methods analyzed in a laboratory.
- Additional information is needed to better assess seasonal variability of emissions sources at dairies, particularly feed sources.
- Research should continue to determine which specific VOC compounds (e.g. alcohols, VFAs, aldehydes, esters) have the greatest contribution to the total mass of VOC from emitted from important sources at dairies and which of these compounds may have greater potential for ozone formation.
- Research should be conducted to determine if representative compounds can be measured to represent general categories of similar compounds (e.g. alcohols, VFAs, aldehydes) for purposes of assessing potential mitigation strategies.
- Additional information is needed comparing the effects of different sample collection techniques (e.g. flux chambers and wind tunnels) on calculated emissions rates
- Additional information is required regarding total land application area in relation to the number of milk cows and/or total head at a dairy and the frequency of land application of solid and liquid manure

Appendix 1 – Partial List of Emissions Studies Papers and Presentations Reviewed

Previous Papers and Presentations Reviewed to Establish the 2005 Dairy VOC Emission Factor

Cassel, T. Flocchini, R. Green, P. Higashi, R. Goodrich, B. Beene, M. Krauter, C. (Jan 2005). On-Farm Measurements of Methane and Select Carbonyl Emission Factors for Dairy Cattle. Presented at the Livestock Emissions Research Symposium held on January 26, 2005 at the San Joaquin Valley Air Pollution Control District Office, Fresno, CA
ftp://ftp.arb.ca.gov/carbis/ag/agadvisory/cassel05jan26.pdf

- Carbonyl Emission Factors by DNPH

Hobbs, P.J. Webb, J. Mottram, T.T. Grant, B. Misselbrook, T.M. (2004) Emissions of Volatile Organic Compounds Originating from UK Livestock Agriculture. 2004©. Society of Chemical Industry. J Sci Food Agric 84:1414-1420
http://www.valleyair.org/busind/pto/dpag/VOC_from_UK_livestock.pdf

- Non-methane VOCs emitted from slurry manure in an enclosed chamber measured using adsorbent material and thermal desorption GC/MS

Mitloehner, F. Trabue, S. Koziel, J.A. Research Proposal Summary (~2004) - Measurement of airborne volatile fatty acids emitted from dairy cows and their waste using sorbent tubes
http://www.valleyair.org/busind/pto/dpag/Appendices/Appendix%2024%20%20Plan%20of%20work%20VFAs_FMM.pdf

- VFAs by sorbent tubes and analyzed on a thermal desorption TDS/GC-MS system

Krauter, C. Goodrich, B. Dormedy, D. Goorahoo D., and Beene, M. 2005. Monitoring and Modeling of ROG at California Dairies. Presented at the EPA 14th Emissions Inventory Conference, April 13, 2005, Las Vegas, NV
http://www.epa.gov/ttn/chief/conference/ei14/session1/krauter.pdf
http://www.epa.gov/ttn/chief/conference/ei14/session1/krauter_pres.pdf

- VOC Concentration by EPA Method TO-15; Speciation by GC/MS; Emission Modeling by IST-STv3:

Krauter, C. Goorahoo, D. Goodrich, B. Beene, M (2005). Monitoring and Modeling of ROG at California Dairies, Presented at the Livestock Emissions Research Symposium held on January 26, 2005 at the San Joaquin Valley Air Pollution Control District Central Office, Fresno, CA
ftp://ftp.arb.ca.gov/carbis/ag/agadvisory/krauter05jan26.pdf

McGinn, S. M. Janzen, H. H. Coates, T. (2003). Atmospheric Ammonia, Volatile Fatty Acids, and Other Odorants near Beef Feedlots. J. Environ. Qual. 32:1173-1182

- VFAs (acetic, propionic, butyric, isobutyric, isovaleric, valeric, and caproic acids), cresols, phenol, indole, and skatole from beef feedlots by sorbent tubes and GC

Mitloehner, F. (2005). Volatile Organic Compound Emissions from Dairy Cows and Their Excreta. Presented at the Livestock Emissions Research Symposium held on January 26, 2005 at the San Joaquin Valley Air Pollution Control District Central Office, Fresno
ftp://ftp.arb.ca.gov/carbis/ag/agadvisory/mitloehner05jan26.pdf)

- Cows in an environmental chamber oxygenated VOCs (i.e. Ketones, Aldehydes, Alcohols, Carbonyls, Phenols, and Volatile Fatty Acids (VFAs)) by PTR/MS; TO-15 VOCs by GC/MS; total non-methane, non-ethane organic compounds by GC-FID; VFAs by GC/MS thermo-desorption

Schmidt, C. Card, T. Gaffney, P. (2005). Assessment of Reactive Organic Gases and Amines from a Northern California Dairy Using the USEPA Surface Emission Isolation Flux Chamber. Presented at the Livestock Emissions Research Symposium held on January 26, 2005 at the San Joaquin Valley Air Pollution Control District Central Office, Fresno
ftp://ftp.arb.ca.gov/carbis/ag/agadvisory/schmidt05jan26.pdf

- Flux Chambers with VOCs by EPA Method TO-15 (GC/MS); Amines by NIOSH 2010 (GC/IC); Aldehydes & Ketones by EPA Method TO-11 (GC/HPLC); Volatile Organic Acids by EAS Method (UV-VIS)
- Process units measured: Flush lanes; Solids storage piles; Lagoon (inlet and outlet of lagoon); Solids in Solids separator; Bedding in pile for freestall; Freestall area; Barn turnout and corral area; Manure piles in turnout; Heifer pens (dry cow area); Open feed storage in barn feed lanes; and Milk parlor wastewater effluent stream

Schmidt, C. E. (2005). Technical Memorandum: Results of the Dairy Emissions Evaluation Using Flux Chambers Merced Dairy- Summer Testing Event. April 2005. Final Report to the Central California Ozone Study (CCOS) group.
http://www.valleyair.org/Workshops/postings/PriorTo2008/2005/7-11-05/Appendix%206%20Schmidt%20ARBDairy.TM.02.pdf

Rabaud, N.E. Ebeler, S.E., Asbaugh, L.L, and R.G. Flocchini. 2002©. The application of Thermal Desorption GC/MS with Simultaneous Olfactory Evaluation for the Characterization and Quantification of Odor Compounds from a Dairy. Crocker Nuclear laboratory and department of Viticulture and Enology. American Chemical Society, 10.1021/jf020204u

Ngwabie, N.M. and Hintz, T. 2005©. Mixing Ratio Measurements and Flux Estimates of Volatile Organic Compounds (VOC) from a Cowshed with

Conventional Manure Treatment Indicate Significant Emissions to the Atmosphere. Geographical Research Abstracts, Vol. 7, 01175, 2005 Sref-ID: 1607-7962/gra/EGU05-A-01175

Koziel, J.A., Spinhirne, J.P., and Back, B.H. Measurements of Volatile Fatty Acids Flux from Cattle Pens in Texas. Texas Agricultural Experiment Station, Texas A&M University. Paper #04-A-646-AWMA

Additional VOC Papers and Presentations Reviewed

Schmidt, C. Card, T. (2009) 2008 Dairy Emissions Study: Summary of Dairy Emission Factors and Emission Estimation Procedures. August 2009. Final Report to San Joaquin Valley Air Pollution Control District

Schmidt, C. Card, T. (2009) Recent Sampling of Total Organic Gas Emissions from Dairies. Presented at the UC Davis Green Acres, Blue Skies II Conference, June 1, 2009, Davis, CA
http://airquality.ucdavis.edu/pages/events/2009/greenacres.html

Krauter, C. Blake, D. (2009) Dairy Operations: An Evaluation and Comparison of Baseline and Potential Mitigation Practices for Emissions Reductions in the San Joaquin Valley (May 01, 2009). Final Report for California Air Resource Board (ARB)
http://www.arb.ca.gov/research/single-project.php?row_id=64648

Zhang, Ruihong. (2010) Process-Based Farm Emission Model for Estimating Volatile Organic Compound Emissions from California Dairies. May 2010. Final Report for California Air Resource Board (ARB)
http://www.arb.ca.gov/research/single-project.php?row_id=64722

Alanis, P. Sorenson, M. Beene, M. Krauter, C. Shamp, B. Hasson, A. S. Measurement of non-enteric emission fluxes of volatile fatty acids from a California dairy by solid phase micro-extraction with gas chromatography/mass spectrometry, Atmospheric Environment 42 (2008) 6417–6424

Alanis, P. Ashkan, S. Krauter, C. Campbell, S. Hasson, A. S. Emissions of volatile fatty acids from feed at dairy facilities, Atmospheric Environment 44 (2010) 5084–5092

Sun, H. Trabue, S. Scoggin, K. Jackson, W. Pan, Y. Zhao, Y. Malkina, I.L. Koziel, J.A. and Mitloehner. F.M. (2008) Alcohol, volatile fatty acid, phenol, and methane emissions from dairy cows and fresh waste, Journal of Environmental Quality. Volume 37 (March–April 2008) 615-622.

Shaw, S.L. Mitloehner, F.M. Jackson, W.A. DePeters, E. Holzinger, R., Fadel, J. Robinson, P. and Goldstein, A.H. "Volatile Organic Compound Emissions from Dairy Cows and Their Waste as Measured by Proton Transfer-Reaction Mass Spectrometry", Environmental Science and Technology. VOL. 41, NO. 4, 2007, 1310-1316

Mitloehner, F. Trabue, S. Koziel, J.A. (2006) Volatile Fatty Acids, Amine, Phenol, and Alcohol Emissions from Dairy Cows and Fresh Waste (May 31, 2006). Final Report to California Air Resource Board (ARB)
http://www.arb.ca.gov/ag/caf/MitloehnerDairyChamberEmissions2006.pdf

Schmidt, C. Card, T. (2006) Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures (May 2006). Final Report to California Air Resource Board (ARB)
http://www.arb.ca.gov/ag/caf/SchmidtDairyEmissions2005.pdf
http://www.arb.ca.gov/ag/caf/SchmidtDairyTestData2005.pdf

Sun, H. Pan, Y. Zhao, Y. Jackson, W. A. Nuckles, L. M. Malkina, I.L. Arteaga. V. E. and Mitloehner, F.M. (2008) Effects of Sodium Bisulfate on Alcohol, Amine, and Ammonia Emissions from Dairy Slurry, Journal of Environmental Quality 37:608-614. February 20, 2008

Filipy, J. Rumburg, B. Mount, G. Westberg, H. Lamb,B. (2006) Identification and quantification of volatile organic compounds from a dairy", Atmospheric Environment 40 (2006) 1480–1494

Koziel, J. A. Spinhirne, J. P. and Lloyd, J. D. - Texas Agricultural Experiment Station, Texas A&M University, Amarillo, TX; Parker, D. B. - West Texas A&M University, Killgore Research Center, Canyon, TX; Wright, D. W. and Kuhrt, F. W. - Microanalytics, Round Rock, TX. "Evaluation of Sample Recovery of Malodorous Livestock Gases from Air Sampling Bags, Solid-Phase Microextraction Fibers, Tenax TA Sorbent Tubes, and Sampling Canisters". Journal of the Air & Waste Management Association, Volume. 55:1147–1157. August 2005.

Richard, T. L. and Wheeler, E. Penn State University - Department of Agricultural and Biological Engineering; Varga, G. Penn State University - Department of Dairy and Animal Science; Kaye, J. and Ann Bruns, M. - Penn State University - Department of Crop and Soil Science, 2005 Penn State Dairy Cattle Nutrition Workshop. Strategies for Reducing Gas Emissions from Dairy Farms. (2005)

Parker, D. B. Caraway, E. A. Rhoades, M. B. Donnell, C. and Spears, J. – West Texas A&M University, Canyon, TX; Cole, N. A. and Todd, R. - USDA-ARS, Bushland, TX; Casey, K. D. - Texas AgriLife Research, Amarillo, Texas. "Effect of Wind Tunnel Air Velocity on VOC Flux Rates from CAFO Manure and Wastewater". ASABE Meeting Presentation Paper # 08-3897 for presentation at the 2008 ASABE Annual International Meeting at Providence, Rhode Island, June 29 – July 2, 2008

Caraway, E. A. Parker, D. B. Olsen, M. J. Donnell, C. Rhoades, M. B. and Spears, J. – West Texas A&M University, Canyon, TX; Casey, K. D. - Texas AgriLife Extension, Amarillo, Texas. "Diel VOC Emissions from a Beef Cattle Feedyard". ASABE Meeting Presentation Paper # 084136 for presentation at the 2008 ASABE Annual International Meeting at Providence, Rhode Island, June 29 – July 2, 2008

Hudson, N. and Ayoko, G.A. - International Laboratory for Air Quality and Health, School of Physical and Chemical Sciences, Queensland University of Technology. "Comparison of emission rate values for odour and odorous chemicals derived from two sampling devices". Journal of Atmospheric Environment 10:1016. March 23, 2009.

Hudson, N., Ayoko, G.A., Dunlop, M., Duperouzel D., Burrell D., Bell, K., Gallagher E., Nicholas, P., and Heinrich, N. 2009. "Comparison of Odour Emission Rates Measured from Various Sources using two Sampling Devices". *Bioresource Technology* 100:118-124.

Hudson, N. and Ayoko, G.A. - International Laboratory for Air Quality and Health, School of Physical and Chemical Sciences, Queensland University of Technology. "Odour sampling 1: Physical chemistry considerations". Journal of Bioresource Technology 99 (2008) 3982–3992. June 26, 2007.

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Rhoades, M. B., Parker, D. B., Perscbacher-Buser, Z., and DeOtte, R. E. – West Texas A&M University, Canyon, TX; Auvermann, B. W. - Texas AgriLife Extension, Amarillo, TX; Cole, N. A. - USDA-ARS, Bushland, TX. "Factors Affecting Emission Measurements with Surface Isolation Flux Chambers". ASAE Meeting Presentation Paper # 054026 for presentation at the 2005 ASAE Annual International Meeting at Tampa, Florida, July 17 – 20, 2005

Chung M., Beene M., Ashkan S., Krauter C., Hasson A. (2009) Evaluation of non-enteric sources of non-methane volatile organic compound (NMVOC) emissions from dairies. Atmospheric Environment 44, 786-794.

Appendix 2

San Joaquin Valley Air Pollution Control District Air Pollution Control Officer's Determination of VOC Emission Factors for Dairies, August 1, 2005

http://www.valleyair.org/busind/pto/dpag/APCO%20Determination%20of%20EF_August%201_.pdf

Appendix 3

Mitloehner, F. Trabue, S. Koziel, J.A. (2006) Volatile Fatty Acids, Amine, Phenol, and Alcohol Emissions from Dairy Cows and Fresh Waste (May 31, 2006). Final Report to California Air Resource Board (ARB)

http://www.arb.ca.gov/ag/caf/MitloehnerDairyChamberEmissions2006.pdf

Appendix 4

Schmidt, C.E. Card, T. Gaffney, P. Hoyt., S. California Air Resource Board (ARB) and Central California Ozone Study (CCOS) Project: Assessment of Reactive Organic Gases and Amines from a Northern California Dairy Using the USEPA Surface Emissions Isolation Flux Chamber. 14th USEPA Annual Emissions Inventory Conference Las Vegas, Nevada, April, 2005

a. Technical Paper
http://www.epa.gov/ttn/chief/conference/ei14/session1/schmidt.pdf

b. Presentation
http://www.epa.gov/ttn/chief/conference/ei14/session1/schmidt_pres.pdf

Appendix 5

Schmidt, C. Card, T. (2006) Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures (May 2006). Final Report to California Air Resource Board (ARB)

a. Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures
http://www.arb.ca.gov/ag/caf/SchmidtDairyEmissions2005.pdf

b. Technical Memorandum: Results of the Dairy Emissions Evaluation Using Flux Chambers Phase III Merced and Kings County Dairies
http://www.arb.ca.gov/ag/caf/SchmidtDairyTestData2005.pdf

c. Technical Memorandum: Results of the Dairy Emissions Evaluation Using Flux Chambers Phase III Volatile Fatty Acids (VFAs) Verification and Validation Tasks
http://www.arb.ca.gov/ag/caf/SchmidtVFAValidation2005.pdf

Appendix 6

Schmidt, C. Card, T. (2009) 2008 Dairy Emissions Study: Summary of Dairy Emission Factors and Emission Estimation Procedures. August 2009. Final Report to San Joaquin Valley Air Pollution Control District

a. 2008 Dairy Emissions Study: Summary of Dairy Emission Factors and Emission Estimation Procedures

b. Technical Memorandum: DAIRY EMISSIONS EVALUATION - Results from the Phase 4 Continued Research, “Dairy Emissions Evaluation Using the Surface Isolation Flux Chamber: Feed Sources, Corrals/Turnouts, and Land Application Sources”

Appendix 7

Krauter, C. Blake, D. (2009) Dairy Operations: An Evaluation and Comparison of Baseline and Potential Mitigation Practices for Emissions Reductions in the San Joaquin Valley (May 01, 2009). Final Report for California Air Resource Board (ARB)

http://www.arb.ca.gov/research/apr/past/04-343.pdf

Appendix 8 – Calculation of Uncontrolled VOC Emission Factors for Dairies with less than 1,000 milk cows

Uncontrolled Dairy Emission Factors

In order to calculate the uncontrolled dairy emission factors for the period when no controls/mitigation measures were implemented (i.e. prior to the implementation of District Rule 4570), the dairy emission factors developed in this document were adjusted to remove control efficiencies for certain practices being implemented that reduced emissions. The District's dairy emission factor of 15.8 lb/head-year was used as the basis for this calculation. This emission factor was adjusted to account for the control measures that were being applied at the time when the emission measurements took place. The following control measures are assumed to have been in place at the dairies where the emission measurements were taken:

- Feed according to the NRC guidelines
- Flush or hose milk parlor immediately prior to, after, or during each milking
- Removal of manure from the corrals
- Clean manure from corrals at least once between April and July and at least once between October and December
- Manage corrals such that the depth of manure in the corral does not exceed 12" at any point or time, except for in-corral mounding[14]
- Maintain corrals and pens to ensure drainage and prevent water from standing more than 24 hours after a storm, slope the surface of the pens at least 3% where the available space for each animal is 400 square feet or less or at least 1.5% where the available space for each animal is more than 400 square feet per animal, or rake/harrow/scrape pens to maintain a dry surface[14]
- Inspect water pipes and troughs and repair leaks
- Install all shade structures uphill of any slope in the corrals
- Remove solids from the liquid manure handling system, prior to the manure entering the lagoon
- Incorporation of solid manure applied to land
- Not allowing liquid manure to stand in fields for more than 24 hours after application

Based on the 2006 staff report for District Rule 4570, a conservative control efficiency of 10% was applied to many of the mitigation measures. Therefore, a 10% control efficiency will be assumed for each of the mitigation measures that was being implemented at the time the studies were performed unless otherwise noted. For mitigation measures that were only being implemented at one of two dairies that were measured or were being partially being implemented, a 5%

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[14] 5% control efficiency will be used for this measure since one of the two dairies that were sampled did not include this measure when the testing was performed. Therefore, the average of the two dairies was taken (10%/2=5%)

VOC control efficiency was assumed. Removing the assumed control efficiencies for the mitigation measures that were being from the District's dairy emission factor of 15.8 lb/head-year results in an uncontrolled dairy emission factor of 20.0 lb/head-year. This emission factor will be used to calculate emissions from dairies that are not implementing the mitigation measures outlined in Phase I of District Rule 4570 (i.e. < 1,000 milk cows). The table below shows the mitigation measures that were assumed to be implemented during the emission studies and the respective control efficiencies that were assumed for each measure.

The following sample calculation shows how the uncontrolled emissions were calculated:

Sample Calculation for Uncontrolled Enteric Emissions:

$4.1 \text{ lb/head-year} \div (1\text{-Control Efficiency}_{\text{Feed to NRC Guideline}})$
$4.1 \text{ lb/head-year} \div (1-0.05) = 4.32 \text{ lb/head-year}$

Appendix 8: Calculation of Uncontrolled VOC Emission Factors for Dairies

		Feed	Milking Parlor	Exercise Pens and Corrals					Liquid Manure	Land Application		
Source	District Dairy Emission Factors	Feed to NRC Guidelines	Flush parlor after each milking	Clean manure between Apr. - July & Oct. - Dec.	Depth of manure not exceed 12 " in corral	Ensure drainage, slope surface, or-harrow/rake	Inspect Water pipes	Install Shades uphill	Remove solids with a separator	incorporation	Not allow liquid manure stand in field > 24 hours	Uncontrolled District Dairy Emission Factors
1. Enteric Emissions	4.1	5%	-	-	-	-	-	-	-	-	-	4.32
2. Milking Parlor(s)	0.03	5%	10%	-	-	-	-	-	-	-	-	0.04
3. Freestalls (lanes)	0.8	5%	-	-	-	-	-	-	-	-	-	0.84
Freestall beds	1.0	5%	-	-				-	-	-	-	1.05
4. Corrals/Pens	6.6	5%	-	10%	5%	10%	5%	5%	-	-	-	10.0
5. Liquid Manure Handling (Lagoons, Storage Ponds)	1.3	5%	-	-	-	-	-	-	10%	-	-	1.52
6. Liquid Manure Land Application	1.4	5%	-	-	-	-	-	-	-	-	10%	1.64
7. Solid Manure Land Application	0.33	5%	-	-	-	-	-	-	-	10%	-	0.39
8. Separated Solids Piles	0.06	5%	-	-	-	-	-	-	-	-	-	0.06
9. Solid Manure Storage	0.15	5%	-	-	-	-	-	-	-	-	-	0.16
Total not including Feed	**15.8**											**20.0**

Appendix 9 – Responses to Comments on Proposed Dairy VOC Emission Factors

Comments from C. Alan Rotz, Sasha Hafner, and Felipe Montes of USDA - Agricultural Research Service (ARS)

1. Comment: We have general concern for developing emission factors for these compounds given the very limited data and the relatively poor understanding of these processes that currently exists. Given that you are required to develop these factors, we generally agree that you are working with the best data available. Some further discussion and qualification of the uncertainty of the derived emission factors would be good.

   Response: The purpose of this report was to use the best available research that was useful in determining dairy emission factors. As noted in the comment, the District is required to develop emission factors for this important VOC source and the resulting emission factors are based on the best science available at the time. Measurement uncertainties are discussed in some of the specific project reports. The District's dairy emissions factors are primarily based on studies that measured VOC flux rates at California dairies. Using VOC measurements from actual dairies has clear advantages. However, one factor related to the use of flux measurements to estimate VOC emissions at dairies is that only small areas of the source can be measured at specific times and these measurements are then used to represent emissions from much larger sources that are not completely uniform and emissions from many of these sources vary with time. Additionally, there is a large amount variability in the management practices on different dairies in the San Joaquin Valley and these differing practices can affect VOC emissions. Because of the very large size of the emission sources at dairy operations and the variability in dairy management practices, many of the factors related to uncertainty are basically unavoidable regardless of the emission measurement techniques used. That being said, although additional data are generally desirable, the District used the best data that were available to develop VOC emission factors that are representative of dairy operations in the San Joaquin Valley. The District supports additional studies that will increase the knowledge related to VOC emissions from dairies and the understanding of the underlying processes that affect these VOC emissions.

2. Comment: The EPA emission isolation flux chamber method does not provide accurate measurement of VOC emission rates from manure and silage surfaces on farms and at the end of the report, additional research on differences between flux chambers and wind tunnels is recommended. Some studies have already been completed that address this issue. The emission isolation flux chamber method was designed for use in systems where emission rate is independent of the air speed across the emitting surface. Parker showed that VOC emission rate from cattle manure and wastewater is sensitive to air velocity. Measurements made in our laboratory show that the emission rate of ethanol from compressed

silage (analogous to the exposed face of a silage pile) and loose silage depend heavily on air velocity. A similar response would be expected for TMR.

Response: The studies that were chosen for inclusion in the report were studies that were found to be the most complete and valid for the purpose of generating VOC emission factors for dairy operations. The San Joaquin Valley is generally characterized by low average wind speeds, which will reduce the affect that wind will have on VOC emissions. As previously noted, the information that was used was the best information available to develop emission factors. It is not possible to determine the magnitude of the effect that wind speed will have on the VOC emission rates or adjust measured emission rates without full speciation of the compounds measured. The majority of the studies that were determined to be the most useful for generating VOC emission factors used total VOC methods without speciation because total VOC methods have been found to capture a higher proportion of the total VOC emissions when compared to other methods. Additionally, there are currently no validated procedures to adjust the measured VOC emission rates from dairy emission sources to account for differing wind velocities.

It is also important to note that although research efforts have investigated the effects of wind speed on emissions, many important research efforts have identified turbulence at the emitting surface rather than wind speed itself as an important variable that affects emissions and have concluded that wind speed is only important because of the turbulence it creates at the emitting surface. The majority of studies that have investigated the effects of wind speed on emissions have used small wind tunnels. Because of the small size of the wind tunnels used, even at lower velocities there will be increased turbulence inside the tunnels, which is very likely to artificially increase emissions above levels that would be seen if the tunnels were not present. Therefore, researchers are not in agreement regarding the use different measurement techniques and further research is needed. However, the District is using the most complete scientific data that were available to update the dairy emission factors.

As noted in the comment, the District encourages further research regarding quantification of emissions using different measurement techniques. In conclusion, the District is using the most complete scientific data available to update the dairy emission factors. As with other emission factors, the dairy VOC emission factors will be periodically updated if new scientific information indicates that revisions may be necessary.

3. Comment: Two other problems limit the accuracy of measuring VOC emission from silage. First, since silage is highly porous, sweep gas leakage may occur. Second, high VOC concentrations in silage can lead to high vapor phase VOC concentrations and result in suppression of emission (Kienbusch 1986). Measurements in our laboratory show that both of these problems occur when

measuring ethanol emission from loose corn silage using the emission isolation flux chamber method (Hafner et al).

Response: The District encourages further research regarding quantification of emissions using different measurement techniques. The District is using the most complete scientific data available to update the dairy emission factors. As with other emission factors, the dairy VOC emission factors will be periodically updated if new scientific information indicates that revisions may be necessary.

4. Comment: VOC emission rates from silage and TMR are dependent on porosity, depth, temperature, and exposure time. Mass transport theory also indicates that emission rates are directly proportional to the initial VOC concentration in silage. It would be useful to report the values of these variables for which the proposed emission factors are thought to be accurate.

   Response: The proposed emission factors for silage and TMR are based on emission measurements at dairy farms in the San Joaquin Valley and the District's dairy emission factors are expected to be representative of dairy operations in the San Joaquin valley. The atmospheric temperature would be representative of the San Joaquin Valley. Additional information characterizing the silage and TMR used in the study and the timing of the emission measurements relative to removal of silage from pile and placement of the TMR can be found in the reports for the studies by Schmidt and Card and Krauter and Blake, which have been attached as appendices to the final report. It does not appear that the initial ethanol concentration in the silage was reported but the report by Krauter and Blake does provide limited information on silage density. The District encourages further research regarding characterization of silage and how feed composition affects emissions. As previously mentioned, the District is using the best scientific data that were available to update the dairy emission factors and these factors will be periodically updated if new scientific information indicates that future revisions may be necessary.

5. Comment: The unit used for silage and TMR fluxes ($\mu g/m^2$-min) may not be the best choice. The mass unit (μg) and time unit (min) seem unreasonably small, and it may be confusing to give fluxes in an SI unit while emission factors are given in US customary units. Alternative units are lb/ft^2-day. Also, presenting five digits in the fluxes implies a level of accuracy that is not present.

   Response: The District agrees with the comment. In the final report the flux rates for silage and TMR have been given in lb/ft^2-day.

6. Comment: Page 7, second paragraph: There is some confusion here in the units. I assume these values are all in lb/head-year. Some are listed as per day, which would be very high.

   Response: The reference to lb/head-day has been corrected to lb/head-year.

7. Comment: Page 9, last sentence of third paragraph states that District Rule 4570 has resulted in more than 20 tons per day reduction in VOC emissions. Can you provide a reference that documents this improvement?

   Response: The Health Benefit Analysis for the Proposed Re-Adoption of District Rule 4570 (Confined Animal Facilities) (June 18, 2009) indicated that in the District's 2007 Ozone Plan, District Rule 4570 was estimated to achieve approximately 20 tons per day of VOC reductions by 2012. According to the San Joaquin Valley Air Pollution Control District 2010 Ozone Mid-Course Review (June 2010), District Rule 4570 accounted for 22.8 tons of VOC reductions per day in 2010. However, this statement has been updated to say that significant VOC reductions are expected from implementation of the District Rule 4570 Phase II mitigation measures.

8. Comment: Page 18, last sentence of second paragraph: Can these two emission sources be added? Is the stall bedding that which is emitted by the actual stall while the other value is that occurring simultaneously from the flush lane? If so, then we agree that they can be added. This is not clear as currently presented.

   Response: VOC fluxes were measured from two separate sources in freestall barns, the bedding in the stalls where the cows rest and the flush lanes where manure from the cows was deposited; therefore, it is appropriate to add these sources to represent emissions from the total area contained in the freestall barns.

9. Comment: Page 29, second paragraph: The exposed area of a silage pile should be better defined. The surface area of fresh silage exposed each day may be much less than the actual open surface area. After a surface is exposed for 24 hours, the emission rate from that area will be low because the surface VOCs will have been volatilized.

   Response: The exposed area is generally intended to mean the uncovered "face" of the silage pile from which silage can be removed for feeding. The silage flux rate developed from Dr. Schmidt's research is an average rate based on daily removal of feed over the entire uncovered face of the silage piles, as was observed during the studies. The average daily rate reflects the higher emissions immediately after removal of silage and lower emissions from silage that has not recently been disturbed. The District will consider further evaluating emissions from specific dairies that implement unique silage management practices.

10. Comment: Page 31: It would be helpful to know the surface area per animal that was used to convert this to a per head basis to allow for comparison among farms even if the emission factor is given on a per unit area basis.

Response: The approximate lb/head-year VOC emission value for TMR was based on the averages from the Phase III and Phase IV studies performed by Dr. C. Schmidt and T. Card. The estimated area for the TMR during the studies is included in the study reports, which have been attached as appendices to the final report.

11. Comment: Pages 32 and 33: Not all farms will have all of these components. For example, freestall barns and corrals/pens or liquid and solid manure storage. Therefore, the “Total not including feed” may be overestimated.

    Response: All of these components are typically found at dairies in the San Joaquin Valley and were present on dairies that were studied. In the San Joaquin Valley freestall barns are generally open structures in which cows will continue to have access to exercise pens or corrals. This differs from other parts of the country in which cows in freestall barns typically do not have access to exercise pens or corrals. In addition to ponds for waste storage, dairies in the San Joaquin Valley will typically have stockpiles of solid manure consisting of stored separated solids and scrapings from exercise pens and corrals that are stored for use as bedding or for application to cropland. These components are all typically present for dairies in the San Joaquin Valley and were present at dairies where emissions were measured.

Comments from the Center on Race, Poverty, & the Environment

1. Comment: The District Should Consider Wind Speed Effects on VOC Flux. Research on the effect of wind speed on VOC flux should be included in the new emission factor. The flaw of the flux chamber sampling methodology is that it creates an artificial, wind free environment. Wind is present in California dairies, including artificial “wind” from fans within free stall barns. The District has ignored the effects of wind speed and only recommended evaluation of flux chambers and wind tunnels for future research.

   Response: Please see response to Comment #2 from C. Allan Rotz, Sasha Hafner, and Felipe Montes above. Additionally, it must be noted that cooling fans in freestall barns are designed to direct air at the level of cows rather than ground level where feed is placed and because air velocity profile, these fans are not expected create significant air movement on the TMR.

2. Comment: The District Should Consider Alcohol Sampling Deficiencies. The District also reports the sampling variability between the flux chamber and the INNOVA analyzer when analyzing alcohol compounds. The use of canisters as a means of storing analyte appears to significantly underestimate alcohol compounds. Values for alcohols should be adjusted to account for this analytical error.

Response: The comment is in reference to the report for the Krauter and Blake dairy VOC emission study in which higher alcohol measurements were noted when using an INNOVA analyzer compared to the canister samples analyzed by GC/MS. The report also noted that Dr. Donald Blake had questioned the ability of the GC/MS system to extract all of the alcohols from the canisters. However, the results in the report indicating higher alcohol emissions measured with the INNOVA analyzer as compared to GC/MS were based on preliminary information from an earlier progress report submitted to ARB in April 2007. Later measurements performed by the researchers indicated general agreement between the GC/MS alcohol measurements and the INNOVA analyzer alcohol measurements as mentioned in the following journal article: *Chung M., Beene M., Ashkan S., Krauter C., Hasson A. (2009) Evaluation of non-enteric sources of non-methane volatile organic compound (NMVOC) emissions from dairies. Atmospheric Environment 44, 786-794*. Researchers that were involved in the project indicated that the apparent difference between the two methods occurred in the first year (2006) and possibly the early part of the second year (2007) of the monitoring study while the methodology was still being developed and the field collection and lab analysis techniques were still being modified. These researchers stated that the data from the later years, 2007- 2009, including the measurement values in the main body of the final report to ARB, showed much better agreement and are more reliable than their preliminary work that indicated differences between the GC/MS alcohol measurements and the INNOVA analyzer alcohol measurements. In addition, the project report only provides a small amount of the preliminary INNOVA analyzer measurement data and the reported information is not sufficient to estimate emissions using the INNOVA analyzer measurements. However, after the initial development of the field collection and lab analysis techniques, no significant differences were found between the GC/MS alcohol measurements and the INNOVA analyzer measurements and Dr. Krauter has stated that the primary standard for the project report is the GC/MS measurements. Therefore, the District used the most complete scientific data that were available to update the dairy emission factors.

3. Comment: The District Should Consider the Volatile Fatty Acid Research Conducted at Fresno State University. The District does not discuss research on non-enteric Volatile Fatty Acids conducted at Fresno State University. Alanis (2008) reported 11 kg/cow/year of non-enteric volatile fatty acid emissions. The most significant source was TMR, with a reported flux of 160 g/m2-hr. The District does not consider this research when proposing an emissions estimate for Total Mixed Rations and fails to explain why such research was excluded.

   Response: This comment refers to results of research reported in the following publication: *Alanis, P. Sorenson, M. Beene, M. Krauter, C. Shamp, B. Hasson, A. S. Measurement of non-enteric emission fluxes of volatile fatty acids from a California dairy by solid phase micro-extraction with gas chromatography/mass spectrometry, Atmospheric Environment 42 (2008) 6417–6424*. The purpose of the study was to develop a method using a flux chamber coupled to solid phase micro-extraction (SPME) fibers followed by analysis using gas chromatography/mass spectrometry to quantify volatile fatty acid (VFA) emissions from sources at a dairy. The research was performed at a small research dairy at California State University Fresno (CSUF). The paper reports that the dairy typically used corn silage and that acetic acid contributed 70-90% of the VFA emissions from the sources measured.

The comment incorrectly states that the measured volatile fatty acid (VFA) flux rate from the TMR was 160 g/m^2-hr. The study reported that the highest VFA flux rates were for the silage and TMR, 1.84 g/m^2-hr and 1.06 g/m^2-hr, respectively. Flux rates from other sources were generally two orders of magnitude lower than this and had higher levels of uncertainty. The VFA flux measurements are similar to the total VOC flux rates that the District proposed for silage and TMR, which were based total non-methane non-ethane VOC measurements by Schmidt and Card. However, the VOC flux rates proposed by the District are annual average VOC flux rates that have been adjusted for daily temporal and seasonal variation while there are factors that indicate the VFA emission measurements reported by Alanis et el (2008) are higher than what would be considered representative of a typical commercial dairy in the San Joaquin Valley.

One factor that should be considered is that the article mentions that silage samples were spread to a depth to perform the VFA emission measurements. Removing silage from the pile and spreading it will increase porosity. It is known that greater porosity will generally increase emissions. It is expected that this effect would be more pronounced when measuring VFAs because of their tendency to adhere to surfaces that they contact. Therefore, these emission measurements are likely to be higher than VFA emissions from the compacted open surface of silage piles.

In addition, subsequent research using the same methodologies has also indicated that the VFA flux rates reported by Alanis et el (2008) are much higher than those that are typically observed. Many of the same researchers that were involved with development of the methodology using SPME fibers to collect VFA emissions from dairies used SPME fibers to measure VFA emissions from six dairies in the San Joaquin Valley over a fifteen-month period. The results are reported in *Alanis, P. Ashkan, S. Krauter, C. Campbell, S. Hasson, A. S. Emissions of volatile fatty acids from feed at dairy facilities, Atmospheric Environment 44 (2010) 5084–5092.* Based on the information gathered during this study using SPME fibers to collect VFAs, average annual acetic acid emissions were estimated to be 0.7 g/m^2-hr for silage and 0.2 g/m^2-hr for TMR. VFA emissions from the non-feed sources were typically below the detection limits of the methods used. As noted in the report, these measurements are more comprehensive than the measurements in the previous study and resulted in considerably lower emissions. The Alanis (2010) study reports an estimate of 1.7 kg/cow-year for acetic acid emissions from dairy feed sources (compared to an estimate of 6.4 kg/cow-year from the previous study). Because the total mass of

VFAs are dominated by acetic acid, total VFAs measured are also substantially less than the total VOC flux rates proposed by the District, particularly for TMR.

Acetic acid emissions from thin layers of loose silage samples were also measured using flux chambers and PTR-MS for an ARB project: *California Environmental Protection Agency. Zhang, Ruihong. (2010) Process-Based Farm Emission Model for Estimating Volatile Organic Compound Emissions from California Dairies. May 2010. Final Report for California Air Resource Board (ARB)*. The project report states that, over a twelve-hour period, acetic acid emissions measured from corn silage were 7.0 g/m^2-hr (average flux of 0.58 g/m^2-hr) and were 5.0 g/m^2-hr (average flux of 0.42 g/m^2-hr) for alfalfa silage.

As demonstrated, the District's proposed VOC emission flux rates for dairy feed sources are actually much higher than recent VFA emission measurements from dairy feed sources, including a more comprehensive dairy emissions study performed by the same researchers that were involved with development of the methodology for the use of SPME fibers to collect VFA emissions from sources at dairies. Because the District's proposed VOC emission flux rates are much higher than VFA emission estimates from recent studies and was based on a total VOC method, it is reasonable to believe that these emissions are already included in the District's emission factor and, therefore, the VFA emission measurements from these studies will not be added to the proposed emission flux rate.

4. Comment: The District Should Propose for Public Comment and Adopt a Methanol Emission Factor. Because methanol is a hazardous air pollutant and a toxic air contaminant, the District should present the best available methanol emission factor for comment and adoption.

   Response: The purpose of this document is to adopt a total VOC emission factor to quantify VOC emissions from dairies. The District is committed to using the best information available to quantify toxic emissions from dairies.

Comments from ARB

1. Comment: Overall, the SJV Air Pollution Control District did a good job in deriving and justifying the new emission factors for dairy emissions. The District made it clear that their emission-factor approach is based on best science available at the time the revision was written. The document is informative and educational on issues regarding dairy emission regulations.

   Response: Comment noted and the District thanks ARB for continued support in helping the District develop and fund research to increase the scientific information available pertaining to air emissions from dairies.

2. Comment: ARB would like to request that the District include more comprehensive descriptions of the relevant studies that helped determine the revised emission factors. Since the original experimental description and data are not part of the current document, it is difficult to understand how the conversion from flux data to the emission factor (lb/head-year) was made.

   Response: The current document contains brief descriptions of the studies that were used. More comprehensive descriptions of the experimental descriptions are contained in the original study reports, many of which have been added as appendices to the final report. For enteric emissions of alcohols from cattle, the District's emission factor used unpublished data from Dr. Mitloehner; the environmental experiment was conducted as described in Dr. Zhang's ARB project report but used only the measurements from the time before manure began to accumulate in the environmental chamber.

   For emissions factors that required conversion from measured flux rates to lb/head-year emission rates, the conversion was performed using the data gathered during each respective study. The measured or average flux rate was multiplied by the observed source area and divided by the estimated number of milk cows that were onsite during the measurements.

3. Comment: What are the uncertainties associated with the estimated emission factors? Was the diurnal and seasonal variability considered in the calculation and how?

   Response: Regarding the uncertainties associated with the estimated emission factors, please see the response to Comment #1 from C. Allan Rotz, Sasha Hafner, and Felipe Montes above.

   Based on the measurements by Schmidt and Card (2009), the District's dairy VOC emissions factors for corrals/pens incorporated an adjustment for seasonal variation with no adjustment for diurnal variability since no diurnal pattern was observed for emissions from this source. Also based on measurements from the same study, the District's VOC emissions factors for feed sources incorporated adjustments to account for seasonal variation as well as daily variations in emissions as a result of feeding practices and the reduction in the VOC emission rate from silage after it is removed from the silage pile and feed after it is placed for cattle. Adjustments for diurnal and seasonal variation were not incorporated into the remaining dairy emissions factors.

4. Comment: The report should include the old emission factors in all the emission factor tables. In places the document said that "the EF was not as high as previously thought" but did not give specific numbers to support the assertion.

   Response: The places where the document notes that emissions are not as significant as previously thought are regarding VFA emissions from non-feed sources and VOC emissions from storage ponds/lagoons. Of the District's previous dairy VOC emission factor of 19.3 lb/head-year, 15.5 lb/head-year were attributed to VFA emissions with 8.3 lb/head-year attributed to enteric VFA emissions with nearly all the remaining VFA emissions attributed to wet processes, such as lagoons. As indicated in the report, subsequent research measured much lower emissions of VFA emissions from non-feed sources. Additional references to the District's previous dairy emissions factors have been added to the report and a table listing the District's previous dairy VOC emission factor has been added for reference purposes.

5. Comment: There was no mention of Dr. Ruihong Zhang's work in the draft report. ARB believes that due to the significance of her research related to dairy VOC emissions, Dr. Zhang's report should be mentioned, followed by an explanation of why it was not included. The District should also mention that they will review Dr. Zhang's findings for inclusion in the next revision to the report, as well as mention specific information from the report that will be useful for future updates to the District's dairy VOC emission factors.

   Response: When the District initially completed the draft dairy emission factor report the final report for the study led by Dr. Zhang's was not yet available. The District needed to complete the draft report and proceed with updating the dairy emission factors so more accurate dairy VOC emission factors could be used when the District revised District Rule 4570. Since that time, the District has reviewed the final report and agrees that it provides useful information and has advanced that the state of research regarding quantification and modeling of emissions from dairy feed sources. Some information from Dr. Zhang's report has been added to the final District report. Dr. Zhang's continued work will be particularly useful for developing and evaluating potential mitigation measures to reduce VOC emissions from dairy feed sources.

6. Comment: ARB suggests that it would be valuable for SJVAPCD to rank the various emission factors from strongest to weakest, and to prioritize which factors the District believes should be updated (as research funds become available, or to encourage/direct future funding) so as to develop a somewhat specific roadmap for where SJVAPCD plans to go from here.

   Response: The purpose of this document is to adopt a total VOC emission factor to quantify VOC emissions from dairies. However, the District has begun the process to develop a document explaining the District's priorities for future dairy emissions research. The District will continue to work with ARB, scientists, and dairy stakeholders to establish priorities for future dairy research efforts. One of the District's main priorities will be the development and evaluation of practical measures to reduce emissions from significant sources of emissions, such as silage and TMR.

Comments from Dairy Cares

1. Comments on the Report's General Conclusions: We agree with the following overarching conclusions of your report:
    a. Accurate dairy emissions factors are required for proper implementation of applicable air quality regulations and also for the evaluation of appropriate technologies and practices to reduce emissions;
    b. The District has gained a great deal of experience in the evaluation of emissions from agricultural sources through collaborative efforts with other institutions, agencies and interested stakeholders;
    c. The revised VOC emissions factors for dairies proposed in the report is based on a detailed review of available scientific research findings; and
    d. The District has given appropriate emphasis to studies performed on California dairies and/or in conditions representative of California dairies.

    Response: Comment noted.

2. Comments on the Approach to Categorizing and Quantifying Emissions: The scientific basis for the dairy emission factors has improved and there is considerably more detailed information regarding emissions from specific sources within dairy facilities, such as silage piles (which were not included in the APCO's 2005 dairy VOC emissions estimates), corrals and pens, and more.

    Dairy Cares supports the transition the District has made from reporting the emissions as chemical subsets, for example "volatile fatty acids" or "ethyl amines," as took place in the 2005 report. The current draft report more appropriately focuses on identifying and quantifying emissions in process-specific categories. This not only represents a great improvement in the scientific basis for estimations from those processes, but sets a better context for proposing and evaluating potential emissions reduction techniques and strategies.

    The District has taken the added step of grouping the process categories under the following headings: Per Cow Dairy Emissions Factor, Silage Pile VOC Emissions Flux, and Average Total Mixed Ration (TMR) VOC Emissions Flux. In doing so, the District has rationally concluded that these newly characterized emissions sources (silage piles and TMR) are appropriately calculated based on exposed area rather than on a per head basis. Dairy Cares agrees with the District on this point and notes that this will provide a more solid, science-based foundation for discussion of emissions reduction strategies. Conversely, including these new emissions under a per-cow factor would likely lead to large, built-in systematic errors in calculating VOC emissions on many individual dairies.

    Response: Comment noted and the District thanks Dairy Cares and other dairy stakeholders that helped facilitate the California dairy studies that were used to develop the District's dairy emission factors.

3. Comment: Where possible, we have reviewed the proposed emission factors and the underlying research studies. We generally concur that the District has selected the most appropriate studies as a basis for its decisions. We do not have any major disagreements with the District's analysis and conclusions either on individual process factors, fluxes or on the overall totals. While these appear generally accurate and representative of the underlying research, we would note for the record a few important caveats:
   a. Most of the research to date has been limited to a few dairies and covers a relatively limited range of seasonal conditions. While there has been a vast improvement in the data used for District development of emissions factors and fluxes, these may not adequately reflect variability on individual sites. As such, dairies may wish to undertake site-specific analysis in some cases and future revisions in the emissions factors and emissions fluxes may also be necessary.
   b. In the case of "Per Cow Dairy Emissions Factor" process #1, "Enteric Emissions," the District notes in the report that the determination for the emission factor of 4.1 pounds/head-year is partially derived from an environmental chamber study that was completed in late 2009by Dr. Frank Mitloehner. Because that work has not been published or peer reviewed, and has not been reviewed by Dairy Cares, we can only conditionally support this factor pending future review of the data. However, we also note that similar work by Dr. Mitloehner has been important in estimating California dairy emissions. We remain strongly supportive of the District's approach of relying on studies performed on California dairies or conditions representative of California dairies.
   c. We would like to continue our discussion to further refine the simulation of practices that are associated with silage and TMR flux rates included in the draft report. Both rates are averages based on observed data; we feel additional work is needed to ensure that the rates accurately reflect management practices implied in the simulations.

   Response: As previously mentioned, the District report used the best data that were available to develop VOC emission factors that are representative of typical dairy operations in the San Joaquin Valley. The District supports continued efforts to refine dairy feed VOC emission measurements to better account for management practices that may be implemented at specific dairy operations and looks forward to working with Dairy Cares and other dairy stakeholders regarding this matter.

4. Comments on Future Research Recommendations: The draft report included recommendations for future research to improve the quality of dairy emission factors. We concur that from an academic standpoint, additional research would be helpful to further refine the factors. However, we also are of the view that in some categories of VOC emissions from dairies, a point of diminishing return may be developing on the value of gathering additional data on VOC-generating processes versus investment in research on other pollutant categories and/or

mitigation. According to the District's own health benefit analysis in 2009, the entirety of actions under Phase I of District Rule 4570 resulted in modeled reductions of only 1.5% annually or less for population exposure to ozone. As such, any future research recommendations must be reviewed to ensure there is some possibility they would generate discernible health benefits. With that cautionary note, we remain nevertheless dedicated to collaborating with your agency on determining appropriate ways to improve our understanding and mitigation of emissions.

Response: Because the San Joaquin Valley Air basin is classified as an extreme nonattainment area for the Federal ozone standard, even relatively modest reductions in ozone and ozone precursors can make cumulatively significant contributions towards helping the District reach attainment with health-based ambient air quality standards and accurate characterizations of emissions sources are an important part of this process. However, the District agrees that one of the primary focuses of future research should be development of practical measures that will reduce VOC emissions, in general, and practices that will reduce emissions of the most reactive compounds to provide increased health benefits through greater reductions in ozone formation.

Exhibit 10

Final Report

February 2, 2016

Quantification of the Emission Reduction Benefits of Mitigation Strategies for Dairy Silage

Submitted to: California Air Resources Board

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Timeline: May 1, 2012 - April 29, 2016

Disclaimer

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Contents

List of Photos & Figures

Figure 7. Means of lateral, perpendicular, and EZ rake defacing on ethanol (EtOH) emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

Figure 8. Means of methane emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

Figure 9. Means of nitric oxide emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

Figure 10. Means of nitrogen dioxide emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

Figure 11. Means of nitrous oxide emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

Figure 12. Means of ammonia emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

Figure 13. Means of methanol emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

Figure 14. Means of ethanol emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

Figure 15. Means of methane (CH_4) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

Figure 16. Means of nitrous oxide (N_2O) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

Figure 17. Means of nitric oxide (NO) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

Figure 18. Means of nitrogen dioxide (NO_2) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

Figure 19. Means of ammonia (NH_3) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

Figure 20. Means of methanol (MeOH) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

Figure A2.1. Measured and simulated ethanol emissions for the drive-over piles using the former VOC emission model. For simulation, figures presented are based on various dry bulk densities and moisture contents of a) 70% and b) 60%.

Figure A2.2. Measured and simulated methanol emissions for the drive-over piles using the former VOC emission model. For simulation, figures presented are based on various dry bulk densities and moisture contents of a) 70% and b) 60%.

Figure A2.3. Comparison of simulated and flux-chamber-based emissions for TMR and loose corn silage samples normalized with respect to initial ethanol and methanol contents.

List of Tables

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Abstract

Our previous work (Chapter 1), has shown that silages are a major source of volatile organic compounds (VOC) and oxides of nitrogen (NOx) from dairies contributing to the San Joaquin Valley's (SJV) ozone challenges. In general, emission of VOCs from silage can be mitigated by either 1) reducing VOC production in the liquid/solid phase of the silage pile, or 2) reducing relative emission from the face of the silage pile or the feedlane. Therefore, the focus of the present research was on monitoring and modeling of VOC production using silage additives (Chapter 2), as well as emissions mitigation via various silage storage methods, de-facing practices, and feed management approaches (Chapters 3 & 4). Microbial and chemical silage additives were investigated using bucket silos, to reduce the production and emissions of volatile organic compounds in corn silage. The VOC concentrations were measured using headspace gas chromatography method. For the field monitoring of emissions from different silage storage and defacing methods, we used flux chambers and wind tunnels that were attached vertically on the silage face, immediately after de-facing. These sampling devises were attached to a fully equipped mobile air quality lab, in which concentrations of all relevant gases were analyzed in situ. This set-up allowed us to compare different storage methods (i.e. conventional standard pile vs silage bag), and defacing methods (e.g., perpendicular, lateral, and rake extraction), as well as various water inclusion rates for the feed all aiming at reducing emissions. The monitoring data was used to inform and validate a new VOC process-based model that was developed to predict VOC emissions from silage sources on farms using theoretical relationships of mass transfer and parameters determined through our earlier (published) laboratory experiments and numerical modeling. The results for the silage additive studies showed, that most microbial and chemical additives actually increase VOC production and emissions. Only one chemical additive used at one particular concentration, reduced VOCs. The results for silage storage indicated that silage bags vs. conventional silage piles emit considerably fewer emissions. Furthermore, lateral defacing versus perpendicular- and rake defacing reduced emissions of most gases. Finally, reducing of emissions in the feedlane seems to be possible via inclusion of water to the TMR. Simulations of all relevant silage mitigation options that were studied on the commercial dairies, were conducted using the VOC modeling tool. These simulations clearly showed that most of the reactive VOC emissions on a California dairy occur from feed lying in feed lanes during feeding as opposed to the silage storage pile or bag. In conclusion, regulations aimed at reducing VOC emission could be ineffective or even increase emission if they promote silage additives without recognition of different types of additives. The monitoring results of the storage and defacing study results point at certain practices as being advantageous. However, one shall not view those monitoring results in isolation, because only the integration of other parts of the feed's life cycle, using whole farm modeling, explains not just the relative- but also the absolute effectiveness of mitigation techniques in reducing VOCs and NOx on the entire dairy. The whole farm modeling clearly showed that mitigation efforts should be applied to reducing emissions from feeding rather than focusing solely on those from the exposed face of silage piles.

Executive Summary

Our previous work at UC Davis and USDA-ARS (see page x of this report) has shown that silages are a major source of volatile organic compounds (VOC) and oxides of nitrogen (NOx) on dairies contributing to the San Joaquin Valley's (SJV) ozone challenges. Most recent studies on emission of silage VOCs and NOx have sought to identify and quantify the major VOC and NOx components of silage emissions through field or laboratory measurements (Alanis et al., 2008; Chung et al., 2009; Howard et al., 2010; Montes et al., 2010; Hafner et al., 2010; Malkina et al., 2011; Hafner et al., 2012), while two studies have looked at ozone formation through computer simulations (Howard et al., 2010; Hu et al., 2012). Literature on mitigation strategies for environmental pollutants from silages is extremely sparse and mainly related to minimizing dry matter losses and deterioration of feed quality. Most is known on the use of silage covers and additives to maintain high quality of silage and to reduce DM losses. In general, emission of VOCs from silage can be mitigated by either 1) reducing VOC production in the liquid/solid phase of the silage pile, or 2) reducing relative emission from the face of the silage pile or the feedlane. Therefore, the focus of the present research was on monitoring and modeling of VOC production using silage additives (Chapter 2), as well as emissions mitigation via various silage storage methods, de-facing practices, and feed management approaches (Chapters 3 & 4). The present research primarily addressed mitigation techniques and technologies outlined in SJVAPCD Rule 4570 addressing VOC and NOx production and emissions.

Chapter 1 of the present report is a comprehensive review of the literature around various topics as they relate to the air impacts of silage and, to the extend available, possible mitigation. The chapter clearly shows the considerable complexity and heterogeneity of processes leading to emissions and the need to assessing the topic of silage air emissions using a holistic life cycle approach. The four main phases of silage production, storage, and use are distinctively different from each other and addressing only one phase via mitigation, might likely lead to emissions downstream. Furthermore, it is apparent that while the body of literature on the ensiling process is rich, hardly any work has been reported on emission mitigation from a dairy farm.

Chapter 2 shows the effectiveness of various microbial and chemical silage additives in reducing gaseous emissions from silage. The research found that the addition of the chemical silage additive potassium sorbate may substantially reduce production of ethanol and other important volatile organic compounds. Two of the most widely used microbial additives as well as a commercial buffered propionic acid-based product, strongly stimulated VOC production and emissions from silages. Regulations aimed at reducing VOC emission from silages via use of additives could be counterproductive if they promote silage additives without recognition of different types of additives and their course of action.

Chapter 3 provides monitoring data for a variety of silage mitigation techniques. One major aspect of this monitoring research is to provide gaseous emissions data to inform and validate the concurrent silage air emission modeling study (i.e. Chapter 4). The present monitoring study conducted alongside with the concurrent modeling study, shows that emission reduction potentials of one phase of silage management might be offset throughout later phases throughout the life cycle of the feed. For example, one might reduce emissions at the silage face through lateral- versus perpendicular defacing, but the compounds one might prevent from volatilizing at the face, might become airborne later during feeding in the feedlane. Similarly, silage bags have a much smaller face compared to the conventional silage pile; thus, emissions of the former are considerably lower. However, to benefit from these emission reductions, one must also devise a proper strategy to reduce emissions after feed-out from the bag or else, mitigation effects will be diminished in the feed-out phase. Overall, it is apparent that the most effective VOC mitigation efforts are those that minimize the air exposure time of freshly extracted- as well as freshly mixed feed to the atmosphere (e.g., silage face and feed-lanes).

In Chapter 4, the modelling aspects of the present work are presented. A new process-based model was developed to predict VOC emissions from silage sources on farms using theoretical relationships of mass transfer and surface emission, with simulation parameters refined through laboratory experiments and numerical modeling. For model evaluation, ethanol and methanol emission measurements were made from conventional silage piles, silage bags and feed lanes on a dairy farm in California (i.e. data presented in Chapter 3). The model worked well in predicting ethanol emissions but underpredicted methanol emissions. The new silage VOC emission model was incorporated as a component of the Integrated Farm System Model (IFSM), where it was used to evaluate management and climate effects on VOC emissions along with other aspects of farm performance, environmental impact and economics. Simulations of a representative dairy farm in California indicate that most of the reactive VOC emissions occur from feed lying in feed lanes during feeding rather than from the storage pile. This implies that mitigation efforts should focus on reducing emissions during feeding rather than those from the exposed face of silage piles.

Chapter 1 - Background Literature on the Dairy Industry, Silage Practices, and Related Mitigation of Air Pollutants

United States Dairy Industry

The United States is home to 9,257,000 dairy cows and each cow produces on average 10,096 kg of milk per year. California accounts for twenty percent of the US milk production contributing 21 million tons of milk per year (Hoskin, 2014). The San Joaquin Valley (SJV) in California alone houses three quarters of California's dairy cow population. The combination of numerous emissions sources, including dairies, in the SJV and its topography present environmental and in particular air quality concerns because air pollutants remain within the airshed for prolonged periods of time. Along with numerous other sources of air pollution, the dairy industry contributes to the SJV as having one of the worst air quality conditions throughout the US (Garcia et al., 2013).

The dairy industry in the SJV is a contributor of ozone precursors, such as (VOCs) and (NOx). According to earlier estimates, the California Air Resources Board (CARB) listed dairy farms and associated waste as the second largest contributors to these ozone precursors (Chung et al., 2010). However, research discovered that the CARB estimations were approximately 9 times greater than the true ozone production from dairy animal waste (Shaw et al., 2007, Hu et al., 2012), which led to corrections of the inventory. The majority of the earlier emissions research on dairy farms encompassed manure, lagoons, animals, and heavy machinery (Schmidt, 2009). Animal feed was discovered to produce both VOCs and NOx (Maw et al., 2002). Animal feed includes, but is not limited to, a variety of products such as dried distiller grains (DDGs), almond hulls, cereals, hays, and fermented feed (silage).

A dairy farm typically has three types of production stages: calves, heifers, and dry and lactating cows. Diets fed reflect the production stage and associated nutrient requirements for the animal. Lactating dairy cows have one of the most demanding diets. Their energy demand supports pregnancy, lactation, and body maintenance. A total mixed ration or TMR is often used to fulfill their requirements and to maximize milk production efficiency (Driehuis and Elferink, 2000). A TMR is composed of cereal grains, fats, minerals, vitamins, forage, and a wide array of byproduct feedstuffs. The bulk of the costs associated with dairy farms is related to feed. Fermented feed such as silage, has a long shelf life, and can sustain the herd throughout the year. As such, most TMRs include silage, as a form of forage, as part of a balanced diet. Silage can compose of up to 60% of the total TMR and therefore is a major component of dairy cow diets. In addition to its many benefits as feed, it also has some consequences associated with it, namely the fact that it produces ozone precursors, which make it an environmental concern (Maw et al., 2002). With a majority of California dairies storing and feeding silage, research has been conducted to quantify their contribution to ozone forming potential (OFP). The VOC emissions were measured from animal feeds and the results showed that feeds had significantly higher emissions than other sources on a dairy, for example animal waste (Alanis et al., 2010, Malkina et al., 2011). Volatile fatty acids (VFAs), alcohols, and aldehydes make up the majority of VOCs found on dairy farms. However, silage has been shown to emit not just VOCs but also multiple species of NOx (Howard et al., 2010). The resulting emissions cause dry matter (DM) loss, environmental, and human health consequences. Mitigation and management of fermented feed can result in a win-win situation for both the environment and the dairyman’s financial viability (Hafner et al., 2014).

Factors such as wind speed, temperature, moisture, and extraction methods can strongly alter emissions. Prior to ensiling, other production factors such as crop maturity, crop species, moisture content, and storage method affected the profile of compounds emitted (Rossi and Dellaglio, 2007). Each dairy varies in storage, extraction, and general silage management. Accurate emission projections can best be achieved through modeling of the important factors and management strategies present at a specific farm (Hafner et al., 2012); however, measurements under field conditions are needed to validate model predictions (Hafner et al, 2012).

Air Quality Regulations for the California Dairy Industry

As discussed above, the SJV is home to both the largest dairy herds and some of the worst air quality in the United States. The SJV experiences high levels of ozone and particulate matter pollution. According to National Ambient Air Quality Standards, mitigation techniques and technologies from all sources of pollution need to be managed and evaluated (Shaw et al., 2007). Ozone can affect day-to-day quality of life because of its potential to cause respiratory and cardiac diseases. California’s air regulatory agencies consider dairies as a contributor to ozone pollution. Fermented feedstuff such as silage, rather than animal manure, were found to be the greatest source of ozone precursor gases from dairy farms (Alanis et al., 2010, Malkina et al., 2011, Hafner et al., 2013).

The San Joaquin Valley Air Pollution Control District (SJVAPCD) implemented rule 4570 in 2006 to limit emissions of VOCs from confined animal facilities (i.e. dairies, feedlots, layer houses etc.). For example, dairy mitigation strategies first revolved around fresh and stored manure management but in 2011, an amendment was added to include feed and silage emission management. The amendment mandates that farmers choose several mitigation measures to reduce gaseous losses from silages. A more detailed explanation of the rule can be found in the appendix of the present report along with specific examples of mitigation techniques. Rule 4570 not only provides regulatory restrictions but an opportunity to simultaneously minimize dry matter (DM) losses from feedstuff. A serious limitation of Rule 4570 is that many of the mitigation options contained therein have never been assessed for their efficacy in reducing gaseous emissions.

Over the past century, dairy farms in California have decreased and the number of milking cows per farm has increased (USDA, 2015). Silage is one of the main feed sources used in the dairy sector (Cherney and Cherney, 2003). In California, corn is typically chopped and ensiled in late summer to early fall for ensiling (Schukking, 1976). As previously mentioned, the summer schedule of corn ensiling coincides with the ideal conditions for ozone formation. The environmental impact of silage is 2-fold. The early ensiling process contributes NOx and the continued feed-out phase VOCs into the atmosphere (Maw et al., 2002, Chung et al., 2010). Dairy farms in the summer are potentially emitting both VOCs and NOx simultaneously and in close spatial proximity.

Silage

Silage Preservation

Entire crops such as corn, sorghum, and other forages can be chopped, compacted, and preserved as silage, a fermented feed, to be fed to animals throughout the year. Silage is less weather dependent than hay making and is mechanized more easily. Silage is better suited than hay to large-scale livestock production systems and is adapted to a wider range of crops (Bolsen and Heidker, 1985). Criteria for a crop to ensile properly include knowledge of DM content, moisture, buffering capacity (resistance to acidification), plant maturity, plant species, and sugar content (Zaunmüller et al., 2006). Corn is an ideal silage crop because of its sugar content, buffering ability, and DM content; whereas alfalfa is more difficult to preserve as silage (Blezinger, 2000). Grasses generally contain more water soluble carbohydrates (WSC) and have less resistance to acidification than legumes (Bolsen et al., 1996).

Prior to harvest, chemical properties such as plant maturity and moisture content are important to measure. If maturity and moisture conditions are met, the plant is chopped and ensiled. Various forages such as alfalfa may be left in the field to wilt to 50-60% moisture before ensiling (Pitt, 1990). The amount of time needed for the crop to wilt is dependent on the plant species, environment, and desired moisture content (Nash, 1959). Not all plants require time to field wilt before ensiling, as can be seen in the case of corn, which has a whole crop moisture range of 55-75% (Johnson et al., 1999). Generally, the higher the moisture content the faster the forage ensiles. The abundant supply of water soluble carbohydrates (WSC) is utilized by micro-organisms and the metabolism of WSC causes a rapid pH drop (Perry et al., 1967, Coblentz et al., 1998). In silage making, plants are first chopped to desired particle size. Particle size is important in obtaining optimal compaction rates and nutritional digestibility (Yang et al., 2001). Chopped feed is then placed into its respective storage containers and compacted in layers. In California, compaction is mainly achieved by two methods. The first method involves a tractor rolling over the transverse plane of the pile in layers, a process that generates the “conventional standard pile”. The second method uses a conveyer belt to feed the chopped forage in a horizontal fashion into a ‘silage bag” (aka “Ag bag”) followed by pressure compaction (Johnson et al., 1982). Compaction is essential in removing as much oxygen as possible from the silage, thus reducing porosity. Compaction is inversely linked to porosity, which decreases as compaction increases (Hafner et al., 2010). Pores are areas where oxygen can pool, slowing down the ensiling process and decreasing the silage quality (Stadhouders and Spoelstra, 1990). A swift transition from an aerobic to anaerobic environment minimizes nutritional loss and maximizes preservation (Jaster, 1995). If the transition of an aerobic to anaerobic environment is slow, it can harbor the growth of unfavorable micro-organisms, clostridials, which are capable of causing secondary fermentation (Spoelstra, 1983, Leibensperger and Pitt, 1987). Quickly creating and maintaining an anaerobic environment are critical factors in producing high quality silage and avoiding the negative impacts of plant respiration, plant proteolysis, and aerobic microbial activity (Muck, 1988). Any delays in covering the ensiled material or inadequate sealing, negatively impacts silage quality (Denoncourt et al., 2007). A delay in covering causes the retardation of temperature and pH changes necessary for fermentation. Quality silage preservation is most susceptible during the first and final phase of silage making (phases outlined below). Knowledge of how to minimize the effects of the driving forces of emissions such as air speed, temperature, porosity, and surface roughness will improve management decisions to improve silage quality, the ensiling process, and as a result, lower the emission profile. An increase in any of these physical properties will result in excessive gas loss and DM loss (Hafner et al., 2012).

Silage Production Phases and Gas Production

The ensiling process undergoes four distinct phases. Each phase has unique characteristics and differs by pH, temperature, microbial populations, and gas production.

Phase 1 - Aerobic Phase

Phase 1 represents the chopped plants being compacted and covered with gas tight plastic tarp. This aerobic phase lasts for approximately two days. Major gaseous losses of NOx and CO_2 occur during Phase 1 (Burger and Jackson, 2003) in which cellular respiration breaks down plant sugars causing the production of CO_2, NOx, heat, and water (Hopkins and Hüner, 1995). Plant respiration eliminates oxygen from the pile contributing to the anaerobic environment inside the silage pile. Plant proteases simultaneously break down proteins into amino acids, ammonia, peptides, and amides (Johnson et al., 2002). The conversion of sugar to acid is vital for the preservation and fermentation of silage. Sugars are the main substrate for lactic acid bacteria to produce the acids needed to preserve the crop as silage (Bolsen et al., 1996). Plant enzymes and microorganisms, such as aerobic fungi and spoilage bacteria, remain active because the pH is still within their favorable conditions (i.e. 6.0-6.5) (McGarvey et al., 2013). Toward the end of this phase, temperature increases and pH begins to decline. The low pH limits a majority of enzymatic activity (Vuuren et al., 1989).

Phase 2 - Fermentation Phase

During phase 2, lactic acid, acetic acid, and ethanol are produced. The production of acids and alcohols causes the pH of the silage to drop and the temperature of the silage to increase. Yeast fermentation of the ensiled plant material produces the alcohols needed for preservation (Ranjit et al., 2002). The ensiled forage heats up to 32 °C and pH levels drop to 5.0 (temperature and pH ranges are unique and specific to plant type and effective storage system). The fermentation phase lasts approximately 21 days, facilitating the growth of anaerobic micro-organisms (Seglar, 2013). The organisms compete with lactic acid bacilli (LAB) for the remaining fermentable carbohydrates. All soluble carbohydrates are believed to be metabolized to lactic acid, mannitol, ethanol, and acetic acid after 44 days (Neureiter et al., 2005). The end products of LAB are desired for their preservation characteristics, while the former organisms yield no preservation properties. Enterobacteria can no longer replicate when the pH drops below 5 and as a result, most enterobacteria are depleted with in the first three days of ensiling (Lin et al., 1992). If a rapid transition to an anaerobic environment fails to occur, clostridial growth occur. Clostridials cause the forage to undergo additional fermentation yielding the production of butyric acid, which leads to DM and digestible energy (DE) loss, which reduces silage quality that contributes to lowered DM intake by cows. Silage core sampling may be used to monitor the favorable microorganism population.

Most dairy producers observe their silage piles for the production of what is commonly known as “silage gas” (i.e. NOx), which causes the gas tight barrier to expand and if not released, tear the plastic cover, making the silage susceptible to aerobic deterioration (Seglar, 2013). Once the majority of NOx has left the pile, the storage pile is resealed from the environment for storage. Ideal conditions after the fermentation phase will render the corn silage pile at a pH of about 4 (Pahlow et al., 2003).

Phase 3 - Storage Phase

During the storage phase, the microbial community is dominated by lactic acid bacteria (LAB) effectively lowering the pH and stabilizing the silage (Driehuis et al., 2001). During this phase, silage has become preserved and will remain in storage until feed-out to animals. The pH range remains around 4 and silage temperature (species dependent) averages at 30°C. The low pH prevents the growth of most fungi and spoilage bacteria. Some undesirable micro-organisms, such as clostridia and bacilli, can remain present in the storage phase but continue to lay dormant until phase 4, aka the feed-out phase. The storage phase is of lesser importance with respect to air emissions due to minimal occurrence of physical and chemical changes. Routine inspection of the pile for oxygen exposure is important to the continued preservation of quality silage. Re-exposure to oxygen, leaks, and tears, will promote yeast and mold populations and some pathogens such as Listeria *monocytogenes* (Perry and Donnelly, 1990, Duh and Schaffner, 1993). Micro-organisms such as clostridial spores, yeasts, molds, and *enterobacteriaceae* negatively impact the quality of silage (Dunière et al., 2013).

Phase 4 - Feed-out Phase

The feed-out phase leads to aerobic deterioration (aka spoiling of the feed), due to the re-exposure to oxygen, and is the major phase of VOC gas losses (Courtin and Spoelstra, 1990). Oxides of nitrogen emissions are also lost from the feed-out phase and any further agitation of silage prior to reaching the feed lane (Maw et al., 2002). Oxygen activates the production of aerobic bacteria, mold, and yeast activity at the exposed silage face. The silage face increases in temperature (>43°C) and pH (pH of 7) (Borreani and Tabacco, 2010). The change in temperature and pH makes the environment favorable to the undesired micro-organisms. These micro-organisms consume the nutrient rich lactic acid, acetic acid, and other soluble products. The consumption of these soluble products leads to the production of CO_2 and water, which causes the temperature increase at the face of the pile (Pitt et al., 1991). Caution should be given to yeasts and bacteria if they reach a population of 10^7-10^8 colony forming units per gram (cfu/g) of silage, or molds reach 10^6-10^7 cfu/g. High bacterial and yeast populations cause the digestible components that can be utilized by cows including sugars and fermentation products to be rapidly lost (Dolci et al., 2011). Time required for heating to occur depends on four factors: number of aerobic microorganisms in the silage, time exposed to oxygen prior to feeding, silage fermentation characteristics, and ambient temperature (Bolsen et al., 1996). These four factors vary even between silage piles with the same forage and management. Woolford (1990) quantified under laboratory conditions that a rise in 8-12°C above the ambient temperature causes DM losses at approximately 1.5-3.0% DM.

Silage Air Emissions

Volatile Organic Compounds (VOCs)

Dairies emit VOCs from many sources including animal waste, bedding, flush lanes, and free stalls. Little is known about VOCs from animal feeds and how they compare with other VOC emitters such as light duty vehicles. In 2010, research was conducted on six dairies in the California's SJV with six locations within each dairy being tested (Chung et al., 2010). The locations measured were the silage storage pile, TMR within the free stall barns, the bedding, the flushing lanes, the open lots, and the lagoon to create an emissions profile. A total of 48 VOCs were identified with substantial variation across and between dairies and sources within a dairy. Silage and TMR (containing silage) were the greatest contributors to VOCs amongst the six locations (Chung et al., 2010). Compounds found in silage included but were not limited to alkanes, alkenes, aromatics, carbonyls, alcohols, and halogenated organics. Ethanol made up the majority of the VOC profile from silage followed by ethyl acetate, acetone, and 2-propanol. Compounds such as alkanes and aromatics also contributed to the emissions profile of silage, but were still several orders of magnitude smaller than ethanol.

The reactivity of these VOCs can also be expressed as ozone formation potential (OFP). The OFP from animal feed can be quantified and compared with other pollution sources on similar scale. Howard et al (2010) conducted a study evaluating seven common animal feeds: cereal silage, alfalfa silage, corn silage, high moisture ground corn, almond shells, almond hulls, and TMR (55% corn silage, 16% corn grain, 8% almond hulls, 7% hay, 7% bran and seeds, and 5% protein, vitamins, and minerals). The objective of that work was to measure the OFP of these animal feeds and provide estimations for the source of VOCs and their ozone formation compared with light duty vehicles. Alcohols accounted for about half of the ozone formation for the measured feed types. Alkenes were significant in corn silage, alfalfa silage, and TMR. Acetaldehyde contributed about 25-30% of ozone formation in cereal silage. The OFP of these feeds range from 0.4 g-O_3 per g-VOC to 0.2 g-O_3 per g-VOC. Light duty vehicles in comparisons have an OFP of 0.7 g-O_3 per g-VOC. The OPF of animal feed on confined animal facility (CAF) is 25± 10 t O_3 day^{-1} was estimated compared with 13 ± 1.3 t O_3 day^{-1} of light duty vehicles. The consumption of these feeds was also evaluated and although almond hulls may have a larger OFP they make up a smaller contribution in a TMR as compared with silages. Based of the Department of Agriculture's census for animal numbers and the ozone production of corn silage, total emissions were calculated to be approximately 20 ± 9.5 t day^{-1} (Census of Agriculture, 2007, Howard et al., 2010) .

Ethanol is a major contributor at >70% of VOCs from animal feed; therefore the flux of ethanol's emission rate becomes a crucial part of the problem (Howard et al., 2010, Malkina et al., 2011). Based on plant maturity at harvest, ethanol ranged from 0.45 to 2.7 % of DM in the subsequent corn silage (Sheperd and Kung Jr, 1996). As much as 40% of the ethanol emissions were lost from recently extracted silage piles within the first 5 hours (Shaw et al., 2007). The percent lost between silage piles varied and could be attributed to packing density of the silage pile. Poor packing density caused the silage pile to sustain a semi-aerobic environment. Sufficient acid production was still observed under semi-aerobic environments, but there were fewer formed metabolites (Neureiter et al., 2005, Hafner et al., 2010).

Studies have then translated packing density to measured emissions from silage faces, i.e. extracted and exposed silage. The high variation of measured emissions from feed sources presents challenges when using traditional models. Process-based models incorporate parameters that influence VOC emissions and have more accurately quantified emissions from silage (Zhang et al., 2009, Hafner et al., 2012). Additional variations were present in the mode of transport of VOCs from the silage into the atmosphere (Hafner et al., 2012). The mass transfer model of ethanol emissions developed from a convective transport model, and it addresses the pathway of ethanol emissions from the liquid to gaseous phase in thin layers of corn silage. The final mathematical model for ethanol emissions can predict ethanol emissions in the silage as a function of initial ethanol concentration and exposure time (Hafner et al., 2012). The mass transfer coefficient of ethanol was also calculated against temperature and air velocity. The results illustrate, two orders of magnitude greater mass transfer coefficient of ethanol from 15 °C at 0.2 m s^{-1} to 35 °C at 2.5 m s^{-1}. Ethanol contributes as much as 10 g m^{-2} h^{-1}, the majority of the compound released within 10h, and follows an exponential emission decay curve over time (hours) (Hafner et al., 2012, Hafner et al., 2013).

Oxides of Nitrogen (NOx)

The oxides of nitrogen emissions present an environmental concern, a potential parameter for quality silage (i.e. progression of fermentation and overall quality), and a worker health hazard.

Oxides of nitrogen are a precursor in ozone formation. Documented animal feed related emission sources of NOx are not as well defined as those for VOCs. The NO_2 is the only compound of the NOx family that the EPA regulates because of its prevalence and it is both an air pollutant and a precursor to ozone and acid rain. The EPA has created NAAQS for the tropospheric ozone. The primary and secondary standard for NO_2 is 0.053 ppm (Lyndon Cox, 1999).

Nitrogen dioxide in the atmosphere reacts with air and UV radiation to create nitric oxide (NO) and ozone (O_3). The UV radiation releases free radicals from VOCs that can react with NO. Free radicals can then recycle the newly formed NO back to NO_2. The recycling of NO to NO_2 continues until the carbon chains in the VOCs are no longer photo sensitive. Typically, five rotations of the recycling process can occur, providing many opportunities for ozone formation (Grano, 1997). The NO_2 can also be readily absorbed in atmospheric moisture to produce acid rain and undesirable environmental effects.

There are seven NOx species: nitrous oxide (N_2O), nitric oxide (NO), dinitrogen dioxide (N_2O_2), dinitrogen trioxide (N_2O_3), nitrogen dioxide (NO_2), dinitrogen tetroxide (N_2O_4), and dinitrogen pentoxide (N_2O_5). With regards to silages, the main species of interest are NO (colorless gas/slightly water soluble), NO_2 (red-brown gas/water soluble and decomposes in water), and N_2O (colorless gas/water soluble) (Ataku, 1982). According to the EPA, mobile sources account for 50%, electric power plants 20%, and “everything else” 30% of the NOx emitted in the US. Identifying the sources emitted from the “everything else” category could help the nation reduce overall NOx emissions and achieve proposed NAAQS standards (EPA, 2015).

The process of ensiling is one of the unaccounted sources of NOx emissions. Nitrate is found in plants naturally and also in other anthropogenic sources i.e. fertilizers (Lindsay et al., 1981). The majority of nitrate is broken down in the feedstuff during the ensiling process. The degradation of nitrate is related to high pH levels and high ratios of NH_3-N to total N. A high pH and high ratio of NH_3-N to total N constitute unfavorable conditions in the ensiling process and retard the rapid transition to an acidic anaerobic environment (Spoelstra, 1985). The ensiling process causes the reduction of nitrate and starts producing nitrite, nitrogen oxides, and ammonia within the first week (Ohshima et al., 1978, Spoelstra, 1985, McDonald et al., 1987, Henderson, 1993, Petersen et al., 2006). The first phase of ensiling contains microbes such as *enterobacter sp., lactobacillus plantarum,* and *clostridium tyrobutyricum.* These microbes can all reduce nitrate (Ohshima et al., 1978, Spoelstra, 1983, Bolsen et al., 1996) and lead to the reduction of nitrate to nitrite, nitrite to ammonia, and the release of nitrogen oxides (Hasan and Hall, 1975). The nitrogen oxides can be formed from the interaction of nitrate and organic acids with by-products of water (Grayson, 1956). Research has been conducted to correlate the reduction products of nitrate to overall improved silage quality (Ohshima et al., 1978, Ataku, 1982, Spoelstra, 1983, Spoelstra, 1985).

Oshima et al., (1978) characterized high quality silage by having low pH, high lactic acid content, low VFA concentration, and low volatile basic nitrogen (VBN). Their research compared two experiments of ensiled ladino clover. Each experiment had silage enriched with a glucose additive and silage without additive. Silage with glucose added had a pH range of 3.96-4.02 compared with the silage without added glucose, which showed pH values of 4.55-4.62. Silage with glucose added had almost twice as much lactic acid present and half the percentage of VFAs and VBNs. High-sugar crops have reported low pH levels that plateau for quality preservation and low ammonia production. Low-sugar crops are not able to reach similar acidic conditions, increase pH over days ensiled, and yield high ammonia production (Wilkins, 2013). Oshima et al., (1978) also found that density had no effect on nitrite content but nitrogen oxide gas production increased with density (with and without glucose added). A greater density may be correlated to a better compaction rate and oxygen expulsion and the compaction minimized the activity of aerobic bacteria (Ohshima et al., 1978). Ataku et al. (1982) found that the majority of nitrate was reduced in the first phase of ensiling and no additional reduction of nitrate was found in the remaining stages of ensiling. Further research showed that nitrate reduction could be completed by both aerobic and anaerobic microorganisms throughout the phases despite low pH levels and an anaerobic environment (Henderson, 1993).

Recent research has been conducted measuring the oxides of nitrogen throughout the ensiling phase, storage phase, feed-out phase, and associated agitations prior to reaching the feed lane (i.e. mixer wagon, extraction from pile, etc.) (Maw et al., 2002). These workers also reported that the majority of NOx measured at the face of the silage was approximately 95% NO and 5% NO_2. Peak concentrations of NOx in corn silage ranged from 460-2137 ppbv (Maw et al., 2002). The variation was likely due to the seasonality effects of ambient temperatures (e.g. warmer temperatures increase NOx). In addition, NOx emissions increased as the exposed silage face area increased and time exposed to air increased (Maw et al., 2002, Montes et al., 2010). Maw et al., (2002) reported that after seven months of ensiling, corn silage placed in the mixer wagon and agitated produced significant amounts of NOx, approximately 1700 ppbv compared with background levels of 21 ppbv. Maw et al., (2002) reported that the NOx emissions that were lost, posed minimal effects on nutritional content, but instead presented a health risk to people as well as animals, and were an environmental pollution concern (i.e. ozone production).

Silo-filler’s disease, a health condition caused by a reddish brown (i.e. NO_2) gas, is responsible for pulmonary injury (Fleetham et al., 1978). Silo-filler’s disease is a result of the fermentation process of silage. As previously mentioned, crops contain nitrate, and nitrate is converted to nitrites with organic acids to make nitrous acid. The transition from phase 1 to phase 2 of ensiling incorporates rising temperatures. The temperature increase caused nitrous acid to decompose into water and NOx (Ramirez and Dowell, 1971). Nitrogen dioxide (NO_2) is the reddish brown gas with its pungent odor. The NO_2 concentrations in phase 1 of ensiling increase with fertilization, lack of water, and immature plant harvest (Fleetham et al., 1978). Inhalation of NO_2 is toxic and can be fatal depending on the dose and duration of exposure. The NO_2 readily reacts with water in the respiratory epithelium to form nitric- and nitrous acids. The resulting acid formation can cause severe burns, pulmonary edema, bronchoconstriction, and inflammation (Jiang et al., 1991, Zwemer Jr et al., 1992). The toxic gas appears within the first couple days and can last up to a week (Reid et al., 1984). Nitrogen dioxide was reported to be a dense cloud of orange gas covering the silage or pooling in silo buildings (Wang and Burris, 1960, Zwemer Jr et al., 1992). Ramirez and Dowel (1971) illustrated the partitioning of NOx within a silo. Nitrous acid occurs toward the base of the silage, whereas NO, the colorless gas, travels toward the silage surface. Once in contact with air, the NO becomes NO_2, the reddish brown gas, settling on the surface. The N_2O_4 is present within the proximal head space of the silo, characterized by a yellow gas. Symptoms from Silo Filler’s Disease can be the result of acute exposure and/or chronic low-level exposures (Goldstein et al., 1977). Symptoms of the disease could be overlooked and unaccounted for because of the rare prevalence of the disease. Silo-Filler’s disease is also common to industrial exposure of nitrous fumes. Silage consequently presents a risk to workers and animals acutely when ensiling occurs and with chronic low level exposure in poorly ventilated buildings (Ramirez and Dowell, 1971).

Mitigation Strategies for Gas Emissions and Nutritional Losses in Silage

In general, mitigation strategies for environmental losses from silages is sparse and mainly related to minimize DM losses and deterioration of feed quality. Most is known on the use of silage covers and additives to maintain high quality of silage and to reduce DM losses.

Silage Covers

Silage making reduced farmers’ dependency on the weather and minimized potential losses when harvesting grasses. However, the storage of silage presents a large initial investment. Silos and silage bunkers are well established storage venues for ensiled material across the United States but may present feasibility challenges for a farm to be profitable (Savoie, 1988). The agricultural industry has also adopted the use of low density polyethylene (LDPE), high density polyethylene (HDPE), and linear low density polyethylene (LLDPE) in their operations (Briassoulis, 2007). Polyethylene (i.e. plastic film) provides farmers an alternative storage system to silage management. The plastic film can vary in composition and layers, but typically provides UV resistant, specific thickness, and gas-tight properties for proper ensiling.

Savoie (1988) researched the costs associated with plastic covers, optimal thickness, and DM losses. He devised several modeling equations to quantify the optimal characteristics to ensile high quality feed. The equations involved the cost of the plastic, which increased with size and thickness, the permeability and volumetric infiltration rate of oxygen, oxygen consumption of carbohydrates, and DM losses. Oxygen consumption rate was determined as a gram of oxygen needed by microbes to consume 0.9375 g of soluble sugars and was reported as DM loss (Wood and Parker, 1971). Thickness varied from 25 µm to 400 µm with a corresponding permeability of 1.95-0.12 cm atm^{-1} h^{-1}. The DM losses were reported as a percent (%) per 30-day period. Dry matter losses during the 30-day period were between 0.16 and 2.44% with the 400 µm polyethylene cover. Monthly intervals accounted for temperature differences and their influence on DM loss. Polyethylene cover thickness recommendations for a 120-day storage period were 0.0120 cm and for 360-day storage a thickness of 0.0200 cm. Additional cover thickness should be factored for pest control and environmental damage (Savoie, 1988).

Gaseous emissions and nutrient losses were affected by plant species, chemical composition of the forage, oxygen, physical preparation, preservatives, temperature, storage, and moisture content (Gordon, 1967). The most common way to determine total DM losses is the comparison between amount of feed ensiled and removed silage for feed-out. The three main routes for total DM constituents losses were: effluent or liquid loss, spoilage or unsafe to feed, and gaseous loss (Gordon, 1967). Controlling moisture levels and crop maturity prior to ensiling minimized DM loss. Recommended moisture levels for a specific crop facilitated favorable conditions for lactic acid bacteria, but the duration of wilting required could influence the cost benefit (i.e. DM loss) (Wilkinson, 1981).

Emissions from silage were largely driven by air velocity, temperature, porosity, and surface area (Alanis et al., 2010, Chung et al., 2010, Montes et al., 2010). Hafner et al. (2010) provided estimates of the rate of ethanol emissions from loose corn silage, quantifying the effects of temperature, air velocity, and exposed surface area on ethanol emission rates, and assessed the accuracy of the US EPA emission isolation flux chamber method for measuring VOC emissions from loose silage. Hafner et al. (2010) concluded that the VOC emission rate from loose corn silage was high initially and declined rapidly to plateau over time. Temperature, air velocity, and different silage types had significant effects on the overall emissions of ethanol (Muck, 1988, Elferink et al., 2000, Alanis et al., 2008, Hafner et al., 2010). Temperature and air velocity had the largest effects on VOC emissions (Montes et al., 2010). Emissions increased by a factor of 4 in response to a 30 °C increase in temperature and by a factor of 10 in response to a 90-fold increase in air velocity (Hafner et al., 2010, Hafner et al., 2013). Low density or high porosity silage, increased surface area between silage particles for oxygen and aerobic bacteria to negatively impact silage quality and promote VOC emissions (Hafner et al., 2013). The resulting VOC emission losses continued with loosely packed silage piles post-extraction, excess mixing time in the TMR wagon, and prolonged exposure time in the feed lanes (Hobbs et al., 2004, Hafner et al., 2010).

Silage Additives

The fermentation process can vary based on silage moisture, maturity, nitrate levels, and storage type. Research on silage additives has been conducted in order to minimize variability of the above mentioned parameters and enhance the ensiling process for the production of quality silage (Buxton and O' Kiely, 2003). In the 1970s, the addition of glucose was reported to improve silage quality and depress the nitrate reduction process. The glucose treated silages yielded lower pH values (Ohshima et al., 1978). The use of additives were further studied to minimize DM loss, rapidly lower pH, support desired microorganisms, limit secondary fermentations, and maximize quality and preservation (Merensalmi and Virkki, 1991). Enzyme inoculant mixtures of cellulose, xylanase, cellobiase, and glucose oxidase were reviewed to ascertain their effects on ensiling corn. The inoculant mixture had no effect on silage pH but did increase titratable acidity, reduced fiber components, and promoted partial degradation of structural carbohydrates. The reduction of fiber components improved nutritional value of the silage and subsequent animal performance (Stokes and Chen, 1994).

The factors influencing the preservation of crops as silage include enzymes and micro-organisms. The enzymes involved are respiratory, proteolytic, and polysaccharide-degrading enzymes. Major micro-organisms that can alter crop preservation, emissions, and nutrient quality are lactic acid bacteria, enterobacteria, clostridia, fungi (yeasts and molds), bacilli, listeria, acetic acid bacteria, and propionic acid bacteria (Henderson, 1993). Most forage crops other than corn should be harvested at the driest time of day and field wilted for approximately 24 hours. Research is still required to reduce DM loss, improve animal performance, and reduce losses throughout the ensiling phases (Henderson, 1993).

While numerous microbial additives have been reported to improve silage quality, research on decreasing gaseous emissions is at a nascent stage. Many of the microbial additives that have been studied (including *lactobacillus buchneri*, *lactobacillus plantarum*, and propionic acid mixtures) were originally believed to reduce the production of VOCs emissions but the following chapter is the first work that shows actual efficacy of that claim.

Chapter 2 - Effects of Silage Additives on Gaseous Emissions[1]

Task 1: To investigate the effects of selected microbial and chemical silage additives on air emissions

Abstract

The objective of this chapter was to evaluate the effects of microbial and chemical silage additives on the production of volatile organic compounds (VOC) (methanol, ethanol, 1-propanol, methyl acetate, and ethyl acetate) within corn silage. Recent work has shown that silage VOC can contribute to poor air quality and reduce feed intake. Silage additives may reduce VOC production in silage by inhibiting the activity of bacteria or yeasts that produce them. We produced corn silage in 18.9 L bucket silos using the following treatments: 1) control (distilled water); 2) *Lactobacillus buchneri* 40788, 400,000 colony-forming units (cfu) per g wet forage; 3) *Lactobacillus plantarum* MTD1, 100,000 cfu/g; 4) a commercial buffered propionic acid-based preservative (68% propionic acid, containing ammonium and sodium propionate and acetic, benzoic, and sorbic acids), 1 g per kg wet forage (0.1%); 5) a low dose of potassium sorbate, 91 mg per kg wet forage (0.0091%), 6) a high dose of potassium sorbate, 1 g per kg wet forage (0.1%); and finally, 7) a mixture of *L. plantarum* MTD1 (100,000 cfu/g) and a low dose of potassium sorbate (91 mg/kg). VOC concentrations within silage were measured after ensiling and sample storage using a headspace gas chromatography method. The high dose of potassium sorbate was the only treatment that inhibited the production of multiple VOC. Compared to the control response, it reduced ethanol by 58%, ethyl acetate by 46%, and methyl acetate by 24%, but did not clearly affect production of methanol or 1-propanol. The effect of this additive on ethanol production was consistent with results from a small number of earlier studies. A low dose of this additive does not appear to be effective. While it did reduce methanol production by 24%, it increased ethanol production by more than two-fold, and did not reduce ethyl acetate. All other treatments increased ethanol production at least two-fold relative to the control, and *L. buchneri* addition also increased 1-propanol to approximately 1% of DM. No effects of any treatments on fiber fractions or protein were observed. However, *L. buchneri* addition resulted in slightly more ammonia compared with the control. If these results hold under different conditions, a high dose of potassium sorbate will be an effective treatment for reducing VOC production in and emission from silage. Regulations aimed at reducing VOC emission could be ineffective or even increase emission if they promote silage additives without recognition of different types of additives.

Introduction

Silage contains numerous volatile organic compounds (VOC), including organic acids, alcohols, esters, aldehydes, and ketones (Hafner et al., 2013). Volatile organic compounds present in silage can contribute to poor air quality (Howard et al., 2010), and reduce feed intake by livestock (Weiß and Auerbach, 2012; Gerlach et al., 2013). Both problems could be addressed through the use of silage additives if VOC production can be reduced by inhibiting the activity of the bacteria or yeasts that produce them. Both biological additives (usually consisting of lactic

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[1] The present chapter has been published in the peer reviewed literature: Hafner, S.D., R. B. Franco, L. Kung Jr, C.A. Rotz, and F.M. Mitloehner. 2014. Potassium sorbate reduces production of ethanol and 2 esters in corn silage. *Journal of Dairy Science*. 97:7870-8.

acid bacteria) and chemical additives are commonly used to reduce fermentation losses, improve silage quality, and improve aerobic stability (Duniere et al., 2013). In general, effects of these additives on VOC have not received much attention, but several studies have reported effects of additives on ethanol production during ensiling. Ethanol may be produced by at least four groups of microorganisms present within silage: lactic acid bacteria, enterobacteria, clostridia, and yeasts (Hafner et al., 2013). Excluding acetic acid, it is generally the most concentrated VOC present in corn silage (Hafner et al., 2013) and contributes to the production of additional VOCs—ethyl esters (Weiß and Auerbach, 2009, 2012, 2013), and possibly acetaldehyde (Hafner et al., 2013). Biological additives have been reported to increase or decrease ethanol production in silage, or even have no effect (see review in Hafner et al., 2013). However, a small number of studies have reported large reductions in ethanol production with the addition of potassium sorbate. Teller et al. (2012) found that 0.1% addition of potassium sorbate (fresh mass basis) reduced ethanol production in corn silage by at least 70%. Kleinschmit et al. (2005) reported that 0.1% of a 1:1 mixture of potassium sorbate and ethylenediaminetetraacetic acid (EDTA) (fresh mass basis) reduced ethanol production in corn silage by 80%. Weiß and Auerbach (2012) reported a 70% reduction in ethanol by addition of a commercial mixture of sodium benzoate and potassium sorbate (21.9% sodium benzoate, 13.2% potassium sorbate, applied at 0.2% (Kirsten Weiß, Humboldt Universität Berlin, Germany, personal communication)) to corn silage. Furthermore, production of two esters (ethyl lactate and ethyl acetate) was reduced by at least 45%. In another study, Queiroz et al. (2013) found that 0.1% addition of sodium benzoate (fresh mass basis) reduced ethanol production in corn silage by 68%. Auerbach and Nadeau (2013) found reductions of 73% to 85% in ethanol production in corn silage treated with two commercial products containing potassium sorbate, sodium benzoate, and, in one product, sodium nitrite (potassium sorbate application ranged from 130 to 300 mg/kg, while sodium benzoate application ranged from 250 to 515 mg/kg). Most recently, Bernardes et al. (2014) evaluated two doses of potassium sorbate or sodium benzoate (0.1% and 0.2%). All treatments reduced ethanol by at least 54%, and the high dose of potassium sorbate was most effective, reducing ethanol by 85%.

The protonated form of the sorbate ion, sorbic acid, is toxic to many microorganisms (Lambert and Stratford, 1999). This uncharged molecule diffuses through cell membranes, and may acidify the cytosol, which would interfere with the proton gradient used for ATP production and with other cellular processes (Beek et al., 2008). Natural acidification of silage increases the ratio of sorbic acid to sorbate, and therefore, would be expected to increase this inhibitory effect. Yeasts, molds, and most Gram-negative bacteria are generally sensitive to sorbic acid, but lactic acid bacteria are not (Emard and Vaughn, 1952; Woolford, 1975). Because yeasts and enterobacteria may be responsible for production of many silage VOC, their inhibition would be expected to reduce VOC production (Hafner et al., 2013).

Confirmation of the effects of potassium sorbate on ethanol and ester production is needed. Furthermore, it is important to determine the effect of potassium sorbate on other important VOC. In the present study, our objective was to evaluate the effect of potassium sorbate and other additives on the production of three alcohols and two esters: methanol, ethanol, 1-propanol, methyl acetate, and ethyl acetate. These compounds were selected because they are among the most significant silage VOC from an air quality perspective (Hafner et al., 2013), and are relatively easy to measure. Ethanol is generally the single most important compound emitted from corn silage, based on its relative effect on air quality (Hafner et al., 2013). However, other compounds that may have a significant effect on air quality under some conditions, such as some aldehydes, were not included.

Materials and methods

Silage production

Corn silage was made from a single batch of forage collected from a commercial dairy farm. Each silage additive was applied to a single subsample of forage that was divided among six replicate buckets after mixing. The process of applying additives and mixing was done by the same people using the same method all on a single day to minimize confounding handling effects, so differences were expected to have a negligible effect on measured variables. Corn forage, at approximately 25% DM, was harvested from a commercial dairy farm in Elk Grove, CA on September 22, 2012 and chopped in the field to a nominal length of 10-15 mm. Treatments were applied in 1.0 L of distilled water applied to 75 kg of wet forage using spray bottles, and the forage was thoroughly mixed using shovels and rakes on the top of plastic tarps. To avoid cross-contamination, tarps were either new or disinfected with a 10% bleach solution, thoroughly washed, and then dried for each treatment.

Treatments were: 1) control (distilled water only); 2) LB: *Lactobacillus buchneri* 40788 (Lallemand Animal Nutrition, Milwaukee, WI) 400,000 colony-forming units (cfu) per g wet forage; 3) LP: *Lactobacillus plantarum* MTD1 (Ecosyl Products Ltd., Stokesley, UK), 100,000 cfu/g; 4) PA: a commercial buffered propionic acid-based preservative (68% propionic acid, containing ammonium and sodium propionate and acetic, benzoic, and sorbic acids; total concentrations of acids 82% by mass; Kemin Americas, Des Moines, IA), 1 g per kg wet forage (0.1%); 5) PSL: a low dose of potassium sorbate, 91 mg per kg wet forage (0.0091%); 6) PSH: a high dose of potassium sorbate, 1 g per kg wet forage (0.1%); and finally, 7) M: a mixture of *L. plantarum* MTD1 (Ecosyl Products Ltd., Stokesley, UK) (100,000 cfu/g) and the low dose of potassium sorbate (91 mg/kg), added separately. Potassium sorbate was 99.0% pure (Sigma-Aldrich, Germany). Twelve kg of each treated forage was then manually compressed in 18.9 L buckets. Buckets were covered with tight-fitting lids, which were installed with silicone caulk to ensure a gas-tight seal. Excess silage gas accumulated in 5 L tedlar gas bags (SKC-West Inc., Fullerton, CA) attached to the bucket silo lids using a plastic through-wall connector sealed with a rubber o-ring. Each treatment was replicated six times and all bucket silos were stored inside an unheated building with air conditioning in summer months. The temperature inside the building was not monitored during the entire trial but based on limited measurements ranged from approximately 15°C to 27°C. Outside temperature during this period ranged from 3°C to 43°C.

Bucket silos were opened after 303 days, and the top 10 cm of silage was removed and discarded as a precaution in case any air infiltration had occurred. Samples (approximately 100 g) were collected from a depth of 10-20 cm and immediately (within 5 min.) vacuum packed in polyethylene/nylon bags (FoodSaver, Sunbeam Products, Jarden Consumer Solutions, Boca Raton, FL) where they remained until analyzed. Vacuum-packed samples were stored under refrigeration (about 4°C), apart from one week at about 20°C due to an equipment failure. Five of the six replicates were analyzed for VOC over a period of 66 d after opening the silos, and the last set of replicates were analyzed 170 d after opening the silos. A second set of vacuum-packed samples were shipped on ice to a commercial laboratory and analyzed for all other analysis within four weeks of opening the silos.

Silage analysis

Concentrations of methanol, ethanol, 1-propanol, methyl acetate, and ethyl acetate were measured using a headspace gas chromatography procedure. About two hours prior to analysis, vacuum-packed bags were removed from refrigeration, N_2 gas was added using a needle, bags were resealed with tape, and the samples were allowed to warm to room temperature. Then, a 1.0 mL gas sample was removed using a gas-tight syringe and manually injected in a Varian CP 3800 GC with an 0.53 mm (inner diameter) capillary column with an 0.5 µm SPB-1000 coating (Supelco Analytical, Bellefonte, PA, US). Split injection was used, with a split ratio of 5:1 and an injector temperature of 75°C. Carrier gas was N_2 at 10 mL/min. The oven temperature was 35°C, and the flame ionization detector temperature was 250°C. Standards were produced by mixing a stock mixture of pure compounds in water, and were equilibrated with an air phase in 125 mL jars with a septum in the cover (I-Chem Septa Jars, Fisher Scientific, Hampton, NH) alongside bagged silage samples. Standard solutions were made using pure compounds (methanol, ethanol, 1-propanol, and methyl acetate were ≥99.9% pure; ethyl acetate was 99.8% pure; all Sigma Aldrich, St. Louis, MO, USA) in 18 MΩ-cm deionized distilled water. Chilled pure chemicals were originally combined in a stock mixture with no water, which was stored below -18°C, and added to water to make standards each time the GC was used. Headspace samples from the standards were removed and injected as with silage samples. Compounds were identified based on retention time relative to ethanol. Retention times within 2.5% of expected values were accepted (based on results from the standards), although 6% was allowed for two injections where carrier gas flow appeared to differ slightly from the standards), and were quantified using peak height to minimize the influence of overlapping peaks. Typical relative standard deviation for the method was 2-10%, depending on the compound and the sample. The underlying mechanism of this headspace method is a fixed aqueous-gas partitioning coefficient (i.e., concentration ratio) for each individual compound at a given temperature. If the partitioning coefficient is identical in solution standards and silage solutions, a calibration curve determined from headspace samples taken from aqueous standards can be used with the FID response from silage samples to directly calculate aqueous-phase concentrations without determining gas-phase concentrations. These aqueous phase concentrations can be converted to a dry mass basis using the corrected DM. Evaluation of this headspace method is described in the online data supplement.

Silage dry matter content, fiber fractions, crude protein, organic acids, 1,2-propanediol, pH, and yeast counts were determined by a commercial laboratory (Cumberland Valley Analytical Services, Cumberland, MD, USA). Dry matter was determined by oven drying at 60°C for 4.5 h in a forced-air oven, followed by grinding and then additional drying for 2 h at 105°C. Dry matter values were corrected for loss of volatile compounds by assuming that 8% of lactic acid and 95% of the acetic acid (based on Weißbach and Strubelt, (2008)), 100% of NH_3 (based on Porter and Murray (2001)), and all VOC mass (based on the 100% estimate made by Weißbach and Strubelt, (2008) for alcohols) was volatilized during drying). For determination of pH, ammonia-N, organic acids, and 1,2-propanediol a 25 g sample of silage was mixed with 200 mL of deionized water. The sample mixture sat overnight, was blended for 2 min and then filtered through coarse filter paper (20-25 µm particle retention). Sample pH was measured using a 30 mL subsample. Ammonia-N was measured by distillation and titration. L-Lactic acid was measured with a YSI 2700 Select Biochemistry Analyzer (YSI Inc., Yellow Springs, Ohio), and multiplied by two for an estimate of total lactic acid. For determination of 1,2-propanediol and acetic, propionic, and butyric acids, 3 mL of extract was filtered through a 0.2 µm filter membrane and a 1.0 µL sub-sample was injected into a Perkin Elmer AutoSystem gas chromatograph (Perkin Elmer, Shelton, Connecticut) using a Restek column packed with Stabilwax-DA (Restek Corporation, Bellefonte, Pennsylvania) and a flame ionization detector. Helium was used as the carrier gas, and injector, oven, and detector temperatures were 225°C, 150°C, 150°C, respectively. Nitrogen content was determined by total combustion of the sample using a LECO CNS 2000 Analyzer (LECO Corp., St. Joseph, MI) and was multiplied by 6.25 to obtain crude protein. Soluble protein content was determined using the borate-phosphate buffer procedure by Krishnamoorthy et al. (1982). Samples were analyzed for neutral detergent fiber (NDF) using sulfite and amylase (Van Soest et al., 1991) and acid detergent fiber (ADF) was determined using the AOAC Official Method 973.18 (AOAC, 2000a). Starch was measured using the procedure described by Hall (2009). Yeast and mold counts were measured using the AOAC Official Method 995.21 (AOAC, 2000b). The detection limit for yeast and mold was 1000 cfu/g (wet mass basis).

Data analysis

Linear regression with dummy variables to represent the treatments was used in R (v. 3.02, R Core Team, 2013) for data analysis. “Treatment” coding was used with the control group as the baseline. Each treatment was compared to the control response using separate *t* tests with a single pooled estimate of the standard error of the difference (calculated using the “summary” method for “lm” objects). The type I error rate α was set at 0.05, and the Bonferroni adjustment was applied for the comparison, resulting in an α of 0.00833. All VOC concentrations were log-$_{10}$-transformed to account for error distributions closer to log-normal than normal and to eliminate heteroscedasticity. Means of VOC concentrations presented below are back-transformed values, and standard errors were also back-transformed and expressed as a relative value, using the formula $10^{SE_l} - 1.0$ where SE_l is the standard error of $\log_{10}$-transformed data. Standard errors were not expressed as a percentage to avoid confusion with units of % of DM. Because of values below the detection limit for yeast count, these results were analyzed using a nonparametric approach, the Wilcoxon Rank Sum Test, with the Bonferroni correction. Analysis of covariance was used to assess the effect of storage duration at 4°C on VOC concentrations. The lm function was used as above for this analysis, but storage duration was included as a covariate. For each compound, both the overall effect of duration and separate effects for each treatment were evaluated using *t*-tests, with α = 0.05 and no adjustment for multiple comparisons. Lastly, multiple linear regression (also with the lm function) was also used to assess correlation between esters, alcohols and acetic acid.

Results

Fresh forage composition and typical silage properties are summarized in Table 1. Dry matter content was lower than recommended values for corn silage (typically 30-40%). Silage pH, lactic acid, and acetic acid were within the range of typical corn silage with DM of 30%-40% (Kung and Shaver, 2001), with some exceptions: lactic acid was above 7% in the control (7.87%) and PSL (7.18%), and acetic acid was well above 3% in LB (5.73%). Additionally, propionic acid was above 0.1% in PA (0.18%), presumably due to addition of the compound, and also very high in LB (1.3%). The LB treatment markedly increased acetic acid production, markedly reduced lactic acid, and increased pH ($P < 0.001$ for each). All other treatments moderately reduced lactic acid production, and apparently did not change acetic acid production, resulting in a decline in lactic acid:acetic acid ratio for all treatments relative to the control. The LB treatment slightly increased production of ammonia (by 0.026% of DM, $P < 0.001$). Additives did not affect the concentrations of total or soluble crude protein, fiber fractions, or starch.

Table 1. Characteristics of corn silage treated with biological and chemical additives[1]

	Treatments							*Pooled*
Item	*C*	*LB*	*LP*	*PA*	*PSL*	*PSH*	*M*	*SE*
DM	27.5	26.7	26.8	27.4	26.6	27.5	27.0	0.255
pH	3.68	4.08***	3.70	3.69	3.68	3.77*	3.75	0.022
CP	7.66	7.67	7.67	7.83	7.67	7.45	7.67	0.127
NH_3	0.134	0.16***	0.129	0.145	0.128	0.127	0.126	0.00342
ADF	30.7	31.2	30.5	30.9	31.7	30.6	32.4	0.545
NDF	45.6	47	46.8	46.6	47.6	46.9	48.2†	0.708
Starch	22.3	21	22.2	22.1	20	21	19.8	0.846
Yeasts[2]	<3.70	<3.00	6.88*	6.46*	6.67*	<3.00	6.73*	0.278
Lactic acid	7.87	1.8***	6.87**	5.97***	7.18*	6.57***	6.41***	0.173
Acetic acid	1.14	5.73***	1.22	1.26	1.26	1.31	1.25	0.105
Lactic:acetic	6.95	0.324***	5.64***	4.76***	5.74***	5.05***	5.18***	0.255
Propionic acid	n.d.	1.28	n.d.	0.179	n.d.	n.d.	n.d.	n.d.

[1] Abbreviations used for means are: C, control; LB, *Lactobacillus buchneri 40788*, 400,000 cfu/g; LP, *Lactobacillus plantarum MTD1*, 100,000 cfu/g; PA, buffered propionic acid-based preservative; PSL, potassium sorbate, 0.0091% of wet forage mass; PSH, potassium sorbate, 0.1%; M, *Lactobacillus plantarum MTD1*, 100,000 cfu/g, plus potassium sorbate, 0.0091%. Number of replicates was 6 for all groups. The symbol n.d. indicates no detection. 1,2-Propanediol was detected only in silage treated with *L. buchneri*, where it was 1.01% of dry matter. All results are given as percent of DM except pH and yeasts. Ammonia is expressed as % of DM as N. Statistical significance is based on comparisons of each group to the control with the Bonferroni adjustment: †$P < 0.10$, *$P < 0.05$, **$P < 0.01$, ***$P < 0.001$.

[2] Units are $\log_{10}$(colony-forming units/g) on a wet mass basis, and the detection limit was 3.0. All replicates for PSH and all but one replicate for C and LB were below the detection limit. Asterisks show results of comparisons to C, with the single high value excluded, or LB or PSH (identical results for each).

Mold counts were below the detection limit (10^3 cfu/g) for every sample. Additives appeared to have effects on yeasts, but it was difficult to conclusively detect differences using the control group in comparisons, since one of the six replicates had a high yeast count and the remaining five replicates were at or below the detection limit. Counts in both LB and PSH were below the detection limit (10^3 cfu/g) for almost all samples, and it was not possible to determine if these results were any different from the control treatment. But all other treatments appeared to increase yeast counts by at least 2800-fold whether compared to the control samples with the high value omitted or to LB and PSH samples

The most concentrated VOC present in the silages (Table 2) was ethanol, which ranged from 1,440 to 10,100 mg/kg (0.15 to 1.0% of DM) based on mean values. The LB samples, where 1-propanol reached 10,200 mg/kg (1.1% of DM), were an exception. Silage additives had clear effects on production of some VOC, but in many cases additives actually stimulated their production (Table 2). *Lactobacillus buchneri* stimulated production of all three alcohols and both esters relative to the control treatment. The largest relative increase due to an additive was seen in this treatment, where 1-propanol was approximately 400-fold the control mean ($P < 0.001$). Additionally, 1,2-propanediol was about 1% of DM in these samples, but was not detected in any others. All additives except PSH substantially increased production of ethanol. The increase ranged from 2.0-fold ($P < 0.001$) by LB to 3.0-fold ($P <0.001$) by PA. Conversely, all treatments except LB and PSH reduced methanol production, albeit slightly—the largest reduction was 24% by PSL ($P < 0.001$).

Table 2. Mean concentrations of volatile organic compounds (mg/kg, DM basis) in corn silage treated with biological and chemical additives, measured using a headspace gas chromatography method[1]

	Treatments							*Pooled*
Item	*C*	*LB*	*LP*	*PA*	*PSL*	*PSH*	*M*	*SE*[2]
Methanol	538	696***	415***	450**	409***	470†	402***	0.0368
Ethanol	3450	6810**	8400***	10100***	7780***	1440***	9420***	0.138
1-propanol	25.6	10200***	43.3	47.7	42.3	14.1	38.6	0.309
Methyl acetate	9.91	28.9***	8.52	8.63	7.83	7.48*	8.85	0.0713
Ethyl acetate	20.5	168***	38.5**	61.8***	29.1	11.1**	47.7***	0.132
TOFP[3] ($\mathrm{O_3}$ mg/kg DM basis	5421.0	16529.5	12588.7	15111.3	11672.9	2428.5	14072.4	0.5

[1] Abbreviations used for means are: C, control; LB, *Lactobacillus buchneri 40788*, 400,000 cfu/g; LP, *Lactobacillus plantarum MTD1*, 100,000 cfu/g; PA, buffered propionic acid-based additive; PSL, potassium sorbate, 0.0091% of wet forage mass; PSH, potassium sorbate, 0.1%; M, *Lactobacillus plantarum MTD1*, 100,000 cfu/g, plus potassium sorbate, 0.0091%. Number of replicates was 6. Statistical significance is based on comparisons of each group to the control with a *t* test using the pooled standard error (*SE*) and the Bonferroni adjustment: †$P < 0.10$, *$P < 0.05$, **$P < 0.01$, ***$P < 0.001$.

[2] Pooled *SE* was calculated from $\log_{10}$-transformed values, and the values here are relative values calculated by $10^{SE_l} - 1.0$, where SE_l is the standard error of the $\log_{10}$-transformed values.

[3] Total Ozone Forming Potential (TOFP) was the sum of the 4 VOC concentrations multiplied by their Maximum Incremental Reactivity (MIR) values.

The high dose of potassium sorbate (PSH) was the only treatment that reduced concentrations of multiple VOC: it reduced ethanol by 58% ($P < 0.001$), ethyl acetate by 46% ($P = 0.0014$), and methyl acetate by 24% ($P = 0.0068$). Conversely, the low potassium sorbate treatment (PSL) increased ethanol production and did not reduce ethyl acetate concentration (42% increase, $P = 0.052$). Ethanol concentrations were more variable in the control samples than in most other groups, which affected the precision and power of all estimates of relative effects on production of this compound. The control sample with the highest ethanol concentration (9120 mg/kg, about 2.7-fold the mean value) was also the one with the most yeasts ($\log_{10}$ cfu/g = 7.20), but other variables were similar to mean values. To determine if the apparent reduction in ethanol by PSH was caused by a small number of particularly high samples in the control treatment, a comparison was made without this highest and without the control sample with the second-highest ethanol concentration (7460 mg/kg, about 2.2-fold the mean value). In this case the mean concentration in the control group was 2230 mg/kg, for an apparent reduction by PSH of 36% instead of 58% (95% confidence interval: 15% to 53% from a two-sample *t*-test).

It is possible that potassium sorbate can reduce production of other alcohols as well. The mean methanol concentration for PSH was slightly lower than the control, but the *P* value (0.014) was above the critical value. However, PSL did reduce methanol (described above). For 1-propanol, the PSH mean was about 50% smaller than the control mean, but there was some overlap between the two groups, and the comparison *P* value (0.13) was much higher than the adjusted critical value. Additional experiments will be needed to assess effects on these compounds. Importantly, there is no evidence that PSH increased production of any VOC.

Ester concentrations were strongly correlated with their respective alcohols and acids. Based on least-squares regression using results from individual samples, the concentration of ethyl acetate could be related to ethanol (e) and acetic acid (a) concentrations (all in mg/kg) by: $-31.6+0.00465e+0.00291a$ (adjusted $R^2 = 0.958$, $P < 0.001$ for each term). Similarly, methyl acetate could be related to methanol (m) and acetic acid by: $-4.11+0.0194m+0.000338a$ (adjusted $R^2 = 0.957$, $P < 0.001$ for each term).

Only one bucket showed signs of air infiltration: mold was present at the surface of a low potassium sorbate replicate, but measured variables for this silage were similar to the other replicates and it was not excluded. In general, there was little evidence that storage duration of vacuum-packed samples at 4°C affected VOC concentrations. Only ethyl acetate in the control ($P = 0.007$) and PSL ($P = 0.024$) treatments, and ethanol in the control treatment showed significant responses to storage duration (all positive, 0.96% d^{-1} or less). An overall effect of storage duration was detected for ethyl acetate only ($P = 0.0046$), but this appeared to be due to the apparent responses in the control and PSL samples. There were no clear trends with storage duration for other treatments.

Discussion

With the exception of PSH, the additives evaluated here were not effective at reducing VOC production under these ensiling conditions. It is useful to understand why these additives increased VOC production. Ethanol is the single most important VOC, but understanding effects of additives on production of this alcohol can be challenging, since it is produced by at least four groups of microorganisms present in silage: lactic acid bacteria, enterobacteria, clostridia, and yeasts (Hafner et al., 2013). Increases in ethanol production by LP, PA, PSL, and M are difficult to explain. Yeast activity may have played a role because, except for LB, all treatments resulted in higher yeast counts than PSH. But why yeasts may be stimulated, or less inhibited, when these additives are used is not clear. Alternatively, the ethanol increase due to LP and M treatments could be due to direct production through the facultative heterolactic fermentation by *Lactobacillus plantarum*. An increase in ethanol production due to addition of bacterial additives is not uncommon (Steidlová and Kalac, 2003; Kleinschmit et al., 2005; Tabacco et al., 2009; Queiroz et al., 2013). Increased ethanol production has also been reported in response to addition of a formic and propionic acid mixture (Weiß and Auerbach, 2012), but the mechanism is not clear.

The strong correlations between the acetate esters and alcohols and acetic acid suggest that reducing alcohol production will reduce ester production also, and so effects of additives on esters can largely be explained by effects on alcohols and acids. Correlation between ethyl esters and ethanol has been observed before and has been cited as evidence of abiotic esterification reactions in silage (Weiß and Auerbach, 2009; 2012; 2013). However, PSH reduced methyl acetate production without a clear change in methanol, which is not consistent with this explanation. Limited statistical power for detecting an effect on methanol may underlie this apparent inconsistency. Implications of alcohol conversion to esters for air quality are probably insignificant. The tendency of esters to form ozone is less than for alcohols, and so production of esters at the expense of alcohols would actually reduce effects on air quality. However, the low concentrations of esters compared to alcohols, shown here for just two esters but for other esters for corn silage in general (Hafner et al., 2013; Weiß and Auerbach, 2009; 2012; 2013; Gerlach et al., 2013) limit the impact of this conversion.

Concentrations of alcohols measured in these silage samples are within the wide range of values reported in earlier studies, as summarized by Hafner et al. (2013). But ester concentrations measured in this study are lower than those reported in other studies summarized in this work (Hafner et al., 2013) and reported since then (Gerlach et al., 2013). Gerlach et al. (2013) found mean ethyl acetate concentrations of 138 to 400 mg/kg in corn silage made with different chopping lengths and densities. In our measurements, the mean methyl acetate concentrations ranged from 7.5 to 29 mg/kg, and mean ethyl acetate ranged from 11 to 170 mg/kg. Variability in VOC concentrations among silages can be very high; based on empirical tolerance intervals for a set of silage samples from within the US, Hafner et al. (2013) estimated that 25% of silage samples will have ethanol and ethyl lactate concentrations more than a factor of 2.4 of the median value. The differences between the concentrations we measured and those reported in previous studies may be the result of this variability, but may also be due to biases of the measurement techniques.

The primary sources of methanol in silage have not been identified, but this compound may be produced from pectin demethylation catalyzed by plant enzymes (see review in Hafner et al., 2013). It is not clear why additives would affect this process, which can occur after harvest before additives are added.

In contrast with the other additives, the effects of LB on silage composition are consistent with the current understanding of this bacterium. *Lactobacillus buchneri* is added to silage to improve aerobic stability, which is thought to be a result of the higher acetic acid concentrations resulting from conversion of lactic acid to acetic acid (Oude Elferink et al., 2001) but could be due to other substances as well. However, *L. buchneri* is not recommended for wet silages, where it grows particularly well and can consume so much lactic acid that pH is substantially elevated (Nishini and Touno, 2005; Schmidt et al., 2005). This additive was probably not appropriate for the wet silage used in this work. *Lactobacillus buchneri* can produce ethanol directly through heterolactic fermentation of carbohydrates (Oude Elferink et al., 2001). Additionally, it produces 1,2-propanediol (Oude Elferink et al., 2001), which can result in propionic acid and 1-propanol production by the *Lactobacillus diolivorans* (Krooneman et al., 2002). Therefore, the increases in ethanol, 1,2-propanediol, propionic acid, 1-propanol compared to the control group, along with the effects on lactic and acetic acid described above, are consistent with high activity of *L. buchneri*. However, some of these effects are not typically observed for this inoculant. Conversion of lactic acid to acetic acid is generally more limited, propionic acid increases are typically not observed, and ethanol is not typically elevated when *L. buchneri* is used for corn silage (Kleinschmidt and Kung, 2006). Effects on ethanol and the organic acids are probably due to the stimulation of *L. buchneri* by high moisture. Whether the high moisture also affected the activity of *L. diolivorans* and therefore production of propionic acid and 1-propanol, or the population of this or related bacteria was particularly high for this forage is unknown. Effects of *L. buchneri* addition on 1-propanol have generally not been reported, but in at least two studies, addition of ≥ 100,000 cfu/g of *L. buchneri* led to large increases in production of the compound, up to 7160 mg/kg (Kristensen et al., 2010), and 14200 mg/kg (Driehuis et al., 2001), which encompass the mean observed in the LB samples. The reactivity of 1-propanol is higher than for ethanol (Carter, 2009), so effects of *Lactobacillus buchneri* on air quality will depend on 1-propanol production. For the LB samples, the potential effect of 1-propanol on air quality is about twice the effect from ethanol (based on the product of concentration and EBIR from Carter (2009)). At least for the wet silage used here, *L. buchneri* appears to be a very poor additive for the purpose of reducing VOC production. Additionally, the effects of this additive provide an example of potential complexities of additive effects on air quality. If 1-propanol were not measured, the potential effect of this treatment on air quality would be substantially underestimated, and in cases where ethanol production was suppressed, the direction of the estimated effect could be wrong.

The only treatment we evaluated that could reduce VOC emission under conditions of this study was PSH. The 58% reduction in ethanol based on all data is comparable to other studies summarized in the introduction (Kleinschmit et al 2005; Teller et al., 2012; Weiß and Auerbach, 2012; Queiroz et al., 2013; Auerbach and Nadeau, 2013; Bernardes et al., 2014), although smaller. The response of ethyl acetate to PSH was nearly identical to the result from Weiß and Auerbach (2012) in response to a sodium benzoate and potassium sorbate mixture. Our results provide further evidence that a sufficient dose of potassium sorbate can reduce ethanol production and the production of two esters, even under wet conditions. The mechanism behind the reduction in ethanol and ethyl acetate is probably inhibition of yeasts, although inhibition of enterobacteria could also play a role. It is surprising that the effect of a lower dose of this additive (PSL), which approximates the concentration most commonly used in practice, appeared to stimulate ethanol production.

It will be important for future research to evaluate the effect of PSH on production of these, and, ideally, other VOC. There were features of this study that may affect VOC production, and so other studies may find different VOC concentrations and possibly different effects of silage additives. The DM content, chemical composition, and composition of the native microbial population all could influence VOC production. And in this particular experiment, the ensiling period (303 days) was relatively long, which could influence both total production of different VOC and also relative effects of additives, since at least ethanol can be produced by multiple groups of microorganisms. The type of water used to dilute the microbial additives could affect their activity—here, we used distilled water, while tap water is typically used in the field. Additionally, microbial activity could have continued in vacuum-packed samples after the bucket silos were opened. The small amount of oxygen present in the samples immediately after vacuum packing could have stimulated growth of yeast or other microorganisms, which might have increased or decreased VOC concentrations through partial or complete oxidation, and also increased yeast counts. Gerlach et al. (2013) reported that ethanol and ester concentrations increased during storage of corn silage at room temperature in vacuum-packed samples, but increases were only observed for samples initially exposed to air for more than four days (Katrin Gerlach, University of Bonn, Bonn, Germany, personal communication). The samples in this work were exposed for less than five minutes. Some oxygen exposure usually occurs during full-scale silage production, so these conditions were not unlike typical silage production, but a more typical ensiling period and more controlled storage conditions would be better.

Conclusions

Silage additives can reduce production of volatile organic compounds in corn silage, but not all additives are equivalent. Addition of potassium sorbate at 0.1% (fresh forage mass basis) can substantially reduce production of ethanol, methyl acetate, and ethyl acetate, but a lower dose (91 mg/kg fresh weight) can increase VOC production. A commercial propionic acid-based product and the biological additives evaluated here can stimulate production of ethanol and ethyl acetate (and possibly 1-propanol) in corn silage. Regulations aimed at reducing VOC emission could be ineffective or even increase emission if they promote silage additives without recognition of different types of additives. Future work should be carried out to evaluate the effectiveness of potassium sorbate under different conditions, and at different doses. Additionally, it will be important to evaluate the effect on production of aldehydes.

Chapter 3 - Measurements of the Emission Reduction Benefits of Mitigation Strategies for Silage

Task 2: Emissions of VOCs and NOx from various defacing methods
Task 3: Emissions of VOCs and NOx from storage types
Task 4: Emissions of VOCs and NOx from TMR treated with water vs raw silage

Abstract

Silage management continues to be critical component of the dairy industry both economically and environmentally. The purpose of the present study was to identify air emission mitigation options for the silage storage and feed-out phases. The three main tasks were 1) to evaluate the emissions of VOCs and NOx from different silage storage types (conventional silage piles vs. silage bags), 2) to study the emissions of VOCs and NOx from different silage defacing methods, 3), and to reduce emissions of VOCs and NOx from a total mixed-ration (TMR) in the feedlane through the addition of water[2]. Experiments were conducted comparing emissions between conventional silage piles and silage bag using flux chambers that were attached vertically on the silage face immediately after de-facing (aka extraction) of silage material. Furthermore, different de-facing methods such as perpendicular, lateral, and EZ rake extraction, were compared to quantify the effects of extraction method on air emissions. Finally, the inclusion of water into the TMR at 0%, 5%, and 10%, aiming at emission reduction, were tested using flux chambers and monitored for 23 h. Overall, the scope of the present monitoring study was to measure emission losses from storage, and feed-out processes and to generate data to inform and validate a prediction model for silage air emissions (see chapter 4). The results indicated that silage bags vs. conventional silage piles emit fewer emissions when comparing the total exposed silage faces. When comparing different types of defacing methods, the lateral defacing technique appeared to emit fewer emissions compared to the EZ rake and perpendicular defacing. Finally, reducing emissions in the feedlane is possible by use of water to the TMR. Overall, the results of the present Chapter 3 shall not be viewed in isolation, because only the integration with the modeling results from Chapter 4 explain not just the relative- but also the absolute effectiveness of mitigation techniques in reducing VOCs and NOx on California dairies.

Introduction

Central California's San Joaquin Valley (SJV) has the highest concentration of dairy cows (Agricultural Statistics Board, 2008) in the United States. The SJV has long suffered from some of the country's worst air pollution (US EPA, 2008), and in particular high tropospheric ozone levels. The US Environmental Protection Agency (EPA) has designated the SJV as an "extreme non-attainment" area based on the federal 8-hour ozone standard. In order to attain the standard, the reduction of the ozone precursors including VOCs and NOx from all major sources is imperative.

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[2] Many oxygenated VOCs have a high affinity to stay in the liquid vs. the gas phase. The application of water to the feed is intended to make the VOCs stay in the liquid phase and to prevent them from volatilization into the atmosphere.

Silage is among the leading operational costs and a critical feed commodity on dairies and its continued use is essential to a highly productive and economically viable dairy industry. It is natural to assume that environmental gains can and must be made from mitigation research relating to VOC and NOx emissions from silage on dairies. There are also highly compelling economic reasons to pursue mitigation research, as the reduction of VOC emissions from silage can reduce the loss of nutrients and increase cow productivity and thus, the industry's economic potential. Emission losses are economic losses.

Our previous work conducted at UC Davis, showed that among various emission sources on dairies, silages were the largest source of both VOCs and NOx, posing a significant source of ozone precursors in the San Joaquin Valley (Howard et al. (2010). Alcohols, VFA, aldehydes, and multiple species of NOx were shown to be emitted from silage sources. Ethanol and methanol accounted for the majority of total VOCs emitted from silage sources but isopropanol, acetic acid, and acetyl-aldehyde were other major compounds emitted (Malkina et al., 2010, Zhang et al., 2010).

The VOCs and NOx gases are emitted during the distinct phases of the silage/feeding process, which include:

- The aerobic phase: when chopped material is piled, compacted, and covered,
- The fermentation phase: when silage material is sealed and fermented,
- The storage phase: when silage material is sealed and few emissions released,
- The feed-out phase: during which silage material is removed from the face daily,
- The daily mixing phase: when silage is mixed with other feedstuffs in a mixer wagon, and
- The daily feed-lane phase: during which feed is placed in the feed lanes.

For the purpose of the present study, the silage life cycle is defined by four production phases (aerobic, fermentation, storage, and feed-out phase, the latter including defacing, TMR mixing, and feed-lane feeding. Our recent research (see page x of the present report for a listing of peer reviewed papers related to silage topics) revealed the initial ensiling phase as the time of significant NOx release, yet its measurement is highly complex and even dangerous due to the toxic properties of these NOx gases and related safety concerns to the investigative team. The closed storage phase at which the pile is covered, produces minimal gaseous losses because the pH is too low for microbial activity. The open-face storage phase in which silage is extracted to feed cows, is clearly the major VOC loss phase of the pile: compounds are exposed to the atmosphere for many hours and dependent on the wind, temperature, and volatility of the compound, losses can occur rapidly. Finally, the mixing and feeding phases significantly contribute to losses of VOCs from dairies. Indeed, the actual feeding of cows at which feed is spread out over a relatively large area (i.e. feedlane in front of the cows) is the greatest contributor to gaseous losses on dairies (as shown in Chapter 4 of this report).

Earlier published work from our lab on monitoring and modeling of different silage types during numerous phases, showed high concentrations of emitted alcohols and other oxygenated species and lower concentrations of highly reactive alkenes and aldehydes (Malkina et al., 2011). Emission profiles also differ distinctively across silage/feeding phases. To complement our understanding of the complex issues around silage emissions on dairies, additional monitoring and modeling of these emissions throughout the entire life cycle of the feed were essential to be conducted on commercial dairies for the assessment of, and response to, the specific needs of the regional air quality in the SJV.

The present research for monitoring in described in Chapter 3 (and for modeling in Chapter 4) primarily addresses mitigation techniques/technologies outlined in SJVAPCD Rule 4570, addressing VOC and NOx emissions. The research was largely conducted on commercial dairy farms and assessed the effectiveness of Rule 4570 mitigation practices: namely different pile storage methods, de-facing practices, and feed moisture management.

Materials and Methods

General

Corn silage was made from the fields neighboring a dairy farms in the SJV of California. The chopped corn was placed in two types of storage systems: a conventional silage pile and a silage bag. Whole-plant corn was harvested at approximately 30% dry matter using a commercial flail chopper, providing a chop forage material with a cut length between 1 and 2 cm. The commercial flail chopper excavated an area of approximately 7.0 km for a week. Trucks drove adjacent to the chopper to facilitate continuous operation and transport the chopped forage to the silage storage site. Transport trucks reversed into the LX1214 Professional Silage bagger (Ag-Bag, WI). The silage bagger simultaneously pushed the truck forward and packed the silage into the silage bag in a straight line (see Photo 1 and 2). Trucks not used for the silage bagger were sent to a nearby location on the farm to form a conventional silage pile. An area of 1,020 m^2 was designated for the conventional silage pile. Wheel tractors were used to compact the freshly unloaded chopped corn, in a drive-over fashion. The compaction continued until the apex of the pile reached a height of 6.1 m. The pile was covered with two layers of gas tight plastic cover material and the plastic held against the silage surface using recycled tires to prevent oxygen exposure. Silage bags were sealed for approximately one week. The silage bag was monitored for excessive gas build up, if notable, gaseous pressure was released via small cut in the fabric. Once the silage bag stopped releasing gas, the so-called “blow hole” was sealed and patched.

The present gas monitoring research involved three separate main aspects: collection of silage core samples for GC analysis (for use in a concurrent modeling study; Chapter 4), the inclusions of water at 0%, 5%, and 10% of the TMR, and direct air emission monitoring from the silage face.

Photo 1. Chopped corn being delivered by truck into the ensiling machine.

Photo 2. The open tray area for chopped corn collection, and the silage bags (white) being filled at the dairy.

Sampling Equipment

The Mobile Agricultural Air Quality Laboratory (MAAQ Lab) measured ethanol, methanol, ammonia, NO, N_2O, NO_2, and methane.

The following equipment was available in the MAAQ Lab for real time sample collection and analysis.

1. An automatic control and data acquisition system,
2. An automatic gas sampling system,
3. An infrared photo-acoustic multi-gas INNOVA 1412 analyzer,
4. A TEI 55C methane and non-methane hydrocarbon analyzer,
5. A TEI 17i NH3 analyzer,
6. A TEI 46i N_2O analyzer.
7. Four flux chambers,
8. Two wind tunnels,
9. An Environics 4040 Gas dilution system.

In addition to the equipment listed above, both gas and solid samples were collected using bags and sorbent tubes, respectively, for laboratory analyses to be later conducted in UC Davis laboratories using GC, GCMS, and HPLC.

Following is a detailed description of the analytical equipment that was used.

Automatic control and data acquisition system

The automatic control and data acquisition system consisted of an industrial grade desktop computer, interface hardware, and interface software based on the Labview (National Instruments, TX) program. The system controls sample collection sequence and timing, acquires data from all analyzers and sensors, and sends the images of computer screen to registered users over internet for remote review of the current operational status.

Automatic gas sampling system.

The automatic gas sampling system involved an 8-port rotary valve, a manifold, a Teflon coated sampling pump, a bypass pump, a sampling flow meter, a temperature sensor, a relative humidity (RH) sensor, a pressure sensor, Teflon tubing, and particle filters. The sampling system collected gas samples from 8 different locations in sequence controlled by the automatic control and data acquisition system. Gas samples were pulled into the system by the Teflon coated pump through the rotary valve and fed to analyzers through the manifold. Sample lines that were not currently selected by the rotary valve for analysis were connected to the bypass pump for purging to keep the air in these sample lines fresh. All sensors of temperature, RH, pressure, and flow meter were used to monitor the performance of the gas sampling system.

INNOVA 1412 analyzer

The INNOVA 1412 (LumaSense Technologies Inc., Ballerup, Denmark) analyzer is an infrared (IR) photoacoustic multi-gas analyzer, which measures up to six gases including water vapor.methanol and ethanol in sequence . In addition to its ability for multi-gas measurement, the INNOVA 1412 is a sensitive gas analyzer and has a wide dynamic measurement range. Measurement ranges for methanol and ethanol were 0-14000 ppm and 0-8000 ppm with detection limits of 0.14 and 0.08 ppm, respectively.

TEI 55C methane and non-methane hydrocarbon analyzer

The TEI 55C (Thermo, MA) is a stable gas analyzer that can accurately measure methane in a wide range from 0 to 1000 ppm with 20 ppb detection limit using a Flame Ionization Detector (FID). Although the TEI 55C can also accurately measure non-methane hydrocarbons in a wide range, the non-methane hydrocarbon data were not used because these hydrocarbons cannot be separated.

TEI 17i NH_3 analyzer

The TEI 17i (Thermo MA, USA) is a chemiluminescence NH_3 analyzer. It directly measures NO, NOx ($NO+NO_2$), NOt ($NO+NO_2+NH_3$) separately by converting both NO_2 and NH_3 to NO. The difference between NOx and NO is NO_2 (NO_2=NOx-NO) and the difference between NOt and NOx is NH_3 (NH_3=NOt-NOx). The measurement ranges for NO, NO_2 and NH_3 were 0-20 ppm and the detection limit was 1 ppb

TEI 46i N_2O analyzer

The TEI 46i (Thermo, MA) is an infrared gas analyzer that can accurately measure N_2O in the range of 0-50 ppm at 0.02 ppm detection limit using a gas filter correlation technology.

Table 3 summarizes the detection limits and measurement ranges of each gases measured by above mentioned gas analyzers.

Table 3. Measurement ranges and detection limits of gas analyzers used in this study.

Gases	Molecules	Gas Analyzers	Detection limit (ppb)	Measurement range (ppm)
Methane	CH_4	Thermo 55C	20	0 - 1000
Nitric Oxide	NO	Thermo 17i	1	0 - 20
Nitrogen Dioxide	NO_2	Thermo 17i	1	0 - 20
Ammonia	NH_3	Thermo 17i	1	0 - 20
Nitrous Oxide	N_2O	Thermo 46i	20	0 - 20
Methanol	MeOH	Innova 1412	140	0 - 14000
Ethanol	EtOH	Innova 1412	80	0 - 8000

Flux chambers

Flux chambers can be used to determine air emission rate by measuring the gas concentrations, air ventilation rate, temperature, RH, and pressure in the monitoring environment. Flux chambers are suitable for emissions from small surface areas at any location, including commercial dairies. Because the ventilation rate is low in flux chamber sampling, gas concentrations inside the flux chamber can be measured using our gas analyzers. Although the flux chamber cannot be used to simulate the wind speed over a small surface area, this method has been widely used to determine the air emission rate.

The flux chambers (Odotech Inc., Montreal, Canada; see Photo 3) are made of acrylic resin with a volume of 64.5 L and consists of a cylindrical enclosure with a spherical top. Teflon tubing (50 cm, 6.35 mm OD) is installed around the inside circumference of the chamber to allow air to circulate throughout the chamber when connected to a compressed air distribution system. An opening on top of the chamber (fitted with a stainless steel Swagelok connector) is used to sample air. Of the remaining two openings on the flux chamber top, one is used for the thermo couple, and the other allows extra air to escape and equalized inside pressure while sweeping air and sampling (Sun et al., 2008).

Gas dilution system

The Environics 4040 (Environics Inc. CT) gas dilution system is used to mix the standard calibration gas with ultra-zero air to produce variable concentration gas mixture for multi-points calibration of gas analyzers. The current dilution rate of this dilution system was 100:1.

Safety Container

To ensure that researchers could safely work without the associated risks of silage avalanche, a 3m by 2m by 2m industrial safety container was used (see Photo 4). The safety container was fitted with a 2.4m wide roll-up door on the side, a 1m man door on the end, and a 36cm turbine vent on the roof. The safety container was moved to the desired location alongside the face of the silage pile with the use of a fork lift that had fork extensions. All silage face monitoring using the flux chambers, were conducted from within the safe environment of this safety container.

Photo 3. Flux chamber and wind tunnel sampling silage face within protective shipping container.

Photo 4. Safety container positioned next to defaced conventional silage pile via forklift.

Silage Sample Preparation

Silage core samples were obtained using a drill driven spiral-assisted uni-forage sampler (Star Quality Samplers Inc. AB, Canada) at a depth of 30cm. Samples were extracted from the silage core sampler and placed immediately into an airtight plastic bag. These bags were depressed and manually evacuated prior to being placed on dry ice.

Samples on dry ice were transported back to UC Davis for silage analysis. Sample preparation included placing 10 g of silage (±0.1) into a 120 ml plastic bottle. Then, 90 g of DI water (±0.1) were added to the 120 ml plastic bottle. Bottles were tightly closed and inspected for any leaks. The plastic bottles were placed on the wrist action shaker for 30 min. Post wrist action shaker, the samples were analyzed for pH. Samples were then centrifuged for 10 min at 5000 rpm. Supernatant was filtered using a 0.45 µm. Samples were acidified using ortho-phosphoric acid (10%) to a pH <2 before the injection into the GC. The GC conditions included DB wax 530µm × 30 m. Helium was used as a carrier gas at a flow rate of 5 mL min $^{-1}$. Oven temperature increased from 40°C by 5°C min-1 to 60°C, held for 1 min, and then increased by 25°C min-1 to a final temperature of 160°C. Inlet and detector temperatures were set at 170°C and 270°C, respectively. The VFA standards used for GC analysis included acetic acid, propionic acid, butyric acid, iso-butyric acid, valeric acid, and isovaleric acid.

Silage Emission Monitoring

Dairy staff defaced the silage piles twice a day for feedings at 0300h and 1200h. The safety container was placed against the silage face immediately following extraction. The flux chambers were set up vertically against the face of the silage face (see Photo 2) and inside the shipping container, then the flux chambers were connected using Teflon tubing to the MAAQ Lab. Gas sampling began within 30 min of defacing. The safety container and related equipment were removed prior to the 0300h feeding to minimize interference with dairy farm management. Datalogger probes (HOBOs) (Onset Computer Corporation, MA) were placed inside the flux chamber and safety container to continuously monitor for temperature, relative humidity, and moisture. The analyzers in the MAAQ Lab recorded the concentration of CH_4 (ppm), N_2O (ppm), NO (ppb), NO_2 (ppb), NH_3 (ppb), MeOH (ppm), and EtOH (ppm) every minute electronically. The emission rate of CH_4 (g/hr/m$^{2)}$, N_2O (g/hr/m$^{2)}$, NO (mg/hr/m$^{2)}$, NO_2 (mg/hr/m$^{2)}$, NH_3 (mg/hr/m$^{2)}$, MeOH (g/hr/m$^{2)}$, and EtOH (g/hr/m$^{2)}$ were determined in 1h averages for 14h.

Emission Calculations

Concentration samples analyzed in the flux chambers over the 15 minute period were truncated to remove the first five minutes and last two minutes of sample to prevent carry over effects. Total flux (mg/hr) was then calculated using the following equation:

$$Total\ flux = \frac{MIX \times FL \times 60}{V} \times MW \times Conv$$

where *MIX* is the concentration in either ppm or ppb, *FL* is the ambient air flow rate at 20 L/min, 60 is the conversion from minute to hour, *MW* is the molecular weight in grams per mole, *Conv* is a conversion factor of 10^{-3} for concentration in ppm and 10^{-6} for concentration in ppb, V is the volume of one molar gas at temperature T in liter/mole and is calculated as:

$$V = \frac{V_s \times T}{T_s}$$

where Vs is the standard volume 22.4 liters at 0^0C, T_S is the standard temperature 0^0C that equals to 273.15 K, T is the air temperature in K equaling to T in ^{0}C +273.15.

The emission rate by surface for the flux chambers (mg/hr/m^2) was calculated by:

$$Emission\ rate = \frac{Total\ Flux}{Surface\ area}$$

Water Inclusion on TMR and Silage

The effect of water inclusion rate into the TMR was measured at 0%, 5%, and 10%, respectively (see Photo 1). Total mixed ration samples were removed from the mixer wagon after mixing was complete and measured into 2 kg samples. All samples were collected at 1215 h and placed under the flux chambers by 1230 h. Samples were treated with the above water inclusion rates and placed under flux chambers for gas monitoring. The 2 kg sample was placed immediately under the flux chamber. Water was added to the TMR or raw silage samples, respectively. The samples were hand mixed for a homogenous sample and placed under the flux chambers. Gas measurements were collected for 23 hours. Three replications were performed and each included: a control (0% water), 5% water, 10% water, and raw corn silage for comparison.

Task 2: Emissions of VOCs and NOx from various defacing methods

Emissions of VOCs and NOx from the silage defacing process were compared using three types of extraction methods. The first extraction method was using a standard front-end loader parallel to the face. The second extraction method was a standard front-end loader defacing in a perpendicular fashion to the face. The third extraction method was using a de-facer attachment that had a rake-like appendage (aka EZ rake, Hanson, MN; see Photo 5). Using the first extraction method, the standard front-end loader defaced the pile in a lateral fashion or parallel to the face (aka smoothing action; see Photo 6). For the second extraction method, the front-end loader de-faced the pile in a frontal, perpendicular fashion (aka jagged action). Finally, for the third extraction method, the front-end loader received a rake attachment and during de-facing, the vehicle approached the pile in a perpendicular fashion (similar to the first), but extracted the face by combing the surface from top to bottom effectively shaving the surface layers (again, see Photo 6). During the present study, each method was conducted and measured for three days. Immediately after silage extraction, flux chambers were placed on the freshly excavated silage surface and connected via Teflon tubing directly to the MAAQ Lab and associated analyzers for measurements.

Photo 5. Standard front-end loader with quick connect to EZ rake attachment.

Photo 6. EZ rake defaced surface on left and lateral defaced surface on right of a conventional silage pile

Task 3: Emissions of VOCs and NOx from storage types

Emissions of VOCs and NOx from conventional silage piles were compared to those of silage bags during the open-face phase. The flux chamber was placed on each open face after perpendicular extraction with the standard front-end loader. The flux chamber was also connected via Teflon tubing directly to the MAAQ Lab and associated analyzers for measurements.

Task 4: Emissions of VOCs and NOx from TMR treated with water vs raw silage

Emissions of VOCs and NOx were analyzed from the TMR with water added at 0%, 5%, and 10% inclusion rate. Raw corn silage was also evaluated for VOCs and NOx emissions but without the addition of water (see Photo 7). The TMR was removed directly from the feed wagon and measured into 2 kg samples. The 2 kg samples were adjusted to appropriately incorporate the water percentage mentioned above.

Photo 7. Flux chambers located outside the MAAQ Lab sampling water inclusion rates and silage.

Results and Discussion

The present study shows effects of numerous silage storage and management schemes on gas emissions. The results from the current study (Chapter 3) were used to refine and validate our silage emission model (see Chapter 4).

Continuous monitoring of seven key gases including methane, ammonia, nitric oxide, nitrous dioxide, nitrous oxide, ethanol, and methanol was conducted for all experiments.

Defacing Method and Emissions on Conventional Silage Pile

The effects of defacing methods on the emissions of seven key gases (Figures 1-7) were reported as g/d/m^2 or mg/d/m^2 depending on the gas per surface area covered by the flux chamber. While measurement variability (expressed as standard deviation) were sometimes considerable, Figures 1-7 seem to show that lateral vs. perpendicular de-facing lead to fewer emissions. The EZ rake treatment did not seem to offer advantages in lowering emissions when compared to perpendicular extraction. The EZ rake treatment showed particularly high variability across different sampling dates. For most gases the EZ rake showed equal or greater emissions compared to perpendicular defacing. The defacing method greatly affects the roughness of the face and lateral defacing leads to the lowest roughness when compared to perpendicular and EZ rake de-facing. The lateral defacing treatment seems to be advantageous in reducing gaseous emissions during the defacing phase.

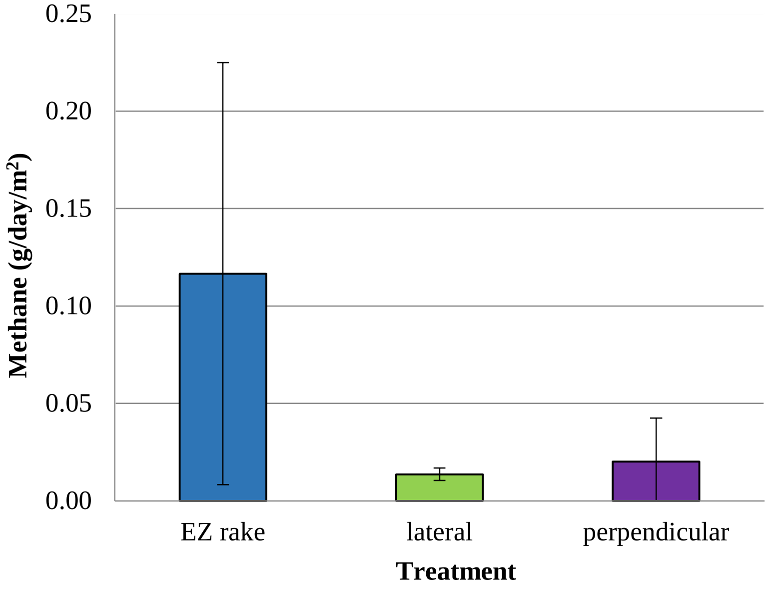

Figure 1. Means of lateral, perpendicular, and EZ rake defacing on methane (CH_4) emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

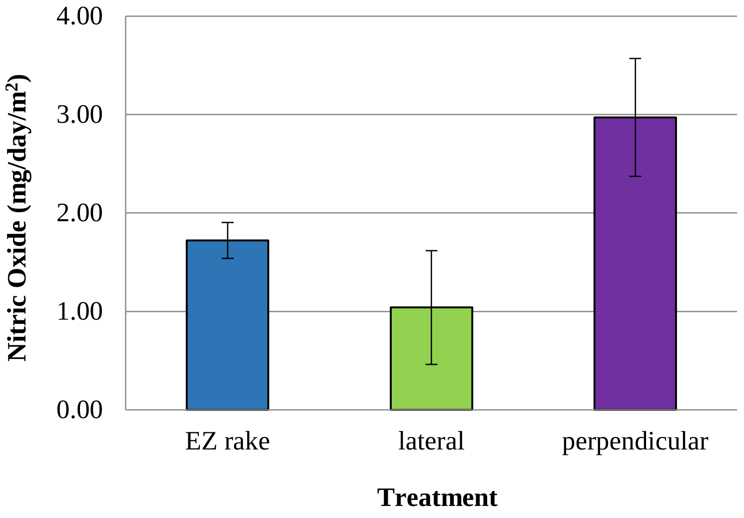

Figure 2. Means of lateral, perpendicular, and EZ rake defacing on nitric oxide (NO) emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

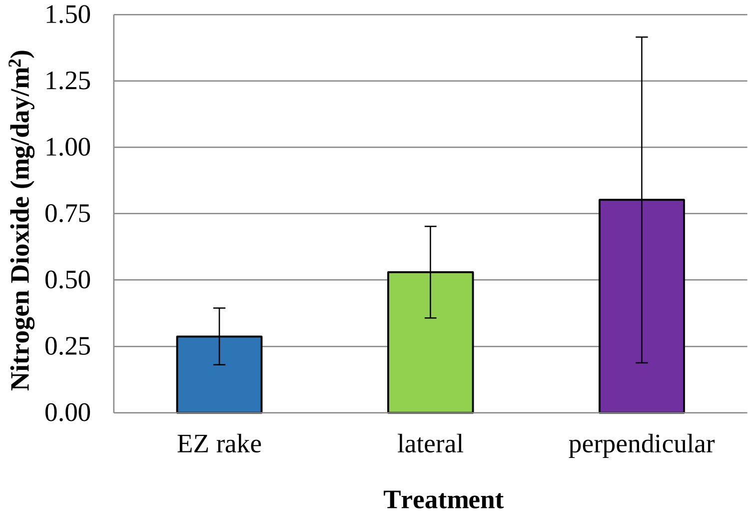

Figure 3. Means of lateral, perpendicular, and EZ rake defacing on nitrogen dioxide (NO_2) emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

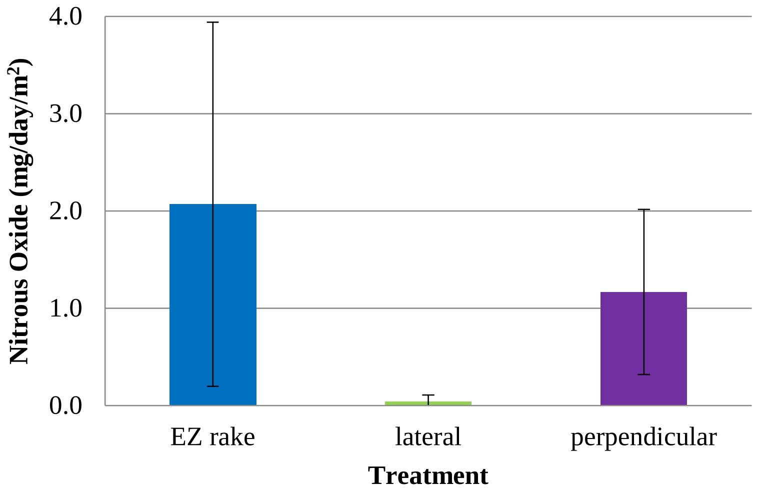

Figure 4. Means of lateral, perpendicular, and EZ rake defacing on nitrous oxide (N_2O) emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

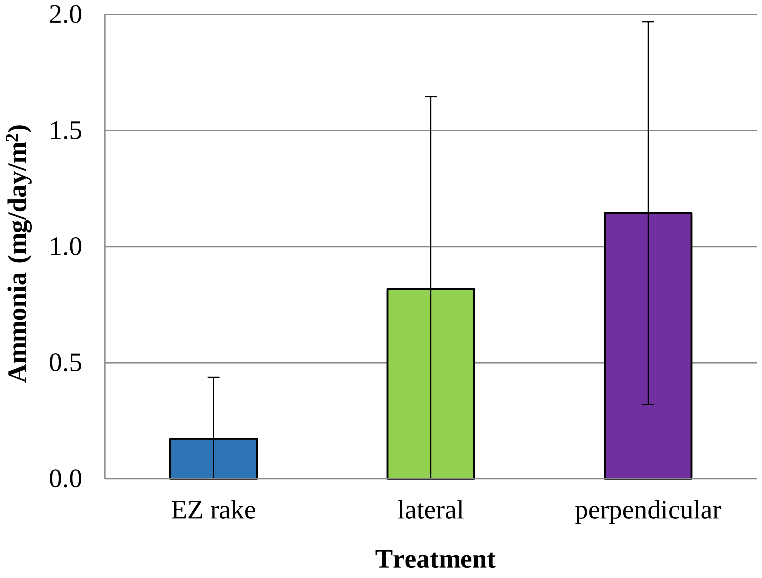

Figure 5. Means of lateral, perpendicular, and EZ rake defacing on ammonia (NH_3) emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

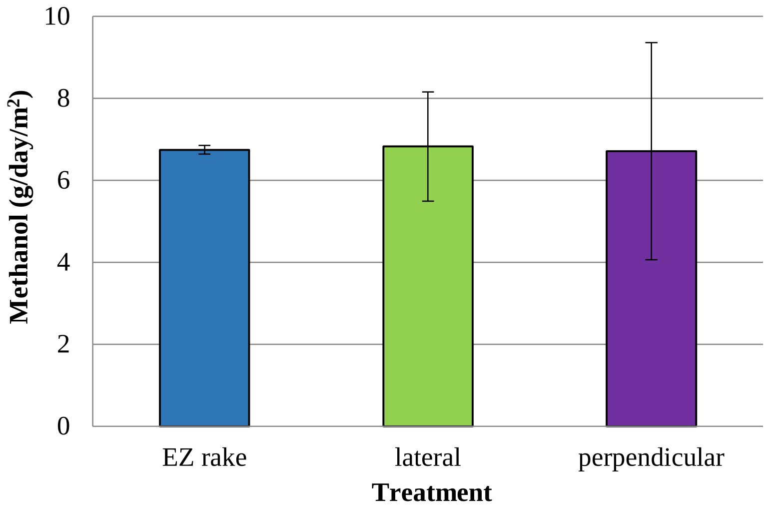

Figure 6. Means of lateral, perpendicular, and EZ rake defacing on methanol (MeOH) emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

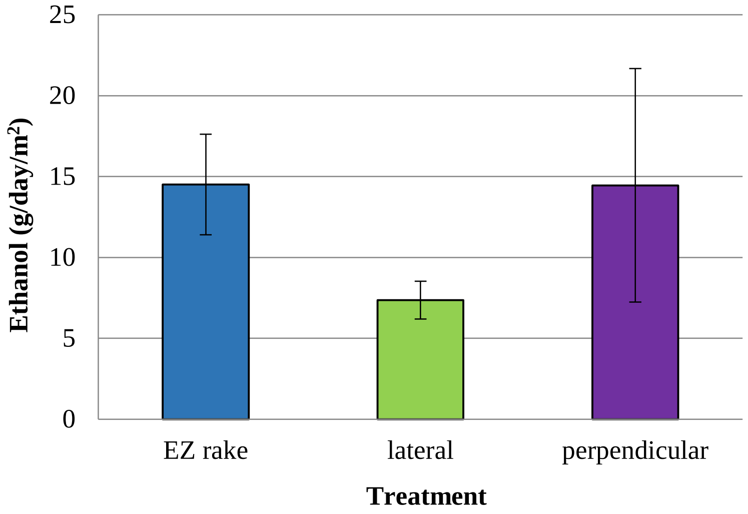

Figure 7. Means of lateral, perpendicular, and EZ rake defacing on ethanol (EtOH) emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

Table 4 summarizes the results of Figures 1-7 comparing the emissions across different defacing methods.

Table 4. Comparisons of gas emissions from different defacing methods

	Defacing treatment		
Gas Emissions	**EZ rake**	**lateral**	**perpendicular**
Methane (g/day/m^2)	0.12 ± 0.11	0.01 ± 0.00	0.02 ± 0.02
Nitric Oxide (mg/day/m^2)	1.72 ± 0.18	1.04 ± 0.58	2.97 ± 0.60
Nitrogen Dioxide (mg/day/m^2)	0.29 ± 0.11	0.53 ± 0.17	0.80 ± 0.61
Nitrous Oxide (mg/day/m^2)	2.07 ± 1.87	0.04 ± 0.07	1.17 ± 0.85
Ammonia (mg/day/m^2)	0.17 ± 0.26	0.82 ± 0.83	1.14 ± 0.82
Methanol (g/day/m^2)	6.74 ± 0.11	6.83 ± 1.33	6.71 ±2.65
Ethanol (g/day/m^2)	14.52 ± 3.11	7.36 ± 1.17	14.46 ± 7.21
TOFP[1] (O_3 g/day/m^2)	25.43	15.11	25.33

[1] TOFP: Total Ozone Forming Potential of Methane, Methanol, and Ethanol

Emissions between Face Emissions of the Conventional Silage Pile vs. Silage Bag

Figures 8-14 show measured and calculated emissions from the entire silage face of the two silage storage methods. The difference in surface area between the silage bag exposed face and conventional silage pile exposed face is approximately a factor of 10 (the exposed surface of the conventional silage face was 460m^2 compared to the exposed silage bag face was 43m^2).

Once the factor of 10 is applied (460m^2 vs. 43m^2) to correct for face area differences and the two storage methods are compared by exposed face, one can clearly see the conventional silage pile emitting far more of the seven gases compared to the silage bag (expect for N_2O). The difference in measured emissions is a function of the surface area difference between the silage storage systems.

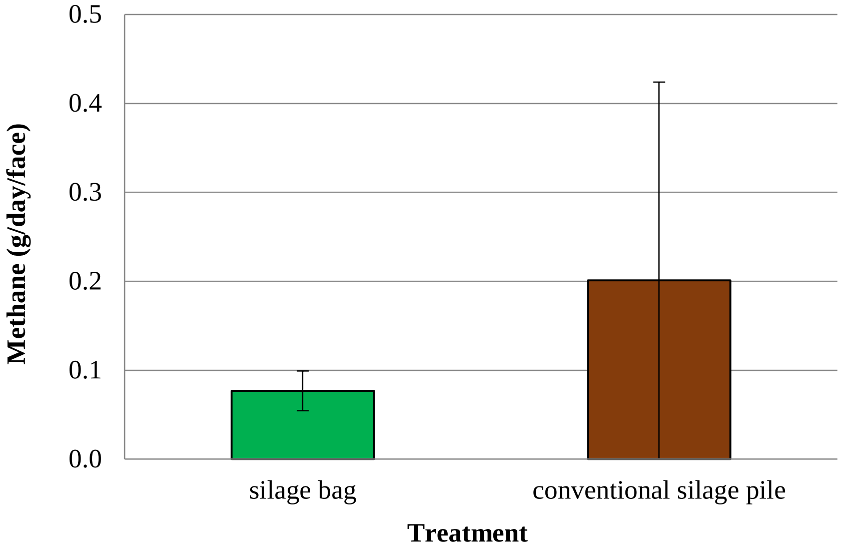

Figure 8. Means of methane emissions from the total face area of a silage bag vs. a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

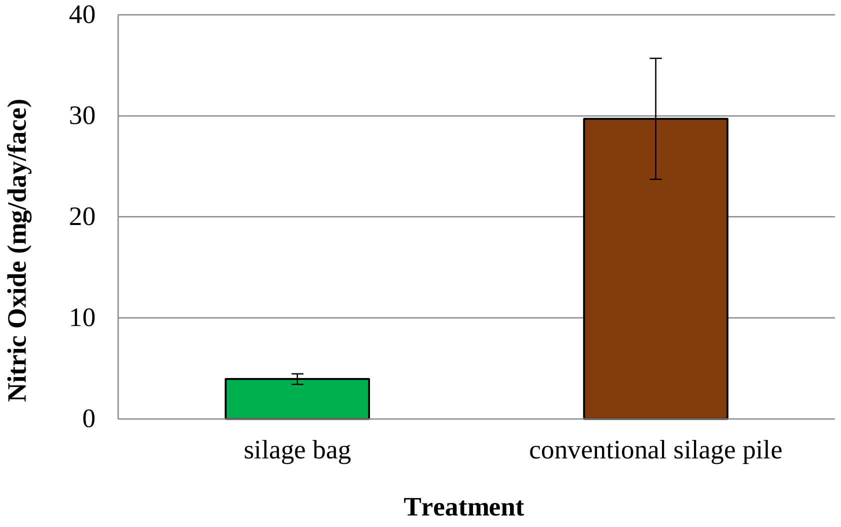

Figure 9. Means of nitric oxide emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

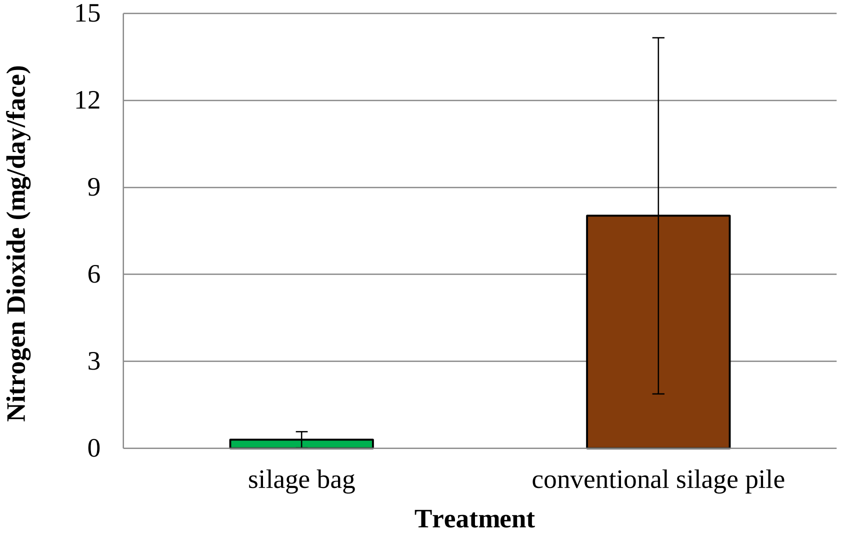

Figure 10. Means of nitrogen dioxide emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

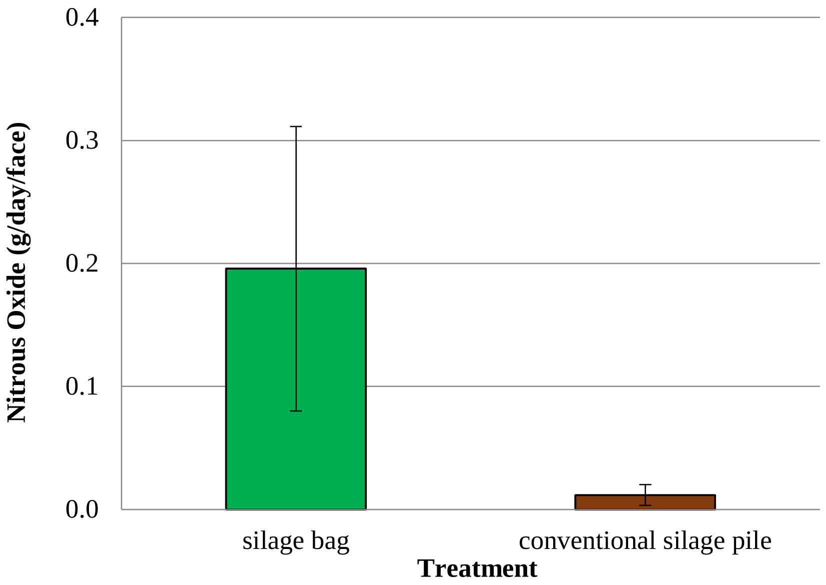

Figure 11. Means of nitrous oxide emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

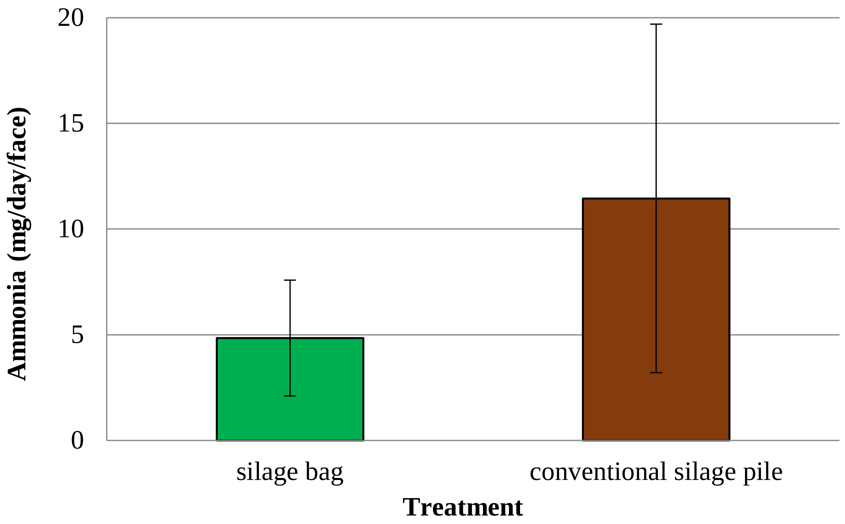

Figure 12. Means of ammonia emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

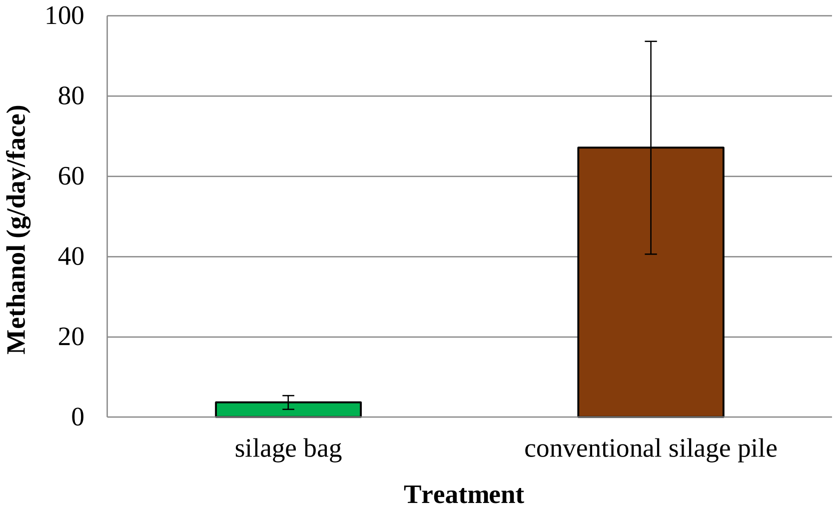

Figure 13. Means of methanol emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

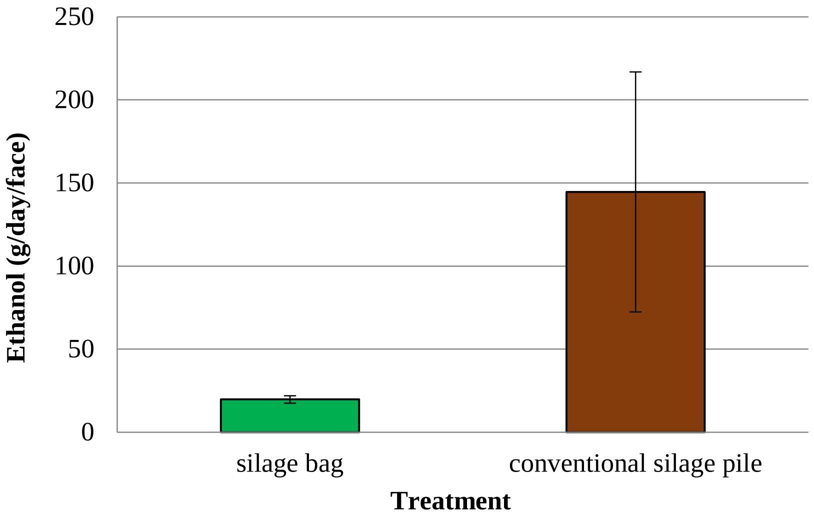

Figure 14. Means of ethanol emissions from the total face area of a silage bag vs. that of a conventional silage pile, respectively (each storage form was measured on three different days and the bars indicate the standard deviation).

Table 5 summarizes the results of Figures 8-14 comparing the between Face Emissions of the Conventional Silage Pile vs. Silage Bag.

Table 5. Comparisons of gas emissions between the faces of different silage storage methods.

	Silage storage methods	
Gas emissions	Silage bag	Conventional silage pile
Methane (g/day/face)	0.08 ± 0.02	0.02 ± 0.02
Nitric Oxide (mg/day/face)	3.94 ± 0.53	2.97 ± 0.60
Nitrogen Dioxide (mg/day/face)	0.30 ± 0.28	0.80 ± 0.61
Nitrous Oxide (mg/day/face)	0.20 ± 0.12	0.001 ± 0.001
Ammonia (mg/day/face)	4.84 ± 2.74	1.14 ± 0.82
Methanol (g/day/face)	3.67 ± 1.71	6.71 ± 2.65
Ethanol (g/day/face)	19.76 ± 2.20	14.46 ± 7.21
TOFP[1] (O_3 g/day/m^2)	31.04	253.32

[1] TOFP: Total Ozone Forming Potential of Methane, Methanol, and Ethanol

Emissions of TMR with Water Inclusion Rates

Task 4, the evaluation of the effects of water inclusion rate on TMR on the seven gases, provided interesting data. Figures 15-21 depict the four treatments evaluated: TMR 0%, TMR 5%, TMR 10%, and raw silage. The raw silage was added to the comparison to show how loose silage differs from loose TMR. Each treatment comparison was repeated with fresh samples on three separate days.

Nitrogen dioxide, ammonia, methanol and ethanol follow the curve of a high initial gas fluxes within the first five hours followed by a gradual emission decline to zero. The curve observed is similar to the flux of ethanol measured by Montes et al. (2010), who evaluated ethanol from intact silage samples at different temperatures and wind velocities using wind tunnels. However, with the increasing percentage of water included, a reduction of the initial flux of emissions was observed. As a result, when reviewing NO_2, NH_3, MeOH, and EtOH, treatments with 10% water had the greatest decrease (compared to 5% and 0%) in total emissions, particularly during the initial period. Methane, nitrous oxide, and nitric oxide did not follow a similar curve of initial emission flux and emission plateau; instead gaseous emissions appear to be very low until 10 h, then increase until 20 h, after which their emission subsided.

Of the seven gases measured, EtOH has been the most widely documented in the literature The initial EtOH emissions in the present study were similar to measurements by Chung et al. (2010) and Malkina et al. (2011).

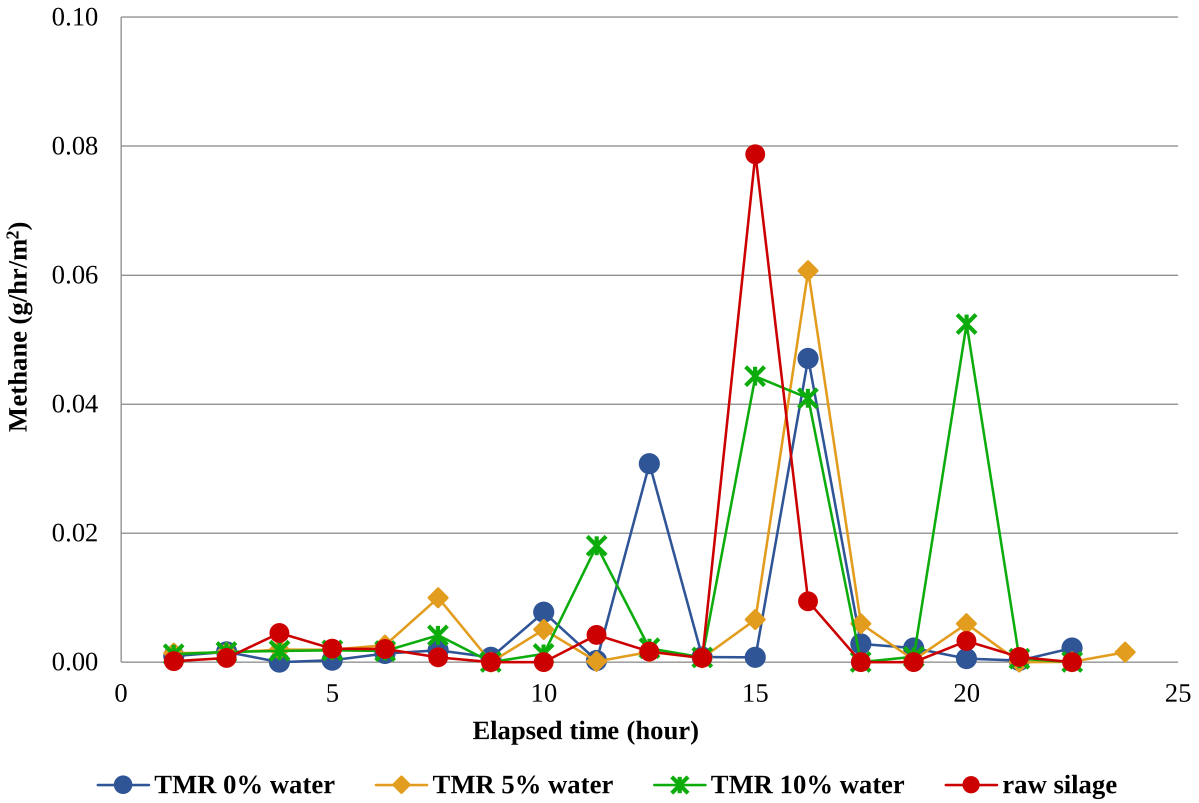

Figure 15. Means of methane (CH_4) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

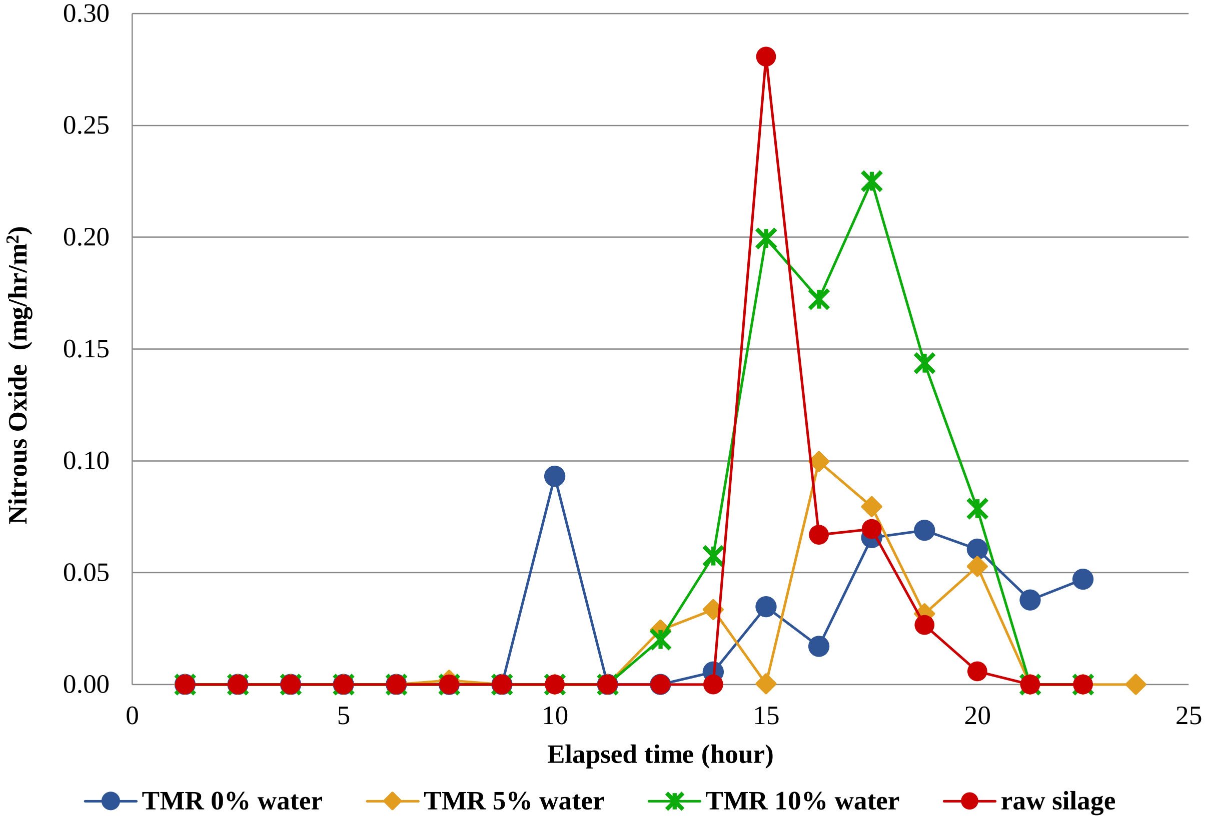

Figure 16. The effect of water inclusion into the TMR on nitrous oxide emissions. Means of nitrous oxide (N_2O) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

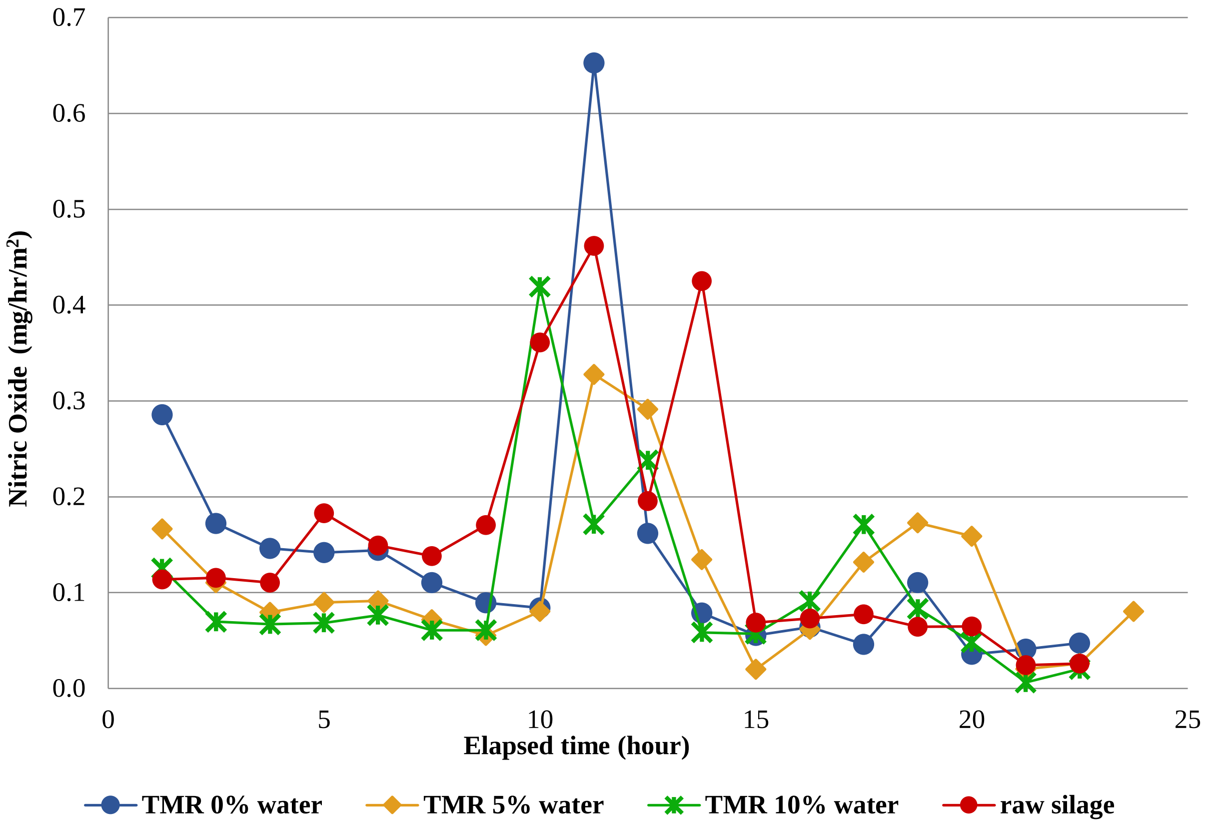

Figure 17. Means of nitric oxide (NO) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

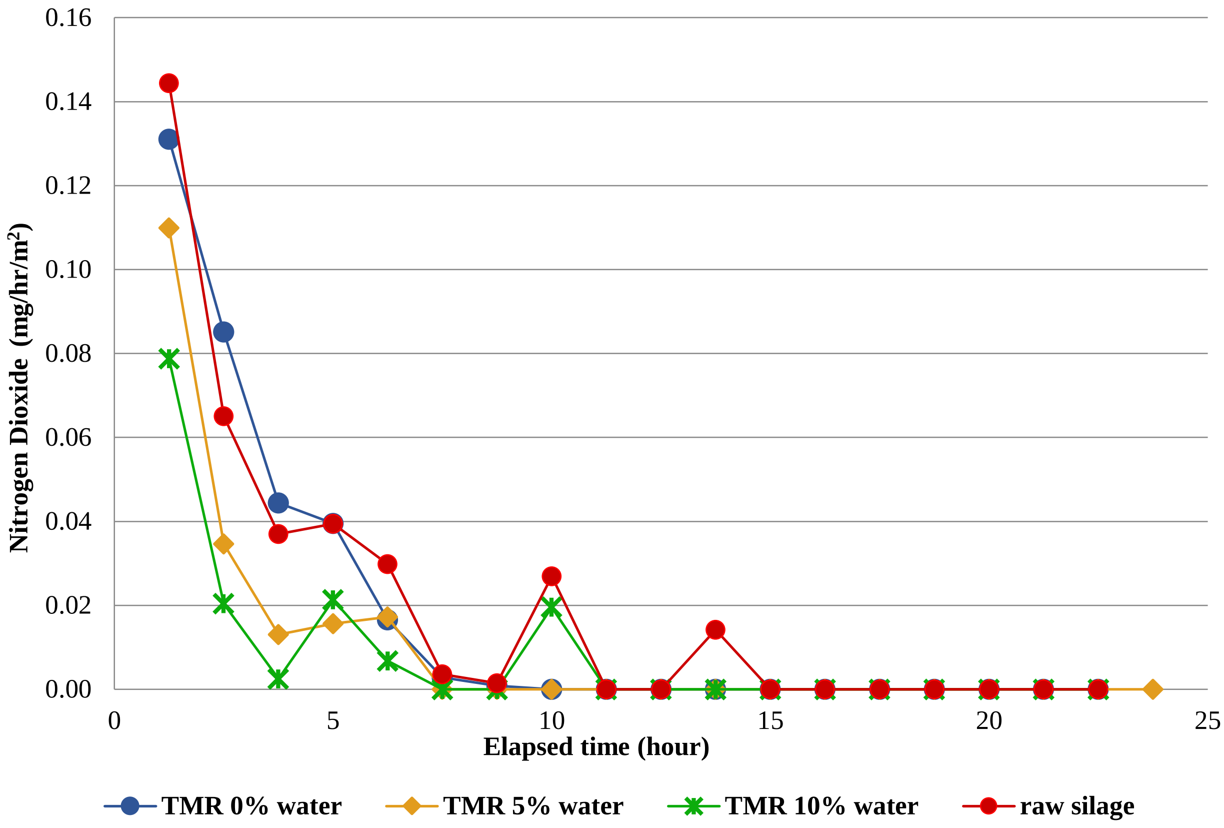

Figure 18. Means of nitrogen dioxide (NO_2) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

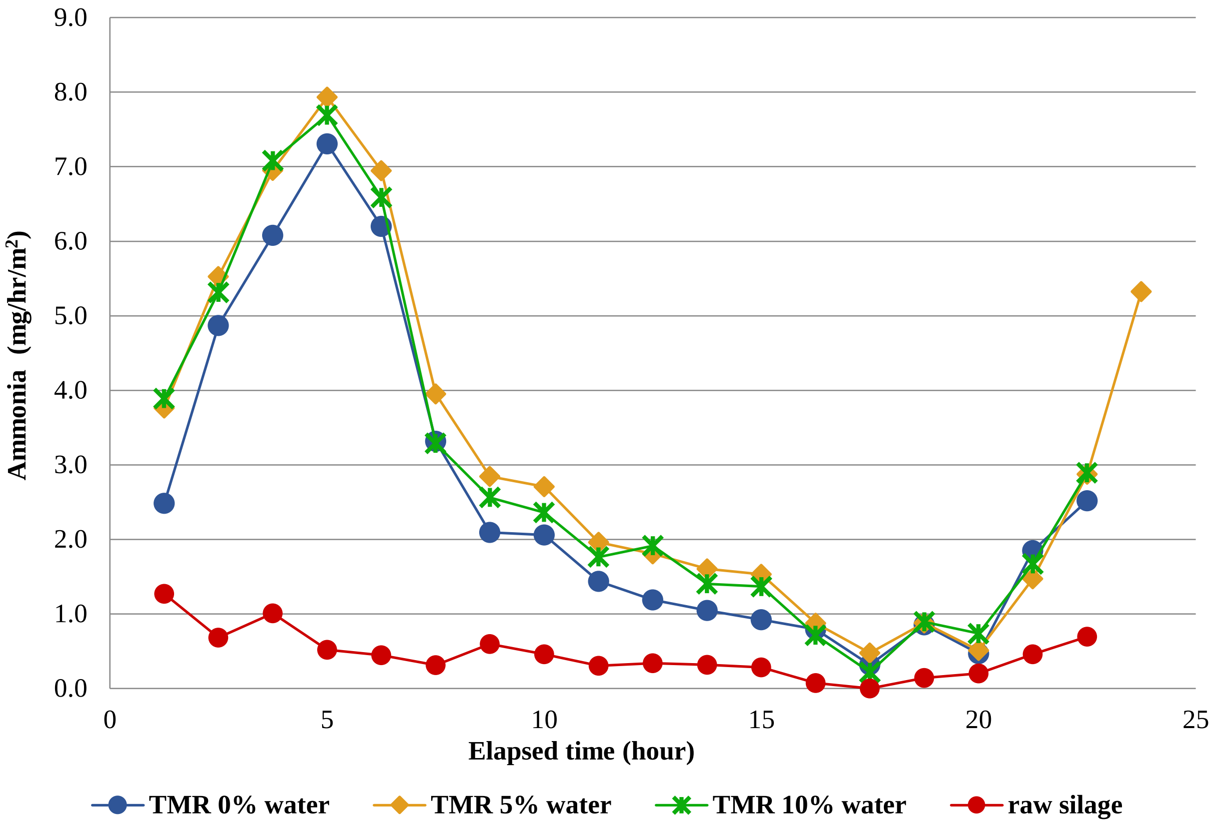

Figure 19. Means of ammonia (NH_3) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

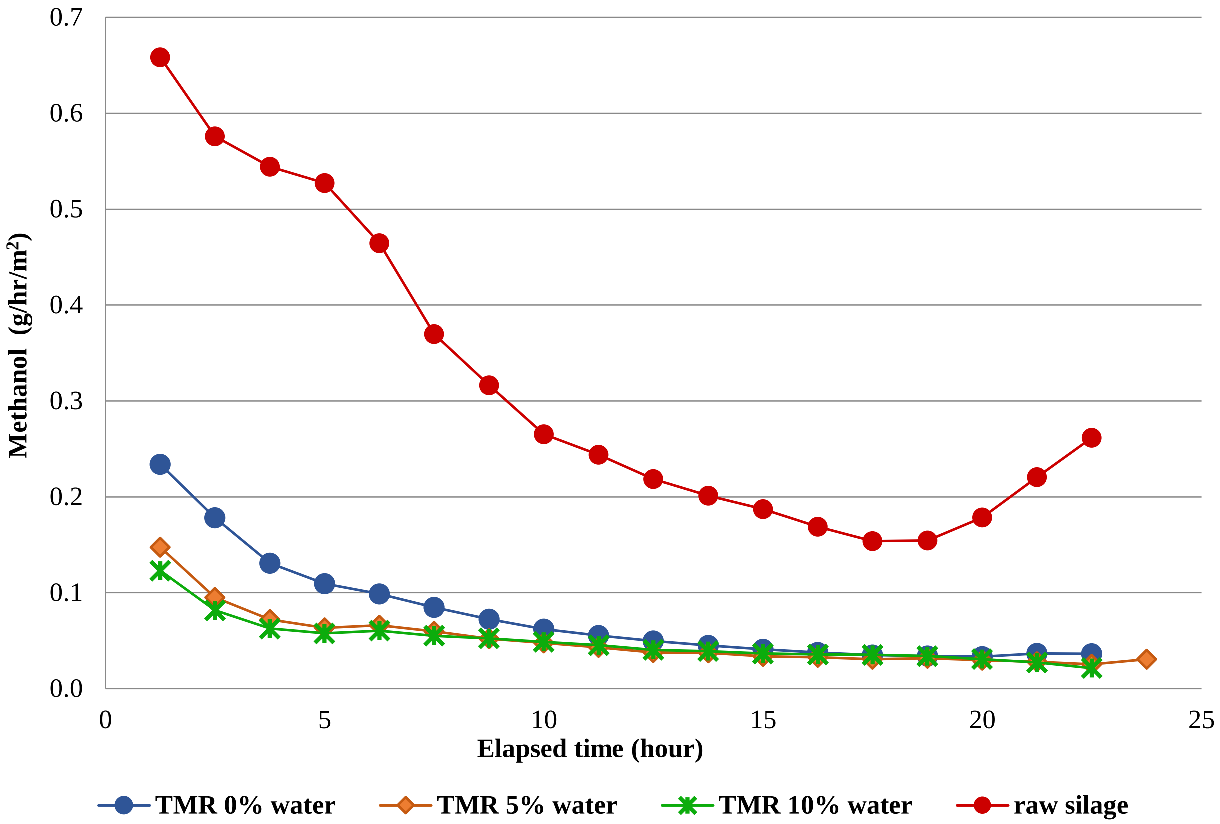

Figure 20. Means of methanol (MeOH) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

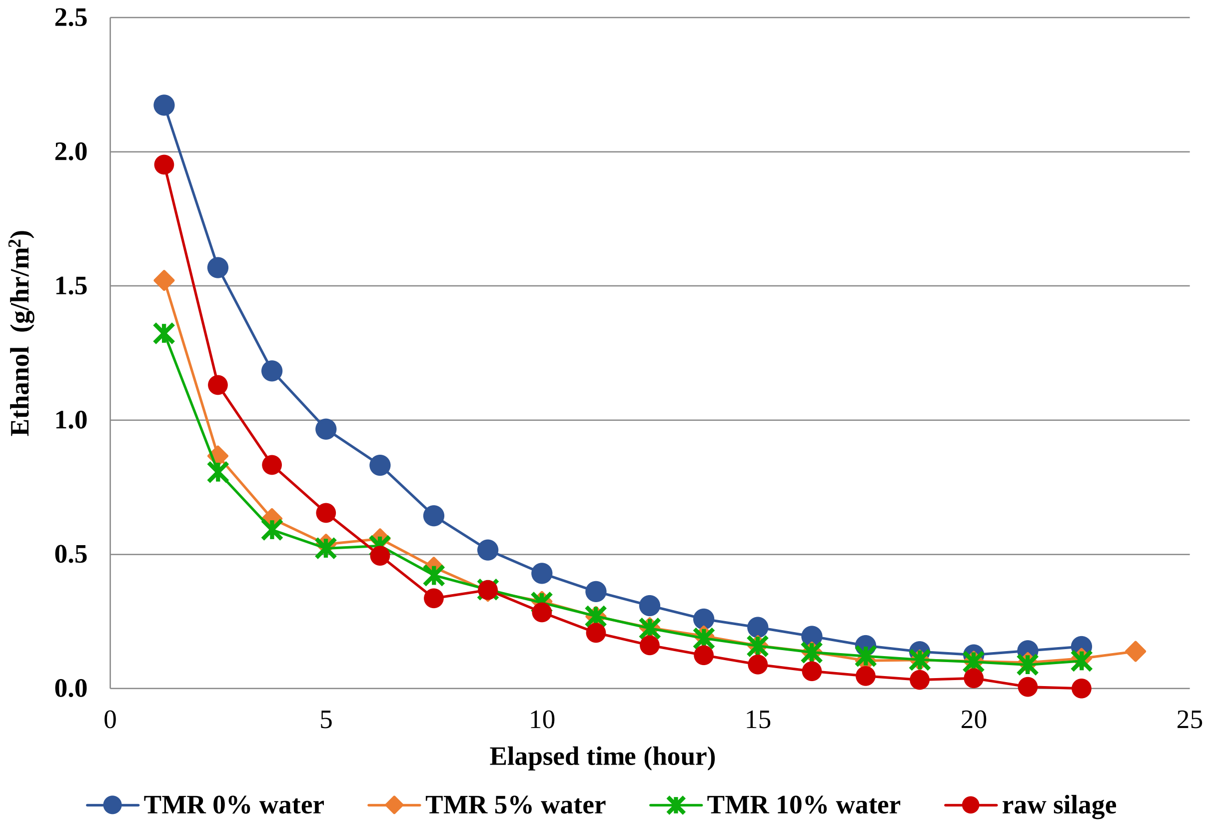

Figure 21. Means of ethanol (EtOH) emissions from TMR treated with 0%, 5% and 10% water vs. raw silage.

Table 6 summarizes the results of Figures 15-21 comparing the emissions of TMR with water inclusion rates. Because of the changes of emissions rate over time, data were averaged in 5-hr intervals and compared in Table 6.

Table 6. Comparison of gas emissions of TMR between different water inclusion rates.

Emission gases	**Average over 5-hr interval elapsed from starting**											
	0-5				**5-10**				**10-15**			
	Water inclusion rate				**Water inclusion rate**				**Water inclusion rate**			
	Raw	0%	5%	10%	Raw	0%	5%	10%	Raw	0%	5%	10%
CH_4 (g/hr/m^2)	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.02	0.01	0.00	0.02
N_2O (g/hr/m^2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO (mg/hr/m^2)	0.13	0.19	0.11	0.08	0.20	0.11	0.07	0.15	0.29	0.24	0.19	0.13
NO_2 (mg/hr/m^2)	0.07	0.08	0.04	0.03	0.02	0.01	0.02	0.01	0.01	0.00	0.00	0.00
NH_3 (mg/hr/m^2)	0.87	5.19	6.04	5.99	0.45	3.42	4.11	3.70	0.31	1.15	1.73	1.61
MeOH (g/hr/m^2)	0.58	0.16	0.09	0.08	0.35	0.08	0.06	0.05	0.21	0.05	0.04	0.04
EtOH (g/hr/m^2)	1.14	1.47	0.89	0.81	0.37	0.61	0.42	0.41	0.15	0.29	0.21	0.21
TOFP[1] (O_3 g/hr/m^2)	2.03	2.24	1.35	1.23	0.77	0.93	0.65	0.63	0.35	0.45	0.33	0.33

Table 6. Continue

Emission gases	Average over 5-hr interval elapsed from starting											
	15-20				20-25				Over 25 hr			
	Water inclusion rate				Water inclusion rate				Water inclusion rate			
	Raw	0%	5%	10%	Raw	0%	5%	10%	Raw	0%	5%	10%
CH_4 (g/hr/m^2)	0.01	0.01	0.02	0.03	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
N_2O (g/hr/m^2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO (mg/hr/m^2)	0.07	0.06	0.13	0.10	0.04	0.06	0.04	0.02	0.18	0.16	0.14	0.12
NO_2 (mg/hr/m^2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.02	0.02	0.01
NH_3 (mg/hr/m^2)	0.14	0.61	0.69	0.64	0.60	3.16	3.22	3.45	0.59	3.38	3.95	3.85
MeOH (g/hr/m^2)	0.16	0.04	0.03	0.03	0.27	0.04	0.03	0.03	0.39	0.09	0.06	0.06
EtOH (g/hr/m^2)	0.05	0.15	0.11	0.12	0.01	0.16	0.12	0.10	0.43	0.67	0.44	0.41
TOFP[1] (O_3 g/hr/m^2)	0.17	0.25	0.18	0.19	0.18	0.25	0.19	0.16	0.88	1.03	0.68	0.64

[1] TOFP: Total Ozone Forming Potential ofCH_4, MeOH, and EtOH

Conclusions

The present Chapter 3 provides monitoring data for a variety of silage mitigation techniques to provide input and validation data for the concurrent modeling study (i.e. Chapter 4). The past and present research on the individual phases or processes of the silage life cycle, provide emission data on the major emissions present in each step. However, the present monitoring study conducted alongside the concurrent modeling study, show that emission reduction potentials of one phase of silage management might be negated throughout later phases of the life cycle of the feed. For example, one might reduce emissions at the silage face through lateral defacing but the compounds one might prevent from volatilizing there, might later get lost in the feedlane.

Our concurrent modeling study (Chapter 4), which received the feedlane monitoring data from the present (Chapter 3) study, showed that the TMR placed in the feedlane, has the greatest exposure to the atmosphere, resulting in the greatest emissions throughout the silage life cycle. As a result, the present Chapter 3 may guide the reader to favor specific mitigation treatments (e.g., lateral defacing and 10% water inclusion) but these mitigation steps could result in relatively insignificant overall farm effects when evaluating the entire life cycle of silage, including the feedlane phase. It is apparent that the most effective VOC mitigation effort would minimize the air exposure time of freshly extracted- as well as freshly mixed feed to the atmosphere (e.g., silage face and feed-lanes).

Chapter 4 - Modeling of the Emission Reduction Benefits of Mitigation Strategies for Silage

Task 5: To use emission data measured on the commercial farms to refine and evaluate the existing silage VOC emission model

Abstract

A process-based model was further developed, which predicts VOC emissions from silage sources on farms using theoretical relationships of mass transfer and surface emission. Model parameters were refined through laboratory experiments and numerical modeling. For model evaluation, ethanol and methanol emission measurements made from conventional silage piles, silage bags and feed lanes on California dairy farms were compared to emissions predicted by the model. The model worked relatively well in predicting ethanol emissions but underpredicted methanol emissions. The new silage VOC emission model was incorporated as a component of a whole farm simulation model where it was used to evaluate management and climate effects on VOC emissions along with other aspects of farm performance, environmental impact and economics. Simulations of a representative dairy farm in California indicate that most of the reactive VOC emissions occur from feed lying in feed lanes during feeding. This implies that mitigation efforts should be applied to reducing emissions during feeding rather than those from the exposed face of silage piles.

Introduction

Pprior to the present study, an initial VOC emission model for silage was developed as a component of the Integrated Farm System Model (IFSM) and the Dairy Gas Emissions Model (DairyGEM), two farm simulation models created by the USDA-ARS (Rotz et al., 2015a and b). This component model was developed and refined using our early experimental mass balance data that were presented in Hafner et al. (2012). However, using measurements obtained from commercial California dairy farms through the present project (see Chapter 3), it was found that the original model performed inadequately in simulating emissions of ethanol and methanol from silage storages and feed lanes. Compared to measurements, the model generally predicted very high ethanol emissions and relatively low methanol emissions from both silage piles and bags. In addition, the original model did not respond appropriately to changes in simulation settings for silage bulk density and moisture content (Appendix Figures A2.1 and A2.2), two important parameters that differ among silage storage types. Inability to simulate effects of these two parameters limited the capability of the farm simulation models in evaluating changes in VOC emissions with respect to different mitigation strategies.

Through the present grant, the process-based VOC emission model for silage was further developed to address the previous limitations in simulating ethanol and methanol emissions and to account for effects of bulk density (e.g., compacted vs. loose silage) and moisture content. Ethanol and methanol emissions measured from silage storages and feed lanes on California dairy farms were used to evaluate the performance of the new model in predicting VOC emissions under field conditions. The new model incorporated in IFSM provides a tool for studying silage VOC emissions and evaluating VOC emission mitigation strategies from a whole farm perspective. This report provides a brief description of the silage VOC emission model, the evaluation with measured farm data, and an example application of the model in evaluating mitigation strategies for a representative California dairy farm.

Model Description

Rather than simulating emission and transport processes involved, the previous VOC emission model estimated the fraction of VOC loss from silage sources with respect to time (equation 1). Silage sources, which included silage storages and feed lanes, were treated as a three-pool model: surface pool, representing the first 2 cm from the surface; middle pool, representing the next 5 cm (i.e., depths of 2 to 7 cm); and a deep pool, representing the rest of the silage profile (i.e., total depth minus 7 cm) (Rotz et al., 2015b). Each pool was treated independently, composed of a gas film and a silage layer (Rotz et al., 2015b). For each pool, the fraction of a VOC lost through emission was represented using equation 1 (Rotz et al., 2015b):

$$f_{emis} = 1 - e^{-Kt/L} \tag{1}$$

where f_{emis} is the fraction of a given VOC lost at time t, K is the overall mass transfer coefficient (m/s), L is the layer thickness of the pool (m), and t is the cumulative exposure time (s). The L value was set to 0.02 and 0.05 m for surface and middle pools, respectively, while the remaining thickness was the deep pool. The total thickness was based on the calculated amount of silage needed for feeding the cows each day. Defined as the reciprocal of the sum of the two resistances to mass transfer (i.e., inverse of mass transfer coefficient), K was given by (Hafner et al., 2012; Rotz et al., 2015b):

$$K = 1/\left({}^{1}/_{\alpha} + {}^{l}/_{D_b}\right) \tag{2}$$

where α is the effective surface mass transfer coefficient (m/s), D_b is the effective bulk diffusion coefficient (m^2/s), and l is the distance from the center of the emitting layer (pool) to the exposed surface (m). The α is computed using equation 12 of Hafner et al. (2012). The surface mass transfer coefficient (h_m) used in calculating α is based on Mackay and Yeun (1983). The value of D_b is a function of diffusion-dispersion coefficients for both gaseous (k_{sg}) and aqueous (D_{ss}) phases (Hafner et al., 2012). Because k_{sg} is several orders of magnitude higher than D_{ss} (Hafner et al., 2012), D_b is calculated as a function of k_{sg} only. From Hafner et al. (2012), k_{sg} was held constant at 2.33 x 10^{-5} m/s. However, using measurements obtained from California dairy farms, this original model was found to perform poorly in predicting ethanol and methanol from silage piles and bags.

Through the present project, we revised the process-based model for silage VOC emissions. The governing emission and transport equations describing the new model were based on the convection-diffusion-dispersion model presented by Hafner et al. (2012). But instead of using the analytical solution to these equations (i.e., which led to overestimation of VOC emissions, Hafner et al., 2012), the new model was based on numerical modeling, in which the equations for surface emission from and transport within the silage were solved numerically through discretization. Numerical models (i.e., numerical solution), however, often require very fine spatial and temporal resolution, and, consequently, a very long simulation time. As an example, model refinement performed for this study was conducted with a grid size of 1 mm, resulting in 1,000 simulation layers for a 1-m depth of silage source, and a time step of 1 second – with this very fine resolution, modeling of just 120 hourly data points (i.e., equivalent to 5 days) required more than 8 hours of simulation time. In IFSM, simulation of all farm components, which include crop production, harvesting, feed storage, animal performance, manure production and handling, etc., using daily weather conditions over a 25-year period requires a very short simulation time for any one component farm. Therefore, to be incorporated in a whole farm model, a much faster simulation was required. To achieve this, simulation layer depths for the numerical model were defined as functions of certain parameters, as discussed below, to significantly reduce spatial (e.g., 2/3 simulation layers for 1-m depth) and temporal (e.g., 1-hr time step) resolution, and simulation time. Expressions defining simulation layer depths were developed through refinement using emission profiles obtained from numerical modeling using the high spatial and temporal resolution. A detailed description of the model will be presented in a future publication; a brief overview follows.

In the new process-based model, calculation of VOC emission from silage is performed on an hourly basis. The simulation domain for silage storages, such as bunkers, piles, and silage bags, has a total depth of 1 m from the exposed surface, which is divided into three layers. For feed lanes, the simulation domain has a shorter depth (0.15 m), which is modeled as two layers. As presented in Table 7, the surface layer, from which VOCs are emitted, is calculated as a function of the friction velocity (u_*) of air movement and feed dry bulk density (ρ_{dry}) for both silage storages and feed lanes. For silage storages, the second layer, which is adjacent to the surface layer, is a function of ρ_{dry}. In the new model, equations for these simulation depths were developed based on experimental data by Montes et al. (2010) and Hafner et al. (2010) and through numerical modeling. For the surface layer, simulation depth is directly proportional to u_* (i.e., more VOCs are readily available for volatilization at higher wind speeds) but inversely proportional to ρ_{dry} (i.e., more VOCs are readily available for volatilization at lower bulk densities). These depths were set using ethanol measurements. In the absence of experimental or measured data (e.g., different friction velocities), the same depths were applied for other VOCs (i.e., other alcohols, acids, aldehydes, esters, etc.).

Table 7. Depths (m) of simulation layers for silage in storages and feed lanes.

Layers	*Silage storage*	*Feed lane*
1st (surface layer)	$f_{1,s}(\rho_{dry})$ + [$f_{2,s}(\rho_{dry})$ x u_*]	$f_{1,f}(\rho_{dry})$ + [$f_{2,f}(\rho_{dry})$ x u_*]
2nd	$f_{3,s}(\rho_{dry})$	Remaining
3rd	Remaining	-
Total	1 m	0.15 m

In the new model, processes simulated for the 1st (surface layer) are VOC emission and volatilization. Unlike the previous model, mass transfer of VOCs between layers is simulated. For VOC emission, the following assumptions were applied: the amount of VOC emitted was limited by the amount of VOC present in the 1st layer; and the mass transfer resistance due to depth of the 1st layer was neglected.

Following Hafner et al. (2012), simulated hourly VOC emission from the surface layer is given by:

$$j_{sur} = 3600\alpha(C_{sur} - C_{air}) \tag{3}$$

where j_{sur} is the hourly VOC emission (g/m^2-hr), α is the effective surface mass transfer coefficient (m/s), C_{sur} is the VOC concentration in bulk silage (g/m^3), and C_{air} is the VOC concentration in ambient air (g/m^3). The C_{air} value is assumed negligible (Hafner et al., 2012). Similar to the previous model, α is computed using eq. 12 of Hafner et al. (2012). The value of h_m used in calculating α for ethanol is based on experimental data by Montes et al. (2010), where the derived equation is a function of u_*. In the absence of data, h_m for other VOCs is based on Mackay and Yeun (1983) as implemented in the previous model.

The amount of VOC transferred from one layer to the layer above is given by Hafner et al. (2012):

$$j_{lyr} = \frac{3600D_b(C_{lyr} - C_{lyr-1})}{l} \tag{4}$$

where j_{lyr} is the hourly mass transfer of VOC from the lower layer (g/m^2/hr), D_b is the effective diffusion mass transfer coefficient (m^2/s), *lyr* and *lyr*-1 are the lower and upper layers, respectively, *l* is the distance from the center to the upper edge of the lower layer (m), and C_{lyr} and $C_{lyr\text{-}1}$ are VOC concentrations for *lyr* and *lyr*-1, respectively (g/m^3). Similar to the previous model, D_b is calculated as a function of k_{sg} only. The value of D_b is computed using eq. 11 of Hafner et al. (2012) with the D_{ss} term neglected. As done for h_m, an equation was derived for calculating k_{sg} as a function of u_* using ethanol data from Montes et al. (2010). This same equation was used in calculating k_{sg} for other VOCs but with the minimum value based on relationships from Tucker and Nelken (1982). With this approach, k_{sg} for all VOCs is the same at $u_* > 0.05$ m/s (i.e., 10-m height wind speed of 2.0 m/s). As k_{sg} applies to diffusion in free air, it is adjusted to represent diffusion in a porous media such as silage using the Millington-Quirk model (Hafner et al., 2012).

Both, α and D_b are functions of the Henry's law constant, bulk density, and moisture content (Hafner et al., 2012; Rotz et al., 2015a and b). To estimate K_H, equation 1 of Hafner et al. (2012) can be written as:

$$K_H = \frac{m_i}{P_i} \rightarrow K_H = \frac{m_i}{P_T y_i} \rightarrow K_H = \frac{m_i}{P_{sat} x_i} \tag{5}$$

where m_i is the molal concentration of VOC *i* (mol/kg solution), x_i is the mole fraction of VOC *i* in aqueous phase, y_i is the mole fraction of VOC *i* in the gas phase, P_i is the partial vapor pressure of VOC *i* in equilibrium with m_i (atm), P_{sat} is the partial vapor pressure of VOC *i* (atm), and P_T is the total vapor pressure of the solution (atm). The value of P_{sat} is calculated using the Antoine equation:

$$P_{sat} = \frac{10^{A - \frac{B}{C+T}}}{760} \tag{6}$$

where *A*, *B*, *C* are compound-specific constants, and *T* is the silage temperature (°C). In this study, values for *A*, *B*, and *C* used for ethanol and methanol are based on DDBST (2015).

One shortcoming of using eq. 5 is the need to specify x_i. Based on a summary made by Hafner et al. (2013), 46 VOCs have been measured in silage. Measurement of all these VOCs to determine x_i, however, would be impractical. In this project, although silage samples were characterized in terms of seven VOCs only, the three most concentrated VOCs in silage (i.e., acetic acid, ethanol, and propionic acid; Hafner et al., 2013) were included in silage characterization. In approximating x_i, it was assumed that the moles of other VOCs not measured were negligible compared to the sum of concentrations of the seven VOCs included.

Model Evaluation Procedure

For simulating silage storages, the new VOC emission model was evaluated using the dataset of ethanol and methanol emissions measured from conventional silage piles and silage bags on the commercial dairy farm in California. In addition, performance in simulating feed lanes was evaluated using emission measurements from total mixed ration (TMR) and corn silage samples representing that spread out in feed lanes.

Emission Measurements

Measurement of hourly ethanol and methanol emissions from silage faces using flux-chambers and a wind tunnel system is described in Chapter 3. Information on measurement trials used in model evaluation are provided in Table 8, summarized according to storage type, defacing method, and measurement date.

Table 8. Measurement information on data collected from conventional silage piles and silage bags.

Trial	*Storage type*	*Defacing method*	*Measurement date*	*No. of hourly data points*	*Flux-chamber*	*Wind tunnel*
1	Conventional silage pile	Lateral	09/15/2014	13	Y	Y
2			09/17/2014	14	Y	
3			09/18/2014	14	Y	
4		Perpendicular	09/22/2014	13	Y	Y
5			09/24/2014	14	Y	
6			09/25/2014	14	Y	
7		Rake (EZ rake)	10/01/2014	14	Y	Y
8			10/02/2014	14	Y	
9			10/03/2014	14	Y	
10	Silage bag	-	10/23/2014	23	Y	Y
11			10/29/2014	21	Y	
12			10/30/2014	23	Y	

For both VOCs, measured hourly emission rate ($j_{sur,m}$) was calculated as:

$$j_{sur,m} = \frac{\left(\frac{C_{VOC} MW_{VOC}}{24.45}\right) V_{flow}}{A_{sur}} \tag{7}$$

where C_{VOC} is the hourly concentration of VOC of interest in the headspace (ppm), MW_{VOC} is the molecular weight of the VOC (g/mol), V_{flow} is the hourly flow rate of air through the chamber (i.e., 1.2 m^3/hr for flux-chambers and 5.94 for the wind tunnel), and A_{sur} is the area of the emitting surface (i.e., 0.196 m^2 for flux-chambers and 0.23 m^2 for the wind tunnel).

In evaluating the performance in simulating VOC emissions from feed lanes, ethanol and methanol emissions measured from corn silage and TMR samples were used. To examine whether water application could lower VOC emissions (see Task 4 in Chapter 3), emissions were measured from three types of TMR samples, which varied in the amount of water added (Table 9). Hourly ethanol and methanol emissions from corn silage and TMR samples were determined using flux-chambers (Chapter 3), with each trial lasting 14 hr.

Table 9. Details on total mixed ration (TMR) and corn silage samples used to represent feed lane emissions.

Trial sample	*Trial*	*Source*	*Amount prior water addition (kg)*	*Amount of water added (kg)*	*Effective % water*[1]
TMR + 0% water	13, 14, 15	TMR	2.0	0.0	7%
TMR + 5% water	16, 17	TMR	1.9	0.1	11.5%
TMR + 10% water	18, 19, 20	TMR	1.8	0.2	16.5%
Corn silage	21, 22	Corn silage	2.0	0.0	-

[1] Prior sampling, 7% water was already added to TMR during mixing.

Silage Characterization

Simulation of VOC emissions requires initial concentrations of the compounds within the silage (i.e., C_{sur} in eq. 3). Samples from conventional silage piles and silage bags, obtained using a silage core sampler, and samples of TMR and corn silage were collected for characterizing VOC concentrations. Samples were placed in separate sealed plastic bags, which were then immediately stored in a container with dry ice. Upon arrival at UC Davis, VOC concentrations in these samples were analyzed using gas chromatography (GC). Similar to Zhang et al. (2010), VOCs included in silage characterization were ethanol, methanol, acetic acid, propionic acid, iso-butyric acid, butyric acid, and valeric acid.

Simulation Settings

Parameters α and D_b, used in calculating j_{sur} (eq. 3) and j_{lyr} (eq. 4), respectively, are influenced by silage bulk density and moisture content (Hafner et al., 2012). In the absence of measurements, simulation settings for bulk density and moisture content were set as follows: (1) refinement through numerical modeling for conventional silage piles; (2) published or documented values for silage bags; and (3) estimated from volume and known mass for TMR samples. Values used are presented in Table 10. For conventional silage piles, refinement of bulk density and moisture content settings according to simulated emission profiles was acceptable as the new model worked well using the more comprehensive experimental data of Montes et al. (2010) (i.e., bunker silo silage sample) and Hafner et al. (2010) (i.e., loose silage sample), both of which included silage bulk density and moisture content measurements. But with concerns on low ethanol emissions simulated (as discussed below), this approach was not effective for silage bags; therefore, a dry bulk density of 190 kg/m^3, which is within published values, was used.

Table 10. Simulation settings used for dry bulk density and moisture content in model evaluation.

Silage set-up	*Parameters*	*Simulating setting*	*Published values*	
			Range	*Reference*
Silage bag	Dry bulk density (kg/m^3)	190	65 - 270	Muck and Holmes, 2006; Ohman et al., 2007
	Moisture content (%, wet-based)	50	40 - 70	Savoie and Jofriet, 2003
Conventional silage piles	Dry bulk density (kg/m^3)	240	160 - 320	Roach and Kammel, 2012; Silva-del-Rio, 2010
	Moisture content (%, wet-based)	60	60 - 70	Roach and Kammel, 2012
TMR	Dry bulk density (kg/m^3)	190	120 - 190	Buckmaster, 2005
	Moisture content (%, wet-based)	35	40 - 50	Buckmaster, 2005

As discussed above, h_m is a function of friction velocity. Although not measured in this project, effective air velocity inside the flux chambers was very low (Acevedo Perez, 2011); thus, friction velocity was set to 0 m/s. For the wind tunnel, equivalent average wind speed based on the 99 L/min setting was 0.04 m/s; assuming that friction velocity was 1/10th of the average wind speed, a 0.004 m/s setting was applied. Based on these settings, h_m for flux-chambers were $1x10^{-3}$ m/s for methanol and $2x10^{-4}$ m/s for ethanol. For the wind tunnel, h_m was approximately $1.26x10^{-3}$ for methanol and $8.8x10^{-4}$ m/s for ethanol.

Model Evaluation Results

Below are figures and tables for ethanol and methanol emissions based on field measurements at the California farm and as simulated by the new process-based model for silage VOC emissions. To demonstrate the improvements made in VOC emission simulation using the new model, simulation results from the previous model are also shown. For both new and old models, corresponding ratios of simulated to measured emissions ($R_{s/m}$) were computed. The closer the $R_{s/m}$ to 1.0, the closer the simulated emission is to that measured. Statistical measures that can be used in comparing measured and simulated VOC emissions are also provided, and these included the mean absolute error (MAE), the root mean square error (RMSE), and the index of agreement (IA). Equations for these statistical measures are discussed by Willmott (1981) and Willmott et al. (2012). For IA, a value of 1.0 indicates 100% agreement between measured and simulated data whereas 0.0 indicates no agreement at all.

Conventional Silage Piles

Flux-chamber-based measured and simulated (for both new and old models) ethanol and methanol emissions are shown in Figure 22. With emission (e.g., h_m) and transport (e.g., k_{sg}) parameters derived from previous experimental data, the new process-based model performed well in simulating ethanol emissions (Figure 22). Based on overall values (Table 11), $R_{s/m}$ ranged from 0.62 to 1.49, with an average of 1.12 indicating relatively close agreement. The new model also was able to simulate the typical VOC emissions profiles for silage with high emissions during the first hours of exposure followed by a rapid decline for the remaining period (Montes et al., 2010; Hafner et al., 2010). Compared to the old model, the new model performed much better as the former simulated very high ethanol emissions for conventional silage piles. Using the old model, $R_{s/m}$ values were very high, ranging from 3.57 to 9.22, with an average of 6.36 suggesting that simulated ethanol emissions were 6x the measured values.

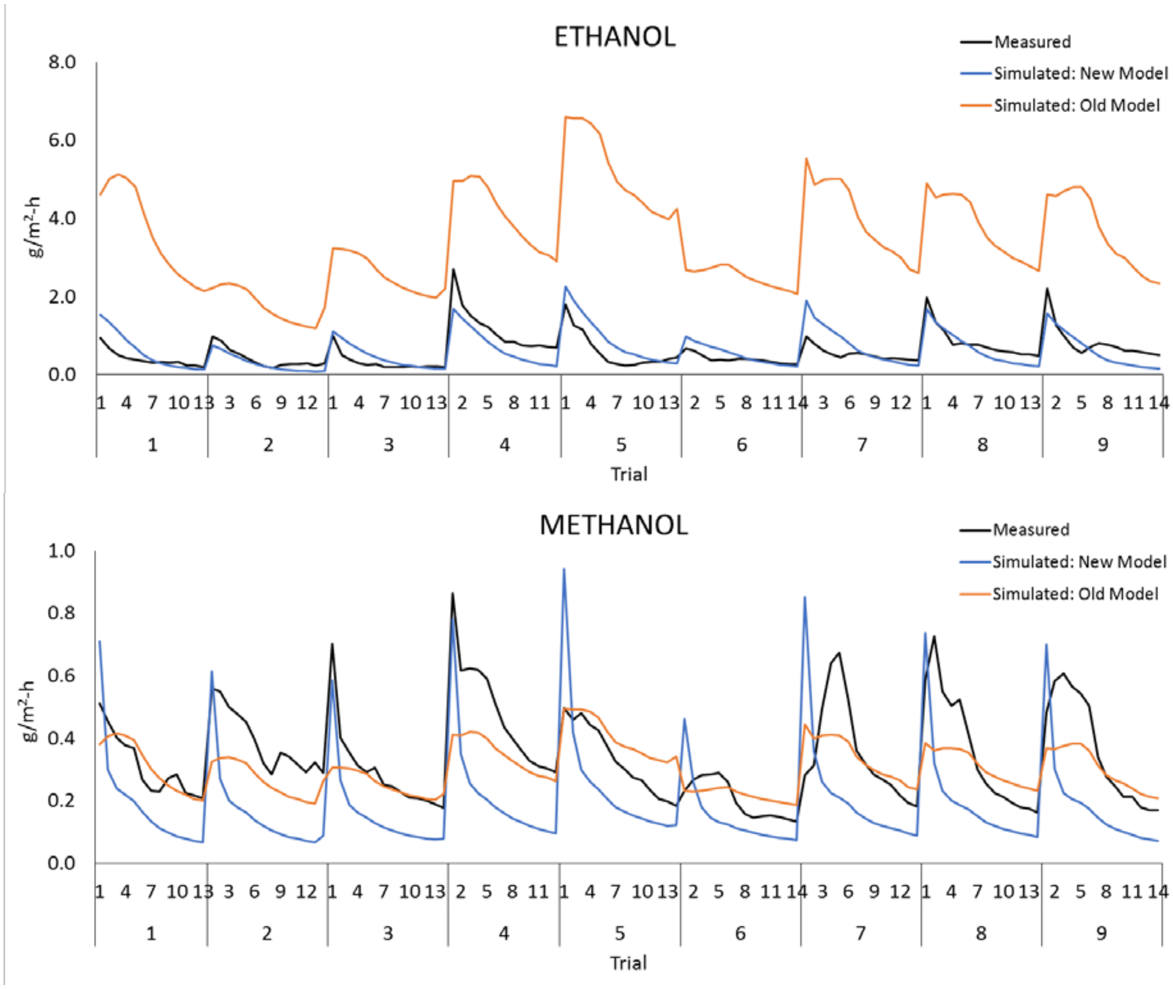

Figure 22. Comparison of simulated and flux-chamber-based emissions for conventional silage piles.

Compared to simulation of ethanol emission, however, a slightly lower model performance was observed for the new model when simulating methanol emissions from conventional silage piles. Except for being able to predict the high methanol emissions measured during the first hour of silage face exposure, the modeled emission profile was lower than that measured (Figure 22). Based on overall values (Table 12), $R_{s/m}$ when simulating methanol emissions was relatively low, with a range of 0.42 to 0.74 and an average of 0.57 (i.e., simulated was about 60% of that measured). This tendency of the model to underpredict methanol emissions is likely due to coefficients assumed in the simulation, specifically the diffusion-dispersion coefficient. Without experimental data, refinement of this parameter for methanol emissions was not possible. In contrast to its performance in simulating ethanol emissions, the old model did better in modeling methanol emissions, with $R_{s/m}$ ranging from 0.69 to 1.21 and an average of 0.91 (i.e., simulated was 91% of measured). Even though the old model seemed to perform much better in simulating methanol emissions from conventional silage profiles, these modeled methanol emissions were obtained with certain limitations and faults present in the model, which included: (1) use of an equation for K_H suggesting ethanol is more volatile than methanol; (2) an assumption that the layers (i.e., pools in the old model) behave independently, with no VOC transfer between any layers (Rotz et al., 2015b); (3) inability to simulate effects of silage dry bulk density and moisture content on VOC emissions (e.g., Figures A2.1 and A2.2); (4) inability to simulate the characteristic high VOC emissions during the first hour of exposure (Montes et al., 2010; Hafner et al., 2010); and (5) inability to simulate the rapid decline in emissions after the first hour of exposure (Montes et al., 2010; Hafner et al., 2010) resulting to generally higher emission profiles.

Table 11. Equivalent 12-h measured and simulated ethanol emissions for conventional silage piles (trials 1-9) and silage bags (trials 10-12) based on flux-chamber and wind tunnel measurements.[1,2]

Trial	*Flux-chamber*				*Wind tunnel*			
	Concentration (mg/L)	*Emission rate (g/m^2)*			*Concentration (mg/L)*	*Emission rate (g/m^2)*		
		Measured	*Simulated*			*Measured*	*Simulated*	
			New	*Old*			*New*	*Old*
1	253	4.7	6.9	44	182	4.4	6.0	28
2	136	4.9	3.4	21				
3	219	3.7	5.4	31				
4	330	13.8	8.6	49	194	15.8	6.4	29
5	436	7.2	10.7	62				
6	276	4.8	6.2	30				
7	389	6.3	9.1	48	336	10.7	9.6	36
8	340	9.9	8.1	45				
9	293	9.9	7.3	44				
10	146	10.6	2.3	19	123	16.6	2.3	14
11	158	11.9	2.7	20				
12	148	8.5	2.3	19				
Conventional silage piles (trials 1-9)		MAE	2.5	34		MAE	4.1	21
		RMSE	2.7	36		RMSE	5.6	22
		IA	0.65	0.14		IA	0.52	0.25
Silage bags (trials 10-12)		MAE	7.9	8.7		MAE	-	-
		RMSE	8.0	8.8		RMSE	-	-
		IA	0.23	0.23		IA	-	-

[1] MAE is the mean absolute error, RMSE is the root mean square error, and IA is the index of agreement.

[2] No MAE, RMSE, and IA computed for silage bags using wind tunnel measurements as one data point only.

Table 12. Equivalent 12-h measured and simulated methanol emissions for conventional silage piles (trials 1-9) and silage bags (trials 10-12) based on flux-chamber and wind tunnel measurements.[1,2]

Trial	*Flux-chamber*				*Wind tunnel*			
	Concentration (mg/L)	*Emission rate (g/m^2)*			*Concentration (mg/L)*	*Emission rate (g/m^2)*		
		Measured	*Simulated*			*Measured*	*Simulated*	
			New	*Old*			*New*	*Old*
1	26	3.7	2.3	3.7	27	5.8	2.3	3.4
2	24	4.7	2.0	3.2				
3	25	3.5	1.9	3.0				
4	33	5.8	2.7	4.2	24	10.2	2.0	3.1
5	40	4.0	3.0	4.9				
6	27	2.4	1.7	2.6				
7	38	4.3	2.6	4.0	40	10.6	2.7	3.8
8	32	4.3	2.3	3.7				
9	29	4.4	2.2	3.6				
10	10	1.2	0.7	1.1	10	3.3	0.7	1.0
11	10	1.6	0.8	1.1				
12	9	2.7	0.7	1.0				
Conventional silage piles (trials 1-9)		MAE	1.8	0.7		MAE	6.5	5.4
		RMSE	2.0	0.9		RMSE	6.8	5.8
		IA	0.42	0.67		IA	0.36	0.40
Silage bags (trials 10-12)		MAE	1.1	0.8		MAE	-	-
		RMSE	1.2	1.0		RMSE	-	-
		IA	0.43	0.45		IA	-	-

[1] MAE is the mean absolute error, RMSE is the root mean square error, and IA is the index of agreement.

[2] No MAE, RMSE, and IA computed for silage bags using wind tunnel measurements as one data point only.

With fewer data points, wind tunnel-based measured and simulated emissions are shown in Figure 23. Compared to flux-chamber measurements (Figure 22), ethanol and methanol emission profiles measured with the wind-tunnel did not consistently decrease through time with some high emissions measured several hours after silage face exposure (Figure 23). Still, based on overall values (Table 11), the new model performed reasonably and similarly in simulating ethanol emissions as measured by the wind tunnel, with $R_{s/m}$ ranging from 0.40 to 1.35 and an average of 0.88, whereas the old model predicted very high ethanol emissions resulting to $R_{s/m}$ ranging from 1.85 to 6.39 and an average of 3.87. As with flux-chambers, the new model underpredicted the methanol emissions as measured by the wind tunnel, with $R_{s/m}$ (0.2 to 0.4) lower than those computed for flux-chambers. As mentioned above, this underprediction of methanol emissions might be due to the relationship used for approximating the diffusion-dispersion coefficient for methanol. Although the old model did well in predicting methanol emissions measured by flux-chambers, it did not do as well in simulating those measured by the wind tunnel based ($R_{s/m}$ of 0.31 to 0.59).

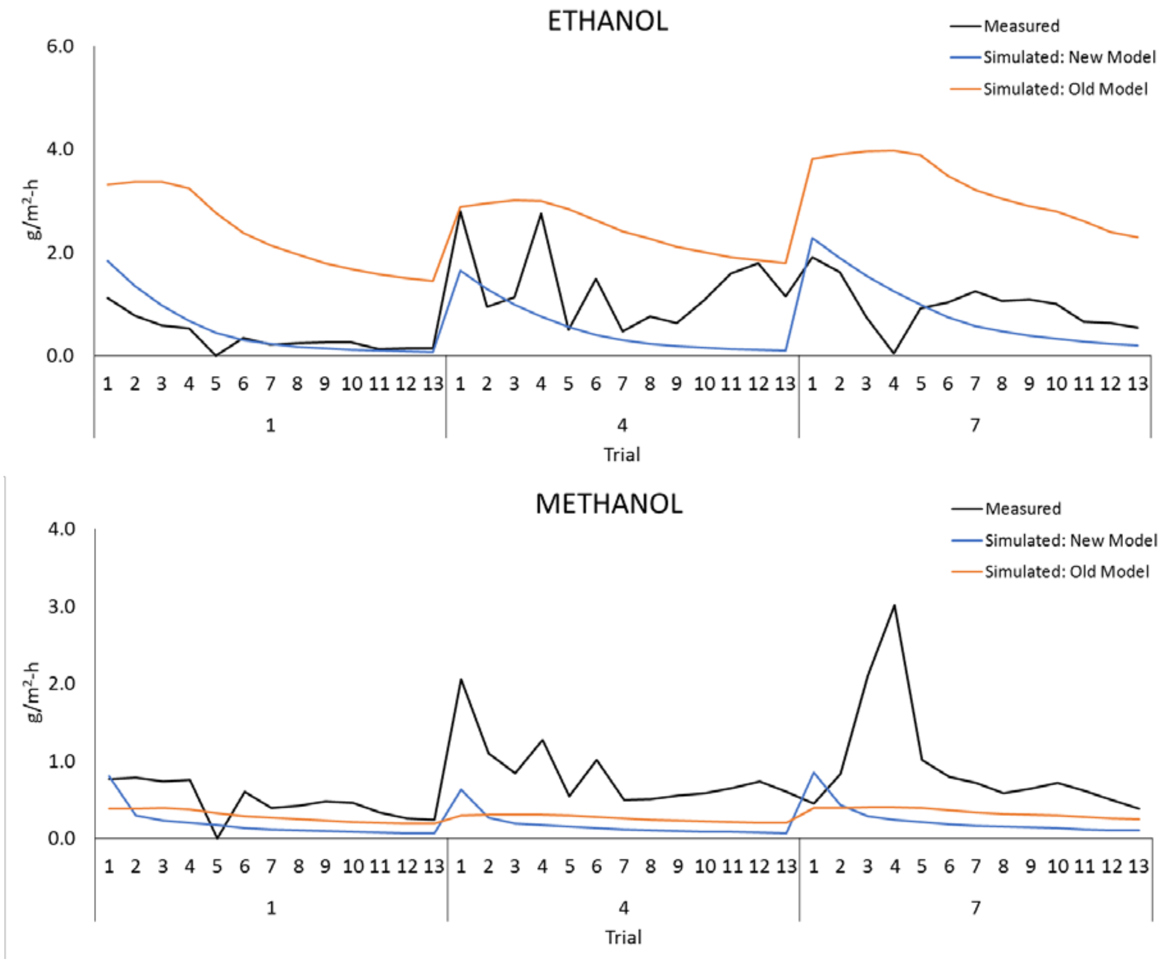

Figure 23. Comparison of simulated and wind tunnel-based emissions for conventional silage piles.

Silage Bags

The new model did not do well in representing ethanol emissions from silage bags through time. For both flux-chamber and wind-tunnel trials (Figures 24 and 25, respectively), although the model did simulate high ethanol emissions during the first hour of exposure, the predicted ethanol emission profile for the next hours was very low. As shown in Figures 24 and 25, after six hours of exposure, ethanol emissions predicted by the model were negligible whereas measured emissions were still above 0.5 g/m^2-h. Based on accumulated loss over time (Table 11), simulated ethanol emissions were just 22% to 28% and 14% of those measured with flux-chambers and the wind tunnel, respectively. Similar findings apply when simulating methanol emissions with the new model where simulated emissions are just 27% to 61% and 22% of measured values for flux-chambers and the wind tunnel (Table 12), respectively.

On the other hand, the old model was inconsistent when simulating emissions from silage bags, similar to its performance for conventional silage piles. For ethanol emissions, simulated profiles were much greater than flux-chamber measurements (Figure 24); but compared to wind tunnel measurements, the simulated profile was comparable to that measured (Figure 25). For methanol emissions, the old model did well in simulating 2 out of 3 trials using flux-chambers (Figure 31); but for wind tunnel measurement, the old model predicted a very low emission profile comparable to that simulated by the new model (Figure 25).

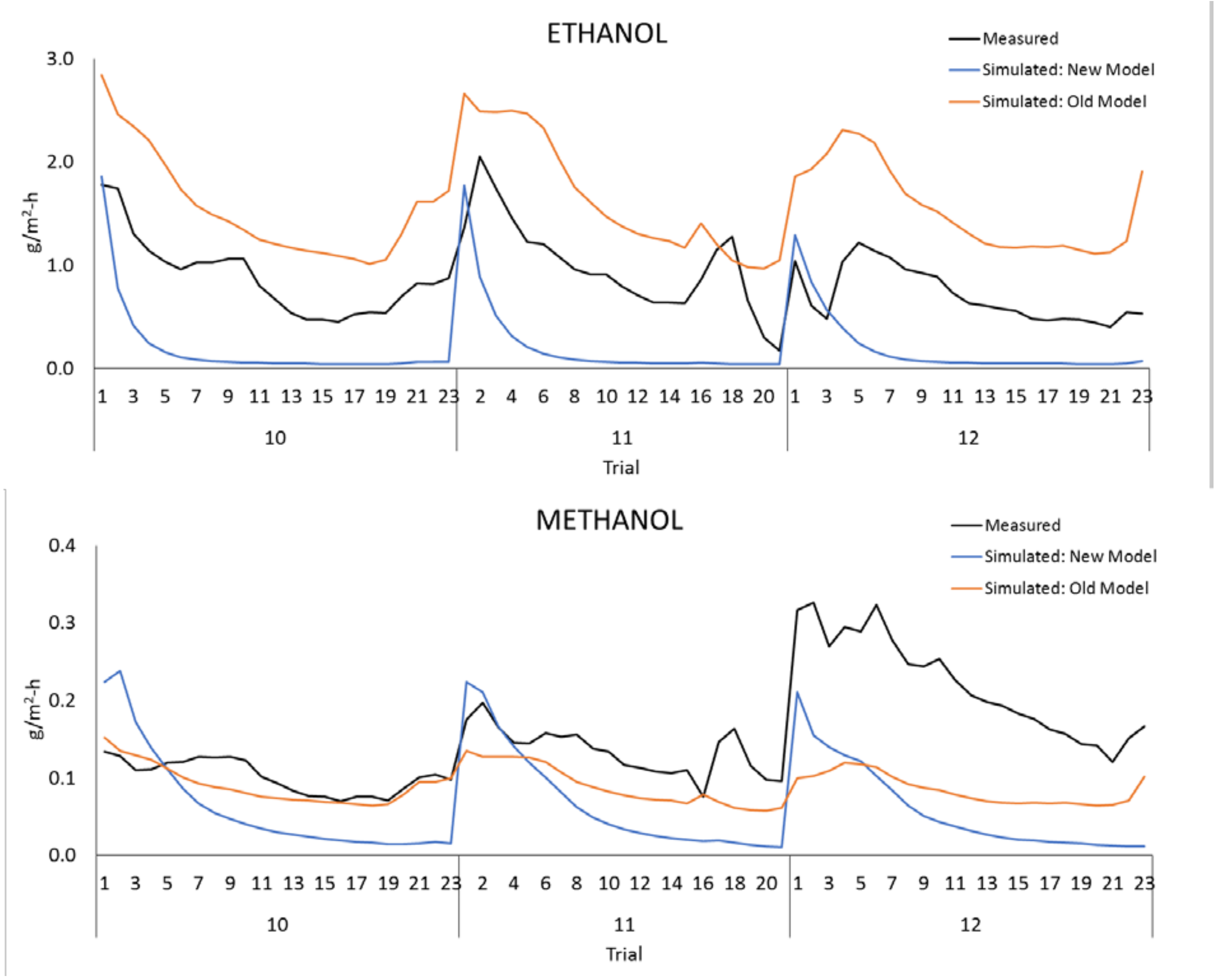

Figure 24. Comparison of simulated and flux chamber measured emissions from silage bags.

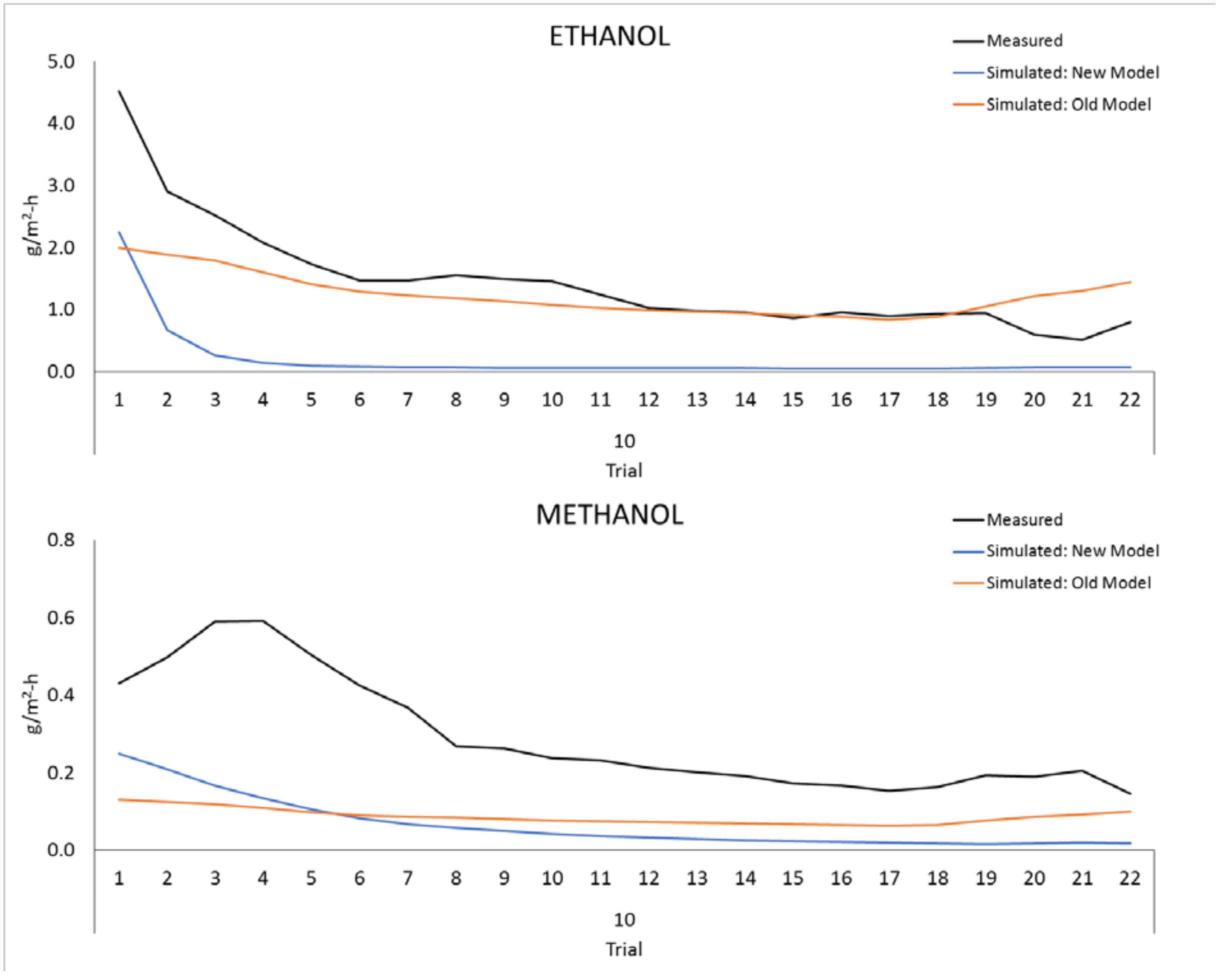

Figure 25. Comparison of simulated and wind tunnel measured emissions from silage bags.

Focusing on the new model, the lower emission profiles simulated for silage bags could be explained largely by the loss of ethanol (and methanol) at the surface layer. This behavior was verified through numerical modeling using fine spatial and temporal resolution, in which there was no need to assume or specify depth for the surface layer. Compared to conventional silage piles, silage bags had lower initial amounts of ethanol (and methanol) at the surface layer, and in the simulation, this contributed to loss of ethanol readily available for volatilization within the first few hours of exposure. Based on average initial silage concentrations, both ethanol and methanol concentrations for silage bags (151 and 10 mg/L, respectively) were less than half of corresponding concentrations for conventional silage piles (297 and 30 mg/L, respectively).

With lower initial alcohol concentrations in the silage, the higher emission profiles measured for silage bags, therefore, must be attributed to other conditions that can potentially increase volatilization. In the simulation, volatilization could be increased by one of the following: (1) decreasing the dry bulk density (e.g., from 190 to 70 kg/m^3), (2) decreasing the moisture content (e.g., from 50% to 30%), and (3) increasing diffusion-dispersion rates within the silage. Among the three, it was the last that led to emission profiles closer to those measured. Higher diffusion-dispersion coefficients allowed the new model to simulate higher transfer rates of ethanol and methanol from the second layer to the surface layer; this was also verified through numerical modeling with fine resolution, in which a faster movement of ethanol and methanol mass within the whole silage profile was modeled. But without comprehensive measured data (e.g., bulk density, moisture content, etc.), diffusion-dispersion coefficients were not refined. Also, it must be emphasized that the diffusion-dispersion coefficient relationship for ethanol implemented in the process-based model worked well with the experimental data by Montes et al. (2010) for packed silage (i.e., minimally disturbed bunker silo sample) and Hafner et al. (2010) for loose silage (i.e., with dry bulk density of around 130 kg/m^3).

Feed lanes (TMR Samples)

In simulating TMR samples representing feed lying in feed lanes, a dry bulk density of 190 kg/m^3 (Table 10) was estimated from known mass and approximate volume of TMR samples measured. In simulating corn silage samples, a lower dry bulk density (120 kg/m^3) was used. For both TMR and corn silage samples, measured and simulated ethanol and methanol emissions are plotted in Figure 26, with overall values summarized in Table 13. Unlike simulation of silage storages, no consistent trend was observed when simulating ethanol emissions from both TMR and corn silage samples using the new model. The new model did well in predicting ethanol emissions for a couple of TMR samples, namely trials 16 (+ 5% water) and 18 (+ 10% water) with $R_{s/m}$ of 0.78 and 0.74, respectively, and also for a corn silage sample (trial 21) with $R_{s/m}$ of 1.24. For trials 14 (TMR), 19 (TMR + 10% water), and 22 (corn silage), the new model was still able to simulate ethanol emissions reasonably, with predicted values within a factor of 2 of measured ($R_{s/m}$ of 0.53 to 0.56). For other remaining TMR samples (trials 13, 15, 17 and 20), $R_{s/m}$ were low, ranging from 0.22 to 0.41. There could be substantial uncertainty in measured ethanol emissions for trials 13, 15, and 22, where the amount of ethanol emitted appeared to exceed the initial ethanol content of the samples (see Figure A2.3 in the Appendix Supplementary Information section). The old model, on the other hand, tended to overpredict ethanol emissions (Figure 26), with $R_{s/m} > 1.5$ for 6 out of 10 trials.

Unlike the performance in simulating methanol emissions from silage storages, the new model overpredicted methanol emissions from TMR (trials 13 to 20) and corn silage samples (trials 21 to 22) (Figure 26). For all TMR samples, the cumulative amount of methanol emitted almost equaled the initial amount of methanol within the first 4 to 5 hours of measurement (Figure S4). Based on overall values (Table 13), $R_{s/m}$ for the new model were lowest for TMR without water addition (1.1 to 1.5) and highest for TMR with 10% water addition (2.4 to 3.5). In contrast, $R_{s/m}$ for corn silage samples were very low, with values of 0.09 and 0.23. These very low $R_{s/m}$ values, however, can be attributed to uncertainty in the measured emissions as total amounts of methanol emitted greatly exceeded the corresponding initial methanol contained in the samples (Figure A2.3). Similarly, the old model did not perform well in simulating methanol emissions from TMR and corn silage samples, with $R_{s/m}$ values (0.14 to 3.18) comparable to those for the new model (0.09 to 3.34).

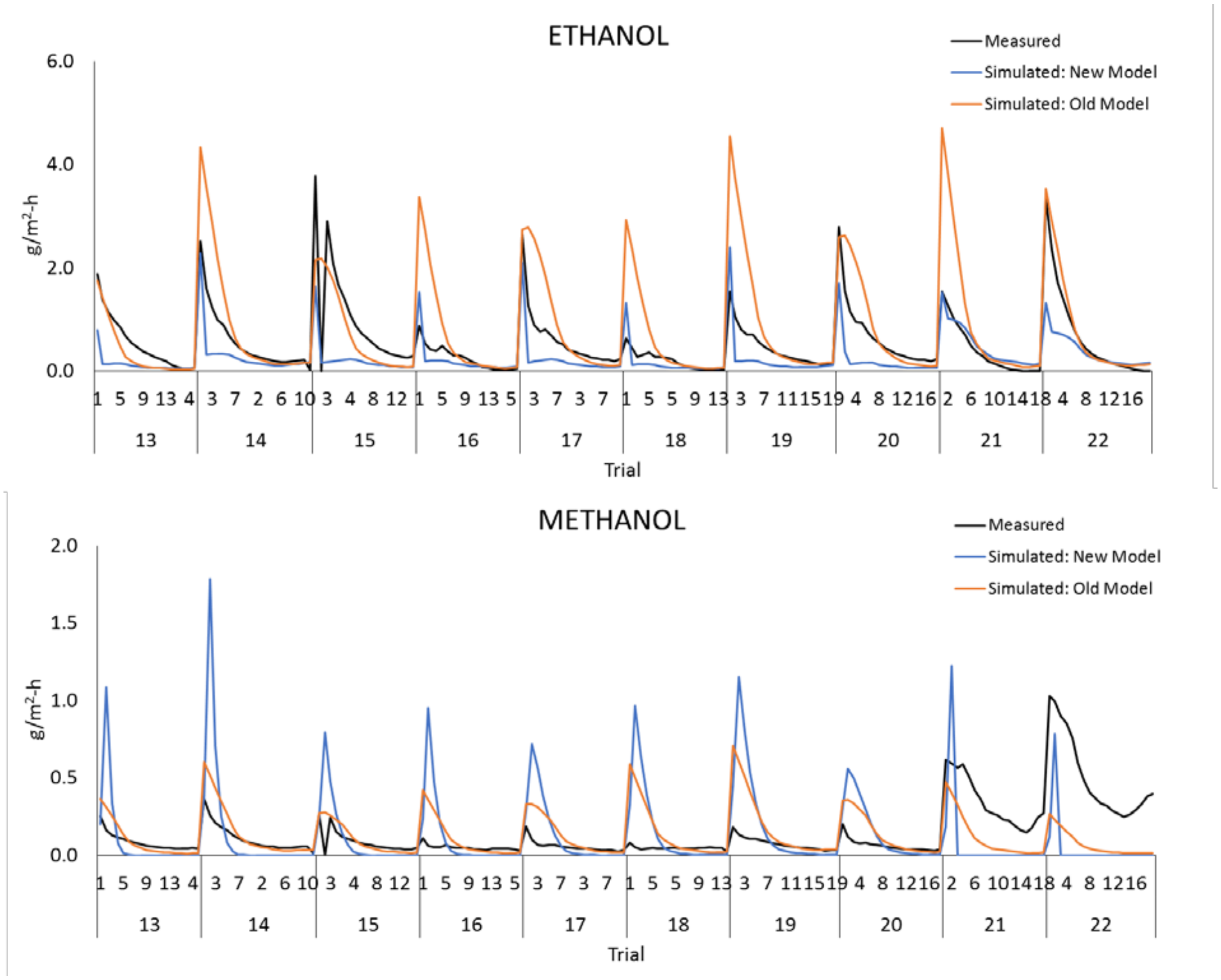

Figure 26. Comparison of simulated and flux chamber measured emissions for TMR and loose corn silage samples.

Similar to silage bags, the new model was able to predict the high ethanol emissions measured during the first hour but predicted a considerably lower emission profile for the succeeding hours (Figure 26). As explained for silage bags, the diffusion-dispersion coefficient relationship used may be causing the model to simulate low ethanol transfer rates from the second layer to the surface layer.

For both TMR and corn silage samples, the high methanol emission was predicted by the new model not for the first hour but for the second. For the first hour, $R_{s/m}$ were as follows: (1) 0.80 to 1.0 for TMR without water additions, (2) 1.5 to 2.1 for TMR + 5% water, (3) 1.5 to 4.0 for TMR + 10% water, and (4) 0.1 to 0.3 for corn silage samples. For the second hours, $R_{s/m}$ increased significantly: (1) ~ 7.0 for TMR without water additions, (2) 7 to 15 for TMR + 5% water, (3) 4.7 to 19.0 for TMR + 10% water, and (4) 0.8 to 2.1 for corn silage samples. To have the simulated profiles agree with measured, these findings suggest the need to lower the diffusion-dispersion coefficients used to predict methanol emission from TMR samples, which is opposite that needed for silage storages.

Table 13. Measured and simulated 12-h accumulated emissions of ethanol and methanol from TMR and corn silage samples.[1]

Trial	*Trial Sample*	*Ethanol*				*Methanol*			
		Concentration (mg/L)	*Emission rate (g/m^2)*			*Concentration (mg/L)*	*Emission rate (g/m^2)*		
			Measured	*Simulated*			*Measured*	*Simulated*	
				New	*Old*			*New*	*Old*
13	TMR + 0% water	62	6.4	1.4	4.4	16	1.0	1.1	1.1
14	TMR + 0% water	177	6.8	3.6	11.2	30	1.3	1.9	1.8
15	TMR + 0% water	127	11.9	2.7	8.8	18	1.1	1.3	1.2
16	TMR + 5% water	119	3.0	2.3	8.4	18	0.6	1.3	1.3
17	TMR + 5% water	165	7.3	3.0	11.2	22	0.7	1.6	1.5
18	TMR + 10% water	103	2.3	1.7	7.3	25	0.5	1.9	1.8
19	TMR + 10% water	186	5.4	2.8	12.3	35	0.9	2.4	2.2
20	TMR + 10% water	155	8.1	2.4	10.6	24	0.7	1.7	1.6
21	Corn silage	166	4.7	5.8	11.8	20	4.1	0.9	1.4
22	Corn silage	145	8.2	4.5	9.6	13	6.0	0.6	0.8
	All data		MAE	3.6	4.2		MAE	1.5	1.4
			RMSE	4.4	4.6		RMSE	2.2	2.0
			IA	0.44	0.38		IA	0.08	0.13

[1] MAE is the mean absolute error, RMSE is the root mean square error, and IA is the index of agreement.

Discussion on the Performance of the New Process-based Model

The new process-based model for silage VOC emissions performed well in simulating ethanol emissions for conventional silage piles. Using the refined settings for silage bulk density and moisture content, hourly ethanol emissions predicted were within range of and followed the trends of measured ethanol emissions. Simulation of methanol emissions for conventional silage piles suggests the need for experimental data to refine the emission and transport coefficients for different VOCs to be used in the new model. As presented, lower methanol emissions were predicted for conventional silage piles when using general equations (e.g., Mackay and Yeun, 1983). In our farm models, there are four different VOC groups simulated for silage sources: alcohols (represented by ethanol), acids (acetic acid), esters (ethyl acetate), and aldehydes (acetaldehydes). Among the four representative VOCs, only ethanol has relationships for these coefficients derived from experimental silage data.

Figure 27 shows the comparison of silage bags and conventional silage piles in terms of ethanol emission rate (i.e., mass of ethanol emitted per unit area of exposed silage face) and total mass of ethanol emitted based on measurements and simulation using the new model. Results for the old model are also included to illustrate the large improvement in VOC emission simulation using the new model. Note that trial 2 for a conventional silage pile was treated separately for demonstration purposes as it had an initial ethanol concentration (136 mg/L) half of that for other conventional silage piles (average of 317 mg/L) but within range of those for silage bags (average of 151 mg/L). Even if conventional silage piles (excluding trial 2) had the highest initial ethanol concentrations, it was silage bags that had the highest measured amounts of ethanol emitted per unit area of exposed silage face (Figure 27a). In addition, comparing measured emissions for silage bags and trial 2 of conventional silage piles showed that changing silage storage from conventional silage piles to silage bags doubled the amount of ethanol emitted per unit area (Figure 27a). These findings just show the high VOC emission rates (i.e., on an area basis) associated with low bulk density settings. With larger areas of exposed silage face, however, conventional silage piles had much greater total emissions than silage bags as shown in Figure 27b. Using areas of 13 m^2 and 140 m^2 for silage bags and conventional silage piles, total masses of ethanol emitted based on measurements were 134 g for silage bags and 684 (trial 2) to 1,051 g from conventional silage piles.

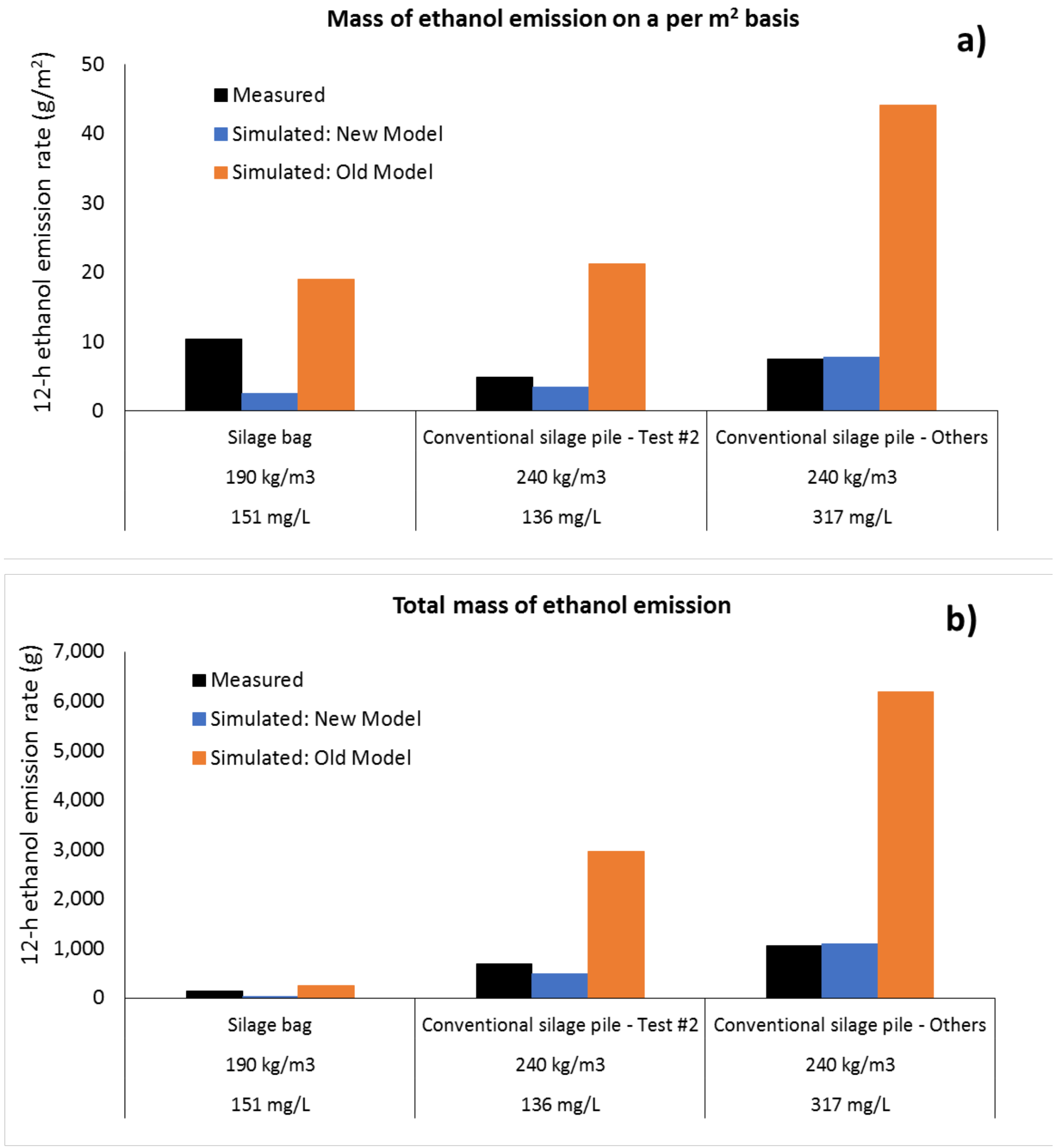

Figure 27. Comparison of simulated and flux-chamber measured 12-h ethanol emissions for TMR and loose corn silage samples: a) mass emitted on a per m^2 basis of exposed silage face; b) total mass emitted.

For silage bags and TMR samples, both of which had lower bulk densities than conventional silage piles, the new model predicted lower ethanol emissions on an area basis. In the new model, dry bulk density affects the calculation of the effective surface mass transfer coefficient (α in eq. 3), effective diffusion mass transfer coefficient (D_b in eq. 4), adjustment of diffusion-dispersion coefficient (k_{sg}) to represent diffusion in a porous media (i.e., Millington-Quirk model), and the amount of VOC in the surface layer readily available for volatilization. With the 240 kg/m^3 setting as reference, simulating the conventional silage piles at different bulk densities with the new model resulted in the following (maximum) percent changes in ethanol emissions: 3% increase at 190 kg/m^3, 7% decrease at 290 kg/m^3, and 18% decrease at 350 kg/m^3. At lower dry bulk densities (< 190 kg/m^3), a decrease rather than an increase in ethanol emissions were simulated. Even by adjusting the depth of the surface layer with respect to dry bulk density (Table 10), a very low dry bulk density setting would eventually have limited the amount of ethanol readily available for volatilization in the simulation.

If dry bulk densities assumed for silage bags and TMR samples were close to actual conditions and emissions measured were reliable, results suggest a need to refine emission and transport coefficients (e.g., k_{sg}) not only as a function of wind speed and friction velocity but also dry bulk density. Refinement was not performed at this time as dry bulk densities for conventional silage piles and silage bags were not measured. It is also important to have more measurements to verify the effects of dry bulk density and/or storage type on VOC emissions. Using measured emissions, percentage losses of initial ethanol and methanol present in the first 1 m of silage were 0.45% and 2.5% for conventional silage piles and 3% and 6% for silage bags, respectively. These indicate that changing the storage type from conventional silage piles to silage bags (or decreasing dry bulk density) resulted to a 7x increase in measured ethanol emissions per unit of exposed surface area but only a 2.5x increase in measured methanol emissions. This was quite unexpected as methanol is more volatile than ethanol. In addition, comparing conventional silage piles and silage bags in terms of measured initial concentrations and measured 12-h emission rates (flux-chambers) resulted to contrasting trends between ethanol and methanol (Tables 11 and 12). Silage bags, which had lower initial methanol concentrations (average of 10 mg/L), had lower 12-h methanol emission rates on an area basis (1.8 g/m^2) than conventional silage piles (30 mg/L, 4.1 g/m^2). In contrast, even with lower initial ethanol concentrations (151 mg/L), silage bags had higher 12-h ethanol emission rates (10 g/m^2) than conventional silage piles (297 mg/L, 7.2 g/m^2).

There could be two possible scenarios to explain why the new model overpredicted methanol emissions from TMR samples, which was in contrast to simulations of conventional silage piles and silage bags. First, given that the new model overpredicted methanol emissions, water addition could have lowered methanol emissions from TMR samples as some VOCs may have high affinity to a liquid phase leading to lower volatilization (which is not simulated in the model); but then again, this might not be the case as the new model actually underpredicted ethanol emissions. Second, with TMR samples having a very loose structure after mixing and methanol having high volatility (i.e., twice that of ethanol), some of the methanol might have been lost during sample collection and set-up prior to emission measurement. Considering the findings for conventional silage piles and silage bags, the second scenario would likely explain the higher methanol emissions predicted by the new model.

Model Application

The new silage VOC emission model is incorporated as a component of the Integrated Farm System Model (IFSM; USDA/ARS, 2015) where it can be used to evaluate the effects of management changes on the performance, economics and environmental impacts of farm systems. Despite the uncertainty remaining in model predictions, it still provides a valuable tool for comparing management options. Although we cannot be certain of the absolute amounts of emissions predicted, the relative differences created through management and environmental changes should reflect the impact of mitigation strategies. To illustrate the use of the model, several silage management options were simulated on a representative dairy farm in Central California.

Whole Farm Model

The IFSM simulates crop production, feed use, and the return of manure nutrients back to the land for many years of daily weather on a crop, dairy, or beef farm (Rotz et al., 2015). Daily growth and development of crops are predicted based upon soil water and N availability, ambient temperature, and solar radiation. Simulated tillage, planting, harvest, storage, and feeding operations predict resource use, timeliness of operations, crop losses, and nutritive quality of feeds. Feed allocation and animal responses are related to the nutrient contents of available feeds and the nutrient requirements of the animal groups making up the herd. The quantity and nutrient contents of the manure produced are a function of the feeds consumed and herd characteristics.

Nutrient flows are tracked to predict losses to the environment and potential accumulation in the soil (Rotz et al., 2015). Losses include ammonia (NH_3) volatilization, denitrification and leaching losses of N, and erosion of sediment and runoff of sediment-bound and dissolved N and P across the farm boundaries. Carbon dioxide, CH_4, and N_2O emissions are tracked from crop, animal, and manure sources and sinks to predict net greenhouse gas emission in CO_2 equivalent units. Whole-farm mass balances of N, P, K, and C are determined as the sum of nutrient imports in feed, fertilizer, deposition, and fixation minus the nutrient exports in milk, excess feed, animals, manure, and losses leaving the operation. A cradle-to-farm gate life cycle assessment is done to determine annual carbon, energy, water, and reactive N footprints of the farm products produced.

Simulated performance is used to determine production costs, incomes, and economic return for each year of weather. A whole-farm budget includes fixed and variable production costs (Rotz et al., 2015). All important production costs are subtracted from the total income received for animal and excess feed sales to determine a net return to management. By comparing simulation results, differences among production systems can be determined, including annual resource use, production efficiency, environmental impacts, production costs, and farm profit. The distribution of annual values can be used to evaluate the risk or variance due to the variation in daily and annual weather patterns.

The new silage VOC component provides the ability to evaluate management effects on VOC emissions along with other aspects of the farm. To represent total VOC emission, we consider four groups of VOCs which have the most potential to contribute to poor air quality: acids, alcohols, esters, and aldehydes (Hafner et al., 2013). On farms, VOC emission from silage is determined by the production of VOCs in silage and the fraction of each compound that is volatilized. VOC production can vary greatly among silages, and the sources of this variability are not yet known (Hafner et al., 2013). Therefore, VOC production is set as an initial concentration based on typical values for different types of silage. From these fixed initial concentrations, we simulate VOC emissions as described above. Emission losses are predicted and the remaining VOC mass is tracked as silage moves through three stages: storage removal (when silage is exposed on the open surface following daily or more frequent feed removal), feed mixing, and feeding in a feed lane or bunk. Emissions during initial filling, fermentation and storage phases of silage management are not modeled. Emissions during these phases have not been measured and they are assumed to be small and unimportant compared to those from the silage face and feeding of the silage. VOC emission during storage removal and mixing reduces the concentration of VOCs present in the remaining stages. Calculated emissions from each group of compounds are aggregated after normalizing emissions based on the ozone formation potential of each group. Normalized ozone formation potential is determined as the predicted VOC emission of that group times the Equal Benefit Incremental Reactivity (kg O3 per kg VOC) of that compound group (Howard et al., 2015).

For completeness, VOC emissions are also predicted from manure sources in the housing facility, during storage and following field application (Rotz et al., 2015). A similar approach as that used for silage is used to estimate manure emissions where an initial concentration is assumed and losses are predicted using theoretical relationships of mass transfer. Total VOCs tracked are divided into 5 groups (C2 and C3 acids, C4 and larger acids, alcohols, aromatic acids and aromatics). Compounds used to represent each of the groups are acetic acid, butyric acid, ethanol, phenyl-acetic and indole, respectively. This portion of the model has not been evaluated with farm data so the accuracy of these estimates are unknown. We include a measure of these predictions in our simulations to indicate how changes in silage emissions affect whole farm emissions. In general, reactive VOC emissions from manure are relatively small compared to that from silage. Our whole farm estimated emissions do not include enteric emissions from the animals other than methane. There are likely other compounds emitted by the animals, but little data exist to support a model of this source. This source is also expected to be relatively small compared to silage and manure sources.

Farm Description

To illustrate the impacts of silage management, a representative dairy farm was simulated in central California. The farm represented a well-managed dairy production system for this region. The farm included 2,000 Holstein cows and 1,650 replacement heifers on 300 ha of clay loam soil. Crops produced were corn silage followed by oat silage in a double crop system. Irrigation was used as needed with up to 60 cm applied to corn and up to 20 cm applied to the winter oat crop. Corn silage harvest was initiated around September 1 and oat silage was harvested in the spring beginning around April 20. Corn and oat silages were preserved in covered silage piles.

Annual milk production was 11,000 kg/cow corrected to 4% fat and 3.3% protein. All animals were fed total mixed rations. Farm produced silage was supplemented with purchased alfalfa hay, corn grain, and high protein feed mixes to meet energy, protein and mineral requirements. All animals were housed in free stall barns with access to open lots. Manure was flushed from free stall floors daily and handled as a liquid slurry. Manure from the lots was handled dry and exported from the farm to maintain a phosphorus balance for the cropland. Liquid manure was stored in a lined earthen basin for up to 6 months and applied to cropland with 70% of the manure applied to the corn crop. Nitrogen fertilizer was applied to corn at a rate of 100 kg/ha. All other crop nutrient needs were met through manure application. The farm was simulated over 25 years of historical weather for Sacramento (1981 to 2005).

Silage Management Options

Simulation results for various silage management options are shown in Table 14. For the base farm with silage stored in conventional piles, about 4,000 kg of reactive VOCs were emitted each year with over 30,000 kg emitted during feeding. Most of the feeding loss occurred from the feed lane with a relatively small emission during the mixing of the total mixed ration. The main driver for this relatively large loss during feeding is the large surface area exposed. The exposed surface area of the silage face is about 140 m^2. When the feed is laid in front of the cattle, the exposed area is about 0.5 m^2 per cow with a little less area for younger animals. For the simulated farm, the exposed surface area of feed in the feed lane was about 1,200 m^2, over 8 times that of the silage face. With similar emission rates per unit of exposed area, much more emission occurs from the feed lane. An additional 8,000 kg of reactive VOC was predicted to be emitted from manure sources, which was about 25% of that emitted from silage.

Table 14. Effect of various silage storage and feeding practices on the potential ozone forming VOC emissions[1] from a representative California dairy farm[2].

		Silage face	*Feeding*[3]	*Total silage loss*		*Total farm*[4]	
		kg	*kg*	*kg*	*% change*[5]	*kg*	*% change*[5]
Storage type	Conventional pile	4,053	30,734	34,787		42,973	
	Bunker	4,474	30,841	35,315	1.5	43,491	1.2
	Bag	427	32,222	32,649	-6.1	40,806	-5.0
Silage unloader	Bucket	4,053	30,734	34,787		42,973	
	Defacer	3,088	30,986	34,974	-2.0	42,260	-1.7
Pack density	Light tractor	4,472	30,663	35,135		43,319	0.8
	Heavy tractor	4,053	30,734	34,787	-1.0	42,973	
Feeding site	Dry lot corral	4,056	49,298	53,354		61,936	44.1
	Free stall barn	4,053	30,734	34,787	-53	42,973	
	Enclosed barn	4,053	31,125	35,178	-52	42,855	-0.3
Location	Central CA	4,053	30,734	34,787		42,973	
	Southern ID	2,844	21,580	24,424	-30.0	31,584	-26.5

[1] Total VOC emissions are converted to their potential to form atmospheric ozone based upon their reactivity.

[2] 2000 cows plus 1650 replacement heifers on 3000 ha of double cropped corn and small grain harvested, stored and feed as silage.

[3] Loss occurring during feed mixing and silage lying in the feed lane.

[4] Total farm includes estimated losses from manure during housing, storage and field application.

[5] Percent change is computed as 100 times the difference between the emission from the alternative option and the base option divided by the base option emission. The base option for each are the conventional pile, bucket unloader, light tractor, dry lot corral and central California, respectively.

The storage type used can have a major effect on VOC emissions (Table 14). A bunker silo can be used with side walls allowing a greater depth and smaller width along with some increase in packed density. This change, however, had little effect on emissions. Use of silage bags greatly reduced the loss from the silage face due to the relatively small exposed surface area. With less loss at the silage face, greater loss occurred during feeding, and overall there was a 7% decrease in reactive VOC emissions from silage and about a 5% decrease from the whole farm.

Technology referred to as a silage defacer, provides a smoother and denser face on the silage surface. Simulation of this option provided a 24% decrease in loss from the face of the silage pile. The increased concentration in the silage fed caused a small 1% increase in emissions from the feed lane. Over all sources, there was only a 2% decrease from silage and less than a 2% decrease from the whole farm (Table 14). Although this defacing technology can provide substantial reductions from the silage face, this simulation indicates relatively low benefit from a whole farm perspective.

The size of the tractor used to pack the silage affects the density of the packed silage. Our simulation indicates that this difference in density has little effect on VOC emissions (Table 14). Our present model assumes that the initial concentrations of VOC compounds in the silage are similar regardless of density. This may not be the case in reality. Better packing should improve silage fermentation, which may reduce the concentrations of some compounds and increase the concentrations of others. If the production of the most volatile and reactive compounds such as alcohols is reduced, this may provide more benefit than the current model illustrates. The effect of silage density on VOC production is not well understood, but is likely relatively small.

The cow housing (i.e. feeding location) may have the greatest impact on silage VOC emissions (Table 12). Our simulations indicate that feeding cows in an open feed lane on an open dry lot can greatly increase reactive VOC emissions compared to an open, naturally ventilated (i.e. roofed but w/o side walls) free stall barn or an enclosed free stall barn that is mechanically ventilated (not used in CA but in the Midwest and Eastern US). The cause of this great difference is the velocity of air moving over the silage surface. When cows are fed inside a structure, air movement is reduced and our model shows a high sensitivity to air speed over the feed. To our knowledge, on-farm measurements have not been made to support or disprove this prediction for emissions across housing/feeding systems. Such measurements are needed before recommendations on mitigation strategies can be made. These simulated data indicate that changes in the feed bunk design to limit air flow over the feed could perhaps provide the greatest benefit in reducing VOC emissions from California dairy farms and this may be achieved with little added cost to the producer.

A final set of simulations illustrates the effect that climate can have on reactive VOC emissions. By simulating the same dairy farm in the climate of southern Idaho, emissions were reduced by 30% (Table 14). This effect is influenced primarily by lower ambient temperatures where the average annual temperature in Idaho was 5^{o}C less than that in the SJV. Wind speed also averaged about 15% less in Idaho, which contributed to the reduction in emissions.

Conclusions

Using measurements from commercial California dairy farms collected through the present project, it was determined that the old silage VOC emission model performed poorly in predicting ethanol and methanol emissions from different silage sources measured under field conditions, particularly those for conventional silage piles in which simulated ethanol emissions were 4 to 9 times the measured data. The tendency to overpredict ethanol emissions and the inconsistency associated with simulating methanol emissions was attributed to the nature of the original simple three-pool model. Rather than simulating the different processes (i.e., surface emission and mass transport) leading to emission of VOCs from silage, the previous model just approximated the fraction of VOC lost from each pool with respect to time. As a result, the old model was not able to simulate effects of silage bulk density and moisture content on VOC emissions, and was not capable of predicting the characteristic trends of VOC emissions.

Through the present grant, these inadequacies in simulating silage VOC emissions were addressed by developing a new process-based model based upon theoretical relationships of mass transfer and surface emission. Surface emission from and mass transfer of VOCs within silage were simulated through numerical modeling. Data from our previous laboratory experiments were used to refine expressions for coefficients for surface mass transfer and gaseous phase diffusion-dispersion for ethanol emissions. Critical for incorporation into whole farm simulation models (IFSM and DairyGEM), simulation layers in the new process-based model were made functions of friction velocity and silage source dry bulk density to significantly shorten the simulation time required (i.e., from several hours to a few seconds). Simulating emissions from the surface and mass transfer of VOC groups within the silage, the new model worked relatively well in predicting ethanol emissions measured from corn silage on California dairies. Profiles characteristic to silage ethanol emissions are now simulated, with high emissions during the first hours of exposure followed by a decline in the succeeding hours. For methanol, however, the new model underpredicted the measured emissions. Hence, more work is needed to determine the cause of and to reduce the discrepancy when simulating emissions of methanol and, possibly, other VOCs.

The new silage VOC emission model was incorporated as a component of a whole farm simulation model where it can be used to evaluate management effects on VOC emissions along with other aspects of farm performance, environmental impact and economics. Simulations of a representative dairy farm in California indicate that most of the reactive VOC emissions occur from feed lying in feed lanes during feeding as opposed to the exposed face of silage piles and/or bags. This implies that mitigation efforts on reducing emissions during feeding rather than those from the exposed face of the silage pile will be most effective.

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Appendix

A1. Emission comparisons between Conventional Silage Pile vs. Silage Bag per Area

The emissions between the conventional silage pile and the silage bag were compared to provide differences of VOC and NOx emissions of two commonly used silage storage systems. Both silage storage systems commonly use extraction via front-end loader with perpendicular defacing action, a practice used in the present study.

Figures A1.1-A1.7 show means of gas emissions of the two major storage forms, namely the conventional silage pile vs. a silage bag for the area of coverage by the flux chamber (m^2). More meaningful are Figures 8-14 in the main text of this report, that show means of gas emissions for conventional silage pile vs. a silage bag but this time corrected for the total exposed silage face (rather than per area coverage of the flux chamber). True comparisons between storage types should be conducted in the latter manner, because the silage bag vs conventional silage pile have exposure areas that differ by an order of magnitude. Figures A1.1-A1.7 present measurements between the silage bag and the conventional silage pile. The silage bag produced greater methane, nitric oxide, nitrous oxide, ammonia, and ethanol emissions when compared by surface area of the flux chamber. Conversely, the conventional silage pile vs. silage bag produced more methanol and nitrogen dioxide (Figures A1.1-A1.7). However, it must be reiterated, that these measurements in Figures A1.1-A1.7 depict only the emissions from the area of the flux chamber (i.e. only sampling the area they covered). For completeness, the raw data from the conventional silage pile and the silage bag are provided, however, more important than the emissions per measured m^2, are the emissions per silage pile face exposed to the atmosphere.

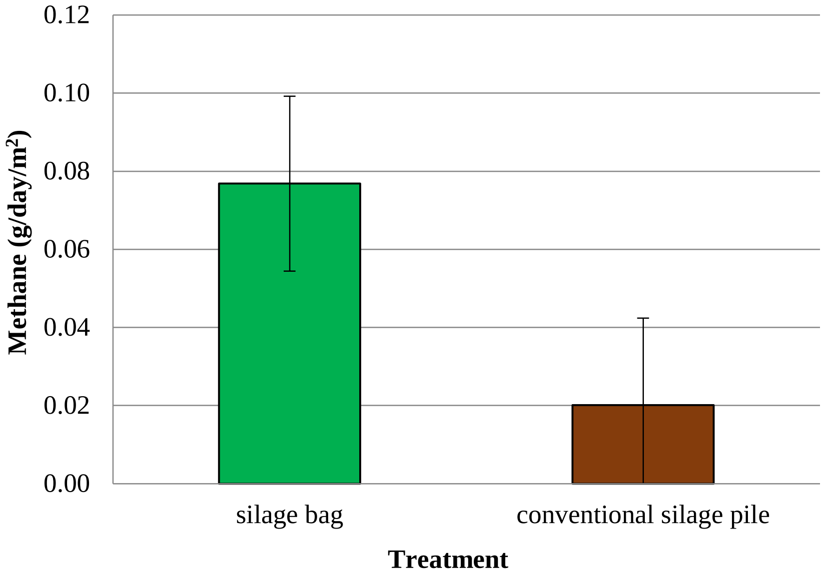

Figure A1.1. Means of silage storage types on methane emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

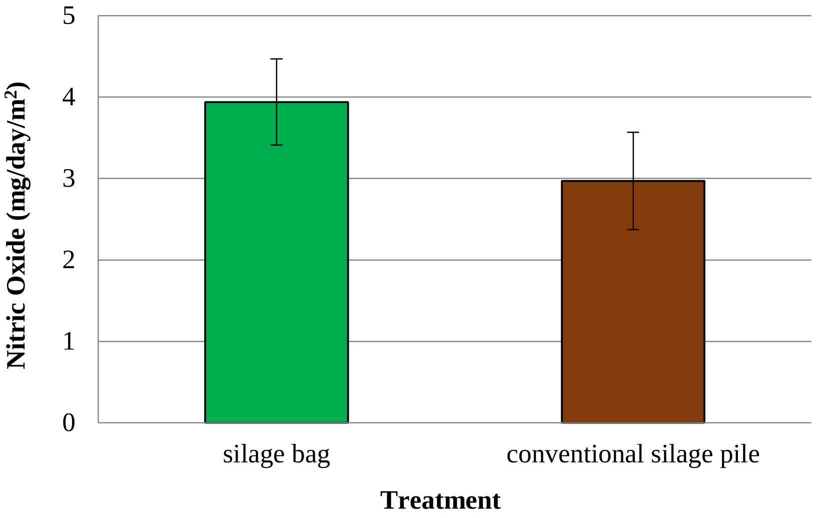

Figure A1.2. Means of silage storage types on nitric oxide emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

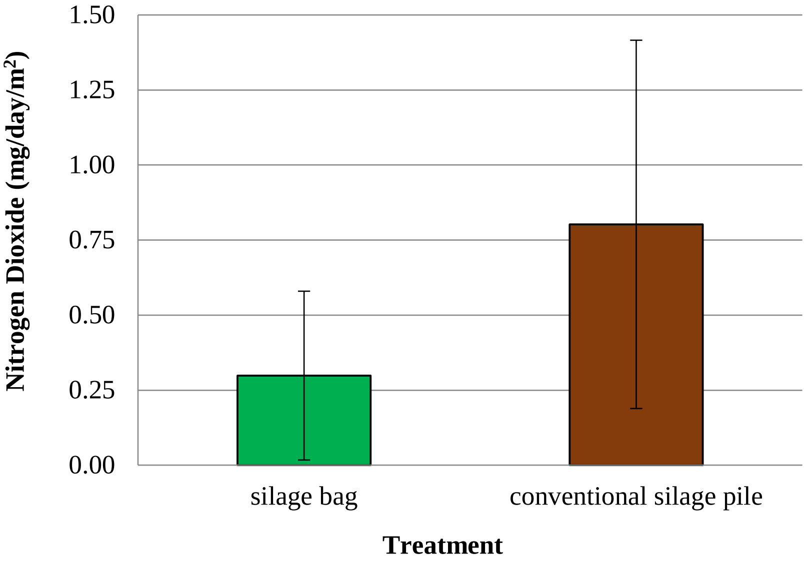

Figure A1.3. Means of silage storage types on nitrogen dioxide emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

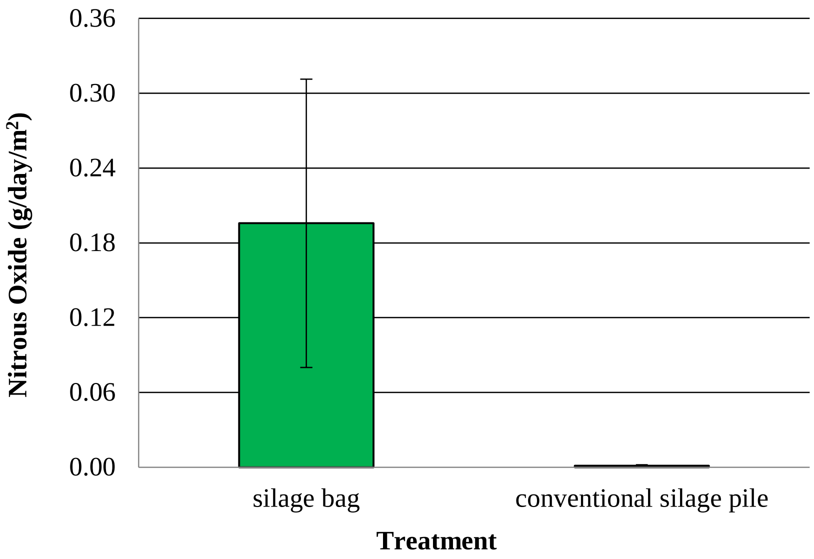

Figure A1.4. Means of silage storage types on nitrous oxide emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

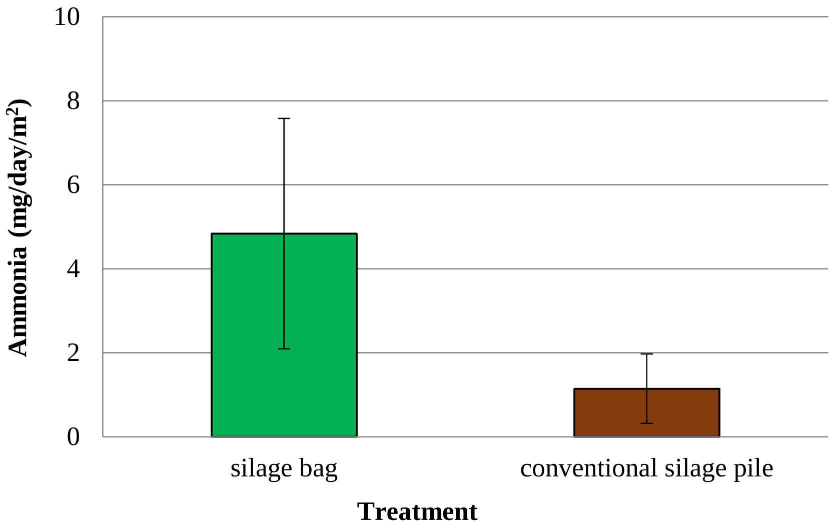

Figure A1.5. Means of silage storage types on ammonia emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

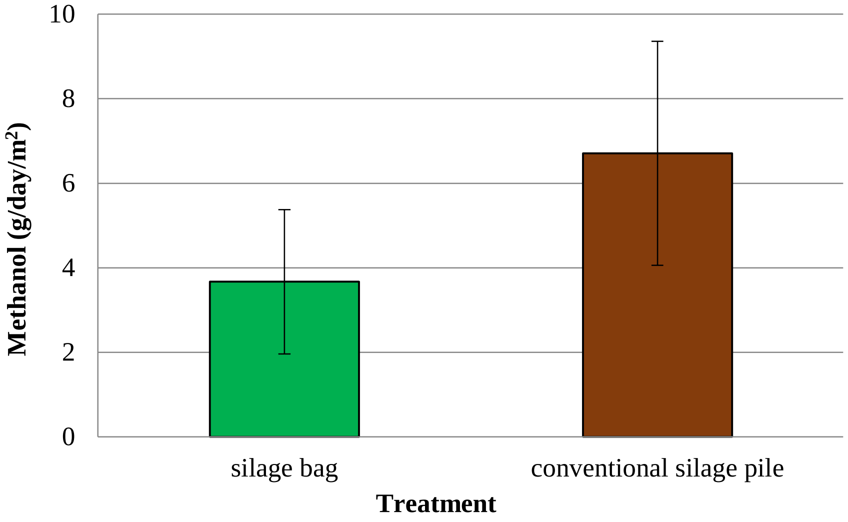

Figure A1.6. Means of silage storage types on methanol emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

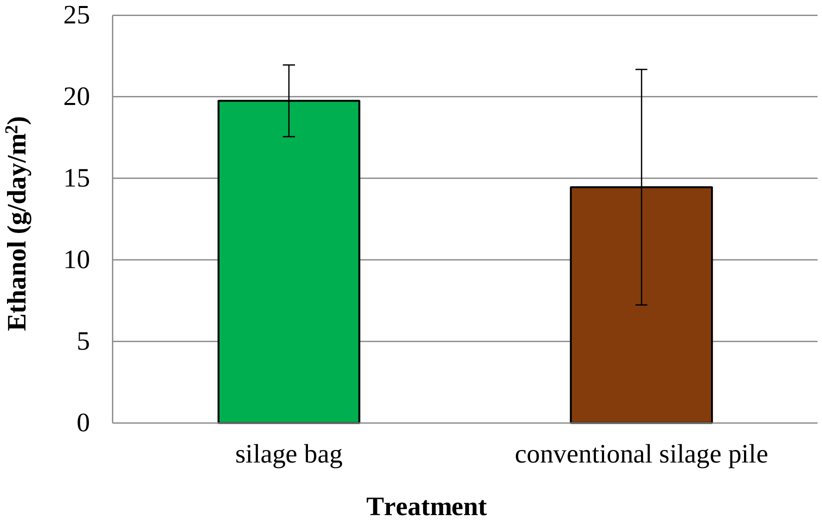

Figure A1.7. Means of silage storage types on ethanol emissions (each of these treatments were measured on three different days and the bars indicate the standard deviation).

Table AD-5 summarizes the results of Figure A1.1-A1.7 comparing the gas emissions per area from conventional silage pile vs. silage bag.

Table A1.1. Comparison of gas emissions per area between different silage storage

	Silage storage	
Gas emissions	Silage bag	Conventional silage pile
Methane (g/day/m^2)	0.08 ± 0.02	0.02 ± 0.02
Nitric Oxide (mg/day/m^2)	3.94 ± 0.53	2.97 ± 0.60
Nitrogen Dioxide (mg/day/m^2)	0.30 ± 0.28	0.80 ± 0.61
Nitrous Oxide (mg/day/m^2)	0.20 ± 0.12	0.001 ± 0.001
Ammonia (mg/day/m^2)	4.84 ± 2.74	1.14 ± 0.82
Methanol (g/day/m^2)	3.67 ± 1.71	6.71 ± 2.65
Ethanol (g/day/m^2)	19.76 ± 2.20	14.46 ± 7.21
TOFP[1] (O_3 g/day/m^2)	31.04	25.33

[1] TOFP: Total Ozone Forming Potential of Methane, Methanol, and Ethanol

A2. Supplementary Information for Chapter 4.

Note: Figures A2.1 and A2.2 are simulation results for ethanol and methanol emissions from the conventional silage piles using the former VOC emission model (i.e., the model incorporated in IFSM ver. 4.2 and DairyGEM ver. 3.2). Similar profiles were obtained for silage bags (profiles not shown).

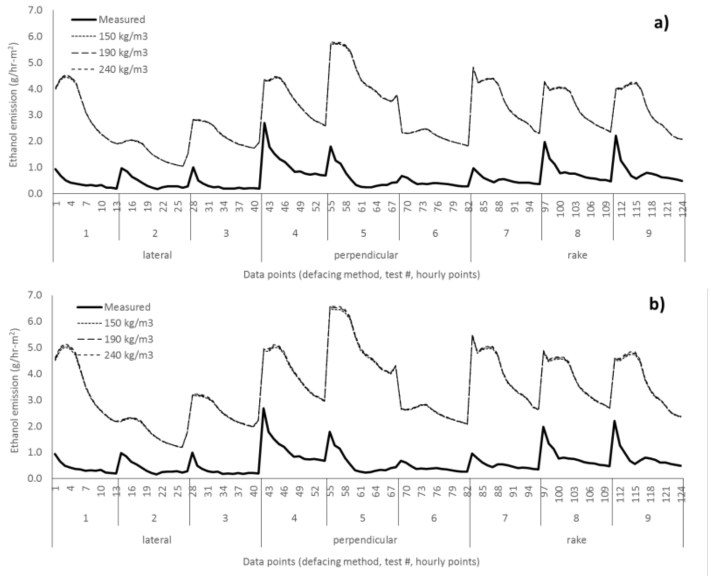

Figure A2.1. Measured and simulated ethanol emissions for the conventional silage piles using the former VOC emission model. For simulation, figures presented are based on various dry bulk densities and moisture contents of a) 70% and b) 60%.

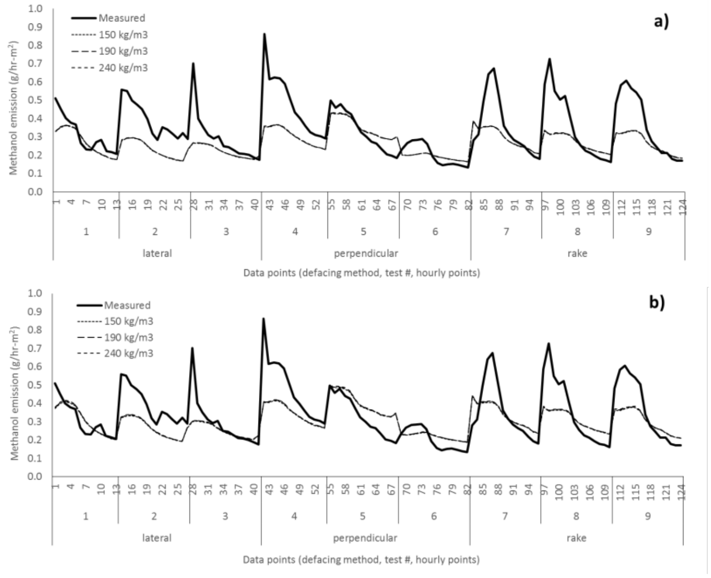

Figure A2.2. Measured and simulated methanol emissions for the conventional silage piles using the former VOC emission model. For simulation, figures presented are based on various dry bulk densities and moisture contents of a) 70% and b) 60%.

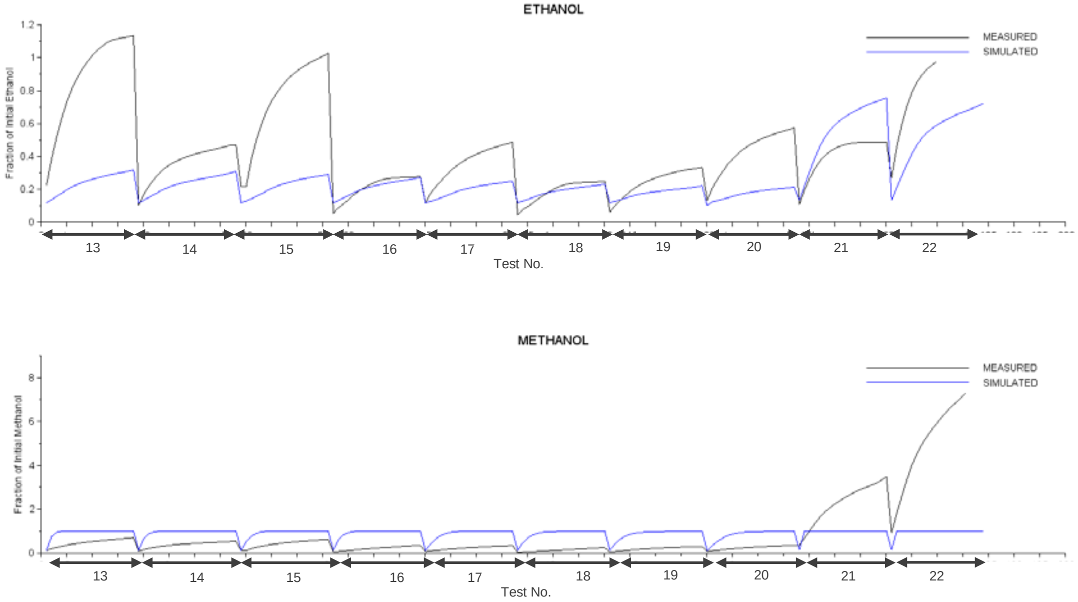

Figure A2.3. Comparison of simulated and flux-chamber-based emissions for TMR and loose corn silage samples normalized with respect to initial ethanol and methanol contents.

SJVAPCD Rule 4570

The following section describes the current feed related rule elements for SJVAPCD Rule 4570:

As a result, we caution the use of additives as a mitigation measure for silage as is currently listed in Rule 4570. Listed below are the various mitigation strategies specifically for animal feed, outlined by Rule 4570.

Rule 4570 “The purpose of this rule is to limit emissions of volatile organic compounds (VOC) from Confined Animal Facilities (CAF).

- Phase I Mitigation Measures: Owners/operators of large CAFs shall comply with the following Phase I Mitigation Measures in Section 5.5 until compliance with all applicable Phase II Mitigation Measures in Section 5.6 is demonstrated in accordance with the compliance schedule in Section 8.0.
- 5.5.1 Dairy CAF: Owners/operators of a large Dairy CAF shall comply with the Phase I requirements in Table 3.1:
  - Table 3.1 – Large Dairy CAF Phase I Mitigation Measure Requirements
    - A. Owners/operators shall incorporate at least four (4) of the following feed mitigation measures:
      - Class One Mitigation Measures
        - 1. a. Feed according to National Research Council (NRC) guidelines.
        - 2. a. Feed animals high moisture corn or steam-flaked corn and not feed animals dry rolled corn.
        - 3. a. At least once every fourteen (14) days remove feed from the area where animals stand to eat feed.
        - 4. a. At least once every fourteen (14) days remove spilled feed from the area where equipment travels to place feed in the feed bunk.
        - 5. a. Remove uneaten wet feed from feed bunks within twenty-four (24) hours of a rain event.
        - 6. a. Feed or dispose of rations within forty-eight (48) hours of grinding and mixing rations.
        - 7. a. Store grain in a weatherproof storage structure from October through May.
        - 8. a. Implement an alternative mitigation measure(s), not listed above.
    - B. Owners/operators shall incorporate at least one (1) of the following feed mitigation measures:
      - Class One Mitigation Measures
          - 1. a. Cover the horizontal surface of silage piles, except for the area where feed is being removed from the pile.

            - 2. a. Collect leachate from the silage piles and send it to a waste treatment system such as a lagoon at least once every twenty-four (24) hours.
            - 3. a. Implement an alternative mitigation measure(s), not listed above.
        - Class Two Mitigation Measures
            - 4. a. Enclose silage in a bag and vent to a VOC control device with a combined VOC capture and VOC control efficiency of at least 80%, or b. Enclose silage in a weatherproof structure and vent to a VOC control device with a combined VOC capture and VOC control efficiency of at least 80%, or c. Eliminate silage from animal diet.
- 5.6 Phase II Mitigation Measures: Owners/operators of CAFs subject to the regulatory threshold in Table 2 shall comply with all applicable Phase II Mitigation Measures in accordance with the compliance schedule in Section 8.0.
    - 5.6.1 Dairy CAF: An owner/operator of a medium or large Dairy CAF shall comply with the Phase II mitigation measures in Table 4.1.
- Table 4.1 – Dairy CAF Phase II Mitigation Measure Requirements
    - A. Feed: An owner/operator of a dairy CAF shall implement mitigation measures 1, 2, 3, and 4 and at least one (1) additional mitigation measure:
    - 1. Feed according to National Research Council (NRC) guidelines.
    - 2. Push feed so that it is within three (3) feet of feed lane fence within two hours of putting out the feed or use a feed trough or other feeding structure designed to maintain feed within reach of the cows.
    - 3. Begin feeding total mixed rations within two (2) hours of grinding and mixing rations.
    - 4. Store grain in a weatherproof storage structure or under a weatherproof covering from October through May.
    - 5. Feed steam-flaked, dry rolled, cracked or ground corn or other steam-flaked, dry rolled, cracked or ground cereal grains.
    - 6. Remove uneaten wet feed from feed bunks within twenty-four (24) hours after the end of a rain event.
    - 7. For total mixed rations that contain at least 30% by weight of silage, feed animals total mixed rations that contain at least 45% moisture.
    - 8. Implement an alternative mitigation measure(s), not listed above.
- B. Silage: An owner/operator of a dairy CAF that feeds silage shall implement at least one (1) of the following silage mitigation measures:
    - 1. Operators selecting this option must choose mitigation measure 1a plus one (1) from mitigation measures 1b, 1c, 1d plus two (2) from mitigation measures 1e, 1f, 1g:
    - a. Cover the surface of silage piles, except for the area where feed is being removed from the pile, with a plastic tarp that is at least five (5) mils thick (0.005 inches), multiple plastic tarps with a cumulative thickness of at least 5 mils (0.005 inches), or an oxygen barrier film covered with a UV resistant material, within seventy-two (72) hours of last delivery of material to the pile.

- b. Build silage piles such that the average bulk density of silage piles is at least 44 lb/cu ft for corn silage and 40 lb/cu ft for other silage types, as measured in accordance with Section 7.11; or
- c. When creating a silage pile, adjust filling parameters to assure a calculated average bulk density of at least 44 lb/cu ft for corn silage and at least 40 lb/cu ft for other silage types, using a spreadsheet approved by the District; or
- d. Incorporate all of the following practices when creating silage piles:
  - i. Harvest silage crop at ≥65% moisture for corn; and ≥60% moisture for alfalfa/ grass and other silage crops; and
  - ii. Incorporate the following parameters for Theoretical Length of Chop (TLC) and roller opening, as applicable, for the crop being harvested. Crop Harvested TLC (inches) Roller Opening (mm) Corn with no processing ≤ 1/2 in N/A Processed Corn
  - iii. Manage silage material delivery such that no more than six (6) inches of material are un-compacted on top of the pile.
- Choose two of the following:
  - e. Manage exposed silage (select one of the following):
    - i. Manage silage piles such that only one silage pile has an uncovered face and the uncovered face has a total exposed surface area of less than 2,150 square feet; or
    - ii. Manage multiple uncovered silage piles such that the total exposed surface area of all uncovered silage piles is less than 4,300 square feet.
- f. Maintain silage working face (select one of the following):
  - i. Use a shaver/facer to remove silage from the silage pile; or
  - ii. Maintain a smooth vertical surface on the working face of the silage pile.
- g. Silage Additives (select one of the following):
  - i. Inoculate silage with homolactic lactic acid bacteria in accordance with manufacturer recommendations to achieve a concentration of at least 100,000 colony forming units per gram of wet forage; or
  - ii. Apply propionic acid, benzoic acid, sorbic acid, sodium benzoate, or potassium sorbate at a rate specified by the manufacturer to reduce yeast counts when forming silage pile; or
  - iii. Apply other additives at specified rates that have been demonstrated to reduce alcohol concentrations in silage and/or VOC emissions from silage and have been approved by the District and EPA.
- 2. Utilize a sealed feed storage system (e.g., Silage bag) for silage.
- 3. Implement an alternative mitigation measure(s), not listed above.

(SJVAPCD, 2010)

Exhibit 11

Assessment of the Emissions and Energy Impacts of Biomass and Biogas Use in California

Provided to the California Air Resources Board
by

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Professor Donald Dabdub
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January 14, 2015

Agreement #11-307

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DISCLAIMER

Table of Contents

List of Figures

List of Tables

Abstract

Biomass contributes more than 5,700 Gigawatt-hour to California's instate renewable power, approximately 19% of in-state renewable power and 2% of full California power mix. Current operating biopower capacity is about 900 Megawatt (MW), including approximately 550 MW of woody biomass solid fuel combustion, 280 MW of landfill gas-to-energy and 75 MW from wastewater treatment biogas. It is estimated that there is sufficient in-state 'technically' recoverable biomass to support another 2,800 MW of capacity or 21 Terawatt-hour of electricity. While most biomass energy is derived from woody material (including urban wood waste, forest product residue as well as agricultural residues), there is a growing interest in using municipal solid waste, food processing waste, increased use of animal manures and applying co-digestion techniques at wastewater treatment facilities to generate electricity and renewable fuels. Increasing production of bioenergy contributes to energy sustainability while reducing greenhouse gas emissions and could help reduce criteria pollutant emissions.

This study assesses the air quality impacts of new and existing bioenergy capacity throughout the state, focusing on feedstocks, and advanced technologies utilizing biomass resources predominant in each region. The options for bioresources include the production of biopower, renewable NG and ethanol. Emissions of criteria pollutants and greenhouse gases are evaluated for a set of scenarios that span the emission factors for power generation, and the uses of renewable natural gas for vehicle fueling and pipeline injection. Emission factors combined with the geospatially-resolved bioenergy outputs (facility locations) are used to generate new emission source locations and magnitudes which are input to the Community Multiscale Air Quality model (CMAQ) to predict regional and statewide temporal air quality impacts from the biopower scenarios.

With current technology and at the emission levels of current installations, maximum biopower production could increase NO_X emissions by 10% in 2020, which would cause increases in ozone and PM concentrations in large areas of the Central Valley where ozone and PM concentrations exceed air quality standards constantly throughout the year. Negative effects on PM would be expected in both summer and winter episodes. Among the alternatives for biomass use, technology upgrades would significantly reduce criteria pollutant emissions. Conversion of biomass to CNG for vehicles would achieve comparable emission reductions of criteria pollutants and minimize emissions of greenhouse gases. As suggested by the analysis of emissions, applying technological changes and emission controls would minimize the air quality impacts of biopower generation. And a shift from biopower production to CNG production for vehicles would reduce emissions and air quality impacts further. From a co-benefits standpoint, CNG production for vehicles appears to provide the benefits in terms of air pollutant and GHG emissions, and air quality.

This investigation provides a consistent analysis of air quality impacts and greenhouse gases emissions for scenarios examining increased biomass use in California. The findings will help inform policy makers and industry with respect to further development and direction of biomass policy and bioenergy technology alternatives needed to meet energy and environmental goals in California.

Acronyms

Acronym	**Definition**
AB	Assembly Bill
BACT	Best Available Control Technology
BDT	Bone-dry ton
BEV	Battery Electric Vehicle
BFB	bubbling fluidized bed
BIGCC	Biomass Integrated Gasification Combined Cycle
Btu	British Thermal Unit
CARB	California Air Resources Board
CARFG	California Reformulated Gasoline
CBC	California Biomass Collaborative
CCS	Carbon Capture and Sequestration
CFB	circulating fluidized bed
CH4	Methane
CHP	Combined Heating and Power
CMAQ	Community Multiscale Air Quality model
CO	carbon monoxide
CO2	carbon dioxide
CPUC	California Public Utilities Commission
CV	conventional vehicles
DOE	Department of Energy
DOT	Department of Transportation
EISA	Energy Independence and Security Act
EMFAC	Emission Factor model
EPRI	Electric Power Research Institute
FFV	Flex-fuel Vehicle
g/kWH	grams per kilowatt-hour
GHG	greenhouse gases
H2	molecular hydrogen
HFCV	hydrogen fuel cell vehicle
HSAD	high-solid anaerobic digestion
IGCC	integrated gasification combined cycle
IOU	investor-owned utilities
LCFS	low carbon fuel standard
LDV	light-duty vehicle
LFG	landfill gas
LUCs	land-use changes
MJ/Nm3	megajoule per normal cubic meter
MMBtu	million British thermal units
MMT	million tons
MSW	municipal solid waste

MW	megawatts
MWth	megawatts of thermal output
NG	natural gas
NGCC	natural gas combined cycle
NMHC	non-methane hydrocarbons
NOx	nitrogen oxides
NRC	National Research Council
NREL	National Renewable Energy Laboratory
OFMSW	organic fraction of municipal solid waste
PM	particulate matter
RFS	renewable fuel standards
RPS	renewable portfolio standards
RSNG	renewable synthetic natural gas
SB	Senate Bill
SoCAB	South Coast Air Basin of California
SOx	oxides of sulfur
U.S. EPA	United States Environmental Protection Agency
USDA	United States Department of Agriculture
WWTP	Wastewater treatment plant

Executive Summary

This study assesses the air quality impacts of new and existing bioenergy capacity throughout the state, focusing on feedstocks, and advanced technologies utilizing biomass resources predominant in each region. The options for bioresources include the production of biopower, renewable NG and ethanol. Emissions of criteria pollutants and greenhouse gases are evaluated for a set of scenarios that span the emission factors for power generation, and the uses of renewable natural gas for vehicle fueling and pipeline injection. Emission factors combined with the geospatially-resolved bioenergy outputs (facility locations) are used to generate new emission source locations and magnitudes which are input to the Community Multiscale Air Quality model (CMAQ) to predict regional and statewide temporal air quality impacts from the biopower scenarios.

The list of scenarios evaluated in this study explores the potential impacts of widespread implementation of biopower driven by regulatory measures and initiatives in place in California: SB1122 requires the CPUC to direct electrical corporations (IOUs) to procure 250 MW (cumulative, state wide) of new small biopower (less than 3 MW per project) in a separate IOU feed-in tariff program, of which 110 MW is for urban biogas and 90 MW for dairy and other agricultural bioenergy (that would include digester gas or small thermochemical conversion). Governor Brown's Clean Energy Jobs Plan calls for 20 GW of new renewable generation by 2020. All these measures provide a pathway to use bioresources in the state within the maximum potential. Figure ES1 provides a summary of potential installed capacity of biopower under different scenarios. Maximum potential for biopower is nearly 4,800 MW.

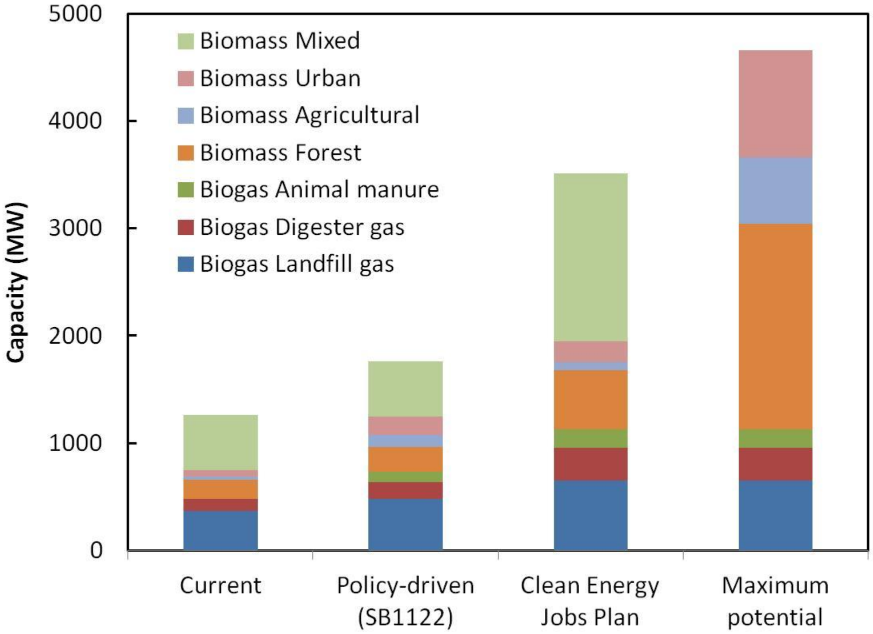


Figure ES1: Summary of power generation capacity from biomass in scenarios with current biomass technology

An alternative use of bioresources is to produce biomethane that can fuel vehicles, and contribute to the production of renewable fuels. Biomethane can be obtained via clean-up of landfill gas and anaerobic digestion biogas. In addition, biomethane can be obtained via gasification of solid biomass and production of renewable synthetic natural gas.

Table ES1 presents the maximum potential for biomethane production via RSNG from biogas and biomass resources in the state of California, and potential for cellulosic ethanol and biomethane from HSAD from solid residue. The total biomethane potential from biogas and biomass is more than $1.1 \cdot 10^6$ MMBtu/day. This amount could potentially meet fuel demand of nearly 16% of gasoline vehicles in California. Conversely, taking into account that CA reformulated gasoline (CARFG) is a blend of 5.7% ethanol and gasoline, bioethanol production from solid biomass could meet the entire state demand for ethanol blending for CARFG.

Table ES1. Maximum potential for biomethane production from biogas and biomass, and potential for cellulosic ethanol production from solid biomass

		Biogas Potential (MMBtu/day)
Biogas	Landfill gas	177424
	Digester gas	83253
	Animal manure	47768
	Total	308445

		Biomass Potential (BDT/day)	**RSNG Potential (MMBtu/day)**	**Ethanol Potential (gal/day)**	**HSAD CNG (MMBtu/day)**
Biomass	Forest	30668	461110	2499430	
	Agricultural	10989	165231	382069	12414
	Urban	20679	213445	475769	11354
	Total	62336	839785	3357269	
Total			1148230		23768

Emissions of criteria pollutants and greenhouse gases are evaluated for all scenarios in order to evaluate the co-benefits of using biomass for both air quality and climate change. Figure ES2 presents the emissions from a case with Technology Upgrade for Efficiency and Emissions, in comparison with the case with maximum potential for biopower with current technology. Technology upgrades consist of switching current boilers and engines with next generation gasification systems and fuel cells. The result is a significant decrease in direct emissions of criteria pollutants with respect to the case with current technology. Direct GHG emissions do not change, as the same amount of carbon is converted into CO_2, but because of the increase in efficiency in power generation, emission savings are also increased with respect to the case with maximum potential and current technology.

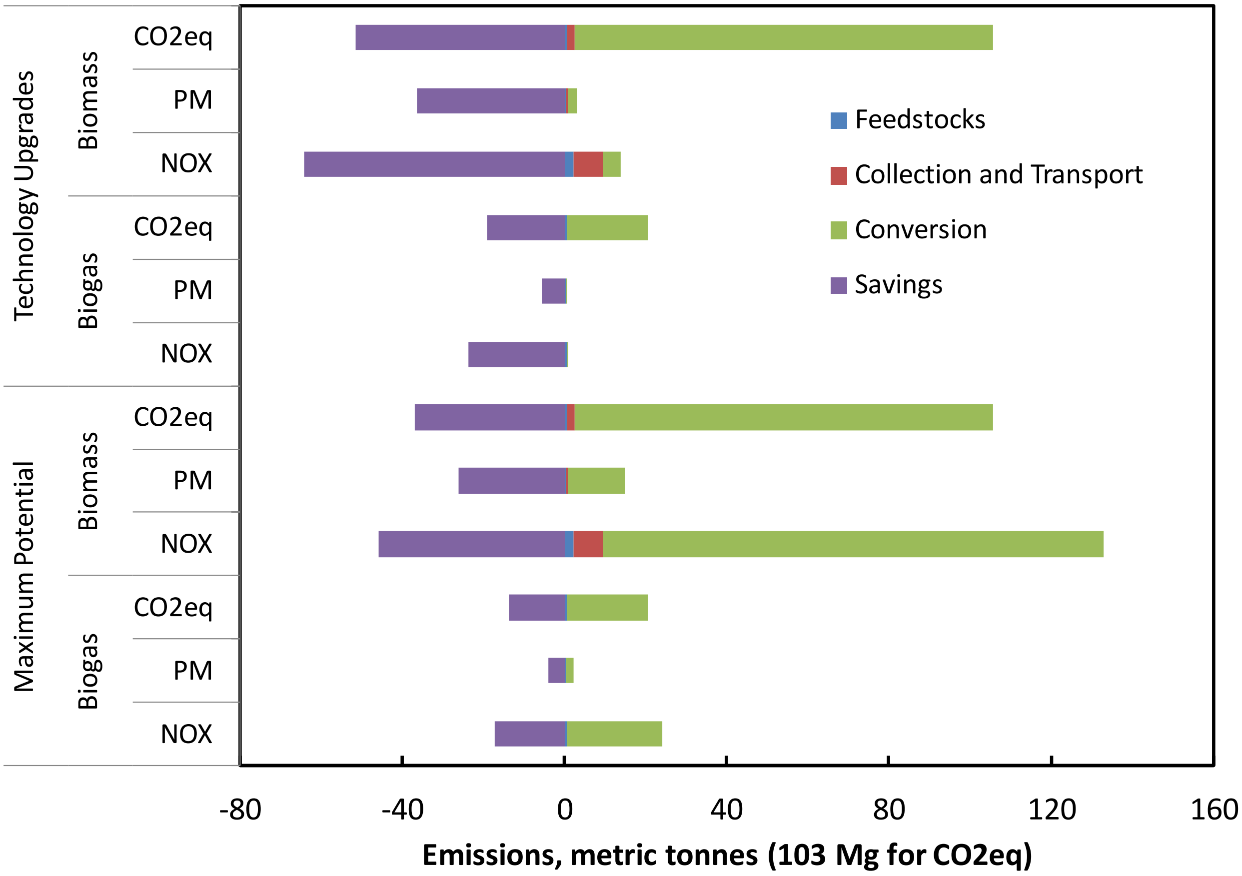


Figure ES2: Comparison of emissions from biomass in scenarios with maximum biomass potential with current technology and with technology upgrades for efficiency and emissions

Figure ES3 presents the emissions of scenarios the present a shift in the end use of biomass from electricity to fuel, together with the case with maximum potential for biopower with current technology. Group C includes two cases with generation of CNG from solid biomass via gasification: one dedicated to produce CNG for vehicle consumption and the other one for pipeline injection. Direct emissions from these two cases are the same, because the processes to generate the CNG are the same in both cases. Emissions from feedstocks in these two cases are considerably higher than in the cases of group A and B, because more energy is required to clean-up biogas and synthesis gas, and to compress them. The only difference between these two CNG scenarios is the emissions displaced by the CNG. In the case that CNG is dedicated to vehicle consumption, emission displacement is due to the savings in gasoline production and marketing needs that production of CNG from biomass provides. In addition, the case includes savings in emissions from vehicles switching from gasoline to CNG consumption. Conversely, in the case that CNG is dedicated to pipeline injection, emission displacement is calculated from the savings in natural gas production and marketing demand that CNG provides. No additional savings are considered in this CNG case as combustion of NG from biomass is assumed to produce the same pollutant emissions as combustion of conventional NG. Hence, comparing the two cases is analogous to contrasting emissions from equivalent energy units of gasoline and natural gas. The result is that producing gasoline for California is more pollutant-intensive than producing natural gas, and thus, reducing gasoline production achieves higher emission savings than reducing production of natural gas containing the same amount of energy. Consequently, on a full fuel cycle emissions standpoint, producing CNG for vehicles is more favorable than producing natural gas for pipeline injection as shown in Figure 28.

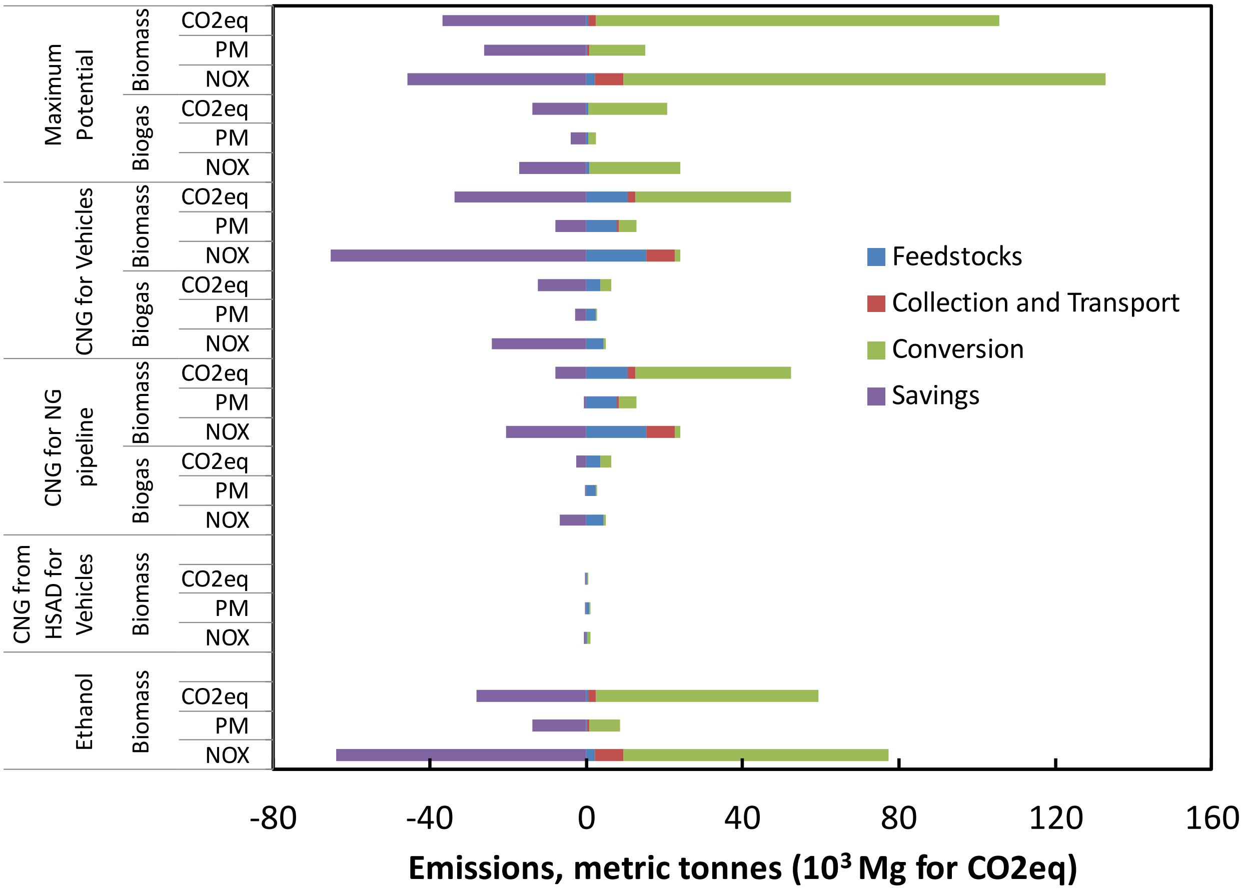


Figure ES3: Comparison of emissions from biomass in scenarios with maximum biomass potential using current technology for biopower (group A) and scenarios with CNG production (group C)

Table ES2 presents the total emissions of scenarios that assume maximum potential for biomass use. In summary, from a full fuel cycle perspective, use of biomass to produce vehicle fuels appears as the best option to minimize GHG emissions. Applying technology upgrades and emission controls for biopower production can mitigate criteria pollutant emissions, but CNG from biogas and gasification of biomass achieves comparable emissions of criteria pollutants and lower GHG emissions. An important aspect to note about the full cycle analysis is that a large portion of emission savings for criteria pollutants occur outside the state. If only the emission savings within the state are accounted for (Table ES3), the case with technological advances for biopower production becomes the most favorable scenario to minimize the impact of biomass use on criteria pollutant emissions but CNG scenarios are still the most favorable for greenhouse gases emissions. Air quality modeling of the emission impacts in the state completes the analysis for the overall air quality impacts of biomass use.

Table ES2: Summary of net emissions from selected scenarios (in tons/day for NO_X and PM, and 10^3 tons/day for $CO_{2,eq}$)

		Maximum Potential	**Technology Upgrades**	**Ethanol**	**CNG from HSAD for Vehicles**	**CNG for Pipeline Injection**	**CNG for Vehicles**
Biogas	**NO_X**	6.9	-22.7			-1.8	-19.1
	PM	-1.8	-5.2			2.6	-0.1
	CO2eq	7.0	1.7			3.7	-6.2
Biomass	**NO_X**	87.2	-50.1	13.6	0.4	3.4	-41.6
	PM	-11.0	-33.3	-5.2	0.7	12.3	5.0
	CO2eq	68.9	54.1	31.1	0.1	44.6	18.5

Table ES3: Summary of net emissions from selected scenarios (in tons/day for NO_X and PM, and 10^3 tons/day for $CO_{2,eq}$) accounting only for in-state savings

		Maximum Potential	**Technology Upgrades**	**Ethanol**	**CNG from HSAD for Vehicles**	**CNG for Pipeline Injection**	**CNG for Vehicles**
Biogas	**NO_X**	16.0	-10.1			4.0	-1.0
	PM	0.5	-2.1			2.7	1.7
	CO2eq	12.0	8.7			5.9	-3.0
Biomass	**NO_X**	111.6	-16.0	77.5	0.9	20.9	7.7
	PM	3.6	-12.8	8.6	0.7	12.8	10.0
	CO2eq	82.4	73.0	59.3	0.3	51.2	27.2

The emissions resulting from the biomass facilities are spatially allocated in the modeling domain. For the air quality impacts it is assumed that the existing facilities will absorb the increase in biomass capacity. The increase in biopower capacity assumed in the maximum potential biopower cases is then scaled up from the existing facilities. In addition to emissions from conversion, emissions from forest residue collection are also included. The spatial allocation of collection and transport is based on the forest residue potential at a county level and location of rural and urban roads in each county. Figure ES4 illustrate the spatial allocation of biopower facilities and collection and transport of forest residue.

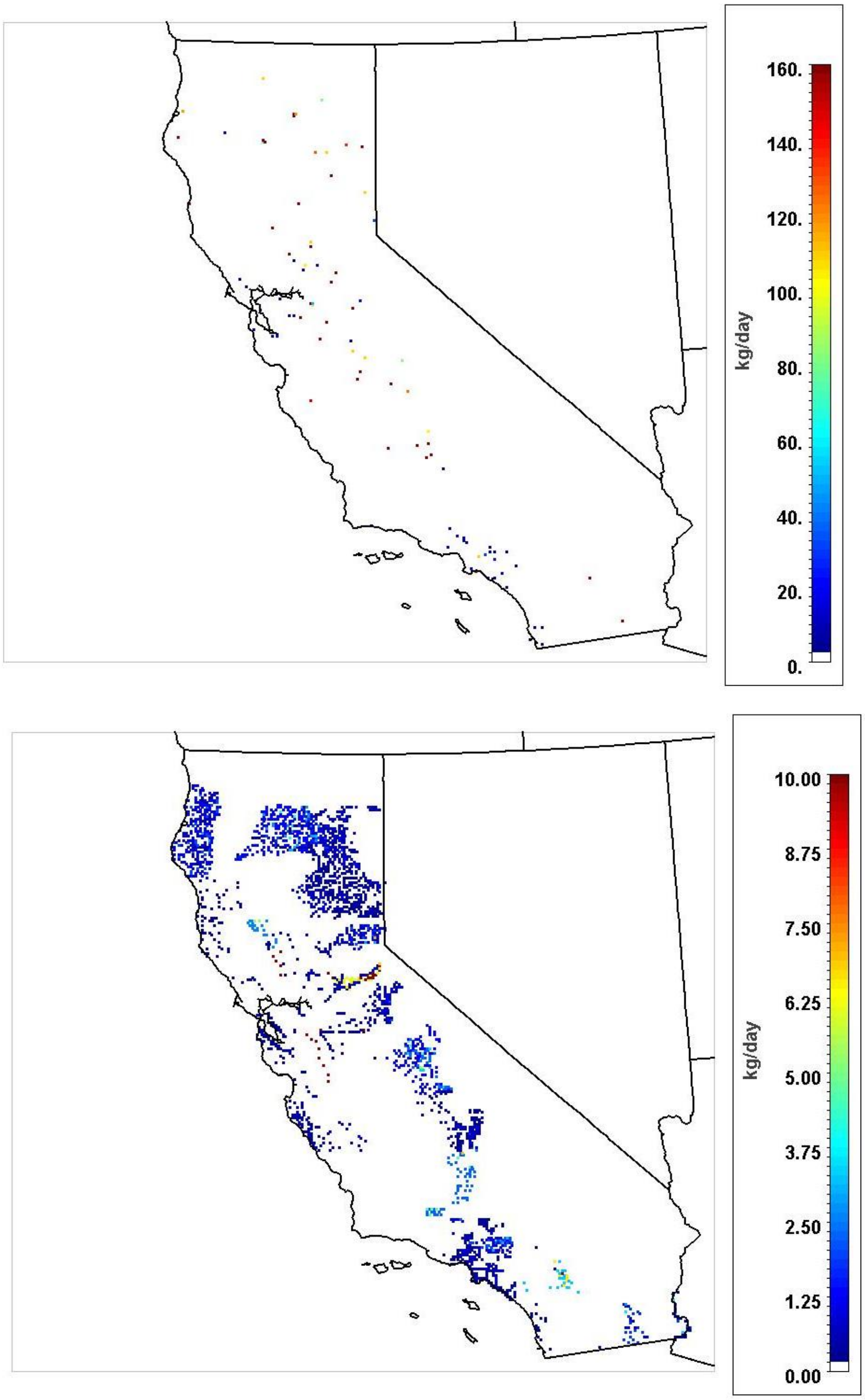


Figure ES4: Locations of emissions from biopower production for the Maximum potential for biopower production with current technology (group A). Top: NO_X emissions from biopower facilities. Bottom: NO_X emissions from forest residue collection

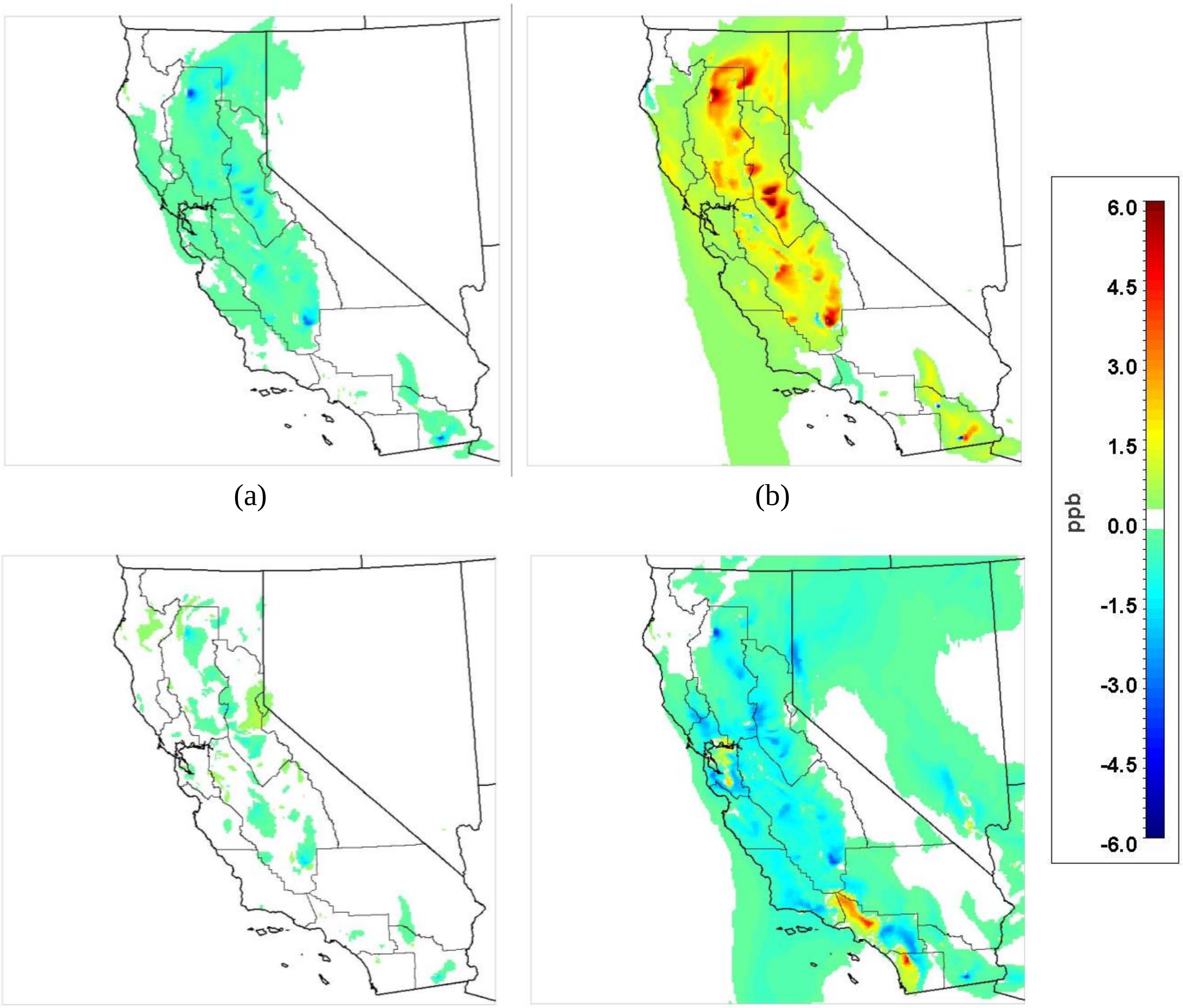
From the technically recoverable biomass resources, there is a potential for up to 4.66 GW of biopower that could be installed in the state. With current technology and at the emission levels of current installations, maximum biopower production could increase NO_X emissions by 10% in 2020. Among the alternatives for biomass use, technology upgrades would significantly reduce criteria pollutant emissions. Conversion of biomass to CNG for vehicles would achieve comparable emission reductions of criteria pollutants and minimize emissions of greenhouse gases.

Emission factors combined with the geospatially-resolved bioenergy outputs (facility locations) are used to generate new emission source locations and magnitudes which are input to the Community Multiscale Air Quality model (CMAQ) to predict regional and statewide temporal air quality impacts from the biopower scenarios. Installing the maximum potential of biopower production with current technology by 2020 would cause increases of over 6 ppb in ozone (shown in Figure ES5) and 2 $\mu g/m^3$ in PM concentrations in large areas of the Central Valley where ozone and PM concentrations exceed air quality standards constantly throughout the year. Negative effects on PM would be expected in both summer and winter episodes. As suggested by the analysis of emissions, applying technological changes and emission controls would minimize the air quality impacts of biopower generation. And a shift from biopower production to CNG production for vehicles would reduce emissions and air quality impacts further. From a co-benefits standpoint, CNG production for vehicles appears to provide the benefits in terms of air pollutant and GHG emissions, and air quality.

It is clear that the state has enough bioresources to meet the goals of SB1122 and Governor’s plan for renewable power, and that biomass could be a large contributor to the renewable portfolio standard for the state. However, if California is to meet the air quality goals for non-attainment areas like the San Joaquin Valley, it should minimize the impact of using biomass with advanced technologies like fuel cells for biogas and gasification systems for solid residue.

This investigation provides a consistent analysis of air quality impacts and greenhouse gases emissions for scenarios examining increased biomass use. The findings will help inform policy makers and industry with respect to further development and direction of biomass policy and bioenergy technology alternatives needed to meet energy and environmental goals in California.

Future research needs should include the collection of more specific emission factors and better characterization of processes for advanced technologies, such as production of renewable synthetic natural gas. For the analysis presented here, emissions and energy balances from generic gasification facilities were assumed. Another area of research related to biomass use would be the in-depth analysis of management of solid waste to maximize recycling, and minimize disposal at landfills. These management strategies could require additional infrastructure and reduce the biogas and biopower yields from landfills.



(a) (b)

(c) (d)

Figure ES5: Changes in peak ozone concentrations due to biomass scenarios in a summer episode with respect to the baseline case: (a) No Biomass Case, (b) Maximum biopower production with current technology, (c) Maximum biopower production with enhanced technology, (d) Maximum production of CNG from biomass for vehicle consumption.

1 Introduction

There is a growing interest in the State of California to support a clean energy future to meet the mandate of the Global Warming Solutions Act – Assembly Bill 32. California has a long history of environmental innovations and regulations that have significantly improved air quality throughout the last four decades, and there is a renewed commitment to environmental stewardship that includes reducing greenhouse gases emissions. Meeting stricter clean air standards while reducing greenhouse gas emissions will require well integrated energy and air quality programs. Renewable energy will be one of the key technologies to reduce both criteria pollutant and greenhouse gas emissions, and sustainable bioenergy can contribute to the mix of renewable energy technologies. Bioenergy technologies and resources can provide a range of economic and environmental benefits to the state. Bioenergy can be garnered from digester gas, landfill gas and biomass resources to produce electric power, heat, and/or renewable gaseous or liquid fuels. Renewable liquid or gaseous biofuels can be used for stationary or vehicular applications. The California Air Resources Board has adopted regulations to promote renewable electric power and renewable transportation fuels through the Renewable Electricity Standard and the Low-Carbon Fuel Standard. These standards require significant reductions in greenhouse gases emissions, which will require a suite of solutions that will include biomass and biogas use, among other types of renewable resources.

This modeling study assesses the potential implementation of biomass infrastructure to determine preferred uses and strategies for use of California's renewable resources. The analysis quantifies the emissions of greenhouse gases and criteria pollutants of different fuel paths for biomass and biogas management and utilization and the potential to exploit emerging biomass and biogas resources. The resulting emissions are spatially and temporally resolved for subsequent use in air quality modeling to account for atmospheric chemistry and transport to determine the overall air quality impacts of the new biomass and biogas infrastructure. The analysis of both greenhouse gases and criteria pollutants provides a scientific basis to evaluate the potential co-benefits of biomass and biogas use for air pollution control and climate change mitigation strategies.

2 Biomass Resources

Biomass contributes more than 5,700 GWh to California's instate renewable power (this is about 19% of in-state renewable power and 2% of full California power mix) (CEC 2010). Current operating biopower capacity is about 900 MW (including approximately 550 MW of woody biomass solid fuel combustion, 280 MW of landfill gas-to-energy and 75 MW from wastewater treatment biogas) (CBC, 2011). It is estimated that there is sufficient in-state 'technically'[1] recoverable biomass to support another 2,800 MW of capacity or 21 TWh of electricity (Williams et al., 2008). While most biomass energy is derived from woody material (including urban wood waste, forest product residue as well as agricultural residues), there is a growing

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[1] Technical biomass resource is that which can be sustainably recovered with minimal impacts to erosion, riparian zones, soil organic matter and other agronomic factors. There is no economic filter applied to the technical resource estimate.

interest in using municipal solid waste and applying co-digestion techniques at wastewater treatment facilities to generate electricity and renewable fuels.

While much of the landfill gas (LFG) in California is collected and utilized or flared and all wastewater treatment biogas is utilized or flared, fugitive emissions (and some LFG venting) contributes to nearly 2% of the total greenhouse gases emissions in California and the U.S. Utilizing more of the currently flared biogas in the state, as well as switching or improving some of the existing biogas energy facilities can reduce criteria and greenhouse gas emissions while increasing renewable power or fuels. Utilizing waste materials as feedstocks for engineered anaerobic digesters (such as food and green waste from the MSW stream and food processor wastes) could potentially support 300 MW of electricity or 30 PJ of fuel (CBC 2011b).

Biogas can be utilized as a substitute for natural gas (after appropriate cleaning and treatment) contributing to energy sustainability while reducing greenhouse gas emissions. In addition, biogas use could help reduce criteria pollutant emissions. Upgraded biogas can be used directly in compressed natural gas vehicles or in stationary fuel cells to produce electricity and hydrogen, which can then be used as a transportation fuel for electric and hydrogen fuel cell vehicles. These vehicle technologies could reduce criteria pollutant emissions compared to combustion-based vehicles using gasoline or compressed natural gas. Methane, hydrogen and/or electricity produced from biogas will contribute to the suite of low-carbon fuels that will be necessary to meet the Low Carbon Fuel Standard (LCFS) goals.

The potential air quality impacts from the use bioresources depends on the location of those resources, how those resources are processed, the products obtained from bioresource utilization, and the technologies used in the processing of biomass. For example, forest residue can be combusted to produce power or digested to produce bioethanol for fuel. The production of biopower or biofuels from the same bioresources may result in very distinct air pollutant emissions. Similarly, biogas from landfills can be combusted in an engine to produce biopower, or it can run fuel cells without any combustion involved resulting in much lower emissions. Section 3 describes the options for biomass use. In California, most of the existing biomass facilities use bioresources to produce power, but there are already two landfill installations that generate up to 18,000 gallons per day of liquefied natural gas that fuel refuse trucks. Some other biogas installations also pipe the biogas to be used for heat production for process heating. Finally, there are 17 installations in the state that produce ethanol and biodiesel from a variety of waste streams, including corn and sorghum residue, and used oils.

Forestry, agricultural waste and urban green clippings, which constitutes the largest portion of solid biomass available in the state of California, is mostly distributed along the Central Valley and the Northern part of the state. Figure 1 presents the technical biopower potential from forestry, agricultural and urban green waste by county for 2020, and the location and capacity of the existing facilities processing that type of biomass. In the San Joaquin Valley, there is a high concentration of agricultural activities that generate high volumes of waste. The northern counties of California are populated with forests that provide a source of forestry waste that can be utilized for biopower. Table 1 presents the technology distribution of the biopower installations processing solid biomass. Approximately 49% of the biopower capacity is produced with stokers, which is the oldest technology, whereas other 45% is produced by fluidized bed technology. One installation uses a suspension boiler for rice hulls to produce 25 MW, and another installation uses walnut shells in a gasifier to produce 100 kW. The total power produced by these installations is 638 MW, from which 155 MW are co-produced with heat for process heating. Based on estimates by the California Biomass Collaborative (Williams et al., 2008), the technical potential for biopower from solid biomass for the year 2020 is 3650 MW, more than 3000 MW additional capacity with respect to the existing capacity. The increase in potential biopower capacity assumes a significant improvement in efficiency from biomass installations from 20% to 30%.

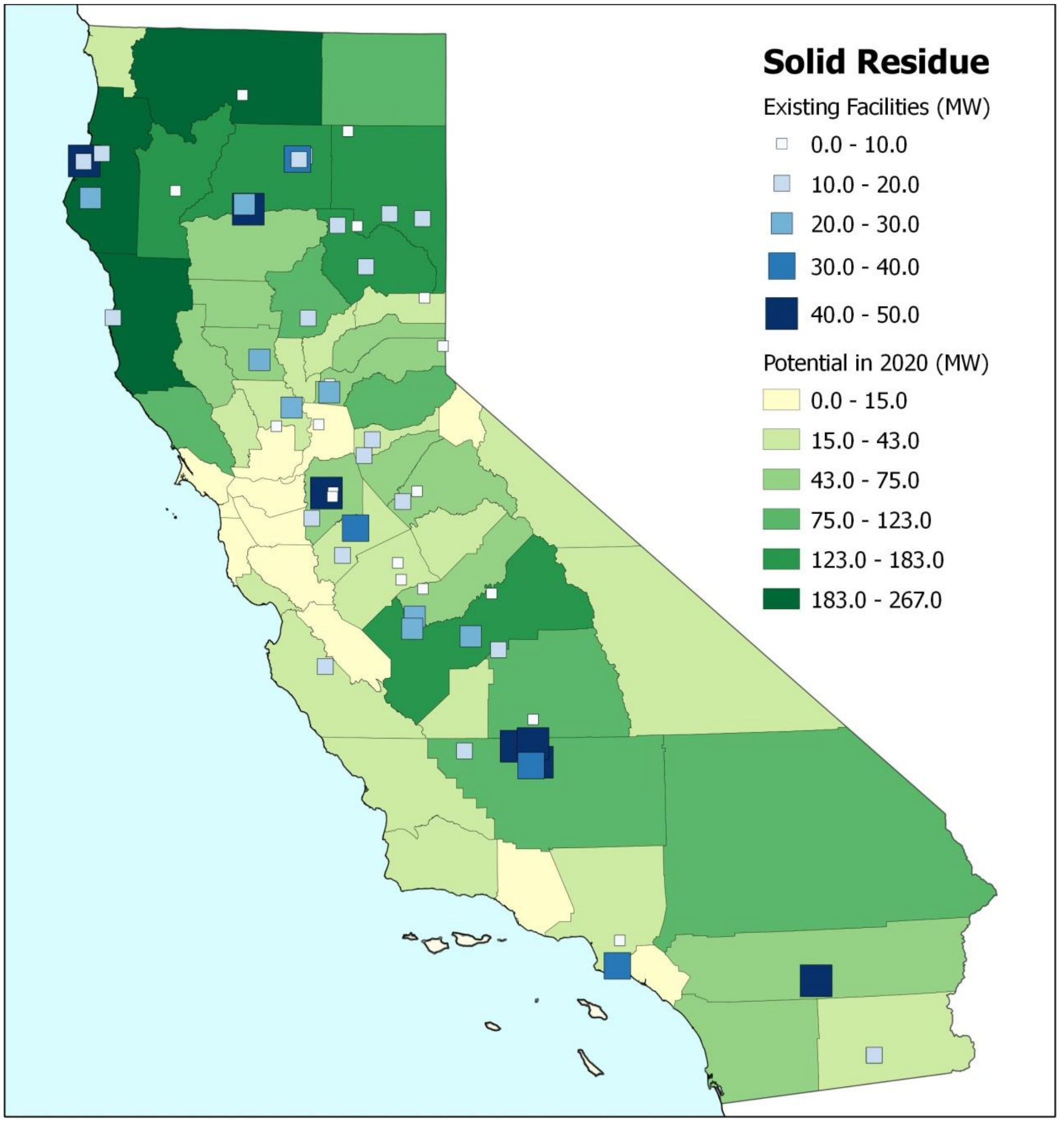

Figure 1: Solid residue potential for biopower production in 2020 and capacity and location of existing facilities in California.

Table 1: Technology distribution for biomass solid residue biopower installations

Technology	Net Capacity (MW)	CHP Capacity (MW)
Bubbling Fluidized Bed	131.5	0.0
Circulating Fluidized Bed	147.0	0.0
Downdraft Gasifier	0.1	0.1
Stoker - Grate	315.0	140.5
Suspension Fired Boiler	25.0	0.0
Not specified	19.0	19.0
Total	637.6	154.6

Municipal solid waste (MSW) constitutes the second major contributor to total biomass in California. The main process for disposal of MSW in the state is accomplished by landfills. The assembly bill AB939 required a diversion of 50% of all potential MSW by the year 2000, and more recently assembly bill AB341 was passed to achieve 75% recycling of all waste including organic material by the year 2020, and AB1826 was specifically targeted to increase the diversion of organic waste and hence reducing the amount of waste sent to landfills. Before AB341 and AB1826 were passed, the CBC estimated that a capacity of 1690 MW could be met by landfill gas from MSW. The implementation of these new assembly bills will likely reduce the amount of biodegradable waste reaching landfills, and as a result, reducing the capacity for long-term production of landfill gas.

The location of major landfills is generally in the outskirts of highly populated areas. Thus, in California, the largest landfills are around the Los Angeles metropolitan area, San Diego, and the Bay Area. Figure 2 presents the technical potential for landfill-gas-to-power installations in the year 2020 and the location of the existing facilities. Currently, the total capacity of biopower generated in landfills is 371 MW, which is 22% of the estimated technical potential in California. Table 2 presents the technology distribution in landfill gas biopower installations. The largest fraction of biopower is generated by gas turbines and reciprocating engines. Typically, the heat demand in landfills and surroundings is low, which disincentivizes installation of combined heat and power plants.

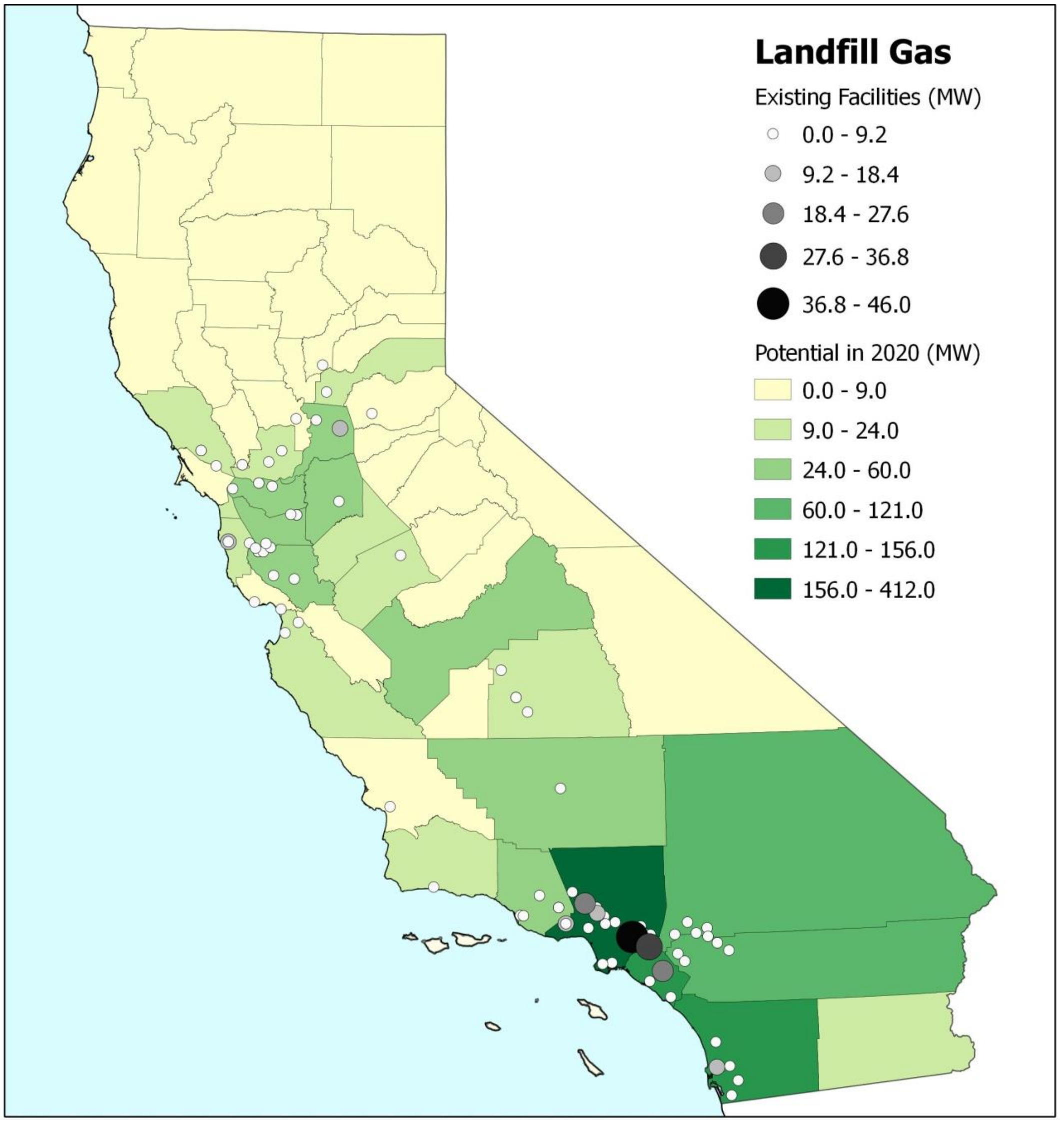

Figure 2: Landfill gas potential for biopower production in 2020 and capacity and location of existing facilities in California.

Table 2: Technology distribution for landfill gas biopower installations

Technology	Net Capacity (MW)
Gas and Steam Turbines	11.7
Gas Turbine	116.2
Microturbine	12.0
Reciprocating Engine	173.4
Steam Turbine	58.0
Total	371.3

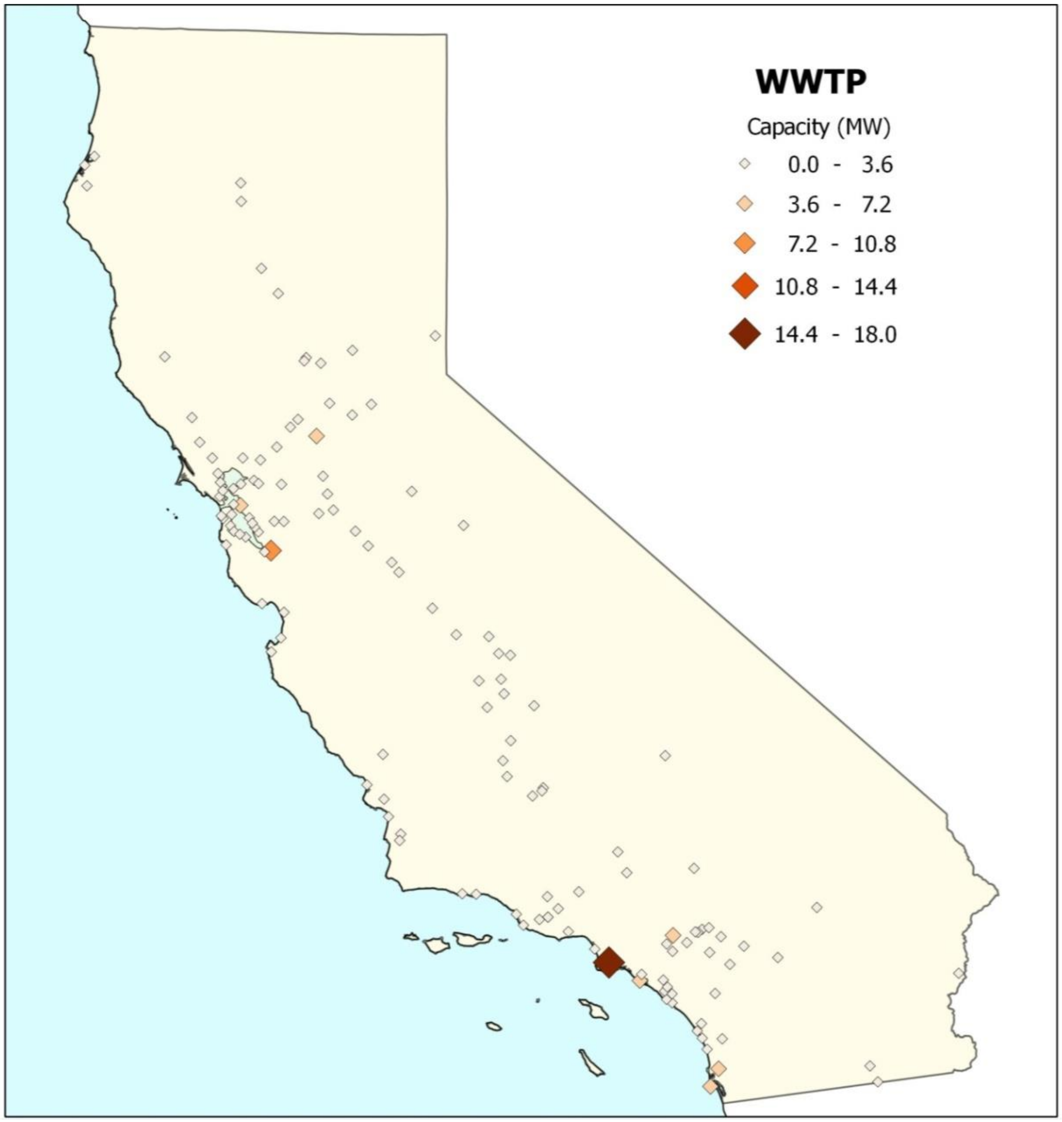

Figure 3: Capacity and location of existing biopower facilities in California in wastewater treatment plants (WWTP).

Table 3: Technology distribution in biopower installations in wastewater treatment plants

Technology	Net Capacity (MW)
Fuel Cells	3.3
Boilers	1.8
Microturbine	1.3
Pipeline	0.4
Reciprocating Engine	43.8
Gas Turbine	18.0
Total	68.6

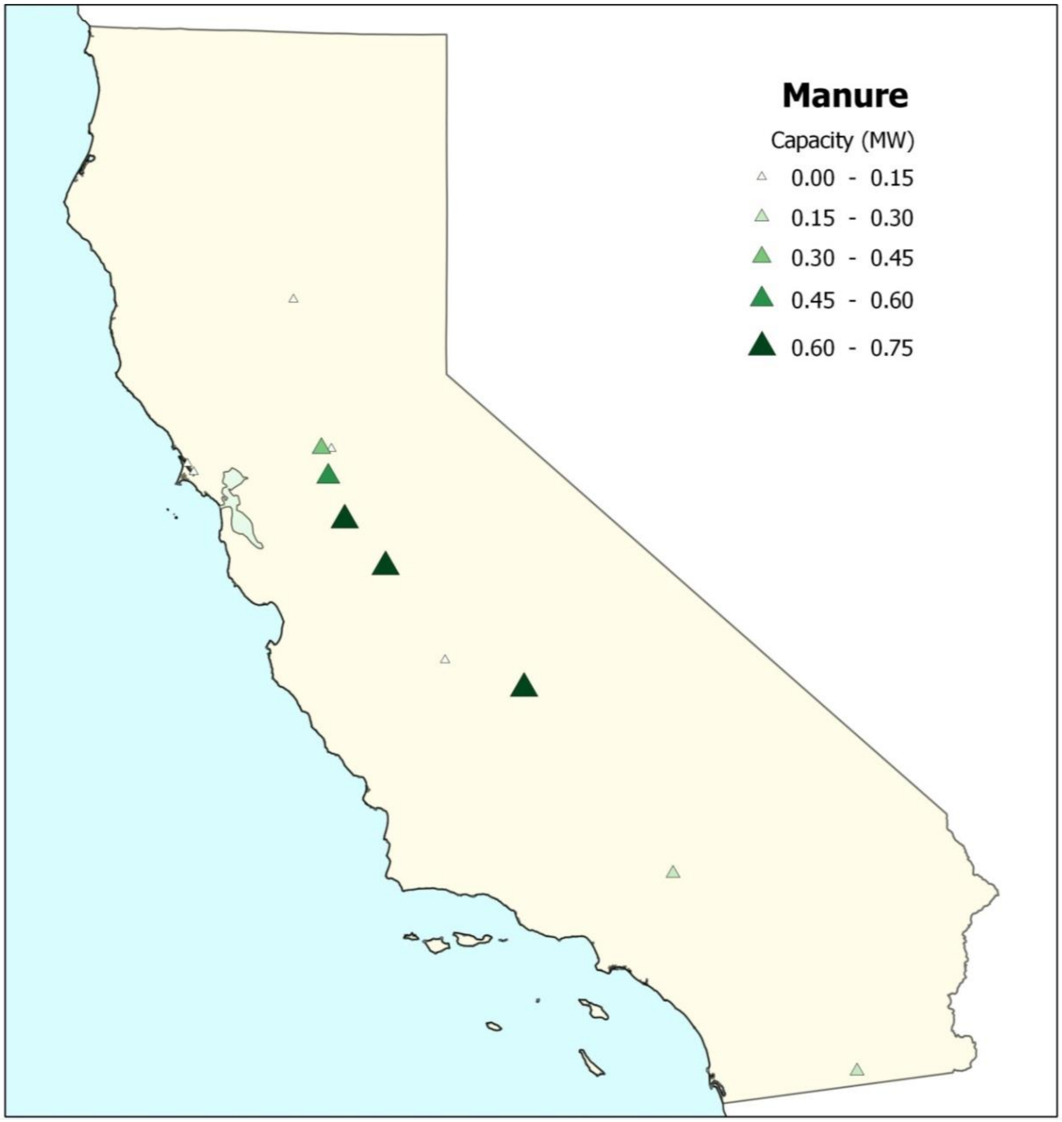

Figure 4: Capacity of existing biopower facilities in California using biogas from animal manure.

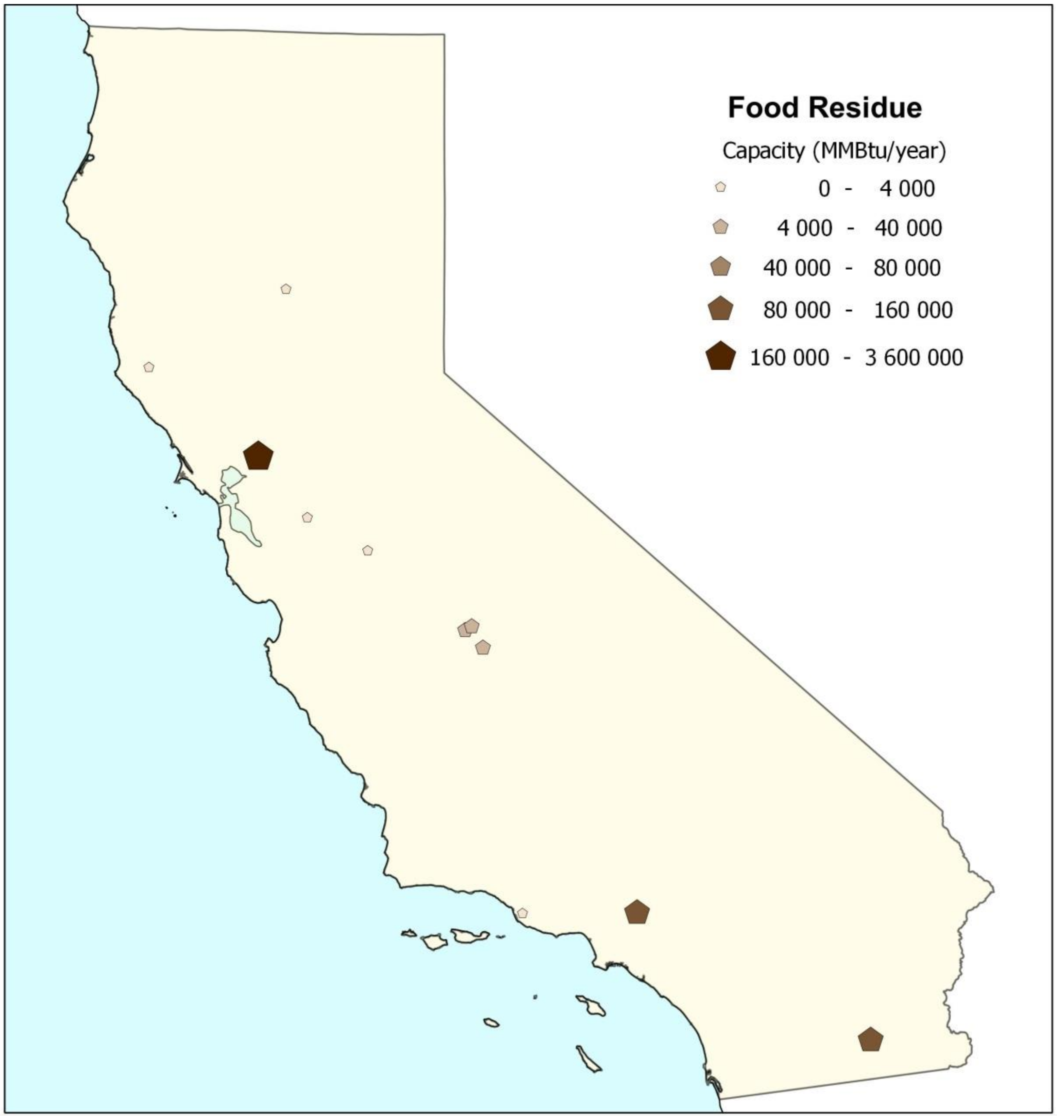

Figure 5: Capacity and location of existing biogas facilities in California from anaerobic digestion of food residue.

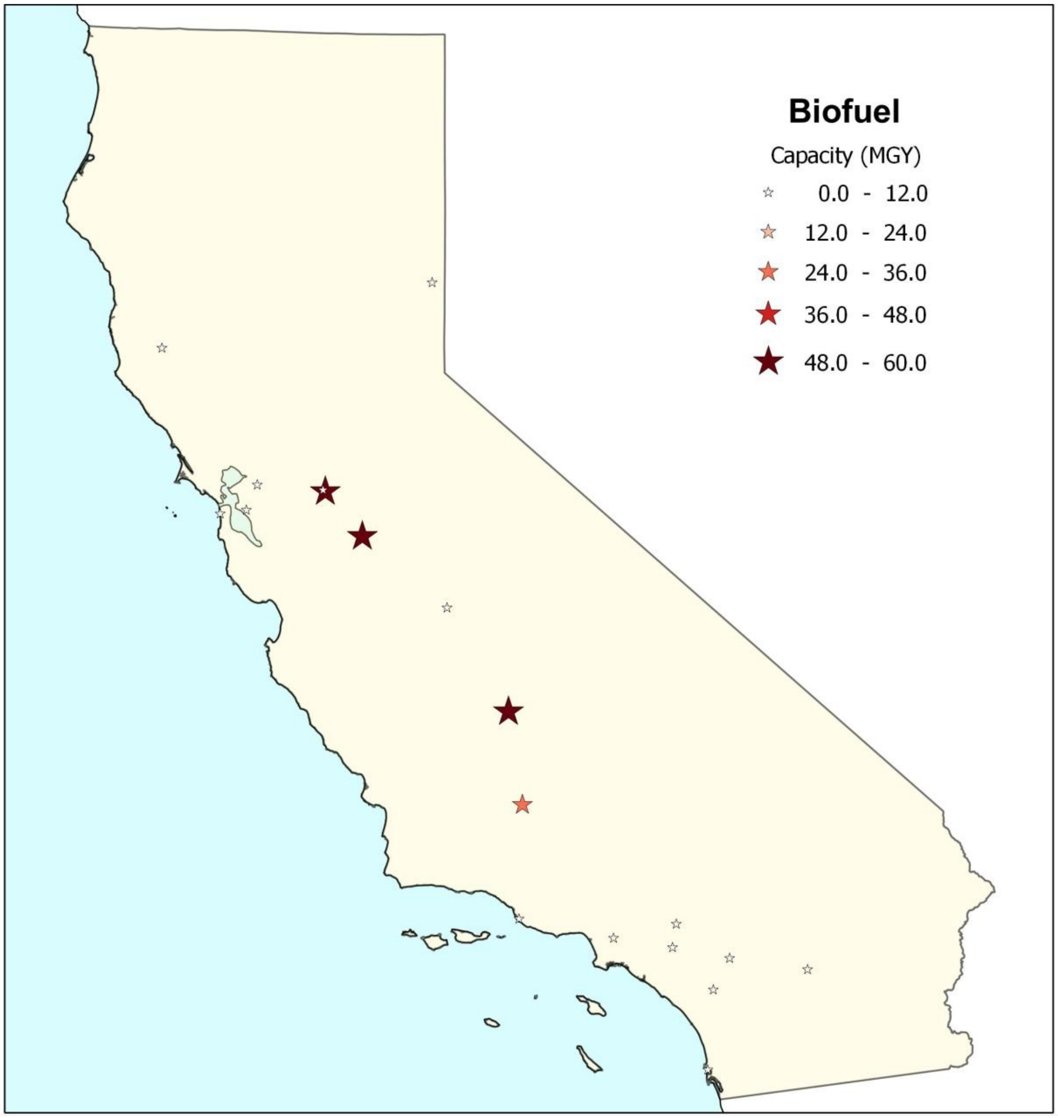

Figure 6: Capacity and location of existing biofuel facilities in California

3 Uses of Biomass

3.1 Biopower

Generation of electricity from biomass is unique among the potential technologies for meeting RPS goals in that it is associated with the generation of substantial amounts of GHGs and pollutants at generation sites during operation. This feature elucidates the importance in assessing GHG and air quality impacts from biopower.

Biomass can be defined as all matter from living and dead biological systems, but when discussing renewable energy sources, it is typically defined as matter from living or *recently* living biological systems. Biomass fueled power plants provided 2.1% and 2.4% of California's total electricity needs and 19.3% and 17.5% of the total renewable electricity generated in 2007 and 2010 (CEC, 2010). California Executive Order S-06-06 requires 20% of the renewable electricity generated in California to come from biopower resources in 2010 through 2020. The biopower percentage of total renewable electricity generated has declined, and the 2011 Bioenergy Action plan prepared by the California Energy Commission addresses the issues impeding biopower expansion in the state and provides recommendations to increase new installations, prevent idling of current installations, and restarting of idle plants. Williams et al. projected that the technically recoverable biomass from waste and residue streams in 2020 could provide 11.9% of California's electricity needs in 2020 (Williams et al., 2007). This could significantly contribute to meeting California's Renewable Portfolio Standard goals of 33.3% renewable energy contribution to the state's electricity needs in 2020 as well as also reducing greenhouse gas emissions associated with these waste/residue streams. However, significant expansion of biomass facilities in order to reduce greenhouse gas (GHG) emissions could lead to increased environmental stresses without proper analysis and planning, e.g., direct combustion of woody biomass to generate electricity may significantly increase pollutant emissions compared to natural gas combined cycle plants. Additionally, poor planning with regard to dedicated energy crops could also lead to increased GHG emissions or only marginal reduction in GHG emissions while also possibly having detrimental environmental impacts on the land, water, and air quality. Therefore, it is important to assess the environmental impacts throughout the life cycle of the particular feedstock and electricity conversion technology employed. The following sections will first discuss the feedstocks available within California and then move into the characterization of the various biomass electricity conversion technologies. Finally, some environmental impacts that have been shown to result from the production of electricity from biomass will be reviewed, although previous work has shown the importance of performing these life cycle assessments for each considered installation such that the many locations and technology specific parameters are used in the assessment; rather than relying on previous studies that may have used more general figures for model parameters.

3.1.1 Feedstock

The biomass resources available within California are categorized in the following manner by Williams et al. (2007).

- Agricultural residue
- Forestry residue
- Municipal solid waste
- Landfill gas
- Sewage digester gas
- Dedicated crops

Figure 7 shows the technically available and existing biomass electricity capacity by feedstock in 2007 as determined in a California Energy Commission study by Williams et al. (2007). The technically available capacity was estimated using several general assumptions relative to the efficiency of the biomass to energy conversion process. There is potential for a large expansion of electricity generation via biomass waste and residue feedstocks. There may be an even larger potential if dedicated energy crops are considered although Williams et al. projects only modest increases in the technical availability of dedicated energy crop expansion within the state (2% of the state's electrical energy needs in 2020 met from technically available dedicated crops).

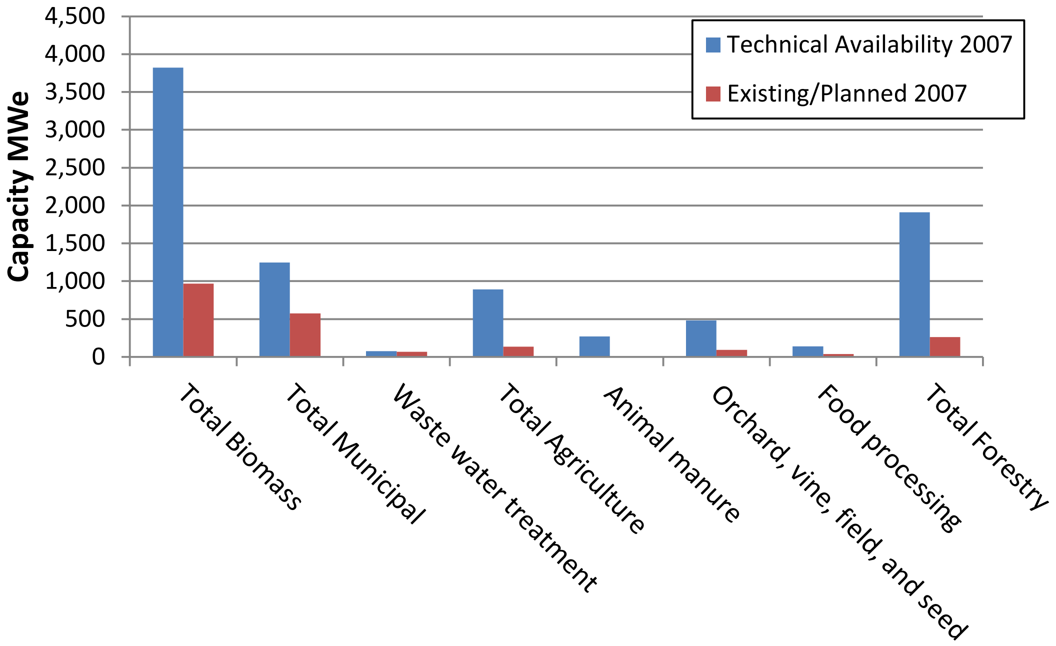

Figure 7: Allocation of biomass resources in California (Williams et al., 2007)

The utilization of waste/residue streams can contribute to GHG emission reductions since the decomposition or treatment of these waste/residue streams result in GHG emissions, which in some cases may be emissions of high global warming potential methane. Forestry residues represent the largest potential for generating electricity from biomass waste/residue available in the state (Figure 7). Existing capacity that uses forestry residues as fuel typically burn the biomass directly to generate steam to drive a turbine which is the same process used by many coal power plants in the US. Pollutant emissions from these direct combustion plants typically exceed those of natural gas fired plants, which may have significant air quality impacts. Additional potential impacts include soil quality and water quality impacts that result from the removal of these residues which would otherwise have decomposed in place. Large expansion in the use of agricultural residues and municipal solid waste (waste water treatment resources are already highly utilized via anaerobic digestion methods) are also possible. Most of the existing capacity for agricultural residue is in the form of direct combustion, which, in a similar manner to the direct combustion of forestry residue, has air quality implications. The treatment of animal manure using anaerobic digestion can contribute nicely to GHG emission reductions but the current use of the digester gas in economically viable heat engines (reciprocating, gas turbines) will not meet current pollutant emission regulation. This is a result of the poor air quality in the regions where animal manure is produced (San Joaquin Valley). Implementation of cleaner technologies such as fuel cells would meet pollutant emission standards but these cleaner technologies remain expensive. Landfill gas utilization is an example where GHG emission reductions have been made via the installation of a large amount of existing capacity as a result of regulations regarding landfill gas emissions and their recovery for flaring or energy use Weitz et al. (2002). However, the use of landfills is being phased out in certain parts of the world such as Europe (EC, 2001). In these locations, the controlled anaerobic digestion of the organic fraction of municipal solid waste (OFMSW) in bioreactors as well as incineration of the

OFMSW is being used for the management of this waste (gasification is also being considered in some instances). The motivation for this are limited land resources and the adverse environmental effects of landfilling such as the leakage of landfill gas (high global warming potential) due to the inability of the wells to capture this gas with 100% efficiency (USEPA, 1995). Leakage of leachate in landfills can also contaminate groundwater. The various environmental impacts associated with biomass power generation are potentially significant especially with regard to the pollutant emissions from those direct combustion conversion technologies that are the most widespread. Although air quality impacts can be substantial, other impacts that are important when considering biomass resources are soil quality, water quality, and biodiversity impacts that might occur as a result of harvesting residues. These environmental impacts will be discussed in more depth in a subsequent section but prior to that discussion the various technologies used in the conversion of biomass into electricity will be characterized more fully.

3.1.2 Electricity Conversion Technologies

Biomass conversion methods can be categorized as follows: thermal, biological, and mechanical. Thermal conversion is currently the method by which most of the biomass generated electricity (biopower) is produced in the US and CA (Williams et al, 2007; Boundy et al., 2011). Figure 8 illustrates the different processing and conversion methods and the various corresponding products. It is important to note that some of the conversion pathways allow for co-products that may have beneficial synergistic effects on the overall system efficiency (Bridgwater, 2006). For direct combustion systems, biomass is burned directly to generate heat for use in a Rankine (steam) cycle rather than converting the biomass to another fuel before combustion. Digestion refers to a process wherein the biomass is digested using bacteria in oxygen deficient (anaerobic) conditions to produce a digester gas and solid digestate. This process occurs in landfills in an uncontrolled manner, and in this application the gas produced is called landfill gas rather than digester gas. Anaerobic digestion is widely used in waste water treatment plants for the processing of this waste stream. The digester gas produced in these plants is also widely used to generate electricity as seen in Figure 7. Anaerobic digestion may also be used to process the organic fraction of municipal solid waste, which is currently utilized to some degree in Europe, however, the solid content of these waste streams must still be below 40% or diluted with water to 40% solids content (EC, 2001; Vandervivere et al., 2003). Gasification is a thermal process where the solid biomass is converted to gas by heating the solid biomass in a manner that produces a gas instead of full combustion. Gasification technologies may provide benefits in efficiency and lower pollutant emissions, however, this technology is not yet fully commercial (Bridgwater, 2006). Pyrolysis is another thermal process and is actually the first step in a gasification process, however, in pyrolysis only this first step is completed yielding a different product that contains volatile liquids and gases. Given that the focus of this report is on renewable electricity generation the processes producing transport fuels will not be considered here, i.e., fermentation and mechanical processes (See Figure 8).

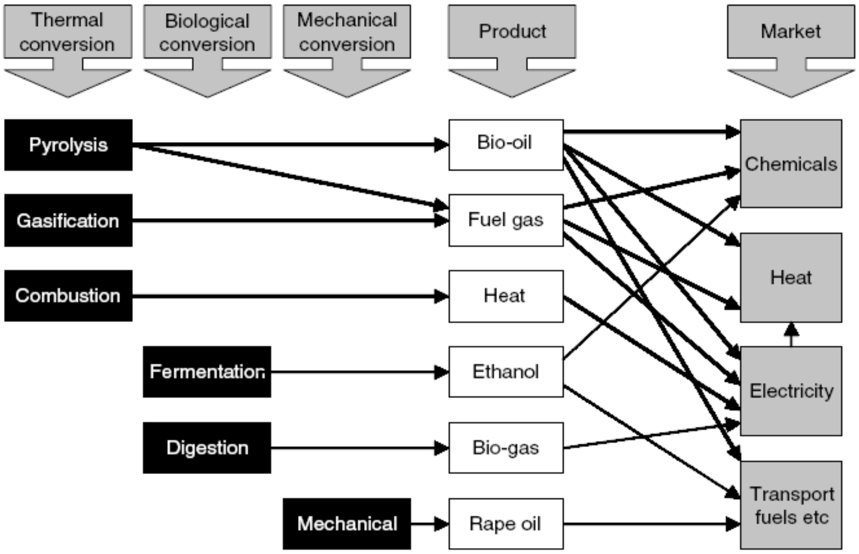

Figure 8: Different biomass conversion technologies and the associated potential products (Brusstar et al. 2005)

3.1.2.1 Direct Combustion

The direct combustion of biomass in boilers for steam production in Rankine cycles is a fully commercialized technology with many plants in California that have been in operation for 20 years or more (See the National Electricity Energy Data System) (EPA, 2006). This technology is most commonly used in the conversion of solid biomass although it could also be used for the conversion of biogas or syngas, it is typically not done since the use of the gaseous fuel in another thermodynamic cycle produces higher efficiencies. This section will focus on the different types of boilers currently used to burn solid biomass. The most frequently used boilers in these systems are stoker and fluidized bed boilers (EPA, 2007), but pulverized fuel boilers will also be discussed here.

3.1.2.1.1 Stoker Boilers

Stoker boilers were first introduced in the 1920s for use with coal (EPA, 2007). Combustion air is fed from under the grate upon which the solid fuel burns. This grate can either move or remain stationary but must allow for the removal of ash. Air is usually also injected at locations above the grate to ensure complete combustion (overfire air). The air flow design is very important in biomass stoker boilers for efficient and complete combustion with typical modern biomass designs having more overfire air than in coal systems with air flow splits between the overfire and underfire flows being 60% and 40%, respectively (EPA, 2007). The manner in which the fuel is distributed over the grate is a major mode of classification. The fuel can be fed onto this grate from underneath the grate (underfeed) or over the grate (overfeed). Underfeed stokers are usually best suited for dry fuels (i.e., less than 40-45% moisture content) and are less popular because of their higher cost and worse environmental performance compared to overfeed stokers (EPA, 2007). Overfeed stokers can be further classified into mass feed and spreader categories. Again these names refer to how the fuel is distributed over the grate. Mass feed stokers typically feed fuel into the furnace at one end and use a moving grate to distribute the fuel throughout the furnace. Spreader stokers will actually throw the fuel into the furnace above the grate such that the fuel is distributed evenly across the grate which allows for more even air flow distribution throughout. This “throwing” is done using air injection or overthrow/underthrow rotors. This also results in more suspension burning in these boilers, which results in better response times compared to mass fed or underfed boilers (EPA, 2007). Spreader stokers are the most common stoker boilers (EPA, 2007).

3.1.2.1.2 Fluidized Bed Boilers

Fluidized beds were initially studied by Winkler in the 1920s for application as a gasifier, and in the early 1960s the US and UK began programs focused on this technology for the development of a compact boiler package that could reduce costs. These early studies showed that emissions could also be reduced by utilizing this technology (Highley, 1980). Since then with certain governmental regulations and funding opportunities, this technology has become commercial with every major US boiler manufacturer offering an atmospheric fluidized bed combustor in their product line (DOE, 2006). However, the more advanced technologies (pressurized and supercritical fluidized beds) have only several units operational (six-pressurized; 1-supercritical) and are in need of additional research and development due to their potential for higher efficiencies compared to the older commercially available atmospheric technologies (Koomneef et al., 2007; Patel, 2009). Fluidized bed boilers burn fuel in a fluidized state, i.e., in a bed of granular solids with typical sizes 0.1 to 1 mm (depending on the boiler type) with primary combustion air flowing up through the bed material where the temperature of this bed material is typically maintained at 800-900 °C through heat transfer either to the flue gas or heat exchange tubes buried in the bed material (Basu, 2006). This lower operating temperature compared to that of the stoker boilers results in lower NOx production. The bed material can be sand, gravel, limestone, ash, or other special synthetic materials. The interaction of the bed material with the fuel as it is burning allows for more efficient combustion as well as the ability to capture pollutants (e.g., addition of limestone absorbs SOx).

The two main types of fluidized bed boilers are the bubbling fluidized bed (BFB) and the circulating fluidized bed (CFB) with further classification according to operating pressure (atmospheric vs. pressurized) and state of the steam product (sub vs. supercritical). The BFB technology was first to become commercial with the CFB becoming commercial later. There are now more CFB units in operation than BFB units (Koomneef et al., 2007). The velocity of the primary air flowing through the bed is higher in the CFB than in that BFB, which is the primary distinction between these two technologies. The CFB primary air flow is high enough to actually blow the bed material upward to the top of the furnace where it is then separated from the flue gas and re-circulated to the bottom of the furnace. The more advanced technologies attempt to increase the efficiency of these systems by increasing the operating pressure for combined cycle operation or by increasing the temperature and/or pressure of the steam produced to supercritical conditions. Each of these methods of increasing efficiency can be applied to the BFB or CFB technologies although the CFB technology is typically used because of the higher combustion efficiencies and better sulfur capture achievable with these systems compared to the BFB (Koomneef et al., 2007; Basu, 2006).

3.1.2.1.3 Pulverized Fuel Boilers

Pulverized fuel boilers are less likely to be used for biomass combustion; although co-firing pulverized coal plants with biomass has been accomplished. This is because of the much more intensive processing of the biomass prior to combustion, i.e., to attain the appropriate particle sizes (<10mm) (Van Loo, 2008). However, higher efficiencies are achievable with these systems when compared to BFB and CFB technologies because of the lower excess air used (See Table 4). But during the bidding process of a supercritical CFB in Poland, it was found that the CFB option was 20% cheaper in capital cost and 0.3% higher in net efficiency than the competing supercritical pulverized coal option (Basu, 2006). Additionally, these systems require post processing for SOx removal unlike the fluidized bed options.

3.1.2.1.4 Summary of Issues Related to Direct Combustion of Biomass

Table 4 summarizes the advantages and disadvantages of several direct combustion technologies.

Table 4: Summary of the advantages and disadvantages of various direct combustion technologies (Van Loo, 2008)

Advantages	Disadvantages
Grate Furnaces	
• Low investment costs for plants <20MWth • Low operating costs • Low dust load in flue gas • Less sensitive to slagging than fluidized beds	• Usually no mixing of wood fuels and herbaceous fuels possible (only special constructions can cope with such fuel mixtures) • Efficient NOx reduction requires special technologies (combination of primary and secondary measures) • High excess oxygen (5-8% vol) decreases efficiency • Combustion conditions not as homogeneous as in fluidized beds • Low emission levels at partial load operation requires a sophisticated process control
Underfeed stokers	
• Low investment costs for plants <6MWth • Simple and good load control due to continuous fuel feeding and low fuel mass in the furnace • Low emissions at partial load operation due to good fuel dosing • Low flexibility in regard to particle size	• Suitable only for biomass fuels with low ash content and high ash melting point (wood fuels) (<50 mm)
BFB furnaces	
• No moving parts in hot combustion chamber • NOx reduction by air staging works well • High flexibility concerning moisture content and kind of biomass fuels used • Low excess oxygen (3-4%) raises	• High investment costs, interesting only for >20MWth • High operating costs • Reduced flexibility with regard to particle size <80mm • Utilization of high alkali biomass fuels (e.g., straw) is critical due to possible bed

efficiency and decreases flue gas flow	agglomeration without special measures • High dust load in the flue gas • Loss of bed material with the ash without special measures
CFB furnaces	
• No moving parts in the hot combustion chamber • NOx reduction by air staging works well • High flexibility regarding moisture content and kind of biomass fuels used • Homogeneous combustion conditions in the furnace if several fuel injectors are used • High specific heat transfer capacity due to high turbulence • Use of additives easy • Very low excess oxygen (1-2%) raises efficiency and decreases flue gas flow	• High investment costs, interesting only for plants >30MWth • High operating costs • Low flexibility with regard to particle size (,40mm) • Utilization of high alkali biomass fuels (e.g., straw) is critical due to possible bed agglomeration • High dust load in flue gas • Loss of bed material with the ash without special measures • High sensitivity concerning ash slagging
Pulverized fuel	
• Low excess oxygen increases efficiency (4-6%) • High NOx reduction by efficient air staging and mixing possible if cyclone or vortex burners are used • Very good load control and fast alteration of load possible	• Particle size of biomass is limited (<10-20mm) • High wear rate of the insulation brickwork if cyclone or vortex burners are used • An extra start up burner is necessary

3.1.2.2 Gasification

Gasification technologies are less available commercially than direct combustion technologies, however, gasification provides opportunities for cleaner plant operation and higher efficiencies (EPA, 2007). This process is different from direct combustion in that the solid fuel is partially oxidized in an oxygen deprived environment sometimes with the addition of steam or carbon dioxide such that a gas is produced. This gas has a low heat content (5000-15000 kJ/kg) and the remaining char may still have a heating value associated with it which results in less than 100% energy conversion from the original solid fuel (typical conversion efficiencies are 60-80% (EPA, 2007). The process of gasification occurs in four sets of processes: drying, pyrolysis (devolatilizaton), combustion, and reduction (Basu, 2006). The first, second, and last of these processes are endothermic, absorbing heat from the combustion process. The drying process occurs quickly (>150 °C) with pyrolysis reactions following this process (150-700 °C). The pyrolysis process is complex and progresses to fast reaction rates at higher temperatures. The pyrolysis process is responsible for the production of some gases, tar, and char. Tar causes many issues in gasification processes (Knoef, 2000). The combustion process occurs in an oxygen deprived atmosphere thereby only partially oxidizing the solid fuel rather than completing the combustion process. These partial oxidation reactions supply the heat required for the endothermic processes (i.e., drying, pyrolysis, reduction). The process of reduction or gasification involves several main sets of reactions: the water gas, Boudouard, water gas shift, and methanation reactions (Basu, 2006).

Gasification units are classified according to the oxidant used (oxygen vs air blown gasifiers) and according to the reactor technology used (fixed/moving bed, fluidized bed, entrained flow). The typical efficiencies and example schematics of these systems are shown in Figure 9 and Figure 10, respectively. The fixed bed gasifiers can be further classified by the flow of the gasifying medium (air/steam/oxygen): updraft, downdraft, side draft/cross flow. Fluidized bed gasifiers are classified in a similar fashion to fluidized bed boilers/combustors (i.e., circulating vs. bubbling, atmospheric vs. pressurized). The commercial availability of each technology was inventoried in 2000 for the European Commission through industry surveys (Knoef, 2000). This inventory showed that downdraft gasifiers accounted for 75% of commercially available products with fluidized beds accounting for 20%, updraft for 2.5% and 2.5% of other types (Bridgwater, 2006).

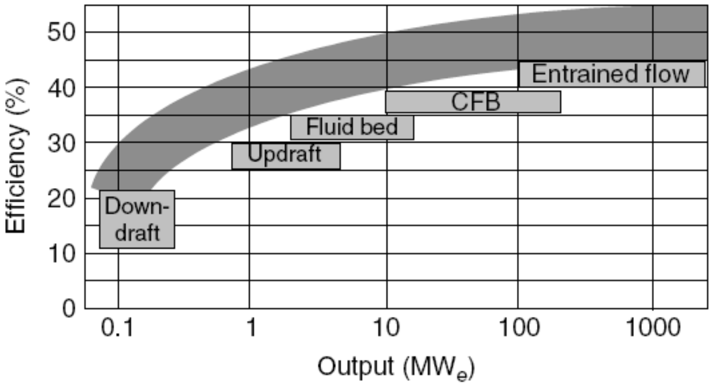

Figure 9: Typical electrical conversion efficiencies for different types of gasification technologies (Bridgwater, 2006)

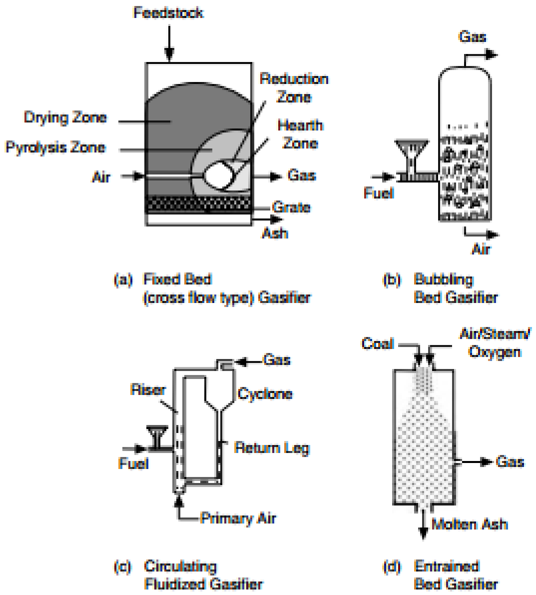

Figure 10: Schematic representations of different types of gasifiers (West et al., 2009)

3.1.2.2.1 Fixed/Moving Bed Gasifiers

In the fixed/moving bed design, the solid fuel is fed into the bed while the gasifying medium (i.e., steam, air, or oxygen) flows past the fuel. The flow of this gasifying medium is how these designs are classified: updraft, downdraft, and side draft/cross flow. In the case of an updraft gasifier, the gasifying medium feed flows upward through the bed of fuel, char, and ash as seen in Figure 11 with different reactions occurring in the bed. Fixed bed gasifiers are limited to small scale applications typically less than 2-5 MW (Bridgwater, 2006; EPA, 2007).

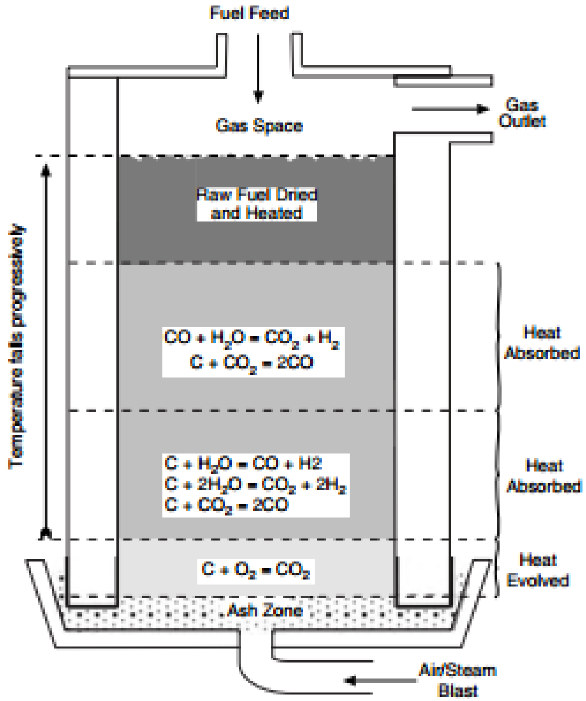

Figure 11: Schematic of an updraft gasifier, taken from Basu, 2006

3.1.2.2.2 *Fluidized Bed Gasifiers*

Fluidized bed gasifiers were first studied in the 1920s by Winkler, and in fact he developed a commercial air blown fluidized bed gasifier (EPA, 2007; Basu, 2006). The fluidization of the bed is completed in a similar fashion to those in fluidized bed boilers, however, the fluidization is accomplished by the gasifying medium which can be air, steam, or oxygen. As in the case of fluidized bed boilers, fluidized bed gasifiers can have bubbling (BFB) or circulating fluidized beds (CFB) operating at either pressurized or atmospheric conditions. BFB gasifiers have lower gasifying medium velocities compared to CFB gasifiers where the gasifying medium flow rate is high enough to actually blow the bed material upward to the top of the gasifier where the bed material is then separated from the syngas and circulated back to the bottom of the gasifier. Similar to the fluidized bed boilers except that the product is now a synthetic gas (syngas) rather than a hot flue gas for producing steam.

3.1.2.2.3 *Entrained Bed Gasifiers*

Entrained flow systems require pulverized fuel particles to be used (<0.15 mm). These fuel particles are typically injected at the top of the gasifier along with the gasifying medium, and these particles are surrounded/suspended/entrained by the gasifying medium. These gasifiers are usually used in coal gasification processes for large systems (>100MWe). Biomass gasification with this technology is not typical because of the fuel particle size requirement. However, the syngas produced has very low or zero tar content in addition to high carbon conversion efficiencies.

3.1.2.2.4 *Hybrid or Other Gasification Technologies*

There are other gasification technologies that may have hybridized two technologies; may have slightly different reactor conditions such that the technology does not fit neatly into the classifications given here; or the technology could be completely different. One example of a hybridized approach is the Gussing gasifier in Austria that uses a dual fluidized bed process wherein one bed operates in a combustion mode which supplies heat to the other bed which operates in a gasification mode. Other twin fluidized bed gasifiers have been investigated in Europe and Asia (Corella et al., 2007). This gasification process has also been termed indirect gasification and has been quite successful (Bridgwater, 2006; Thunman et al., 2010). Another example of a different gasification technology is plasma gasification where a plasma torch (electric arc between two electrodes) is used to provide the heat for the gasification process. This technology requires electricity but it is insensitive to the feedstock type (Basu, 2010).

3.1.2.2.5 *Summary of Issues Related to Gasification*

Table 5 summarizes the various issues related to each gasification technology discussed above.

Table 5: Summary of challenges and advantages of the various gasification technologies (compiled from (Bridgwater, 2006; Basu, 2010; Wang et al., 2008)

	Main Advantages	Main Technical Challenges
Gasifying Agents		
Air	1. Partial Combustion for heat supply of gasification 2. Moderate char and tar content	1. Low heating value (3-6 MJ/Nm3) 2. Large amount of N2 in syngas 3. Difficult determination of

		equivalence ratio
Steam	1. High heating value (10-15 MJ/Nm^3) 2. H2 rich syngas	1. Require indirect or external heat supply 2. Required catalytic tar reforming
Carbon Dioxide	1. High heating value syngas 2. High H2 and CO in syngas and low CO2 in syngas	1. Require indirect or external heat supply 2. Required catalytic tar reforming
Oxygen	1. High heating value syngas (12-28 MJ/Nm^3) 2. Higher quality gas (low tar)	1. Energy intensive to supply oxygen 2. Expensive
Gasifier Design		
Fixed/Moving Bed	1. Simple and reliable design 2. Capacity for wet biomass gasification 3. Favorable economics on small scale	1. Long residence time 2. Non uniform temperature distribution 3. High char and/or tar contents 4. Low cold gas energy efficiency 5. Low productivity
Fluidized Bed	1. Short residence time 2. High productivity 3. Uniform temperature distribution 4. Low char and/or tar content 5. High cold gas efficiency 6. Reduced ash related problems	1. High particulate dust in syngas 2. Favorable economics on medium to large scale
Gasifier operation		
Increase of temperature	1. Decreased char and tar content 2. Decreased methane in syngas 3. Increased carbon conversion 4. Increased heating value of syngas	1. Decreased energy efficiency 2. Increased ash related problems
Increase of pressure	1. Low char and tar content 2. No costly syngas compression required for downstream utilization of syngas	1. Limited design and operational experience 2. Higher costs at small scale
Increase of equivalence ratio	1. Low char and tar content	1. Decreased heating value

3.1.2.3 Pyrolysis

Pyrolysis is defined as thermal decomposition in the absence of oxygen and is the first step in combustion and gasification processes. This process of pyrolysis can be performed in different modes as seen in Table 6. Pyrolysis has been proposed for the production of bio-oils and given that fast pyrolysis provides the highest yield of liquids this is the typical mode of operation for the production of bio-oils from pyrolysis (Bridgwater, 2006).

Table 6: Typical product yields obtained from different modes of pyrolysis of dry wood (Bridgwater, 2006)

Mode	Conditions	Liquid (%)	Char (%)	Gas (%)
Fast	Moderate temperature, around 500 °C, Short hot vapour residence time, ~1 s	75	12	13
Intermediate	Moderate temperature, around 500 °C, Moderate hot vapour residence time ~10–20 s	50	20	30
Slow (carbonisation)	Low temperature, around 400 °C, very long residence time	30	35	35
Gasification	High temperature, around 800 °C, long residence times	5	10	85

The different pyrolysis reactors (pyrolysers) are fluidized beds (CFB and BFB), transported bed, entrained bed, and ablative. The fluidized and entrained beds are similar to the reactors used in the boiler and gasification processes but with different residence times and reactor temperatures. The ablative pyrolyser mechanically applies pressure to the biomass particles such that an appropriate rate of heat transfer is achieved (biomass particles can be larger in this reactor than in the others where small particles are required for sufficient heat transfer). Bridgwater likened this process to the melting of butter in a frying pan (Bridgwater, 2006). The pyrolysis oil must then be collected and in fact the reactor only amounts to about 10-15% of the total plant cost yet most of the research has been focused on this part of the process. Figure 12 shows a conceptual schematic for a pyrolysis plant being utilized for the production of bio-oil (Bridgwater, 2006).

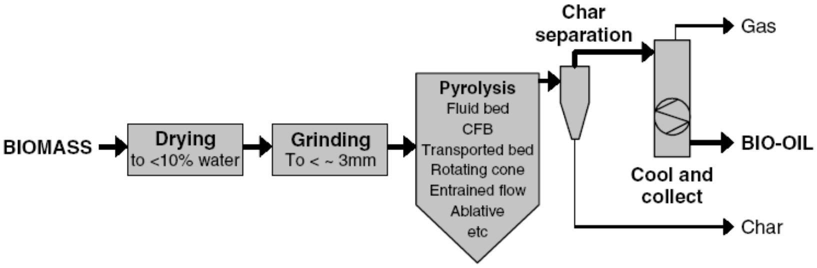

Figure 12: Schematic of a fast pyrolysis process (Bridgwater, 2006)

Charcoal and gas are by-products of fast pyrolysis, and they typically contain 25 and 5%, respectively, of the energy in the biomass feedstock. Some of these byproducts must be utilized in the pyrolyser to supply heat. The bio-oil produced would ideally be readily used as a substitute for conventional liquid fossil fuels, however, differences in properties prohibit easy substitution, which is not to say that it cannot be done.

3.1.2.4 Digestion

Anaerobic digestion is the conversion of organic matter using certain types of bacteria in the absence of oxygen. This process produces a fuel gas with a methane content of 50-80% with the balance being mostly CO_2 in addition to small amounts of hydrogen sulfide, nitrogen, hydrogen, methylmercaptans, and oxygen. Residue slurry called digestate is also produced in this process.

Aerobic digestion is another process of conversion of organic matter, however, this occurs in the presence of oxygen with the major products being compost, carbon dioxide, and water. Since this does not provide a fuel gas, it is not considered for bio-energy applications although it is used for processing of waste in some landfills. The process of anaerobic digestion is used in both anaerobic digesters (controlled) and in landfills (uncontrolled) (Basu, 2010), but typically, the term anaerobic digestion is used when referring to anaerobic digesters and not landfills. The anaerobic digestion of organic matter consists of several steps: hydrolysis, fermentation, acetogenesis (Beta-oxidation), and methanogenesis (Nayono, 2009). Figure 13 illustrates these steps schematically.

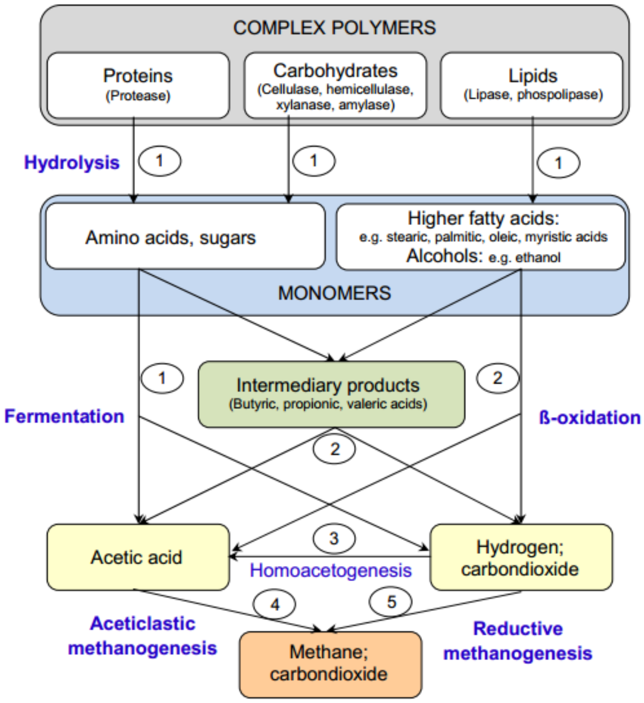

Figure 13: Illustration of the various sets of biological reactions that occur in anaerobic digestion (U.S. EPA, 2010)

3.1.2.4.1 Anaerobic Digesters

Anaerobic digesters are classified according to the digester temperature (psychrophilic, mesophilic, thermophilic), feed mode (batch vs. continuous), and solids content in feed (i.e., wet vs. dry). They have traditionally been used for processing of wet waste (<15% solid content), but new developments in solid state fermentation have allowed higher solid content (Brusstar et al., 2005). The typical temperature ranges for psychrophilic, mesophilic and thermophilic digestion are respectively: 5-20 °C, 30-38 °C, and 50-57 °C. Thermophilic conditions provide higher biogas production, increased solids reduction, improved dewatering, and increased destruction of pathogenic organisms; however, these bacteria have less process stability due to their sensitivity to temperature fluctuations, are more energy intensive, and have a higher odor potential (Appels et al., 2008). Mesophilic conditions in contrast have lower biogas production rates but have better stability. Digestion under psychrophilic conditions is being considered as a low cost alternative because no added heat is required for the feed, although it requires long residence times for digestion due to low temperatures (Saady and Masse, 2013). Figure 14 shows the regions of temperature for the different bacteria and the corresponding relative rates of reaction. The different feed modes are straightforward to understand. Batch mode is where the digester is filled with waste once and then left to proceed through the digestion process without the addition of more waste. This has sometimes been termed "landfill in a box", however, the biogas production of batch systems is much higher than in landfills because of the active control of the system through recycling of the leachate and operation at higher temperatures than those seen in landfills (Nayono, 2009). The continuous mode is where the waste is continually fed into the digester. Wet digesters are those digesters designed to process waste with a solid content of less than 13% (Vandevivere et al., 2003; Lissens et al., 2001). Batch and continuous systems can also have single or multiple stages where certain processes occur in certain stages, which for example, would allow the separation of hydrolysis and fermentation processes from the methanogenesis process. These multiple stage systems are the most complex and hence the most expensive. Batch systems have the simplest design and least cost. In comparing dry and wet systems, dry designs are more robust and flexible than wet systems. The majority of industrial applications as of 2001 used single stage systems with an even split between dry and wet systems (Lissens et al., 2001).

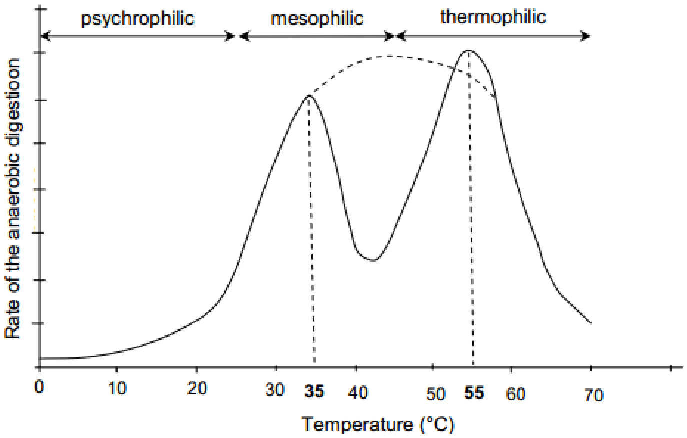

Figure 14: Rate of anaerobic digestion vs. digester temperature (U.S EPA, 2010a)

Further classification is typically applied when discussing digestion of low solid content agricultural solid waste residues, such as manure. Three systems are usually cited as being available to these agricultural enterprises: covered lagoon, complete mix, and plug flow (Demirbas et al., 2005; Krich et al., 2005). Each of these three designs would be classified as wet technologies since they require feeds with less than 13% solids content (Demirbas et al., 2005). The covered lagoon is a specific digester design that requires dilute waste (<2% solids) to be collected in a covered pond or lagoon. The cover allows for the collection of biogas as well as separation from air. These systems are simple and low cost to install, however, they only work well in warm climates since the temperature within the lagoon is not controlled. Complete mix digesters are covered, heated tanks that use a mechanical or gas mixer to keep the solids in suspension. They require a feed with a solid concentration of 3-10%. These units are more complex and expensive than covered lagoons but are suitable for cold climates. Plug flow digesters are also heated and require a feed with a solid concentration of 11-13%. These designs are usually covered for gas collection and rectangular with new feed entering at one end of the digester and the leftover sludge exiting at the other.

3.1.2.4.2 Landfill

The same process of anaerobic digestion occurs in landfills to produce landfill gas; however, landfill processes may be distinguished from digester technologies in that the process is uncontrolled in landfills. Landfill gas is extracted from the sealed landfill through a network of wells drilled in the landfill. However, these wells do not recover the landfill gas with 100% efficiency, rather some leakage still occurs. Typical recovery efficiencies are 60-85% (EPA, 1995). Treatment of the gas coming out through the well head is required. Landfill gas will have a typical methane content of 50-55% (Bridgwater, 2006).

3.1.3 Emissions Impacts

Environmental impacts resulting from the use of biomass for electricity generation (biopower) differ from the environmental impacts of other renewable technologies such as wind and solar in that biopower technologies have operational pollutant emissions comparable to conventional fossil fuel sources, which could potentially have adverse impacts on regional and local air quality. Quantification of GHG benefits is complicated by uncertainty with regards to allocation of any “negative” emissions occurring from carbon uptake. The carbon emissions occurring during the conversion to electricity (typically through combustion) are assumed to be reabsorbed by photosynthesis during re-growth of the biomass, or in the case of the use of waste or residue, would have been emitted during decomposition, therefore, power generation via biomass waste/residue is also considered a carbon offset. Biopower technologies that utilize appropriately selected, dedicated energy crops on the correct land type have the potential to sequester carbon in the soil and crop roots (Tilman et al., 2006; Tolbert et al., 2002). Sequestration technology currently being considered for coal plants can also be applied at biopower plants to effect negative carbon emissions. Additionally, biopower allows dispatch of electricity unlike wind and solar, which are intermittent. Wind and solar must rely on other dispatchable resources to meet unserved load that are typically less efficient, higher emitting fossil fuel technologies. Biopower also has a large environmental impact in terms of land and water resources consumed (See Water Impacts section), especially when considering dedicated energy crops where significant energy inputs occur upstream of the conversion to electricity. Removal of residues such as forestry and agricultural residues may also have an impact on the soil quality and biodiversity (Stewart et al., 2010). There is also the question of transporting the biomass to biopower plant sites, which can also have an environmental impact in terms of pollutant, GHG, and noise emissions as well as traffic congestion. These issues will be discussed in the following sections.

3.1.3.1 Feedstocks

The differences in life cycle analyses of dedicated energy crop and waste/residue feedstocks are important to note because dedicated energy crops require changes in use of land and water resources that affect biodiversity, food resources, hydrologic cycles (Le et al., 2011), surface heat balances (Georgescu et al., 2011), etc. in a complex way that make life cycle environmental impact studies extremely challenging. In fact, varying levels of impacts for the same energy crop species have been claimed by different life cycle assessment studies (Georgescu et al., 2011). The methods of accounting for GHG emissions resulting from land use change have also been questioned (Searchinger et al., 2009). The life cycle GHG emissions are more straightforward when examining biomass residues and wastes where these emissions can be considered as zero (or even negative when methane emissions are mitigated) because decomposition results in emissions irrespective of any energy generation activities. However, there may still be soil quality, water quality, and biodiversity impacts as a result of residue removal (Stewart et al., 2010). Long term studies investigating the removal of forestry residue in California's mixed conifer forests have concluded that there is no long term loss in forest productivity as a result of residue removal, but similar studies have not been conducted for other forest types or shrublands. Additionally, other benefits and impacts resulting from residue removal have not been quantified such as the possible reduction of wildfire associated emissions and the loss of wildlife habitats (Stewart et al., 2010).

Dedicated energy crops create ecological concern because of possible replacement of food crops, upset of the hydrologic cycle (Le et al., 2011), upset of soil nutrient balance (Adegbidi et al., 2001), biodiversity, effects of land use change on carbon balances (Tolbert et al., 2002; Searchinger et al., 2009), etc. Given these concerns, it should be expected that dedicated energy crops provide more than marginal reductions in GHG emissions when compared to the fossil fuel they are replacing otherwise the risk of these other ecological concerns can be considered too great. Tilman et al. suggest that only several feedstocks be considered: perennial plants grown on degraded lands abandoned from agricultural use, crop residues, sustainably harvested wood and forest residues, double crops/mixed cropping systems, and municipal and industrial wastes (Tilman et al., 2009). Fazio et al. show that the average life cycle GHG emissions are lower for perennial crops than annual crops (Fazio et al., 2011). Adler et al. performed life cycle studies comparing several different energy crops (switchgrass, giant reed, and hybrid poplar) to be used for electricity generation in an integrated gasification combined cycle system (Adler et al., 2007). They showed that the net GHG savings achieved when compared to a coal gasification system were larger than those net GHG savings when used to produce biofuels, which motivates the use of biomass for power generation. Thornley et al. also compared life cycle GHG emissions of short rotation coppice (willow/poplar) to miscanthus for various gasification and combustion systems with some systems including combined heat and power capability (Thornley et al., 2009). Their results show that in terms of the GHG emissions per unit of energy produced, short rotation coppice performs better than miscanthus, however miscanthus performs better in terms of GHG emissions per unit of land used. These results highlight the potential tradeoffs that must be considered with respect to the various available dedicated crops. These researchers also discuss the issue of soil carbon balance, and the dependence upon what the land use was prior to implementation as land for energy crop growth. Thornley et al. also analyzed the life cycle pollutant emissions of the two crops (short rotation coppice and miscanthus) in another publication and found that the biomass production, preparation, and provision was much less significant in determining the CO, NOx, and hydrocarbon emissions than was the electricity production for most of the cases analyzed (Thornley et al., 2008). However, the particulate emissions were largely produced during the biomass production, preparation, and provision phases rather than during the electricity generation phase.

Some researchers such as Tilman et al. (2006) have demonstrated that using low input and high diversity grassland for biopower can actually provide carbon sequestration in the soil and roots of the biomass. However, these demonstrations were in climates much different from California, but some preliminary work has begun in demonstrating the potential of low input grasses (e.g., switchgrass) in California (Pedroso et al., 2011). Appropriate selection of land and feedstock for dedicated energy crop use has high importance in limiting indirect and direct environmental impacts, and the use of thorough life cycle analyses that take into account the specific location of interest are vital to minimizing the impacts.

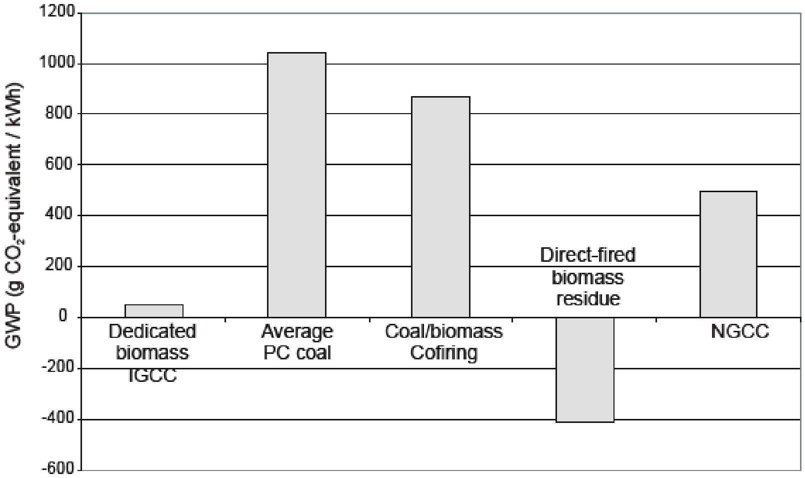

Figure 15: Life cycle GHG emissions for several different scenarios of electricity generation (Bain et al., 2003)

Bain et al. discusses various life cycle assessments performed at the National Renewable Energy Laboratory that illustrate the differences between the use of biomass residues and dedicated energy crops for electricity generation (Bain et al., 2003). The systems considered include a dedicated biomass (hybrid poplar) integrated gasification combined cycle, pulverized coal, coal/biomass co-firing, direct fired biomass residue, and natural gas combined cycle systems. The analyses demonstrate that the use of biomass residue is preferable to the use of dedicated energy crops in terms of both the net energy ratio (energy out /energy in) and the life cycle GHG emissions. In fact the life cycle GHG emissions for the biomass residue case are negative because of the decomposition that would have otherwise occurred, which would have resulted in methane emissions (see Figure 15). Additionally, Bain et al. also showed life cycle pollutant emissions from different power generation technologies (Bain et al., 2003) (see Figure 16).

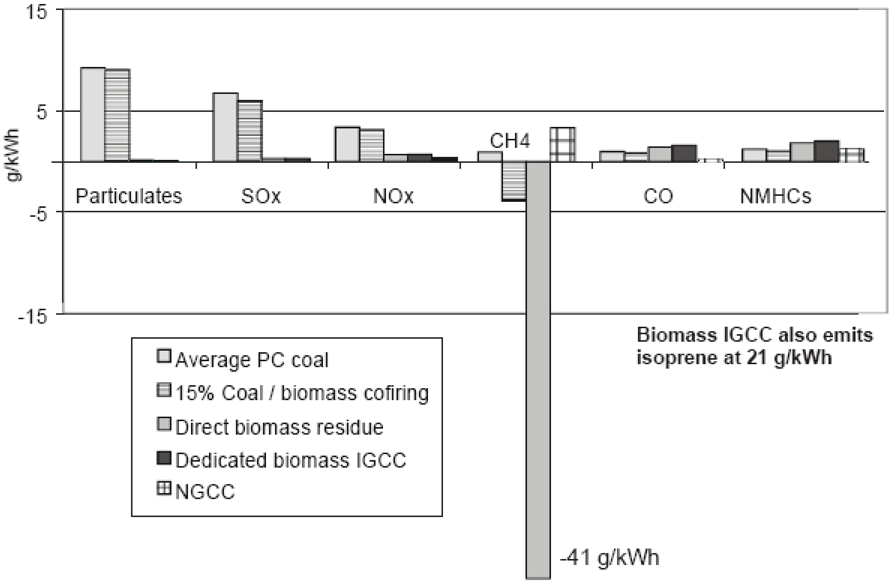

Figure 16: Life cycle pollutant emissions for several different scenarios of electricity generation (Bain et al., 2003)

To conclude, the implementation of dedicated energy crops must be considered carefully with the appropriate analysis of the life cycle environmental impacts resulting from those changes (land, water, albedo, soil health, etc.). The use of biomass waste and residue streams are more straightforward in their carbon reduction benefits and represent a lower risk path to increased use of renewable technologies than do the dedicated energy crops which if done incorrectly can have significant negative environmental impacts. Recall that Williams et al. showed the use of biomass waste and residue in California could contribute 11.9% of total electricity consumed in the state (Williams et al., 2007). Although the use of these waste and residue streams is more tractable in the near term, there is still risk of negative environmental impact particularly with regard to the pollutant emissions from these technologies as well as any additional GHG emissions that may occur due to changes in the transportation and processing of the particular waste/residue stream compared to normal operations.

3.1.3.2 Electricity Conversion Technologies

The environmental impacts associated with the electricity conversion technology itself are typically a large contribution to the pollutant emissions associated with biopower (Thornley et al., 2008). Waste and residue streams will also typically have lower emissions (GHG and pollutant) upstream of the electricity conversion technology, which emphasizes the importance of the environmental performance of the electricity conversion technology itself. Additionally, pollutant emissions occurring from biopower sources could have large air quality impacts if they are spatially located within urban air sheds with poor air quality; a significant concern in many regions of California.

From Figure 7, the largest potential for expansion of biomass residue utilization exists for forestry residues. The conversion technologies most applicable for use with this feedstock are gasification and direct combustion, as the use of anaerobic digestion would require the addition of water such that the solid content was reduced to less than 40% (Vandevivere et al., 2003). These conversion technologies are also applicable to those agricultural residues with high solid content (>40% solid content) and municipal solid waste. Direct combustion technologies exist commercially but exhibit low efficiencies and may have poor pollutant emission performance. Integrated gasification combined cycle systems will have higher efficiencies but remain in the development stages and are currently limited by high costs. Opportunities for modular, distributed small scale systems are also in development and make sense to the extent that biomass resources are diffuse and require collection and transportation to the point of conversion; whereas a modular system could reduce the need for this, and could potentially have cost benefits. However, if pollutant emissions from these distributed modular systems are high the potential for negative localized air quality impacts exists. The use of fuel cells with both small and large scale gasification systems could produce efficiency gains and reduce pollutant emissions although the efficiency gains could be highly beneficial to the small scale systems since fuel cell systems do not suffer from reduced efficiency at smaller scales like heat engines. Some typical numbers comparing the pollutant emission performance of gasification and direct combustion systems are shown in Figure 17 and Figure 18. Figure 17 and Figure 18 show differences in the emissions performance between the various gasification and combustion technologies despite the generality mentioned in earlier sections that gasification processes result in cleaner plant operation (EPA, 2007). This further motivates the need to examine biopower installations on a case by case basis given that no general rules of thumb exist across the different thermal conversion technologies.

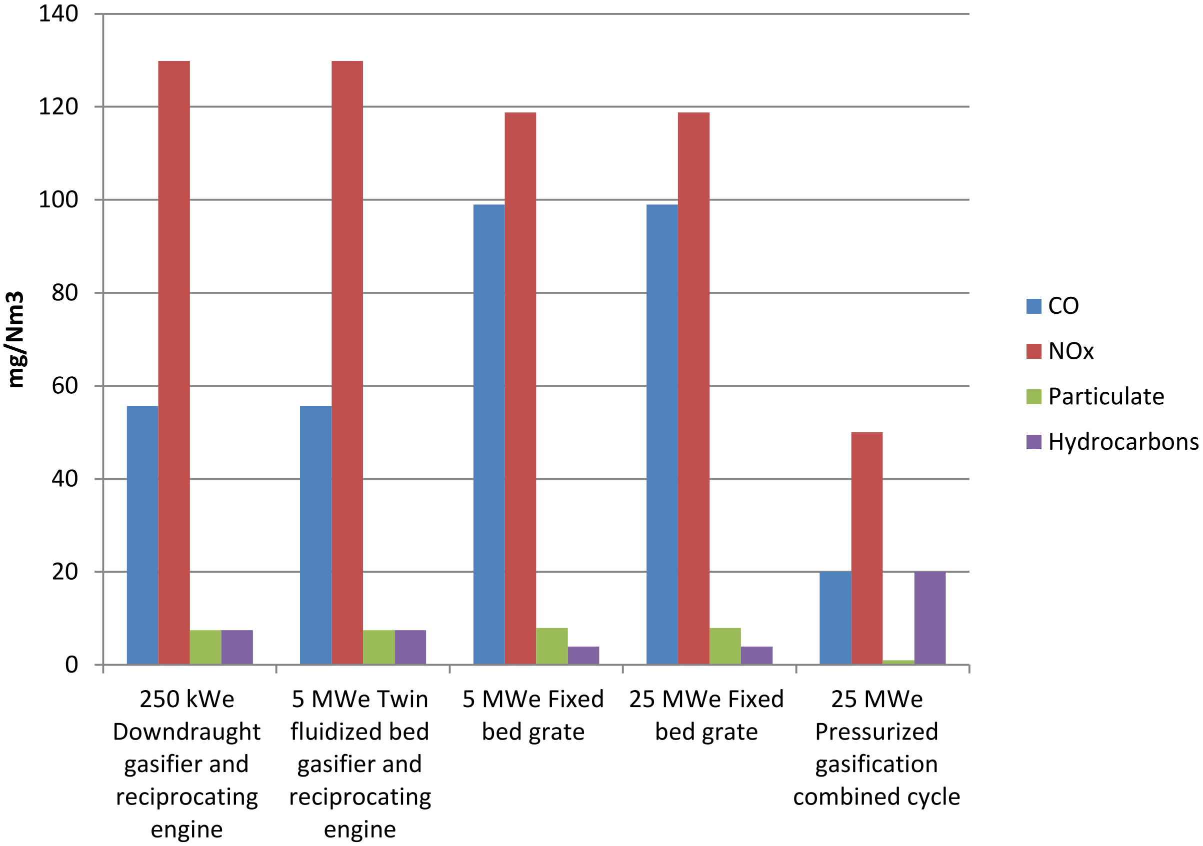

Figure 17: Emissions performance for several biopower technologies (Thornley, 2008)

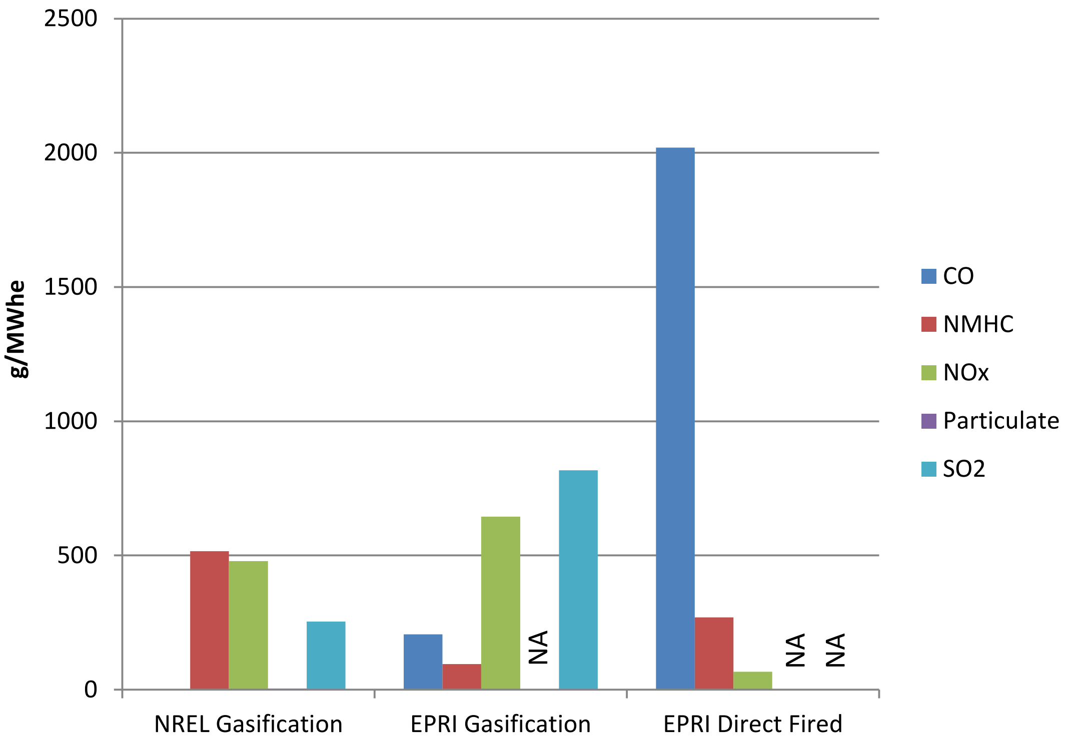

Figure 18: Emissions performance for several biopower technologies (Le et al., 2011)

The processing of agricultural residue and municipal solid waste for energy conversion can contribute to significant reductions in GHG emissions. In fact, simple changes in the management of municipal solid waste have led to significant reductions in GHG emissions from this sector (Weitz et al., 2002). These reductions are possible since any reduction in the emission of landfill gas has large GHG reduction benefits as a result of the methane content of this gas (50-80%) and the high global warming potential of methane, which is 28 times greater than CO_2. The implementation of gas collection systems at landfills for flaring or energy recovery has reduced GHG emissions by limiting these landfill gas emissions. However, these collection systems are not 100% efficient, and landfill gas is still emitted even in landfills with gas recovery (EPA, 1995). This issue and other issues related to land and water resources (leachate leakage) have led some countries to implement more sophisticated systems for management of MSW. These systems include high solid content anaerobic digesters, incineration facilities, gasification units, etc. (EC, 2001). Although the incineration or digestion of petroleum based products represents net GHG emissions to the atmosphere just as with fossil fuel fuels, the incineration or digestion of the organic (biogenic) fraction of municipal solid waste would lead to GHG emission reduction by eliminating the emission of landfill gas. Not all of the organic fraction of municipal solid waste should be handled in this manner because life cycle assessments have shown recycling to result in much larger GHG emission reductions than incineration (Finnveden et al., 2005; Moberg et al., 2005). Murphy et al. performed life cycle assessments of the GHG emissions associated with processing municipal solid waste using gasification, incineration, and anaerobic digestion using a commercial high dry solids content digester (DRANCO process by Organic Waste Systems) (Murphy et al., 2004). These researchers showed that use of the high solid content anaerobic digester provided the best GHG reductions when compared to the scenario of flaring landfill gas. Finnveden et al. showed that the digestion of food waste provided the highest reductions in GHG emissions when compared to incineration and landfilling (Finnveden et al., 2005). This shows the potential of using these controlled anaerobic digesters for the processing of municipal solid waste. The European Commission also published a report in 2001 that analyzed the GHG emissions from several different waste management options. This report found that the anaerobic digestion of the organic fraction of municipal solid waste along with composting can lead to lower GHG emissions than the best practice landfill techniques that involve gas recovery for energy use and use of restoration layers (EC, 2001). The pollutant emissions associated with these processes as well as the electricity conversion of the biogas also remain an area of concern because in California these landfills may be located within non-attainment air basins and could then have significant effects on air quality.

Other ‘wet’ (low solid content) digester technologies are used to process wet waste such as manure and sewage. These wet digester technologies are currently utilized by waste water treatment plants and agricultural operations for processing animal manure with significant expansion possible in using animal manure for energy production (See Figure 7). These technologies provide GHG reductions as well and for similar reasons, i.e., decomposition leads to carbon emissions and use of the digester gas for electricity production can reduce these emissions. However, a similar problem remains: how do local emissions of pollutants from electricity conversion technologies (gas turbine, reciprocating engine, fuel cell, etc.) affect air quality.

3.1.4 Biopower Conclusions

Given that Executive Order S-06-06 requires 20% of the renewable electricity generated in California to come from biopower resources in 2010 through 2020 and in 2010 the biopower percentage of total renewable electricity generated was 17.5%, an increase in biopower capacity is expected in coming years. However, capacity increases could have negative environmental impacts, particularly with regards to localized air quality, for some generation pathways dependent on utilized feedstocks and conversion technologies. A major concern is pollutant emissions at the point of conversion, as well as emissions associated with the collection and transport of feedstock. The diffuse nature of waste/residue streams motivates the use of distributed biopower plants which could result in pollutant emissions in nonattainment regions (i.e. the San Joaquin Valley), however in centralized power generation situations the waste/residue streams require transportation, which also has associated pollutant emissions. Studies that assess potential air quality impacts across a range of different future year scenarios involving various deployment strategies of increased biopower capacity are needed. The spatial allocation of biomass resources performed by Williams et al. provides a starting point for such analyses considering that the spatial and temporal allocation of emissions sources is essential to air quality analyses (Williams et al., 2007). However, technically recoverable biomass resources may not be the actual recoverable resources due to economic or societal reasons; therefore, an assessment of the economically recoverable biomass resources under different scenarios would also be of worth. Important considerations in spatially and temporally resolved air quality impact studies include the many different conversion technologies available with currently limited available data (e.g., gasification technologies cannot be assumed to have a standard emission factors since these technologies have widely different emission factors depending on the design and manufacturer), therefore, it is important to use specific technologies that are applicable in the scenario under consideration.

In addition to the impacts on air quality, there are also issues related to water consumption and water/soil quality. Studies have shown that forestry residue removal in California mixed conifer forests does not affect the productivity of these forests, however, similar studies have not been completed for other types of woodlands and shrublands (Stewart et al., 2010). Water consumption in biopower plants will be similar to fossil fuel plants as both use similar thermodynamic cycles; although biopower plants utilizing fuel cell technology could have significant benefits for water consumption in that many fuel cell systems commercially available are water neutral. Water quality is an issue that is more difficult to address than water consumption and requires further analysis in conjunction with soil quality analyses.

Finally, the need to ensure that GHG reductions are actually achieved through the use of additional biopower resources is paramount due to the risk for other potential negative environmental impacts (i.e. local air quality disbenefits). For example, using municipal solid waste for the production of electricity may emit more GHGs than what recycling the material for re-use (e.g., paper), even if closed-vessel anaerobic digestion is utilized. GHG emission reductions throughout the life cycle of the feedstock-conversion technology pathway must be identified as not all pathways are equivalent in achieving reductions. Further, estimating emissions from biopower plants is essential in assessment of the effectiveness of California climate change targeted policy, such as programs related to AB 32.

It should also be noted that fuel cells and combined heat and power (CHP) systems can play an important role in addressing biopower related issues. Fuel cells can address two biopower related issues: air quality and water consumption. Fuel cells have very low pollutant emissions and can be sited in air basins with poor quality allowing distributed generation nearer to locations of waste/residue production. Most commercially available fuel cells designed for natural gas operation are water neutral. One challenge associated with fuel cells and biopower is their use with solid biomass typically burned or gasified. No commercial fuel cell units exist currently that will run with a syngas produced via a gasification process. However, with limited further development fuel cell systems could be adjusted for a syngas type fuel source. Combined heat and power can address the same two issues that fuel cells do but in a different manner; CHP increases system efficiency thereby reducing the amount of pollutants emitted and water consumed per unit of electric energy produced.

3.2 Biomass Derived Liquid Transportation Fuels

The use of liquid fuels produced from the conversion of biomass has gained considerable interest in recent years from both a GHG mitigation and energy independence stand point. Liquid transportation fuels that can be produced from biomass include ethanol and biobutanol produced from conversion of sugar, starch or cellulosic material, bio-diesel from oil crops such as soybean, and multiple fuels produced from the Fischer-Tropsch conversion process. Currently, ethanol produced from corn is the most widely used alternative transportation fuel in the U.S. with production levels of roughly 10.6 billion gallons in 2009, off-setting roughly 7 billion gallons of gasoline (RFA, 2010. Bio-diesel has the second highest production volume in the U.S., though significantly less than ethanol, at 491 million gallons in 2007 with 628 biodiesel refueling stations nationwide in 2009 (USDOT, 2010).

Third generation biofuels offer the potential for significant GHG benefits and include those produced from microalgae, including hydrogen, ethanol and bio-diesel. A benefit of algae-based fuels is extremely high yields per acre, estimated to be a magnitude larger than conventional crops. Current biofuel yields are estimated at 50 gallons of biodiesel and 440 gallons of ethanol per acre for soybeans and corn respectively, while algae yields have been estimated at over 5,000 gallons per acre per year (Greene et al., 2011). Production of fuels from algae also avoids many of the issues concerning direct competition with food crops as algae growth does not require fertile land or high quality water. Algae growth may also offer a synergy with CCS technology as algae growth is accelerated by exposure to concentrated CO_2, such as from a power plant exhaust stream. However, strains of algae must be identified that have high oil content and resistance to viral infection. Further, costs associated with growing, harvesting, and fuel processing much be reduced. Due to these and other challenges, significant technological advancements in algae production processes are necessary prior to large scale commercialization, and it is unknown if high volumes of algae-based fuels will be available by 2050 (Wigmosta et al., 2011).

The GHG impact of biofuel use in the transportation sector is currently a source of significant scientific debate. A deep literature base of life cycle analyses displays wide ranging and contradictory values for quantified carbon intensities among different biofuels, and in some cases even for the same biofuel, depending on biomass feedstock, conversion technology, and life cycle energy requirements (Larson, 2006; Groode et al., 2008). Many factors influence whether the net environmental effects, including GHG and criteria emissions, are beneficial or detrimental (Börjesson, 2009). For biofuels to be viable GHG mitigation strategies GHG emissions must be reduced on a net life cycle basis relative to the displaced petroleum fuel. It is clear there is significant potential for mitigation as the uptake of carbon and soil carbon sequestration during growth of the biomass feedstock off sets much of the direct vehicle emissions occurring during fuel combustion. However, in parallel with direct vehicle emissions, upstream processes such as the agricultural practices associated with feedstock growth and harvesting (i.e. fertilizer and pesticide use, fossil fuel use in off-road farm equipment), transportation of feedstock, and bio-refining processes result in significant GHG emissions (Hill et al., 2006).

A factor that adds considerable complexity to estimating life cycle biofuel emissions is the impacts associated with direct and indirect land use changes (LUCs) (Escobar et al., 2009). Emissions from direct land use changes occur as a result of conversion of non-cropland (i.e. clearing of grassland or forest) into cropland to facilitate feedstock growth, releasing carbon sequestered in the soil. Emissions from indirect land use changes occur when cropland conversion occurs as a result of diversion of existing cropland elsewhere to facilitate biomass growth. Avoiding LUCs requires the continued increase in both the yields of biomass feedstock and the efficiencies of fuel conversion. Other factors include careful consideration of what areas are chosen for biomass plantations and responses by farmers to fluctuations in crop prices. Estimation of the magnitude of GHG emissions associated with land use change involves significant uncertainty and remains controversial, with some researchers arguing indirect LUCs actually result in negative life cycle GHG emissions relative to gasoline and others arguing biomass fuels can be produced without significant adverse LUCs (Searchinger et al., 2008; Tyner et al., 2010). As a result of this and uncertainties associated with other stages of fuel production, large variation is seen in the literature regarding life cycle GHG estimates for both ethanol and biodiesel.

The Federal Renewable Fuel Standards (RFS), adopted in 2005 and updated in 2007 as part of the Energy Independence and Security Act (EISA), establishes minimum volumes of renewable fuels to be used as a blend in on-road gasoline (Wiser et al., 2005). The most current version, RFS2, designates various sub-categories for renewable fuels and mandates life cycle GHG reduction thresholds for each category relative to conventional gasoline. In addition to conventional biofuel, the three added categories include non-cellulosic advanced biofuel, biomass-based diesel, and cellulosic biofuel requiring GHG reductions of 50%, 50% and 60% respectively relative to conventional petroleum fuels. The volumetric requirements federally mandated by 2022 are displayed in Figure 19. Bio-diesel is limited by feedstock availability and its application in the LDV sector is unlikely. As ethanol currently makes up the vast majority of the biofuel consumed in the U.S. today and is the only biofuel projected to expand significantly in the study period, particularly to meet RFS2 requirements, ethanol is the only biofuel pathways examined in-depth.

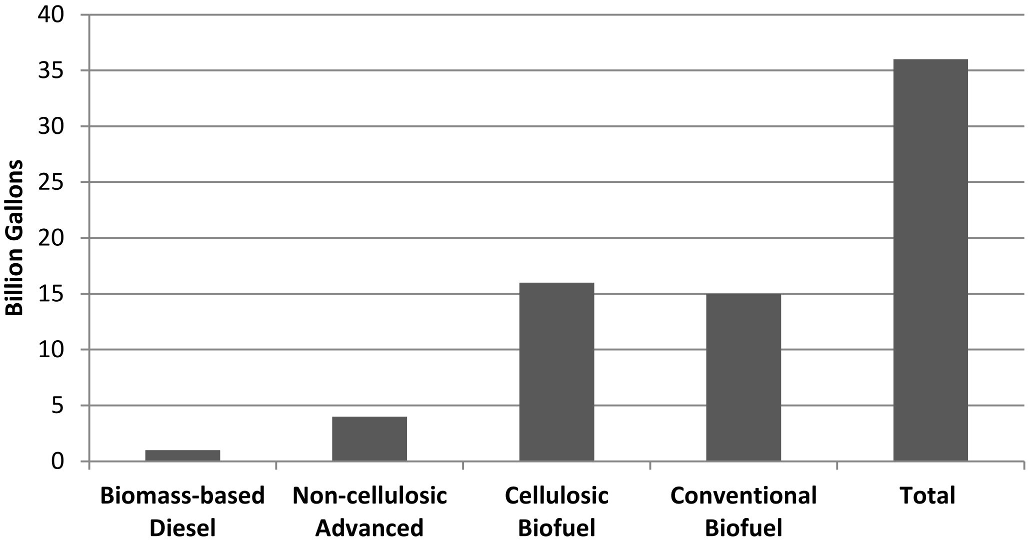

Figure 19: Federal RFS2 volume requirements mandated by 2022. Adapted from Greene, 2011

3.2.1 Ethanol

Ethanol can be produced from a variety of feedstock and production pathways. Current U.S. ethanol production relies heavily on corn as a cost effective, technically feasible, high-volume feedstock. Cellulosic materials that can serve as feedstock include switchgrass, prairie grasses, short rotation woody crops, agricultural residues, and forestry materials and residues. Cellulosic material compromise approximately 60-90% of terrestrial biomass by weight, allowing for a higher total percentage of feedstock utilization than corn, although breaking down cellulosic material into usable sugars requires additional processing. The increased complexity and processing times for cellulosic ethanol result in higher cost relative to corn-based ethanol although costs are expected to be reduced with increased commercialization (Greene et al., 2004). Future pathways for ethanol production that offer significant benefits from both a GHG mitigation and sustainability perspective include production from algae, biomass waste, or from feedstocks farmed on abandoned agricultural land.

Ethanol has some intrinsic energy qualities such as a higher octane than gasoline which could have beneficial implications for efficiency and power in an internal combustion engine, particularly if the engine was optimized for ethanol (Brusstar et al., 2005). Research conducted by the NREL estimated that vehicle fuel efficiency increase for E10 and E85 vehicles could be up to 1-2 and 5.4% respectively (mile/BTU basis) (Tyson et al., 1993). However, the energy density of ethanol is roughly two-thirds that of gasoline, requiring a higher volume of fuel to be used for equivalent propulsion and necessitates the price of ethanol be two-thirds that of gasoline for economic competitiveness. An NRC committee concluded that for ethanol to be deployed economically, crude oil costs much reach 100 and 115 dollars per barrel gasoline equivalent (gge) for corn and cellulosic ethanol respectively (Figure 20) (NRC, 2009).

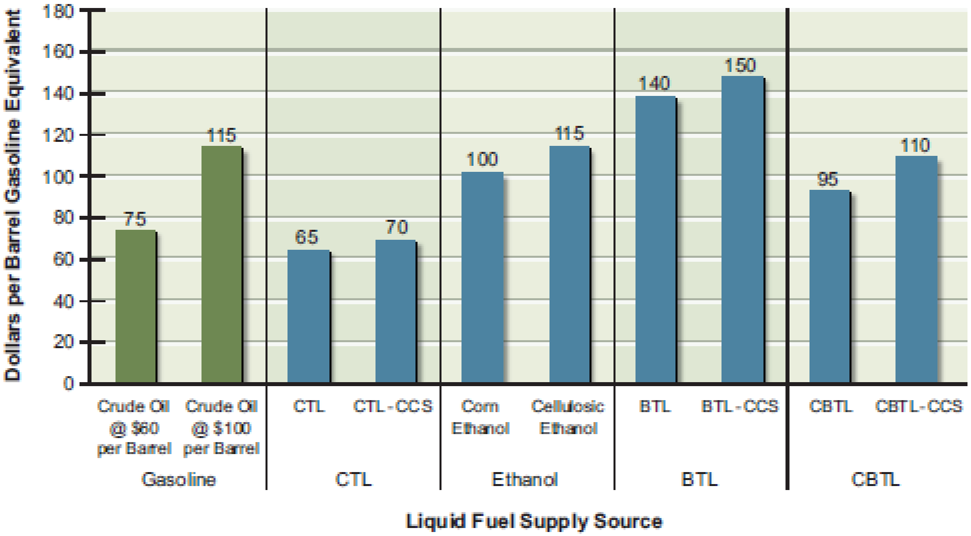

Figure 20: Estimated gasoline-equivalent costs of alternative liquid fuels in 2007 dollars. Note: BTL=biomass-to-liquid; CBTL=coal-and-biomass-to-liquid; CTL= coal-to-liquid fuel Source: NRC 2009[60]

By December 2014, 210 ethanol bio-refineries were in operation in the U.S. with an estimated capacity of 14.9 billion gallons annually and 3 new bio-refinery were under construction with a potential annual capacity of 100 million gallons (Renewable Fuels Association, 2014)[2]. The growing production trend is a result of such factors as the phase-out of methyl tertiary butyl ether (MTBE) and the Federal RFS2, which requires 36 billion gallons of biofuel, largely projected to be met with ethanol, be blended with gasoline by 2022 (U.S. CRS, 2011). Of this total, contribution of conventional biofuels – mostly corn ethanol – is capped at 15 billion gallons and 16 billion gallons must be cellulosic biofuels, having life cycle GHG emissions 60% below the 2005 average for petroleum fuel. Non-cellulosic advanced biofuel derived from renewable feedstocks which can be co-processed with petroleum is limited to 4 billion gallons and biomass-based diesel is limited to 1 billion gallons per year. These volumes are illustrated in Figure 19.

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[2] Renewable Fuels Association, last update in December 2014. From: http://www.ethanolrfa.org/bio-refinery-locations/

Ethanol is blended with conventional gasoline in amounts per volume of up to 85% (E85) with E10 and E85 being the two most commonly available. Currently all light-duty vehicles in the U.S. can operate on E10 and ethanol flex-fuel vehicles (FFVs) can operate on E85, although currently FFVs have a small market share and are limited by lack of E85 fueling outlets (Andress et al., 2011).

A limiting factor for the availability of ethanol, and thus potential GHG mitigation, is the quantity of economically available biomass feedstock. Similar to the difficulty associated with emissions accounting, future volumetric feedstock estimates contain uncertainties regarding future crop yields, agricultural economics, national/state level policy, and others. An NRC committee concluded that in order to avoid increasing food prices only 25% of U.S. corn crops could be devoted to ethanol, limiting corn ethanol to about 12 billion gallons after 2015 (NRC, 2008). This would meet less than 6% of the reference case gasoline demand for LDVs for 2015 with the percentage falling in later years; however the assessment did not include sources for ethanol other than corn. A 2005 joint report by the U.S. DOE and the U.S. Department of Agriculture (USDA) estimated the future potential biomass resource available for energy production to be 1.3 billion dry tons per year from all sources, including starch, oil, and sugar food crops, energy crops such as rapid growth trees and grasses, agricultural residues, biomass wastes, and animal wastes (Perlack et al., 2005). The estimation assumed among others significant increases in crop yields, efficiencies for residue harvesting equipment, and improved land management strategies. Further, the estimations did not account for economic or resource allocation factors and should be taken as an upper bound as it is unlikely that all available biomass resources will be used for transportation fuel only. A joint study from Sandia National Laboratory and General Motors concluded that 90 billion gallons of ethanol annually could be feasible by 2030, but several conditions, including a minimum conversion yield of 74 gallons ethanol per dry ton biomass, were necessary (West et al., 2009). A study conducted by Andress, et al. (2011) accounted for competing demands for biomass resources, such as biopower plants, and capped the amount of available biomass in 2060 at 800 million dry tons annually, producing about 72 billion gallons of ethanol (Andress et al., 2011). *Reducing US Greenhouse Gas Emissions: How Much at What Cost?* reported in a mid-range case that production of biofuels could reach 30 billion gallons per year by 2030, equivalent to 14% of gasoline consumption, with 14 billion gallons derived from cellulosic biofuels (McKinsey, 2007). These studies demonstrate that though ethanol could be potentially available in the study horizon in considerable amounts, only a fraction of the liquid transportation fuel required to meet the huge projected demand in the LDV sector will be met. For example, in the extreme upper bound scenario in the DOE study, assuming an optimistic future conversion efficiency of 90 gallons ethanol per dry ton, the potential volume of produced ethanol would meet roughly 50% of the projected 2050 LDV transportation sector energy needs in the reference case developed by the NRC committee. Reported literature estimates of current and future feedstock availability and corresponding volumetric availabilities of ethanol are provided in Table 7.

Table 7: Current and future estimates of biomass feedstock and corresponding volumetric ethanol availability for use as a transportation fuel

Study	Year	Potentially Available Biomass [Tons]	Potentially Available Ethanol [gallons]	Potentially Available Ethanol [gge]
U.S. Production	2009	NA	10.6 Billion	7.067 Billion
U.S EPA RFS2	2022	NA	36 Billion	24 Billion (12% gasoline)
Perlack 2005	2030	1.3 Billion	137.4 Billion	91.6 Billion
McKinsey & Co.	2030		30 billion	20.1 Billion (14% gasoline)
NRC 2008	2015	25% U.S. Corn Crops	12 billion	8.04 Billion (<6% gasoline)
	2050	500-700 million cellulosic	45-63 billion	30-42 Billion (20% gasoline)

* Values in parenthesis represent the percentage of LDV fleet gasoline consumption displaced by the corresponding volume of ethanol

Estimates of the fuel carbon intensity of ethanol generally fall into two categories, estimates for corn ethanol and estimates for ethanol produced from cellulosic sources. Reported carbon intensities for corn ethanol vary significantly depending on assumptions regarding feedstock growth, production pathway, and LUCs. It has been argued that when LUCs are included in analyses of corn ethanol no benefits, and even net negative impacts, occur relative to petroleum fuels (Fargione et al., 2008; Hertel et al., 2010). Searchinger, et al. (2008) includes LUCs associated with conversion of forest and grassland to cropland and estimates that on a life cycle basis corn ethanol increases GHG emissions by 93% compared to gasoline. Hill, et al. (2009) estimates that when LUCs are included corn ethanol has no GHG benefits compared to gasoline if production occurs in a facility that uses natural gas for process heat, and GHG emissions increase by 28% if coal is used (Hill et al., 2009). However, other work has concluded that corn feedstock can be grown without large LUCs and improvements including crop yield increases and distillery efficiency mean corn ethanol can offer substantial life cycle GHG emissions reductions compared to gasoline (Greene et al., 2011). Tyner, et al. (2010) conducted a study involving comprehensive modeling of LUCs and concluded life cycle emissions of ethanol are 9.5-16.3% lower than those from gasoline (Tyner et al., 2010). Work by Wang, et al. (2011) estimates that current U.S. corn ethanol, on average, results in a life cycle reduction in GHG emissions of 24% compared to gasoline (Wang et al., 2011). The contrasting results from the Searchinger study was attributed by the authors to updated data reflecting technology improvements over time and detailed simulations in modeling LUCs. Another important factor in the carbon intensity of ethanol is the fuel source used to provide process heat and electricity to the ethanol plant. Wang, et al. (2007) examined different types of corn based ethanol plants and reports a full fuel LCA range of 3% increase to in GHG emissions if coal is used to generate necessary power to a 52% reduction if wood chips were used (Wang et al., 2007). It is clear that the carbon intensity of corn ethanol has experienced reductions as a result of technology improvements. Including LUCs, the EPA has concluded that corn ethanol produced in new, natural gas-fired production facilities will have emissions at minimum 20% below 2005 gasoline levels (U.S. EPA, 2010). Integrating biomass fuels such as wood chips or corn stover to produce heat and power further reduces the life cycle GHG emissions of corn ethanol. Kaliyan, et al. (2011) estimate reductions for corn ethanol compared to gasoline of 38.9%-119 % depending on the biomass conversion technology and system characteristics (Figure 21) (Kaliyan et al., 2011). Reductions over 100% without including carbon capture and sequestration indicate that the production of biofuel co-produces electricity that is exported to the grid and displaces emissions from electricity generation from coal. The authors estimate that a reduction of 151.2% over motor gasoline would be possible for a biomass integrated gasification combined cycle (BIGCC) system utilizing corn stover as fuel in conjunction with sequestration of CO_2 in deep underground wells. Heath, et al. (2009) reported that E85 produced from corn-based ethanol in 2022 would offer a 40% reduction in global warming potential compared to 2005 gasoline, which is the standard set by the Federal EISA requirements (Heath et al., 2007).

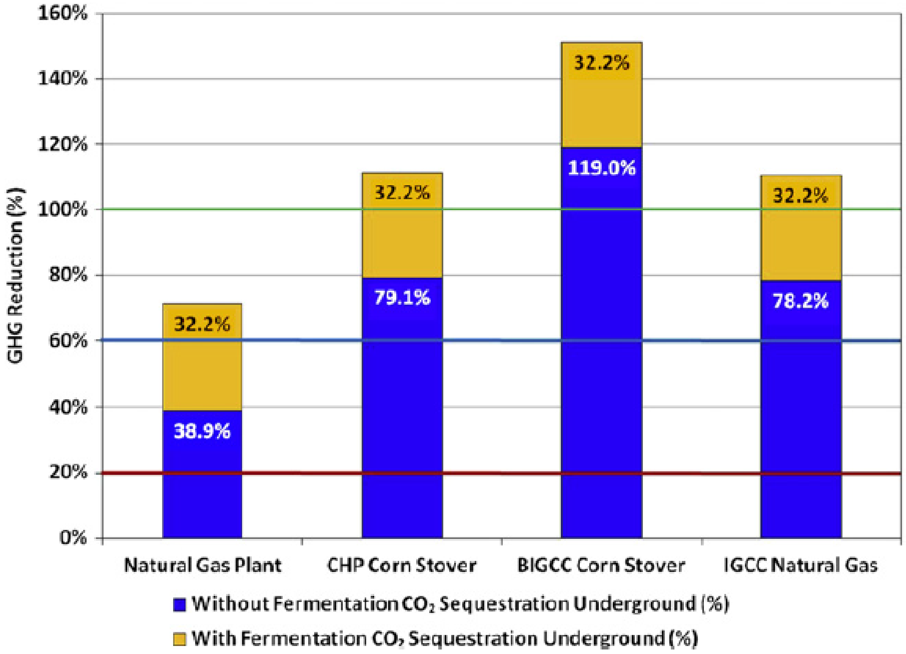

Figure 21: Percentage of lifecycle GHG reductions for corn ethanol compared to motor gasoline for plants utilizing various technologies and fuels. Source: Kaliyan et al., 2011

The most promising biofuel pathway, in terms of reducing carbon intensity, is ethanol produced from cellulosic biomass sources. The U.S. DOT estimates that life cycle GHGs for vehicles operating on E85 derived from ethanol produced from cellulosic sources is roughly half that of a vehicle operating on E85 produced from corn ethanol (USDOT, 2011). The consensus reached in the majority of studies is that ethanol produced from cellulosic feedstock does offer substantial reductions in carbon intensity relative to displaced petroleum fuels (one exception being the Searchinger study, which concluded that ethanol produced from switchgrass represented a 50% increase in emissions). Farrell, et al. (2006) estimated that ethanol produced from cellulosic sources could reduce GHG emissions by 90% with respect to gasoline (Farrell et al., 2006). Similarly a report issued by Argonne National Laboratory estimated that a vehicle operating on E85 produced from cellulosic sources would have net GHG emissions of 160 g/mile, equivalent to a 70% reduction relative to a baseline vehicle operating on gasoline (Brinkman et al., 2005). If improvements in cellulosic ethanol production allow for significant volumes of low carbon ethanol to be available GHG mitigation impacts could be significant. For instance, in the Sandia/GM study's reference case GHG reductions reached 400 $MMTCO_2eq$ per year in 2030, equivalent to offsetting emissions from 25% of the current fleet of gasoline vehicles.

Table 8: Estimates of LCA GHG Emissions for Various Ethanol Production Pathways with and without Estimates of Land Use Change Impacts. Source(s) CARB 2010 & Searchinger, et al. 2010

Study	CARB 2010 Without LUC [gCO_2eq/MJ] (LHV)	CARB 2010 With LUC [gCO_2eq/MJ] (LHV)	Searchinger, et al. 2010 With LUC [gCO_2eq/MJ] (LHV)
Gasoline	93.8	93.8	92
Corn-based Ethanol			177 (+93%)
Mid-West wet mill	75.1	89.8	
Mid-West dry mill, wet DGS	60.1	74.8	
Mid-West dry mill, wet DGS, 80% NG, 20% Biomass	56.8	78.3	
CA dry mill, dry DGS, NG	58.9	73.6	
CA dry mill, wet DGS, NG	50.7	65.4	
CA dry mill, wet DGS, 80% NG, 20% Biomass	47.4	62.1	
Sugarcane ethanol (Brazil)	27.4	73.4	
Cellulosic (Farmed)	5.4	23.4	138 (+50%)
Agriculture Waste	22.2	22.2	27 (-70%)

Extensive use of ethanol as a transportation fuel could impact criteria pollutant emissions spatially and temporally, leading to perturbations in ambient concentrations of air pollutants (Jacobson et al., 2007; Smith et al., 2009). Further, emissions of compounds labeled air toxics due to associated health effects may also increase. Direct vehicle emission perturbations from ethanol use are difficult to quantify as significant variation and contradictory values have been reported in the literature. Impacts on VOC and NO_x emissions are thought to be dependent on vehicle control technology and operating conditions, but the available data is somewhat unclear and a range of reported values exist in the literature (U.S. EPA, 2007a; Hsieh et al., 2002). It is known that adding ethanol in any capacity to gasoline increases the emissions of acetaldehyde (Gaffney et al., 2009; Knapp et al., 1998; Graham et al., 2008), but reduces others including benzene, a compound prevalent in motor gasoline (Yanowitz et al., 2009; Niven, 2005). In general studies have shown decreases in CO and total hydrocarbons in exhaust emissions for LDVs operating on E10 (USEPA, 2007a; Knapp et al., 1998; Poulopoulos et al., 2001), however others have shown equivalent or slightly increased emissions (Durbin et al., 2007). E10 use has been correlated with reductions in PM emissions relative to baseline gasoline, however PM increases substantially with decreases in temperature (Mulawa et al., 1997). With regards to NO_x, E10 use is generally correlated with increases in emissions (Hsieh et al., 2002; Reuter et al., 1992), although some studies have shown mixed results (Mulawa et al., 1997; He, 2003) and/or reduced emissions (Knapp et al., 1998). Graham, et al. (2008) conducted a statistical analysis of results from two studies as well as aggregate data reported in literature and reported statistically significant decreases in emissions of CO (16%), increases in emissions of NMHC (9%) and no statistically significant changes in NO_x, CO_2, CH_4 or N_2O. Ambient temperature was also important for NO_x emissions, for example vehicles operating on E10 at 75° F and 0° F showed decreased emissions but vehicles operating at -20° F showed increases in NO_x emissions relative to baseline gasoline (Knapp et al., 1998).

Criteria pollutant emission perturbations relative to gasoline differ for vehicles operating on E85 compared to E10. Graham, et al. reported statistically significant decreases in emissions of NO_x (45%), and NMHC (48%), statistically significant increases in acetaldehyde (2540%), and no statistically significant change in CO and CO_2 emissions. Similarly, a study examining emissions of Tier 1 and Tier 2 FFV operating on E85 reported reductions in NO_x of 54% and 28% and reductions in CO of 18% and 20% respectively (Yanowitz et al., 2009). E85 use has also been correlated with decreases in VOCs, which could have positive implications with regards to ozone formation. It is also important to consider associated increases in direct emissions of ethanol, which have been shown to be substantial and raise health and secondary air quality concerns. Further, in addition to tailpipe emissions, fuel evaporative losses have been shown to be 20-80% higher for E10 and E20 relative to baseline gasoline and are a major concern (Niven, 2005). A total emissions model of SoCAB, including evaporative losses, predicted lower CO emissions, equivalent NO_x, and higher acetaldehyde and ethanol emissions[92]. Differences across studies make accurate air quality impact assessment difficult, and can be attributed to such factors as fuel composition, test cycle, vehicle age, and emissions control technology.

Similar to evaluating GHG impacts, upstream emissions of pollutants, including those associated with feedstock growth, fuel production, and distribution, must be accounted for. Emissions associated with feedstock production occur from farm equipment, fertilizer and pesticide application, fugitive dust, and transportation of feedstock by rail, marine vessels, or trucks. Ethanol production facilities have significant emissions, as does the generation of energy that is consumed during the production process (Brady et al., 2007). Transport and distribution of ethanol and gasoline/ethanol blends via current shipping methods will result in increased emissions from trucks, ships, and rail unless a reliable pipeline infrastructure is developed (current gasoline pipelines can transport blends only up to 10% ethanol by volume). Transportation and distribution emissions include those associated with evaporative and spillage of fuel and could be important from an air quality perspective (Wakeley et al., 2009). A full LCA of criteria emissions for alternative/fuel vehicle systems demonstrated increase in total criteria pollutant emissions for E85 FFVs compared to gasoline vehicles, however reductions in urban emissions of up to 30% were reported due to the majority of emissions occurring from farming equipment, fertilizer manufacture, and ethanol plants, all of which are located in rural areas (Huo et al., 2009).

Detailed air quality modeling has demonstrated significant impacts on ambient air quality associated with fleet-wide ethanol use, particularly in regards to surface level ozone concentrations. Jacobson, et al. (2007) modeled the effects of 100% replacement of CVs with vehicles operating on E85 in Los Angeles and the U.S in the year 2020[78]. The study concluded that E85 use increased 24 hour and afternoon ozone up to 3 and 4 ppb respectively in L.A. and the Northeastern U.S., but decreased ozone concentrations in some areas of the Southeastern U.S. Further work by Jacobson, et al. (2008) compared air pollution health impacts from a conversion of on-road light- and heavy-duty gasoline powered vehicles to several alternative technologies including BEVs, HFCVs, and E85 and concluded replacement with E85 might increase the air pollution premature death rate by up to 185 deaths per year while significant health benefits were realized by BEV and HFCV replacement (Jacobson et al., 2008).

While a 100% fleet penetration of vehicles operating on E85 is not realistic in the 2050 horizon, these studies offer important insights into potential impacts and can be taken as upper bounds on potential impacts. On a regional scale Alhajeri, et al. (2011) compared regional photochemical pollution impacts in Texas from a 17% penetration of PHEVs to a 100% replacement with E85 and found that the highest reduction in maximum 1 hour ozone concentrations regardless of time of day occurred during PHEV scenarios (-8.5 ppb) and the maximum increase (2.8 ppb) occurred for the E85 scenario. An comprehensive EPA study examining the air quality impacts of the RFS2 mandated increase in ethanol consumption as a vehicle fuel concluded that ozone concentrations could increase by up to 1 ppb over much of the U.S., however several highly populated areas with poor ambient air quality experienced decreases in ozone concentrations. The observed improvements were likely a result of increased NO_x emissions in areas that are VOC-limited, which is not necessarily desirable. The study also demonstrated relatively small effects on air toxics other than increases in ethanol concentrations. Though the study was comprehensive the results are limited by uncertainties underlying data limits, for example $PM_{2.5}$ was not addressed due to an error in spatial emissions allocation that limited local-scale results.

4 Biomass Scenarios

4.1 Description of Biomass Scenarios

The list of scenarios analyzed in this report is designed to evaluate the potential impacts of biomass use for biopower using current technologies, and the potential effects of technological improvements for biopower production and of switching from biopower to biofuel production. The analysis is solely based on air pollutant and greenhouse gases emissions, and does not take economic parameters into consideration to determine the plausibility of the technology options. The list of scenarios is categorized in three major groups:

Group A: Increasing Capacity with Conventional Technology

These scenarios assume that the technology used for biomass/biogas conversion will stay the same as it is in existing installations. Solid residue facilities are typically solid-fuel boilers that power steam turbines to produce electricity and heat. Biogas installations are generally internal combustion engines, either reciprocating engines or gas turbines. This set of three scenarios assumes an increasing penetration of bioenergy installations assuming the existing mix of technologies. The end product of biomass conversion is the production of electricity and heat.

Biogas Installed Capacity:

1. Current biogas capacity:
    - Installed capacity of biogas-to-energy in the state is estimated to be ~ 370 MW from landfill gas, ~69 MW from digester gas from wastewater treatment plants, and nearly 4 MW from animal manure digester gas.[3]

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[3] California Biomass Collaborative Bioenergy Facilities Database; http://biomass.ucdavis.edu/files/2013/09/11-20-2013-cbc-facilities-database_1May_2013_update.xlsx

2. Policy-driven new biopower from biogas:
    - SB1122 requires the CPUC to direct electrical corporations (IOUs) to procure 250 MW (cumulative, state wide) of new small biopower (less than 3 MW per project) in a separate IOU feed-in tariff program, of which 110 MW is for urban biogas and 90 MW for dairy and other agricultural bioenergy (that would include digester gas or small thermochemical conversion).
    - Governor Brown's Clean Energy Jobs Plan calls for 20 GW of new renewable generation by 2020: 8 GW would be large scale at 20MW or higher with 12 GW from distributed generation (presumes less than 20 MW per facility). Assume Gov.'s 20 GW goal is implemented with 20% met by biomass/biogas. Biogas facilities tend to be smaller than 20 MW and would be part of the distributed generation mix. Assuming that 20% of 12GW of distributed generation implies that 2.4 GW would be met by small scale new generation of biogas. However, this level of penetration is higher than the maximum potential for biogas, which is 1,130 MW. Consequently, biogas facilities are capped at the maximum potential levels.

3. Maximum potential for biogas based on current resources:
    - Potential biogas power capacity is approximately 175 MW from cow/cattle manure, 650 MW from landfill gas, 185 MW from food waste/green waste in current disposal stream and 120 MW from waste water treatment plants (does not include potential from food processing residues).[4] The total biogas capacity in this case is 1130 MW, which represents the maximum power capacity based on current biogas resources.

Solid-fuel Biomass Installed Capacity:

1. Current solid-fuel capacity:
    - There is approximately 725 MW of installed and operating solid-fuel bioenergy capacity in California (consuming forest, agricultural and urban residue).[5]

2. Policy-driven new biopower:
    - SB1122 requires the CPUC to direct electrical corporations (IOUs) to procure 250 MW (cumulative, state wide) of new small biopower (less than 3 MW per project) in a separate IOU feed-in tariff program, of which 50 MW are from material from sustainable forest management and 90 MW from agriculture (biogas or thermal conversion).
    - Governor Brown's Clean Energy Jobs Plan calls for 20 GW of new renewable generation by 2020: 8 GW would be large scale at 20MW or higher with 12 GW from distributed generation. Assume Gov.'s 20 GW goal is implemented with

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[4] California Biomass Collaborative (unpublished) &
Williams, R. B., M. Gildart and B. M. Jenkins (2008). An Assessment of Biomass Resources in California, 2007. CEC PIER Contract 500-01-016, California Biomass Collaborative.

[5] CBC, Op. cit.

20% met by biomass/biogas. Assuming biomass facilities as part of the large scale mix (>20 MW), new biomass capacity would be 1.6 GW (20% of 8GW).

3. Maximum potential for solid-fuel (or thermal conversion):
    - Potential solid-fuel power generation capacity is approximately 620 MW from agricultural residues, 1910 MW from forestry resources and 1000 MW from the organic fraction of municipal solid waste.[6]

The overall installed capacity for both biogas and solid biomass installations is summarized in Figure 22. For the maximum potential case, the California Biomass Collaborative estimates overall potentials for urban, agricultural and forest waste, disaggregating the components of the "mixed" solid biomass category.

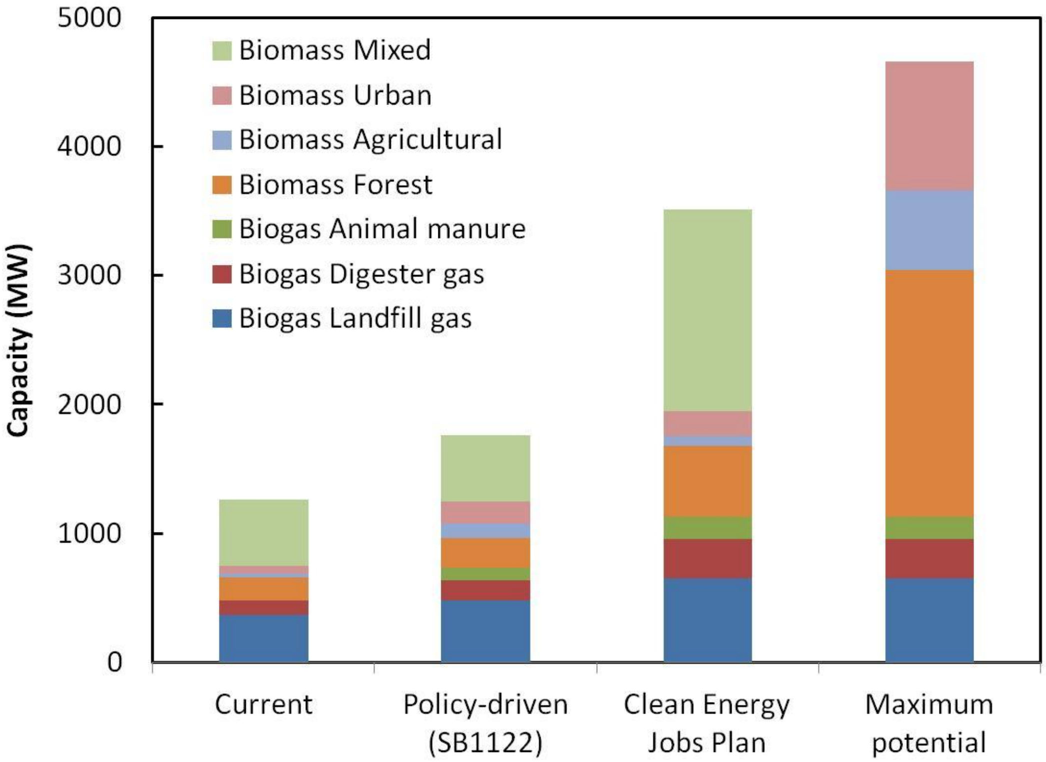

Figure 22: Summary of power generation capacity from biomass in scenarios with current biomass technology

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[6] Ibid.

Group B: Technology Upgrade for Efficiency and Emissions

This group of scenarios assumes a shift in technology for both biogas and solid-fuel installations. For biogas installations, fuel cells will be used instead of internal combustion engines. For biomass installations, biomass-integrated-gasifier-combined-cycle is used instead of solid fuel boilers. The end products would still be electricity and heat. These technologies represent an improvement in emissions and total power production, due to lower emissions and improved efficiency. Maximum potential for both biogas and solid biomass is assumed.

Group C: Shift End Use from Electricity to Fuel

This group of scenarios assumes a shift in the end product from electricity and heat to renewable (and renewable synthetic) natural gas for vehicle fueling. Maximum potential for both biogas and solid biomass is assumed.

1. Production of compressed biomethane (a CNG like fuel) for vehicle fueling
   This scenario assumes that biogas will be cleaned and upgraded to biomethane, and compressed to be used for CNG vehicle fueling. Emissions from CNG vehicles will be added and emissions from gasoline/diesel vehicles will be displaced.
   Renewable-synthetic natural gas (RSNG) will be modeled from thermal conversion of solid biomass, and then compressed for fuel for CNG vehicles.

2. Production of pipeline quality biomethane for injection into natural gas pipeline
   This scenario assumes that biogas will be cleaned, upgraded and injected to the natural gas transmission and distribution system.
   Renewable-synthetic natural gas (RSNG) will be modeled from thermal conversion of solid biomass, and then injected to natural gas transmission and distribution system as well.

3. Assume co-digestion of bio-resources to produce (CNG)
   In this scenario, different streams of biomass will be co-digested to produce digester gas that will be cleaned-up and compressed to produce CNG for vehicles.

The yield in RSNG plants is calculated assuming a fraction of carbon mass in solid residue. Table 9 presents typical values for carbon content in selected residue types. For this study, the carbon content in grass is assumed as a conservative estimate for forest and agricultural waste. From the total carbon content in the residue, RSNG plants can achieve methane yields that range from 60% to 73% of maximum methane forming potential (Zwart et al. 2006). The range in yields depends on the configuration of the gasification process and the management of ashes formed, and for this study the lowest value is used to calculate RSNG potential.

Table 9: Carbon content of selected solid residues

Waste Type	Carbon content %
Forest residue	
Beech wood[1]	48.7%
Grass[1]	43.7%
Conifers[2]	50.0%
Angiosperms[2]	48.0%
MSW[3]	30.0%

[1]Zwart et al., 2006; [2]Thomas and Martin, 2012; [3]Bahor et al., 2008

An alternative to produce RSNG via gasification, solid residue can be treated to produce cellulosic ethanol as explained in Section 3. This bio-ethanol can be a substitute for the ethanol that is used for blending in gasoline. The theoretical yields of selected components of solid residue are presented in Table 10. For this study, the ethanol potential for agricultural waste is based only on the fraction of field and seed residue, because it is assumed that orchard and vegetable residues are not suitable for bio-ethanol production. Ethanol yield for forest thinnings is assumed to be representative of all forestry waste.

Table 10. Theoretical yields of selected components of solid residue[7]

Feedstock	Ethanol yields (gal/BDT)
Corn Grain	124.4
Corn Stover	113.0
Rice Straw	109.9
Cotton Gin Trash	56.8
Average yield	103.0
Forest Thinnings	81.5
Hardwood Sawdust	100.8
Bagasse	111.5
Mixed Paper	116.2
Switchgrass	96.7
Mixed feedstock	89.8

A second alternative to RSNG production for certain solid waste is the co-digestion of green and food waste in a high-solid anaerobic digester (HSAD). The high-solid digestate generates biogas similar to the one produced from wastewater treatment plants. The biogas can then be cleaned to produce CNG. A small fraction of the biogas is used for process heating. In addition

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[7] Source: U.S. Department of Energy Bioenergy Technologies Office, Theoretical Ethanol Yield Calculator and Biomass Feedstock Composition and Property Database. http://www.afdc.energy.gov/fuels/ethanol_feedstocks.html

to biogas, 80% of the solid residue is converted into high-quality compost that can be marketed as soil amendment or fertilizer. Based on the ARB LCFS pathway for HSAD,[8] a plant would require 40/60 mix of green waste/food waste that would yield 2.29 MMBtu of biomethane per ton of residue. If the green waste and food waste fraction from MSW was used for HSAD, limiting the 40/60 mix ratio at county level, there is a potential for 4,858 BDT/day of residue that could yield 11,354 MMBtu/day biomethane. Similarly, if green waste from orchard and vine agricultural waste and waste from food industry was used for HSAD limiting the 40/60 mix ratio at county level, there is a potential for 5,421 BDT of residue that could yield 12,414 MMBtu/day of biomethane. Total potential for the production of biomethane from HSAD is 23,768 MMBtu, which is a small fraction of total potential for RSNG production.

Table 11 presents the maximum potential for biomethane production via RSNG from biogas and biomass resources in the state of California, and potential for cellulosic ethanol and biomethane from HSAD from solid residue. The total biomethane potential from biogas and biomass is more than $1.1 \cdot 10^6$ MMBtu/day. Assuming that CNG has an equivalency of 7.74 gallon of gasoline equivalent per MMBtu, this potential translates to approximately 8.9 million gallons of gasoline equivalent. Considering that projections from EMFAC suggest that gasoline consumption in 2020 will be 56.4 million gallons per day, CNG from biomass could potentially meet fuel demand of nearly 16% of gasoline vehicles in California. Conversely, taking into account that CA reformulated gasoline (CARFG) is a blend of 5.7%[9] ethanol and gasoline, bioethanol production from solid biomass could meet the entire state demand for ethanol blending for CARFG.

Table 11. Maximum potential for biomethane production from biogas and biomass, and potential for cellulosic ethanol production from solid biomass

		Biogas Potential (MMBtu/day)
Biogas	Landfill gas	177424
	Digester gas	83253
	Animal manure	47768
	Total	308445

		Biomass Potential (BDT/day)	**RSNG Potential (MMBtu/day)**	**Ethanol Potential (gal/day)**	**HSAD CNG (MMBtu/day)**
Biomass	Forest	30668	461110	2499430	
	Agricultural	10989	165231	382069	12414
	Urban	20679	213445	475769	11354
	Total	62336	839785	3357269	
Total			1148230		23768

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[8] HSAD to CNG LCFS pathway: http://www.arb.ca.gov/fuels/lcfs/2a2b/internal/hsad-rng-rpt-062812.pdf

[9] California Energy Almanac: http://energyalmanac.ca.gov/gasoline/types_of_gasoline.html

Production of CNG requires a significant amount of power to clean-up biogas, generally using a pressurized filter, and to compress the biomethane at the required pressure for fueling or injection into pipeline. Based on ARB's LCFS pathways analysis, landfill gas purification requires 65,700 Btu of electricity per MMBtu of gas recovered.[10] In addition, assuming 98% efficiency in the compression stage recommended for the pathways for landfill gas to CNG and digester gas to CNG[11], the total electric power that would be required for RSNG clean-up and compression is 98,750 MMBtu/day. This is equivalent to 1,311 MW of new power generation, including grid losses of 8.1%.[12]

4.2 Emissions from Biomass Scenarios

As presented in Section 3, there are numerous ways of biomass utilization that can derive into a wide range in emission impacts. Even for the same type of technology, there exist a variety of emission factors that yields a range in the potential impacts of biomass use. We present here the emission factors of the most common technologies used currently for both solid biomass and biogas installations.

4.2.1 Conversion of Solid Biomass

Biopower production from solid residue in the state includes the following steps: collection and pre-processing of forest residue; transport to a biomass facility; and combustion in an average boiler. For urban and agricultural residue, its collection and transport to a disposal site occurs generally regardless of whether the residue is used for biopower or it is landfilled. Consequently, to calculate the air quality impacts of biopower from urban and agricultural residue it is assumed that no additional emissions from collection and transportation occur. In contrast, forest residue not used for biopower is generally left in the woods. Although some existing forest management measures may require the use of off-road equipment that results in pollutant emissions without using the residue for power, this study assumes that emissions from collection and transport of forest biomass should be accounted for.

Emissions from forest residue for electricity production are presented in Table 12. The calculations assume an average heat content of 9,000 BTU/lb for forest residue and emission factors for biomass boiler are based on the values used in CA-GREET 1.8b. Emissions from biomass collection are based on a comprehensive life-cycle assessment of biomass collection in California.[13] The lifecycle analysis included an estimate of fuel use, hours of operation and mass of forest residue collected and processed by over 20 different types of off-road equipment. Collection of forest biomass included both commercial thinning in plantations and industrial

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[10] Landfill gas to CNG LCFS pathway: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_lfg.pdf

[11] Low Carbon Fuel Standard pathways: http://www.arb.ca.gov/fuels/lcfs/workgroups/workgroups.htm#pathways

[12] Grid losses based on CA-GREET 1.8b

[13] LCA of Producing Electricity from CA Forest Wildfire Fuels Treatment, J. Cooper, 2008 - Included in Appendix 4 of Biomass to Energy: Forest Management for Wildfire Reduction, Energy Production and Other Benefits, CEC-500-2009-080-AP4. Emission factors based on EPA's NONROAD and MOBILE6 models

forest lands, and fire prevention operations in public lands. Emissions from transportation of biomass are based on NONROAD and MOBILE6 emission factors, and assume an average trip length of 60 miles from collection site to biomass plant. The biomass boiler emissions are based on the values used by CA-GREET 1.8b, which is in the range of emissions of biomass boilers inventoried by the California Biomass Collaborative.

In addition to direct emissions, Table 12 presents indirect emissions from the production of fuels required to operate the equipment to collect, pre-process and transport the forest residue. In total, collection and transport use 3.32 and 0.22 gallons of diesel per BDT of biomass, respectively. Emissions from diesel production are based on the values used by CA-GREET 1.8b.

Table 13 presents the contribution of the processes involved in the production of biopower from forest residue to the full lifecycle emissions. Overall, conversion of biomass to power is the biggest contributor to total emissions. More than 90% of NO_X, CO, PM and SO_X occur during combustion of biomass to produce power. Conversion also contributes to nearly 98% of total greenhouse gases emissions. Collection of biomass contributes to approximately 5% of criteria pollutant emissions, except for VOC, which contributes to nearly 14%, due to high VOC emissions from off-road equipment. Collection also contributes to nearly 2% of GHG emissions. The contribution of transport to total criteria pollutant emissions is less than 1% and its contribution to total GHG emissions is a small 0.01%. Finally, indirect emissions due to diesel production contribute to less than 2% in the emissions of NO_X, CO, and PM. Production of diesel contributes to 4% of total VOC emissions and 9% of total SO_X emissions, whereas its contribution to GHG emissions is less than 1%.

As shown in Table 13, the potential air quality impacts of biopower from solid residue depend in great part on the emissions from the conversion stage. Hence, any emission reductions in that stage will reduce the potential impacts of solid biomass use. As described in Section 3, combustion of solid biomass can be substituted with a gasification unit, which could potentially reduce emissions of air pollutants. Schueltze et al. (2010) conducted an analysis of several technological options for forest residue, and the overall performance characteristics are presented in Table 14. Just using current technology, switching from a direct fired boiler to an integrated gasification combustion unit, criteria pollutant emissions are reduced by an order of magnitude. In addition, next generation thermo-chemical conversion of solid biomass based on an integrated biofuels and energy production (IBEP) plant, NO_X and SO_X emissions from solid biopower from biomass could be further reduced. An additional benefit of using integrated gasification is an increase in efficiency in electricity production. Increasing power production from biomass will reduce the electricity needed from central power plants, hence potentially reducing emissions from the electric grid.

The IBEP plant (Shueltze et al., 2008) is an example of next generation biofuel production facility that integrates power and ethanol production. Other applications for biomass include the production of synthetic natural gas, which can then be used for heat and power generation, it can be compressed to produce CNG for vehicle or it can be used in the synthesis of Fischer-Tropsch fuels. There are numerous pilot plants and full scale operations in Europe and the United States.

[14] Because there is not available information on emissions from a synthesis gas installation, emissions for synthetic natural gas production are assumed to be similar to the emissions from the next-generation thermo-chemical bio-alcohol plant reported by Schueltze et al., (2010).

Table 12: Emissions from forest biomass use for biopower production

Process	**Harvest**	**Transport**	**Conversion**
Description	Biomass collection and pre-processing	On-road transport	Biomass Combustion
Equipment	Off-road equipment	Diesel Truck	CA average biomass boiler
Energy type	Diesel fuel	Diesel fuel	
Energy Use	3.32	0.22	
Energy Units	gal/BDT	gal/BDT	
Direct Emissions			
Units	lbs/BDT	lbs/BDT	lbs/BDT
VOC	0.0350	0.0011	0.2118
CO	0.1474	0.0010	3.0449
NO_X	0.2568	0.0044	4.3612
PM_{10}	0.0179	0.0020	0.5020
$PM_{2.5}$	0.0161	0.0018	0.2510
SO_X	0.0001	0.0000	0.1626
CH_4	0.0005	0.0000	0.1520
N_2O	0.0017	0.0000	0.4361
CO_2	68.2522	0.5032	3510.0
Indirect Emissions			
Units	lbs/BDT	lbs/BDT	
Description	Diesel production	Diesel production	
VOC	0.0093	0.0006	
CO	0.0255	0.0017	
NO_X	0.0730	0.0048	
PM_{10}	0.0089	0.0006	
$PM_{2.5}$	0.0041	0.0003	
SO_X	0.0149	0.0010	
CH_4	0.0956	0.0063	
N_2O	0.0002	0.0000	
CO_2	17.7808	1.1786	

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[14] European Biofuels, Technology Platform: http://www.biofuelstp.eu/bio-sng.html

Table 13: Contribution (in %) to total emissions from processes in biopower production from forest residue

	Direct			Indirect
	Collection	**Transport**	**Conversion**	**Diesel**
VOC	13.59	0.43	82.15	3.83
CO	4.58	0.03	94.55	0.84
NO_X	5.46	0.09	92.79	1.66
PM_{10}	3.37	0.38	94.47	1.78
$PM_{2.5}$	5.89	0.67	91.83	1.61
SO_X	0.08	0.02	91.00	8.89
$CO_{2,eq}$	1.84	0.01	97.57	0.58

Table 14: Performance characteristics and emission factors for four different biomass energy plants (Schuetzle et al. 2010)

	Current Generation Biomass Combustion Power Plant	**Current Generation Integrated Gasification/ Combustion Power Plant**	**Next Generation Thermo-Chemical Conversion Power Plant**	**Next Generation Thermo-Chemical Conversion Bioalcohol & Power Plant**
Plant Size (BDT/day)	450	450	450	450
Electricity (kWh/BDT)	1000	1200	1400	550
Alcohol Fuel (gallons/BDT)	-	-	-	80
Diesel Fuel	-	-	-	50
Average Net Energy Efficiency	20%	22%	28%	50%
Emissions (lb/MMBtu output)				
NO_X	0.329	0.067	0.008	0.005
SO_X	0.125	0.010	0.002	0.001
PM	0.269	0.030	0.032	0.018
CO	0.897	0.070	0.042	0.023
VOC	0.085	0.018	0.003	0.002
CO_2	972	884	694	389

As described in Section 4.1, HSAD can be used for a fraction of MSW and agricultural waste that includes green and food waste. Table 14 presents the potential emissions per ton of residue from a HSAD plant that processes 100,000 tons of residues per year. Table 15 presents the emissions values per MMBtu of biomethane produced by the HSAD plant.

Table 15: Emissions from co-digestion of green and food waste in a high-solids anaerobic digestion facility with 100,000 tons per year processing capacity (emissions per ton of residue)

Process	**Handling/Processing**	**Plant Operation**	**Conversion**
Description	Biomass handling and compost processing	Electricity Use	Anaerobic Digestion
Equipment	Loader/Windrower	Waste handling and compression and purification of biogas	CA average biomass boiler for process heat
Energy type	Diesel fuel	Electricity	Biogas
Energy Use	0.09	0.22	0.05
Energy Units	MMBtu/BDT	MMBtu/BDT	MMBtu/BDT
Direct Emissions			
Units	lbs/BDT		lbs/BDT
VOC	0.0217		0.0002
CO	0.0813		0.0029
NO_X	0.1484		0.0030
PM_{10}	0.0088		0.0003
$PM_{2.5}$	0.0088		0.0003
SO_X	0.0016		0.0001
CH_4	0.0020		0.0001
N_2O	0.0002		0.0000
CO_2	15.5881		5.8720
Indirect Emissions			
Units	lbs/BDT	lbs/BDT	
Description	Diesel production	Electricity production	
VOC	0.0020	0.0109	
CO	0.0054	0.0270	
NO_X	0.0156	0.0345	
PM_{10}	0.0018	0.1364	
$PM_{2.5}$	0.0009	0.0353	
SO_X	0.0032	0.0093	
CH_4	0.0205	0.1355	
N_2O	0.0000	0.0013	
CO_2	3.8199	50.3084	

Table 16: Emissions from co-digestion of green and food waste in a high-solids anaerobic digestion facility with 100,000 tons per year processing capacity (emissions per MMBtu of biomethane produced)

Process	Collection	Plant Operation	Conversion
Description	Biomass collection and compost processing	Electricity Use	Anaerobic Digestion
Equipment	Loader/Windrower	Waste handling and compression and purification of biogas	CA average biomass boiler for process heat
Energy type	Diesel fuel	Electricity	Biogas
Energy Use	0.04	0.10	0.02
Energy Units	MMBtu/MMBtu	MMBtu/MMBtu	MMBtu/MMBtu
Direct Emissions			
Units	lbs/MMBtu		lbs/MMBtu
VOC	0.0095		0.0001
CO	0.0355		0.0013
NO_X	0.0647		0.0013
PM_{10}	0.0038		0.0001
$PM_{2.5}$	0.0038		0.0001
SO_X	0.0007		0.0000
CH_4	0.0009		0.0000
N_2O	0.0001		0.0000
CO_2	6.7991		2.5612
Indirect Emissions			
Units	lbs/MMBtu	lbs/MMBtu	
Description	Diesel production	Electricity production	
VOC	0.0009	0.0048	
CO	0.0024	0.0118	
NO_X	0.0068	0.0150	
PM_{10}	0.0008	0.0595	
$PM_{2.5}$	0.0004	0.0154	
SO_X	0.0014	0.0041	
CH_4	0.0089	0.0591	
N_2O	0.0000	0.0006	
CO_2	1.6661	21.9430	

4.2.2 Conversion of Biogas

Generation of biopower from biogas – landfill gas or digester gas – involves generally two steps: transmission from the point of biogas generation to the biopower plant, and combustion of the biogas in an engine, turbine or boiler. The transmission of biogas is accomplished with an electric blower that applies enough pressure to the biogas so that it can run through the cleanup system (if any) and be fueled to the conversion device. Table 17 presents the emissions from biopower production from landfill gas using a Best Available Control Technology (BACT) engine.[15] The only direct emissions from this process occur in the combustion of biogas in the engine. Indirect emissions are accounted for the production of the electricity consumed by an electric blower. The emissions correspond to California marginal grid, obtained from CA-GREET 1.8b. The required power to transmit the biogas to the biopower plant is based on estimates by ARB, following the recommended low-carbon fuel standard pathway for CNG from landfill gas.[16]

Table 17: Emissions from landfill gas (LFG) use for biopower production

Process	**Harvest**	**Conversion**
Description	LFG recovery	LFG combustion
Equipment	Electric blower	BACT Engine
Energy type	Electricity	
Energy Use	9,262	
Energy Units	Btu/MMBtu	
Direct Emissions		
Units		lbs per MMBtu of gas recovered
VOC		0.2224
CO		0.6939
NO_X		0.1660
PM_{10}		0.0136
$PM_{2.5}$		0.0136
SO_X		0.0068
CH_4		1.1133
N_2O		0.0022
CO_2		143.6914
Indirect Emissions		
Units	lbs per MMBtu of gas recovered	
Description	Electricity for blower	
VOC	0.0003	
CO	0.0020	
NO_X	0.0033	
PM_{10}	0.0019	
$PM_{2.5}$	0.0006	
SO_X	0.0004	
CH_4	0.0045	
N_2O	0.0000	
CO_2	2.5496	

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[15] Best available control technology (BACT) guidelines for a landfill gas engine in the South Coast Air Quality Management District, from: http://www.aqmd.gov/docs/default-source/bact/laer-bact-determinations/aqmd-laer-bact/ic-engine-a-n-391009-1850-hp.doc

[16] ARB LCFS pathway for CNG from Landfill gas: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_lfg.pdf.

Table 18 presents the contribution of both direct and indirect sources of emissions to total emissions from biopower production from landfill gas. Except for PM_{10}, direct emissions contribute to more than 95% of total emissions of criteria pollutants. Indirect PM_{10} emissions are largely dominated by extraction of natural gas and petroleum products to produce the electricity in California. Finally, direct emissions of greenhouse gases comprise 98.5% of total emissions from biopower production from landfill gas.

Table 18: Contribution (in %) to total emissions from processes in biopower production from landfill gas

	Direct	**Indirect**
VOC	99.9	0.1
CO	99.7	0.3
NO_X	98.0	2.0
PM_{10}	87.8	12.2
$PM_{2.5}$	96.1	3.9
SO_X	95.1	4.9
$CO_{2,eq}$	98.5	1.5

Use of biogas from manure to produce biopower is similar to the process for landfill gas-to-energy applications. Assuming that the biogas is collected from a covered lagoon, the two main processes required for biopower generation from digester gas are compression using an electric blower, and combustion of biogas in an engine to produce power. Table 19 presents the emissions from biopower production with digester gas from dairy manure. The emissions assumed for the engine using digester gas are based on BACT guidelines,[17] and are comparable to the emissions from a landfill gas engine. Based on ARB estimates for a dairy biogas installation, the energy required for the electric blower is 22,209 Btu per MMBtu of recovered biogas.[18] Per unit of energy in the biogas, the required energy for the electric blower in a manure digester gas installation is more than twice the energy required in a landfill gas installation. As a result, the indirect emissions from digester gas recovery are more than twice as much as the emissions from collection of landfill gas. Table 20 presents the contribution of direct and indirect emissions from biopower production using digester gas. Because digester gas recovery is more energy intensive than landfill gas recovery, the contribution of indirect emissions from digester gas doubles the contribution of indirect emissions from landfill gas recovery for biopower production. For example, indirect emissions of NO_X add up to 4.4% of total emissions, and indirect emissions of PM_{10} correspond to 19.6% of total emissions. It is important to note, however, that a large fraction of indirect emissions from electricity use are

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[17] Best available control technology (BACT) guidelines for a digester gas engine in the South Coast Air Quality Management District, from: http://www.aqmd.gov/docs/default-source/bact/laer-bact-determinations/aqmd-laer-bact/ic-engine-an-388050-1408-hp.doc)

[18] ARB LCFS pathway for CNG from dairy digester gas: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_lfg.pdf. Electricity consumption to recover digester gas (11,124 Btu) + Energy to produce the electricity, including feedstocks (11,085 Btu)

related to the extraction of natural gas and other fuels required for electricity production. California imports over 90% of the natural gas it consumes,[19] and hence, most of the extraction of natural gas occurs outside of the state, thus having no effect on local air quality.

Table 19: Emissions from biopower production using biogas from manure

Process	**Harvest**	**Conversion**
Description	Digester gas collection	Biogas combustion
Equipment	Electric blower	BACT Engine
Energy type	Electricity	
Energy Use	22,209	
Energy Units	Btu/MMBtu	
Direct Emissions		
Units		lbs per MMBtu of gas recovered
VOC		0.2307
CO		0.7209
NO_X		0.1730
PM_{10}		0.0186
$PM_{2.5}$		0.0186
SO_X		0.0112
CH_4		1.1133
N_2O		0.0022
CO_2		143.6914
Indirect Emissions		
Units	lbs per MMBtu of gas recovered	
Description	Electricity for blower	
VOC	0.0007	
CO	0.0047	
NO_X	0.0080	
PM_{10}	0.0045	
$PM_{2.5}$	0.0013	
SO_X	0.0008	
CH_4	0.0108	
N_2O	0.0001	
CO_2	6.1136	

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[19] Natural gas supply to California, Energy Almanac: http://energyalmanac.ca.gov/naturalgas/natural_gas_supply.html

Table 20: Contribution (in %) to total emissions from processes in biopower production from digester gas

	Direct	**Indirect**
VOC	99.7	0.3
CO	99.4	0.6
NO_X	95.6	4.4
PM_{10}	80.4	19.6
$PM_{2.5}$	93.3	6.7
SO_X	93.0	7.0
$CO_{2,eq}$	96.4	3.6

As in the case of solid biomass, emissions from biopower using biogas are dominated by the conversion stage. Reduction in the emissions from combustion of biogas in engines will reduce the overall impact of biopower on air quality. California Air Resources Board established emission standards for distributed generation facilities that limit the emissions from biogas generators substantially.[20] These limits are applicable for installations that are exempt from air district regulations, but the South Coast Air Quality Management District adopted the same restrictive limits. There are already several installations that use biogas to run microturbines to generate power and heat, and that have been certified by ARB to meet the restrictive air emission standards.[21] In addition to microturbines, biogas can be used in fuel cells, which emit at a lower rate than any other technology. In particular, emissions from fuel cells are 2 orders of magnitude lower than a biogas engine. Hence, the use of fuel cells to produce power from biogas would significantly reduce the emissions from biopower production. Table 21 presents a comparison of emissions between an engine and a fuel cell.

Table 21: Performance and emissions comparison between a biogas engine and a fuel cell

	Engine	**Fuel Cell**[22]	**ARB limits**
Efficiency	0.34	0.47	
Emissions (lb/MWh)			
VOC	2.23	--	0.02
CO	6.96	--	0.10
NO_X	1.67	0.01	0.07
SO_2	0.07	0.0001	
PM_{10}	0.14	0.00002	
CO_2	1441	940	

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[20] DG emission regulations: http://www.arb.ca.gov/energy/dg/2006regulation.pdf

[21] http://www.arb.ca.gov/energy/dg/eo/eo-current.htm

[22] http://www.fuelcellenergy.com/why-fuelcell-energy/benefits/ultra-clean/

4.2.3 Emissions Displacement from Biomass Use

The assessment of the impacts of biomass needs to account for any displacement of emissions that the use of biomass may provide. For example, new biopower production from biomass will displace power generation that otherwise would have been produced by the existing California grid. New fuel production from biomass, whether it is CNG or ethanol, will displace fuel production and consumption that would otherwise been produced by the current infrastructure of oil refineries in the state. For CNG vehicles, in addition to the emissions displaced from gasoline and diesel marketing, emissions changes due to the shift from gasoline/diesel to CNG engines must also be accounted for. It is not clear however, whether a decrease in gasoline and diesel demand would translate into a decrease in petroleum refining. For this study, we assume that even though CNG or ethanol from biomass could displace a significant portion of the fuels consumed in the state, petroleum refining will remain unaffected as the excess in production could be exported to other parts of the US. However, emissions from petroleum marketing which involves transporting fuel to fueling stations would be affected if gasoline and/or diesel is displaced significantly by CNG.

4.2.4 Summary of Emissions from Biomass Scenarios

The analysis of the emissions from all scenarios includes four major contributors to total emissions from biomass use: (1) feedstocks, (2) collection and transport, (2) conversion and (4) savings.

(1) Feedstocks: emissions from feedstocks refer to all the emissions relates to all indirect emissions that occur during the production of electricity and fuels that are used to operate machinery and processing plants for biomass collection, processing and conversion. Sources of feedstock emissions include: emissions from diesel production for fueling off-road equipment that collects forest residue and loads residue in processing plant, and emissions from electricity production required to power biogas blower, processing plant electrical needs and biomethane compressor.

(2) Collection and transport: emission from collection and transport is only considered for the collection of forest residue. This study assumes that any other solid residue, e.g. MSW and agricultural reside, is collected regardless of whether the residue is used for biopower production. As a result, production of power or fuels from residues other than forestry waste does not incur in additional collection and transportation emissions, and hence, no emissions from this stage are accounted for.

(3) Conversion: emissions from conversion include all direct emissions that occur in the biomass processing plant. Conversion processes include: combustion of biomass or biogas in biopower production, partial oxidation of biogas in the biogas clean-up process, and gasification of biomass for the production of synthesis natural gas.

(4) Savings: emission savings include all the emissions displaced by the production of power and fuels from biomass. When biogas and biomass are used to produce biopower,

> emissions from the production of the same amount of power using California's grid should be subtracted. Similarly, when biogas and biomass are used to produce pipeline-grade natural gas, emissions from the production of California natural gas should be subtracted. In the specific case that biomass is used to produce CNG to fuel gasoline vehicles, emissions from the production of equivalent gasoline fuel need to be subtracted. In addition, emissions from switching from conventional gasoline vehicles to CNG vehicles need to be accounted for.

The analysis is focused on the emissions of NO_X, PM and greenhouse gases expressed as emissions of CO_2 equivalent. NO_X and PM are the most relevant criteria pollutant for the formation of ozone and particulate matter in California. Emissions of CO_2 equivalent include contribution of CH_4 and N_2O, which are emitted at much lower rates than CO_2, but because their global warming potential is 34 and 298 times CO_2 warming potential,[23] respectively, they can contribute sensibly to total climate forcing. A fraction of PM emissions is formed by black carbon (BC), which is known to be a short-lived climate forcing compound. BC contributes to global warming, but it has a relative short atmospheric lifetime. This implies that reduction of BC emissions could dissipate their global warming effect rather quickly, compared to long-lived compounds like CO_2.

Figure 23 presents the emissions for all scenarios in group A: Increasing Capacity with Conventional Technology. All these cases assume that both biogas and biomass are used to produce power by using a biogas engine and a biomass boiler. Emissions are disaggregated between biogas and solid biomass applications. As described in Section 4.2.1 and 4.2.2, emissions from conversion dominate the overall emissions from biopower production. There are no emissions associated to biomass collection and transport in biogas applications, other than the electricity required for the blower to pump the landfill gas and the digester gas to the biopower facility. For biomass, emissions from collection and transport of only forest residue are accounted for.

Emissions of NO_X from current facilities are approximately 45 tons/day, and increase to up to 157 tons/day in the case of maximum potential for biopower production. According to ARB, [24] total statewide emissions for 2012 are 2,162 tons/day, and are expected to decrease to 1,610 tons/day by 2020. This implies that emissions from current biopower plants contribute to 2.1% of total statewide NO_X emissions. In addition, assuming that the maximum potential could be achieved by 2020 using current technology, potentially biopower would contribute to 10% of total statewide NO_X emissions by 2020.

Emissions of PM from current facilities are approximately 5 tons/day, and increase to up to 17 tons/day in the case of maximum potential. ARB estimates for statewide PM are 1,963 tons/day in 2012 and 1,921 tons/day in 2020. Hence, the contribution from biopower could grow from 0.3% with current facilities to 0.9% in 2020 with maximum potential for biopower production using current technology. The impact of biopower on primary PM is less pronounced than the

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[23] Global Warming Potential values from the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. IPCC, 2013. Values include climate-carbon feedbacks, and present an increase in the CH4 GWP from 25 to 34.

[24] ARB Emissions Inventory Data: http://www.arb.ca.gov/ei/emissiondata.htm

effect on NO_X emissions. However, it is important to note that NOX can participate in the formation of secondary PM. Consequently, to account for the overall effect of biomass use on PM concentrations in the state, air quality simulations are required to quantify the formation of secondary PM in addition to the contribution from direct PM emissions.
Emissions of CO_2 equivalent are approximately 37,000 tons/day and could increase up to 151,700 tons/day in the maximum potential case. ARB's estimates for statewide GHG emissions are 460 million tons of $CO_{2,eq}$ per year in 2012 (1.2 million tons/day),[25] and projected to grow up to 600 million tons/year in 2020 (1.64 million tons/day), in a business-as-usual projection. [26] With these GHG emission estimates, biopower production contributes to nearly 3% in total in-state $CO_{2,eq}$ emissions currently, and could increase to 9.2% in 2020.

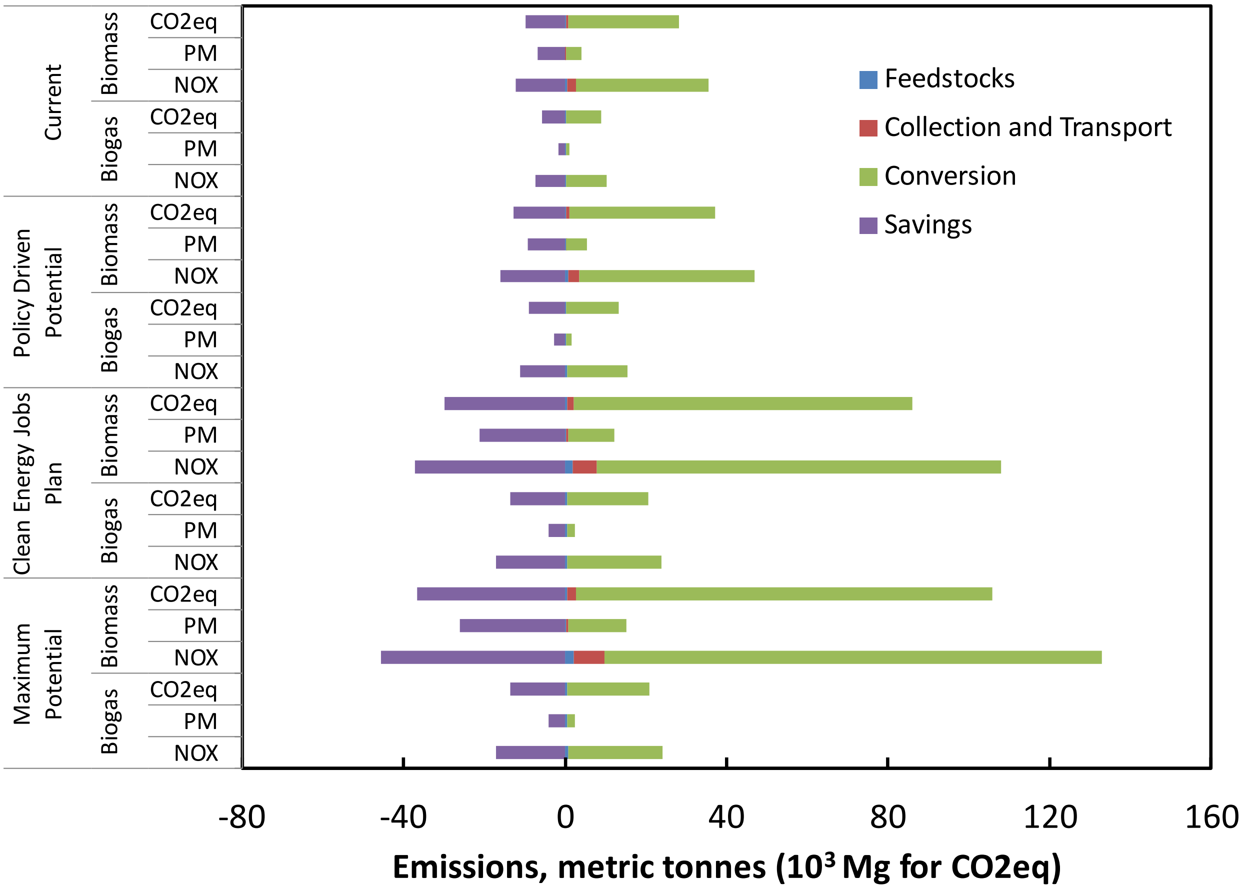

Figure 23: Summary of emissions from biomass in scenarios with current biomass technology (group A)

In addition to direct emissions, Figure 23 shows the potential savings in emissions due to displacing emissions from power generation by biopower production. Figure 24 shows the net emissions for the scenarios in Group A. For NO_X and $CO_{2,eq}$, savings do not totally offset emissions from biopower production. Namely, emissions from biopower using current

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[25] California Greenhouse Gas Emission Inventory, http://www.arb.ca.gov/cc/inventory/inventory.htm
[26] California 1990 Greenhouse Gas Emissions Level and 2020 Limit, http://www.arb.ca.gov/cc/inventory/1990level/1990level.htm

technology are higher than the sum of direct and indirect emissions generated from producing the same amount of electric power by the existing grid, and the net emissions presented in Figure 24 are positive. On the contrary, savings in PM for both biogas and biomass applications are larger than direct emissions, and as a result, net emissions for the entire fuel cycle are negative. However, it is important to note that for NO_X and PM, some of the emission savings occur out of state. Emission savings include emissions from the extraction of natural gas and other fuels in other parts of the country and the world that are required for power generation. Based on the emissions shares by CA-GREET 2.0,[27] using California current mix for in-state power generation and assuming that approximately 33% of the power is imported,[28] the portion of emission savings that occur in the state is shown in Table 22.

Table 22: Fraction of the emissions savings for biopower production for selected pollutants that occur in the state.

Pollutant	**Fraction of in-state Savings**
NO_X	37.8%
PM	24.9%
$CO_{2,eq}$	61.8%

As a result, those savings in criteria pollutant emissions do not have a direct effect on regional air quality in the state. It is also important to note that savings in GHG emissions do not include emission credits for the use of biomass. For example, forest residue not used for biopower may be disposed of by prescribed burning, or left to decompose in the forest. Biogas not used for biopower could either be vented or flared. Hence, not using biomass for biopower can result in emissions of GHG that are not included in the emission savings. Including these GHG emission credits would reduce the carbon footprint of biopower production, and thus the results shown in this section represent an upper bound for GHG impacts.

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[27] CA-GREET 2.0 available at: http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm

[28] California current mix for in-state power generation and imports from: http://energyalmanac.ca.gov/electricity/total_system_power.html

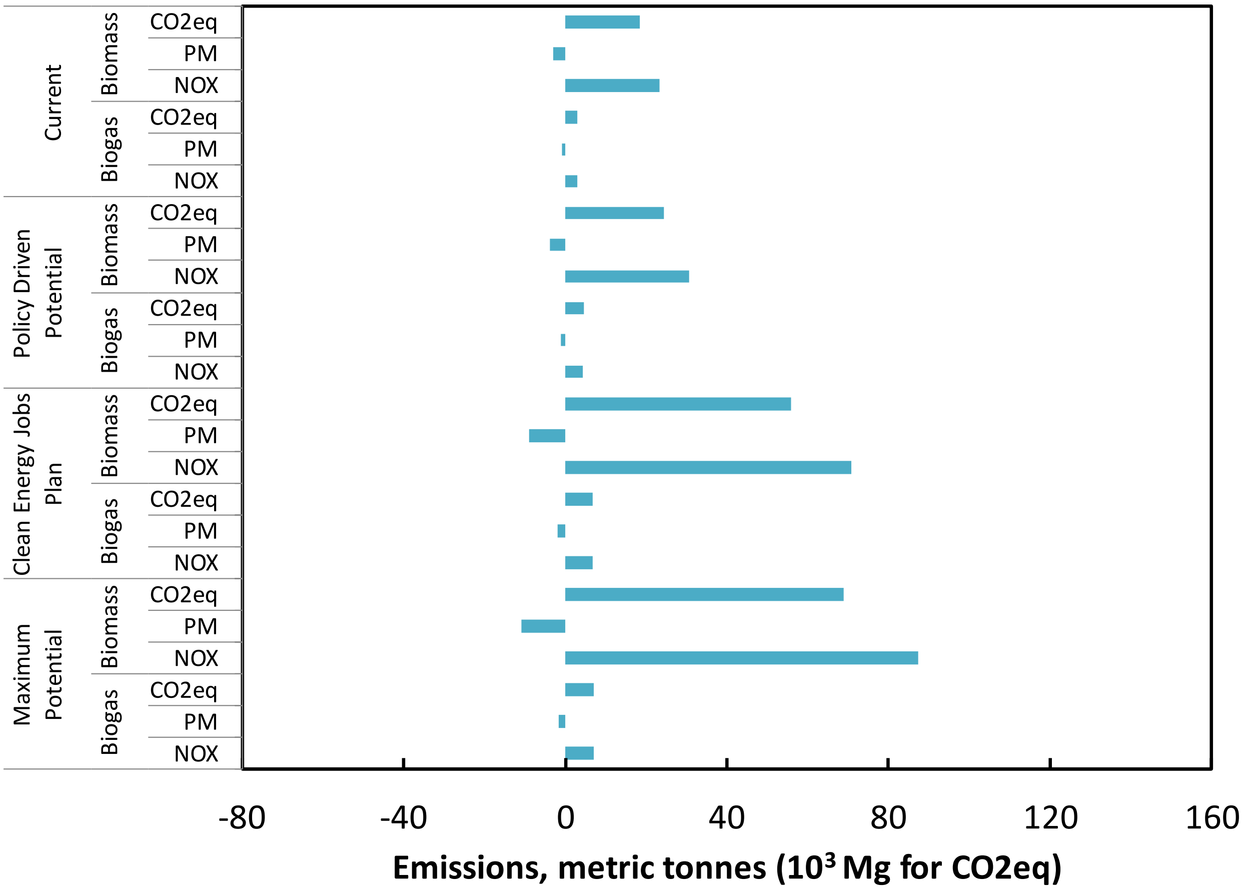


Figure 24: Net emissions from biomass in scenarios with current biomass technology (group A)

Figure 25 presents the emissions from Group B: Technology Upgrade for Efficiency and Emissions, in comparison with the case with maximum potential for biopower with current technology. Technology upgrades consist of switching current boilers and engines with next generation gasification systems and fuel cells. The result is a significant decrease in direct emissions of criteria pollutants with respect to the case with current technology. Direct GHG emissions do not change, as the same amount of carbon is converted into CO_2, but because of the increase in efficiency in power generation, emission savings are also increased with respect to the case with maximum potential and current technology.

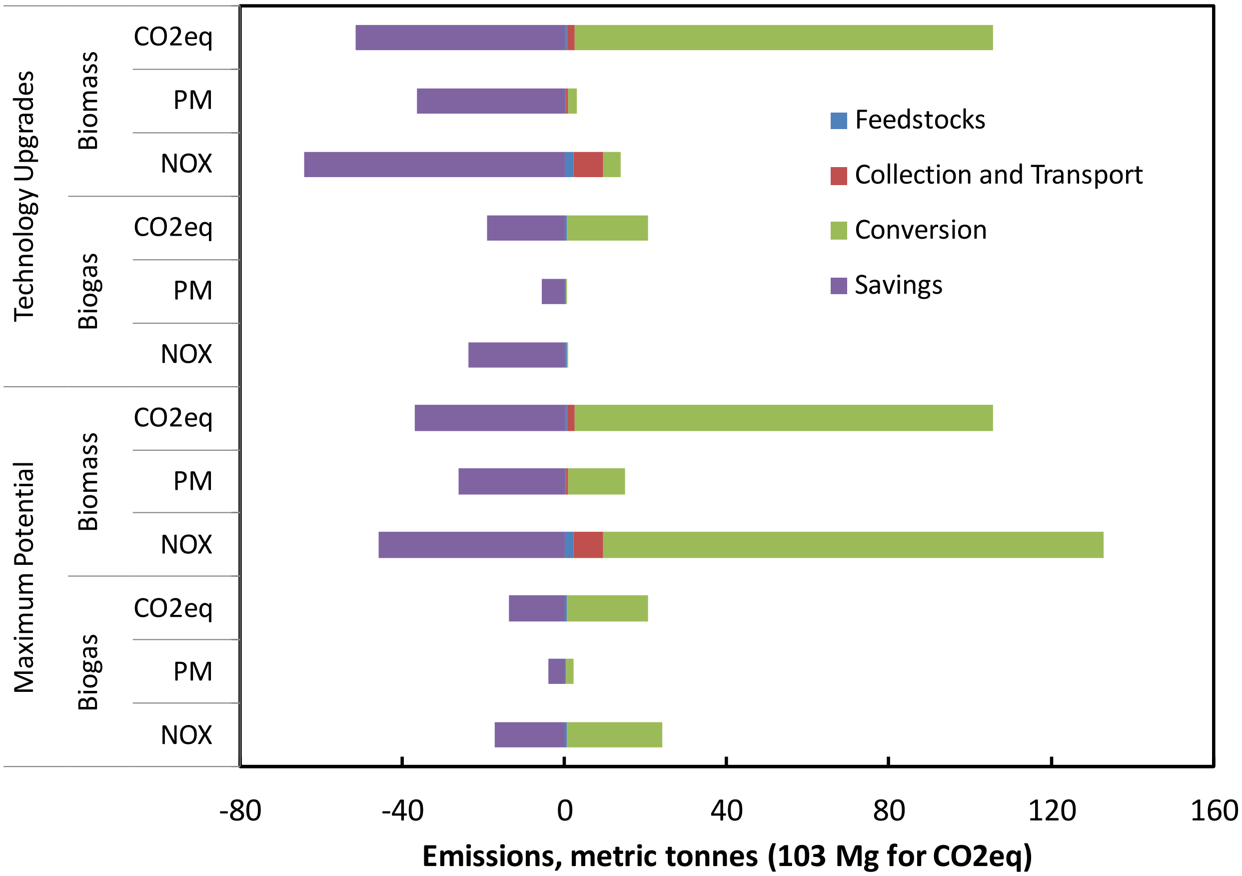


Figure 25: Comparison of emissions from biomass in scenarios with maximum biomass potential with current technology (group A) and with technology upgrades for efficiency and emissions (group B)

Resulting net emissions from group B are presented in Figure 26 together with net emissions for the maximum potential with current technology. Because of the very low emissions from fuel cells and integrated gasification systems, net emissions of NO_X and PM are negative for the entire fuel cycle. As stated above, it is important to note that a large part of the savings in criteria pollutant emissions occur outside of the state (as shown in Table 22), having no effect on air quality. Regarding GHG emissions, technology upgrades decrease net emissions of CO_{2eq} by 26% with respect to the current technology case.

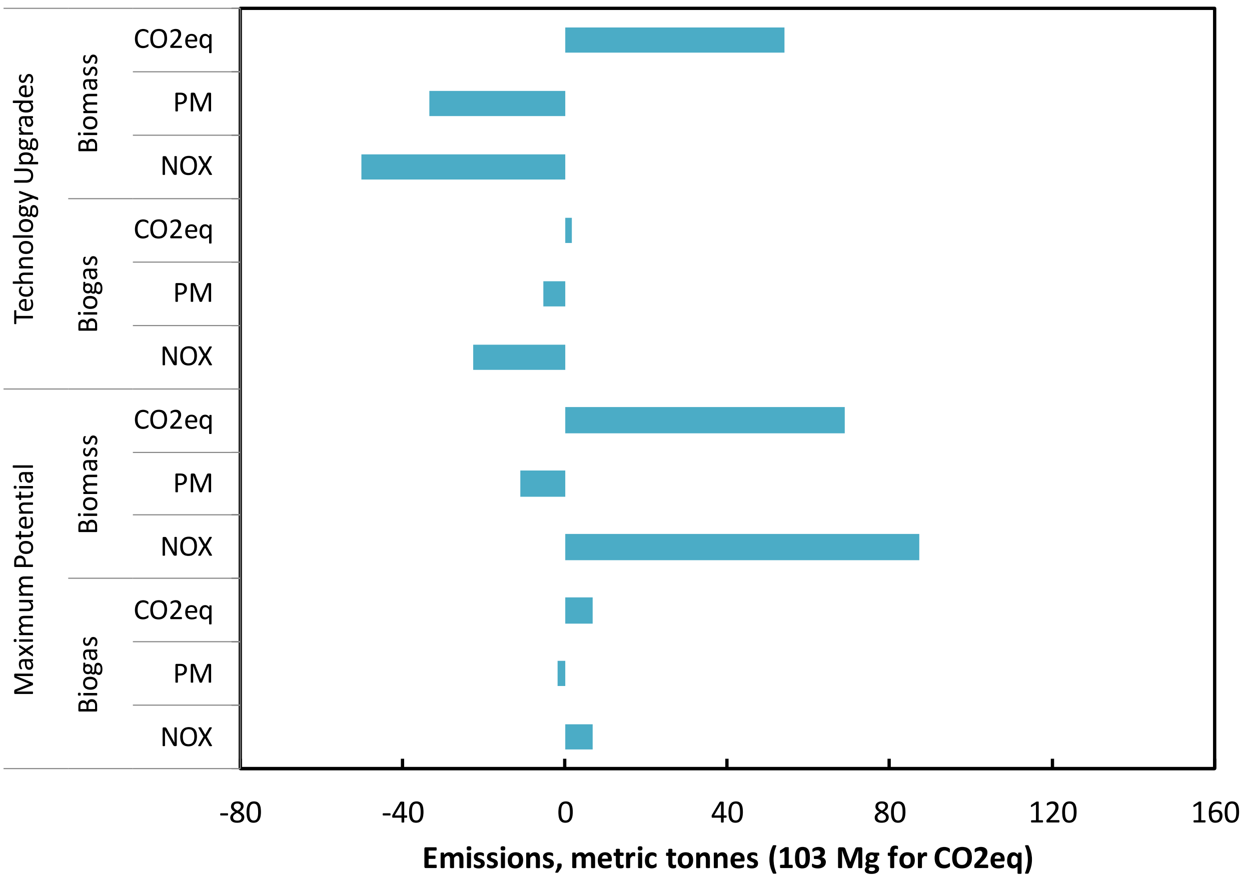


Figure 26: Net emissions from biomass in scenarios with maximum biomass potential with current technology (group A) and with technology upgrades for efficiency and emissions (group B)

Figure 27 presents the emissions of scenarios in Group C: Shift End Use from Electricity to Fuel, together with the case with maximum potential for biopower with current technology. Group C includes two cases with generation of CNG from solid biomass via gasification: one dedicated to produce CNG for vehicle consumption and the other one for pipeline injection. Direct emissions from these two cases are the same, because the processes to generate the CNG are the same in both cases. Emissions from feedstocks in these two cases are considerably higher than in the cases of group A and B, because more energy is required to clean-up biogas and synthesis gas, and to compress them. The only difference between these two CNG scenarios is the emissions displaced by the CNG. In the case that CNG is dedicated to vehicle consumption, emission displacement is due to the savings in gasoline production and marketing needs that production of CNG from biomass provides. In addition, the case includes savings in emissions from vehicles switching from gasoline to CNG consumption. Conversely, in the case that CNG is dedicated to pipeline injection, emission displacement is calculated from the savings in natural gas production and marketing demand that CNG provides. No additional savings are considered in this CNG case as combustion of NG from biomass is assumed to produce the same pollutant emissions as combustion of conventional NG. Hence, comparing the two cases is analogous to contrasting emissions from equivalent energy units of gasoline and natural gas. The result is that producing gasoline for California is more pollutant-intensive than producing natural gas, and thus, reducing gasoline production achieves higher emission savings than reducing production of natural gas containing the same amount of energy. Consequently, on a full fuel cycle emissions standpoint, producing CNG for vehicles is more favorable than producing natural gas for pipeline injection as shown in Figure 28.

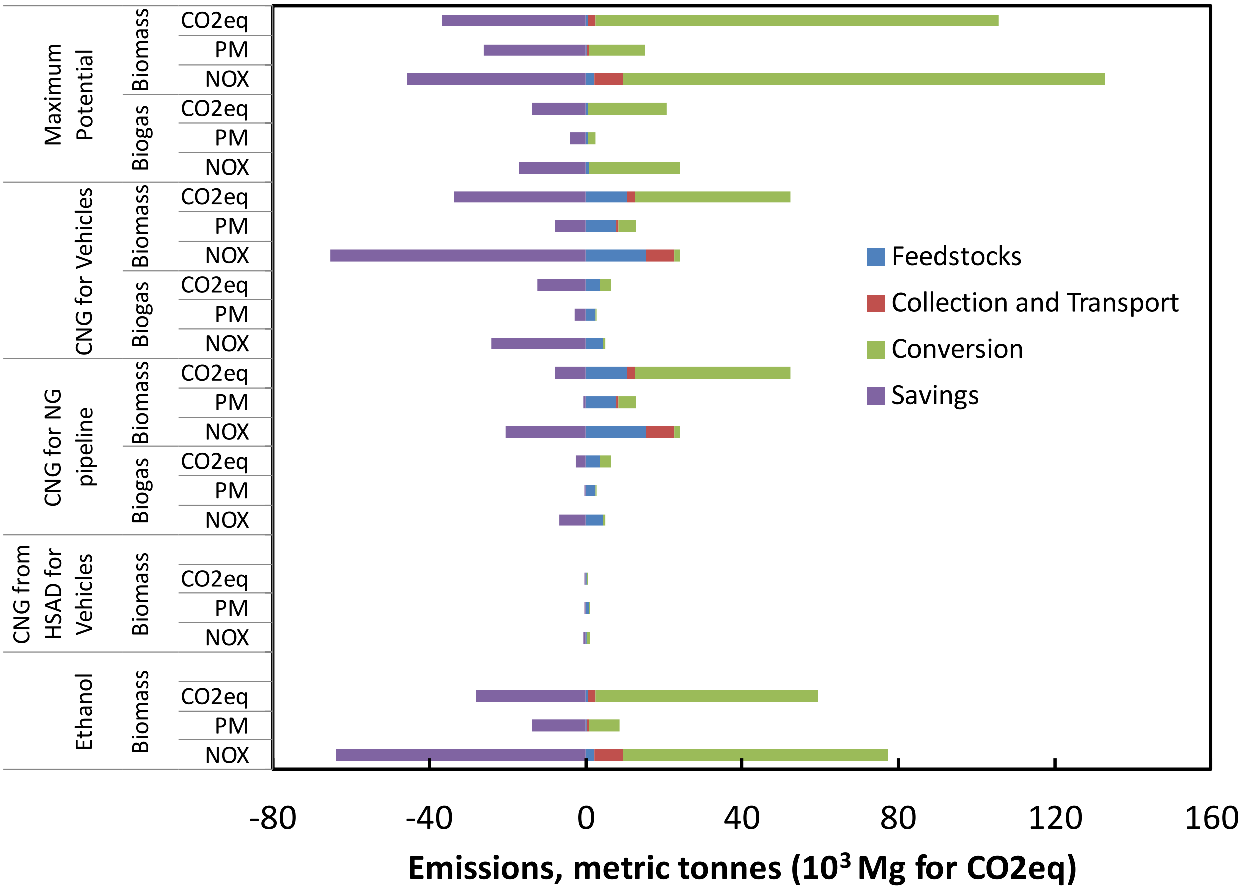


Figure 27: Comparison of emissions from biomass in scenarios with maximum biomass potential using current technology for biopower (group A) and scenarios with CNG production (group C)

Figure 27 also presents emissions resulting from using a fraction of solid biomass to produce CNG via high-solid anaerobic digestion. The HSAD case assumes that only one sixth of the total solid residue is used to produce digester gas. Also, the process yields less digester gas per mass of solid residue than the gasification process, while producing nutrient-rich compost as a byproduct. The result is that the amount of CNG produced through HSAD is only 2% of the potential CNG produced via RSNG. The resulting total emissions from HSAD are very small compared to the other two cases where CNG is produced via gasification, and potential air quality impacts of the HSAD case are expected to be minor.

The last case in Group C represents a scenario where solid biomass is partially oxidized to produce ethanol. The emissions from the conversion stage are from the oxidation of 55% of the solid residue to provide process heat for the formation of ethanol. The savings in emissions correspond to the displacement of ethanol production from corn in the Midwest. The savings are comparable to the savings obtained from producing CNG for vehicles. However, because direct emissions from ethanol production are higher than NG production, net emissions from ethanol production are higher than overall emissions from CNG production for vehicles, but lower than the emissions from CNG production for pipeline injection.

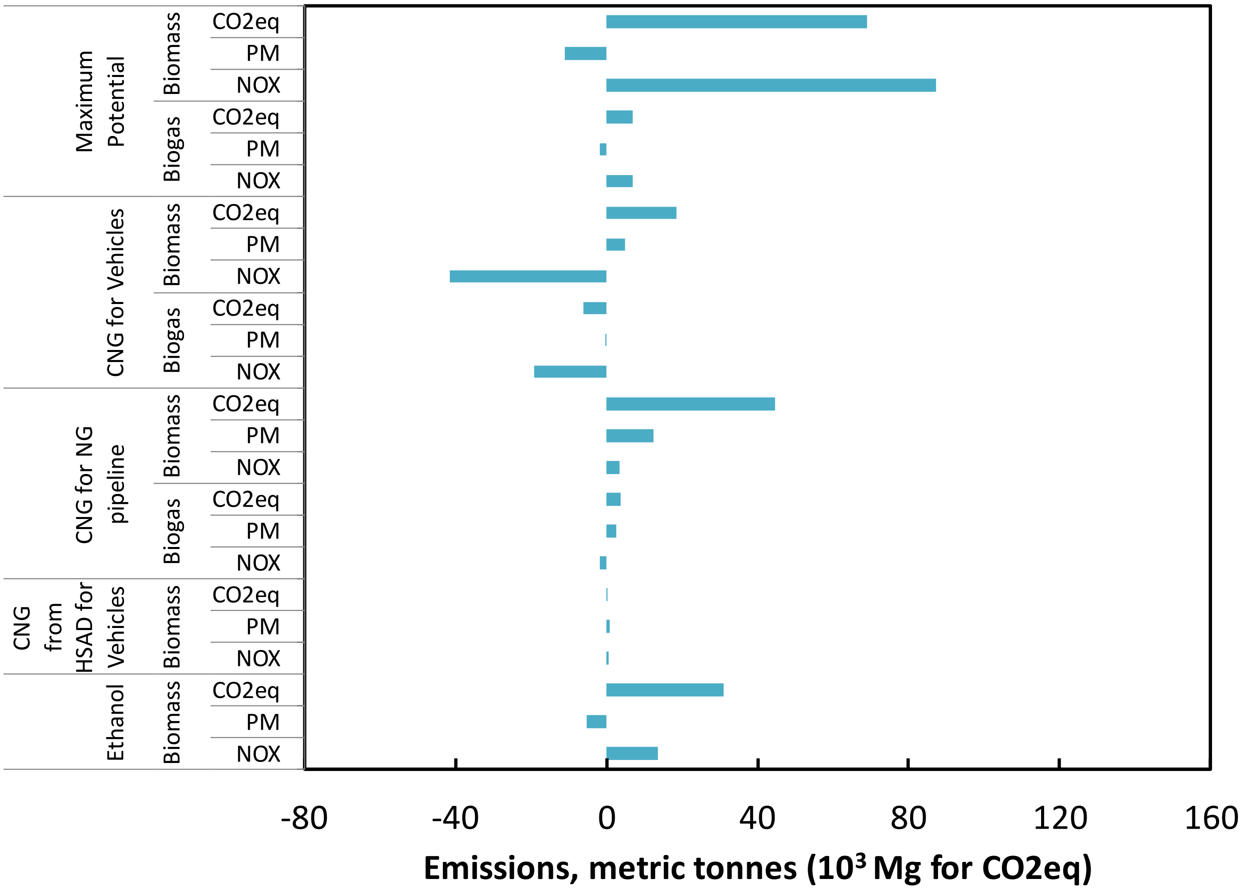


Figure 28: Comparison of emissions from biomass in scenarios with maximum biomass potential using current technology for biopower (group A) and scenarios with CNG production (group C)

Table 23 presents the total emissions of scenarios that assume maximum potential for biomass use. In summary, from a full fuel cycle perspective, use of biomass to produce vehicle fuels appears as the best option to minimize GHG emissions. Applying technology upgrades and emission controls for biopower production can mitigate criteria pollutant emissions, but CNG from biogas and gasification of biomass achieves comparable emissions of criteria pollutants and lower GHG emissions. As stated before, a large portion of emission savings for criteria pollutants occur outside the state. If only the emission savings within the state are accounted for (Table 24), the case with technological advances for biopower production becomes the most favorable scenario to minimize the impact of biomass use on criteria pollutant emissions but CNG scenarios are still the most favorable for greenhouse gases emissions. Air quality modeling of the emission impacts in the state completes the analysis for the overall air quality impacts of biomass use.

Table 23: Summary of net emissions from selected scenarios (in tons/day for NO_X and PM, and 10^3 tons/day for $CO_{2,eq}$)

		Maximum Potential	Technology Upgrades	Ethanol	CNG from HSAD for Vehicles	CNG for Pipeline Injection	CNG for Vehicles
Biogas	**NO_X**	6.9	-22.7			-1.8	-19.1
	PM	-1.8	-5.2			2.6	-0.1
	CO2eq	7.0	1.7			3.7	-6.2
Biomass	**NO_X**	87.2	-50.1	13.6	0.4	3.4	-41.6
	PM	-11.0	-33.3	-5.2	0.7	12.3	5.0
	CO2eq	68.9	54.1	31.1	0.1	44.6	18.5

Table 24: Summary of net emissions from selected scenarios (in tons/day for NO_X and PM, and 10^3 tons/day for $CO_{2,eq}$) accounting only for in-state savings

		Maximum Potential	Technology Upgrades	Ethanol	CNG from HSAD for Vehicles	CNG for Pipeline Injection	CNG for Vehicles
Biogas	**NO_X**	16.0	-10.1			4.0	-1.0
	PM	0.5	-2.1			2.7	1.7
	CO2eq	12.0	8.7			5.9	-3.0
Biomass	**NO_X**	111.6	-16.0	77.5	0.9	20.9	7.7
	PM	3.6	-12.8	8.6	0.7	12.8	10.0
	CO2eq	82.4	73.0	59.3	0.3	51.2	27.2

Emissions savings are based on CA-GREET 1.8b, which is being used in the calculation of LCFS pathway emissions. A newer version, CA-GREET 2.0, is being considered by ARB to replace the previous version. Total full fuel cycle emissions from electricity production are higher in CA-GREET 1.8b than in CA-GREET 2.0. Even though emissions of CH_4 and N_2O increase considerably from feedstock procurement, full cycle emissions of greenhouse gases decreases by 9.3%, if the current technology mix in installed in California is assumed. Also, emissions of NOX decrease by 24% and emissions of PM decrease by 77%. This would results in lower full cycle emission savings from biopower production in California.

5 Air Quality Modeling

5.1 Modeling Framework

Tropospheric ozone is a product of photochemistry between NO_X and volatile organic compounds (VOCs) in the ambient atmosphere in the presence of sunlight. In California, NO_X and VOCs are mostly emitted from anthropogenic sources such as on-road and off-road vehicles, power plants and industrial operations, although there are significant biogenic sources of VOCs (CARB, 2009b). Ozone concentrations depend on spatial and temporal profiles of precursor emissions, meteorological conditions, transport of precursors and reaction products through, and removal processes such as deposition and chemical reaction. Comprehensive models that incorporate all these physical and chemical processes in detail are widely used to understand and characterize ozone formation on regional scales. These air quality models numerically solve a series of atmospheric chemistry, diffusion, and advection equations in order to determine ambient concentrations of pollutants within control volumes over a given geographic region.

Most models employ an Eulerian representation (i.e., one that considers changes as they occur at a fixed location in the fluid, usually called a cell or control volume) of physical quantities on a three-dimensional computational grid. The atmospheric advective diffusion equation for species *m* in a given control volume is:

$$\frac{\partial Q_m^k}{\partial t} = -\nabla \cdot \left(u Q_m^k\right) + \nabla \cdot \left(K \nabla Q_m^k\right) + \left(\frac{Q_m^k}{\partial t}\right)_{sources/sinks} + \left(\frac{Q_m^k}{\partial t}\right)_{aerosol} + \left(\frac{Q_m^k}{\partial t}\right)_{chemi} \qquad (8)$$

where *t* is time, *k* is phase – gas or aerosol, *u* is wind velocity and *K* is the coefficient of eddy diffusivity tensor that parameterizes turbulent diffusion.

The above equation is numerically integrated in time to obtain the concentration, *Q*, of each species *m* in phase *k* (gas phase or aerosol phase), over a series of discrete time steps in each of the spatially distributed discrete cells of the air quality model. Each term on the right side of the advective diffusion equation represents a major process in the atmosphere. From left to right these are: (1) advective transport due to wind, (2) turbulent diffusion due to atmospheric stability/instability, (3) emission (sources) and deposition (sinks), (4) mass transfer between gas and aerosol phases, and (5) chemical reaction.

The outputs from air quality models are spatially and temporally resolved concentrations of pollutant species within control volumes over a geographic region. To minimize the effects of initial conditions, air quality simulations are performed over multiple days and results from the first few days are not included in the analysis.

The CMAQ model (Byun and Ching, 1999) is a comprehensive air quality modeling system developed by the United States Environmental Protection Agency (US EPA) and is used in many regulatory air quality applications such as studying tropospheric ozone, particulate matter, acid deposition and visibility (Appel *et al*. 2008, 2010; Foley *et al*. 2010). The chemical mechanism used in CMAQ is the CB05 (Sarwar *et al*., 2008), which includes the photochemical formation of ozone, oxidation of volatile organic compounds and formation of organic aerosol precursors. The advection model in CMAQ is based on the Yamartino-Blackman Cubic Scheme (Yamartino, 1993) and vertical turbulent mixing is based on K-theory (Chang *et al*., 1987, and Hass *et al*., 1991). For the simulations presented in this report, the spatial resolution of control volumes is 4km × 4km over the entire state, and a vertical height of 10,000 meters above ground, with 30 layers of variable height based on pressure distribution. Meteorological input data for CMAQ was obtained from the Advanced Research Weather Research and Forecasting Model, WRF-ARW (Skamarock *et al*. 2005). The National Centers for Environmental Prediction (NCEP) Final Operational Global Analysis 1° × 1° grid data (NCEP, 2005) were used for WRF-ARW initial and boundary conditions.

5.2 Air Quality Modeling Performance

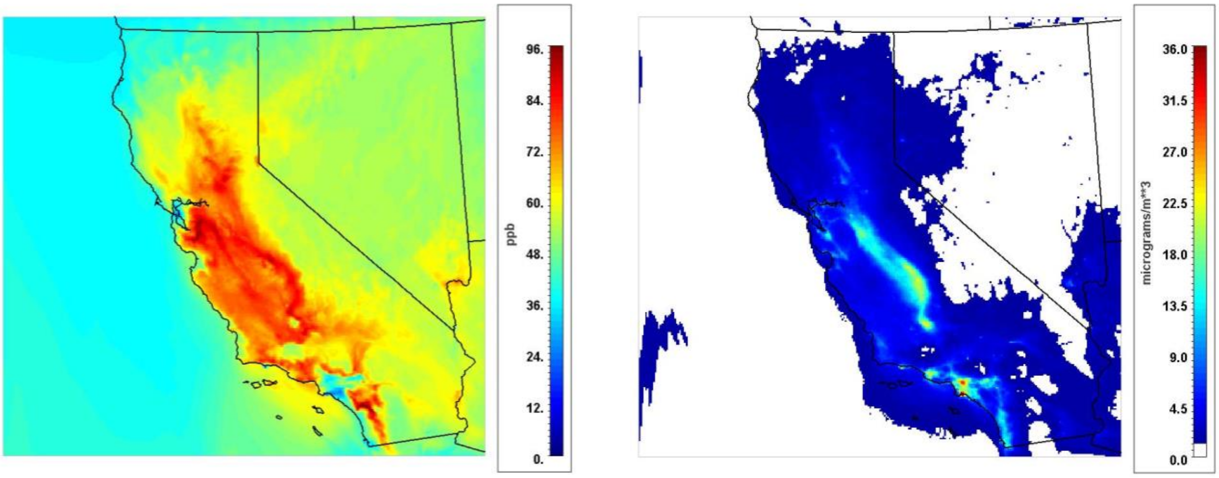
This section discusses air quality resulting from modeling the Summer Baseline and the Winter Baseline cases, and the air quality impacts resulting from the emissions increases in the six scenarios. Two meteorological episodes were simulated: July 7-13, 2005, a summer period with high observed ozone concentrations, and December 1-7, 2005, a winter period with high PM concentrations. Annual emissions were spatially and temporally disaggregated by SMOKE to approximate hourly emissions over the simulation domain. Figure 29 presents observed 8-hour average ozone concentrations and 24-hour average $PM_{2.5}$ concentrations for 4x4 kilometers grid cells over California for Monday, July 13, the summer base case. Simulated 8-hour average ozone concentrations were high, with many areas in the Central Valley, San Jose, and Riverside, above 80 ppb (Figure 29a). Concentrations of $PM_{2.5}$ on July 13 showed a spatial distribution typical for California, with peaks in the South Coast Air Basin and along the San Joaquin Valley (Figure 8b).

Figure 30 presents modeled hourly ozone concentrations together with observed ozone concentrations at five selected locations in California, and it shows that the model agrees well with observations. Overall, model performance is determined by the Mean Normalized Bias (MNB) and Mean Normalized Gross Error (MNGE), using Equations 8 and 9. Hourly observations are obtained from ARB’s monitoring data recorded in 145 stations (ARB, 2012). Both MNB and MNGE are calculated using concentrations that are higher than 40 ppb, which is the background level for ozone. These metrics are recommended by the USEPA for model evaluation (U.S. EPA, 2007), and have been used extensively in the literature (Russell and Dennis, 2000; Eder and You, 2006; Appel et al., 2008; Foley et al., 2010).

$$\mathrm{MNB}=\frac{1}{N}\sum_{i=1}^{N}\frac{C_M(x_i,t)-C_O(x_i,t)}{C_O(x_i,t)} \tag{9}$$

$$\text{MNGE} = \frac{1}{N}\sum_{i=1}^{N}\frac{|C_M(x_i,t) - C_O(x_i,t)|}{C_O(x_i,t)}, \qquad (10)$$

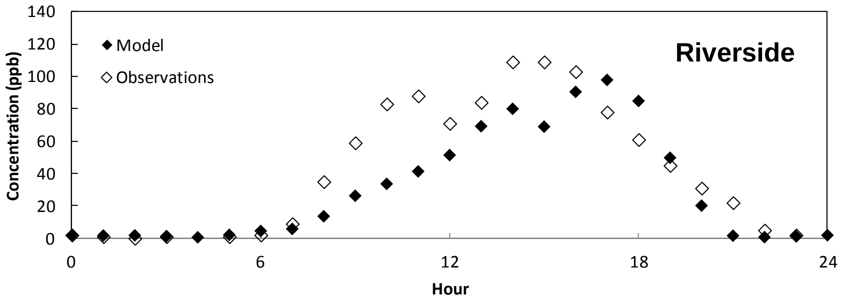
where N is the number of observations in the region of interest during the campaign, $C_O(x_i,t)$ is the concentration of the i^{th} observation, and $C_M(x_i,t)$ is the corresponding modeled concentration at the same position and time. MNB and MNGE for July 13, 2005 are -7.6% and 29.3%, respectively. These values are within acceptable model performance parameters (U.S. EPA, 2007).

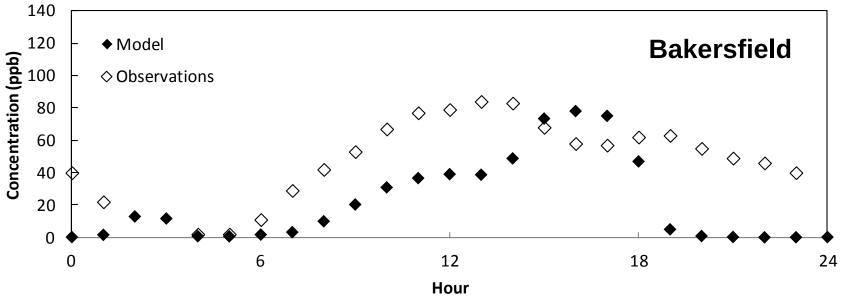


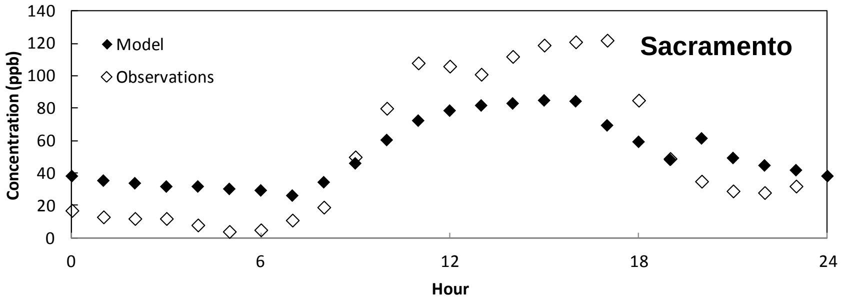
(a) (b)

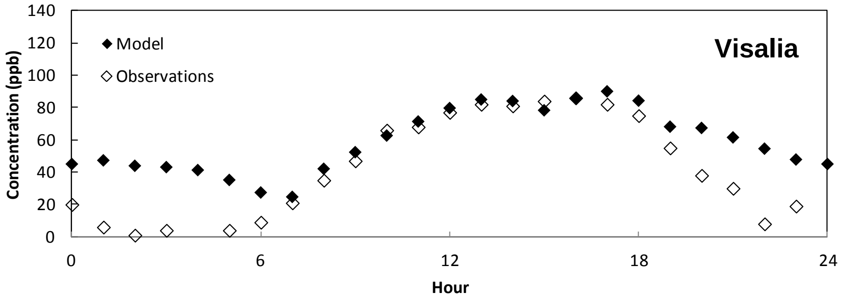
Figure 29 Ambient air concentrations for July 13, 2005: (a) 8-hour average ozone, (b) 24-hour average $PM_{2.5}$.

Figure 31 presents modeled and observed 24-hour average $PM_{2.5}$ concentrations at all monitoring stations that reported data for July 13, 2005. Model MNB and MNGE, calculated with no cut-off value for 24-hour average concentrations of $PM_{2.5}$, are -2.8% and 31.9%, respectively.


Riverside
◆ Model
◇ Observations
Concentration (ppb)
0
20
40
60
80
100
120
140
Hour
0
6
12
18
24


Bakersfield
◆ Model
◇ Observations
Concentration (ppb)
0
20
40
60
80
100
120
140
Hour
0
6
12
18
24


Sacramento
◆ Model
◇ Observations
Concentration (ppb)
0
20
40
60
80
100
120
140
Hour
0
6
12
18
24


Visalia
◆ Model
◇ Observations
Concentration (ppb)
0
20
40
60
80
100
120
140
Hour
0
6
12
18
24

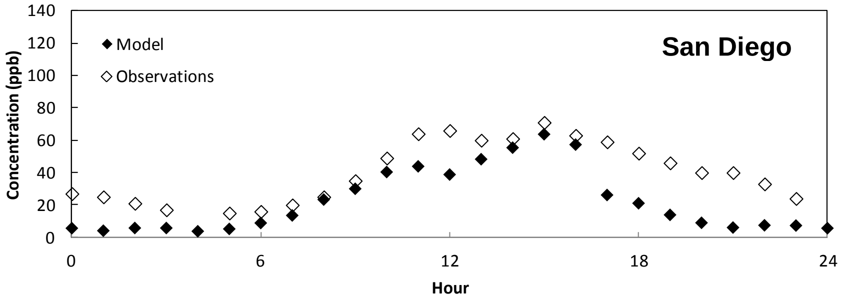

San Diego
◆ Model
◇ Observations
Concentration (ppb)
0
20
40
60
80
100
120
140
Hour
0
6
12
18
24

Figure 30 Modeled and observed hourly ozone concentrations for July 13, 2005 at selected locations

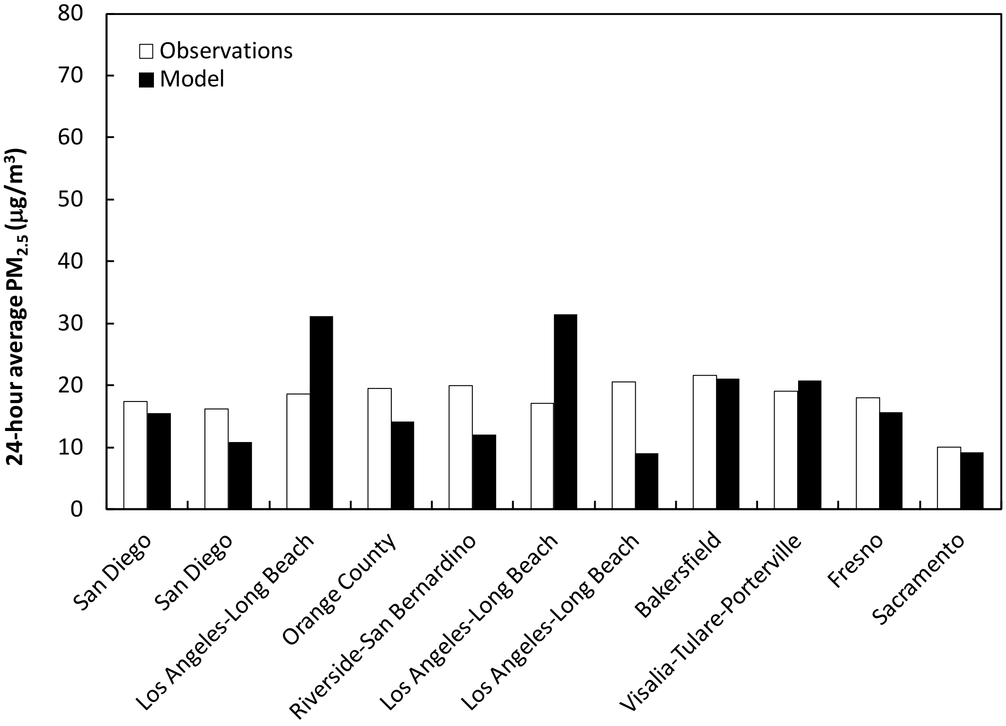
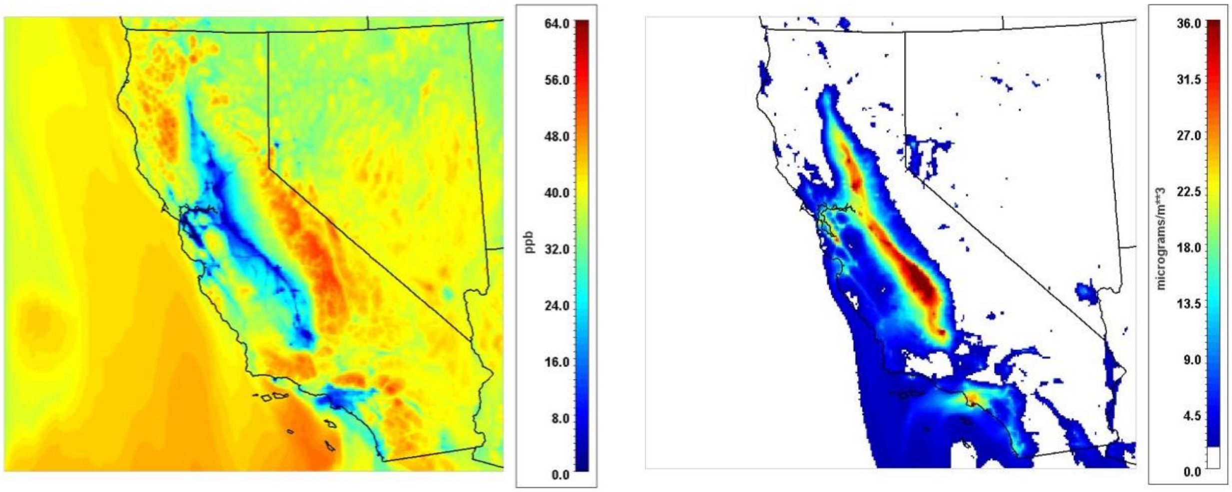


Figure 31 Modeled and observed 24-hour average $PM_{2.5}$ concentrations for July 13, 2005 at selected locations

Figure 32 shows simulated 8-hour ozone concentrations and 24-hour $PM_{2.5}$ concentrations for 4x4 km grid cells over California for Wednesday December 7, 2005, the Winter Baseline case. Simulated 8-hour ozone concentrations are low and below the state standard of 75ppb, which is typical for winter. The 24-hour average $PM_{2.5}$ concentrations are higher for the Winter Baseline case than the Summer Baseline case, especially along the Sacramento and San Joaquin Valleys. Some regions in the Sacramento and San Joaquin Valleys experience 24-hour average $PM_{2.5}$ concentrations higher than the 35 $\mu g/m^3$ federal EPA standard.

Figure 33 presents winter modeled hourly ozone concentrations together with observed ozone concentrations for Wednesday December 7, 2005at five selected locations in California, and it shows that the model also agrees well with observations. MNB and MNGE for December 7, 2005 are -10.9% and 12.0%, respectively. These values are within acceptable model performance parameters (U.S. EPA, 2007).

Figure 34 presents modeled and observed 24-hour average $PM_{2.5}$ concentrations at all monitoring stations that reported data for December 7, 2005. Model MNB and MNGE, calculated with no cut-off value for 24-hour average concentrations of $PM_{2.5}$, are -27.8% and 29.3%, respectively.



(a) (b)

Figure 32 Modeled pollutant concentrations for December 7, 2005: (a) 8-hour average ozone, (b) 24-hour average $PM_{2.5}$.

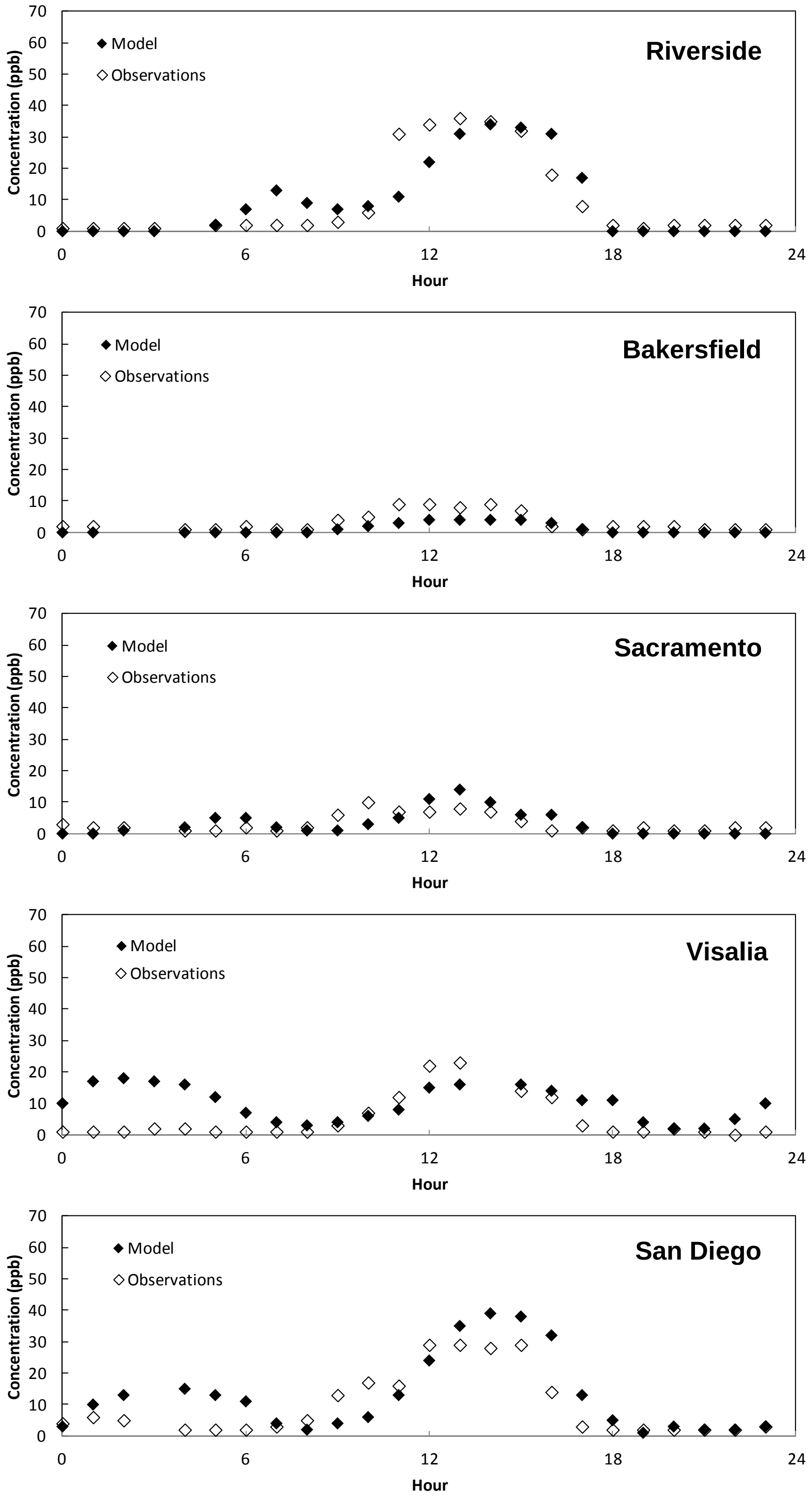


Figure 33 Modeled and observed hourly ozone concentrations for December 7, 2005 at selected locations

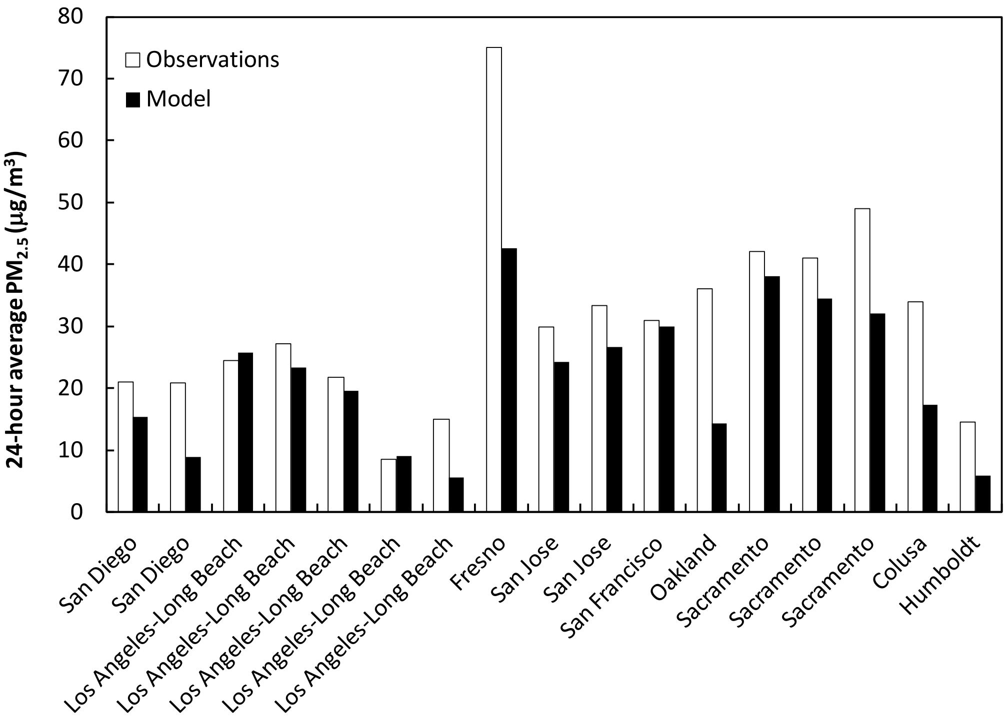


Figure 34 Modeled and observed 24-hour average $PM_{2.5}$ concentrations for December 7, 2005 at selected locations

5.3 Air Quality Impacts of Biomass Scenarios

5.3.1 General Air Pollution Dynamics

To enable understanding the presented simulation results, some of the processes that impact atmospheric ozone and particle concentrations are briefly discussed here.

<u>Ozone:</u>

Ozone (O_3) is a secondary pollutant; it is not directly emitted, but rather is formed in the atmosphere through photochemical reactions of other pollutants. The formation of ozone is initiated by the photolysis of nitrogen dioxide (NO_2, a component of NO_X) in reaction R1:

$$NO_2 + h\nu \rightarrow NO + O \qquad (R1)$$

$$O + O_2 \rightarrow O_3 \qquad (R2)$$

$$NO + O_3 \rightarrow NO_2 + O_2 \qquad (R3)$$

Photolysis of NO_2 produces a single atom of oxygen (O) that reacts readily with molecular oxygen (O_2) present in the atmosphere, producing ozone by reaction R2. In the absence of other components, ozone is consumed by its reaction with NO to produce NO_2 and O_2 again by reaction R3, the ozone titration reaction. During the day, ozone also produces hydroxyl radical via photolysis and water addition by reaction R4:

$$O_3 + H_2O + h\nu \rightarrow O_2 + 2\,OH \qquad \text{(R4)}$$

VOC in the atmosphere can provide a catalyst to recycle NO back to NO_2 without undergoing ozone titration, hence contributing to the build-up of ozone. For example, an alkane VOC has a carbon-hydrogen bond (R-H) that can react with OH by reacti0on R5 to form H_2O and an alkyl radical R, which then reacts with NO to reform NO_2 by reaction R6.

$$R\text{-}H + OH \rightarrow R + H_2O \qquad \text{(R5)}$$

$$R + NO + O_2 \rightarrow RO + NO_2 \qquad \text{(R6)}$$

Finally, ozone production can also be terminated by reaction R7, the combination of NO_2 with OH to form nitric acid (HNO_3), which can deposit to surfaces, effectively removing NO_2 from the atmosphere (Jacob, 1999).

$$OH + NO_2 \rightarrow HNO_3 \qquad \text{(R7)}$$

Ozone formation is not a linear process. Ozone concentrations depend on NO_X concentrations, but also on a complex system of reactions that compete to increase (reactions R1, R2 and R6) and decrease (reactions R3 and R7) ozone. In Los Angeles, emissions of NO_X are high enough that consumption reactions prevail over production of ozone. Under these conditions, referred as a VOC-limited regime, an increase in VOC emissions tends to increase ozone concentrations, but increases in NO_X emissions can lead to a decrease in ozone (Jacob, 1999). This phenomenon has been regularly observed in the South Coast Air Basin during weekends, when emissions of NO_X are typically lower than on weekdays but measured ozone concentrations are statistically higher than during weekdays (Qin *et al*. 2004). In other areas where NO_X emissions are more moderate than in Los Angeles, such as the San Joaquin Valley, conditions for ozone build-up prevail, and an increase in NO_X emissions generally produces an increase in ozone concentration.

Particulate Matter:

Unlike ozone, particulate matter (PM) is both emitted and formed in the atmosphere. Main sources of particulate matter emissions include combustion, suspension of material from natural processes and human activity, and from wear and tear of tires and brakes. Fine particles may be formed by the reaction of nitric and sulfuric acid with ammonia to form ammonium nitrates and ammonium sulfates. Because ammonia emissions from cattle and agricultural operations can be high, formation of ammonium nitrate and sulfates is an important PM source in the Central Valley and in Riverside and San Bernardino Counties where those activities are common. In general, increasing NO_X emissions leads to greater formation of atmospheric nitric acid and hence, an increase in secondary PM formation.

5.3.2 Air Quality Impacts

To illustrate the potential air quality impacts of biomass use for biopower and fuel production a baseline case, and four different scenarios are simulated. The baseline case assumes that current biomass installations are operating to produce power. The total biopower capacity in the state is 1.26 GW. The four cases simulated are the following:

- No biomass case, which removes the emissions from current biomass installations. This scenario is simulated to evaluate the contribution of current biomass facilities on air quality. The biopower capacity removed from the state is compensated with an increase in power production in the state.

- Maximum potential for biopower production with current technology (group A). The total biopower capacity in the state is 4.66 GW. This scenario represents the worst case scenario as it assumes the highest penetration of biomass use with the highest emissions for biopower production.

- Maximum potential for biopower production with technology and emissions upgrade (group B). The total biopower capacity in the state is 4.66 GW. This scenario represents the best case scenario for biopower production, as it assumes the highest penetration of biomass use with the lowest emissions for biopower production. This cases illustrates the potential air quality benefits of technology improvements with respect to the worst case.

- Maximum production of CNG from biomass for vehicle consumption (group C). This scenario represents the best case for GHG emissions. It assumes that 16% of gasoline vehicles are converted to CNG vehicles. Emissions from gasoline marketing in California are reduced by 16%. Emissions from petroleum refining are not modified, because it is assumed that the refining capacity will remain the same, and the excess gasoline will be exported

The emissions resulting from the biomass facilities are spatially allocated in the modeling domain. For the air quality impacts it is assumed that the existing facilities will absorb the increase in biomass capacity. The increase in biopower capacity assumed in the maximum potential biopower cases is then scaled up from the existing facilities. This approach concentrates emissions from biopower in some locations, which could overestimate the air quality impacts of some facilities. In addition to emissions from conversion, emissions from forest residue collection are also included. The spatial allocation of collection and transport is based on the forest residue potential at a county level and location of rural and urban roads in each county. Figure 35 illustrate the spatial allocation of biopower facilities and collection and transport of forest residue.

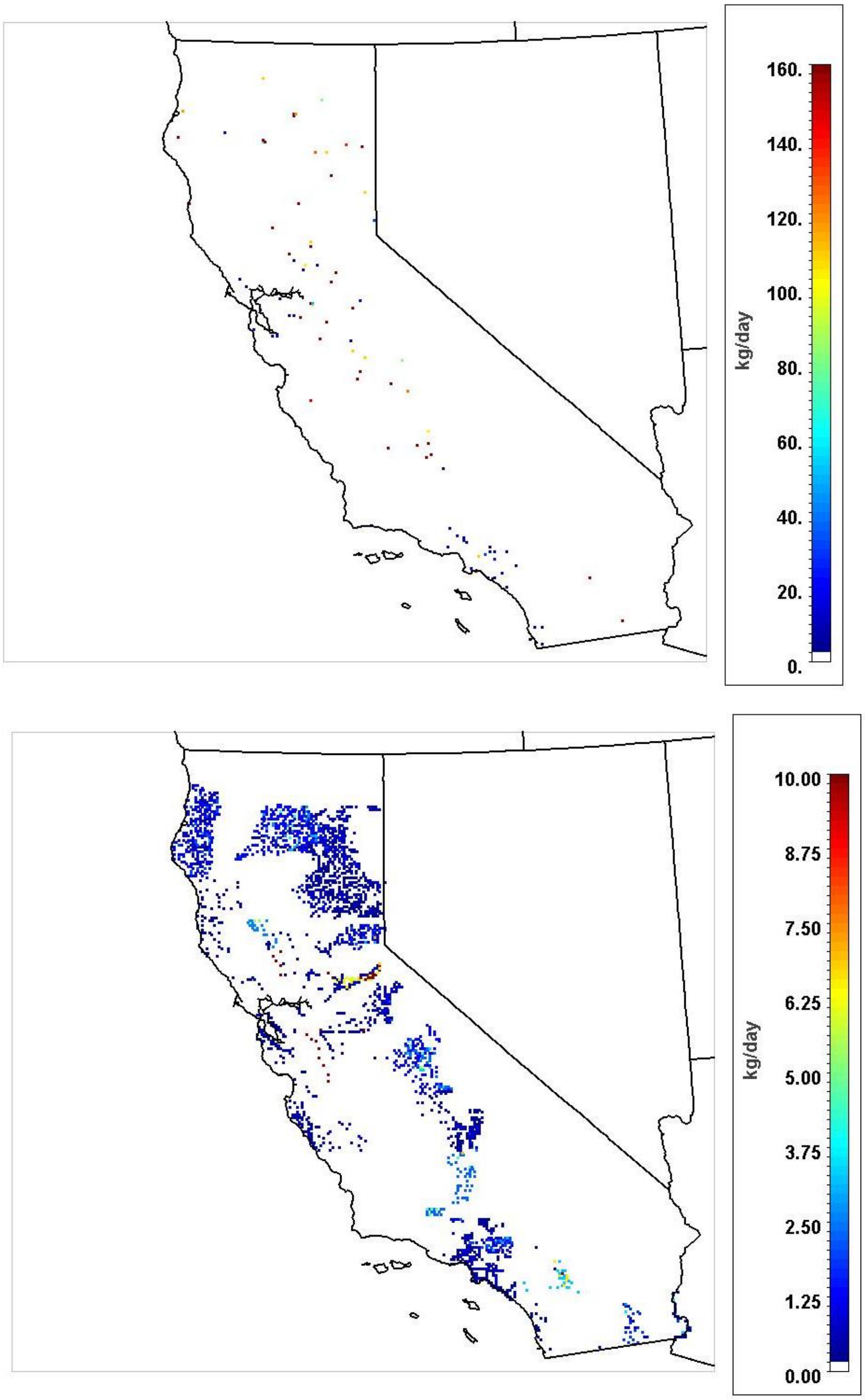


Figure 35: Locations of emissions from biopower production for the Maximum potential for biopower production with current technology (group A). Top: NO_X emissions from biopower facilities. Bottom: NO_X emissions from forest residue collection

The air quality results are discussed having the baseline case as reference. Air quality impacts are expressed as the difference between a study case minus the baseline case. Analysis of ozone is based on the difference of ozone concentration at the peak. Analysis of $PM_{2.5}$ is based on average 24-hour difference between the cases. Simulations are conducted for two different episodes: a one-week episode in July, which represents a high ozone event with high PM concentrations, and a one-week episode in December, which represents a high PM episode, with low ozone concentrations. These simulations are meant to represent high smog events, for both summer and winter, to illustrate potential maximum air quality impacts. Namely, the impacts presented here should be considered as upper bounds for potential air quality impacts from biomass use. In spring or fall, during weather conditions that are not conducive to high pollutant concentrations, effects of these scenarios would be lower than what is presented here.

Figure 36 presents the impacts on ozone concentration produced by the four scenarios for the summer episode. Table 25 presents the average change (Mean), and the maximum decreases (Min) and increases (Max), for ozone and $PM_{2.5}$ in each air basin for all scenarios. The No Biomass case leads to reduction in ozone concentrations in most of the northern half of the state (Figure 36a). Decreases in ozone are due to the removal of biopower plants. Emissions from added central power generation to compensate for the loss of 1.26 GW due not cause a noticeable effect on ozone concentrations. Decreases surpass 3 ppb, which are important in areas like the San Joaquin Valley, which suffers from constant high ozone concentrations throughout the summer months.

As expected, the case with Maximum biopower production with current technology experiences the highest impacts on ozone concentration (Figure 36b). Increases in peak ozone occur in large areas of Sacramento and San Joaquin Valley, the Mountain counties basin, and in the Salton Sea air basin in Southern California. Increases in ozone are localized around the biopower facilities and downwind areas, and the magnitude of the increases exceeds 6 ppb. These increases in ozone concentration could seriously hinder the effort of air pollution control districts to attain ozone standards in areas like the Central Valley.

The case of Maximum biopower production with technology and emissions upgrade illustrates how emission controls could minimize the impacts of biopower production on air quality (Figure 36c). The effect of this case on ozone concentration results in changes in ozone concentrations along the Central Valley that are 1 ppb or less. The increase in emissions from biopower production is offset by decreases in the emissions from the existing biopower plants. The result is that there are some areas in the central valley that experience decreases of over 1 ppb in peak ozone concentrations (shown in Table 25).

The case of Maximum production of CNG from biomass for vehicle consumption (group C) illustrates the benefits of switching from biopower production to fuel production (Figure 36d). The emissions from current biomass facilities are significantly reduced due to a much less emission-intensive CNG production. In addition, emissions from gasoline marketing, which are mostly VOC emissions, are reduced. As a result, ozone concentrations are reduced throughout most of the state, achieving reductions similar to the No Biomass case. Reductions in peak ozone are on the order of 4 pbb in areas close to some biopower plants, in the Sacramento and San Joaquin Valleys (noted in Table 25). There are two distinct regions in the South Coast Air

Basin and San Diego, where ozone increases by nearly 5 ppb. This is due to the VOC-limited regime that predominates in those two regions. In a VOC-limited regime, moderate decreases in NO_X emissions lead to an increase in ozone concentrations.

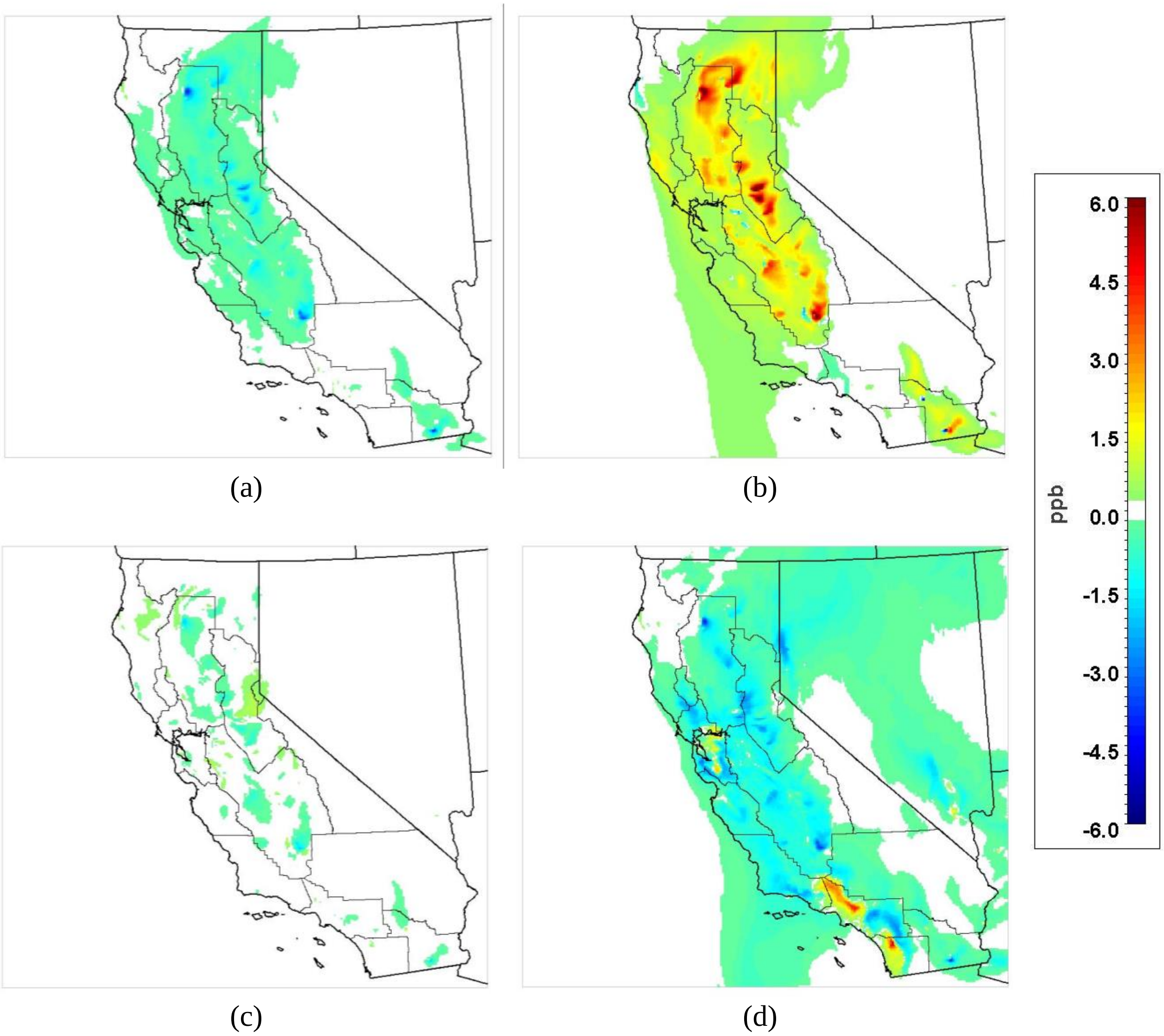
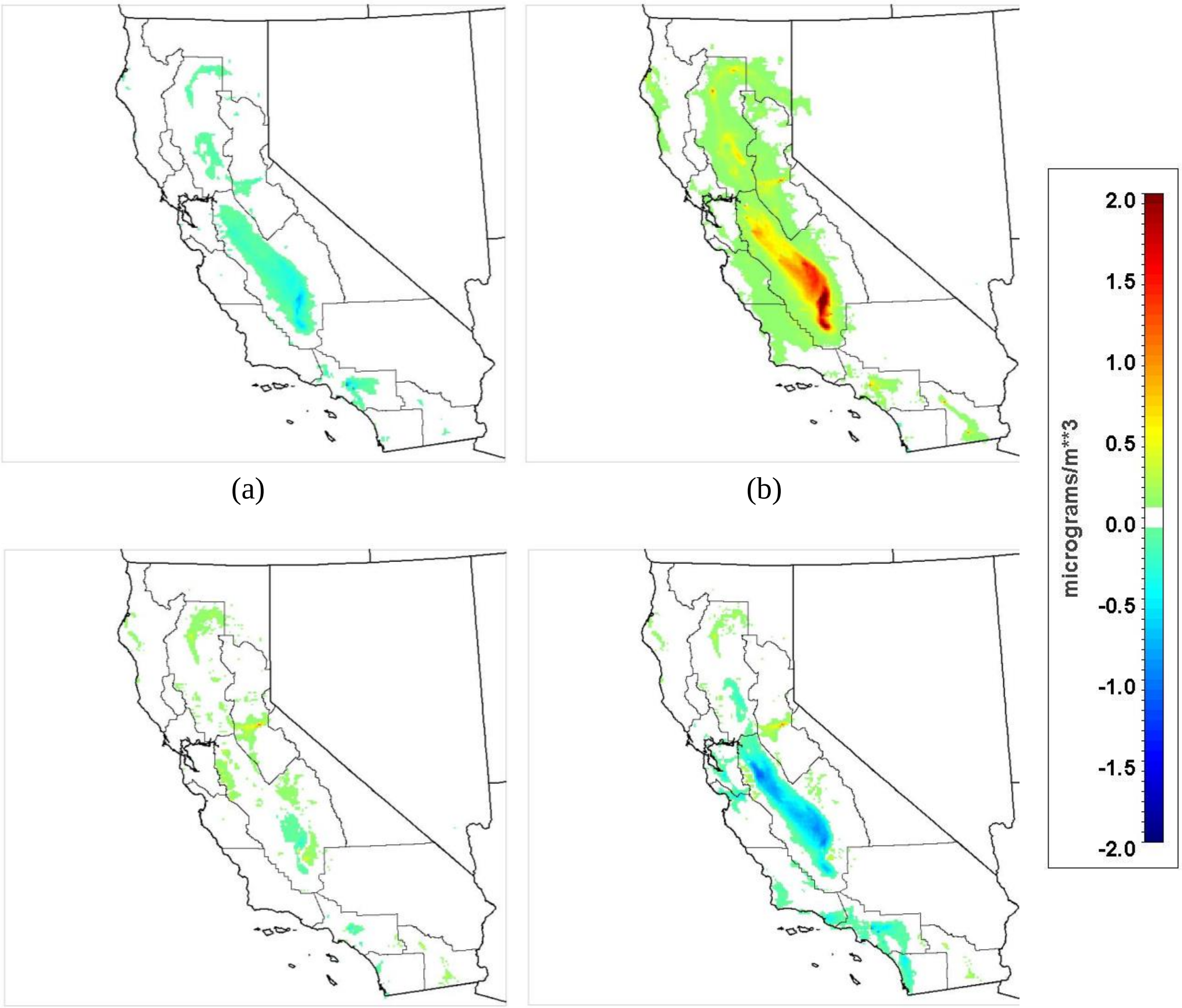


Figure 36: Changes in peak ozone concentrations due to biomass scenarios in a summer episode with respect to the baseline case: (a) No Biomass Case, (b) Maximum biopower production with current technology, (c) Maximum biopower production with enhanced technology, (d) Maximum production of CNG from biomass for vehicle consumption.

Figure 37 presents the effects of the four scenarios on 24-hour average $PM_{2.5}$ in the summer episode. As in the case of ozone concentration, the worst case as expected is the scenario with Maximum biopower production with current technology. The greatest changes in PM concentrations occur in the Central Valley. Even though biopower production and forest residue collection generates emissions of PM, the biggest effects on PM are due to the formation of ammonium nitrate. Nitric acid is formed from the oxidation of NO_X, and then reacts with ammonia present in agricultural regions such as the San Joaquin Valley. Removal of biopower production in the No Biomass case leads to maximum reductions of $PM_{2.5}$ concentrations that are less than 1 $\mu g/m^3$ (Figure 37a). Conversely, the case with maximum potential with current technology produces increases in $PM_{2.5}$ that exceed 2 $\mu g/m^3$ in areas around Bakersfield and Visalia (Figure 37b). As shown in Table 25, the San Joaquin Valley experiences the highest increases in $PM_{2.5}$ amongst all air basins in California. This is important to note as the San Joaquin Valley experience high $PM_{2.5}$ concentrations throughout the year, and efforts to curb PM2.5 concentrations could be hindered by widespread use of highly emitting biomass technologies.



(a) (b)

(c) (d)

Figure 37: Changes in 24-hour average $PM_{2.5}$ concentrations due to biomass scenarios in a summer episode: (a) No Biomass Case, (b) Maximum biopower production with current technology, (c) Maximum biopower production with enhanced technology, (d) Maximum production of CNG from biomass.

The effect of technology upgrade is minimal as well for $PM_{2.5}$, with changes that are less than 0.5 μg/m^3(Figure 37c). Finally, the effect of switching from biopower generation to CNG production shows moderate decreases in $PM_{2.5}$ of 1 μg/m^3 in the Central Valley and the South coast Air Basin and decreases of less than 1 μg/m^3 in San Diego, South Central and San Francisco basins (Figure 37d).

Table 25: Changes in peak O_3 and 24-hour average $PM_{2.5}$ in all air basins of California due to biomass scenarios in a summer episode

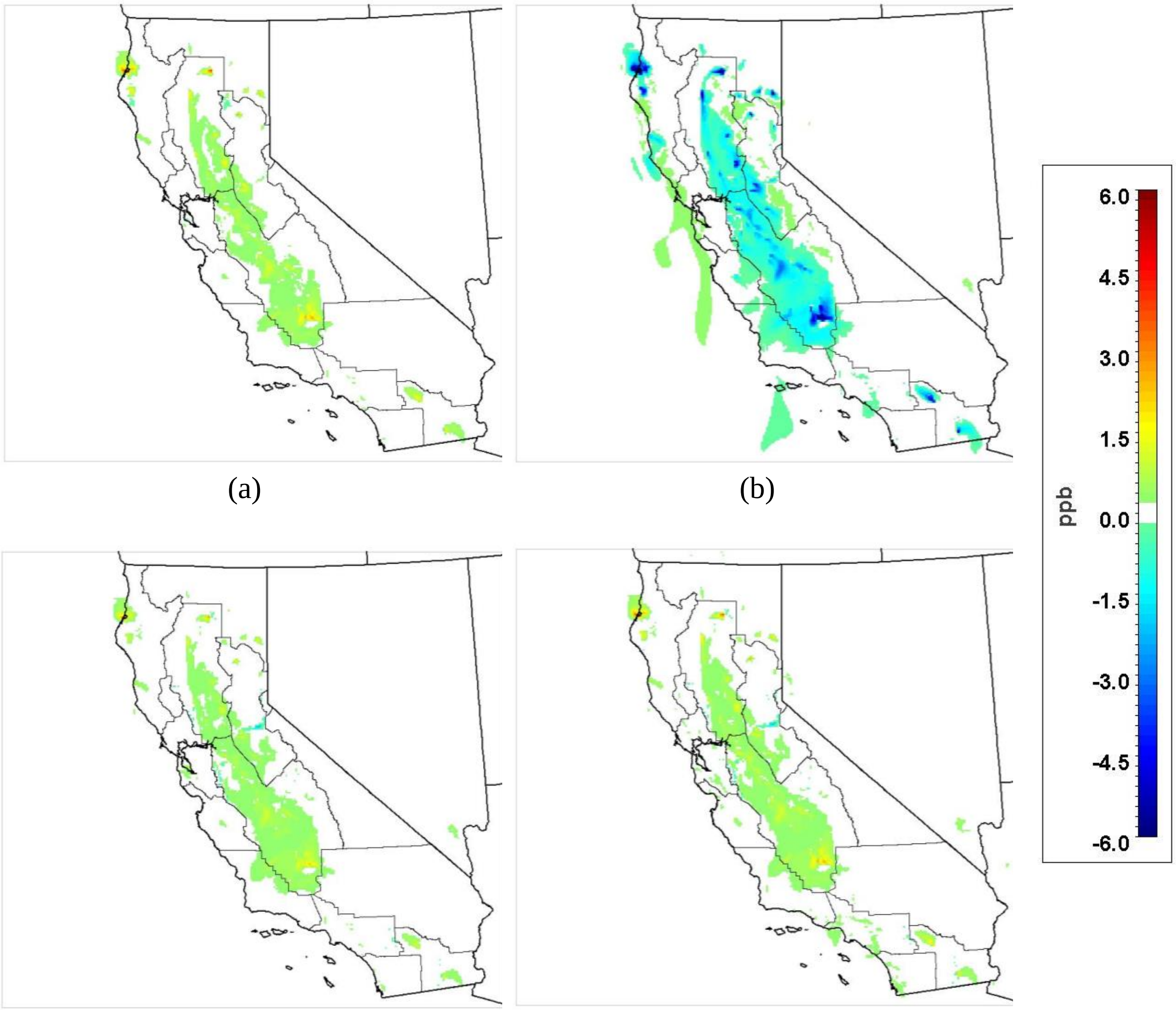
		ΔO_3 (ppb)			**Δ$PM_{2.5}$ (μg/m^3)**		
Case	**Air Basin**	**Mean**	**Min**	**Max**	**Mean**	**Min**	**Max**
No Biomass							
	North Coast	-0.1	-0.6	0.5	0.0	-0.1	0.0
	Northeast Plateau	-0.4	-2.1	0.0	0.0	-0.1	0.0
	Sacramento Valley	-0.5	-4.0	-0.1	0.0	-0.3	0.0
	Mountain Counties	-0.5	-3.6	-0.1	0.0	-0.3	0.0
	Lake County	-0.2	-0.3	-0.2	0.0	0.0	0.0
	Lake Tahoe	-0.3	-0.4	-0.1	0.0	-0.1	0.0
	Great Basin Valleys	0.0	-0.7	0.0	0.0	0.0	0.0
	San Joaquin Valley	-0.4	-3.5	0.7	-0.1	-0.8	0.0
	North Central Coast	-0.2	-0.6	0.0	0.0	-0.1	0.0
	Mojave Desert	0.0	-0.8	0.1	0.0	-0.2	0.0
	South Central Coast	-0.1	-0.4	0.1	0.0	-0.2	0.0
	Salton Sea	-0.2	-4.2	1.2	0.0	-0.3	0.1
	San Francisco Bay	-0.3	-0.6	-0.1	0.0	-0.1	0.0
	South Coast	0.0	-0.3	0.3	0.0	-1.1	0.1
	San Diego County	0.0	-0.1	0.2	0.0	-0.2	0.3
Maximum biopower production with current technology							
	North Coast	0.5	-1.5	1.8	0.0	0.0	0.4
	Northeast Plateau	1.1	0.0	5.5	0.0	0.0	0.4
	Sacramento Valley	1.6	-1.6	7.3	0.1	0.0	1.2
	Mountain Counties	1.5	-0.5	9.6	0.1	0.0	1.1
	Lake County	0.7	0.5	1.1	0.0	0.0	0.1
	Lake Tahoe	1.0	0.5	1.4	0.1	0.0	0.3
	Great Basin Valleys	0.1	0.0	2.3	0.0	0.0	0.1
	San Joaquin Valley	1.1	-2.7	7.2	0.3	0.0	2.9
	North Central Coast	0.6	-0.3	1.6	0.1	0.0	0.3
	Mojave Desert	0.1	-0.4	1.8	0.0	0.0	0.1
	South Central Coast	0.3	-0.3	1.0	0.1	0.0	0.2
	Salton Sea	0.6	-9.1	4.3	0.0	0.0	1.1
	San Francisco Bay	0.7	0.3	1.5	0.1	-0.1	0.3
	South Coast	0.0	-1.2	0.3	0.0	0.0	1.1
	San Diego County	0.0	-0.2	0.4	0.0	-0.8	0.2

Table 25 (continued): Changes in peak O_3 and 24-hour average $PM_{2.5}$ in all air basins of California due to biomass scenarios in a summer episode

		ΔO_3 (ppb)			$\Delta PM_{2.5}$ ($\mu g/m^3$)		
Case	**Air Basin**	**Mean**	**Min**	**Max**	**Mean**	**Min**	**Max**
Maximum biopower production with enhanced technology							
	North Coast	0.0	-0.2	0.4	0.0	0.0	0.2
	Northeast Plateau	0.0	-0.8	0.3	0.0	0.0	0.1
	Sacramento Valley	-0.1	-2.0	0.4	0.0	0.0	0.5
	Mountain Counties	0.0	-1.2	1.0	0.0	-0.1	1.0
	Lake County	0.0	-0.1	0.4	0.0	0.0	0.1
	Lake Tahoe	0.5	0.2	0.8	0.0	0.0	0.3
	Great Basin Valleys	0.0	-0.4	0.5	0.0	0.0	0.1
	San Joaquin Valley	-0.1	-1.9	1.1	0.0	-0.3	0.9
	North Central Coast	-0.1	-0.4	0.0	0.0	0.0	0.1
	Mojave Desert	0.0	-0.4	0.2	0.0	0.0	0.1
	South Central Coast	-0.1	-0.2	0.1	0.0	-0.1	0.0
	Salton Sea	-0.1	-2.1	1.0	0.0	0.0	0.5
	San Francisco Bay	-0.1	-0.3	0.5	0.0	-0.1	0.3
	South Coast	0.0	-0.3	0.3	0.0	-0.5	0.4
	San Diego County	0.0	-0.1	0.2	0.0	-0.8	0.0
Maximum production of CNG from biomass							
	North Coast	-0.2	-2.2	0.5	0.0	-0.1	0.2
	Northeast Plateau	-0.5	-2.6	0.1	0.0	0.0	0.1
	Sacramento Valley	-0.8	-4.1	1.7	0.0	-0.3	0.5
	Mountain Counties	-1.0	-2.8	0.3	0.0	-0.4	1.0
	Lake County	-1.3	-2.5	0.0	0.0	0.0	0.1
	Lake Tahoe	-0.1	-0.6	0.3	0.0	0.0	0.3
	Great Basin Valleys	-0.1	-1.1	0.1	0.0	0.0	0.1
	San Joaquin Valley	-0.9	-3.8	3.1	-0.2	-1.1	0.9
	North Central Coast	-0.9	-1.9	0.2	0.0	-0.3	0.1
	Mojave Desert	-0.3	-1.8	3.8	0.0	-0.2	0.1
	South Central Coast	-0.9	-2.6	2.0	0.0	-0.6	0.0
	Salton Sea	-0.4	-4.3	1.2	0.0	0.0	0.5
	San Francisco Bay	-0.9	-3.1	2.3	0.0	-0.6	0.3
	South Coast	-0.2	-2.8	5.4	-0.1	-1.0	0.2
	San Diego County	0.1	-1.9	4.8	0.0	-0.5	0.3

The effects of the biomass scenarios on ozone concentration in the winter episode are shown in Figure 38. Ozone dynamics in the winter cases are practically the opposite of the summer cases. In general, winter provides shorter days with much lower solar radiation, which is needed to photolyze NO_X in order to generate ozone. With less formation of ozone in the winter, NO_X

also reacts with ozone and acts as an ozone sink. The result is that increases in NO_X emissions in the winter lead to decreases in ozone concentrations, and vice versa. The No Biomass cases causes increases in ozone concentration around the biopower plants, due to the removal of NO_X emissions (Figure 38a). As shown in Table 26, maximum increases in ozone in the Central Valley (Sacramento, San Joaquin valleys and mountain counties basin) are higher than 2 ppb.



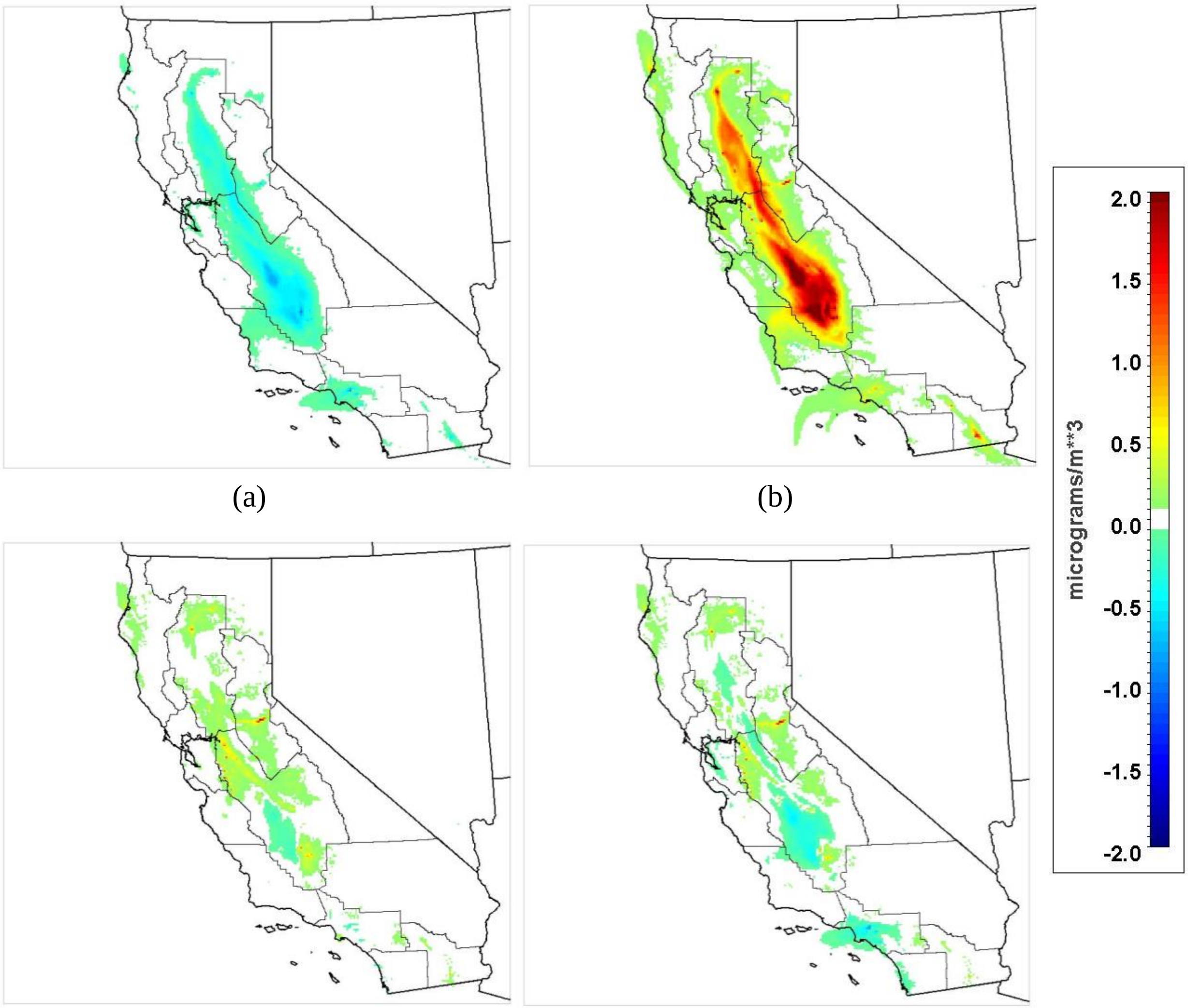
(a) (b)

(c) (d)

Figure 38: Changes in peak ozone concentrations due to biomass scenarios in a winter episode: (a) No Biomass Case, (b) Maximum biopower production with current technology, (c) Maximum biopower production with enhanced technology, (d) Maximum production of CNG from biomass.

Similar increases occur in the cases with technology upgrades (Figure 38c) and with CNG for vehicles (Figure 38d), because the effect of reducing the emissions from current facilities dominate the overall change in emissions. The case with Maximum potential with current technology produces distinct decreases in ozone concentrations of up to 6 ppb in the vicinity of some biopower plants. Even though these decreases in peak ozone concentrations are significant, they occur in the winter when ozone concentrations are low and do not pose an air quality problem.

Figure 39 presents the effects of the four scenarios on 24-hour average $PM_{2.5}$ during the winter episode. Table 26 presents the average change (Mean), and the maximum decreases (Min) and increases (Max), for ozone and $PM_{2.5}$ in each air basin for all scenarios in the winter episode. Unlike ozone, formation of PM dynamics follows similar patterns in both summer and winter episodes. The No Biomass case produces decreases of up to 1 $\mu g/m^3$ in 24-hour average $PM_{2.5}$ concentrations along the Central Valley, due to the removal of NO_X emissions from biopower plants (Figure 39a). The case with Maximum potential with current technology produces increases of nearly 4 $\mu g/m^3$ in most of the San Joaquin Valley and nearly 4 $\mu g/m^3$ in the Sacramento Valley (noted in Table 26).



(a) (b)

(c) (d)

Figure 39: Changes in 24-hour average PM$_{2.5}$ concentrations due to biomass scenarios in a winter episode: (a) No Biomass Case, (b) Maximum biopower production with current technology, (c) Maximum biopower production with enhanced technology, (d) Maximum production of CNG from biomass.

In addition, localized increases of 1-2 μg/m^3 appear in the South Coast and Salton Sea air basins (Figure 39b). The other two cases – technology upgrade and shift to CNG for vehicles – present similar trends (Figure 39c and d). Both cases experience moderate decreases of less 0.5 μg/m^3 in PM$_{2.5}$ in some areas of the San Joaquin Valley, and increases of up to 1 mg/m^3 in some areas of the Central Valley east from the Bay Area. The increases are attributed to direct emissions from collection and transport of forest residue.

Table 26: Changes in peak O_3 and 24-hour average PM2.5 in all air basins of California due to biomass scenarios in a winter episode

		ΔO_3 (ppb)			$\Delta PM_{2.5}$ ($\mu g/m^3$)		
Case	**Air Basin**	**Mean**	**Min**	**Max**	**Mean**	**Min**	**Max**
No Biomass							
	North Coast	0.0	-0.2	2.9	0.0	-0.2	0.0
	Northeast Plateau	0.0	-0.2	2.1	0.0	-0.2	0.0
	Sacramento Valley	0.1	-0.3	4.2	-0.1	-0.7	0.0
	Mountain Counties	0.1	-0.2	2.5	-0.1	-0.6	0.0
	Lake County	0.0	0.0	0.0	0.0	0.0	0.0
	Lake Tahoe	0.0	0.0	0.3	0.0	-0.1	0.0
	Great Basin Valleys	0.0	-0.1	0.0	0.0	0.0	0.0
	San Joaquin Valley	0.2	-0.1	2.7	-0.2	-1.1	0.0
	North Central Coast	0.0	-0.2	0.4	0.0	-0.2	0.0
	Mojave Desert	0.0	-0.1	1.1	0.0	-0.1	0.0
	South Central Coast	0.0	0.0	0.5	0.0	-0.2	0.1
	Salton Sea	0.1	-0.4	2.0	0.0	-0.6	0.1
	San Francisco Bay	0.0	-0.4	0.2	0.0	-0.2	0.1
	South Coast	0.0	0.0	0.4	-0.1	-0.9	0.1
	San Diego County	0.0	-0.1	0.2	0.0	-0.2	0.2
Maximum biopower production with current technology							
	North Coast	-0.1	-8.3	0.5	0.1	0.0	0.6
	Northeast Plateau	0.0	-7.5	0.6	0.0	0.0	0.6
	Sacramento Valley	-0.5	-13.3	0.3	0.4	0.0	2.8
	Mountain Counties	-0.3	-8.9	0.4	0.2	0.0	1.9
	Lake County	0.1	-0.1	0.1	0.0	0.0	0.1
	Lake Tahoe	0.0	-0.9	0.1	0.0	0.0	0.5
	Great Basin Valleys	0.0	0.0	0.3	0.0	0.0	0.1
	San Joaquin Valley	-0.9	-6.7	0.4	0.7	0.0	3.9
	North Central Coast	-0.1	-1.4	0.5	0.1	0.0	0.7
	Mojave Desert	0.0	-3.5	0.1	0.0	0.0	0.2
	South Central Coast	-0.2	-1.5	0.1	0.1	-0.2	0.7
	Salton Sea	-0.2	-5.9	0.2	0.1	-0.1	1.6
	San Francisco Bay	0.1	-0.8	1.0	0.1	-0.2	0.8
	South Coast	-0.1	-0.5	0.1	0.1	0.0	0.9
	San Diego County	0.0	-0.2	0.2	0.0	-0.7	0.2

Table 26 (continued): Changes in peak O_3 and 24-hour average $PM_{2.5}$ in all air basins of California due to biomass scenarios in a winter episode

		ΔO_3 (ppb)			**$\Delta PM_{2.5}$ ($\mu g/m^3$)**		
Case	**Air Basin**	**Mean**	**Min**	**Max**	**Mean**	**Min**	**Max**
Maximum biopower production with enhanced technology							
	North Coast	0.1	-0.2	2.0	0.0	0.0	0.2
	Northeast Plateau	0.0	-0.2	1.5	0.0	0.0	0.2
	Sacramento Valley	0.1	-0.6	3.0	0.1	0.0	1.1
	Mountain Counties	0.1	-2.1	1.8	0.1	-0.1	1.9
	Lake County	0.0	-0.1	0.1	0.0	0.0	0.1
	Lake Tahoe	0.0	-1.0	0.0	0.0	0.0	0.5
	Great Basin Valleys	0.0	-0.1	0.2	0.0	0.0	0.1
	San Joaquin Valley	0.3	-2.0	2.1	0.1	-0.2	2.4
	North Central Coast	0.1	-0.1	0.4	0.0	0.0	0.2
	Mojave Desert	0.0	-0.2	0.7	0.0	0.0	0.1
	South Central Coast	0.1	0.0	0.5	0.0	0.0	0.1
	Salton Sea	0.0	-0.4	1.3	0.0	0.0	0.8
	San Francisco Bay	0.0	-0.8	0.9	0.0	-0.3	0.8
	South Coast	0.0	-0.4	0.4	0.0	-0.3	0.4
	San Diego County	0.0	0.0	0.5	0.0	-0.7	0.0
Maximum production of CNG from biomass							
	North Coast	0.1	-0.2	2.8	0.0	-0.1	0.2
	Northeast Plateau	0.0	-0.2	2.1	0.0	0.0	0.2
	Sacramento Valley	0.2	-0.7	4.1	0.0	-0.2	1.1
	Mountain Counties	0.1	-2.1	2.5	0.1	-0.2	1.9
	Lake County	0.0	-0.1	0.3	0.0	0.0	0.1
	Lake Tahoe	0.0	-1.0	0.1	0.0	0.0	0.5
	Great Basin Valleys	0.0	-0.1	0.2	0.0	0.0	0.1
	San Joaquin Valley	0.3	-2.0	2.6	0.0	-0.5	2.4
	North Central Coast	0.1	-0.1	0.5	0.0	-0.1	0.1
	Mojave Desert	0.0	-0.2	1.1	0.0	-0.1	0.1
	South Central Coast	0.1	0.0	0.5	0.0	-0.1	0.1
	Salton Sea	0.1	-0.6	1.9	0.0	-0.1	0.8
	San Francisco Bay	0.1	-0.8	0.3	0.0	-0.2	0.7
	South Coast	0.1	-0.4	0.5	-0.1	-0.9	0.2
	San Diego County	0.1	0.0	0.4	0.0	-0.3	0.2

6 Conclusion

This study assesses the air quality impacts of new and existing bioenergy capacity throughout the state, focusing on feedstocks, and advanced technologies utilizing biomass resources predominant in each region. The options for bioresources include the production of biopower, renewable NG and ethanol. Emissions of criteria pollutants and greenhouse gases are evaluated for a set of scenarios that span the emission factors for power generation, and the uses of renewable natural gas for vehicle fueling and pipeline injection. Emissions are evaluated for the entire fuel cycle.

From the technically recoverable biomass resources, there is a potential for up to 4.66 GW of biopower that could be installed in the state. With current technology and at the emission levels of current installations, maximum biopower production could increase NO_X emissions by 10% in 2020. Among the alternatives for biomass use, technology upgrades would significantly reduce criteria pollutant emissions. Conversion of biomass to CNG for vehicles would achieve comparable emission reductions of criteria pollutants and minimize emissions of greenhouse gases. One important caveat to note is that the emissions savings quantified in this study are based on CA-GREET 1.8b, which is being used in the calculation of LCFS pathway emissions. A newer version, CA-GREET 2.0, is being considered by ARB to replace the previous version. Total full fuel cycle emissions from electricity production are higher in CA-GREET 1.8b than in CA-GREET 2.0, for GHG and criteria pollutants. This would results in lower full cycle emission savings from biopower production in California.

Emission factors combined with the geospatially-resolved bioenergy outputs (facility locations) are used to generate new emission source locations and magnitudes which are input to the Community Multiscale Air Quality model (CMAQ) to predict regional and statewide temporal air quality impacts from the biopower scenarios. Installing the maximum potential of biopower production with current technology by 2020 would cause increases of over 6 ppb in ozone and 2 $\mu g/m^3$ in PM concentrations in large areas of the Central Valley where ozone and PM concentrations exceed air quality standards constantly throughout the year. Negative effects on PM would be expected in both summer and winter episodes. As suggested by the analysis of emissions, applying technological changes and emission controls would minimize the air quality impacts of biopower generation. And a shift from biopower production to CNG production for vehicles would reduce emissions and air quality impacts further. From a co-benefits standpoint, CNG production for vehicles appears to provide the benefits in terms of air pollutant and GHG emissions, and air quality.

It is clear that the state has enough bioresources to meet the goals of SB1122 and Governor’s plan for renewable power, and that biomass could be a large contributor to the renewable portfolio standard for the state. However, if California is to meet the air quality goals for non-attainment areas like the San Joaquin Valley, it should minimize the impact of using biomass with advanced technologies like fuel cells for biogas and gasification systems for solid residue.

This investigation provides a consistent analysis of air quality impacts and greenhouse gases emissions for scenarios examining increased biomass use. The findings will help inform policy makers and industry with respect to further development and direction of biomass policy and bioenergy technology alternatives needed to meet energy and environmental goals in California. Future research needs should include the collection of more specific emission factors and better characterization of processes for advanced technologies, such as production of renewable synthetic natural gas. For the analysis presented here, emissions and energy balances from generic gasification facilities were assumed. Another area of research related to biomass use would be the in-depth analysis of management of solid waste to maximize recycling, and minimize disposal at landfills. These management strategies could require additional infrastructure and reduce the biogas and biopower yields from landfills.

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Exhibit 12

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

MAR 22 2016

N. Ross Buckenham
ABEC #3 LLC dba Lakeview Dairy Biogas
c/o California Bioenergy, LLC
2828 Routh St, Suite 500
Dallas, TX 75201-1438

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: S-8637
Project Number: S-1143770

Dear Mr. Buckenham:

Enclosed for your review and comment is the District's analysis of ABEC #3 LLC dba Lakeview Dairy Biogas's application for an Authority to Construct for installation of an anaerobic digester system and two 1,468 bhp digester gas-fired IC engines with selective catalytic reduction (SCR) systems for emissions control at Lakeview Farms dairy, at 17702 Bear Mountain Blvd, Bakersfield, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Ramon Norman of Permit Services at (559) 230-5909.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:rn

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

Seyed Sadredin
Executive Director/Air Pollution Control Officer

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San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Digester System and Two Digester Gas-Fired IC Engines with SCR

Facility Name:	ABEC #3 LLC dba Lakeview Dairy Biogas	Date:	March 7, 2016
Mailing Address:	ABEC #3 LLC c/o California Bioenergy, LLC 2828 Routh Street, Suite 500 Dallas, TX 75201-1438	Engineer: Lead Engineer:	Ramon Norman Jerry Sandhu
Contact Person:	N. Ross Buckenham - California Bioenergy/ ABEC #3 LLC		
Telephone:	(214) 849-9886	Cell Phone:	(214) 906-9359
E-Mail:	rbuckenham@calbioenergy.com		
Application #(s):	S-8637-1-0, -2-0, and -3-0		
Project #:	S-1143770		
Deemed Complete:	May 14, 2015		

I. Proposal

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kW. The new digester will be constructed in an area of the existing dairy that is currently used for manure drying and storage. Lakeview Farms dairy will send manure from the dairy to the ABEC #3 LLC anaerobic digesters located on the dairy site. The digester system will produce renewable biogas that will be used to fuel the IC engine generator sets.

ABEC #3 LLC dba Lakeview Dairy Biogas and Lakeview Farms dairy, which are separate companies, are undertaking the project as a partnership. ABEC #3 LLC has provided information supporting that the dairy and the ABEC #3 LLC biogas facility will be separately owned and operated. The following is a summary of some of the information provided by the applicant. The proposed digester system at the dairy will be operated and maintained by ABEC #3 LLC. The responsibility of the dairy will be limited to providing the manure feedstock and disposing of the effluent, which the dairy already must do for compliance with water quality regulations. ABEC #3 LLC will not be involved at all in the dairy's primary activity, production of milk. The feedstock and lease agreements specify that ABEC #3 LLC will build, own, and operate the biogas facility and also allows ABEC #3 LLC to make plant and equipment improvements. The proposed digester gas-fired IC engine generator sets that will be constructed on land leased from the dairy site and will be owned, operated, and maintained by ABEC #3 LLC. ABEC #3 LLC will be solely responsible for ensuring that the digester system and digester gas-fired IC engines comply with all applicable air quality regulations. The generator sets will sell all the power generated to the grid and will not provide any power directly to the dairy. Because the dairy and the proposed digester gas power plant at the site will be separately owned and operated and will have different two-digit Standard Industrial Classification (SIC) codes (Industry Group 24: Dairy Farms for the dairy vs. Industry Group 49: Electric, Gas, And Sanitary Services for the IC engine generator sets), pursuant to Section 3.39 of District Rule 2201, the proposed digester system and the digester gas-fired IC engines will not be part of the dairy agricultural stationary source. Therefore, the digester system and digester gas-fired IC engines will be permitted as a separate non-agricultural stationary source (Facility S-8637).

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (4/21/11)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4701	Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702	Stationary Internal Combustion Engines (11/14/13)
Rule 4801	Sulfur Compounds (12/17/92)
40 CFR Part 60, Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
40 CFR Part 63, Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
CH&SC 41700	Health Risk Assessment
CH&SC 42301.6	School Notice

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)

California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The ABEC #3 LLC Stationary Source (Facility S-8637) is located on Lakeview Farms dairy at 17702 Bear Mountain Blvd, Bakersfield, CA (Mt. Diablo Meridian T 31S, R 26E, Sec 20 in Kern County). The proposed equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

Anaerobic Digester System

An anaerobic digester is a sealed basin or tank that is designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. Anaerobic decomposition results in the conversion of organic compounds in the substrate into methane (CH_4), carbon dioxide (CO_2), and water rather than intermediate Volatile Organic Compounds (VOCs). The gas generated by this process is known as biogas, waste gas, or digester gas. In addition to methane and carbon dioxide, biogas may also contain small amounts of Nitrogen (N_2), Oxygen (O_2), Hydrogen Sulfide (H_2S), and Ammonia (NH_3). Biogas may also include trace amounts of various VOCs that remain from incomplete digestion of the volatile solids in the incoming substrate. Because biogas is mostly composed of methane, the main component of natural gas, the gas produced in the digester can be cleaned to remove H_2S and other impurities and used as fuel.

The proposed anaerobic digester system will be designed to process the manure generated by the cattle at Lakeview Farms dairy. The manure will be flushed from the cow housing areas at the dairy to a mechanical separation system prior to the digester system. This pre-digester mechanical separation system will remove fibrous solids from the manure. After the mechanical separation system, the liquid manure will flow to a sand settling lane that is designed to remove heavy solids by sedimentation. After the separation systems, the liquid manure will gravity flow into the proposed covered lagoon digesters. The liquid effluent from the covered lagoon digesters will be pumped to the existing large storage pond at the dairy from where it can be used to irrigate and fertilize adjacent cropland.

The proposed anaerobic digester system will process the liquid fraction from the dairy manure solid separation system. The anaerobic digester system will consist of an in-ground, covered lagoon anaerobic digester that will be divided into one or more cells. The final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based on borings to locate subsurface sand and groundwater that are required to demonstrate compliance with the requirements of the Regional Water Quality Control Board. The preliminary information submitted by the applicant indicates that the first cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 655 ft long by 262 ft wide at the top, with an average depth of 23 ft, and a side slope (run/rise) of 2.0 and that the second cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 500 ft long by 200 ft wide at the top, with an average depth of 22.75 ft, and a side slope (run/rise) of 2.0. The covered lagoon digester will operate at ambient temperatures; however, the covered lagoon digester may utilize heat from the engines to warm the substrate to promote more efficient anaerobic digestion. An area located east of the existing lagoons at the dairy, which is currently used for drying and storage of solid manure, will be excavated to create the proposed covered lagoon anaerobic digester.

The applicant indicates that the lagoon cell(s) will be covered in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 – Roofs and Covers. The bottom and the walls of the new lagoon cell(s) will be lined with high-density polyethylene (HDPE) membranes and a gas collection system will be installed. The new lagoon cells will be fitted with HDPE covers. The gas collection system will consist of perforated piping under the HDPE covers of the covered lagoons.

The covered lagoon digester will be equipped with an air injection system for removal of H_2S from the digester gas. The continuous injection of controlled quantities of air under the digester covers increases the amount of oxygen in the space under the digester covers and in the surface layer of the digester liquid, which facilitates oxidation of sulfides in the digester gas and at the surface of the liquid to elemental sulfur and water. Injection of air also promotes biological removal of H_2S from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize H_2S to elemental sulfur. The digester gas will be captured by the covered lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional H_2S and for removal of moisture. The gas will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system. When the gas cannot be used in the engines, the digester gas will collect under the lagoon covers. As the gas collects under the lagoon covers, the pressure in the digesters will rise. In rare emergency situations when the gas cannot be combusted in the engines for an extended period, the pressure will cause the relief valves to open and release the digester gas, composed primarily of methane and carbon dioxide, into the atmosphere. As the pressure decreases, the gas relief valves will automatically close and normal operation will proceed.

When operating at full capacity, the digester system is expected to produce an average of 360,000 ft^3 of biogas per day. The applicant has indicated that the biogas produced by the covered lagoon digester will be composed of approximately 60-70% methane and 30-40% carbon dioxide. Because the proposed digester system will be able to store the biogas for extended periods under the digester covers and the proposed engines at the ABEC #3 LLC Stationary Source (Facility S-8637) will have more than sufficient capacity to combust all of the gas generated, no flare is being proposed for the digester installation at this facility.

Covered Lagoon Anaerobic Digester Measurements

The measurements given below for the proposed covered lagoon anaerobic digester cells at the ABEC #3 LLC Stationary Source (Facility S-8637) are based on the preliminary information provided by the applicant. As discussed above, the final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based compliance with the requirements of the Regional Water Quality Control Board.

- 1st Covered Lagoon Anaerobic Digester Cell
    - Top Dimensions: 655 ft long x 262 ft wide
    - Average Depth: 23 ft
    - Side Slope (run/rise): 2.0
    - Approximate Volume (not including 2 ft. freeboard): 2,705,808 ft^3 (~20,239,444 gal)
- 2nd Covered Lagoon Anaerobic Digester Cell
    - Top Dimensions: 500 ft long x 200 ft wide
    - Average Depth: 22.75 ft
    - Side Slope (run/rise): 2.0
    - Approximate Volume (not including 2 ft. freeboard): 1,613,210 ft^3 (~10,612,380 gal)

Digester Gas-Fired IC Engines

The applicant is proposing to install two 1,468 bhp GE Jenbacher model J 320 GS-C82 lean burn digester gas-fired IC engines (or equivalent engines of equal or lesser rating approved by the District, such as 1,412 bhp Caterpillar model A3516A+ IC engines or 1,431 bhp Dresser Rand Guascor model SFGLD 560 IC engines). Each engine will be equipped with an SCR system and will power an electrical generator that will produce up to 1,059 kWe. Digester gas, which consists mostly of methane, the main component of natural gas, will be combusted in the IC engines to produce power. After initial removal of H_2S in the digester system, the digester gas will be piped to the gas conditioning system for polishing to remove H_2S using an iron sponge and/or activated carbon H_2S scrubber or an equivalent H_2S removal system and for removal of moisture. The digester gas will then be piped to the IC engines for use as fuel. The engines will power electrical generators that will produce power to be sold to a utility. Excess heat from the engines will be used in the first covered lagoon anaerobic digester (West

Lagoon Digester) to promote more efficient production of digester gas. The engines will be permitted to operate up to 24 hr/day and 8,760 hr/year.

In addition to the use of digester gas as fuel, the engines will also be permitted to use natural gas as fuel for no more than 96,000 kW-hrs of operation during initial utility interconnect testing in the event that insufficient digester gas is available for the engines at the time that the required utility testing is scheduled. The engines will remain subject to the same emission limits during the limited period that allows the use of natural gas fuel for required utility testing.

V. Equipment Listing

S-8637-1-0: ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

S-8637-2-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

S-8637-3-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

Digester System (S-8637-1-0)

The digester system will be equipped with a pressure-vacuum (PV) relief valves or an emergency venting system. The digester gas will be scrubbed to remove hydrogen sulfide (H_2S) and will be used to fuel engines to generate electricity. Combustion of the digester gas in the engines will convert any VOCs present in the gas into carbon dioxide and water. As stated above, because the digester system will be able to store the gas for extended periods and the engines will have more than enough capacity to combust all of the gas generated, no flare is being proposed for this digester project.

H_2S Removal

As described above, the covered lagoon anaerobic digester will utilize an air injection system for removal of H_2S from the digester gas. The continuous injection of controlled quantities of air under the lagoon covers increases the amount of oxygen in the space under the digester covers and the surface layer of the liquid in the covered lagoon digester, which facilitates oxidation of sulfides in the digester gas and in the liquid surface to elemental sulfur and water.

The sulfur dissolves in the liquid in the digester and can be removed from the digester system by deposition and filtration. Injection of air also promotes biological removal of H_2S from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize H_2S to elemental sulfur and sulfates that can be removed from the digester system. Use of air injection to remove H_2S from digester gas has been shown to have higher effectiveness in covered lagoon digesters because the large areas under the lagoon covers facilitate contact with the digester gas and lagoon surface, which enables improved oxidation and biological reduction of sulfides. Successful installations of the air injection sulfur removal system have demonstrated significantly reduced operation costs when compared to other methods of sulfur removal.

For final polishing, the digester gas will be sent through an iron sponge H_2S scrubber and/or an activated carbon H_2S scrubber or an equivalent system to remove H_2S from the gas prior to combustion in the proposed engines.

An iron sponge scrubber is comprised of vessel(s) containing iron sponge, which consists of a hydrated form of iron oxide infused onto wood shavings. The wood shavings serve only as a carrier for the iron oxide powder. Iron oxide infused into the wood surface will not wash off or migrate with the gas. As the gas passes through the iron sponge material, the H_2S is removed by the following chemical reaction producing black iron sulfide and water:

$$H_2S + Fe(OH)_2 \longrightarrow FeS + 2H_2O + \text{heat}$$

For the iron sponge to perform effectively, it must be maintained within a defined range of sufficient moisture content. This requirement is typically satisfied if the gas is saturated with water vapor, as is frequently the case with digester gas. If the iron sponge becomes dry, it can be re-wet and remain effective. The iron sponge reaction is not pressure sensitive.

Specially treated activated carbon can also be used to remove H_2S from gas streams. H_2S will be adsorbed as the gas flows through the activated carbon bed. Activated carbon has a large number of pores, which greatly increase the surface area for adsorption. Contaminants in the gas diffuse into these pores and are retained on the carbon surface due to both chemical and physical forces. Activated carbon used for the removal of H_2S is usually treated with chemical bases to increase the holding capacity for H_2S.

The proposed scrubber will consist of enclosed vessels filled with iron sponge and/or treated activated carbon. The digester gas will flow through the scrubber and then to a dryer and chiller to remove moisture. For continuous operation, there will be a secondary unit that will be brought online at specified times or when monitoring indicates that the primary unit is nearing saturation. Valves can be arranged so either bed can operate while the other is serviced. The useful life of the iron sponge and activated carbon vessels will vary depending on the inlet concentration of H_2S, the flow rate, and the mass in the vessels. Before a scrubber is completely spent, it must be regenerated or replaced. Spent iron sponge or activated carbon vessels will be sent to a regeneration facility or to an appropriate disposal facility.

The proposed scrubber will be capable of reducing H_2S concentrations in the digester gas to 40 ppmv or less. Reducing the H_2S concentration in the gas will minimize SO_X emissions from combustion and will also reduce the maintenance requirements for the engines and will protect catalysts from masking, plugging, and poisoning.

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

The proposed engines will be equipped with:

- Turbocharger
- Aftercooler
- Air/Fuel Ratio or an O_2 Controller
- Lean Burn Technology
- Positive Crankcase Ventilation (PCV) or 90% efficient control device
- Selective Catalytic Reduction (SCR)

The turbocharger reduces NO_X emissions from engines by increasing the efficiency and promoting more complete burning of the fuel.

The aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize engine operation and catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

The PCV system or 90% efficient control device reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, pass through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it is converted to ammonia. The ammonia is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

VII. General Calculations

A. Assumptions

- ABEC #3 LLC dba Lakeview Dairy Biogas (Facility S-8637) and Lakeview Farms dairy (Facility S-5254) are separate stationary sources at the same site.
- Because of the high moisture content of separated manure solids, PM emissions from the handling of separated solids for the digester system are considered negligible.
- Because the manure for the digester system will be taken from the mechanical separation system at Lakeview Farms dairy and the digested solids and effluent from the digester system will be returned to Lakeview Farms dairy for use, all emissions from the manure

processed in the digester system will be allocated to the liquid manure handling system at Lakeview Farms dairy.

- The proposed digester system will reduce potential VOC emissions from manure generated by the cattle at Lakeview Farms dairy. Manure that is currently stored in uncovered lagoon(s) and pond(s) will instead be placed in covered ponds at the ABEC #3 LLC facility, thereby decreasing volatilization of compounds from the manure. In a digester, most VOCs present will be converted to methane (an exempt compound) and carbon dioxide further reducing the potential for VOC emissions. Because results of dairy digester analyses have indicated very low VOC content (less than 1% by weight), fugitive VOC emissions from the digester system are assumed to be negligible, consistent with District Policy SSP 2015. During operation, the digester gas will be directed to the engines where the gas will be combusted resulting in the oxidation of gaseous hydrocarbons into carbon dioxide and water. Therefore, VOC emissions from the digester system are considered negligible.
- Molar composition of typical digester gas is about 60% methane and 40% carbon dioxide with trace amounts of hydrogen sulfide, VOC, and other compounds.[1]
- Typical Higher Heating Value for Digester Gas: 600 Btu/scf (Per AP-42 (4/00) - notes to Tables Table 3.1-1, Table 3.1-2b, Table 3.1-7, and Table 3.1-8)
- Typical EPA F-factor for Digester Gas: 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (Estimated based on previous digester gas fuel analyses for source tests)
- Average sulfur content of the scrubbed digester gas: 40 ppmv as H_2S (required as BACT; approximately 2.4 grains/100 scf)
- bhp to Btu/hr conversion: 2,545 Btu/hp-hr
- Thermal efficiency of engines: commonly ≈ 33%
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Molecular weights:
  - NO_X (as NO_2) = 46 lb/lb-mol
  - CO = 28 lb/lb-mol
  - NH3 = 17 lb/lb-mol
  - VOC (as CH_4) = 16 lb/lb-mol
  - SO_X (as SO_2) = 64.06 lb/lb-mol
- Each of the engines will be permitted to operate 24 hours/day and 365 days per year.
- There will be no increase in permitted emissions for the limited use of natural gas for required initial utility testing in the event that sufficient digester gas is not available for the engines at the time that the required initial utility testing is scheduled.
- PM2.5 emissions from the digester gas-fired IC engines are assumed to be equal to PM10 emissions.

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[1] U.S. EPA AgSTAR (http://www2.epa.gov/agstar), "Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities" (November 2011, http://www2.epa.gov/agstar/agstar-market-opportunities-report); American Biogas Council – Frequent Questions (https://www.americanbiogascouncil.org/biogas_questions.asp); "Anaerobic Digestion Overview", David Schmidt, University of Minnesota Department of Biosystems and Agricultural Engineering (http://www.extension.umn.edu/agriculture/manure-management-and-air-quality/manure-treatment/docs/anaerobic-digestion-overview.pdf); and "Anaerobic Digestion of Animal Wastes: Factors to Consider", ATTRA - National Sustainable Agriculture Information Service (https://attra.ncat.org/attra-pub/summaries/summary.php?pub=307)

Assumptions for Commissioning Period

- The applicant has requested that the ATC permits include a commissioning period to allow testing, adjustment, tuning, and calibration of the engines without the SCR systems installed. The duration of the commissioning period shall consist of no more than 120 hours of operation of each engine without an SCR system installed.
- Engine emissions during the commissioning period will be calculated as uncontrolled based on information provided by the engine supplier.

B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include: checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent damage to this equipment. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[2] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

The emission factors for NO_X (1.0 g/bhp-hr), CO (4.85 g/bhp-hr), and VOC (1.0 g/bhp-hr) for the commissioning period are the emission factors provided by the engine supplier for the engines without SCR systems or oxidation catalysts. The emission factors during the commissioning period for SO_X (0.04 g/bhp-hr), PM_{10} (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) after initial installation of the SCR system are assumed to be the same emissions factors as during normal operation. SO_X emissions are based on the maximum sulfur content of the dairy digester gas (required as BACT; approximately 2.4 grains/100 scf). PM_{10} emissions on a lb/MMBtu basis are assumed to be similar to natural gas-fueled IC engines. For more conservative PM_{10} emission calculations, the PM emission factor for rich burn natural gas-fueled engines given in EPA's Compilation of Air Pollutant Emission Factors (AP-42) is used because it is higher than the value for lean burn natural gas-fueled engines listed in EPA AP-42. The ammonia emission factor is based on the ammonia slip limit of 10 ppmv NH_3.

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[2] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/airtoxics/icengines/docs/20120717riceqaupdate.pdf)

Commissioning Period Emission Factors for Digester Gas-Fired Engines		
Pollutant	g/bhp·hr	Source
NO_X	1.0	Engine Supplier's Information
SO_X	0.04	40 ppmvd in fuel gas; BACT Requirement/Mass Balance equation below
PM_{10}	0.07	AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines)
CO	4.85	Engine Supplier's Information
VOC	1.0	Engine Supplier's Information
NH_3	0.05	10 ppmvd @ 15% O_2 in exhaust; Required/Proposed – See equation below

SO_X – 40 ppmvd H_2S in fuel gas

$$\frac{40\,\text{ft}^3\ \text{H}_2\text{S}}{10^6\ \text{ft}^3}\ \text{x}\ \frac{32.06\,\text{lb S}}{\text{lb - mol H}_2\text{S}}\ \text{x}\ \frac{\text{lb - mole}}{379.5\,\text{ft}^3}\ \text{x}\ \frac{64.06\,\text{lb SO}_2}{32.06\,\text{lb S}}\ \text{x}\ \frac{\text{ft}^3}{600\,\text{Btu}}\ \text{x}\ \frac{10^6\ \text{Btu}}{\text{MMBtu}} = 0.0113\ \frac{\text{lb SOx}}{\text{MMBtu}}$$

$$0.0113\ \frac{\text{lb SOx}}{\text{MMBtu}}\ \text{x}\ \frac{1\,\text{MMBtu}}{10^6\,\text{Btu}}\ \text{x}\ \frac{\text{Btu}_{\text{in}}}{0.33\text{Btu}_{\text{out}}}\ \text{x}\ \frac{2{,}545\ \text{Btu}}{\text{hp - hr}}\ \text{x}\ \frac{453.59\ \text{g}}{\text{lb}} = 0.040\ \frac{\text{g SOx}}{\text{bhp - hr}}$$

NH_3 – 10 ppmvd @ 15% O_2 in exhaust

$$\frac{10\,\text{ppmv NH}_3}{10^6}\ \text{x}\ \frac{17\,\text{lb NH}_3}{\text{lb - mole}}\ \text{x}\ \frac{\text{lb - mole}}{379.5\,\text{ft}^3}\ \text{x}\ \frac{9{,}100\,\text{ft}^3}{\text{MMBtu}}\ \text{x}\ \frac{20.9\%\ \text{O}_2}{(20.9 - 15)\%\ \text{O}_2} = 0.0144\,\frac{\text{lb NH}_3}{\text{MMBtu}}$$

$$0.0144\ \frac{\text{lb NH}_3}{\text{MMBtu}}\ \text{x}\ \frac{1\,\text{MMBtu}}{10^6\,\text{Btu}}\ \text{x}\ \frac{\text{Btu}_{\text{in}}}{0.33\text{Btu}_{\text{out}}}\ \text{x}\ \frac{2{,}545\ \text{Btu}}{\text{hp - hr}}\ \text{x}\ \frac{453.59\ \text{g}}{\text{lb}} = 0.05\ \frac{\text{g NH}_3}{\text{bhp - hr}}$$

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for NO_X (0.15 g/bhp-hr), CO (1.75 g/bhp-hr), and VOC (0.10 g/bhp-hr) for the proposed engines during normal operation were proposed by the applicant and are supported by information provided by the engine supplier. The emission factors for NO_X and VOC were required as BACT. The emission factors for SO_X (0.04 g/bhp-hr), PM_{10} (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) during normal operation are same as the emission factors presented above for the commissioning period.

Emission Factors for Digester Gas-Fired Engines (Normal Operation)				
Pollutant	g/bhp·hr	lb/MMBtu	ppmvd (@ 15%O_2)	Source
NO_X	0.15	0.0429	11 ppmvd	BACT Requirement; Proposed by Applicant – See equation on Page 11 below
SO_X	0.04	0.0113	40 ppmvd in fuel gas	BACT Requirement/Mass Balance equation above
PM_{10}	0.07	0.01941	--	AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines)
CO	1.75	0.500	210 ppmvd	Proposed by Applicant – See equation on Page 11 below
VOC	0.10	0.0286	21 ppmvd as CH_4	BACT Requirement; Proposed by Applicant – See equation on Page 11 below
NH_3	0.05	0.0144	10 ppmvd	Required/Proposed – See equation above

NO_X – 0.15 g/bhp-hr

$$0.15\frac{\text{g NOx}}{\text{bhp-hr}} \times \frac{1\text{ lb}}{453.59\text{ g}} \times \frac{1\text{ hp-hr}}{2{,}545\text{ Btu}} \times \frac{0.33\text{Btu}_{\text{out}}}{1\text{Btu}_{\text{in}}} \times \frac{10^6\text{ Btu}}{1\text{ MMBtu}} = 0.0429\frac{\text{lb NOx}}{\text{MMBtu}}$$

$$0.0429\frac{\text{lb NOx}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\text{ MMBtu}}{9{,}100\text{ ft}^3} \times \frac{379.5\text{ ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{46\text{ lb NOx}} \times \frac{10^6\text{ ppmv}}{1} = 11\text{ ppmvd NOx @ 15\% } O_2$$

CO – 1.75 g/bhp-hr

$$1.75\frac{\text{g CO}}{\text{bhp-hr}} \times \frac{1\text{ lb}}{453.59\text{ g}} \times \frac{1\text{ hp-hr}}{2{,}545\text{ Btu}} \times \frac{0.33\text{Btu}_{\text{out}}}{1\text{Btu}_{\text{in}}} \times \frac{10^6\text{ Btu}}{1\text{ MMBtu}} = 0.500\frac{\text{lb CO}}{\text{MMBtu}}$$

$$0.500\frac{\text{lb CO}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\text{ MMBtu}}{9{,}100\text{ ft}^3} \times \frac{379.5\text{ ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{28\text{ lb CO}} \times \frac{10^6\text{ ppmv}}{1} = 210\text{ ppmvd CO @ 15\% } O_2$$

VOC – 0.10 g/bhp-hr

$$0.10\frac{\text{g VOC}}{\text{bhp-hr}} \times \frac{1\text{ lb}}{453.59\text{ g}} \times \frac{1\text{ hp-hr}}{2{,}545\text{ Btu}} \times \frac{0.33\text{Btu}_{\text{out}}}{1\text{Btu}_{\text{in}}} \times \frac{10^6\text{ Btu}}{1\text{ MMBtu}} = 0.0286\frac{\text{lb VOC}}{\text{MMBtu}}$$

$$0.0286\frac{\text{lb VOC}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\text{ MMBtu}}{9{,}100\text{ ft}^3} \times \frac{379.5\text{ ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{16\text{ lb VOC}} \times \frac{10^6\text{ ppmv}}{1} = 21\text{ ppmvd VOC @ 15\% } O_2$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since the digester system and the engines are new emissions units, PE1 = 0 for all affected pollutants.

2. Post Project Potential to Emit (PE2)

Digester System (S-8637-1-0)

As explained above, the digester system will be composed of sealed lagoons that will reduce VOC emissions from the manure and will have negligible fugitive emissions; therefore, VOC emissions from the manure will only be attributed to Lakeview Farms dairy for manure prior to entering the digester system and when returned to the dairy and emissions from the digester system are considered negligible.

Digester Gas-Fired Engines (S-8637-2-0 and -3-0)

Daily PE2 for Each Engine during the Commissioning Period:

Daily PE during the commissioning period for each of the proposed engines is calculated in the table below:

Daily PE for Engines S-8637-2-0 &-3-0 During the Commissioning Periods								
NO_X	1.0	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**77.7**	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.07	(g/hp·hr) . x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.4**	(lb/day)
CO	4.85	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**376.7**	(lb/day)
VOC	1.0	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**77.7**	(lb/day)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.9**	(lb/day)

Daily PE2 for Each Engine during Normal Operation after the Commissioning Period:

Daily PE for each of the proposed engines during normal operation after completion of the commissioning periods is calculated in the table below:

Daily PE for Engines S-8637-2-0 &-3-0 After Commissioning								
NO_X	0.15	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**11.7**	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.07	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.4**	(lb/day)
CO	1.75	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**135.9**	(lb/day)
VOC	0.10	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**7.8**	(lb/day)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.9**	(lb/day)

Maximum Annual PE2 for Each Engine During the first Year Including the Commissioning Periods:

As discussed above, each of the proposed engines will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for each engine will calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

NO_X
1,468 bhp x (1.0 g-NO_X/bhp-hr x 120 hr + 0.15 g-NO_X/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **4,583 lb-NO_X**

SO_X
1,468 bhp x (0.04 g-SO_X/bhp-hr x 120 hr + 0.04 g-SO_X/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,134 lb-SO_X**

PM_{10}
1,468 bhp x (0.07 g-PM_{10}/bhp-hr x 120 hr + 0.07 g-PM_{10}/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,985 lb-PM_{10}**

CO
1,468 bhp x (4.85 g-CO/bhp-hr x 120 hr + 1.75 g-CO/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **50,818 lb-CO**

VOC
1,468 bhp x (1.0 g-VOC/bhp-hr x 120 hr + 0.10 g-VOC/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **3,185 lb-VOC**

NH_3
1,468 bhp x (0.05 g-NH_3/bhp-hr x 120 hr + 0.05 g-NH_3/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **1,418 lb-NH_3**

Maximum Total Combined Annual PE2 from Both Engines, Including Commissioning:

The maximum total combined annual PE2 for both the engines, including commissioning emissions, is calculated as follows:

NO_X: 4,583 lb-NO_X/yr-engine x 2 engines = **9,166 lb-NO_X/yr**
SO_X: 1,134 lb-SO_X/yr-engine x 2 engines = **2,268 lb-SO_X/yr**
PM_{10}: 1,985 lb-PM_{10}/yr-engine x 2 engines = **3,970 lb-PM_{10}/yr**
CO: 50,818 lb-CO/yr-engine x 2 engines = **101,636 lb-CO/yr**
VOC: 3,185 lb-VOC/yr-engine x 2 engines = **6,370 lb-VOC/yr**
NH_3: 1,418 lb-NH_3/yr-engine x 2 engines = **2,836 lb-NH_3/yr**

Annual PE2 for Each Engine in years with no Commissioning:

The annual PE2 for each of the engines after completion of the first year of operation when there will not be any commissioning emissions is calculated as follows:

Annual PE2 for Engines S-8637-2-0 &-3-0 with no Commissioning								
NO_X	0.15	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**4,253**	(lb/yr)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,134**	(lb/yr)
PM_{10}	0.07	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,985**	(lb/yr)
CO	1.75	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**49,614**	(lb/yr)
VOC	0.10	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**2,835**	(lb/yr)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,418**	(lb/yr)

Max Total Combined Annual PE2 from Both Engines in years with no Commissioning:

The maximum total combined annual PE2 for both the engines in years with no commissioning is calculated as follows:

NO_X: 4,253 lb-NO_X/yr-engine x 2 engines = **8,506 lb-NO_X/yr**
SO_X: 1,134 lb-SO_X/yr-engine x 2 engines = **2,268 lb-SO_X/yr**
PM_{10}: 1,985 lb-PM_{10}/yr-engine x 2 engines = **3,970 lb-PM_{10}/yr**
CO: 49,614 lb-CO/yr-engine x 2 engines = **99,228 lb-CO/yr**
VOC: 2,835 lb-VOC/yr-engine x 2 engines = **5,670 lb-VOC/yr**
NH_3: 1,418 lb-NH_3/yr-engine x 2 engines = **2,836 lb-NH_3/yr**

Maximum Daily and Annual PE2 from Calculations Above:

The maximum daily and annual emissions for each pollutant calculated above, including commissioning emissions, are shown in the table below.

Max. Post-Project Potential to Emit (PE2) for S-8637-2-0 &-3-0			
	Max. Daily Emissions for each engine (lb/day)	Max. Annual Emissions for each engine (lb/year)	Max. Total Combined Annual Emissions for both engines (lb/year)
NO_X	77.7	4,583	9,166
SO_X	3.1	1,134	2,268
PM_{10}	5.4	1,985	3,970
CO	376.7	50,818	101,636
VOC	77.7	3,185	6,370
NH_3	3.9	1,418	2,836

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site.

Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 is equal to zero for all pollutants.

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

SSPE2 (lb/year)						
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC	NH_3
ATC S-8637-1-0 (Digester System)	0	0	0	0	0	0
ATC S-8637-2-0 (1,468 bhp Digester Gas Engine)[3]	4,583	1,134	1,985	50,818	3,185	1,418
ATC S-8637-3-0 (1,468 bhp Digester Gas Engine)[3]	4,583	1,134	1,985	50,818	3,185	1,418
SSPE2	9,166	2,268	3,970	101,636	6,370	2,836

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[3] The SSPE2 values listed in this table include the worst case annual emissions during the 120 hours of allowed commissioning time where the engines are allowed to operate uncontrolled for setup and tuning purposes. After the first year, the PE for NO_X, CO, and VOC emissions will go down as the engines will no longer be allowed to operate without controls in place for these pollutants.

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. transportable IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)

	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	9,166	2,268	3,970	3,970	101,636	6,370
Major Source Threshold	20,000	140,000	140,000	200,000*	200,000	20,000
Major Source?	No	No	No	No	No	No

* The application for this project was deemed complete before 2/18/2016, which was when the District's PM2.5 Major Source Threshold was lowered to 140,000 lb/year

Note: PM2.5 assumed to be equal to PM10

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)

	NO2	VOC	SO2	CO	PM	PM10
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	N	N	N	N	N

Because this is a new facility, the PE for all regulated NSR pollutants prior to the project is equal to zero.

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since the proposed digester system and engines are new emissions units, BE = PE1 = 0 for all pollutants from each unit.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a “Major Modification” as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for PM_{10} (140,000 lb/year), it is not a major source for PM2.5 (200,000 lb/year since the application for the project was deemed complete before 2/18/2016).

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Hydrogen sulfide (H2S)[4]
- Total reduced sulfur (inlcuding H2S)[4]

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)

	NO2	VOC	SO2	CO	PM	PM10
Total PE from New and Modified Units	4.6	3.2	1.1	50.8	2.0	2.0
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix A.

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[4] Because the facility is not included in the specific source categories listed in 40 CFR 51.165, for PSD purposes only non-fugitive emissions from the engine exhaust stacks must be addressed for this project. Although the sulfur (primarily H_2S) in the fuel will be converted almost entirely to SO_X during combustion, the maximum possible amount of H_2S and total reduced sulfur compounds from the engine stacks can be calculated by assuming that all sulfur in the fuel is emitted as H_2S. Based on the fuel sulfur limit of 40 ppmv as H_2S, the maximum possible H_2S emission factor for the engines is calculated to be 0.02 g-H_2S/bhp (0.0056 lb-H_2S/MMBtu), resulting in a total combined maximum of < 0.06 tpy H_2S from the exhaust stacks of both engines. This is well below the applicable PSD threshold of 250 tpy.

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the applicant is proposing to install a new digester system with and two new digester gas-fired IC engines.

<u>Digester System (S-8637-1-0)</u>

As explained above, the digester system will consist of sealed lagoon(s) that will reduce VOC emissions from the manure at the dairy and emissions from the digester system are considered negligible. Therefore BACT for new units with PE > 2 lb/day purposes is not required for the digester system.

<u>Digester Gas-Fired Engines (S-8637-2-0 and -3-0)</u>

The proposed engines will each have a PE greater than 2.0 lb/day for NO_X, SO_X, PM_{10}, CO, VOC, and NH_3. Therefore, BACT is triggered for NO_X, SO_X, PM_{10}, and VOC. As part of the BACT requirements, NH_3 slip from the SCR systems will also be limited. The PE for CO from each unit also exceeds 2.0 lb/day; however, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 above.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered for relocation of an emissions unit.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore, BACT is not triggered for modification of a unit.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 or Federal Major Modification. Therefore BACT is not triggered for Major Modification purposes.

2. BACT Guideline

<u>S-8637-2-0 & -3-0</u>

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engines. (See Appendix B)

3. Top-Down BACT Analysis

Pursuant to the Top-Down BACT Analysis (See Appendix B), BACT has been satisfied with the following:

NO_X: NO_X emissions ≤ 0.15 g/bhp-hr
SO_X: Fuel sulfur content ≤ 40 ppmv (as H_2S)
PM_{10}: Fuel sulfur content ≤ 40 ppmv (as H_2S)
VOC: VOC emissions ≤ 0.10 g/bhp-hr
NH_3: NH_3 slip emissions ≤ 10 ppmv @ 15% O_2

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	9,166	2,268	3,970	101,636	6,370
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Public noticing is required for:
a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements.

The PE2 for the proposed new IC engines is compared to the daily PE Public Notice thresholds in the following table:

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO_X	77.7	100 lb/day	No
SO_X	3.1	100 lb/day	No
PM_{10}	5.4	100 lb/day	No
CO	376.7	100 lb/day	**Yes**
VOC	77.7	100 lb/day	No
NH_3	3.9	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	9,166	20,000 lb/year	No
SO_X	0	2,268	54,750 lb/year	No
PM_{10}	0	3,970	29,200 lb/year	No
CO	0	101,636	200,000 lb/year	No
VOC	0	6,370	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for surpassing an offset threshold.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	9,166	0	9,166	20,000 lb/year	No
SO_x	2,268	0	2,268	20,000 lb/year	No
PM_{10}	3,970	0	3,970	20,000 lb/year	No
CO	101,636	0	101,636	20,000 lb/year	**Yes**
VOC	6,370	0	6,370	20,000 lb/year	No
NH_3	2,836	0	2,836	20,000 lb/year	No

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE > 20,000 lbs is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating, this change is not a Title V Significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for CO emissions from an emissions unit in excess of 100 lb/day and for an SSIPE for CO that exceeds 20,000 lb/yr. Therefore, public notice documents will be submitted to the California Air Resources Board (ARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and must be enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions for the Digester System (S-8637-1-0)

As stated above, the digester system will reduce emissions from the manure produced by cattle at Lakeview Farms dairy. The following condition will be placed on the ATC permit to ensure that fugitive emissions from the digester system will be negligible:

- The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
- The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions for the Digester Gas-Fired Engines (S-8637-2-0 & -3-0)

Proposed Rule 2201 (DEL) Conditions for Engines during Both Commissioning and Normal Operation:

- This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]

- During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
- The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
- Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For these digester gas-fired IC engines, the DELs for NO_X, PM_{10}, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr) and maximum number of hours allowed for commissioning activities.

- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
- The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Normal Operation:

For the proposed digester gas-fired IC engines, the DELs for NO_X, PM_{10}, CO, and VOC during normal operation are stated in the form of emission factors (g/hp-hr & ppmv), the maximum engine horsepower rating (1,468 bhp), and the maximum operational time of 24 hours per day.

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

E. Compliance Assurance

1. Source Testing

The proposed 1,468 bhp digester gas-fired engines are subject to District Rule 4702 - Internal Combustion Engines. Section 6.3.2.1 of District Rule 4702 requires source testing of NO_X, CO, and VOC emissions at least once every 24 months for a non-agricultural spark-ignited IC engine. The periodic source testing required by District Rule 4702 will ensure compliance with the applicable New Source Review (NSR) requirements NO_X, CO, and VOC. Therefore, source testing for NO_X, CO, and VOC will be required within 90 days of initial start-up and at least once 24 months thereafter. Since the control equipment will include an SCR system, periodic testing of ammonia slip will also be required. In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. The PM_{10} emissions from the engine are not expected to change much over time as long as the quality of the gas used to fuel the engines remains consistent. The facility will be required to periodically monitor the sulfur content of the digester gas fuel, which should ensure that the quality of the digester gas fuel is consistent. Therefore, initial PM_{10} source testing will be required to demonstrate compliance with the PM_{10} emission limit, but ongoing PM_{10} source testing will not be required.

The proposed engines are also subject to 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, no testing requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

The following conditions will be placed on the engine permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]
- Fuel sulfur analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided it to the District upon request. [District Rules 2201 and 4702]
- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

2. Monitoring

As stated above the engines are subject to District Rule 4702. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of NO_X emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. Therefore, quarterly monitoring of NO_X, CO, and O_2 concentrations in accordance with pre-approved alternate monitoring plan "A" within District Policy SSP 1810 will be required. Since the engines will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the engine permits to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]
- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Because of the variable composition of digester gas, additional monitoring of the fuel sulfur content of the digester gas will be required. The following conditions will be placed on the engine permits to ensure compliance:

- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

The following conditions will be listed on the engine permits:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or

volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

4. Reporting

No reporting is required to demonstrate compliance with District Rule 2201.

As stated above, the proposed 1,468 bhp engines are subject to 40 CFR 60, Subpart JJJJ. 40 CFR 60, Subpart JJJJ requires uncertified engines rated 500 bhp or more to submit an initial notification to EPA. As explained above, the District has not been delegated the authority to implement this regulation for non-Major Sources; therefore, this requirement will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

F. Ambient Air Quality Analysis (AAQA)

District Rule 2201 requires that an ambient air quality analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Appendix C of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds.

The results of the Criteria Pollutant Modeling conducted for the AAQA are summarized in the following table:

Criteria Pollutant Modeling Results*

Digester Gas-Fired IC Engines	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_X	Pass[1]	X	X	X	Pass
SO_X	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
H2S	Pass	X	X	X	X

* Results were taken from the PSD spreadsheet.

[1] The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.

[2] The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

[3] H_2S emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4101 Visible Emissions

Rule 4101 states that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity.

Since the IC engines are fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

A Health Risk Assessment (HRA) is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix C), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project. The results of the health risk assessment are summarized in the table below.

RMR Summary			
Categories	**1,468 bhp Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score[1]	107 (each)	214	>1
Acute Hazard Index	0.48 (each)[1]	0.95	0.95
Chronic Hazard Index	0.16 (each)	0.31	0.31
Maximum Individual Cancer Risk (10^{-6})	0.002 (each)	0.004	0.004
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

[1] H_2S emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix C of this report, the emissions increases for this project was determined to be less than significant.

To ensure compliance with the HRA; the following condition will be listed on the engine permits:

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

This condition, along with the engine rating in the equipment description, will ensure that the H_2S emissions from the engine exhaust stack shall not exceed 1.97 lb/hr, as required by the Health Risk Assessment.

Rule 4201 Particulate Matter Concentration

The purpose of this rule is to protect the ambient air quality by establishing a particulate matter emission standard. Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

$$0.07 \quad \frac{g}{hp \cdot hr} \times \frac{1 hp \cdot hr}{2{,}545 Btu} \times \frac{10^6 Btu}{9{,}100 dscf} \times \frac{0.33 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = \quad 0.015 \quad \frac{grain}{dscf}$$

Since 0.015 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4701 Stationary Internal Combustion Engines – Phase I

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

Rule 4702 Internal Combustion Engines

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides (SO_X) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0. The proposed new engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the proposed engines.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 NO_X, CO, and VOC emission limits pursuant to Table 2;
5.2.2.1.2 SO_X control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and

5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the NO_X emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. Pursuant to Section 5.2.2.2.1, engines in the fee payment program shall have actual emissions not greater than the applicable limits in Table 1 during the entire time the engine is part of the fee payment program. Pursuant to Section 5.2.2.2.2, compliance with Section 5.7 and 5.10, pursuant to the deadlines specified in Section 7.5, is also required as part of the fee payment option.

Section 5.2.2.3 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. An operator electing this option shall not be eligible to participate in the fee payment option outlined in Section 5.2.2.2 and Section 5.6.

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations

(Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.)

Engine Type	NO_X Emission Limit (ppmv @ 15% O_2, dry)	CO Emission Limit (ppmv @ 15% O_2, dry)	VOC Emission Limit (ppmv @ 15% O_2, dry)
1. a. Rich-Burn, Waste Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. b. Rich-Burn, Cyclic Loaded, Field Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. c. Rich-Burn, Limited Use	25 ppmv	2,000 ppmv	250 ppmv
1. d. Rich-Burn, Not Listed Above	11 ppmv	2,000 ppmv	250 ppmv
2. a. Lean-Burn, 2-Stroke, Gaseous Fueled, >50 bhp & <100 bhp	75 ppmv	2,000 ppmv	750 ppmv
2. b. Lean-Burn, Limited Use	65 ppmv	2,000 ppmv	750 ppmv
2. c. Lean-Burn Engine used for gas compression	65 ppmv or 93% reduction	2,000 ppmv	750 ppmv
2. d. Waste Gas Fueled	65 ppmv or 90% reduction	2,000 ppmv	750 ppmv
2. e. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	750 ppmv

The proposed digester gas-fired engines will be operated as a separate stationary source than the dairy farm and the District has determined that the IC engines are a non-agricultural IC engines. The digester gas-fired, engines are waste gas-fired engines and are required to comply with the following emissions limits from Table 2, Row 2.d: 65 ppmvd NO_X, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2).

Therefore, the following previously presented condition will be listed on the proposed ATC permits for the engines to ensure compliance:

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3.1 requires that the operator of a spark-ignited internal combustion engine rated > 50 bhp that is used exclusively in agricultural operations shall not operate it in such a manner that results in emissions exceeding the limits in Table 3 of Rule 4702 for the appropriate engine type on an engine-by-engine basis.

Section 5.2.3.2 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 3 on an engine-by-engine basis, an operator of a spark-ignited agricultural IC engine may elect to implement an alternative emission control plan pursuant to Section 8.0.

Section 5.2.3.3 requires an operator of an agricultural IC engine in that is subject to the applicable requirements of Table 3 shall not replace such engine with an engine that emits more emissions of NOx, VOC, and CO, on a ppmv basis, (corrected to 15% oxygen on a dry basis) than the engine being replaced.

As stated above, the proposed digester gas-fired engines will be operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the proposed engines.

Section 5.2.4 requires the operator of a certified compression-ignited engine rated >50 bhp shall comply with the following requirements of Sections 5.2.4.1, 5.2.4.2, 5.2.4.3, 5.2.4.3, and 5.2.4.4. The proposed digester gas-fired engines are not compression-ignited engines; therefore, Section 5.2.4 does not apply to the proposed engines.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NO_X emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NO_X emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the digester gas-fired engines comply with the applicable emission limits of Table 2 of District Rule 4702; therefore payment of annual emissions fees for the engines is not required and this section of the Rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or
5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or
5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or
5.7.4 Use California Reformulated Diesel for compression-ignited engines; or
5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or
5.7.6 Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

To satisfy BACT, the average sulfur content of the digester gas fuel for the engine will be limited to 40 ppmv (approximately equal to 2.4 grains sulfur per 100 standard cubic feet). The following condition will be listed on the proposed engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 – 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NO_X, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic NO_X and CO emission concentrations,
5.8.1.2 Engine exhaust oxygen concentration,

5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the Rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on the engine ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The proposed engines will be subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the proposed ATC permits for the proposed digester gas-fired engines include an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engines in this project. Therefore, the following condition will be placed on the engine ATC permits to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the permittee shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.8 requires that for each engine, collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, use of a portable NO_X analyzer to take NO_X emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NO_X emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NO_X emissions readings shall be reported to the APCO in a manner approved by the APCO. NO_X emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be placed on the ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that requires periodic NO_X, CO, and O_2 emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. In lieu of installing a nonresettable fuel meter, the operator may use an alternative device, method, or technique in determining daily fuel consumption provided that the alternative is approved by the APCO. The operator shall maintain, operate, and calibrate the required fuel meter in accordance with the manufacturer's instructions. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The proposed spark-ignited non-agricultural digester gas-fired engines are subject to the requirements of Section 5.8; therefore this section of the Rule is not applicable.

Section 5.10 specifies SO_X Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The proposed spark-ignited non-agricultural digester gas-fired engines are required to have a District Permit to Operate; therefore this section of the Rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.1.1.2 Engines subject to Section 8.0;
6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for each engine:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.2.2 Engine manufacturer,
6.1.2.3 Model designation and engine serial number,
6.1.2.4 Rated brake horsepower,
6.1.2.5 Type of fuel and type of ignition,
6.1.2.6 Combustion type: rich-burn or lean-burn,
6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.2.11 Applicable emission limits,
6.1.2.12 Documentation showing existing emissions of NO_X, VOC, and CO, and
6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engine is in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2.

The applicant has submitted all the required information for Section 6.1 in the application for the IC engines evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

6.2.1.1 Total hours of operation,
6.2.1.2 Type of fuel used,
6.2.1.3 Maintenance or modifications performed,
6.2.1.4 Monitoring data,
6.2.1.5 Compliance source test results, and
6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on the ATC permits:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following previously presented condition will be listed on the proposed ATC permits to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and provided to the APCO upon request. The records shall include, but are not limited to, the following:

6.2.3.1 Total hours of operation,
6.2.3.2 The type of fuel used,
6.2.3.3 The purpose for operating the engine,
6.2.3.4 For emergency standby engines, all hours of non-emergency and emergency operation shall be reported, and
6.2.3.5 Other support documentation necessary to demonstrate claim to the exemption

The applicant is not claiming an exemption for the proposed engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Section 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.
6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following conditions will be included the ATC permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the

Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NO_X, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of NO_X emissions shall also be reported.

The following conditions will be included in the ATC permits to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The proposed engines will be fueled on digester gas; therefore this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engines; therefore this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
6.4.6 SO_X Test Methods
  6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.

6.4.6.2 Determination of total sulfur as hydrogen sulfide (H_2S) content – EPA Method 11 or EPA Method 15, as appropriate.

6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.

6.4.6.4 The SO_X emission control system efficiency shall be determined using the following:

% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$

Where:

$C_{SO2,\ inlet}$ = concentration of SO_X (expressed as SO_2) at the inlet side of the SO_X emission control system, in lb/Dscf

$C_{SO2,\ outlet}$ = concentration of SO_X (expressed as SO_2) at the outlet side of the SO_X emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.

6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on the proposed ATC permits to ensure compliance:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.5.1.2 Engines subject to Section 8.0;

6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.

6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of NO_X and oxidation catalysts for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engines.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of NO_X and oxidation catalysts for control of CO and VOC. The applicant has proposed the following alternate monitoring program to ensure compliance with Sections 6.5.2 and 6.5.3 of the Rule.

NO_X Emissions:

In order to satisfy the I & M requirements for NO_X emissions, the applicant has proposed to perform the following:

1. Measurement of NOx emissions concentrations with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and the catalyst control system inlet exhaust temperature and NO_X emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

CO and VOC Emissions:

In order to satisfy the I & M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. Measurement of CO emissions concentrations with a portable analyzer at least once every calendar quarter. Generally, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, no additional monitoring for VOC emissions is required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emissions concentration measurements, the applicant is proposing to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure and CO emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance with the I & M requirements for NO_X, CO, and VOC:

- Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]
- Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s)

within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

- The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_X, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_X, CO, VOC, or oxygen concentrations.

The applicant has proposed that the alternate monitoring program will ensure compliance with these two sections of the Rule. Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance:

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control

system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engines will be operated and maintained per the specifications of the manufacturer or emissions control system supplier. Therefore, the following conditions will be listed on the proposed ATC permits:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Section 6.5.7 requires procedures and a schedule for using a portable NO_X analyzer to take NO_X emission readings pursuant to Section 5.8.9. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule. The following previously proposed condition will be listed on the proposed ATC permits:

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time.

The applicant has proposed to comply with the I&M plan modification requirements per this section of the Rule. The following condition will be listed on the proposed ATC permits to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The proposed IC engines will be required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the NO_X emission requirements of Section 5.2 for a group of engines. Requirements for use of an AECP include: only engines subject to Section 5.2 are eligible for inclusion in an AECP; during any seven consecutive day period, the operator shall operate all engines in the AECP to achieve an actual aggregate NO_X emission level that is ≤ 90% of the NO_X emissions that would be obtained by controlling the engines to comply individually with the NO_X limits in Section 5.2; the operator shall establish a NO_X emission factor limit for each engine; the operator must submit the AECP at least 18 months before compliance with the emission limits in Section 5.2 is required and receive approval from the APCO; the operator must submit and updated or modified AECP for approval by the APCO prior to any modifications; and the operator must maintain records necessary to demonstrate compliance with AECP. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines proposed under this project; therefore this section of the Rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the IC engines under this project is not currently being proposed and, in addition, certification under this section of the Rule would require that the engines or identical units with the same fuel supply and exhaust control systems were operating and could be source tested to demonstrate compliance with the applicable limits; therefore this section of the Rule is not applicable.

Conclusion

As shown above, the proposed non-agricultural, digester gas-fired, lean burn, IC engines are expected to comply with the applicable requirements of Rule 4702 upon initial operation and no further discussion is required.

Rule 4801 Sulfur Compounds

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of SO_X as (SO_2) = (n x R x T) ÷ P
Where:
n = moles SO_X
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$0.0113\ \frac{lb}{MMBtu}\times\frac{1\,MMBtu}{9{,}100 scf_{exhaust}}\times\frac{1\,lb\cdot mol}{64\,lb\cdot SO_2}\times\frac{10.73\,psi\cdot ft^3}{lb\cdot mol\cdot{}^\circ R}\times\frac{520^\circ R}{14.7\,psi}\times 1{,}000{,}000\,ppm = \quad 7.4 \quad \text{ppmv}$$

Since 7.4 ppmv is ≤ 2000 ppmv, the engines are expected to comply with Rule 4801. The following condition will be placed on the engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

This rule incorporates the New Source Performance Standards (NSPS) from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of NO_X, SO_X, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The proposed engines are 1,468 bhp SI ICEs that will be constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engines are subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part. As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project is for construction of a renewable energy plant at an existing dairy facility. The proposed renewable energy plant will combust dairy digester gas in IC engines to produce electricity. The proposed project will involve diverting manure from existing open basin(s) and pond(s) at the dairy to covered lagoon digester(s), which will result in the capture of much of the methane that is currently released into the atmosphere from the open basins and pond at the dairy. Combustion of the dairy digester gas at the proposed renewable energy plant will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential at least 21 times that of carbon dioxide, combustion of the methane from the dairy digesters will result in a large net decrease in the global warming potential emitted from the dairy when compared to current levels. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that, although the project is considered to take place at a separate stationary source for NSR purposes, the activity will occur on previously developed land at an existing dairy facility and the project involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. The District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs S-8637-1-0, -2-0, and -3-0 subject to the permit conditions on the attached draft ATC in Appendix D.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-8367-1-0	3020-06	Covered Lagoon Digester	$111.00
S-8367-2-0	3020-10-F	1,468 bhp IC engine	$785.00
S-8367-3-0	3020-10-F	1,468 bhp IC engine	$785.00

Appendixes

A: Quarterly Net Emissions Change (QNEC)
B: BACT Analysis for the Proposed Digester Gas-Fired IC Engines
C: Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)
D: Draft ATCs (S-8367-1-0, -2-0, & -3-0)

APPENDIX A
Quarterly Net Emissions Change (QNEC)

Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

S-8637-1-0 (Digester System)

PE1 (lb/qtr) S-8637-1-0					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

PE2 (lb/qtr) S-8637-1-0					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

Quarterly NEC [QNEC] S-8637-1-0					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	0.0	-	0.0	=	0.0
SO_X	0.0	-	0.0	=	0.0
PM_{10}	0.0	-	0.0	=	0.0
CO	0.0	-	0.0	=	0.0
VOC	0.0	-	0.0	=	0.0

S-8637-2-0 & -3-0 (1,468 bhp Digester Gas-Fired, Lean Burn, IC Engines)

PE1 (lb/qtr) S-8637-2-0 & -3-0					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

PE2 (lb/qtr) S-8637-2-0 & -3-0					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	4,583	÷	4 qtr/year	=	1,145.8
SO_X	1,134	÷	4 qtr/year	=	283.5
PM_{10}	1,985	÷	4 qtr/year	=	496.3
CO	50,818	÷	4 qtr/year	=	12,704.5
VOC	3,185	÷	4 qtr/year	=	796.3

Quarterly NEC [QNEC] S-8637-2-0 & -3-0					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	1,145.8	-	0.0	=	1,145.8
SO_X	283.5	-	0.0	=	283.5
PM_{10}	496.3	-	0.0	=	496.3
CO	12,704.5	-	0.0	=	12,704.5
VOC	796.3	-	0.0	=	796.3

APPENDIX B

BACT Analysis for Digester Gas-Fired IC Engines

SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*

Last Update: 3/6/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_X	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
SO_X	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S) (dry absorption, wet absorption, chemical H_2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM_{10}	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O_2) 3. Gas Turbine (<60 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
VOC	0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent)		Fuel Cells (<0.02 lb-VOC/MW-hr as CH_4)
Ammonia (NH_3) Slip	≤ 10 ppmv @ 15% O_2		

*** For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

3.3.15

Top-Down BACT Analysis for Project S-1143770
Digester Gas-Fired IC Engines

Current District BACT Guideline 3.3.15 applies to the proposed waste gas-fired IC engines. In accordance with the District BACT policy, information from District BACT Guideline 3.3.15 will be utilized for the BACT analysis for the digester gas-fired engines proposed under this project.

I. Proposal and Process Description

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kWe. The covered lagoon digester will utilize an air injection system for biological removal of H_2S from the digester gas. After initial removal of H_2S in the covered lagoon digester, the digester gas will be captured by the covered the lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional H_2S by an iron sponge scrubber and/or activated carbon or an equivalent H_2S removal system and for removal of moisture. The cleaned digester gas, which consists mostly of methane, the main component of natural gas, will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system.

II. BACT Applicability

New emissions units – PE > 2.0 lb/day

New Emissions Unit BACT Applicability for S-8637-2-0 & -3-0 After Commissioning				
Pollutant	PE2 for each unit after commissioning (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/yr)	BACT Triggered?
NO_X	11.7	> 2.0	N/A	**Yes**
SO_X	3.1	> 2.0	N/A	**Yes**
PM_{10}	5.4	> 2.0	N/A	**Yes**
CO	135.9	> 2.0 and SSPE2 ≥ 200,000 lb/yr	101,636	No
VOC	7.8	> 2.0	N/A	**Yes**
NH_3	3.9	> 2.0	N/A	**Yes**

* BACT is not required for CO from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

III. Top-Down BACT Analyses for the Digester Gas-Fired Engines

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed digester gas-fired IC engines under this project.

1. BACT Analysis for NO_X Emissions:

a. Step 1 - List all control technologies

District BACT Guideline 3.3.15 lists the following options to reduce NO_X emissions from waste gas-fired IC engines:

1) NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)
2) Fuel Cell (≤ 0.05 lb/MW-hr) (Alternate Basic Equipment)
3) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
4) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Description of Control Technologies

1) NO_X emissions ≤ 0.15 g/bhp-hr (9-11 ppmv NO_X @ 15% O_2) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

2) Fuel Cell (≤ 0.05 lb- NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of CO_2 that is found biogas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for biogas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, biogas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

3) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, NO_X emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for biogas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, biogas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller biogas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

4) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 biogas-fired microturbines operating in California as of the year 2006.[5] Microturbines generally have electrical efficiencies

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[5] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)

of 25-30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30-33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X, or DLN) combustion technology. Microturbines manufacturers will generally guarantee NO_X emissions of 9-15 ppmv @ 15% O_2. However, several emission tests performed on biogas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[6], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 4) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

b. Step 2 - Eliminate technologically infeasible options

Option 3 - Gas Turbine (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

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[6] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles

[7] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies

[8] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

The proposed project would require gas turbines rated 1,059 kW each, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
2) Digester gas-fueled microturbines (Alternate Basic Equipment)
3) NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engines are non-agricultural IC engines. The lean burn, digester gas-fired, engines are subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.d: 65 ppmvd NO_X (or 90% reduction), 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). The proposed digester engines are also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a more stringent VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engines will be based on the emission limits contained in these applicable regulations.

Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Because fuel cells have reduced NO_X and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis demonstrates that replacement of the proposed engines with a fuel cell is not cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Price for electricity: \$127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[9] *in February 2016*)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and fuel cells will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [8]

Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day (*1,468* bhp_{out}*/engine x 1* bhp_{in}*/0.33* bhp_{out} *x 2,545* Btu_{in}/bhp_{in}*-hr x 1 MMBtu/*10^6 *Btu x 24 hr/day x 1 engine*)
- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468* bhp_{out}*/engine x 1* bhp_{in}*/0.33* bhp_{out} *x 2,545* Btu_{in}/bhp_{in}*-hr x 1 MMBtu/*10^6 *Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: \$1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: \$387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)

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[9] See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in the engines, there will be no increase in operating costs related to cleaning the digester gas for use in IC engines.
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

<u>Assumptions for Fuel Cell System</u>

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace each proposed engine: 1,500 kW (estimated based on 271.71 MMBtu/day and 45% efficiency)
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: $4,550/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at: <u>http://www.wbdg.org/resources/fuelcell.php</u>) states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".*)
- Additional capital investment for biogas conditioning and cleanup for fuel cells: $563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: $5,113/kW

- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: $0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for biogas conditioning and cleanup for large fuel cells: $0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: $0.19/kW-hr
- Fuel Cell NO_X emissions: 0.01 - 0.02 lb/MW-hr *(Note: Fuel cells have been certified to the ARB Distributed Generation Certification level of 0.07 lb-*NO_X*/MW-hr but measured emissions from fuel cells are generally much lower)*
- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr (≤ 2.0 ppmv VOC @ 15% O_2 as CH_4 based on ARB Distributed Generation Certification level of 0.02 lb-VOC/MW-hr and emission tests on fuel cells)
- Unlike the proposed engines, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

Capital Cost

The estimated increased incremental capital cost for replacement of the proposed engines with fuel cells is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a fuel cell power plant is calculated as follows:

(1,500 kW x $5,113/kW) - (1,059 kW x $2,139/kW) = $5,404,299

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

A = $[P \times i(I+1)^n]/[(I+1)^n-1]$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

A = $[\$5{,}404{,}299 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$
= **$879,525/year**

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

Fuel Cells (Alternate Equipment)
271.71 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 1,493 kW

99,175.4 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 13,076,159 kW-hr /year

Cost Decrease from Increased Revenue for Power Generation from Replacing each Proposed 1,059 kW Engine with a Fuel Cell
(9,276,840 kW-hr/yr - 13,076,159 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = -$485,249/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 IC kW Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Fuel Cells (Alternate Equipment)
13,076,159 kW-hr/yr x $0.19/kW-hr = $2,484,470/year

Annual Costs of Increased Maintenance
$2,484,470/yr - $185,537/yr = $2,298,933/year

Total Increased Annual Costs for Fuel Cell as an Alternative to Each Proposed Engine

$879,525/year + (-$485,249/year) + $2,298,933/year = **$2,693,209/year**

Emission Reductions:

NO_X and VOC Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the engines will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b. The District Standard Emissions for VOC emissions from the engines will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2) and 1.0 g-VOC/bhp-hr

Emissions from Fuel Cells as Alternative Equipment: 0.01 lb-NO_X/MW-hr and 0.02 lb-VOC/MW-hr as CH_4

Emission Reductions:

Each Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 0.01 lb-NO_X/MW-hr)
(99,175.4 MMBtu/yr x 0.2540 lb-NO_X/MMBtu) – (13,076,159 kW-hr/yr x
1 MW/1,000 kW x 0.01 lb-NO_X/MW)
= 25,060 lb-NO_X/year (12.53 ton-NO_X/year)

VOC Emission Reductions (1.0 g/bhp-hr → 0.02 lb-VOC/MW-hr)
(1,468 bhp/engine x 8,760 hr/yr x 1 engine x 1.0 g-VOC/bhp-hr x 1 lb/453.59 g) –
(13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.02 lb-VOC/MW)
= 28,089 lb-VOC/year (14.04 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for NO_X and VOC Reductions based on District Standard Emission Reductions

(12.53 ton-NO_X/year x \$24,500/ton-NO_X) + (14.04 ton-VOC/year x \$17,500/ton-VOC)
= **\$552,685/year**

As shown above, the annualized capital cost of this alternate option exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO_X and VOC emission reductions. Therefore, this option is not cost effective and is being removed from consideration.

Option 2 - Microturbines ($\leq$ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

The cost analysis below demonstrates that the NO_X emission reductions achieved by replacement of the proposed engines with microturbines would not be cost effective based on the District's Revised BACT Cost Effectiveness Thresholds (May 14, 2008).

In addition, it should be noted that large lean burn IC engines generally have higher overall efficiencies than microturbines. The difference in efficiency between engines and microturbines will minimize and possibly eliminate any overall differences in NO_X emissions between these options. For example, information from a Capstone Turbine Corporation specification sheet indicates that the guaranteed NO_X emissions rate of 9 ppmvd @ 15% O_2 for their 1,000 kW renewable gas fuel microturbine package is equivalent to 0.14 g-NO_X/hp-hr.[10] This level is not significantly different than the current BACT requirement for waste gas-fired engines of 0.15 g-NO_X/bhp-hr.

The following discussion demonstrates how the difference the efficiency of engines and microturbines can affect the emission rate. NO_X emissions from the engines will be limited to no more than 0.15 g/bhp-hr (approximately 11 ppmv NO_X @ 15% O_2). Microturbine suppliers will generally guarantee NO_X emissions $\leq$ 9 ppmv @ 15% O_2 For digester gas-fired microturbines. The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11] (March 2015), Table 2-2: Gas Spark Ignition Engine CHP - Typical Performance Parameters, lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12] (October 5, 2015), Page A-28 indicates that "Typical observed efficiencies on IC engines deployed in the SGIP are 27% for electrical conversion (HHV)..." Therefore, the expected HHV electrical efficiency of each of the proposed 1,059 kW engines is between 27-36.8%.

The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11], Table 5-2: Gas Spark Ignition Engine CHP - Microturbine Cost and Performance Characteristics, lists HHV electrical efficiencies of 26-28% for microturbine systems rated at least 200 kW. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12], Table A-15: Microturbine Electrical Conversion Efficiency, lists a HHV electrical efficiencies of 21% for microturbines based on SGIP metered data. Therefore, the expected HHV electrical efficiency of large microturbines is between 21-28%.

The maximum expected NO_X emission factor for the proposed engine-generator sets is approximately 0.47 lb/MW-hr (based on 0.15 g/bhp-hr and 95% generator efficiency). Based on 9 ppmv NO_X @ 15% O2 and the expected range of microturbine electrical conversion efficiency given above, the NO_X emission factor from large digester gas-

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[10] See: http://www.adigo.no/wordpress/wp-content/uploads/2015/02/CR1000-teknisk-spesifikasjon-engelsk.pdf. Note that because of lower efficiencies for smaller microturbines, the guaranteed emission rate of 9 ppmvd NO_X @ 15% O_2 from smaller units will actually be higher than 0.15 g-NO_X/bhp-hr

[11] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies

[12] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

fueled microturbines is expected to range from 0.43 – 0.57 lb/MW-hr. Because, the maximum NO_X emission factor for the proposed engine-generator sets falls within this range, the options could be considered equivalent.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and microturbines will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[11] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and microturbines, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [12]
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines or microturbines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in both engines and microturbines and the same amount of total digester gas will be available for either option, there will be no difference in operating costs related to cleaning the digester gas for use in IC engines or microturbines.
- Price for electricity: $127.72/MW-hr (based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)[9] in February 2016)

<u>Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 24 hr/day x 1 engine*)

- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468* bhp_{out}*/engine x 1* bhp_{in}*/0.33* bhp_{out} *x 2,545* Btu_{in}/bhp_{in}*-hr x 1 MMBtu/*10^6 *Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu

<u>Assumptions for Microturbines</u>

- Net HHV electrical efficiency for a 950 kW net (1,000 kW nominal capacity) microturbine package: 24.5% (*conservative estimate, SGIP metered data indicates an efficiency of 21%*)
- Estimated Size of microturbine system needed to replace each engine: 950 kW net (1,000 kW nominal capacity)
- Estimated Purchase and Installation Cost for 950 kW net (1,000 kW nominal capacity) microturbine package: $2,500/kW (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- Estimated additional capital investment for biogas conditioning and cleanup for microturbines: $744/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled microturbine system rated 950 kW net (1,000 kW nominal capacity): $3,244/kW
- Typical operation costs for a 950 kW net (1,000 kW nominal capacity) microturbine package: $0.012/kW-hr (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- NO_X Emissions for Digester gas-fueled microturbines: ≤ 9 ppmv NO_X @ 15% O_2 (~ 0.0352 lb-NOx/MMBtu)

Capital Cost

The estimated increased incremental capital cost for replacement of each the proposed engines with microturbines is calculated based on the difference in cost of a microturbine system and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a microturbine system is calculated as follows:

(950 kW x \$3,244/kW) - (1,059 kW x \$2,139/kW) = \$816,599

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^{n}]/[(I+1)^{n}-1]$$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$A = [\$816,599 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$132,898/year}$$

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

950 kW (net) Microturbine Package (Alternate Equipment)
271.71 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 813 kW

99,175.4 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 7,119,242 kW-hr /year

Cost of Decreased Revenue from Power Generation from Replacing each Proposed 1,059 kW Engine with Microturbines
(9,276,840 kW-hr/yr - 7,119,242 kW-hr/yr) x 1 MW/1,000 kW x \$127.72/MW-hr = \$275,568/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 kW IC Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Microturbines (Alternate Equipment)
7,119,242 kW-hr/yr x $0.012/kW-hr = $85,431/year

Cost from Annual Decrease in Maintenance Costs
$85,431/yr - $185,537/yr = -$100,106/year

Total Increased Annual Costs for Microturbines as an Alternative to Each Proposed Engine

$132,898/year + $275,568/year + (-$100,106/year) = **$308,360/year**

Emission Reductions:

NO_X Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the engines will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2)

Emissions from Microturbines as Alternative Equipment: 0.0352 lb-NO_X/MMBtu (9 ppmv NO_X @ 15% O_2)

Emission Reductions for Each Proposed Engine Compared to Microturbines based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 9 ppmv @ 15% O_2)
99,175.4 MMBtu/yr x (0.2540 lb-NO_X/MMBtu – 0.0352 lb-NO_X/MMBtu)
= 21,700 lb-NO_X/year (10.85 ton-NO_X/year)

Cost of NO_X Emission Reductions

Cost of reductions = ($308,360/year)/[(21,700 lb-NO_X/year)(1 ton/2000 lb)]
= **$28,420/ton of NO_X reduced**

As shown above, the cost of the NO_X emission reductions for replacing each of the proposed engines with microturbines exceeds the $24,500/ton cost effectiveness threshold of the District BACT policy. Therefore, this option is not cost effective and is being removed from consideration.

Option 3: NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

This option is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engines must be satisfied with the following: NO_X: NO_X emissions to ≤ 0.15 g/bhp-hr

The applicant has proposed to use SCR systems for the digester gas-fired lean burn IC engines to reduce NO_X emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

2. BACT Analysis for SO_X Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce SO_X emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for SO_X emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X are satisfied.

3. BACT Analysis for PM_{10} Emissions:

a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engines. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and CO_2 (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engines:

1) Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X are satisfied.

4. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as CH_4) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_X and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engines is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed IC engines with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

5. BACT Analysis for NH_3 Slip Emissions:

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%. Ammonia slip is the result of unreacted ammonia exiting the SCR system.

a. Step 1 - Identify all control technologies

The District has not established a cost effectiveness threshold for ammonia. Therefore, only options that are determined to be Achieved-in-Practice controls will be considered for ammonia in this analysis.

District BACT Guideline 3.3.15 lists an ammonia slip emission limit of 10 ppmvd @ 15% O_2 as an Achieved in Practice BACT requirement for waste gas-fired IC engines.

1) NH_3 emissions ≤ 10 ppmvd @ 15% O_2 (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) NH_3 emissions ≤ 10 ppmvd @ 15% O_2 (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved in practice and has been proposed by the applicant. Additionally, as stated above, a cost effectiveness threshold for ammonia has not been established by the District. Therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for NH_3 slip emissions from the proposed engines is NH_3 slip emissions ≤ 10 ppmvd @ 15% O_2. The applicant has proposed IC engines with NH_3 slip emissions ≤ 10 ppmvd @ 15% O_2. Therefore, the BACT requirements for NH_3 slip are satisfied.

APPENDIX C

Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)

San Joaquin Valley Air Pollution Control District
REVISED Risk Management Review

To:	Ramon Norman – Permit Services
From:	Yu Vu – Technical Services
Date:	October 22, 2015
Facility Name:	ABEC #3 dba Lakeview Dairy Biogas
Location:	17702 Bear Mountain Blvd, Bakersfield, CA 93311 at Lakeview Dairy (S-5254)
Application #(s):	S-8637-2-0, 3-0
Project #:	S-1143770

A. RMR SUMMARY

RMR Summary			
Categories	**1,468 BHP Bio Gas Engines (Unit 2-0 & 3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	107 (ea.)	214	>1
Acute Hazard Index	0.48 (ea.)[1]	0.95	0.95
Chronic Hazard Index	0.16 (ea.)	0.31	0.31
Maximum Individual Cancer Risk (10^{-6})	0.002 (ea.)	0.004	0.004
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

[1] H_2S emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Unit # 2-0, 3-0

1) The H_2S emissions from the engine shall not exceed 1.97 lbs/hr. as determined by source testing. [District Rule 2201]

B. RMR REPORT

I. Project Description

Technical Services received a request on October 7, 2015, to perform a revised Risk Management Review for a proposed installation of two 1,468 BHP Dairy Bio gas-fired full time IC engines. Per the project engineer, the following changes to the project were made in this revision:

1) An increase in each engine's rating from 1,412 bhp to 1,468 bhp.
2) An increase in digester gas consumption of each engine from 16,303 scf/hr and 142,812,528 scf/yr to 16,327 scf/hr and 143,024,520 scf/yr.
3) A change in the stack parameters, resulting in the stack exit velocity of each engine increasing from 19.766 m/s to 23.636 m/s.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculated using District approved Dairy Bio Gas emission factors for internal combustion were input into the HEARTs database. The AERMOD model was used, with the parameters outlined below and meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 2-0, 3-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	9.144	**Closest Receptor (m)**	Various
Stack Diameter. (m)	0.4572	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	23.636	**Max Hours per Year**	8,760
Stack Exit Temp. (°K)	699.817	**Fuel Type**	Dairy Bio Gas
BHP	1,468		

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The emission rates used for criteria pollutant modeling were:

Pollutant	lb/hr	lb/yr
CO	15.6966	50,818
NO_x	3.2364	4,582.7
SO_x	0.1295	1,134.0
PM_{10}	0.2265	1,984.6
H_2S	6.0834	N/A

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Bio-Gas Engine	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass[1]	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
H_2S	Pass[3]	X	X	X	X

*Results were taken from the attached PSD spreadsheet.

[1] The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.

[2] The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

[3] H_2S emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Toxic emissions summary
D. Prioritization score
E. Facility Summary

APPENDIX D
Draft ATCs
(S-8637-1-0, -2-0, & -3-0)

FOR PROJECT FILE
Emissions Profiles

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8637-1-0

ISSUANCE DATE: DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

CONDITIONS

1. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
4. The digester system cover(s) shall be designed and installed in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 - Roofs and Covers. [District Rule 2201]
5. The digester system shall be designed to allow gas generated during summer conditions to be stored for more than 24 hours prior to venting in the event that the gas cannot be combusted in digester gas-fired engines or sent to another device with a VOC control efficiency of at least 95% by weight as determined by the APCO. [District Rule 2201]
6. The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]
7. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services
S-8637-1-0 Mar 16 2016 1:06PM – NORMANR Joint Inspection NOT Required

8. {3658} This permit does not authorize the violation of any conditions established for this facility in the Conditional Use Permit (CUP), Special Use Permit (SUP), Site Approval, Site Plan Review (SPR), or other approval documents issued by a local, state, or federal agency. [Public Resources Code 21000-21177: California Environmental Quality Act]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-8637-2-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS

MAILING ADDRESS:
2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION:
17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services
S-8637-2-0 : Mar 16 2016 1:06PM – NORMANR Joint Inspection NOT Required

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]

10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]

11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]

12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]

15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]

16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]

17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]

18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]

19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]

21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]

22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]
53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]
54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]
55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]
56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-8637-3-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

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Arnaud Marjollet, Director of Permit Services
S-8637-3-0 : Mar 16 2016 1:06PM – NORMANR : Joint Inspection NOT Required

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]
10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]
14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

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31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

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35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

Exhibit 13

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Jim Rexroad
Avenal Power Center LLC
500 Dallas Street, Level 31
Houston, TX 77002

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rexroad:

Enclosed is the District's final determination of compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the PDOC were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

cc: Gary Rubenstein, Sierra Research

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Tollstrup:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

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Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

www.valleyair.org www.healthyairliving.com

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Gerardo C. Rios (AIR 3)
Chief, Permits Office
Air Division
U.S. E.P.A. - Region IX
75 Hawthorne Street
San Francisco, CA 94105

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rios:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the Preliminary Determination of Compliance (PDOC) were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Joseph Douglas
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Douglas:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

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Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

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www.valleyair.org www.healthyairliving.com

Fresno Bee

NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to Avenal Power Center LLC for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the DOC in direct response to comments received from the oversight agencies and other interested parties. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements.

The application review for project C-1100751 is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

Avenal Power Center Project
California Energy Commission
Application for Certification Docket #: 08-AFC-01

Facility Name: Avenal Power Center, LLC
Mailing Address: 500 Dallas Street, Level 31
Houston, TX 77002

Contact Name: Jim Rexroad
Telephone: (713) 275-6147
Fax: (713) 275-6115
Cell: (832) 748-1060
E-Mail: jim.Rexroad@macquarie.com

Alternate Contact: Eric Walther
Telephone: (916) 444-6666
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Cell: (916) 883-8774
E-Mail: ewalther@sierraresearch.com

Alternate Contact: Tracey Gilliland
Telephone: (713) 275-6148
Cell: (512) 217-3002
E-Mail: tracey.gilliland@macquarie.com

Engineer: Derek Fukuda, Air Quality Engineer
Lead Engineer: Joven Refuerzo, Supervising Air Quality Engineer

Project #: C-1100751
Application #'s: C-3953-10-1, C-3953-11-1, C-3953-12-1, C-3953-13-1, and C-3953-14-1
Submitted: March 3, 2010

Table of Contents

I. PROPOSAL:

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 564 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

While Avenal Power Center, LLC has already received a Determination of Compliance for the above described facility, they are now proposing to limit the annual facility wide NO_X emissions from 288,618 lb/year to 198,840 lb/year, and the annual facility wide CO emissions from 1,205,418 lb/year to 197,928 lb/year. The effect of these limits will be two-fold: one, should the facility operate to its full permitted extent, it will have the lowest annual average permitted emissions of NO_X (0.045 lb-NOx/MWh) and CO (0.044 lb-CO/MWh) of any natural gas fired power plant known to the District; and two, the facility will be limited to less than the 100 tons/year major source thresholds of the federal prevention of significant deterioration program.

The Avenal Energy Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

The facility submitted an application to revise their existing DOC issued under Project C-1080386. This revision consists of limiting the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year. The equipment the DOC was issued for in project C-1080386 has not been implemented. All units in this project will be treated as new emissions units.

II. APPLICABLE RULES:

Rule 1080	Stack Monitoring (12/17/92)
Rule 1081	Source Sampling (12/16/93)
Rule 1100	Equipment Breakdown (12/17/92)
Rule 2010	Permits Required (12/17/92)
Rule 2201	New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 2540	Acid Rain Program (11/13/97)

Rule 2550	Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001	New Source Performance Standards (4/14/99) Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units Subpart GG - Standards of Performance for Stationary Gas Turbines Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines Subpart JJJJ -Standards of Performance for Stationary Spark Ignition Internal Combustion Engines Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/20/2004) Subpart ZZZZ - National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4202	Particulate Matter Emission Rate (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4305	Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
Rule 4351	Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
Rule 4701	Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702	Stationary Internal Combustion Engines – Phase 2 (1/18/07)
Rule 4703	Stationary Gas Turbines (9/20/07)
Rule 4801	Sulfur Compounds (12/17/92)
Rule 8011	General Requirements (8/19/04)
Rule 8021	Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031	Bulk Materials (8/19/04)
Rule 8041	Carryout and Trackout (8/19/04)
Rule 8051	Open Areas (8/19/04)
Rule 8061	Paved and Unpaved Roads (8/19/04)
Rule 8071	Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 8081	Agricultural Sources (9/16/04)

California Environmental Quality Act (CEQA)

California Code of Regulations (CCR), Section 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment)

California Health & Safety Code (CH&S), Sections 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment) 41700 (Health Risk Analysis), 42301.6 (School Notice), 44300 (Air Toxic "Hot Spots"), and 93115 (Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines)

III. PROJECT LOCATION:

The proposed equipment will be located within NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 (See Attachment B). The closest population center is the residential district of Avenal approximately 6 miles to the southwest. The City of Huron is located approximately 8 miles to the north, and the City of Coalinga is located approximately 16 miles to the west.

The site is located northeast of the city of Avenal, in Kings County. The proposed location is not within 1,000' of a K-12 school.

IV. PROCESS DESCRIPTION:

Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0048 lb/MMBtu (without duct burner firing)
0.0050 lb/MMBtu (with duct burner firing)

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the

HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners
Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator
The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler
One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump
Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

V. EQUIPMENT LISTING:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

Each CTG will be equipped with a Dry Low NO_X combustor and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO catalyst. The use of Dry Low NO_X combustors and a SCR system with ammonia injection can achieve a NO_X emission rate of 2.0 ppmvd @ 15% O_2. CO emissions of 2.0 ppmvd @ 15% O_2 have been demonstrated with the use of an oxidation catalyst (1). And the use of DLN combustors and good combustion practices can achieve VOC emissions of 2.0 ppmvd @ 15% O_2.

Emissions from natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X. Prompt NO_X is formed in both fuel-rich flame zones and dry low NO_X (DLN) combustion zones. The contribution of prompt NO_X to overall NO_X emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_X emissions in DLN combustors. For this reason prompt NO_X becomes an important consideration for DLN combustor designs, and establishes a minimum NO_X level attainable in lean mixtures.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

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[1] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_X formation during combustion. This is known as dry low NO_X (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_X formation can result in increased CO emissions.

Post-combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

ii. C-3953-12-1 (Boiler)

Emissions from natural gas-fired boilers include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when burning natural gas. NO_X formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_X) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_X). Due to the low fuel nitrogen content of natural gas, nearly all NO_X emissions are thermal NO_X. Formation of thermal NO_X is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The Cleaver Brooks boiler will control the formation of thermal NO_X with an Cleaver Brooks ultra low NO_X burner. Cleaver Brooks burners reduce NO_X by pre-mixing gaseous fuel and combustion air in a region near the burner exit, at a stoichiometry that minimizes Prompt NO_X. This also eliminates the traditional NO_X versus CO tradeoff.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The diesel-fired emergency IC engine (fire pump) will be equipped with a turbocharger, an intercooler/aftercooler, and will be fired on very low (0.0015%) sulfur diesel.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[2]

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.0015% by weight sulfur maximum) diesel fuel reduces SO_X emissions by approximately 99% from standard diesel fuel.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

The natural gas-fired emergency IC engine (generator) will be equipped with an intercooler/aftercooler, lean burn technology, and will be fired on PUC-Regulated natural gas.

The emission control devices/technologies and their effect on natural gas engine emissions are detailed below.

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[2] From "Non-catalytic NO_X Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

VII. GENERAL CALCULATIONS:

The facility has proposed to limit the annual facility wide NO_X emission to 198,840 lb/year, and the annual facility wide CO emission to 197,928 lb/year.

All PM_{10} emissions are assumed to be $PM_{2.5}$ emissions.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- Maximum daily emissions for each CTG for VOC, PM_{10} and SO_X during the commissioning period are estimated assuming twenty-four (24) hours operating while firing at full load.
- The commissioning period will not exceed 408 hours per CTG and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.
- Maximum daily emissions for each CTG for NO_X, CO, and VOC are estimated assuming six (6) hours operating in startup and shutdown mode and eighteen (18) hours operating while firing at full load with operation of the duct burner.
- Maximum daily emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming twenty-four (24) hours operating while firing at full load with the operation of the duct burner.
- Maximum annual emissions for each CTG for VOC are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was

operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule.

- The facility has proposed a facility wide NO_X emission limit of 198,840 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for NO_X are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated NO_X emissions from an individual turbine operating at this scenario (calculated in Section VII.C.2) is not greater than the proposed facility wide NO_X emission limit; however the NO_X emissions from the operation of both turbines according to this scenario are far greater than the proposed facility wide NO_X emission limit. Therefore, the facility wide limit is a valid limit and the NO_X emissions from the turbines will ultimately be restricted by this limit.

- The facility has proposed a facility wide CO emission limit of 197,928 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for CO are estimated assuming the CTG is operated according to a weekend shutdown and weekday hot start scenario. The weekend shutdown and weekday hot start scenario results in CTG operation of 624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated CO emissions from this scenario (calculated in Section VII.C.2) are greater than the proposed facility wide CO emission limit; therefore the facility wide emissions limit is a valid limit and the turbine's CO emissions will ultimately be restricted by this limit.

- Maximum annual emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming the CTG is operated according to a baseload scenario. The baseload scenario results in CTG operation of 800 hours operating while firing at full load with the duct burner and 7,960 hours operating while firing at full load without the duct burner.

ii. C-3953-12-1 (Boiler)

- External O_2 stack gas concentration is 3%.
- Natural gas F factor is 8,710 dscf/MMBtu (Ref. 40 CFR Part 60, Appendix A, Method 19).
- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- The applicant is proposing a maximum natural gas usage rate of 37.4 MMBtu/hr.
- Maximum SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

  (1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00282 lb/MMBtu

- Maximum daily and annual emissions for all pollutants are estimated assuming twelve (12) hours per day and 1,248 hours per year operating at full load.[3]
- Operating schedule of 12 hr/day and 1,248 hrs/year.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

- Diesel F factor (adjusted to 60 °F) is 9,051 dscf/MMBtu.
- Density of diesel is 7.1 lb/gal.
- Higher heating value of diesel is 137,000 Btu/scf.
- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

iv. C-3953–14-1 (Natural gas IC engine powering electrical generator)

- EPA F-factor (adjusted to 60 °F) is 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Fuel heating value 1,013 Btu/dscf (per applicant)
- Maximum daily SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

  (1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00282 lb/MMBtu

- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

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[3] Applicant has indicated that the unit will be used a maximum of 12 hours on a startup day.

B. Emission Factors

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

Commissioning Period Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A(5)	N/A[4]

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% O_2), and startup and shutdown emissions rates (lb/hr) provided by the applicant (see Attachment D for applicant proposed emissions) for the proposed CTGs are summarized below.

The emission rates from the turbines and duct burners are calculated below:

Maximum Emission Rate Without Duct Burner Firing:

The worst-case NO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 32 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG without the duct burner firing:

Emission Rate (lb/hr) = CTG Max Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 13.55 lb-NO_X/hr

CO Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= 8.35 lb-CO/hr

VOC Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0018 lb-VOC/MMBtu)
= 3.34 lb-VOC/hr

PM_{10} Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0048 lb-PM_{10}/MMBtu)
= 8.91 lb-PM_{10}/hr

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[4] PM_{10} and SO_X emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= 5.23 lb-SO_X/hr

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:

ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64×10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w/o duct burner 1.832 MMscf/hour, as calculated below)
(1,856.3 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 1.832 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 1.832 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= 25.31 lb-NH3/hr

Maximum Emission Rates and Concentrations Without Duct Burner Firing (@ 100% Load & 32 °F)

	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	13.55	8.35	3.34	8.91	5.23	25.31
ppmvd @ 15% O_2 limits	2.0	2.0	1.4	--	--	10.0
lb/MMBtu*	0.0073	0.0045	0.0018	0.0048	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Maximum Emission Rate With Duct Burner Firing:

The worst-case NO_X, SO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 101 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG with the duct burner firing:

Emission Rate (lb/hr) = [CTG Max Heat Input + Duct Burner Max Heat Input] (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 17.20 lb-NO_X/hr

CO Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= **10.60 lb-CO/hr**

VOC Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0025 lb-VOC/MMBtu)
= **5.89 lb-VOC/hr**

PM_{10} Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0050 lb-PM_{10}/MMBtu)
= **11.78 lb-PM_{10}/hr**

SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= **6.65 lb-SO_X/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:

ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64 x 10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w duct burner 2.326 MMscf/hour, as calculated below)
(2,356.5 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 2.326 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x
1,013 (Btu/scf) x 2.326 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= **32.13 lb-NH3/hr**

Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 101 °F)

	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	17.20	10.60	5.89	11.78	6.65	32.13
ppmvd @ 15% O_2 limits	2.0	2.0	2.0	--	--	10.0
lb/MMBtu*	0.0074	0.0045	0.0025	0.0050	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Startup and Shutdown Emissions					
	NO$_X$	CO	VOC	PM$_{10}$	SO$_X$
Maximum Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A(6)	N/A(5)
Average Mass Emission Rate (per turbine, lb/hr)	80	900	16	N/A(6)	N/A(6)

ii. C-3953-12-1 (Boiler)

For the new boiler, the emissions factors for NO$_X$, CO, VOC, and PM$_{10}$ are provided by the applicant. The SO$_X$ emission factor is calculated as shown below.

Boiler Emission Factors*		
Pollutant	ppmv @ 3%O$_2$	lb/MMBtu
NO$_X$	9.0	0.011
CO	50.0	0.037
VOC	10.0	0.0043
PM$_{10}$	--	0.005
SO$_X$**	--	0.00282

*Note: lb/MMBtu equivalent of ppmv values @ 3% O$_2$ as provided by the Applicant
** SO$_X$ emission factor based on the maximum proposed sulfur content of 1 gr/100 dscf.

(1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO$_X$/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

For the new emergency diesel-fired IC engine powering a fire water pump, the emissions factors for NO$_X$, CO, VOC, and PM$_{10}$ are provided by the applicant and are guaranteed by the engine manufacturer. The SO$_X$ emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

Diesel-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO$_X$	3.4	Engine Manufacturer
CO	0.447	Engine Manufacturer
VOC	0.38	Engine Manufacturer
PM$_{10}$	0.059	Engine Manufacturer
*SO$_X$	0.005	Mass Balance Equation Below

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[5] PM$_{10}$ and SO$_X$ emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.

$$^{*}0.0015\% \times \frac{7.1\,lb \cdot fuel}{gallon} \times \frac{2\,lb \cdot SO_2}{1\,lb \cdot S} \times \frac{1\,gal}{137{,}000\,Btu} \times \frac{1\,hp\ input}{0.35\,hp\ out} \times \frac{2{,}542.5\,Btu}{hp \cdot hr} \times \frac{453.6\,g}{lb} = 0.005\,\frac{g\ SOx}{hp \cdot hr}$$

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

For the new emergency natural gas-fired IC engine powering an electrical generator, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the fuel sulfur content from District Policy APR 1720.

Natural Gas-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	1.0	Engine Manufacturer
CO	0.6	Engine Manufacturer
VOC	0.33	Engine Manufacturer
PM_{10}	0.034	Engine Manufacturer
**SO_X	0.0094	Mass Balance Equation Below

**SO_X is calculated as follows:

$$0.00285\,\frac{lb-SO_x}{MMBtu} \times \frac{1\,MMBtu}{1{,}000{,}000\,Btu} \times \frac{2{,}542.5\,Btu}{bhp-hr} \times \frac{1\,bhp\ input}{0.35\,bhp\ out} \times \frac{453.6\,g}{lb} = 0.0094\,\frac{g-SO_x}{bhp-hr}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this is a brand new facility, the pre-project potential to emit (PE1) for all the emissions units associated with this project is equal to zero.

2. Post Project Potential to Emit (PE2):

i. C-3953-10-1 and C-3953-11-1 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A(6)	11.78	8.91	8.91	23.56
SO_X	N/A(7)	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. Maximum Daily PE

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A(7)	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A(7)	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

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[6] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

c. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

$$SO_X\ EF = (0.36\ \cancel{gr\ S}/100\ \cancel{dscf}) \times (1\ \cancel{lb\ S}/7000\ \cancel{gr}) \times (64\ lb\ SO_X/32\ \cancel{lb\ S}) \times (1\ \cancel{scf}/1013\ \cancel{Btu}) \times (10^6\ \cancel{Btu}/MMBtu)$$
$$\mathbf{= 0.001\ lb\text{-}SO_X/MMBtu}$$

<u>CTG w/o Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 1.86 lb-SO_X/hr

<u>CTG w/ Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 2.36 lb-SO_X/hr

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

<u>Scenario 1) Weekend and Weekday Hot Start:</u>

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit
Scenario 1) Weekend and Weekday Hot Start*

	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO$_X$	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM$_{10}$	N/A$^{(7)}$	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO$_X$	N/A$^{(7)}$	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH$_3$	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM$_{10}$, SO$_X$, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit
Scenario 2) Weekend Shutdown and Weekday Hot Start*

	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO$_X$	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM$_{10}$	N/A$^{(7)}$	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO$_X$	N/A$^{(7)}$	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH$_3$	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*

	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit

	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	197,928 lb/year	Facility Wide Limit
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

d. Maximum Quarterly PE

Maximum quarterly emissions for each unit will be determined by dividing the maximum annual emissions into 4 quarters:

Maximum Quarterly Potential to Emit						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
1st Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
2nd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
3rd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
4th Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993

ii. C-3953-12-1 (Boiler)

The potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{NOx} = (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.41 lb NO_X/hr**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **4.9 lb NO_X/day**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **513 lb NO_X/year**

= (513 lb NO_X/year) ÷ (4 qtr/year)
= **128 lb NO_X/qtr**

PE_{CO} = (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **1.38 lb CO/hr**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **16.6 lb CO/day**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **1,727 lb CO/year**

= (1,727 lb CO/year) ∗ (4 qtr/year)
= **432 lb CO/qtr**

PE_{VOC} = (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.16 lb VOC/hr**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.9 lb VOC/day**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **201 lb VOC/year**

= (201 lb/year) ∗ (4 qtr/year)
= **50 lb VOC/qtr**

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

PE_{SOx} = (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.11 lb SO_X/hr**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.3 lb SO_X/day**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **132 lb SO_X/year**

= (132 lb/year) ∗ (4 qtr/year)
= **33 lb SO_X/qtr**

Post Project Potential to Emit (PE2)
(C-3953-12-1)

	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	0.41	4.9	128	513
CO	1.38	16.6	432	1,727
VOC	0.16	1.9	50	201
PM_{10}	0.19	2.2	58	233
SO_X	0.11	1.3	33	132

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **2.16 lb NO_X/hr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **51.8 lb NO_X/day**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **27 lb NO_X/qtr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **108 lb NO_X/year**

PE_{CO} = (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.28 lb CO/hr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb ∗ (24 hr/day)
= **6.8 lb CO/day**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **4 lb CO/qtr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **14 lb CO/year**

PE_{VOC} = (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.24 lb VOC/hr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **5.8 lb VOC/day**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **3 lb VOC/qtr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **12 lb VOC/year**

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

PE_{SOx} = (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.00 lb SO_X/hr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.1 lb SO_X/day**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **0 lb SO_X/year**

Post Project Potential to Emit (PE2)
(C-3953-13-1)

	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	2.16	51.8	27	108
CO	0.28	6.8	4	14
VOC	0.24	5.8	3	12
PM_{10}	0.04	0.9	0.5	2
SO_X	0.00	0.1	0	0

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

The emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.90 lb NO_X/hr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **45.5 lb NO_X/day**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **24 lb NO_X/qtr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **95 lb NO_X/year**

PE_{CO} = (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.14 lb CO/hr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **27.3 lb CO/day**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **14 lb CO/qtr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **57 lb CO/year**

PE_{VOC} = (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.63 lb VOC/hr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **15.0 lb VOC/day**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **8 lb VOC/qtr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **31 lb VOC/year**

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

PE_{SOx} = (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.02 lb SO_X/hr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.4 lb SO_X/day**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1 lb SO_X/year**

Post Project Potential to Emit (PE2)
(C-3953-14-1)

	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	1.90	45.5	24	95
CO	1.14	27.3	14	57
VOC	0.63	15.0	8	31
PM_{10}	0.06	1.5	1	3
SO_X	0.02	0.4	0	1

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. The District is issuing a DOC for this project and not individual ATC's. Therefore, the SSPE2 will be determined by summing the potential emissions from the units included in the DOC.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)							
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3	$PM_{2.5}$ ***
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972	80,656
C-3953-11-1			34,489	80,656	16,694	219,972	80,656
C-3953-12-1			201	233	132	0	233
C-3953-13-1			12	2	0	0	2
C-3953-14-1			31	3	1	0	3
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**	**161,550**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.
*** All PM_{10} emissions are $PM_{2.5}$.

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a major source is a stationary source with post-project emissions or a Post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

Major Source Determination						
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)	$PM_{2.5}$ (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521	161,550
Major Source Threshold	50,000	200,000	50,000	140,000	140,000	200,000
Major Source?	Yes	No	Yes	Yes	No	No

6. Annual Baseline Emissions (BE)

Per District Rule 2201, Section 3.7, the baseline emissions, for a given pollutant, shall be equal to the pre-project potential to emit for:

- Any emission unit located at a non-major source,
- Any highly utilized emission unit, located at a major source,
- Any fully-offset emission unit, located at a major source, or
- Any clean emission unit located at a major source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201

As shown above, this facility will be a major source for NO_X, VOC, and PM_{10} emissions after this project. However, since the units in this project are all new emissions units, there are no historical actual emissions or pre-project potential to emit. Therefore, the baseline NO_X, CO, VOC, PM_{10} and SO_X emissions will be set equal to the following:

BE = 0 lb/year

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

Since this is a new facility, this project cannot be considered a Major Modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. COMPLIANCE:

Rule 1080 Stack Monitoring

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The two CTGs will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

- Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

ii. C-3953-12-1 (Boiler)

The boiler will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

- {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

Rule 1081 Source Sampling

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

- Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001]

- Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

ii. C-3953-12-1 (Boiler)

The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

<u>Proposed Rule 1081 Conditions</u>:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1100 Conditions:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]
- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of a DOC application, Avenal Power Center, LLC is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. BACT:

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install two new combustion turbine generators with PEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

The PE of ammonia is greater than two pounds per day for the two CTGs. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_X. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

ii. C-3953-12-1 (Boiler)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new boiler with a PE greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, and PM_{10} criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new diesel-fired IC engine (fire pump) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas-fired IC engine (generator) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

2. BACT Guidance

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

Attachment E will include the BACT Guidelines from the BACT Clearinghouse applicable to the new emissions units associated with this project.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT Guideline 3.4.2 is applicable to the two combustion turbine generator installations [Gas Fired Turbine = or > 50 MW, Uniform Load, with Heat Recovery].

ii. C-3953-12-1 (Boiler)

BACT Guideline 1.1.2 is applicable to the 37.4 MMBtu/hr boiler. [Boiler - > 20 MMBtu/hr, Natural gas-fired, base-loaded or with small load swings.]

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engine powering a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump]

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

BACT Guideline 3.1.8, applies to the natural gas-fired emergency IC engine powering an electrical generator. [Emergency Gas-Fired I.C. Engine > or = 250 hp, Lean Burn]

3. Top-Down Best Available Control Technology (BACT) Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

For Permit Units C-3953-10-1 and -11-1 see Attachment F.

For Permit Unit C-3953-12-1 see Attachment F.

For Permit Unit C-3953-13-1 see Attachment F.

For Permit Unit C-3953-14-1 see Attachment F.

4. BACT Summary:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT has been satisfied by the following:

NO_X: 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with Dry Low NO_X Combustors, SCR with ammonia injection and natural gas fuel.

VOC: 1.5 ppmv @ 15% O_2 (without duct burner firing; 3-hour rolling average).
2.0 ppmv @ 15% O_2 (with duct burner firing; 3-hr rolling average).

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_X: PUC regulated natural gas with a sulfur content of 1.0 gr/100 scf or less

ii. C-3953-12-1 (Boiler)

BACT has been satisfied by the following:

NO_X: 9.0 ppmv @ 15% O_2 with Ultra Low NO_X burners and natural gas fuel.

VOC: Natural gas fuel.

PM_{10}: Natural gas fuel.

SO_X: Natural gas fuel.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

BACT has been satisfied by the following:

NO_X: Certified NO_X emissions of 6.9 g/hp·hr or less

VOC: No VOC control. Any add on VOC control device would void the Underwriters Laboratory (UL) certification.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

BACT has been satisfied by the following:

NO_X: = or < 1.0 g/bhp-hr (lean burn natural gas fired engine, or equal)

VOC: 90% control efficiency (oxidation catalyst, or equal)

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

C. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X, CO, VOC, PM_{10}, and SO_X emissions. Therefore, offset calculations are necessary.

Offset Determination

	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	No	Yes	Yes	No

2. Quantity of Offsets Required:

Per District Rule 2201, Section 4.6.1, emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X, VOC, and PM_{10} is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
SSPE2 = Post Project Facility Potential to Emit, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit units C-3953-13-1 and C-3953-14-1 will be exempt from providing offsets and the emissions associated with these permit units contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = ([SSPE2 – Emergency Equipment - Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

<u>NO_X Offset Calculations:</u>

The facility has proposed to provide the same quarterly offsets that were required to be provided in the facility's initial project (C-1080386). The reason for this request is to enable the facility to preserve full flexibility to operate the facility at the previously permitted rates during any calendar quarter, provided the new annual emission limits are not exceeded. The facility is required to maintain a 12 month rolling calculation of their NO_X and CO emissions; therefore compliance with this quarterly limit will be enforceable. The quarterly offsets from project C-1080386 are shown below.

Quarterly Emissions to be Offset (Project C-1080386)

Annual Offsets = 268,415 lb/year $*$ DOR

Quarterly Offsets $_{\text{1st Qtr}}$ = 67,103.75 lbs of $NO_X * $ DOR
Quarterly Offsets $_{\text{2nd Qtr}}$ = 67,103.75 lbs of $NO_X * $ DOR
Quarterly Offsets $_{\text{3rd Qtr}}$ = 67,103.75 lbs of $NO_X * $ DOR
Quarterly Offsets $_{\text{4th Qtr}}$ = 67,103.75 lbs of $NO_X * $ DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of NO_X ERC's that need to be withdrawn is:

Offsets Required = 268,415 lb-NO_X/year x 1.5
Offsets Required = 402,623 lb-NO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
NO_X	100,655	100,656	100,656	100,656	402,623

The applicant has stated that the facility plans to use ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 to offset the increases in NO_X emissions associated with this project. The above Certificates have available quarterly NO_X credits as follows:

Offset Proposal

	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-899-2	2,243	2,243	2,243	2,243	**8,972**
ERC #C-902-2	13,879	6,131	1,086	8,539	**29,635**
ERC #N-720-2	0	9	1,255	437	**1,701**
ERC #N-722-2	0	1,166	88,317	1,422	**90,905**
ERC #N-726-2	0	0	4,728	0	**4,728**
ERC #N-728-2	10,542	3,731	2,487	5,171	**21,931**
ERC #S-2814-2	6,121	13,869	18,914	11,461	**50,365**
ERC #S-2321-2*	51,000	51,000	51,000	51,000	**204,000**
Total	**83,784**	**78,147**	**170,027**	**80,269**	**412,227**

*ERC certificate split from this ERC.

Project NO_X offset requirements

The applicant states that NO_X ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 will be utilized to supply the NO_X offset requirements.

Per Rule 2201 Section 4.13.8, Actual Emission Reductions (i.e. ERCs) that occurred from April through November (i.e. 2nd and 3rd Quarter), inclusive, may be used to offset increases in NO_X or VOC during any period of the year. Since 3rd quarter NO_X ERCs will be used to offset NO_X emissions, the above applies to the NO_X ERCs.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NO_X Emissions to be offset: (at a 1.5:1 DOR):	100,655	100,656	100,656	100,656
Available ERCs from certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2*:	83,784	78,147	170,027	80,269
3rd qtr. ERCs applied to 1st qtr. ERCs:	16,871	0	-16,871	0
3rd qtr. ERCs applied to 2nd qtr. ERCs:	0	22,509	-22,509	0
3rd qtr. ERCs applied to 4th qtr. ERCs:	0	0	-20,387	20,387
Remaining ERCs from certificates S-2321-2:	0	0	9,604	0
Remaining NO_X emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly NO_X emissions increases associated with this project.

VOC Offset Calculations:

VOC SSPE2 = 69,222 lb/year
C-3953-13-1 (VOC) = 12 lb/year
C-3953-14-1 (VOC) = 31 lb/year
VOC offset threshold = 20,000 lb/year

Offsets = [69,222 – (12) – (31) – 20,000]
= 49,179 lb/year ∗ DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

Offsets = (49,179 lb/year ÷ 4 qtr/year) ∗ DOR
= 12,294.75 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of VOC ERC's that need to be withdrawn is:

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
VOC	18,442	18,442	18,442	18,442	73,769

The applicant has stated that the facility plans to use ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 to offset the increases in VOC emissions associated with this project. The above Certificates have available quarterly VOC credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-897-1	45	45	45	45	**180**
ERC #C-898-1	5,480	6,496	4,696	6,616	**23,288**
ERC #N-724-1	0	0	241	0	**241**
ERC #N-725-1	0	0	709	0	**709**
ERC #S-2812-1	31,432	31,424	31,417	31,417	**125,690**
ERC #S-2813-1	12,500	12,500	12,500	12,500	**50,000**
ERC #S-2817-1	11,431	11,424	11,417	11,417	**45,689**
Total	**60,887**	**61,887**	**61,022**	**61,991**	**245,787**

Project VOC offset requirements

The applicant states that NO_X ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 will be utilized to supply the VOC offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
VOC Emissions to be offset: (at a 1.5:1 DOR):	18,442	18,442	18,442	18,442
Available ERCs from certificates C-897-1, C-898-1, N-724-1, N-725-1,	5,525	6,541	5,691	6,661
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
VOC Emissions to be offset: (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
Available ERCs from certificates S-2812-1, S-2813-1, and S-2817-1	55,363	55,348	55,334	55,334
Remaining ERCs from certificates S-2812-1, S-2813-1, and S-2817-1:	42,446	43,447	42,583	43,553
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

PM_{10} Offset Calculations:

PM_{10} SSPE2 = 161,550 lb/year
C-3953-13-1 (PM_{10}) = 2 lb/year
C-3953-14-1 (PM_{10}) = 3 lb/year
PM_{10} Offset threshold = 29,200 lb/year

Offsets = [(161,550 – (2) – (3) - 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Offsets = (132,345 lb/year ÷ 4 qtr/year) ∗ DOR
= 33,086 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{2nd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{3rd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{4th\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	49,630	49,629	49,629	49,630	198,518

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-896-4	80	80	80	80	**320**
ERC #N-721-4	0	0	3,215	0	**3,215**
ERC #N-723-4	0	0	985	0	**985**
ERC #S-2791-5	92,179	23,666	69,157	96,288	**281,290**
ERC #S-2790-5	12,862	491	0	8,499	**21,852**
ERC #S-2789-5	6	14	12	8	**40**
ERC #S-2788-5	5	7	3	6	**21**
ERC #N-762-5	21,000	21,000	21,000	21,000	**84,000**
Total	**126,131**	**45,256**	**94,449**	**125,877**	**391,723**

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Attachment H). Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

Offset Conditions:

The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

- ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

D. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Any project which results in the offset thresholds being surpassed (Offset Threshold Notification), and/or
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources.

As shown in Section VII.C.6 above, the SSPE2 is greater than the Major Source threshold for NO_X, VOC, and PM_{10}. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

b. Major Modification

As demonstrated in Section VII.C.7 above, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE Notification

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the table below.

Post-Project Potential to Emit						
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
C-3953-10-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-11-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-12-1	4.9	16.6	1.9	2.2	1.3	0
C-3953-13-1	51.8	6.8	5.8	0.9	0.1	0
C-3953-14-1	45.5	27.3	15.0	1.5	0.4	0
Threshold (lb/day)	**100**	**100**	**100**	**100**	**100**	**100**
Notification Required?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

According to the table above, permit units C-3953-10-1 and -11-1 will each have a Potential to Emit greater than 100 lb/day for NO_X, CO, VOC, PM_{10}, SO_X, or NH_3 emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

e. Offset Threshold

Public notification is required if the Pre-Project Stationary Source Potential to Emit (SSPE1) is increased from a level below the offset threshold to a level exceeding the emissions offset threshold, for any pollutant.

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	198,840	20,000 lb/year	Yes
CO	0	197,928	200,000 lb/year	No
VOC	0	69,222	20,000 lb/year	Yes
PM_{10}	0	161,550	29,200 lb/year	Yes
SO_X	0	33,521	54,750 lb/year	No

As detailed above, offset thresholds were surpassed for NO_X, VOC, and PM_{10} emissions with this project; therefore public noticing is required for offset purposes.

f. SSIPE Notification

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary

Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

SSIPE Notification					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_X	198,840	0	198,840	20,000 lb/year	Yes
CO	197,928	0	197,928	20,000 lb/year	Yes
VOC	69,222	0	69,222	20,000 lb/year	Yes
PM_{10}	161,550	0	161,550	20,000 lb/year	Yes
SO_X	33,521	0	33,521	20,000 lb/year	Yes

As demonstrated above, the SSIPE's for NO_X, CO, VOC, PM_{10} and SO_X emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Requirements

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. New Major Source, PE's > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

E. Daily Emission Limits:

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity.

Proposed Rule 2201 (DEL) Conditions:

The following condition will be included to demonstrate compliance with facility wide annual NO_X and CO emissions limits.

- Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

i. C-3953-10-1 and C-3953-11-1 (Turbines)

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, SO_X, and NH_3 will consist of lb/day and/or emission factors.

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

- Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

In addition to the daily emissions limits specified above, the following conditions will also be included to ensure continued compliance for the proposed turbines:

- Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

ii. C-3953-12-1 (Boiler)

The DELs for the boiler will consist of lb/MMBtu and ppmv emissions limits. This will be sufficient to establish a maximum daily potential to emit based on the maximum daily fuel use limit.

- Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00282 lb/MMBtu. [District Rules 2201, 4305, 4306, and 4351]

In addition the following permit conditions will appear on the permit:

- {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

iii. C-3953-13-1 (Diesel IC engine fire pump)

For the emergency IC engine powering a fire pump, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

For the emergency IC engine powering a generator, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

F. Compliance Certification:

Section 4.15.2 of this Rule requires the owner of a new major source or a source undergoing a major modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed above, this facility is a new major source; therefore this requirement is applicable. Included in Attachment I is Avenal Power Center's certification for the Avenal Energy Project.

G. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment G of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

AAQA Results Summary					
Pollutant	1 hr Average	3 hr Average	8 hr Average	24 hr Average	Annual Average
CO	Pass	N/A	Pass	N/A	N/A
NO_x	Pass	N/A	N/A	N/A	Pass
SO_x	Pass	Pass	N/A	Pass	Pass

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.38	1.6	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

H. Compliance Assurance:

1. Source Testing

i. C-3953-10-1 and C-3953-11-1

District Rule 4703 requires NO_X and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, CO, VOC, PM_{10}, and ammonia slip will be required within 60 days after the end of the commissioning period and at least once every 12 months thereafter.

Also, initial source testing of NO_X, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for NO_X, CO, and O_2. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be documented or monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

40 CFR Part 60 subpart Db requires NO_X testing for the duct burners. The District will accept the NO_X source testing required by District Rule 4703 as equivalent to NO_X testing required by 40 CFR 60 subpart Db.

ii. C-3953-12-1

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*. Source testing requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-1 and C-3953-14-1

Pursuant to District Policy APR 1705, source testing is not required for emergency standby IC engines to demonstrate compliance with Rule 2201.

2. Monitoring

i. C-3953-10-1 and C-3953-11-1

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK and District Rule 4703 requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to allow the facility to demonstrate compliance with the limit by providing gas purchase contracts, supplier certification, tariff sheet or transportation contract; or, if these documents cannot be provided, physically monitor the fuel sulfur content weekly for eight consecutive weeks and semi-annually thereafter if the fuel sulfur content remains below 1.0 gr/scf. Avenal Power Center, LLC will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

ii. C-3953-12-1

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to monitoring requirements. Monitoring requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-1 and C-3953-14-1

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

i. C-3953-10-1 and C-3953-11-1

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

ii. C-3953-12-1

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

The following permit condition will be listed on permit as follows:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

iii. C-3953-13-1 and C-3953-14-1

Recordkeeping is required to demonstrate compliance with the offset, public notification, and daily emission limit requirements of Rule 2201. As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, these IC engines are subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

4. Reporting

i. C-3953-10-1 and C-3953-11-1

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the NO_X emission limit of the permit. Such reporting will be required.

ii. C-3953-12-1

No reporting is required to demonstrate compliance with Rule 2201.

iii. C-3953-13-1 and C-3953-14-1

No reporting is required to demonstrate compliance with Rule 2201.

Rule 2520 Federally Mandated Operating Permits

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.3 states, "Any major source." The facility will be a major source for NO_X, VOC, and PM_{10} after this project.
- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.
- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.
- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is not required to obtain a PSD permit.

Pursuant to Rule 2520 section 5.3.1 Avenal Power Center must submit a Title V application within 12 months of commencing operations. No action is required at this time.

  - Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Rule 2540 Acid Rain Program

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in November of 2011.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

The following condition will be placed on permits C-3953-10-1, -11-1 and -14-1 to ensure that Avenal Power Center, LLC submits an application to comply with the requirements of the acid rain program within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00, and Table 3.4-1 of the Background Document for Section 3.1), from the California Air Resources Board's CATEF database for gas turbines, and from source tests on a similar turbine. Specifically, factors for all pollutants except formaldehyde, hexane, propylene, and naphthalene and other PAHs were taken from AP-42.[8] AP-42 did not contain factors for hexane or propylene, and did not include speciated data for PAHs. Factors for these pollutants and for naphthalene were taken from the CATEF database (mean values). The emission factor for formaldehyde was taken from the results of a June 2000 source test on a dry Low NO_X combustor-equipped large frame turbine.

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[7] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).

[8] Factors for acrolein and benzene reflect the use of an oxidation catalyst and were taken from Table 3.4-1 of the Background Document for Section 3.1.

Hazardous Air Pollutant Emissions (per CATEF)
Avenal Energy Project – GE Frame 7 (with Duct Burners)

Hazardous Air Pollutant	CATEF Emission Factor (lb/MMSCF)(1)	Maximum Hourly Emissions per Turbine (lb/hr) (2)	Maximum Annual Emissions per Turbine (tpy) (3)	Maximum Annual Emissions both Turbines (tpy)
Acetaldehyde	4.08E-02	0.09	0.33	0.67
Acrolein	3.69E-03	0.01	0.03	6.04E-02
Benzene	3.33E-03	0.01	0.03	5.45E-02
1,3-Butadiene	4.39E-04	9.38E-04	3.59E-03	7.19E-03
Ethyl benzene	3.26E-02	0.07	0.27	0.53
Formaldehyde	1.65E-01	0.35	1.35	2.70
Hexane	2.59E-01	0.55	2.12	4.24
Naphthalene	1.33E-03	2.84E-03	1.09E-02	2.18E-02
Polycyclic aromatic hydrocarbons (PAH)	---	---	---	---
Anthracene	3.38E-05	7.22E-05	2.77E-04	5.53E-04
Benzo(a)anthracene	2.26E-05	4.83E-05	1.85E-04	3.70E-04
Benzo(a)pyrene	1.39E-05	2.97E-05	1.14E-04	2.28E-04
Benzo(b)fluoranthrene	1.13E-05	2.41E-05	9.25E-05	1.85E-04
Benzo(k)fluoranthrene	1.10E-05	2.35E-05	9.00E-05	1.80E-04
Chrysene	2.52E-05	5.38E-05	2.06E-04	4.12E-04
Dibenz(a,h)anthracene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Indeno(1,2,3-cc)pyrene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Propylene oxide	2.96E-02	6.32E-02	2.42E-01	0.48
Toluene	1.33E-01	0.28	1.09	2.18
Xylenes	6.53E-02	0.14	0.53	1.07
Total			**6.01**	**12.02**

(1) From AP-42 and CATEF databases and source tests.
(2) Based on a maximum hourly turbine fuel use of 2,224.1 MMBtu/hr (with duct burner) and fuel HHV of 1,021 Btu/scf. (2.14 MMscf/hr)
(3) Based on a maximum annual turbine fuel use of 16,711,728 MMBtu/year (with duct burner) and fuel HHV of 1,021 Btu/scf. (16,368 MMscf/yr)

Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein and benzene emission factors reflect any control effectiveness. As discussed above, these factors are based on test data rather than any assumption regarding catalyst control efficiency.

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the Avenal Power Center, LLC Project will not be a major air toxics source and the provisions of this rule do not apply.

Rule 4001 New Source Performance Standards

40 CFR 60 – Subpart Dc

NSPS Subpart Dc applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for SO_X and PM_{10}.

60.42c – Standards for Sulfur Dioxide

Since coal is not combusted by the boiler in this project, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter

The boiler is not fired on coal, combusts mixtures of coal with other fuels, combusts wood, combusts mixtured of wood with other fuels, or oil; therefore it will not be subject to the requirements of this section.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

Since the boiler in this project is not subject to the particulae matter requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.46c – Emission Monitoring for Sulfur Dioxide

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.47c – Emission Monitoring for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the units are not subject to §60.42c or §40.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO_2 emissions.

Section 60.48 c (g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be added to the permit to assure compliance with this section.

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

- Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4306 requires that records be kept for five years.

40 CFR 60 – Subpart GG

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 - Subpart IIII

§60.4200 - Applicability

40 CFR Part 60 Subpart IIII applies to all owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

1) Manufactured after April 1, 2006, if not a fire pump engine.
2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engines will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable standards of this subpart are less restrictive than current District requirements. This engine will comply with all current District standards so further discussion is required.

40 CFR Part 60, Subpart JJJJ

The engine in this project is rated at over 100 bhp and per 60.4233(e) is subject to the limits presented in Table 1 of this subpart. The Table 1 limits as well as the proposed emissions are shown on the following table. This regulation does not specify an emissions averaging period.

	Table 1 Limit	Proposed Emissions	Compliant
NOx (g/bhp-hr)	2.0	1.0	Yes
CO (g/bhp-hr)	4.0	0.6	Yes
VOC (g/bhp-hr)	1.0	0.33	Yes

Therefore, the natural gas-fired IC engine in this project meets all applicable requirements of this subpart.

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 1,794.5 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

Avenal Power Center is proposing a NO_X emission concentration limit of 2.0 ppmvd @ 15% O_2 for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_X emission requirements of this subpart. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.44 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 6.13 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.72 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.28 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.23 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.97 lb/hr; or SOx (as SO2) – 5.11 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 60.4330 - Standards for Sulfur Dioxide:

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Avenal Power Center is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Avenal Power Center does not use water or steam injection in their turbines therefore; the requirements of this section are not applicable to the turbines in this project.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

Avenal Power Center has proposed to install a CEMS system as described in §§60.4335(b) and 60.4345 therefore; the following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

Avenal Power Center will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, Avenal Power Center is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]
- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

Section 60.4350 – CEMS Data and Excess NO_X Emissions:

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Avenal Power Center is proposing to monitor the NO_X emissions rates from the turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

<u>Section 60.4355 – Parameter Monitoring Plan:</u>

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, Avenal Power Center is proposing to install CEMS on each of these turbines that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Avenal Power Center is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, Avenal Power Center has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, Avenal Power Center is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. Avenal Power Center is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for the turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Avenal Power Center is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. Avenal Power Center is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

Avenal Power Center will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. Avenal Power Center is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Susequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

Avenal Power Center will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). Avenal Power Center has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, Avenal Power Center is proposing to install a CEMS system to monitor the NO_X emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Avenal Power Center is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. Avenal Power Center is not proposing to measure the SO_2 in the exhaust stream of the turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

40 CFR 63 Subpart ZZZZ

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§6585(b) states, "A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site."

§6585(c) states, "An area source of HAP emissions is a source that is not a major source."

The facility is not a major source as defined in §6585(b). Therefore, this facility is an area source of HAP emissions.

§6590(a) states, "An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand." Since the engines in this project are new stationary RICE's at an area source of HAP emissions, they are defined as affected sources.

§6590(a)(2) defines the criteria for an new stationary RICE as follows:

> (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.
>
> (ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.
>
> (iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

This facility is an area source of HAP emissions. The engines at this facility have not been constructed and therefore meets the definition of an new stationary RICE as defined in §6590(a)(2)(iii).

§6590(b)(1) states that an affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

> (i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.
>
> (ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

Since the enignes in this project are not located at a major source of HAP emissions they do not qualify for the limited requirements stated above.

§6590(b)(2) and (3) apply to landfill or digester gas fired RICE's and existing RICE's. Since the engines in ths project are not exsiting RICE's and are fired on diesel fuel or natural gas, these sections do not apply to the RICE's in this project.

§6590(c) states that an affected source that is listed below must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

- new or reconstructed stationary RICE located at an area source,
- new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP,
- or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP,

Since both the RICE's in this project are new stationary RICE's located at an area source, they will demonstrate compliance with this Subpart by demonstrating compliance with the requirements of 40 CFR part 60 subpart IIII and for compression ignition engines and 40 CFR part 60 subpart JJJJ for spark ignited engines. As shown previously in this evaluation, the RICE's in this project meet the requirements of 40 CFR part 60 subpart IIII and subpart JJJJ; therefore they meet the requirements of this subpart.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

ii. C-3953-12-1 (Boiler)

Based on past experiences with natural gas-fired boilers, no visible emissions are expected to be as dark as or darker than Ringelmann 1 (or 20% opacity). The following condition will be placed on the DOC to assure compliance with this rule.

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, the following condition will be added to the permit to assure compliance with this rule.

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit as shown in the table below:

Screen HRA Summary

	Acute Hazard Index	Chronic Hazard Index	70 yr Cancer Risk	T-BACT Required?
C-3953-10-1 (Turbine #1)	0.0	0.0	0.02	No
C-3953-11-1 (Turbine #2)	0.0	0.0	0.02	No
C-3953-12-1 (Auxiliary Boiler)	0.0	0.0	0.01	No
C-3953-13-1 (Diesel-Fired IC Engine Fire Pump)	N/A*	N/A*	0.01	No
C-3953-14-1 (NG-Fired IC Engine Generator)	0.2	0.0	0.0	No

* Acute and Chronic Hazard Indices were not calculated since there is not a risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

i. C-3953-10-1 and –11-1 (Turbines)

PM Conc. (gr/scf) = (PM emission rate) x (7000 gr/lb)

PM_{10} emission rate = 11.78 lb/hr. Assuming 100% of PM is PM_{10}
Exhaust Gas Flow = 1,071,653 dscfm

PM Conc. (gr/scf)=[(11.78 lb/hr) ∗ (7,000 gr/lb)] ÷ [(1,071,653 ft^3/min) ∗ (60 min/hr)]
PM Conc. = 0.0012 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all these turbines will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

ii. C-3953-12-1 (Boiler)

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
PM10 Emission Factor: 0.005 lb-PM10/MMBtu
Percentage of PM as PM10 in Exhaust: 100%
Exhaust Oxygen (O_2) Concentration: 3%
Excess Air Correction to F Factor = $\frac{20.9}{(20.9 - 3)}$ = 1.17

$$GL = \left(\frac{0.005\ lb-PM}{MMBtu} \times \frac{7{,}000\, grain}{lb-PM} \right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times\ 1.17 \right)$$

$$GL = 0.0035\ \ grain/dscf < 0.1\, grain/dscf$$

Therefore, compliance with District Rule 4201 requirements is expected and a permit condition will be listed on the permit as follows:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iii. C-3953-13-1 (Diesel IC engine fire pump)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.059\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.014\ \frac{grain-PM}{dscf}$$

Since 0.014 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.034\ \frac{g-PM_{10}}{bhp-hr}\times\frac{1g-PM}{0.96g-PM_{10}}\times\frac{1bhp-hr}{2{,}542.5\,Btu}\times\frac{10^{6}\,Btu}{9{,}051\,dscf}\times\frac{0.35\,Btu_{out}}{1\,Btu_{in}}\times\frac{15.43\,grain}{g}=\ 0.008\ \frac{grain-PM}{dscf}$$

Since 0.008 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to any of the permit units in this project, and no further discussion is required.

Rule 4301 *Fuel Burning Equipment*

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The CTG's primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTG's primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

ii. C-3953-12-1 (Boiler)

District Rule 4301 Limits			
Pollutant	NO_2	Total PM	SO_2
C-3953-12-1 (lb/hr)	0.41	0.19	0.10
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance is expected.

iii. C-3953-13-1 (Diesel IC engine fire pump)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

Rule 4304 Tuning Procedure for Boilers, Steam Generators and Process Heaters

This rule is only applicable to unit C-3953-12-1.

Pursuant to District Rules 4305 and 4306, Section 6.3.1, the boiler is not required to tune since it follows a District approved Alternate Monitoring scheme where the applicable emission limits are periodically monitored. Therefore, the unit is not subject to this rule.

Rule 4305 Boilers Steam Generators and Process Heaters – Phase 2

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

Conclusion

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

Rule 4306 Boilers Steam Generators and Process Heaters – Phase 3

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306.

Section 5.1, NO_X and CO Emissions Limits

Section 5.1.1 requires that except for units subject to Sections 5.2, NO_X and carbon monoxide (CO) emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

With a maximum heat input of 37.4 MMBtu/hr, the applicable emission limit category is listed in Section 5.1.1, Table 1, Category B, from District Rule 4306.

Rule 4306 Emissions Limits

Category	Operated on gaseous fuel		Operated on liquid fuel	
	NO_X Limit	CO Limit	NO_X Limit	CO Limit
B. Units with a rated heat input greater than 20.0 MMBtu/hr, except for categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	400 ppmv	40 ppmv or 0.052 lb/MMBtu	400 ppmv

For the unit:

- the proposed NO_x emission factor is 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% O_2 (0.037 lb/MMBtu).

Therefore, compliance with Section 5.1 of District Rule 4306 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

Section 5.2, Low Use

The unit annual heat input will exceed the 9 billion Btu heat input per calendar year criteria limit addressed by this section. Since the unit is not subject to Section 5.2, the requirements of this section do not apply to the unit.

Section 5.3, Startup and Shutdown Provisions

Section 5.3 states that on and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.3.1 through 5.3.4.

According to boiler manufacturers, low NO_X burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the unit will be subject to the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 while in operation.

Section 5.4, Monitoring Provisions

Section 5.4.2 requires that permit units subject to District Rule 4306, Section 5.1 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NO_X, CO and O_2, or install and maintain APCO-approved alternate monitoring.

The facility has proposed to install a CEMS system to satisfy the requirements of this section. The following condition will assure compliance with this section.

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

Since the unit is not subject to the requirements listed in Section 5.2.1 or 5.2.2, it is not subject to Section 5.4.3 requirements.

Since the unit is not subject to the requirements of category H (maximum annual heat input between 9 billion and 30 billion Btu/year) listed in Section 5.1.1, it is not subject to Section 5.4.4 requirements.

Section 5.5, Compliance Determination

Section 5.5.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the permit as follows:

- {2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

Section 5.5.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the permit as follows:

- {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

Section 5.5.4 requires that for emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Since the applicant does not use a portable analyzer to satisfy the monitoring requirements of District Rule 4306 the requirements of Section 5.5.4 do not apply.

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

- {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

Section 6.1, Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

A permit condition will be listed on the permit as follows:

- {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

Section 6.1.2 requires that the operator of a unit subject to Section 5.2 shall record the amount of fuel use at least on a monthly basis. Since the unit is not subject to the requirements listed in Section 5.2, it is not subject to Section 6.1.2 requirements.

Section 6.1.3 requires that the operator of a unit subject to Section 5.2.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. The unit is not subject to Section 6.1.3. Therefore, the requirements of this section do not apply to the unit.

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO_X	ppmv	EPA Method 7E or ARB Method 100
NO_X	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O_2	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

The following permit conditions will be listed on the permit as follows:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {2977} NO_X emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]
- {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]
- {2979} Stack gas oxygen (O_2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

Section 6.3, Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months.

The following permit conditions will be listed on the permit as follows:

- {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]
- {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]
- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.4, Emission Control Plan (ECP)

Section 6.4.1 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4306.

The proposed modified unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule and with periodic monitoring and source testing requirements. Therefore, this current application for the new proposed unit satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is required.

Section 7.0, Compliance Schedule

Section 7.0 indicates that an operator with multiple units at a stationary source shall comply with this rule in accordance with the schedule specified in Table 2, Section 7.1 of District Rule 4306.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule, and periodic monitoring and source testing as required by District Rule 4306. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4306, are satisfied. No further discussion is required.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permit(s). Therefore, compliance with District Rule 4306 requirements is expected.

Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1

This rule is only applicable to unit C-3953-12.

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. If applicable, the emission limits, monitoring provisions, and testing requirements of this rule are satisfied when the unit is operated in compliance with Rule 4306. Therefore, compliance with this rule is expected.

Rule 4701 Internal Combustion Engines – Phase 1

This rule is only applicable to units C-3953-13-1 and –14-1.

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

Rule 4702 Internal Combustion Engines – Phase 2

This rule is only applicable to units C-3953-13-1 and –14-1.

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.

Pursuant to Section 4.2, except for the requirements of Sections 5.7 and 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following condition:

1) An emergency standby engine as defined in Section 3.0 of this rule, and provided that it is operated with a nonresettable elapsed operating time meter. In lieu of a nonresettable time meter, the owner of an emergency engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Section 3.15 defines an "Emergency Standby Engine" as an internal combustion engine which operates as a temporary replacement for primary mechanical or electrical power during an unscheduled outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the operator. An engine shall be considered to be an emergency standby engine if it is used only for the following purposes: (1) periodic maintenance, periodic readiness testing, or readiness testing during and after repair work; (2) unscheduled outages, or to supply power while maintenance is performed or repairs are made to the primary power supply; and (3) if it is limited to operate 100 hours or less per calendar year for non-emergency purposes. An engine shall not be considered to be an emergency standby engine if it is used: (1) to reduce the demand for electrical power when normal electrical power line service has not failed, or (2) to produce power for the utility electrical distribution system, or (3) in conjunction with a voluntary utility demand reduction program or interruptible power contract.

Therefore, unit C-3953-14-1, the emergency standby IC engine powering an electrical generator involved with this project will only have to meet the requirements of Sections 5.7 and 6.2.3 of this Rule.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, unit C-3953-13-1, the emergency IC engine powering a firewater pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 5.7 of this Rule requires that the owner of an emergency standby engine shall comply with the requirements specified in Section 5.7.2 through Section 5.7.5 below:

1) Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier.

2) Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.

3) Install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO and is allowed by Permit-to-Operate or Stationary Equipment Registration condition. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the following conditions will be listed on the DOC to ensure compliance:

C-3953-14-1 (Natural Gas IC engine electrical generator)

- This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

- During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

- An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

- This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be listed on the DOC to ensure compliance:

C-3953-13-1 (Diesel IC engine fire pump)

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the DOC to ensure compliance:

- {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

- {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

C-3953-14-1 (Natural Gas IC engine electrical generator)

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

Rule 4703 Stationary Gas Turbines

This rule is only applicable to units C-3953-10-1 and -11-1.

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 180 MW gas turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – NO_X Emission Requirements:

Section 5.1.1 (Tier I) of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR). Since the proposed turbines will meet the more stringent Tier 2 emission equirements in Section 5.1.2, compliance with this section is assured.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.0 ppmv @ 15% O_2 (based on a 1-hour average), therefore compliance with this section is expected. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines (General Electric Frame 7) must be less than 25 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

Avenal Power Center is proposing a CO emission concentration limit of 2 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The DEL conditions shown in the Section 5.1.2 compliance section will ensure continued compliance with the requirements of this section.

Section 5.3 – Startup and Shutdown Requirements:

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

Avenal Power Center is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than six hours per day. Since this proposed duration is longer than what is allowed in Section 5.3.1.1, the facility must meet the requirements of Section 5.3.3.2. Section 5.3.3.2 states that at a minimum, a justification for the increased duration shall include the following:

A clear identification of the control technologies or strategies to be utilized; and

The facility has identified the following control technologies:

- Dry low-NOx combustors in the turbines;
- Oxidation catalyst in the HRSGs;
- SCR in the HRSGs;
- Good combustion practices;

- Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures specified by the SCR vendor.

<u>A description of what physical conditions prevail during the period that prevent the controls from being effective; and</u>

The combined-cycle equipment startup duration depends on how fast the thick steel walls of the common steam turbine can be warmed to operating temperature without generating stress cracks. Steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. The allowable rate of temperature increase at the steam turbine is the limiting factor determining how quickly the gas turbines can achieve higher loads. This, in turn, limits how quickly the gas turbine combustors can achieve the lowest emitting operating mode, and this latter step is necessary for the units to be able to comply with the limits of Rule 4703.

<u>A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and</u>

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of four hours is required for the unit to come into compliance with the limits of Rule 4703. Depending on the temperature of the steam turbine at the time the start is initiated, shorter durations may be possible.

<u>A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and</u>

The facility has provided the District with a detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity.

<u>A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and</u>

The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the HRH and HP bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NOx to N_2. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufacturer's recommended procedures.

The basis for the requested additional duration.

The startup curve in Attachment I and the description of activities above demonstrate that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbines. To be confident that the startup time allowed is adequate and will not be exceeded, one hour is added to the above startup time to account for possible delays.

Since the facility has demonstrated compliance and provided all the information asked for in Section 5.3.3.2, the proposed increase in startup and shutdown emissions is compliant with District Rule 4703. The following conditions will ensure continued compliance with the requirements of this section:

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Recordkeeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the NO_X and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbines have not been installed. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Avenal Power Center will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. Avenal Power Center will be required, by permit condition, to submit information correlating the NO_X control system operating parameters to the associated measured NO_X output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. Avenal Power Center will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, Avenal Power Center will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

Sections 6.3 and 6.4 - Compliance Testing:

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The turbines operated by Avenal Power Center are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbines will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner both on and off. The following condition will ensure continued compliance with the requirements of this section:

- Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

i. C-3953-10-1 and –11-1 (Turbines)

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the SO_X exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_X: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_X produced per MMBtu of fuel.
- Weight of SO_X as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00282\ lb}{MMBtu} \times \frac{1\ (lb-mol)}{64\ lb} = 0.000045\ (lb-mol)$

- $R = \frac{0.7302\, ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \frac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.016}{8{,}578} = 0.0000019 = 1.9\ ppmv = 0.00019\%\ by\ volume$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines, the boiler, and the gas engine are expected to comply with Rule 4801.

ii. C-3953-12-1 (Boiler)

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

$$\text{Volume } SO_2 = \frac{n\ RT}{P}$$

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot °R}$

$$\frac{0.00282\, lb - SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\, dscf} \times \frac{1\, lb \cdot mol}{64\, lb} \times \frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot °R} \times \frac{520°R}{14.7\, psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 1.97\, \frac{parts}{million}$$

$SulfurConcentration = 1.97 \frac{parts}{million}$ < 2,000 ppmv (or 0.2%)

Therefore, compliance with District Rule 4801 requirements is expected.

iii. C-3953-13-1 (Diesel IC engine powering a fire water pump)

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

$$\frac{0.000015\,lb - S}{lb - fuel} \times \frac{7.1\,\text{lb}}{\text{gal}} \times \frac{64\,\text{lb} - \text{SO}_2}{32\,\text{lb} - \text{S}} \times \frac{1\,\text{MMBtu}}{9{,}051\,\text{scf}} \times \frac{1\,\text{gal}}{0.137\,\text{MMBtu}} \times \frac{\text{lb} - \text{mol}}{64\,\text{lb} - \text{SO}_2} \times \frac{10.73\,\text{psi} - \text{ft}^3}{\text{lb} - \text{mol} - {}^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7\,\text{psi}} \times 1{,}000{,}000 = 1.0\ \text{ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-1 (Natural gas IC engine powering an electrical generator)

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

$$2.85\ \frac{lb - S}{MMscf - gas} \times \frac{1\,scf - gas}{1{,}000\,Btu} \times \frac{1\,MMBtu}{8{,}578\,scf} \times \frac{1\,lb - mol}{64\,lb - S} \times \frac{10.73\,psi - ft^3}{lb - mol - {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times 1{,}000{,}000 = 1.97\ \text{ppmv}$$

Since 1.97 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

District Rule 8011	***General Requirements***
District Rule 8021	***Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities***
District Rule 8031	***Bulk Materials***
District Rule 8041	***Carryout And Trackout***
District Rule 8051	***Open Areas***
District Rule 8061	***Paved And Unpaved Roads***
District Rule 8071	***Unpaved Vehicle/Equipment Traffic Areas***
District Rule 8081	***Agricultural Sources***

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

California Environmental Quality Act (CEQA)

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

California Health & Safety Code, Section 42301.6 (School Notice)

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)

The requirements of this section are only applicable to C-3953-13-1.

Particulate Matter and VOC + NO_X, and CO Exhaust Emissions Standards:

This regulation stipulates that off-road compression-ignition engines shall not exceed the following applicable emissions standards.

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.15 g/bhp-hr (with 1.341 bhp/kW, equivalent to 0.20 g/kW-hr) for 2003 - 2005 model year engines with maximum power ratings of 174.3 - 301.6 bhp (equivalent to 130 - 225 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

Title 17 CCR, Section 93115, (e)(2)(A)(3)(b) stipulates that new stationary emergency diesel-fueled CI engines (> 50 bhp) must meet the VOC + NO_X, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13 CCR, Section 2423) or the Tier 1 standards for an off-road engine if no standards have been established for an off-road engine of the same model year and maximum rated power.

In addition, Title 17 CCR, Section 93115, (e)(2)(A)(4)(a)(II) allows new direct-drive emergency fire pump engines to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423) until three years after the date the Tier 3 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 3 emission standards, until three years after the date the Tier 4 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 4 emission standards; and not operate more than the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition, which is incorporated herein by reference. In addition, this subsection does not limit engine operation for emergency use and for emission testing to show compliance with (e)(2)(A)4. For this project the proposed emergency diesel IC engine will be used to power a firewater pump and is therefore allowed to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines three years after the applicable dates specified. This additional three-year allowance is reflected in the following table.

The engine involved with this project is a certified 2007 model engine. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the 288 bhp Cummins Model #CFP83-F40 diesel-fired emergency IC engine as given by the manufacturer (for NO_X + VOC and PM emissions).

Requirements of Title 13 CCR, Section 2423							
Source	Maximum Rated Power	Model Year	NO_X	VOC	NO_X + VOC	CO	PM
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	1996-2002 (Tier 1)	6.9 g/bhp-hr (9.2 g/kW-hr)	1.0 g/bhp-hr (1.3 g/kW-hr)	--	8.5 g/bhp-hr (11.4 g/kW-hr)	0.40 g/bhp-hr (0.54 g/kW-hr)
Title 13 CCR, §2423	**174.3 – 301.6 bhp (130 - 225 kW)**	**2003-2005, extended to 2008 (Tier 2)**	--	--	**4.9 g/bhp-hr (6.6 g/kW-hr)**	**2.6 g/bhp-hr (3.5 g/kW-hr)**	**0.15 g/bhp-hr (0.20 g/kW-hr)**
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	2006 and later, extended to 2009 (Tier 3)	--	--	3.0 g/bhp-hr (4.0 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Cummins, Model #CFP83-F40	288 bhp	2007	--	--	3.8g/bhp-hr (5.1 g/kW-hr)	0.447 g/bhp-hr (0.60 g/kW-hr)	0.059 g/bhp-hr (0.079 g/kW-hr)
Meets Standard?			N/A	N/A	Yes	Yes	Yes

As presented in the table above, the proposed engine will satisfy the requirements of this section and compliance is expected.

The engine manufacturer's data and/or CARB/EPA engine certification for this engine lists a NO_X emissions factor of 3.4 g/bhp-hr, a VOC emissions factor of 0.38 g/bhp-hr, a NO_X + VOC emission factor of 3.8 g/bhp-hr, a CO emission factor of 0.447 g/bhp-hr, and a PM_{10} emissions factor of 0.059 g/bhp-hr, all of which satisfy the requirements of 13 CCR, Section 2423. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

Right of the District to Establish More Stringent Standards:

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, NO_X + VOC, VOC, NO_X, and CO emission rate standards; and

2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial start-up testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

The requirements of this section are only applicable to C-3953-13-1.

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;
c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:
    I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
    II. Amount of fuel purchased;
    III. Date when the fuel was purchased;
    IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
    V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-3953-10-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-11-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-12-1	3020-02-H	37.4 MMBtu/hr boiler	$953.00
C-3953-13-1	3020-10-C	288 bhp IC engine	$222.00
C-3953-14-1	3020-10-E	860 bhp IC engine	$557.00

ATTACHMENT A

FDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-3953-10-1:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in

accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated

emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from

the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance

with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

58. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

59. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

60. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

61. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

62. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

63. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

64. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

65. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

66. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

67. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality

assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the

equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with

the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

EQUIPMENT DESCRIPTION, UNIT C-3953-12-1:
37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

5. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

6. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this DOC. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

7. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the DOC. [District Rule 2201]

9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

10. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

11. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

12. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

13. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

14. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

15. {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

16. Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00285 lb/MMBtu. [District Rules 2201, 4305, and 4306]

17. {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

18. {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]

19. {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]

20. {2976} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

21. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

22. {2977} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]

23. {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]

24. {2979} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

25. {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

26. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

27. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

28. Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

29. {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

30. {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

27\. {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

28. {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

29. {1835} The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

30. {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

31. {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

32. {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

33. {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

EQUIPMENT DESCRIPTION, UNIT C-3953-13-1:
288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

7. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

8. {3403} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

9. Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

10. Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

11. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

12. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

13. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

14. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

EQUIPMENT DESCRIPTION, UNIT C-3953-14-1:
860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

6. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

7. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

8. {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

9. {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

10. Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

11. {3405} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

12. {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

13. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

14. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

15. {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

16. {3496} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

17. {3497} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

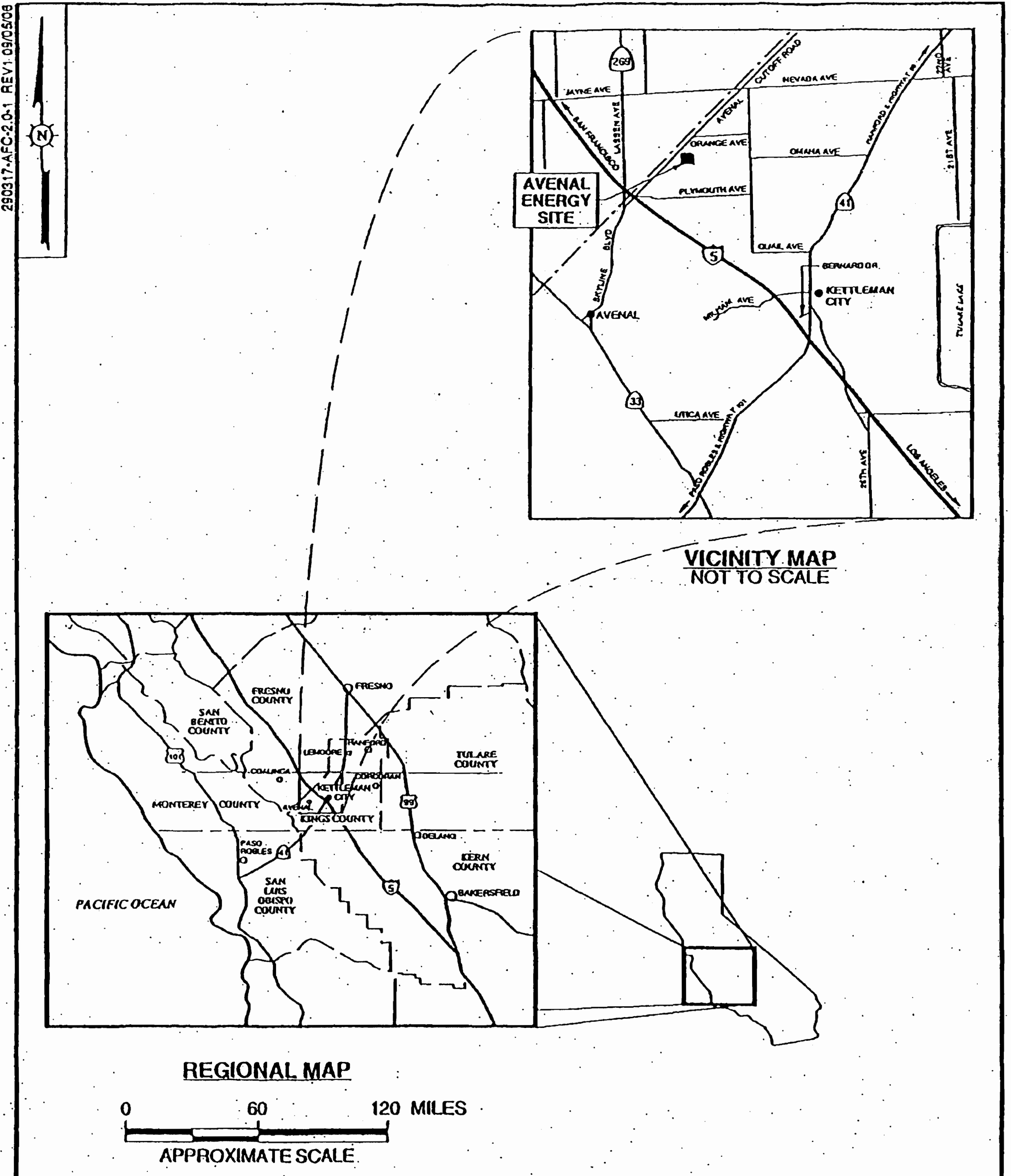
ATTACHMENT B

Project Location and Site Plan

ATTACHMENT C

CTG Commissioning Period Emissions Data

290317-AFC-2.0-1 REV1 09/05/08



VICINITY MAP
NOT TO SCALE

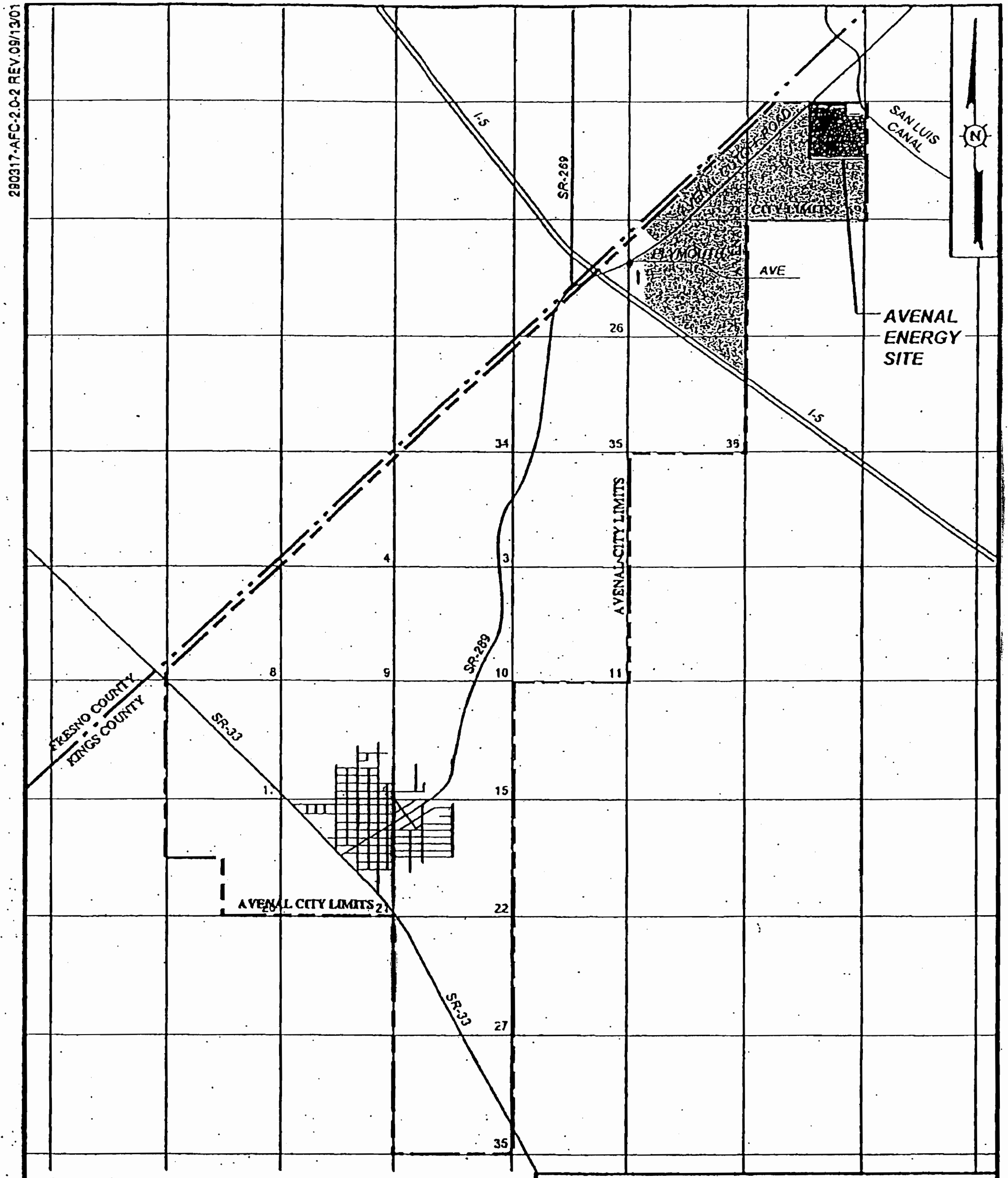
REGIONAL MAP

REGIONAL LOCATION MAP

FEDERAL ENERGY AVENAL, LLC

AVENAL ENERGY	FIGURE 2.0-1

280317-AFC-2.0-2 REV.09/13/01



LEGEND

▨ INDUSTRIAL ZONE (CITY OF AVENAL GENERAL PLAN AND ZONING ORDINANCE)

0 6,000 12,000 FEET

SCALE

REFERENCE: CITY OF AVENAL GENERAL PLAN.

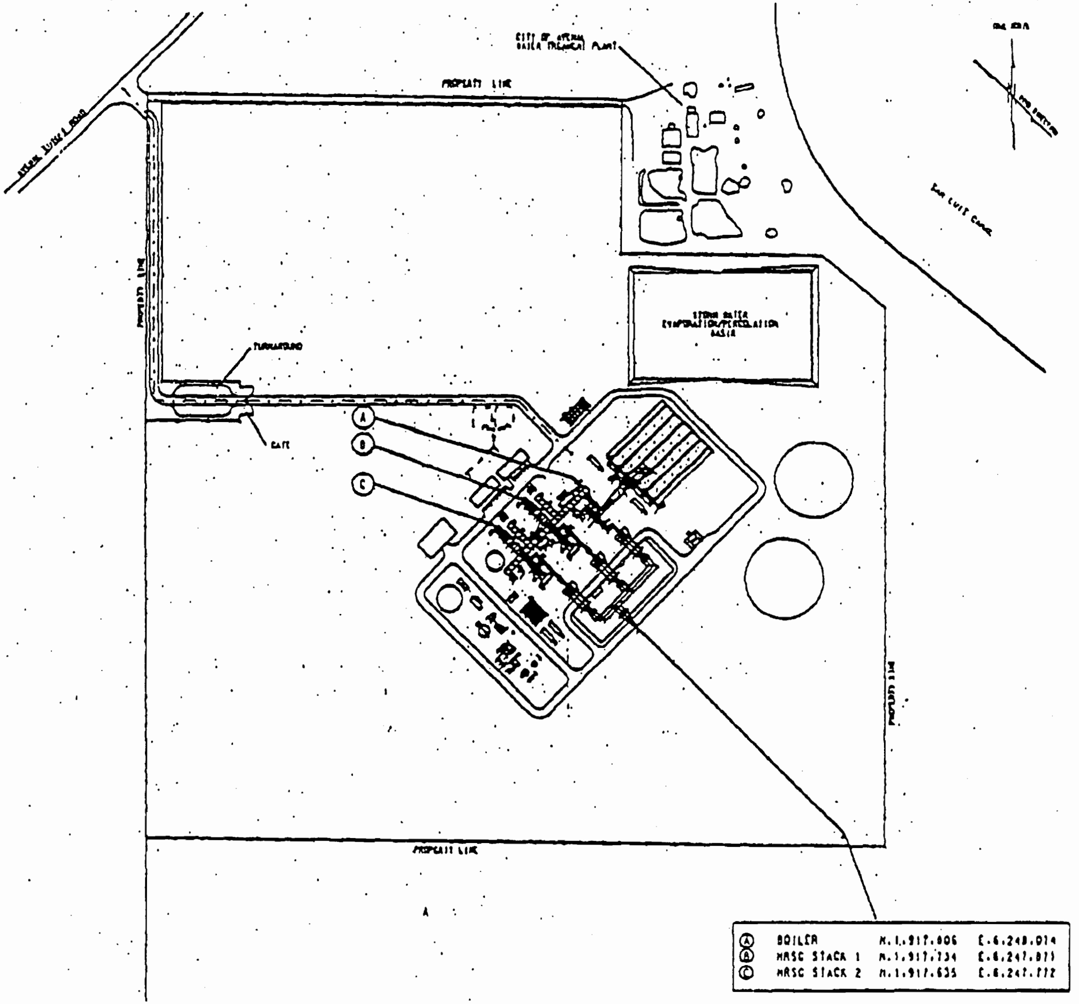
1 36.094 -120.093

SITE LOCATION

② Av Rd crosses horiz rd near development
36.109 -120.0486

FEDERAL POWER AVENAL, LLC

AVENAL ENERGY	FIGURE 2.0-2



Ⓐ	BOILER	N.1,917,806	E.6,248,014
Ⓑ	HRSG STACK 1	N.1,917,734	E.6,247,811
Ⓒ	HRSG STACK 2	N.1,917,635	E.6,247,772

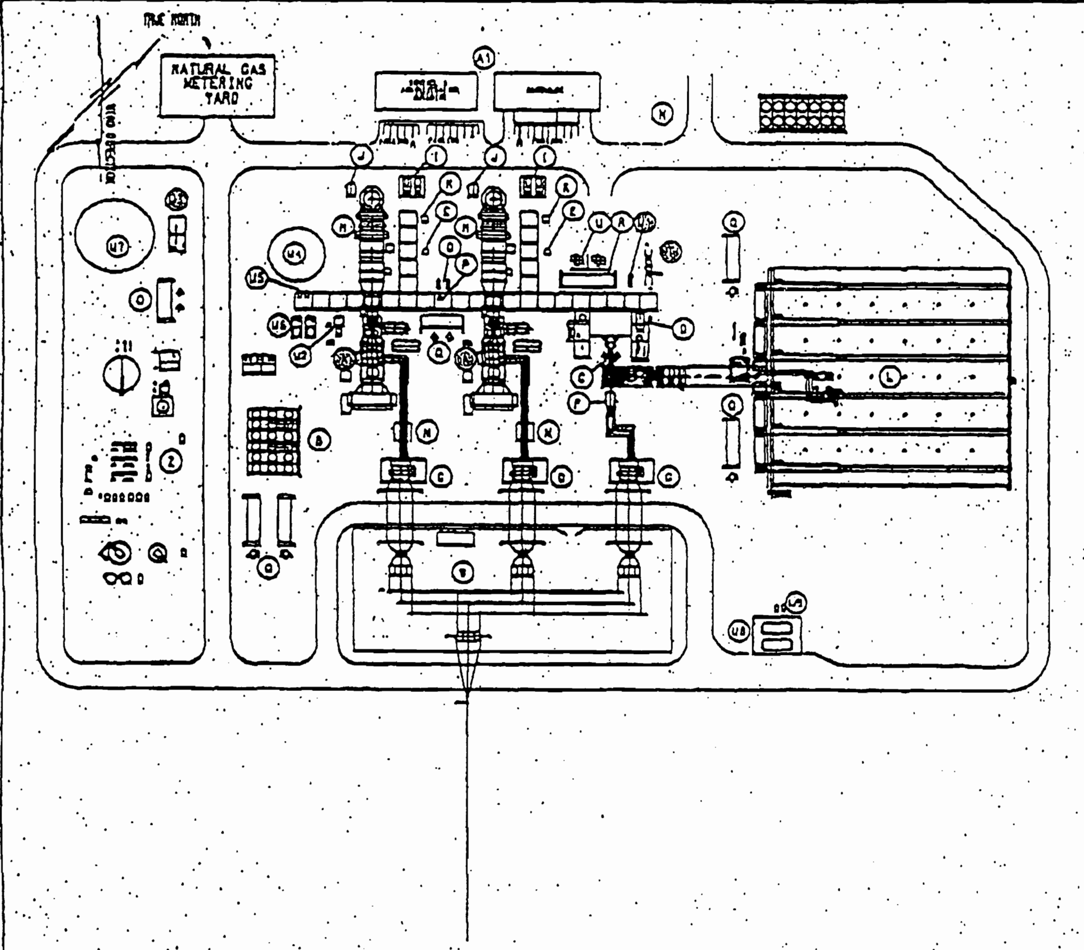
A	11/01	ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

FIGURE 2.1-4
SITE PLAN
CONCEPTUAL DESIGN

A3DV01-1-SP-5-00-1
A



MAJOR EQUIPMENT LIST

A GAS TURBINE GENERATOR
B INLET AIR CHILLERS
C STEAM TURBINE
D STG LUBE OIL SKID
E HRSG BLOW DOWN DRUM
F STG GENERATOR
G MAIN TRANSFORMERS
H HEAT RECOVERY STEAM GENERATOR
I HP/IP BOILER FEED WATER PUMPS
J CONTINUOUS EMISSIONS MONITORING SYSTEM
K HRSG BLOWDOWN SUMP
L AIR COOLED CONDENSER
M GENERATOR BREAKERS
N CLOSED COOLING WATER AIR COOLER
O CIRCULATING COOLING WATER PUMPS
P CLOSED COOLING WATER EXPANSION TANK
Q POWER DISTRIBUTION CENTER (480 V)
R POWER DISTRIBUTION CENTER (4160 V)
S
T AUXILIARY BOILER
U UNIT AUXILIARY TRANSFORMER
V
W SWITCHYARD
X RAW WATER SOFTENER CLARIFIERS (RWSC)
Y RWSC FILTER PRESS
Z ZERO LIQUID DISCHARGE FACILITY (ZLDF)

A1 SEPTIC TANK & LEACH FIELD (IMMEDIATELY NW)
A2 STORM WATER EVAPORATION/PERCOLATION BASIN

UTILITIES

U1 STANDBY DIESEL GENERATOR
U2 OIL/WATER SEPARATOR
U3 FIREWATER PUMP HOUSE
U4 DEMINERALIZED WATER STORAGE TANK
U5 DEMINERALIZED WATER PUMPS
U6 PLANT/INSTRUMENT AIR COMPRESSORS
U7 RAW WATER/FIREWATER STORAGE TANKS
U8 AMMONIA STORAGE TANKS
U9 AMMONIA TRANSFER PUMPS

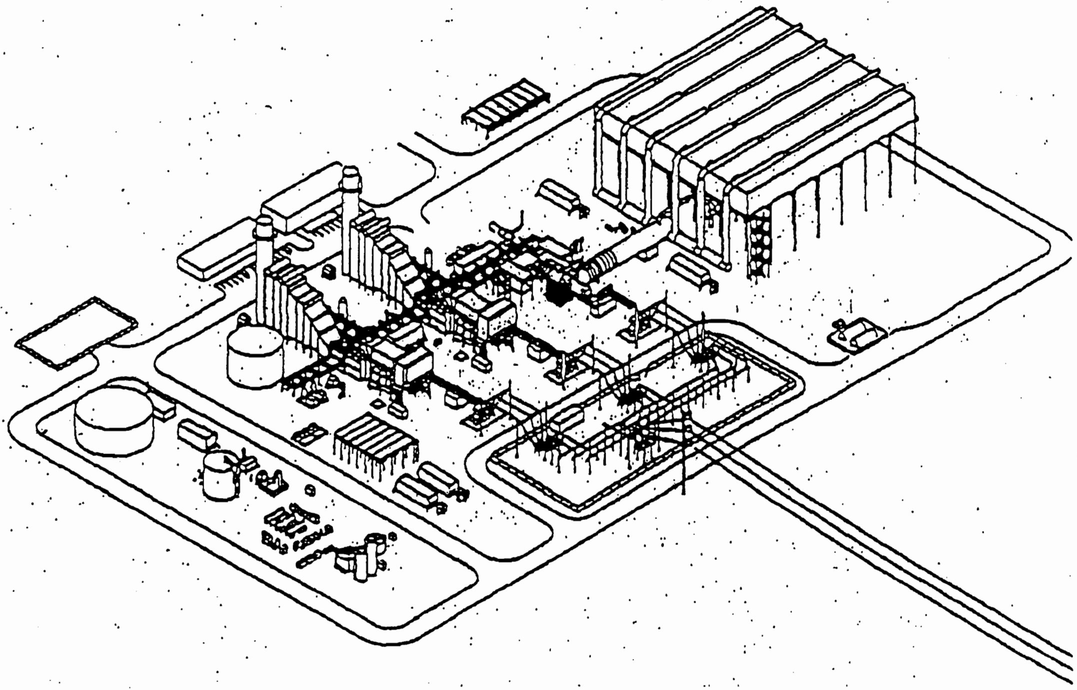
A [illegible] ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

FIGURE 2.3-3
PLOT PLAN
CONCEPTUAL DESIGN

1"=120'
A3DY01-1-PP-0-00-1
A



A	[illegible]	ISSUED FOR REVIEW						

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

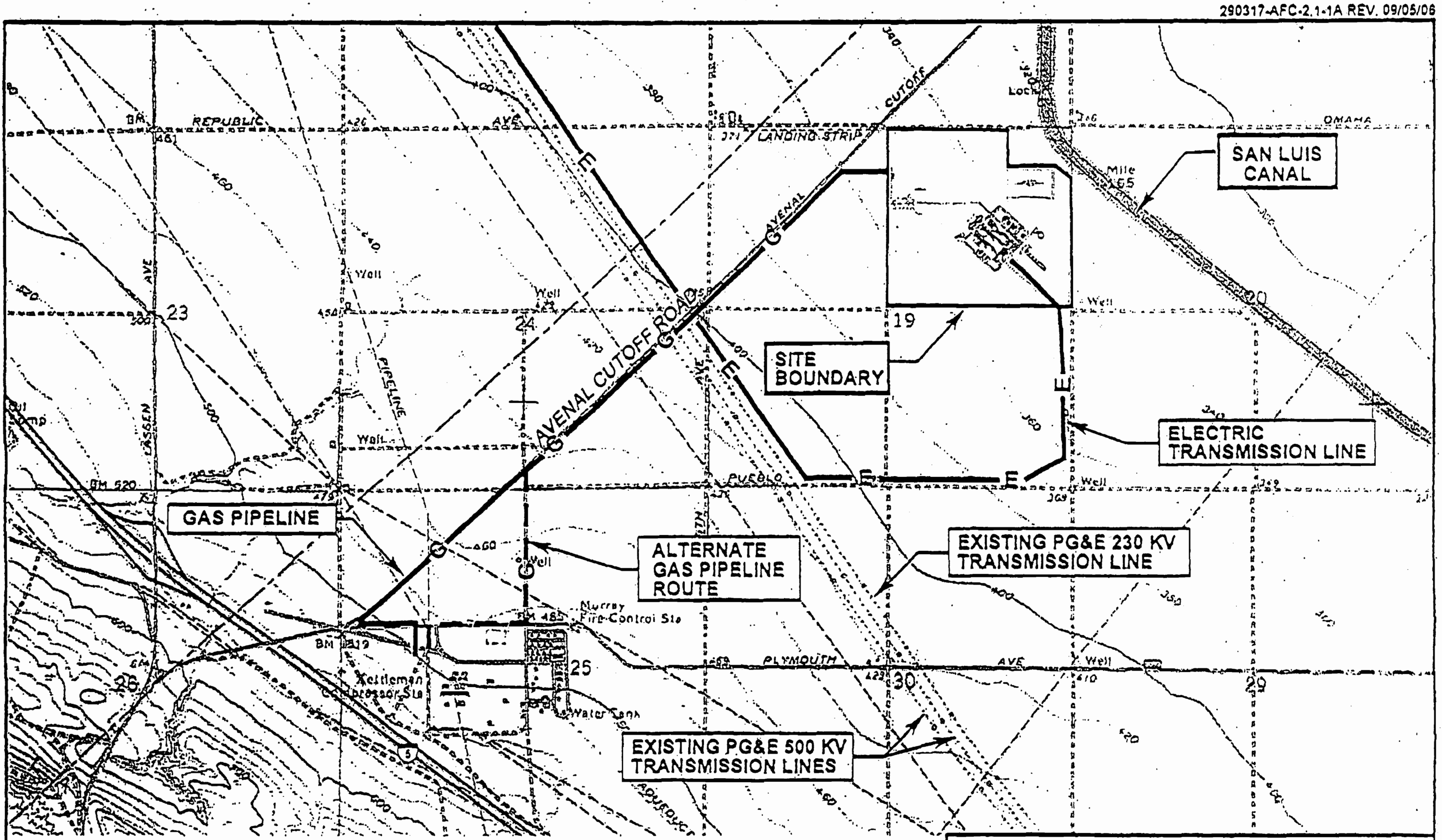
ISO VIEW
CONCEPTUAL DESIGN

NONE

A30YOY-1-PP-0-00-2

A

290317-AFC-2.1-1A REV. 09/05/06



REFERENCE:
U.S.G.S 7.5 MINUTE TOPOGRAPHIC SERIES MAP OF LA CIMA, CALIFORNIA, DATED 1978.

NATURAL GAS AND ELECTRICAL INTERCONNECTION ROUTES

FEDERAL POWER AVENAL LLC

AVENAL ENERGY

FIGURE 2.1-1A

ATTACHMENT D

CTG Emissions Data

The maximum heat input rates (fuel consumption rates) for the gas turbines, duct burners, and auxiliary boiler are shown in Table 6.2-22.

TABLE 6.2-22
MAXIMUM FACILITY FUEL USE, MMBTU (HHV)

Period	Gas Turbines and Duct Burners (each[a])	Auxiliary Boiler	Total Fuel Use (all Units)
Per Hour	2,356.5	37.4	4,750
Per Day	56,555[b]	449[c]	113,111[d]
Per Year	16,176,000[e]	46,650[f]	32,353,000[g]

Notes:

[a] Each of two trains.

[b] Based on 24 hours per day of duct firing.

[c] Based on a startup day, during which the auxiliary boiler would be used 12 hours.

[d] The maximum facility fuel use day, during which the turbines run 24 hours with duct firing, has no use of the auxiliary boiler (i.e., no startup).

[e] Based on maximum fuel use of 7,960 hours per year without duct firing, and 800 hours per year with duct firing, per turbine.

[f] Based on 1,248 hours of operation per year.

[g] Based on baseload scenario (see Footnote d) that includes no operation of the auxiliary boiler.

CTG Emissions During Startup and Shutdown

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 6.2-23. PM_{10} and SO_2 emissions have not been included in this table because emissions of these pollutants depend on fuel flow, which will be lower during a startup period than during baseload facility operation.

TABLE 6.2-23
FACILITY STARTUP/SHUTDOWN EMISSION RATES[a]

	NOx	CO	VOC
Startup/Shutdown, lb/hour, average	80	900	16
Startup/Shutdown, lb/~~start~~, hour maximum	160	1,000	16

[a] Estimated based on vendor data and source test data. See Appendix 6.2-1, Table 6.2-1.6 and -1.7.

The analysis of maximum facility emissions of each criteria pollutant was based on the turbine/HRSG and auxiliary boiler emission factors shown in Tables 6.2-19, 6.2-20, and 6.2-21; the startup emission rates shown in Table 6.2-23; the three operating scenarios described above, and the ambient conditions that result in the highest emission rates. The maximum annual, daily, and hourly emissions of each criteria pollutant for the Project are shown in Table 6.2-24 and are based on the following operating conditions and scenario parameters:

CTG Emissions During Commissioning

Gas turbine commissioning is the process of initial startup, tuning and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process consists of sequential test operation of each of the two gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 410 operating hours for each CTG. With the planned sequential testing of the two gas turbines, the overall length of the commissioning period would be approximately 3 months. Commissioning of the proposed project may be phased into two commissioning periods each approximately 1.5 months long.

There are several commissioning modes. The first is the period prior to SCR system installation, when the combustor is being tuned. During this mode, the NO_x emissions control system would not be functioning and the combustor would not be tuned for optimum performance. CO emissions would also be affected because combustor performance would not yet be optimized. The second emissions scenario will occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the gas turbine operating system are being checked out. Because the combustor would be tuned but the emission control system installation would not be complete, NO_x and CO levels could again be affected.

Noncriteria Pollutant Emissions

Noncriteria pollutants are compounds that have been identified as pollutants that pose a potential health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[24] In addition to these nine compounds, the federal Clean Air Act listed 187 to 189[25] substances at different times as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The State of California defined a set of toxic air contaminants through Assembly Bill (AB) 2588, the Air Toxics "Hot Spots" Information and Assessment Act. The SJVAPCD published a list of compounds it defined as potential toxic air contaminants in its May 1991 Toxics Policy. Any pollutant that may be emitted from the Project and is on the federal New Source Review list, the federal Clean Air Act list, the AB2588 list or

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[24] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.

[25] Currently 187 substances are listed.

ATTACHMENT D

CTG Emissions Data

Table 8.2-1.1
Emissions and Operating Parameters for New Turbines
Avenal Energy Project

	Case 1 101°F Full Load w/ DB[1]	Case 5 63°F Full Load w/ DB[1]	Case 9 32°F Full Load w/ DB[1]	Case 2 101°F Full Load no DB	Case 6 63°F Full Load no DB	Case 10 32°F Full Load no DB	Case 4 101°F 50% Load	Case 8 63°F 50% Load	Case 12 32°F 50% Load
Ambient Temp, °F	101	63	32	101	63	32	101	63	32
GT Load, %	100%	100%	100%	100%	100%	100%	50%	50%	50%
Both GTs Gross Power, MW	344.8	345.0	359.0	345.6	345.6	359.5	144.1	168.6	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.6	130.6
Plant Gross Power Output, MW	635.6	618.3	613.7	517.2	521.7	537.2	262.5	296.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	506.5	525.5	250.3	286.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	161.8	156.4	156.4	161.8	87.2	96.2	102.2
DBs Fuel Flow, kpph	49.0	39.8	31.0	0.0	0.0	0.0	0.0	0.0	0.0
GTs Heat Input, MMBtu/hr (HHV)	1,794.2	1,794.3	1,855.4	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	562.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	2,356.5	2,248.6	2,211.8	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,628,000	3,630,000	3,743,000	2,232,700	2,336,800	2,413,300
Stack Flow, acfm	1,044,365	1,025,495	1,069,636	1,051,631	1,037,822	1,071,653	620,528	644,316	666,146
Stack Temp, °F	195.3	184.9	189.0	207.4	198.8	200.9	180.2	175.8	177.4
Stack exhaust, vol%									
O_2 (dry)	11.40%	11.67%	12.34%	13.78%	13.77%	13.78%	14.46%	14.11%	13.93%
CO_2 (dry)	5.42%	5.16%	4.89%	4.09%	4.08%	4.08%	3.70%	3.89%	3.89%
H_2O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.63%
Emissions									
NO_x, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NO_x, lb/hr[2]	17.13	16.34	16.06	13.03	13.03	13.47	7.26	8.01	8.51
NO_x, lb/MMBtu (HHV)	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SO_2, ppmvd @ 15% O_2 [3]	0.139	0.139	0.140	0.140	0.140	0.140	0.140	0.140	0.140
SO_2, lb/hr[2,3]	1.66	1.59	1.56	1.27	1.27	1.31	0.71	0.78	0.83
SO_2, lb/MMBtu (HHV)[3]	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O_2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO, lb/hr[2]	20.86	19.90	19.56	15.86	15.86	16.39	8.84	9.75	10.36
CO, lb/MMBtu (HHV)	0.0089	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088
VOC, ppmvd @ 15% O_2[4]	2.0	2.0	2.0	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/hr[2,4]	5.96	5.68	5.59	3.17	3.17	3.28	1.77	1.95	2.07
VOC, lb/MMBtu (HHV)[4]	0.0025	0.0025	0.0025	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
PM_{10}, lb/hr[2,5]	11.81	11.27	10.78	9.00	9.00	9.00	9.00	9.00	9.00
PM_{10}, lb/MMBtu (HHV)[5]	0.0050	0.0050	0.0049	0.0050	0.0050	0.0048	0.0090	0.0081	0.0077
PM_{10}, gr/SCF (dry)[5]	0.00189	0.00179	0.00165	0.00142	0.00142	0.00137	0.00230	0.00220	0.00212
NH_3, ppmvd @ 15% O_2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH_3, lb/hr[2]	35.39	33.57	32.86	26.28	26.25	26.98	14.60	16.08	17.02
CO_2, lb/MMBtu (HHV)[7]	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CH_4, lb/MMBtu (HHV)[8]	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N_2O, lb/MMBtu (HHV)[8]	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO_2, lb/hr[9]	275,599	262,984	258,674	210,000	209,976	217,102	117,114	129,153	137,055
CH_4, lb/hr[9]	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N_2O, lb/hr[9]	0.52	0.50	0.49	0.40	0.40	0.41	0.22	0.24	0.26

1) Includes duct burner firing only up to plant maximum output of 600 MW.

2) All mass flow values reported are on a per stack basis. Plant total mass flows are double these values.

3) All of the assumed 0.25 gr S in 100 scf of the fuel is assumed to be converted to SO_2 with no SO_3 conversion.

4) Based on an assumption that 20% of reported UHC emissions are VOCs.

5) Includes front-half (filterable) portion only. Back-half (condensible) portion is excluded.

6) CH_4 emission factor (kg/MMBtu) = 0.0059

ARB. *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

7) CO_2 emission factor (kg/MMBtu) = 53.06

ARB. *Draft Emission Factors for Mandatory Reporting Program*, Table of Carbon Dioxide Emission Factors and Oxidation Rates for Stationary Combustion, August 10, 2007.

8) N_2O emission factor (kg/MMBtu) = 0.0001

ARB. *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

ATTACHMENT E

SJVAPCD BACT Guidelines 1.1.2, 3.1.4, 3.1.8, and 3.4.2

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.1.2*

Last Update: 3/14/2002

Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings.**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Natural gas fuel with LPG backup		
NOx	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Ultra-Low NOx main burner system burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire).	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NOx@ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire).	
PM10	Natural gas fuel with LPG backup		
SO	Natural gas fuel with LPG backup		
VOC	Natural gas fuel with LPG backup		

** For the purpose of this determination, "small load swings" are defined as normal operational load fluctuations which are within the operational response range of an Ultra-Low NOx burner system(s).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

Emergency Diesel I.C. Engine Driving a Fire Pump

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO		Oxidation Catalyst	
NOx	Certified NOx emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered)		
SOx	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
VOC	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]	Catalytic Oxidation	

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.8*

Last Update: 4/4/2002

Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	= or < 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	> or = 80% control efficiency (Rich-burn engine with NSCR, or equal)
NOx	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)		= or > 90% control efficiency (Rich-burn engine with NSCR, or equal)
PM10	Natural gas fuel		
VOC	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	= or > 50% control efficiency (Rich-burn engine with NSCR, or equal)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.2*

Last Update: 10/1/2002

Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	4.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	
NOx	2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	
PM10	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal		
SOx	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmv @ 15% O2	1.5 ppmv @ 15% O2	

** Applicability lowered to > 50 MW pursuant to CARB Guidance for Permitting Electrical Generation Technologies. Change effective 10/1/02. Corrected error in applicability to read 50 MW not 50 MMBtu/hr effective 4/1/03.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT F

Top Down BACT Analysis
(C-3953-10-1, -11-1, -12-1, -13-1, and –14-1)

Units C-3953-10-1 and –11-1 (Turbines)

I. NO$_X$ Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of a selective catalytic reduction system with NO$_X$ emissions of 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). The facility has proposed to use an inlet air filtration and cooling system, water injection, and a Selective Catalytic Reduction system on each of these turbines to achieve NO_X emissions of less than or equal to 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). Therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 1.5 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 1.5 ppmvd VOC @ 15% O_2
2. 2.0 ppmvd VOC @ 15% O_2

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel or LPG with emissions of less than or equal to 2.0 ppmv @ 15% O_2. The facility has proposed to use natural gas fuel with emissions of less than or equal to 2.0 ppmv @ 15% O_2; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air in inlet filter, lube oil vent coalescer and natural gas fuel or equal. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of an air inlet filter, lube oil vent coalescer and natural gas fuel or equal. Avenal Power Center is proposing to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

IV. SO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel; or
- Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use PUC-regulated natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel. Avenal Power Center has proposed to fire each of the turbines solely on PUC-regulated natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies technologically feasible BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)
2. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the boiler will not exceed 9.0 ppmv @ 3% O_2. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - <u>Select BACT</u>

BACT for the emission unit is determined to be NO_X emissions of less than 9.0 ppmvd @ 3% O_2. The facility has proposed NO_X emissions of less than 9.0 ppmv @ 3% O_2. Therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for VOC emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

III. PM$_{10}$ Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM$_{10}$ emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-13-1 (Diesel IC engine powering fire water pump)

I. NO$_X$ Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Certified NO$_X$ emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. Certified NO$_X$ emissions of 6.9 g/bhp-hr or less

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the engine will not exceed 3.4 g/bhp-hr. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be Certified NO$_X$ emissions of 6.9 g/bhp-hr or less. The facility has proposed NO$_X$ emissions of less than 6.9 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-13-1 (Diesel IC engine powering fire water pump)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Catalytic Oxidation

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. Catalytic Oxidation
2. Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system or a positive crankcase ventilation system, and the addition of a catalytic oxidation system or a positive crankcase ventilation system would void the UL certification, which is required for firewater pump engines. Therefore, both the catalytic oxidation system and the positive crankcase ventilation system options will not be required.

Step 5 - <u>Select BACT</u>

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for VOC emissions. The applicant has proposed to install a 288 bhp emergency diesel IC engine powering a firewater pump with no control technology for VOC emissions; therefore BACT for VOC emissions is satisfied.

Units C-3953-14-1 (Natural gas IC engine powering electrical generator)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)
2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_X reduction is \$9,700 per ton of NO_X reduced.

Based upon the fact that there are only a few existing IC engine installations within this class and category of source that operate with emissions of ≤ 1.0 g NO_X/hp-hr, the District will assume that the Industry Standard will be 2.8 g NO_X/hp-hr (lb/MMBtu converted to g/hp-hr, Attachment I), pursuant to a AP-42 (07/00) values of uncontrolled four-stroke lean burn IC engines (< 90% load).

AP-42 publishes an uncontrolled NO_X value of 2.21 lb/MMBtu (90 – 105% load), which is approximately 13.4 g NO_X/hp-hr. Several major engine manufacturers were surveyed (Cummins, Caterpillar, and Waukesha) and the District found that lean burn engines sold by these engine manufacturers do not emit emissions close to the uncontrolled value for 90 – 105% load, published in AP-42. Based on the discussions with service representatives of each engine manufacturer, emissions were closer to the AP-42 value published for the < 90% load, which was around 2.5 g NO_X/hp-hr than it was for the value published for the 90 – 105% load. Therefore, industry standard for lean burn natural gas-fired emergency IC engine will be 2.8 g NO_X/hp-hr.

The proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

NO_X (annual):

$$\frac{2.8\ \cancel{\text{g}}}{\cancel{\text{hp-hr}}}\,\Bigg|\,\frac{860\ \cancel{\text{hp}}}{1}\,\Bigg|\,\frac{\text{lb}}{453.6\ \cancel{\text{g}}}\,\Bigg|\,\frac{50\ \cancel{\text{hr}}}{\text{year}} = 265\ \text{lb NO}_X\text{/year}$$

PE_{NOx} = 265 lb NO_X/year = 0.1325 tons NO_X/year

The proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a NO_X control efficiency of ≥ 90% can be calculated as:

NO_X (annual):

$$\frac{7.4\ \cancel{\text{g}}^{(1)}}{\cancel{\text{hp-hr}}}\,\Bigg|\,\frac{(1-0.9)}{1}\,\Bigg|\,\frac{860\ \cancel{\text{hp}}}{1}\,\Bigg|\,\frac{\text{lb}}{453.6\ \cancel{\text{g}}}\,\Bigg|\,\frac{50\ \cancel{\text{hr}}}{\text{year}} = 70\ \text{lb NO}_X\text{/year}$$

PE_{NOx} = 70 lb NO_X/year = 0.035 tons NO_X/year

District BACT policy demonstrates how to calculate the cost effectiveness of alternate basic equipment or process:

$$CE_{alt} = (Cost_{alt} - Cost_{basic}) \div (Emission_{basic} - Emission_{alt})$$

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[1] Pursuant to AP-42 (07/00) the NO_X value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

where,

CE_{alt} = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced

$Cost_{alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

$Cost_{basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost

$Emission_{basic}$ = the emissions from the proposed basic equipment, without BACT.

$Emission_{alt}$ = the emissions from the alternate basic equipment

The District conducted research to determine the appropriate cost information for installing a rich burn IC engine with a Non-Selective Catalytic Reduction System versus the cost information for installing a uncontrolled lean burn IC engine. Based on information from various engine manufacturers, the initial costs for installing an uncontrolled rich burn engine versus an uncontrolled lean burn engine would be minimal. The main difference in cost would be incurred in the installation of the NSCR system and the air to fuel ratio controller to the rich burn IC engine.

According to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" (pgs. V-2 & V-3), the approximate capital cost for installing a NSCR system for a 1,000 hp engine would be approximately \$28,000, the capital cost for installing an air to fuel ratio controller would be \$5,300, and the overall installation cost would be \$2,500. The CARB RACT/BARCT document also states the annual cost for operating and maintenance is between \$8,000 – 10,000, but these values are assuming full time operation. Since the proposed installation will be limited only to emergency operation and testing and maintenance, a conservative assumption of \$1,000 per year will be utilized for this evaluation.

Per District BACT Policy, the equivalent annual capital cost is calculated as follows:

$$A\ (\$/yr) = P \times [i \times (1 + i)^n] \div [(1 + i)^n - 1]$$

Where:
A = Equivalent annual capital cost of the control equipment
P = Present value of the control equipment including installation
i = interest rate (10% used as default value)
n = equipment life (10 years used as default value)

Using a total capital cost of \$35,800 in the above equation results in an equivalent annual cost of \$5,826/year. Adding this equivalent annual cost to the annual operating cost of \$1,000/year, the ($Cost_{alt}$ - $Cost_{basic}$) is equal to \$6,826/year. It should be noted that the operating the rich burn IC engine versus a lean burn IC engine would result in an efficiency loss and would potentially result in higher annual fuel expenses. These costs will be set aside for the present and only a partial cost analysis will be performed.

District BACT policy also requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a NSCR system will control NO_X, CO, and VOC emissions. Therefore, the MCET is calculated as follows:

$$\text{MCET (\$/yr)} = (E_{NOx} \times T_{NOx}) + (E_{CO} \times T_{CO}) + (E_{VOC} \times T_{VOC})$$

Where:
E_{NOx} = tons-NO_X controlled/yr
E_{CO} = tons-CO controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_X
= \$9,700/ton-NO_X
T_{CO} = District's cost effectiveness threshold for CO
= \$300/ton-CO
T_{VOC} = District's cost effectiveness threshold for VOCs
= \$5,000/ton-VOCs

Since this BACT cost effectiveness analysis is analyzing alternate basic equipment with a control technology which controls multiple pollutants; in order to calculate the cost effectiveness for the alternate basic equipment, the District will take the MCET and compare that value with the ($Cost_{alt} - Cost_{basic}$), to determine if this control technology is cost effective.

To determine E_{CO}, the District has to establish what Industry Standard is for CO emissions. As detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for CO emissions @ < 90% load (1.83 g CO/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>CO (annual):</u>

$$\frac{1.83\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 173\ lb\ CO/year$$

PE_{CO} = 173 lb CO/year = 0.0865 ton CO/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB (pg. B-20), the CO control effectiveness from a NSCR system is greater than 80%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a CO control efficiency of ≥ 80% can be calculated as:

CO (annual):

$$\frac{11.6\ \cancel{\text{g}}^{(2)}}{\cancel{\text{hp-hr}}}\;\Bigg|\;\frac{(1-0.8)}{1}\;\Bigg|\;\frac{860\ \cancel{\text{hp}}}{1}\;\Bigg|\;\frac{\text{lb}}{453.6\ \cancel{\text{g}}}\;\Bigg|\;\frac{50\ \cancel{\text{hr}}}{\text{year}} = 220\ \text{lb CO/year}$$

PE_{CO} = 220 lb CO/year = 0.11 ton CO/year

As demonstrated above, the CO emissions from the rich burn IC engine with a NSCR system are higher than the uncontrolled CO emissions from the lean burn IC engine. Therefore, CO will not be included in the MCET calculations.

To determine E_{VOC}, the District has to establish what Industry Standard is for VOC emissions. Again, as detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for VOC emissions (0.39 g VOC/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

VOC (annual):

$$\frac{0.39\ \cancel{\text{g}}}{\cancel{\text{hp-hr}}}\;\Bigg|\;\frac{860\ \cancel{\text{hp}}}{1}\;\Bigg|\;\frac{\text{lb}}{453.6\ \cancel{\text{g}}}\;\Bigg|\;\frac{50\ \cancel{\text{hr}}}{\text{year}} = 37\ \text{lb VOC/year}$$

PE_{VOC} = 37 lb VOC/year = 0.0185 ton VOC/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB, the VOC control effectiveness from a NSCR system is greater than 50%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a VOC control efficiency of ≥ 50% can be calculated as:

VOC (annual):

$$\frac{0.10\ \cancel{\text{g}}^{(3)}}{\cancel{\text{hp-hr}}}\;\Bigg|\;\frac{(1-0.5)}{1}\;\Bigg|\;\frac{860\ \cancel{\text{hp}}}{1}\;\Bigg|\;\frac{\text{lb}}{453.6\ \cancel{\text{g}}}\;\Bigg|\;\frac{50\ \cancel{\text{hr}}}{\text{year}} = 5\ \text{lb VOC/year}$$

PE_{VOC} = 5 lb VOC/year = 0.0025 ton VOC/year

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[2] Pursuant to AP-42 (07/00) the CO value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

[3] Pursuant to AP-42 (07/00) the VOC value for uncontrolled four-stroke rich burn IC engines. (lb/MMBtu converted to g/hp-hr, Attachment I)

Calculating for the MCET derives the following:

E_{NOx} = 0.1325 tpy – 0.035 tpy = 0.0975 tpy
E_{VOC} = 0.0185 tpy – 0.0025 tpy = 0.016 tpy

MCET ($/yr) = (0.0975 x $9,700) + (0.016 x $5,000) = $1,026/year

As presented above, ($Cost_{alt}$ – $Cost_{basic}$) is equal to $6,826/year.

This value is greater than the MCET; therefore, it has been determine that the installation of a rich burn IC engine with a NSCR system as alternate basic equipment is not cost effective using just the partial cost analysis.

2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

The applicant has proposed that the NOx emissions from the engine will not exceed 1.0 g/bhp-hr. This is the highest ranking remaining control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - <u>Select BACT</u>

BACT for the emission unit is determined to be NO_X emissions of 1.0 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 1.0 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-14-1 (Natural gas IC engine powering electrical generator)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the engine will be equipped with an oxidation catalyst with 90% control of VOC emissions. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the used of an oxidation catalyst with 90% control of VOC emissions. The facility has proposed to install an oxidation catalyst with 90% control of VOC emission. Therefore, BACT is satisfied.

ATTACHMENT G

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Unified
Air Pollution Control District

MEMORANDUM

DATE: June 14, 2014

TO: Derek Fukuda, AQE—Permit Services

FROM: Leland Villalvazo, SAQS—Technical Services

SUBJECT: Revised NO_2 1-hour NAAQA Assessment for Avenal Power Center

Technical Services was requested to revise the RMR and AAQA assessment performed for project C-1011324, dated June 25, 2002, to lower the NOx and CO annual emission levels.

A review of the previous project indicated that the major item of concern was the 1-hour standard for NO_2. The previous assessment was based on the State standard of 339 ug/m^3 whereas the new federal standard 188.68 ug/m^3. The assessment contained in this memo will primarily address the new federal NO_2 NAAQS and any updates needed to the previous RMR assessment.

Background:
EPA has revised the primary NO_2 NAAQS in order to provide requisite protection of public health. Specifically, EPA has established a new 1-hour standard at a level of 100 ppb (188.68 ug/m^3), based on the 3-year average of the annual 98th percentile of the daily maximum 1-hour concentrations, to supplement the existing annual standard. EPA has also established requirements for NO_2 monitoring network that will include monitors at locations where maximum NO_2 concentrations are expected to occur, including within 50 meters of major roadways, as well as monitors sited to measure the area-wide NO_2 concentrations that occur more broadly across communities.

The final rule was signed on January 22, 2010. The effective date of the new 1 hour standard is 60 days after the final rule has been published in the Federal Register. The final rule was published in the Federal Register on Feb 9, 2010. The effective date is April 12, 2010.

Results:
Based on guidance from EPA dated February 25, 2010, the District has updated the AAQA assessment to include the new NO_2 1-hour standard, see below. The results follow the procedure outlined in the District's interim draft guidance document entitled "Modeling Procedure to Address The New Federal 1 Hour NO_2 Standard".

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	**P**	13.58
Tier IV	**140.37**		140.37	188.68	**P**	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	**P**	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Conclusion

Based on the updated RMR, the risk from this facility is less than 10 in one million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed below must be included for the proposed unit(s).

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

Conditions

1. PM_{10} emission rate shall not exceed **0.059 g/HP-hr (note method) for the 288 hp engine** (C-3953-13-1).

2. The 860 hp engine (C-3953-14-1) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **50 hours per year**.

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	P	13.58
Tier IV	**140.37**		140.37	188.68	P	48.31

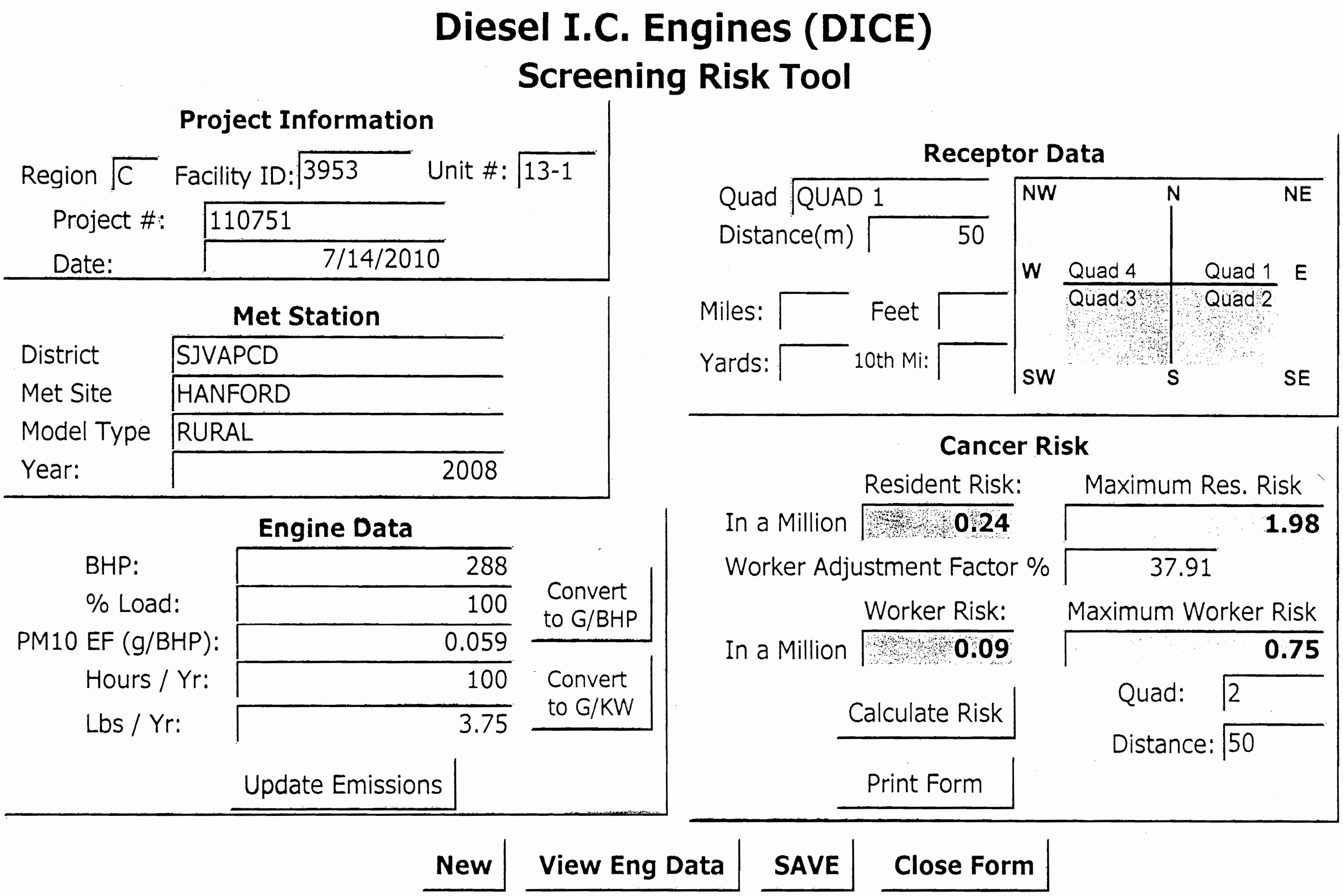
Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	P	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia



Diesel I.C. Engines (DICE)
Screening Risk Tool

Project Information

Region: C
Facility ID: 3953
Unit #: 13-1
Project #: 110751
Date: 7/14/2010

Met Station

District: SJVAPCD
Met Site: HANFORD
Model Type: RURAL
Year: 2008

Engine Data

BHP: 288
% Load: 100
PM10 EF (g/BHP): 0.059
Hours / Yr: 100
Lbs / Yr: 3.75

Receptor Data

Quad: QUAD 1
Distance(m): 50
Miles:
Feet:
Yards:
10th Mi:

Cancer Risk

Resident Risk: In a Million 0.24
Maximum Res. Risk: 1.98
Worker Adjustment Factor %: 37.91
Worker Risk: In a Million 0.09
Maximum Worker Risk: 0.75
Quad: 2
Distance: 50

Print Worksheet

INTERNAL COMBUSTION (NG)
EMISSION FACTORS
(LBS. / MMCF)

FACILITY NAME:
DATE:

Priority Score 0.092999134

Receptor Distance: 1206

Total hrs. of operation	50.00	MMCF/HR	0.0071	MMCF/YR	0.36

POLLUTANT	EMISSION FACTOR (MMCF/HR)					
	<1000	>1000	TURBINE	Acute REL	Chronic REL	Cancer URF
Acetaldehyde	0.944	1.1328	0.037	0	9	2.70E-06
Acrolein	0.3783	0.454	0.009	0.19	2.00E-02	0
Benzene	3.257	3.9084	0.0113	1300	71	2.90E-05
Formaldehyde	32.4963	38.9956	0.094	94	3.6	6.00E-06
Naphthalene	0.1785	0.1785	0.0008	0	14	0
PAH's	0.0179	0.0179	0.0002	0		1.70E-03
Propylene	16.2259	19.4711	1.0522	0	0	0
Toluene	1.1145	1.3374	0.0726	37000	200	0
Xylenes	0.4048	0.4858	0.0289	22000	300	0
Ethyl Benzene	0.3257	0.3908	0.0132	0	0	0
Hexane	0.7491	0.8989	1.75	0	0	0

	<1000 EMISSION FACTORS	LBS./HR.	G/SEC	LBS./YR.	G/SEC	Acute Score	Chronic Score	Carcinogenic Score	Non-Carcinogenic Score
Acetaldehyde	0.944	6.70E-03	**8.45E-04**	3.35E-01	**4.82E-06**	0	0.11170667	0.001538201	0.111706667
Acrolein	0.3783	2.69E-03	**3.39E-04**	1.34E-01	**1.93E-06**	21.204711	20.144475	0	21.20471053
Benzene	3.257	2.31E-02	**2.92E-03**	1.16E+00	**1.66E-05**	0.0266823	0.048855	0.057002386	0.048855
Formaldehyde	32.4963	2.31E-01	**2.91E-02**	1.15E+01	**1.66E-04**	3.6817616	9.61348875	0.117669102	9.61348875
Naphthalene	0.1785	1.27E-03	**1.60E-04**	6.34E-02	**9.12E-07**	0	0.01357875	0	0.01357875
PAH's	0.0179	1.27E-04	**1.60E-05**	6.35E-03	**9.15E-08**	0	0	0.018364505	0
Propylene	16.2259	1.15E-01	**1.45E-02**	5.76E+00	**8.29E-05**	0	0	0	0
Toluene	1.1145	7.91E-03	**9.98E-04**	3.96E-01	**5.70E-06**	0.0003208	0.00593471	0	0.005934713
Xylenes	0.4048	2.87E-03	**3.62E-04**	1.44E-01	**2.07E-06**	0.000196	0.00143704	0	0.00143704
Ethyl Benzene	0.3257	2.31E-03	**2.92E-04**	1.16E-01	**1.66E-06**	0	0	0	0
Hexane	0.7491	5.32E-03	**6.71E-04**	2.66E-01	**3.83E-06**	0	0	0	0

San Joaquin Valley Unified Air Pollution Control District

MEMORANDUM

DATE: June 25, 2002

TO: Errol Villegas, SAQE—Permit Services

FROM: Esteban Gutierrez, AQS—Technical Services

SUBJECT: AAQA and RMR Modeling request for Duke energy Avenal LLC.

As per your request, Technical Service performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR for, two turbines, two IC engines, nineteen (19) cooling towers and a boiler for a power plant. The engineer supplied the maximum fuel rate as well as process rates for all of the units described above. ISCST3 model was used to determine dispersion value for cancer risk exposure.

The results from the RMR modeling runs and Criteria Pollutant Modeling are as follows:

RMR Modeling Results

REFINED HRA SUMMARY			
Device	**(2) Turbines**	**Boiler**	**(3) 4 cell tower**
Fuel	**NG**	**NG**	
Prioritization Score	0.8242	.0107	N/A
Cancer Risk	N/A	N/A	N/A
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
TBACT Required?	No	No	No

REFINED HRA SUMMARY			
Device	**7 cell tower**	**300 Hp ICE**	**660 HP ICE**
Fuel		**Diesel**	**Diesel**
Prioritization Score	N/A	N/A	N/A
Cancer Risk	N/A	2.01E-6	1.00E-6
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
Maximum operating Hrs		200	38
TBACT Required?	No	Yes	No

Criteria Pollutant Modeling Results*

Values are in ug/m^3

	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass***	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass**	Pass**

*Results were taken from the attached PSD spreadsheet.

**The criteria pollutants noted by a double asterisk (**) are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). Operating time for 24 hour risk was adjusted for PM10 levels.

*** Passing score was obtained from running OLM (Ozone Limiting Method.)

(2) NG Turbines Stack Parameters			
Source Type	Point	**Process Rate (T1) MMbtu/yr**	16,958,390
Stack Height (m)	44.2	**Process Rate (T2) MMbtu/yr**	20,582,010
Stack Diam. (m)	5.49	**Hours of operation yr (T1)**	8400
Gas Exit Velocity (m/sec) T1	20.4	**Hours of operation yr (T2)**	8760
Stack Gas Temp (°K)	356	**Receptor Distance (m)**	1609
Location Type	Rural		

7 Cell Cooling Tower Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	13.7	**Process Rate Gal/Yr**	57,153,744,000
Stack Diam. (m)	9.64	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	8.10	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

(3) 4 Cell Cooling Towers Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	16.08	**Process Rate Gal/Yr**	5,308,560,000
Stack Diam. (m)	3.57	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	11.46	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

Boiler Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	11.28	**Process Rate MMbtu/yr**	93,500
Stack Diam. (m)	0.812	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	12.2	**Hours of operation**	2500
Stack Gas Temp (°K)	476		

Diesel Engine (300 Hp)			
Source Type	Point	**Closest Receptor (m)**	1609
Stack Height (m)	3.04	**Location Type**	RURAL
Stack Diam. (m)	0.13	**Max Operating (hr/yr)**	**100**
Gas Exit Velocity (m/sec)	67.1	**Fuel Type**	Diesel
Stack Gas Temp (°K)	716	**PM10 g/bhp-hr**	0.09

Diesel Engine (660 Hp)			
Source Type	Point	**Closest Receptor (m)**	1609
Stack Height (m)	3.04	**Location Type**	RURAL
Stack Diam. (m)	0.23	**Max Operating (hr/yr)**	**38**
Gas Exit Velocity (m/sec)	45.0	**Fuel Type**	Diesel
Stack Gas Temp (°K)	799	**PM10 g/bhp-hr**	0.4

Conclusion:

The Criteria modeling runs indicate that the emissions from the proposed equipment will not have an adverse impact on the State and National AAQS. Therefore, no further modeling will be required to demonstrate that the AAQS or EPA's level of significance would be exceeded.

The carcinogenic risk for the 300 hp engine is 2.01E-06, which is below the maximum allowable risk of 10 in a million for diesel IC engines emitting ≤ 0.149g PM_{10}/bhp/hr. The risk for the 660 hp engine is 1.00E-06 which is the allowable risk of one in a million for engines emitting > 0.149g PM_{10}/bhp/hr. Therefore, **the project is approved for permitting, and TBACT is required for the 300 hp engine.** In order to assure compliance with the assumptions made for the risk management review the following conditions listed on the PTO are required:

1. Only CARB certified fuel containing not more than 0.05% sulfur by weight is to be used in these engines.
2. PM_{10} emission rate shall not exceed **0.09 g/HP-hr (note method) for the 300 hp engine** (C-3953-8-0).
3. PM_{10} emission rate shall not exceed **0.40 g/HP-hr (note method) for the 660 hp engine** (C-3953-9-0).
4. The exhaust stacks shall not be fitted with a rain caps, or any other similar devices, that impedes vertical exhaust flow.
5. The 300 hp engine (C-3953-8-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **100 hours per year**.
6. The 660 hp engine (C-3953-9-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **38 hours per year**.
7. The 660 hp engine (C-3953-9-0) shall not operate more than **7 hours in any rolling 24 hr period during maintenance, testing, and required regulatory purposes.**

ATTACHMENT H

SO_X for PM_{10} Interpollutant Offset Analysis

SO_X for PM_{10} Interpollutant Offset Analysis
Avenal Power Center, LLC

Facility Name:	Avenal Power Center, LLC	Date:	June 30, 2010
Mailing Address:	500 Dallas Street. Level 31 Houston, TX 77002	Engineer:	Derek Fukuda
		Lead Engineer:	Joven Refuerzo
Contact Person:	Jim Rexroad		
Telephone:	(713) 275-6147		
Application #:	C-3953-10-1, -11-1, -12-1, -13-1, and -14-1		
Project #:	C-1100751		
Location:	NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032		
Complete:	March 18, 2010		

I. Proposal

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 562.3 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

In addition, Avenal Power Center, LLC has proposed to limit the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year.

Facility C-3953 will become a major source for NO_X, VOC, and PM_{10}. There will be an increase in emissions for all pollutants and offsets are required for NO_X, VOC, and PM_{10} emissions.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (9/21/06) (Section 3.30 and 4.13.3.2)

III. Process Description

Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0107 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

IV. Equipment Listing:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

V. Interpollutant Offset Ratio Proposal SO_X for PM_{10}

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM_{10} precursor ERCs to offset PM_{10} increases:

> *4.13.3 Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.*
>
> *4.13.3.2 Interpollutant offsets between PM10 and PM10 precursors may be allowed.*

Based on this language, an applicant must demonstrate an appropriate interpollutant offset ratio, based on an air quality analysis (that is, based on the science of the precursor-to-PM_{10} relationship given the atmospheric chemistry and the meteorology of the locale).

The SO_X for PM_{10} interpollutant ratio of 1.000:1 is based on District analysis (see Appendix A). The originating location of reduction of the proposed ERC certificates are greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5 applies. Combining the interpollutant and distance offset ratio, an overall SO_X for PM10 offset ratio of 1.000 x 1.5 = 1.5:1 is valid for project C-1100751.

IV. Project Offset Calculations

i. C-3953-10-1 and C-3953-11-1 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit

	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A(1)	11.78	8.91	8.91	23.56
SO_X	N/A(7)	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. *Maximum Daily PE*

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit (w/ Startup and Shutdown)

	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A(8)	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A(8)	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

c. *Maximum Annual PE*

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based

---

[1] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

$$\mathrm{SO_X\ EF} = (0.36\ \cancel{\mathrm{gr\ S}}/100\ \cancel{\mathrm{dscf}}) \times (1\ \cancel{\mathrm{lb\ S}}/7000\ \cancel{\mathrm{gr}}) \times (64\ \mathrm{lb\ SO_X}/32\ \cancel{\mathrm{lb\ S}}) \times (1\ \cancel{\mathrm{scf}}/1013\ \cancel{\mathrm{Btu}}) \times (10^6\ \cancel{\mathrm{Btu}}/\mathrm{MMBtu})$$

$$= \mathbf{0.001\ lb\text{-}SO_X/MMBtu}$$

CTG w/o Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **1.86 lb-SO_X/hr**

CTG w/ Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **2.36 lb-SO_X/hr**

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit
Scenario 1) Weekend and Weekday Hot Start*

	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit
Scenario 2) Weekend Shutdown and Weekday Hot Start*

	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	197,928 lb/year	Facility Wide Limit
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

ii. C-3953-12-0 (Boiler)

The PM_{10} potential to emit for the boiler is calculated as follows, and summarized in the table below.

$$PE_{PM10} = (0.005\ \text{lb/MMBtu}) * (37.4\ \text{MMBtu/hr})$$
$$= \mathbf{0.19\ lb\ PM_{10}/hr}$$

$$= (0.005\ \text{lb/MMBtu}) * (37.4\ \text{MMBtu/hr}) * (12\ \text{hr/day})$$
$$= \mathbf{2.2\ lb\ PM_{10}/day}$$

$$= (0.005\ \text{lb/MMBtu}) * (37.4\ \text{MMBtu/hr}) * (1{,}248\ \text{hr/year})$$
$$= \mathbf{233\ lb\ PM_{10}/year}$$

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.19	2.2	58	233

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The PM_{10} emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-13-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.04	0.9	0.5	2

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The PM_{10} emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-14-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.06	1.5	1	3

Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
C-3953-13-1			12	2	0	0
C-3953-14-1			31	3	1	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Total Emissions to be Offset

Pursuant to District Rule 2201, Section 4.6, emission offsets shall not be required for emergency equipment that is used exclusively as emergency standby equipment for electric power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year for non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power. Therefore the emission from the diesel-fired fire water pump and the natural gas-fired emergency standby generator are not required to be offset.

Emission to be Offset (lb/year)						
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,179**	**161,545**	**33,520**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.

** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Offset Calculations:

PM_{10}:

SSPE2 (PM_{10}) = 161,545 lb/year
Offset threshold (PM_{10}) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(161,545 – 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
33,087	33,086	33,086	33,086

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year
= 99.26 ton/yr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
49,630	49,629	49,629	49,630

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-896-4	80	80	80	80
ERC #N-721-4	0	0	3,215	0
ERC #N-723-4	0	0	985	0
ERC #S-2791-5	92,179	23,666	69,157	96,288
ERC #S-2790-5	12,862	491	0	8,499
ERC #S-2789-5	6	14	12	8
ERC #S-2788-5	5	7	3	6
ERC #N-762-5	21,000	21,000	21,000	21,000

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Appendix A). This interpollutant ratio has been evaluated by the District's modeler, James Sweet, Air Quality Project Planner. Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

V. Conclusion

Approve use of an overall SO_X for PM_{10} interpollutant offset ratio of 1.5:1 (1.000 x 1.5).

VI. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-3953-10-1, -11-1, -12-1, -13-1, and -14-1 with a SO_X for PM_{10} interpollutant offset ratio of 1.000:1.

Appendix

A: District Review and Approval

Appendix A

District Review and Approval

Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

DEVELOPMENT OF THE INTERPOLLUTANT RATIO

For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

March 2009

Introduction

Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

Analyses included in Interpollutant evaluation

Factors Considered

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

Elements from 2008 PM 2.5 Plan

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

Extension by additional analysis

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

Strengths

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

Limitations

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

Analyses contained in Receptor modeling

Factors Considered

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

Analyses in receptor modeling that use input from regional modeling

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

Extension by additional analysis

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

Strengths

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

Limitations

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

Analyses contained in Regional modeling

Factors Considered

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

Extension by additional analysis

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

Strengths

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

Limitations

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

Results and Documentation

SJVAPCD Interpollutant Ratio Results

SOx for PM ratio: 1.000 ton of SOx per ton of PM

NOx for PM ratio: 2.629 tons of NOx per ton of PM

These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

Interpollutant Ratio Issues & Documentation

	TOPIC	Reference
1	**Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions.	2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2
2	**Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites.	*DV Qtrs*
3	**Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties.	*Q4 Model Pivot, Model-site chem, Model-Daily Q4*
4	**Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM.	2008 PM2.5 Plan, Appendix F
	Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis.	2008 PM2.5 Plan, Appendix G
5	**Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources.	2008 PM2.5 Plan, Appendix F
6	**Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods.	2008 PM2.5 Plan, Appendix G
7	**Common area of influence adjustments used for all receptor evaluations:** Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2) Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3) Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2) Marine emissions not found present in CMB modeling for this analysis.	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* County *2000-2009* worksheets
8	**Variations to reflect secondary area of influence specific to location:** Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2)	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* County *2000-2009* worksheets
9	**Reasons for using 2009 Interpollutant Ratio Projection:** 2009 Interpollutant ratio is consistent with current emissions inventories	2008 PM2.5 Plan
	Regional modeling does not show a significant change in chemical relationships through 2014.	*Q4 Model Pivot*
10	**Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets.	District Rule 2201 Section 4.13.3

ATTACHMENT I

Additional Supplemental Information

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES[a]

(SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	2.21 E+00	A
NO_x[c] <90% Load	2.27 E+00	C
CO[c] 90 - 105% Load	3.72 E+00	A
CO[c] <90% Load	3.51 E+00	C
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	3.58 E-01	C
Methane[g]	2.30 E-01	C
VOC[h]	2.96 E-02	C
PM10 (filterable)[i,j]	9.50 E-03	E
PM2.5 (filterable)[j]	9.50 E-03	E
PM Condensable[k]	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[l]	2.53 E-05	C
1,1,2-Trichloroethane[l]	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene[l]	6.63 E-04	D
1,3-Dichloropropene[l]	<1.27 E-05	E
Acetaldehyde[l,m]	2.79 E-03	C
Acrolein[l,m]	2.63 E-03	C
Benzene[l]	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride[l]	<1.77 E-05	E

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%		
Type of fuel (use table above)	4	GAS
O2 correction (i.e., 3%)	15	%
Enter LB/MMBTU emission factor		
NOx	0.847	LB/MMBTU
CO	0.130	LB/MMBTU
VOC (as methane)	0.000	LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS		
NOx	229.94	ppmv
CO	57.98	ppmv
VOC (as methane)	0.00	ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

Parts Per Million Volume --> Grams/Brake Horsepower - Hour

ppmv --> g/Bhp-hr

Variables:		
Engine Size:	860	hp
NOx:	230	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
MW (NOx):	46	as NO_2
MW (co):	28	
MW (voc):	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula

ppmv	F-factor	$MW_{pollutant}$	20.9	1	1	Conversion #3	1	=
1	1	1	$(20.9 - O_2\%)$	Conversion #1	Conversion #2	1	Engine Eff.	

for NOx

230 ~~parts~~	8578 ~~dscf~~	46 ~~lb~~	20.9	~~1 lb-mol~~	~~MMBtu~~	453.59 g	1	=
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	

= 2.750 g/bhp-hr | 2365 g/hr | 5.21465 lbs/hr | 125 lbs/day

for CO

0 ~~parts~~	8578 ~~dscf~~	28 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	=
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC

0 ~~parts~~	8578 ~~dscf~~	16 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	=
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter LB/MMBTU emission factor	
NOx	2.270 LB/MMBTU
CO	0.130 LB/MMBTU
VOC (as methane)	0.000 LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS	
NOx	616.25 ppmv
CO	57.98 ppmv
VOC (as methane)	0.00 ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

Parts Per Million Volume -> Grams/Brake Horsepower - Hour

ppmv -> g/Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	616	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NO_x)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

ppmv	F-factor	$MW_{pollutant}$	20.9	1	1	Conversion #3	1	
1	1	1	(20.9 - O_2%)	Conversion #1	Conversion #2	1	Engine Eff.	=

for NO_x

616 ~~parts~~	8578 ~~dscf~~	46 ~~lb~~	20.9	~~1 lb-mol~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 7.365 g/bhp-hr | 6334 g/hr | 13.9662 lbs/hr | 335 lbs/day

for CO

0 ~~parts~~	8578 ~~dscf~~	28 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC

0 ~~parts~~	8578 ~~dscf~~	16 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

RECEIVED
JUL 03 2008
Permits Srvc
SJVAPCD

Avenal Power Center, LLC
500 Dallas Street, Level 31
Houston, TX 77002

COPY

July 1, 2008

RE: Certification of Avenal Energy, owned by Avenal Power Center, LLC

I, Stuart Zisman, on behalf of Avenal Power Center, LLC, hereby certify under penalty of perjury as follows:

1. I am authorized to make this certification on behalf of Avenal Power Center, LLC.
2. This certification is made pursuant to Section 4.15.2 of Rule 2201 of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.
3. To the best of the undersigned's knowledge, relative to Section 4.15.2 of District Rule 2201, Avenal Power Center, LLC. does not currently own, operate or control any Major Stationary Source or federal major modification in the State of California other than the proposed Avenal Energy Project.

Each of the statements herein is made in good faith. Accordingly, it is Avenal Power Center, LLC's understanding in submitting this certification that the SJVUAPCD shall take no action against Avenal Power Center, LLC or any of its employees based on any statement made in this certification.

Stuart Zisman
Vice President
Avenal Power Center, LLC

7/1/08
Dated

Joseph Forbes
Senior Lawyer

ATTACHMENT J

EPA Comments and District Responses

EPA Comments / District Response

The comments (from Gerardo Rios) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

EPA Comments – Letters Dated September 13, 2010

EPA Comment #1:

Applicable federal requirements include thresholds for defining a major source of criteria pollutant emissions. For those sources where emission estimates and/or emission limits are relatively close to the federal thresholds, EPA encourages the following: (a) refinement of emissions and compliance demonstration methods that would ensure the thresholds would not be exceeded, and/or (b) a 5-10% buffer between the permitted emission limits and the federal threshold.

The proposed annual NOx emission and CO emission limits are within a margin of less than 5% of the federal annual threshold limit for defining a new major stationary source under the Federal Prevention of Significant Deterioration (PSD) permit program. The threshold is 100 tons per year (tpy) each. If the limits of these pollutants are relaxed, the facility may be subject to the applicable federal requirements, such as the Federal Prevention of Significant Deterioration (PSD) permitting program (See 40 CFR Part 52.21 (r)(4)).

District's Response:

The permitted emissions from this facility are below PSD thresholds. The facility's NO_X and CO emissions limits are included as permit conditions on the PDOC. The facility is also required to maintain records to demonstrate that they do not exceed these emission limits.

In addition, emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

EPA Comment #2:

In the "General Calculations" section (See PDOC Page 27, Section VII. C. 5), the District compares the annual emission estimates for regulated pollutants to the major source threshold to determine whether a pollutant is subject to major source requirements for NO_X, CO, VOC, PM_{10}, and SO_X emissions. However,

$PM_{2.5}$, which also is a regulated pollutant, is not included. On May 8, 2008 EPA finalized regulations to implement the NSR program for $PM_{2.5}$. A source that emits or has the potential to emit 100 tpy or more PM2.5 in a nonattainment area is defined as a major stationary source. (Reference 40 CFR Part 51, Appendix S.) We recommend the District include in its evaluation the $PM_{2.5}$ emission estimates with a comparison to the federal nonattainment major source threshold of 100 tpy (or 200,000 pounds per year).

District's Response:

The potential emissions of PM_{10} from the facility are 161,552 lb-PM_{10}/year (Calculated in the PDOC). Using the conservative assumption that all PM_{10} is $PM_{2.5}$, it is clear that the $PM_{2.5}$ emissions from this facility will not exceed the major source threshold of 100 tons/year. However, to avoid any confusion, the District will revise the PDOC to discuss the potential emissions of $PM_{2.5}$ from this operation.

EPA Comment #3:

The proposed annual emissions (calculated on a twelve consecutive month rolling basis) from the facility are 198,840 pounds per year (lb/yr) NO_X and 197,928 lb/year CO. (See PDOC Page 27, Section VII. C. 5) These annual emissions are equivalent to 99.4 tpy of NO_X emissions and 98.9 tpy of CO emissions, both of which are relatively close to the federal PSD permit program applicability threshold of 100 tpy for each ofthese pollutants. A proposed permit condition requiring that annual emissions not exceed these levels has been added to all combustion related equipment. The condition reads as follows:

> *"Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NOx (as N02) -198,840 lb/year; CO -197,928lb/year."*

In a review of the post-project potential to emit annual emission estimates in Sections VII.C.2.i through C.2.iv. (See PDOC Pages 16-26) for each piece of equipment, we noted that the combustion turbine operations contribute the majority of NOx and CO emissions.

Based on discussions with the District, we understand that in addition to the 12-month rolling facility NOx and CO emission limits that are equivalent to 99.4 tpy and 98.9, respectively, the District has made no other changes to the current FDOC permit conditions. These conditions include, but are not limited to, the following: continuous emissions monitoring of NO_X and CO; compilation of emissions on a daily, monthly, 12 consecutive month rolling average, and annual basis; quarterly reporting of excess emissions; and acid rain (40 CFR Part 75) compliance requirements.

At this time, it appears the proposed requirements provide practically and federally enforceable conditions based on our understanding of the proposed revision. However, given that the NO_X permit limit is within less than 1% of the PSD permit threshold and the CO limit is within 1.1% of the PSD permit threshold, we suggest that the District consider requiring Avenal to report more frequently emissions as the actual emissions approach or exceed 90% of the 12-consecutive month rolling average permit limit to assure the 100 tpy threshold is not exceeded.

District's Response:

Emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

EPA Comment #4:

The District concludes on pp. 53-54 of the PDOC that the proposed project will not cause a violation of an air quality standard for NOx, and refers to Appendix G. PDOC Appendix G contains some additional detail on the air quality impact analysis for the l-hour N02 NAAQS, effective April 12, 2010, and states that "the emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS." The following are our comments specific to PDOC Appendix G:

a. SIP-Approved Rule 2201 -The District's approved SIP, in District Rule 2201, Section 4.14.1, provides that modeling used for purposes of determining whether a new or modified stationary source's emissions will cause or make worse the violation of an Ambient Air Quality Standard shall be consistent with the requirements contained in the most recent edition of EPA's "Guideline on Air Quality Models." This EPA guideline is found in 40 CFR Part 51, Appendix w. EPA recently has had occasion to review and comment on the applicant's l-hour N02 NAAQS analysis for the project in the context of the applicant's pending PSD permit application before EPA.

   We recognize that certain aspects of the project for which Avenal seeks a minor source permit vary from the project for which it seeks a PSD permit, in particular, the proposed addition of a facility-wide NOx emissions limit of the equivalent of approximately 99.4 tons per year (tpy) to the minor source permit. However, given that the equipment emitting NOx from the two projects has the same permitted hourly emission rates, many of the comments EPA made concerning consistency with 40 CFR Part 51, Appendix W in reviewing the applicant's l-hour N02 NAAQS analysis for PSD purposes may be relevant to the l-hour N02 NAAQS analysis for this minor source permit as well. We have attached for your consideration our comments dated June 15, 2010 and August 12, 2010 on the l-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes. We would be happy to discuss any issues or questions you may have concerning these comments.

b. EPA Guidance Memorandum -We also note that EPA recently issued guidance relating to modeling for the l-hour N02 NAAQS, with a cover memorandum entitled *Guidance Concerning Implementation of the 1-hour N02 NAAQS for the Prevention of Significant Deterioration Program,* dated June 29, 2010, that included two attached guidance documents, one of which was entitled *Applicability of Appendix W Modeling Guidance for the 1-hour N02 National Ambient Air Quality Standard,* dated June 28, 2010. We understand that the District is aware of this guidance, and we encourage the District to refer to this guidance for further detail on this subject.

c. Assumptions and Decision-making Process -The District's rationale in Appendix G for its conclusion that the project's emissions will not cause or contribute significantly to a violation of the l-hour N02 NAAQS is not clear from the documents provided. For example, the table addressing "Operational" scenarios on page 2 of Appendix G indicates that Tier 1 and Tier 2 impacts are each greater than the N02 NAAQS limit, while Tier III and Tier IV impacts are each below the N02 NAAQS limit. Furthermore, it is unclear how the modeling analysis meets the requirements of Appendix W (See Comment 4.a.) or whether the District intended to follow those requirements for the proposed permit revision. We recommend that the District provide a discussion of which Tier the District is relying upon to support its conclusion, the basis for selecting that Tier, and the modeling inputs, assumptions, etc. for that Tier.

<u>District's Response:</u>

a. *The District has reviewed your comments dated June 15, 2010 and August 12, 2010 on the 1-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes, and has no comments at this time. We did not use Avenal Power's analysis to make determinations of NAAQS impacts, but used our own guidance to perform the NO2 modeling (please see responses below).*
b. *The District has reviewed the documents stated above and developed a modeling guidance to address EPA's memos that were provided to the modelers at EPA Region 9. The District is currently waiting for EPA's*

response to this guidance, and is, in fact, working with EPA, ARB, and CAPCOA on developing statewide policy on how to implement our guidance, or something similar. The Avenal Power project was analyzed under this guidance, and the project was approved under Tier III of that guidance.

c. *The District uses a tiered approach when determining compliance with any NAAQS. This approach is similar to that required by OAQPS in their memos which require that each progressively more accurate tier be used (Tier I-Complete Conversion, Tier II-NO2 Ration and Tier III-OLM) until compliance is demonstrated. This project was approved under Tier III. We believe our guidance is consistence with EPA modeling practices and direction, and as we have stated above, we are patiently awaiting EPA's input on our guidance.*

EPA Comment #5, Joint letter to District and Avenal Power Center, LLC:

Avenal Power Center, LLC (Avenal) recently applied for a minor source New Source Review (NSR) permit from the San Joaquin Valley Pollution Control District (SJVAPCD or District) for the Avenal Energy Project. This permit seeks authority to construct the project with emissions limits below the major source thresholds triggering Clean Air Act (CAA) prevention of significant deterioration (PSD) preconstruction review. On July 28, 2010, SJVAPCD's public notice announcing its Preliminary Determination of Compliance for this minor source permit application was published in the Fresno Bee, triggering a public review and comment period for the proposed permit.

Concurrently, Avenal is seeking a PSD permit from EPA Region 9 for essentially the same project, but with greater emissions exceeding the major source threshold and thereby triggering PSD preconstruction review. The applicant's simultaneous application for both a minor source permit and a major souce PSD permit for the project raises a potential concern about circumvention of PSD preconstruction requirements.

EPA guidance on this subject states:

> Parts C and D of the Clean Air Act exhibit Congress's clear intent that new major sources of air pollution be subject to <u>preconstruction</u> review. The purposes for these programs cannot be served without this essential element. Therefore, attempts to expedite construction by securing minor source status through receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements... If a major source or major modification permit application is filed simultaneously with or at approximately the same time as the minor source construction permit, this is strong evidence of an intent to circumvent the requirements of preconstruction review.

Guidance on Limiting Potential to Emit in New Source Permitting, Terrell E. Hunt and John S. Seitz, dated June 13, 1989, at pp. 13-14.

We recommend that the applicant carefully review the guidance quoted above and other applicable EPA guidance on this topic prior to commencing construction of the project under the minor source permit, should that permit be finalized by the SJVAPCD.

District's Response:

The District disagrees that if Avenal were to construct under a California Energy Commission license that incorporates this minor source Determination of Compliance (DOC), it would be circumvention of the PSD preconstruction review.

Circumvention might occur if a source obtained a minor source permit and soon thereafter sought a PSD permit due to a small increase in emissions, and not as a new source. In this case, Avenal has applied for a PSD permit as a new source. If they construct as a minor source and don't receive a PSD permit, they will have to continue to comply with the minor source limits. However, constructing as a minor source and then obtaining a PSD permit as a new major source and operating in accordance with that PSD permit cannot be viewed as circumvention. Therefore, the EPA process, not the District's minor source permitting process, will determine whether circumvention will occur, and circumvention will not occur if EPA requires a PSD permit if Avenal pursues a permit with emissions above the PSD triggers.

ATTACHMENT K

Green Action Comments and District Responses

Greenaction Comments / District Response

The comments (from Bradley Angel) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Greenaction Comments – Letter Dated September 11, 2010

Greenaction Comment #1:

The Air District failed to conduct a proper and thorough public notice and public participation process. The failure to conduct proper notice and participation processes to the mostly low-income, Latino and Spanish-speaking residents of the nearest communities (Avenal, Huron and Kettleman City) violated the Air District's own environmental justice policy. The Air District's claim that you met your agency's required notice and participation mandates is insufficient as your own environmental justice policy commits the agency to uphold environmental justice.

Failing to notify residents or their organizations, failing to hold a public hearing and failing to provide Spanish-speaking residents equal time to comment as English speakers is a violation of environmental justice and civil rights policies and laws.

We are surprised and disappointed that the Air District would only translate information into Spanish following concerns being raised by Greenaction, and after the comment period already began. On August 20, 2010, we received an email from Dave Warner of the Air District that stated:

> Bradley,
>
> The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm

As this email was sent one week into the revised comment period, and as Spanish-speakers had not yet had the opportunity to read information in Spanish, this shows that there has been an unequal opportunity to comment that is improper.

The Air District's notice was inadequate for all of the affected public. No resident or organization representing residents received notice. We only learned of the original comment period from US EPA after it already had begun.

The Air District published a "Notice" in the Fresno Bee, but not in any Kings County or Spanish-language paper.

Even after meeting with the Air District on August 30, 2010 to raise all these concerns, the Air District refused to hold a public hearing, provide proper notice or provide equal opportunities to the Spanish-speaking residents who comprise a major percentage of residents of Avenal, Kettleman City and Huron.

Due to the discriminatory and disproportionate impact on low-income, Latino and Spanish-speakers of the lack of notice and full public participation notice for a project that would emit pollutants into an already over-polluted area, the Air District has violated its own environmental justice policy as well as California Government Code section 11135 and Title VI of the US Civil Rights Act of 1964.

District's Response:

The District complied with all applicable regulatory public noticing requirements with respect to the Avenal Power Center Preliminary Determination of Compliance (PDOC) and in fact took considerable actions that went far beyond statutory requirements. The District properly published notice of the proposed issuance of the PDOC in a newspaper of general circulation, in this case, the Fresno Bee whose distribution does cover the area in question. This notice was published according to our federally approved Rule 2201, which defines the timing and process of such notices. There is no additional direction on public noticing in the District's Environmental Justice Strategy document, contrary to the commenter's claims.

However, we went far beyond our required notification processes for this project, as follows:

1. *We published this notice, as we do all public notices, on the District's website, valleyair.org. This is not required by any rule or regulation, but is part of our continuing effort to make information available and accessible.*

2. *Upon hearing on August 16 of the commenter's concern that he was not notified of the District proposal to issue a DOC, we promptly, on August 18, notified him that we would extend the public noticing period for him and his clients a full additional 30 days from the date that he heard about our proposal. This was not required, since the commenter had not requested that he be informed of our actions on this project, and therefore he was not on record as an interested party. However, in the interests of providing the maximum reasonable opportunity for comment, we offered this accommodation.*

3. *Upon receiving the commenter's subsequent August 19 request for bilingual information on the project, and a public hearing, on August 20 we sent the commenter the following email, from which he quoted an excerpt above. We are providing it in full, below, as it explains our response in some additional detail that was missing from the commenter's excerpt:*

> *Bradley,*
>
> *The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm*
>
> *We would welcome your assistance in distributing it to your Spanish-speaking clients and associates. We will also be pleased to accept comments in Spanish as we have translation capabilities here at the District. As you are aware, we have already extended the public comment period to September 13, 2010, and we believe the above steps will provide you and your Spanish speaking associates ample opportunity to provide comment on our proposal.*
>
> *I just want to make sure you understand the status of this project atthis time as it pertains to the District. The District is taking public comment on a Preliminary Determination of Compliance, which is a recommendation to the California Energy Commission (CEC) that the project will comply with District regulations. We are not aware of any requirement that we hold a meeting for the purpose of receiving verbal comments.*
>
> *We are not going to hold a public hearing on this project at this time. Ours is not a final permitting decision and there is no hearing process associated with it - the CEC has the sole power plant licensing authority in the state of California for power plants over 50 megawatts. They conduct any necessary public hearings associated with such a license. Our action is a certification to the CEC that, if granted, CEC's license would meet our air quality requirements. CEC is able to accept or reject our proposed conditions of approval, or can make air quality permitting decisions contrary to our determination of compliance. In addition, the CEC makes all determinations regarding power plant siting.*

> *Finally, contrary to your contention below, the District is not required to hold a public hearing, by rule or by policy We believe the process described above will assure an efficient, fair, and productive public comment process.*
>
> *Dave Warner*
> *Director of Permit Services*
> *San Joaquin Valley APCD*

In summary, we confirmed that we would prepare a Spanish-language summary of the project and make it available to the commenter for his outreach efforts. We also confirmed our commitment to address any comments we received in Spanish, and we explained the limitations of our role in the permitting process to provide clarity to any potential commenters. None of this was required by our rules and regulations, but was intended to provide additional opportunity for community members to participate in the process.

4. *We then worked through the weekend to create a summary of the project, translate it to Spanish, and post it on the website the very next working day, Monday, August 23.*

5. *Next, on August 24 we agreed to meet with the commenter and any of his clients and community members on August 30. The commenter and other activist organization representatives attended the meeting, but, disappointingly, no independent community members. Again, this meeting was not required by any rule or regulation.*

6. *Finally, we granted another request from another employee of GreenAction that she be provided with an <u>additional</u> day to persuade community members of Avenal and Kettleman City to submit comments, extending the comment period to September 14, for a total public comment period of 53 days instead of the required 30 days. This provided GreenAction the opportunity to persuade community members to submit the comments summarized in the next comment section. And again, there was certainly no rule or regulation that required this accommodation.*

In summary, contrary to the assertions of the commenter, the District not only met all legal requirements but went far beyond them in providing the public opportunities to comment on the Avenal Power Center Project.

Greenaction Comment #2:

The claim by the company and the Air District that there would be substantially less emissions than were stated in the initial permit application dramatically conflicts with earlier information and needs extensive scrutiny including a full public environmental review. If there really would be dramatically lower emissions than first claimed, we wonder why the company did not state this initially, raising questions as to whether the lower, newer estimate is based solely on a desire to avoid a PSD permit requirement and protracted appeals and legal battles.

District's Response:

While no response is necessary, it should be noted that the proposal for lower annual emissions was only possible after rigorous analysis by Avenal Power of actual emissions data from other recently constructed similar power plants. In addition, it seems remarkable that there should be a complaint about a company committing to lower emissions from a facility, regardless of the purpose or intent of the proposal.

Greenaction Comment #3:

The Air District's claim that there would be "zero impact" from the proposed power plant's emissions flies in the face of reality. A huge fossil fuel power plant, no matter how much cleaner than others of its kind, still will have pollution impacts. This "zero impact" claim ignores the fact that this would be a fossil fuel power plant that would have emissions and use fuels that contribute to climate change, would emit a broad range of pollutants, and its emissions would act cumulatively in concert with the many other pollution sources in the area.

The proposed fossil fuel power plant would be close to Kettleman City, a small low-income community of color that is suffering a horrible health crisis involving a large number of birth defects and infant deaths. Even a minor increase in emissions near this community could have severe and unforeseen health impacts due to the current health vulnerability of residents. In addition, the entire San Joaquin Valley already suffers from high rates of asthma, and if built this power plant would emit asthma-triggering pollutants.

District's Response:

The District has searched the PDOC and has not been able to locate the phrase "zero impact".

However, the District has performed a Health Risk Assessment (HRA) as well as an Ambient Air Quality Analysis (AAQA) for this facility. The HRA was performed using the AERMOD model and Hot Spots Analysis and Reporting Program (HARP), and demonstrated that the acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Pursuant to the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit with a cancer risk less than one in one million, and chronic or acute hazard index less than 1.

The AAQA demonstrated that the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. In addition, as shown in the PDOC, the calculated contribution of PM_{10} will not exceed the EPA significance level. Therefore, this project will not cause or contribute significantly to a violation of the State or National AAQS.

Greenaction Comment #4:

This proposed fossil fuel power plant is not needed. Many things have changed since the CPUC originally determined that the Avenal Power Center was needed. As California emerges from an economic recession, the energy landscape has changed. PG&E now has access to more electricity generation than it needs. Last summer, PG&E's territory operated with a 44% reserve margin during summer peak. This extraordinarily high margin is in part due to the CPUC's success at increasing energy efficiency and the demand decrease from the recession. These factors, along with delayed facility retirements and inflated population and energy export assumptions made by the CEC demonstrate that the 600 MWs that the Avenal Power Center would generate are no longer needed. Even PG&E has forecasted a decrease in need. In addition, several large solar projects are to be sited here, and other solar projects are already underway, providing truly clean and renewable energy instead of dirty fossil fuel energy.

Despite all this evidence, Avenal Power Center continues its push for this power plant. The pollution and health effects of this proposed facility are unacceptable when the new capacity is clearly not needed. Finally, allowing unneeded fossil fuel energy would also likely crowd out renewable projects.

District's Response:

The District is not able to take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission.

ATTACHMENT L

NRDC and CRPE Comments and District Responses

National Resources Defense Council (NRDC) and Center on Race, Poverty & The Environment (CRPE) Comments / District Response

The comments (from Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

NRDC and CRPE Comments – Letter Dated September 13, 2010

NRDC and CRPE Comment #1:

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year* –$1,600 per person – in the San Joaquin Valley.

District's Response:

The District has demonstrated in the PDOC that the proposed facility is in compliance with all applicable NO_X and VOC rules and regulations. It should be noted that these rules and regulations are among the strictest and most stringent in the nation and are designed to protect the health of the residents of the San Joaquin Valley.

NRDC and CRPE Comment #2:

The June, 2009 EPA Statement of Basis And Ambient Air Quality Impact Report for a prevention of significant deterioration (PSD) permit states, at page 14, that emissions of CO and NOx from the Project are expected to be 1,205,400 pounds per year and 288,600 pounds per year, respectively. The July 13, 2010 Revised Preliminary Determination of Compliance for the Project states, at page 1, that emissions of CO will now be 197,928 pounds per year and NOx 198,840 pounds per year, both to be enforced as permit limitations. Conveniently, this would bring both the CO and NOx emissions under the 100-ton limit for major sources under Title V of the Clean Air Act. This change in emission numbers was accomplished with no changes to the setup or operation of the Project itself.

In addition, this sentence occurs relating to the new CO and NOx limits:

> If the annual [CO/NOx] emissions from these units exceed this value, they will be set equal to the proposed facility wide [CO/NOx] emission limit.

Revised PDOC at pages 9 (NOx) and 10 (CO). There are two ways to read this confusing sentence. One is that the sub-100 tons limits are meaningless and will be ignored if exceeded. The other is that APCD is attempting to engage in the type of "flexible permitting" that USEPA has disapproved in Texas. In either case, the federal Clean Air Act has been violated.

District's Response:

The District agrees that the wording in the PDOC is slightly confusing. The intent of the statement was to explain that the potential annual emissions from each of the turbines was calculated based on a stated scenario that was provided by the applicant and that if the unit was not operated exactly in accordance with this scenario, there was the potential for higher NO_X and CO emissions from the unit. However, the total emissions from the facility would not be allowed to exceed the proposed facility wide NO_X and CO emissions limits.

The stated scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, the facility cannot be held to a specific operational schedule. The main point to understand is that the annual emissions from the facility will not exceed the facility wide limit that is stated as a condition on the PDOC, and therefore the impact from the facility's emissions will not be greater than that evaluated by the District.

Attached Letter Addressed to U.S. EPA - Dated October 14, 2009

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comments

The following comments were sent to U.S. EPA on October 14, 2009 from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit on behalf of El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, the Center on Race, Poverty, & the Environment, and the Natural Resources Defense Council. These comments were not sent to the District therefore, the District did not previously respond to the comments. These comments refer to the DOC performed in District project C-1080386, which analyzed the prior, higher-emitting proposal. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments (from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #1:

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year*–$1,600 per person – in the San Joaquin Valley.

District's Response:

This is the same comment that was made in the NRDC and CRPE Letter Dated September 13, 2010 and addressed above. See above for District Response.

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #2:

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

District's Response:

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #3:

The Project is expected to emit 80.7 tons/year of PM/PM10. *See* the June 16, 2009 EPA Statement of Basis and Ambient Air Quality Impact Report at p. 14. As we discuss below, we believe that the Project's plan to offset these PM emissions through SOx offsets is invalid under the Clean Air Act. Accordingly, ambient air quality will be impaired by the Project.

As you know, the San Joaquin Valley is in non-attainment for PM2.5. The Project proposes to meet 98% of its PM offset requirements from SOx offsets at a one-to-one ratio. *See* Final Staff Report, Air Quality Table 19. This is highly problematic for a number of reasons.

First, the one-to-one ratio ignores the very different health risks of SOx and PM. The U.S. EPA has found that particulate matter can cause or contribute to increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing, for example; decreased lung function; aggravated asthma; development of chronic bronchitis; irregular heartbeat; nonfatal heart attacks; and premature death in people with heart or lung disease.

Second, the Project applicants should not be allowed to use PM10 as a surrogate for PM2.5 emissions.

District's Response:

The facility is not using PM_{10} as a surrogate for $PM_{2.5}$. The facility has proposed to offset PM_{10} emissions with SO_X ERCs at the District evaluated interpollutant offset ratios. District Rule 2201, Section 4.13.3 allows for the use of interpollutant offsets at ratios based on air quality analysis. The SO_X for PM_{10} offset ratio used in this project is based on the best available science for determining how much PM_{10} SO_X can create. In addition, the facility is not a Major Source for $PM_{2.5}$ emissions; therefore $PM_{2.5}$ requirements will not be addressed in this project.

Attached Letter Addressed to U.S. EPA - Dated October 15, 2009

EarthJustice Comments

The following comments were sent to U.S. EPA on October 15, 2009 from Paul Cort of EarthJustice. These comments were not sent to the District therefore, the District did not respond to the comments. These comments refer to the DOC performed in District project C-1080386. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments from Paul Cort regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's response.

EarthJustice Comment #1:

Commenter's find it stunning that the proposed permit does not even mention CO2 emissions or controls. EPA is well aware that the Environmental Appeals Board ("EAB") has returned multiple PSD permits for failing to consider whether CO2 is a pollutant "subject to regulation" under the Clean Air Act. *See In re Deseret Power Elec. Coop.*, PSD Appeal No. 07 - 03 (EAB Nov. 13, 2008); *In re Northern Mich. University Ripley Heating Plant*, PSD Appeal No. 08 - 02 (EAB Feb. 18, 2009). In light of these decisions, EPA Region 9 also withdrew portions of the PSD Permit issued to Desert Rock Energy Company in order to reconsider the issue of whether CO2 is a pollutant subject to regulation. Yet EPA proposes a PSD permit for another power plant that will emit over 1.7 million tons of CO2 each year without any discussion of these contentious issues whatsoever. EPA must revise the proposed permit to explain EPA's position on BACT for CO2 so that the public can comment on the control levels selected or EPA's rationale for refusing to impose such controls.

District's Response:

This is the same comment that was made in the NRDC and CRPE Letter dated September 13, 2010 and addressed above. See above for District Response.

EarthJustice Comment #2:

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

District's Response:

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

EarthJustice Comment #3:

The Proposed Permit Fails to Demonstrate that the Avenal Project Will Not Cause or Contribute to Violations of National Ambient Air Quality Standards for Ozone and Fine Particulate Matter.

District's Response:

The facility is not a Major Source for $PM_{2.5}$*; therefore* $PM_{2.5}$ *(fine particulate matter) requirements will not be addressed in this project.*

There is no EPA approved model capable of accounting for the photochemical complexities of regional ozone formation to determine the impacts of ozone from a single site due to NOx and VOC emissions. In addition, the facility in this project does not directly emit ozone. Therefore, an analysis of nearby ozone emissions impacts was not performed in this project. Finally, we believe that our very strict standards for NOx and VOC from new sources, among the most stringent in the nation, are sufficient safeguard to prevent any single source from contributing significantly to a violation of the ozone NAAQS.

ATTACHMENT M

Rob Simpson Comments and District Responses

Public Comments / District Response

The comments (from Rob Simpson) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Rob Simpson Comments – Emailed Letters Received November 17, 2010

Simpson Comment #1 - Public Notice:

The notice was not given to me in sufficient enough time to prepare adequate comments. The newspaper notice does not provide enough information about the project to the public and was not published in Spanish.

District's Response:

On the contrary, although Mr. Simpson was not on record as being interested in receiving information regarding this specific project, we are always quite interested in providing interested parties an opportunity to provide input, and so we provided a full 30-day period for Mr. Simpson to comment, the same amount of time provided all interested parties on all permitting projects. As for the second comment, please refer to our response to GreenAction's comment #1.

Simpson Comment #2:

The revised PDOC seems to have one purpose, evasion of the Clean Air Act requirements for the Prevention of Significant Deterioration (PSD). The only change in the revised permit is a limitation on annual NOx and CO emissions but the way the permit is worded this limitation is not federally enforceable. Page 9 of the PDOC states that,

> "*The facility has proposed to limit the annual facility wide NOx emissions to 198,840 lb/year. If the annual NOx emissions from these units exceed this value, they will be set equal to the proposed facility wide NOx emission limit.*"

Page 10 of the PDOC states:

> *"The facility has proposed to limit the annual facility wide CO emissions to 197,928 lb/year. If the annual CO emissions from 'these units exceed this value, they will be set equal to the proposed facility wide CO emission limit."*

So essentially there is no change from the original permit and the Avenal Power Project still requires a PSD permit. Issuance of this permit would be a violation of the Clean Air Act and the district and the applicant would be subject to enforcement.

District's Response:

See response to NRDC and CRPE comment #2.

Simpson Comment #3 - The District is the Lead Agency for this Project:

The CEC appears to no longer be the lead agency for the project the district under CEQA, CEC or District rules. The District is now the lead agency since the purpose of the revision to the permit is merely to avoid PSD review and the CEC has no jurisdiction over PSD issues on this project. Thus the district is now the lead agency for review of this project and must conduct a complete EIR prior to issuance of an Authority to Construct for this project.

District's Response:

The District is not the lead agency for this project. Pursuant to California Public Resources Code Section 25500, the CEC "shall have the exclusive power to certify all sites (for power plants over 50 MW) and related facilities in the state". The California Public Resources Code further states that "the issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency".

Simpson Comment #4 - Is an FDOC an ATC?:

- Does the FDOC process comport with the Districts Federal permitting requirements?
- Is it the federal New Source Review (NSR) permit?
- Has the prior FDOC expired for this facility?
- Has the Applicant commenced construction or use of the prior FDOC?

District's Response:

The FDOC complies with Federal non-attainment pollutant permitting requirements, as implemented with the District's EPA-approved non-attainment NSR rule. This rule requires the District to issue a Determination of Compliance, rather than an Authority to Construct because, as noted above, the CEC has the sole licensing authority for large power plants in California. Our NSR rule does not incorporate federal attainment NSR (PSD) requirements. EPA retains the sole authority to issue PSD permits in the San Joaquin Valley.. The prior FDOC is tied to the CEC's license that has been issued, therefore it has not expired. However, the facility has not commenced construction or use of the prior FDOC. The FDOC under which construction is commenced (and only after CEC has approved any related licensing action) will determine the conditions under which the facility must operate.

Simpson Comment #5:

- I contend that the Warren Alquist Act hijacks air districts authority under the Clean Air Act in conflict with Federal law, does the District agree?.
- Does the District agree with the Brief submitted by the South Coast Air District (Exhibit 3) in the Humboldt Superior Court proceeding regarding a power plant permit that I appealed?

District's Response:

The District does not agree with either the "hijack" comment or the South Coast AQMD's brief on the subject. State law provides the CEC with sole permitting authority, but does not allow them to issue a license that violates the District's regulations. The DOC process provides the District ample opportunity to provide the appropriate guidance to the CEC prior to their licensing process. This process does not violate federal permitting requirements in any way. The federal EPA has approved the DOC process as embodied in the language of the District's NSR rule and that approval explicitly acknowledges that the process complies with federal permitting requirements.

Simpson Comment #6:

The District indicated in emails that it did not intend to issue an Authority to Construct for this project. Please provide some indication of how the permit would be enforceable without an Authority to Construct and who could enforce the State and Federal aspects of the permit. The PDOC has extensive references to an ATC.

District's Response:

Thank you for pointing out that we referred to the DOC as the ATC several times in our evaluation. We apologize for that error. The District has removed all references to the issuance of ATC's in the FDOC evaluation.

Pursuant to District Rule 2201, Section 5.8.9, the APCO shall issue a Permit to Operate to any applicant receiving a certificate from the California Energy Commission pursuant to this rule provided that the construction or modification is in compliance with all conditions of the certificate and of the Determination of Compliance, and provided that the Permit to Operate includes the conditions prescribed in Section 5.7. The District will then perform inspections of the facility to determine if it meets all requirements on their PTO.

Simpson Comment #7 - The BACT Analysis for the Permit is Defective:

The district's top down BACT analysis for NOx is defective because it fails to:

- Identify any alternative technologies or work practices which are technologically feasible for reducing NOx emissions, and
- To quantify the collateral impacts from the selection of SCR as the proposed alternative, and
- Identify combustion technologies that are effective is reducing NO_X emissions. (i.e. steam injection, dry low NO_X combustors, and catalytic combustors), and
- Analyze post-combustion controls including selective noncatalytic combustion and EM, and
- Evaluate the risk of an accident from the transport of NH_3, and
- Evaluate NH_3 as a precursor to PM2.5.

District's Response:

The District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The existing Top-Down BACT Analysis did not consider any NO_X emissions control other than the use of SCR to lower the NO_X emissions to 2.0 ppmvd @ 15% O_2, as no more efficient technology has been identified. Pursuant to the District BACT Policy, no analysis is necessary for a project in which the most effective control alternative listed in the BACT Guideline is selected. BACT Guideline 3.4.2 identifies BACT for NO_X as the use of SCR or equal to meet an emission concentration limit of 2.0 ppmvd @ 15% O_2 as the most stringent technologically feasible NO_X requirement. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.

In addition, BACT only covers operational emissions; therefore the risk from accidents during the transport of NH_3 is not evaluated and can not be evaluated under the District's NSR rule.

The evaluation of NH_3 as a precursor to $PM_{2.5}$ was not performed since the facility is not a Major Source for $PM_{2.5}$ emissions. However, it should be noted that the Valley's atmosphere does contain ammonia, largely from the Valley's considerable agricultural operations, and relatively small amounts caused by SCR systems are insignificant and are quite worth the significant NOx emissions reductions generated by the SCR. In addition, the District did analyze the health risk impacts of the NH3 emissions that are resulting from the requirement that SCR be installed, and there is no significant risk. Also see the response to comment #17, below.

Simpson Comment #8 - NO_X Emissions During Startup and Shut Down:

Emissions are greater during startups, shutdowns and combustor tuning periods than they are during steady-state operation, the BACT limits established for steady-state operations are not technically feasible during these periods. As these limits are not "achievable" during these operating modes, they are not "Best Available Control Technology" as defined in the Federal Regulations. Therefore, alternate BACT limits must be specified for these modes of operation. The discussion of Best Available Control Technologies does not include information on minimizing startup emissions or startup durations. The U.S. Environmental Protection Agency (U.S. EPA) requires that BACT apply not only during normal steady-state operations but also during transient operating periods such as startups. The District should consider conducting, as part of the BACT analysis, a review of combustion turbine and combined cycle system operational controls or design features that can shorten start up and shutdown events and optimize emission control systems.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised.

Simpson Comment #9 - BACT VOC Emission Limit:

The district has selected a VOC emission limit of 1.4 ppmvd @ 15% 02 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% 02 when it is fired with the duct burners. The BAAQMD has recently established a BACT VOC emission limit for large gas turbines for VOC's. BACT is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMBtu, which is equivalent to 1 ppm POC, 1-hr average. Since VOC emissions contribute to ozone formation and the district is in severe non attainment for the 8-hour ozone standard the district should adhere to the lower VOC emission rate or provide a top down BACT evaluation which shows that this rate is not achievable or is not cost effective.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The District Top-Down BACT Analysis did not consider any VOC emissions control other than limiting the VOC emissions to 2.0 ppmvd @ 15% O_2 when the duct burner is fired, and 1.5 ppmvd @ 15% O_2 when the duct burner is not fired.

The applicant proposed VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct *burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in the BACT. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.*

Simpson Comment #10 - BACT $PM_{2.5}$ / PM_{10} Emission Limit:

The permit proposes to allow the project to emit as much as 11.78 pounds per hour of PM-10 with the project utilizing duct firing. According to BAAQMD the projects listed in the table below all have lower PM emission limits than those proposed for this project. BACT for PM 2.5 for large combined cycle turbines with duct firing is 9 pounds per hour. The district needs to impose this limit in the FDOC.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. *District BACT Policy, Section IX.D, states that a cost effective analysis is not necessary for a project in which the most effective control alternative is selected. BACT Guideline 3.4.2 identifies BACT for PM_{10} as the use of an air inlet filter, lube oil vent coalescer and natural gas fuel. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed. In addition, it is likely that a PM10 limit of 11.78 lb/hr is substantially the same as a PM2.5 limit of 9.0 lbs/hr, as PM2.5 is a fraction of PM10.*

Simpson Comment #11 - Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether 'the operation of the proposed equipment will cause or make worse a violation of an air quality standard. For NOx the impact analysis conducted by the district in Attachment G page 2 demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98th percentile of the annual distribution of the daily 1 hour max ppb /ug/m3 for the Visalia site which is 115.72 ug/m3. So the project does in fact violate the new federal NO2 standard and thus cannot be permitted.

District's Response:

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour *max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.*

Simpson Comment #12:

The PDOC uses the PM-10 surrogate approach to analyze the particulate matter impacts from the project. On October 20, 2010, the USEPA issued a final rule providing modeling thresholds for evaluating impacts of PM2.5 emissions under the Prevention of Significant Deterioration (PSD) program and the Non attainment NSR program. The rule establishes Class I and Class II Increment Thresholds and Significant Impact Levels (SILs), and a Significant Monitoring Concentration (SMC) threshold. The project according to the analysis presented on page 54 exceeds both the significant impact levels for the annual PM 2.5 standard and the 24 PM 2.5 hour standard. The FDOC needs to address the compliance of the project with the new rules.

District's Response:

The project does not trigger PSD permitting and the facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, the District is not required to perform modeling to evaluate impacts of $PM_{2.5}$.

Simpson Comment #13 - Federal 1 hour NO2 Standard:

The permit does not present an adequate and complete analysis for the new Federal 1 hour NO2 standard. The district failed to include information on any nearby sources which are required to be modeled with Avenal's emissions. A full impact analysis should be presented in the permit for the public to comment on using the EPA's Guideline on Air Quality Models (40 CFR Part 51 Appendix W).

District's Response:

This project does not trigger a PSD permit and therefore it is not required to follow the guideline on air quality models in 40 CFR Part 51 Appendix W. If it did trigger PSD permitting, the federal EPA would be obligated to perform such modeling, if appropriate.

Simpson Comment #14:

The revised permit should provide the input data that was used to determine compliance with the new NO2 standard. Emission factors and NO2 inventories should be presented for the public to review not just the information that is presented on page 2 Attachment G. The analysis on page 2 Attachment G demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98th percentile of the annual distribution of the daily 1 hour max ppb / ug/m3 for the Visalia site which is 115.72 ug/m3.

District's Response:

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.

Simpson Comment #15:

Modeling for the NO2 standard should indicate whether worst case emissions which would be the start up and shut down emissions for the project were utilized in the modeling for compliance with the standard.

District's Response:

The District performed modeling during the commissioning period and the standard operational period to determine compliance with the NO2 standard. The modeling performed by the District for these periods demonstrated compliance with the NO2 standards.

Simpson Comment #16 - The Proposed Interpollutant Trade Values Violates EPA Guidance and $PM_{2.5}$ NSR Regulations:

Based on an EPA assessment, the preferred trading ratios for SO2 to PM2.5 was set at 40:1.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #17 - Ammonia Emissions:

Other power plant turbines have achieved a 2 ppm NO_X limit with a 5 ppm NH_3 slip limit.

The district must consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The district is not an isolated island.

District's Response:

Ammonia is an integral part of the NOx emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.

A high ammonia slip from the turbine will not lead to increased PM_{10} *formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts* $PM_{2.5}$ *plan which does not not rely on ammonia reductions to reduce* $PM_{2.5}$*, but rather relies largely on* NO_X *reductions.*

Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NOx BACT performance levels (2.0 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.

Simpson Comment #18 - Emission Reduction Credits:

ERC's used on the prior PDOC are unavailable for use on the new PDOC.

District's Response:

The ERC listed in the previous FDOC and the ones listed in the new PDOC will only be used for one of the projects. Once they are withdrawn for either project, they will no longer be available to be withdrawn for the remaining project. In addition, the applicant has provided sufficient ERC's of offset the emissions increase in either one of the projects.

Simpson Comment #19:

The PDOC indicates that the closest population center is the residential district of Avenal approximately 6 miles to the southwest. Are there people residing or working closer than that to the project? Could there be sensitive receptors closer to the site?

District's Response:

According to the application submitted by the facility, the nearest resident is 7,700 feet to the Northeast and the nearest business is 3,957 feet to the Northwest. However, our analysis of emissions and risk from those emissions is based on a theoretical long-term exposure at the point of maximum pollutant concentration. Therefore, our conclusion that there will be no significant risk from any emissions from this facility is not dependant on receptor location.

Simpson Comment #20:

It appears that there are residential structures and extensive farm land around the site. Could emissions from the facility affect crops or wildlife?

District's Response:

Such issues are addressed in the CEC's CEQA-equivalent process and are not a part of the District's analysis. However, it should be noted that the District's Health Risk Assessment (HRA) is a multipathway assessment of risk, and would include the affect on public health generated by pollutant deposition on plants and animals that are subsequently ingested by the public.

Simpson Comment #21:

- Has the District conducted and Environmental Justice analysis of the projects effects? Could farm workers be an environmental justice community that suffers a greater impact due to hard physical labor in the vicinity of the project, lack of health care, poverty and additional stressors like chemicals used in farming?
- Can farming activities cause additional air quality impacts that could contribute to a negative cumulative effect?
- Will this facility induce growth?
- Could on site Solar pre-heaters reduce Air quality impacts?
- Can this facility cause an increase of greenhouse gas emissions?
- Are there potential negative localized effects of Greenhouse gases?
- How does this plan comport with AB32?
- How does this plan comport with EXECUTIVE ORDER S-3-05?
- Has the District studied the potential air quality effects of the use of imported LNG?
- The District should study the life cycle effects of fossil fuel extraction and delivery?
- Has the District studied the effects of the facility utilizing water from the California Aqueduct?
- Will the vaporization of this water lead to negative air quality effects by increasing PM or other pollutants in the Air?

- Will the use of this water cause negative air quality effects by the diversion of water that could be utilized for farming or other uses?
- Will the pumping of this water through the Aqueduct, from its source, cause Air quality emissions?
- Is it legal to use Potable water for this Power plant use?
- As water quality changes will these effects change?
- Are there methods of minimizing these potential effects? Dry cooling for instance?

District's Response:

These questions should be directed to the CEQA lead agency for this project (CEC). Since the District is not the lead agency for this project, these comments will not be addressed at this time.

Simpson Comment #22:

How much money does the District receive if this project is approved? Denied?

District's Response:

Whether the project is approved or denied, the District receives application filing fees for all proposed equipment, and hourly engineering fees for the time spent evaluating the project. At this time, we would expect the total will be approximately $5,000. In addition, if the project is approved, the District will receive an annual permit fee to maintain the facility's permits, of approximately $26,000 per year. This latter amount would be the same whether the facility constructs under the conditions of this FDOC and a subsequent CEC approval, or under the existing FDOC which the CEC used in issuing the existing power plant license.

Comments Received from Rob Simpson in Exhibit 4:

The document provided labeled Exhibit 4 is the same document that Mr. Simpson presented as testimony for the CEC Hearings under proceeding 08-AFC-01. This exhibit was discussed at the Pre-Hearing Conference on June 30, 2009. After a review of the document, the CEC Committee overseeing the project concluded that the only information that would be allowed as testimony would be the information included in Exhibit W. A discussion of this can be found in the Pre-Hearing Conference Transcript, available at: http://www.energy.ca.gov/sitingcases/avenal/documents/2009-06-30_TRANSCRIPT.PDF. The District agrees with CEC's conclusion and will respond to the comments presented in Exhibit W. All additional comments in Exhibit 4 are documents pertaining to projects unrelated to this project, and comments that are not applicable to this project.

Simpson Comment #23:

The applicant proposes to offset the projects PM 2.5 emissions on a pound for pound basis with SOx offsets. Proposed interpollutant trading ratios are required to be scientifically justified with a site specific air quality analysis, as required by Rule 2201, Section 4.13.3. The PDOC attempts to establish an interpollutant ratio based on modeling analyses performed in the Districts 2008 PM 2.5 plan.

The EPA has finalized its regulations to implement the New Source Review (NSR) program for fine particulate matter on July 15, 2008. Their recommended ratio of SOx offsets to PM 2.5 offsets is 40 tons of SOx for each ton of PM 2.5. The applicant is proposing a ratio that is 40 times less stringent than EPA has recommended.

In addition the CEC and the air district allow the project to emit 33,521 pounds of SO2 with no mitigation despite the alleged CEC policy to offset all PM2.5 precursors. If one pound of SO2 offsets 1 pound of PM 2.5 the CEC and the Air District are allowing 33,521 pounds of SO2 to remain unmitigated. The new EPA rules on PM 2.5 require a pound for pound offset ratio for PM 2.5 precursors. If the districts assumption that one pound of SOx offsets 1 pound of PM 2.5 as allowed in the interpollutant trade the district is allowing 33,521 pounds of SOx to remain unmitigated creating 33,521 pounds of PM 2.5 in violation of CEQA and EPA NSAR rules for PM 2.5.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #24:

The FDOC allows an ammonia slip of 10 ppm. The 5 ppm ammonia limit in combination with a 2 ppm NO limit has already been required for some CEC licensed facilities. In the alternative the District could perform a site specific analysis that demonstrates that no particulate matter will be formed locally or district wide due to the ammonia slip emissions and require mitigation if the analysis demonstrates that there is significant secondary particulate matter formation from the ammonia emissions from the LGS.

The district must also consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident.

District's Response:

This comment was addressed in the District response to Rob Simpson Comment #17 above.

Comments Received from Rob Simpson in Exhibit 5:

The document labeled Exhibit 5, submitted by Rob Simpson, discusses the California energy landscape. The District does not take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission (CEC).