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AIR QUALITY AND GREENHOUSE GAS EMISSIONS IMPACT ASSESSMENT FROM BIOMASS AND BIOGAS DERIVED TRANSPORTATION FUELS AND ELECTRICITY AND HEAT GENERATION

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PREFACE

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Air Quality and Greenhouse Gas Emissions Impact Assessment from Biomass and Biogas Derived Transportation Fuels and Electricity and Heat Generation is the final report for the Economically and Environmentally Viable Strategies for Conversion of Bioresources to Power project (grant number 500-11-028) conducted by the Advanced Power and Energy Program. The information from this project contributes to Energy-Related Environmental Research Program.

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ABSTRACT

Biomass and biogas are indispensable sources to increase renewable energy production in California. This report (1) addresses the potential for electric power generation and transportation fuel production from the collection, transport, generation, and use of biomass and biogas resources, (2) evaluates the cost for the technologies considered, and (3) quantifies the greenhouse gas emissions, the criteria pollutant emissions, and the air quality impacts. Biomass sources considered are urban wood waste, forest product residue, and agricultural residue, while biogas sources included landfills and wastewater treatment plants. The results show that all power generation and transportation scenarios reduce greenhouse gas emissions. For biomass, the most cost-effective and environmentally sensitive use is generating electrical power rather than producing transportation fuels. However, the criteria pollutant emissions associated with biomass harvesting and use significantly contribute to ozone and particulate matter formation in the Central Valley, where high levels of pollutants occur throughout the year. As a result, the criteria pollutant emissions from collecting, transporting and converting biomass must be proactively targeted for reduction. For biogas, the most cost-effective and environmentally sensitive application is producing transportation fuels (bio-methane and bio-hydrogen) to improve air quality and lower fuel production costs.

Keywords: biomass, biogas, biopower, renewable power, California, air quality, levelized cost of electricity

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EXECUTIVE SUMMARY

Introduction

Organic material from plants (biomass) and the gas released from decomposing organic matter (biogas) can be converted into usable energy (biopower). Biogas and biomass are potentially important resources for renewable power and transportation fuel in California. In 2013, California's 82 biomass and biogas facilities generated 6,393 gigawatt-hours (GWh) of electricity – more than 3 percent of the state's total electricity production.

Biomass and biogas resources can be converted into various types of fuels to support three main energy consumption areas: power, heat, and transportation. Biomass sources in California include urban wood waste, forest product residue, and agricultural residue. Biogas sources in this study include gas generated by landfills and wastewater treatment plants. Decomposition at landfills naturally releases methane, which can be captured for use. Wastewater treatment plants can use anaerobic digesters (processes which decompose organic matter by bacteria in the absence of oxygen) to produce methane and other byproducts making a renewable natural gas. The largest existing biogas facilities are located in landfills in southern California, and the largest biomass facilities are in the Central Valley and the northern part of the state.

Electric power generators in California use a variety of technologies with biogas and biomass resources. California currently has 32 operational solid biomass facilities generating 697 MW of power. Most of these biomass facilities in California are 25-30 years old and generate power by burning the biomass directly.

Biogas projects usually use heat engines; however, more facilities are starting to install fuel cells. Additionally, some recent projects within California use biogas to produce renewable transportation fuels. For example, the Altamont Landfill in Livermore, California, uses the landfill gas to produce 13,000 gallons of liquefied natural gas per day. At the Orange County Sanitation District, a stationary fuel cell has successfully generated more than 220 pounds of renewable hydrogen daily from anaerobic digester gas.

Related costs and emissions of these technologies are key elements in planning and developing more bioenergy infrastructure in California. For the variety of biopower sources available and the associated capacity of those sources, it is important to understand how to most effectively use these resources and have the best air quality, lowest greenhouse gas emissions, and robust economic results.

Project Purpose

This study evaluated the potential to convert biomass and biogas resources into electric power and transportation fuels in California. The study assessed (1) the sources of biomass and biogas resources (including location and capacity), (2) scenarios from harvesting the bio resource using the technological options, converting the bio resource to electricity or a transportation fuel to its energy end-use, (3) the impact of these scenarios on air quality and carbon emissions, and (4) the economics associated with the various use scenarios. The project provided necessary and

valued insight into the best feasible technology for biomass and biogas use, to facilitate developing California's future biopower infrastructure.

Project Approach

The project estimated the volumes of biomass and biogas resources in California, currently not being fully used. Those resources were modeled through a variety of plausible technology pathways to determine how much energy could be generated and where (use scenarios). The researchers estimated air quality emissions in different seasons for each scenario with high geographic detail and then modeled the air quality impacts. Each utilization scenario was then evaluated for greenhouse gas emissions and economics.

Project Results

Electric Power Generation: In 2014, California had 78,865 megawatts (MW) of installed capacity from all fuel types. Turning biomass into synthesis gas, cleaning the gas, and then burning it to make electricity would produce more electric power than any other biomass scenario studied. For biogas scenarios, the most additional electric power production would come from a combination of either a combined cycle or microturbines at landfills and wastewater treatment plants. The maximum biopower that could be produced from the biomass and biogas scenarios studied is 4,049 MW, with 3,000 MW from biomass and 1,049 MW from biogas. When considering installing new biopower facilities and maximizing the potential of biopower to generate electricity, these two scenarios are the most effective. The researchers based the use scenarios on today's commercially viable technology.

Transportation: Biogas' composition and easy extraction from landfills and wastewater treatment plants allows it to produce either a transportation fuel or electricity. When comparing the two uses, the benefits of biogas-based transportation fuel production outweigh those of power production. Transportation fuel from biogas (bio-methane and bio-hydrogen) reduces greenhouse gas emissions, improves air quality, and it is more economical. Generating electricity from biogas requires extra processing called "conditioning" to remove moisture and contaminants from the biogas. Conditioning requires installing new equipment at landfills and wastewater treatment plants for power production, which increases the fuel cost. Transportation fuel is less expensive to produce since the equipment costs less to install and operate than the equipment required to generate power.

Environmental Impacts:
*Air Quality***.** Biomass used to generate electricity or produce transportation fuels can significantly degrade air quality; however the impacts of biogas for the same end-uses are slight to none. Emissions from biomass contribute to the formation of ozone and particulate matter in the Central Valley, which already exceeds air quality standards. Biomass resources must be shipped relatively long distances by truck, causing additional air quality emissions. In contrast, biogas is generated onsite requiring no additional transportation.

Biogas resources from landfills and wastewater treatment plants are centered in California's urban regions such as the San Francisco Bay Area and Los Angeles regions. Using biogas for electric power generation would slightly increase ozone and particulate matter concentrations.

The scenarios using biogas to power a combined cycle system to produce the maximum power would also cause the highest emissions and air quality impacts.

Using biogas to produce transportation fuels (compressed natural gas, liquefied natural gas, and hydrogen) generates the lowest emissions among the biogas scenarios. Replacing gasoline in combustion vehicles with bio-derived compressed or liquefied natural gas results in a measurable but relatively small reduction in criteria pollutant emission. While steam methane reformation to produce hydrogen creates criteria pollutant emissions, the levels are more than offset because hydrogen fuel cell vehicles are much cleaner to operate than the gasoline combustion engines they would displace. In contrast to compressed or liquefied natural gas, using hydrogen-powered fuel cell vehicles provides the largest air pollutant emission reduction and the largest decrease in ozone and particulate matter concentrations.

Greenhouse Gases. One of the reasons for using biomass and biogas is their capability to reduce greenhouse gas emissions compared to conventional fossil fuels. Although the various use scenarios generate different levels of climate benefits, the overall climate benefits of producing transportation fuel from biogas exceed those of using it to generate electric power.

The carbon found in bio resources degrades naturally over time and is released to the atmosphere as greenhouse gases. If these resources are harvested and converted to energy, they could replace the use of high carbon fuels. For biogas resources in particular, the emissions related to the extraction and transport of natural gas from petroleum wells and shale gas deposits would be avoided.

Transportation fuels made from biogas can substantially reduce greenhouse gas emissions from vehicles, especially hydrogen fuel, since savings would occur from both fuel production and zero carbon tailpipe emissions from fuel cell vehicles.

Economics. Biomass resources cost less when used to generate power ($0.10 per kilowatt-hour) than to produce synthetic natural gas ($0.18 per kilowatt-hour).

The economic results from the biogas scenarios favor using a combination of a reciprocating engine or a combined cycle to generate power for onsite use and the onsite production of compressed natural gas. Overall, the most favorable economic impacts of biogas come from production of renewable transportation fuel.

Project Benefits

Biomass and biogas are historically waste products of forestry, agricultural, or industrial operations. As wastes, they come either with a cost to treat them and/or with environmental impacts. As shown in this report, tapping them as energy resources could provide many benefits to Californians. The study calculates how much bio resources could contribute toward meeting California's clean renewable energy and climate goals by replacing conventional, high carbon fuels. Currently the managers of landfills, wastewater treatment plants, or forestry and agricultural operations often have to pay to dispose of or treat these waste products. The report shows the extent to which managers could turn these liabilities into assets, either as a co-product to generate additional income or to use themselves for energy to reduce their operating

costs. Although not specifically analyzed in this study, the economic benefits could be especially valuable in economically depressed rural communities. In addition, many of the options could improve air quality in communities where this is currently a problem. The results of this study provide key insights to guide future energy planning that could provide ratepayers with affordable, reliable energy and associated environmental benefits.

CHAPTER 1: Introduction

1.1 Background

Greenhouse gas (GHG) levels and air quality are affected by the associated emissions from the transportation and electric power generation industry. Increasing the amount of renewable and low emitting technologies focuses on reducing GHG emissions and criteria air pollutants. Biomass and biogas sources are key components of California's expanding versatile renewable energy portfolio and can serve as an energy source for electricity, transportation, and thermal loads. Already, biogas and biomass sources are used to supply existing energy conversion technologies. In 2013, for example, 82 California biomass and biogas facilities generated 6,393 gigawatt-hours (GWh) of electricity, 3.22 percent of the total electricity production in California (California Energy Commision, 2013). Based on the projected value of recoverable biomass and biogas in California, a previous study estimated an additional 2,800 megawatts (MW) could be generated from biomass and biogas resources (Williams et al., 2008).

The main source of biomass is woody material and includes urban wood waste, forest product residue, and agricultural residue. Most biomass resources in California are located in the Central Valley and northern California, which include agricultural and forest residue. California currently has 32 operational solid biomass facilities generating 697 MW of power. Most of these biomass facilities in California are 25-30 years old and generate power by combusting the biomass directly. When considering increasing biomass capacity, new and more efficient technologies must be adopted since emissions from direct combustion processes are challenged to meet current California regulations. For example, innovative bioenergy technologies like a biomass integrated gasifier combined cycle (BIGCC), a gas turbine/fuel cell hybrid, and renewable synthetic natural gas (RSNG) offer higher efficiencies at lower emissions.

Available biogas sources in California include biogas produced at landfills and anaerobic digesters from "water resource recovery facilities" (wastewater treatment plants). Similar to biomass, biogas resources depend upon location. The majority of biogas resources are concentrated in urban centers like the Los Angeles and San Francisco Bay Area regions. California currently uses biogas to generate power and heat and to produce transportation fuels. Bioenergy technologies used with biogas include reciprocating engines, gas turbines, combined cycles, microturbines, and fuel cells. A total of 55 facilities, each producing at least 0.1 MW power from landfill or digester gas, add a total of 390 MW to the California power mix (California Energy Commission 2013). Several applications throughout California use biogas to produce a transportation fuel or create biomethane for injection into the natural gas pipeline or generate power. Using biogas to generate power and heat, and transportation fuel shows promise for California to meet its Renewable Portfolio Standard (RPS) as well as carbon reduction goals.

Using biomass and biogas resources helps California meet current legislative goals and associated policy and standards. Examples of legislation and regulations that encourage using biomass and biogas resources in California include:

AB 32:	Requires carbon reduction in all sectors; the proposed cap and trade system may elevate demand for biogas credits
RPS:	Renewable Portfolio Standard requires 33% renewable electricity generation by 2020
LCFS:	Low Carbon Fuel Standard requires carbon intensity of vehicle fuels to be reduced over time with specific goals in 2020
CAFE:	Corporate Average Fuel Economy requires automakers to improve the average fuel economy of their fleets
SB 1505:	Requires 33% of hydrogen vehicle fuel to be generated renewably
SB 1122:	Requires investor owned utilities to procure 250 MW of new small biopower
ZEV:	Zero Emission Vehicle Mandate requires automakers to market zero emission vehicles; one compelling option is the hydrogen fuel cell vehicle. Combined with SB 1505, this is potentially a large end-use of biogas
EPA NAAQS:	National Ambient Air Quality Standards require improvements in air quality in several regions of California

While using biomass and biogas can potentially improve air quality, reduce carbon emissions, and displace fossil fuels, numerous factors will impact its effectiveness including:

- Location of the biomass and biogas resource
- Capacity of the biomass and biogas resource
- The supply chain from the generation to using the biomass and biogas resource
- The technology that utilizes the biomass or biogas resource in generating electric power or powering transportation.
- The economics associated with the supply chain and technology.

The current study systematically delineated the way California biomass and biogas resources can be processed and used to most effectively meet the state goals for air quality, carbon reduction, and fossil fuel displacement.

1.2 Goal

This study evaluated the potential to generate biomass and biogas sourced electric power generation and transportation fuels by assessing:

1. The sources of biomass and biogas resources (including location and capacity),
2. The utilization scenarios from source of the bio resource by applying the bio resource,
3. The technologies used for converting the bio resource to electricity or a transportation fuel,
4. The impact of the utilization scenarios on air quality and carbon emissions, and
5. The economics associated with the various utilization scenarios considered.

The study characterized biomass and biogas resources in California, which are currently not being used for a variety of realistic utilization scenarios. Each utilization scenario is then evaluated for the impact on air quality, greenhouse gas, and economics. The air pollutant emissions are spatially and temporally resolved in order to establish the air quality impacts.

The study provides necessary and valuable insight on how biomass and biogas resources can be used in harmony in California while considering air quality, greenhouse gas, and economic impacts. The study will inform policy makers of the costs and benefits of potential biomass and biogas infrastructure for California from results of the analysis of various power generation technologies and feedstocks. Air quality modeling of the biopower infrastructure quantifies the effect of increased biopower utilization will inform regulators of the effect of increased biopower on areas of interest in California affected today by degraded air quality (e.g., the San Joaquin Valley and the South Coast Air Basins). Findings will help determine the best bioenergy technology alternatives and develop bioenergy policies to meet California's energy and environmental goals.

CHAPTER 2: Approach

This project is divided into two main areas: (1) the analysis of solid biomass resources, including forestry waste, agricultural residue and municipal solid waste, and (2) the analysis of biogas resources including landfill gas and digester gas from water resource recovery facilities.

Solid Biomass

The analysis of solid biomass was conducted by researchers at the University of California, Davis (UCD) and the California Biomass Collaborative, and coordinated with the atmospheric modeling group at the University of California, Irvine (UCI). The analysis involved integrating two modeling capabilities:

1. A UCD infrastructure and feedstock model that analyzes geospatial information of biomass resources, costs of operation and transport of feedstocks, and costs of electricity production.
2. A UCI emissions and air quality modeling framework to simulate the air quality resulting from existing and new infrastructure for biomass collection, transport and conversion.

These two modeling capabilities, integrated for this particular project, are described in Chapter 3.

Biogas

The analysis of biogas was conducted by the UCI Advanced Power and Energy Program (APEP) in collaboration with the UCI atmospheric modeling group. The analysis involves the integration of two modeling capabilities:

1. An APEP energy, emissions, and economic model that includes a database of landfill and wastewater treatment facilities, with biogas production potentials.
2. The UCI emissions and air quality modeling framework to simulate the air quality resulting from existing and new installations for biogas use.

The two UCI modeling capabilities, integrated for this particular project, are described in Chapter 4.

CHAPTER 3:
California Biomass Power Generation Assessment

3.1 Biomass Resources in California

Biomass resources in California are wastes and residues from agricultural, forestry and urban activities in the state.

3.1.1 Agricultural Biomass

Principal sources of biomass from agriculture in California are residues of crop and livestock production. These include orchard and vineyard prunings; tree and vine removals; straws and stovers from field and seed crops; leaf, vine and other plant residues from vegetable crops; food and fiber processing residues including nut shells, pits, hulls, cotton gin trash, paunch contents, offal, and other residues from meat processing; and animal manures. Dedicated biomass crop production may provide new agricultural opportunities as renewable energy and bio-product markets develop.

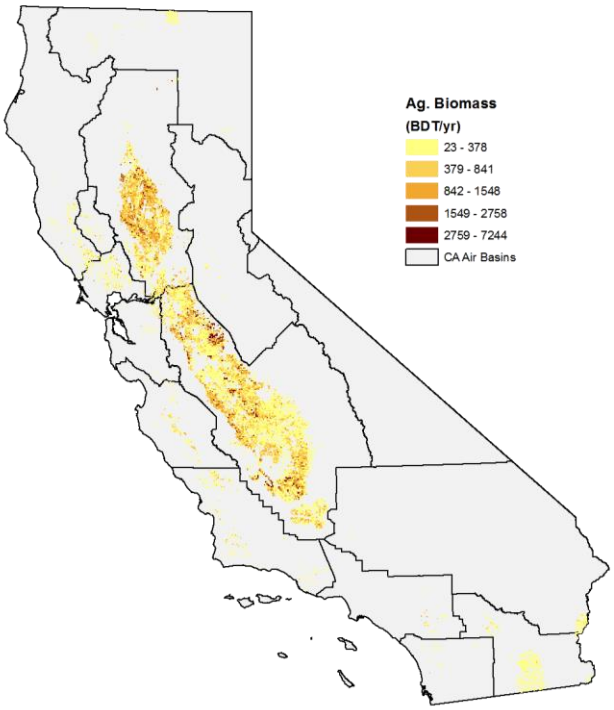
The California Biomass Collaborative (CBC) estimates there are 12.4 million bone dry ton (BDT) of crop residues and processing wastes generated in the state. Of this, the CBC estimates that 8.1 million BDT is a technically available resource. The majority of this resource is produced from nine crops [almonds, pistachios, walnuts, citrus (aggregated), grapes, corn, rice, and wheat]. Limiting the analysis to these crops reduces the total technically available resource considered in the modeling to 6.6 million BDT. The resources lost are evenly split between orchard residues, field & seed, vegetable processing, and meat processing wastes. In addition, 7.9 and 3.5 million BDT/y, respectively, of gross and technical manure are associated with 1.78 million dairy cows in the state.

The resource assessment was performed at the county level using county agricultural commissioner reports on the total area planted in each crop. The Pesticide Use Report (PUR) data have been used to allocate the resource at a higher spatial resolution, which represents pesticide use and crop area at the section level of resolution (one mile square). The crop areas reported by the two sources do not match exactly. The county commissioner data were used to scale the PUR data so that the total crop area within each county matches the areas reported by the county commissioners. The locations of the processing facilities were unknown. For modeling purposes, the processing wastes were assumed to be located at the fields. Figure 1 shows the spatial distribution of agricultural biomass.

3.1.2 Forestry

The four main categories of forestry biomass are logging slash, mill residues, biomass from forest thinning and stand improvement operations, and chaparral. Estimates of logging slash, thinnings, and chaparral were developed, and Mill residues were computed by factoring timber harvest data. Logging slash, mill residues, and forest thinnings are already in commercial use as fuel for power generation. Harvesting of chaparral has not yet been conducted on a large scale in California.

Figure 1: Map of Agricultural Biomass in California



Estimates of forest residue in California have a wide range. The California Department of Forestry and Fire Protection (CALFIRE) developed an assessment in 2005 by applying a realistic but limited number of commercial thinning and fuel reduction prescriptions at a very high spatial resolution of a 100-meter grid (California Department of Forestry and Fire Protection, 2005). This assessment has been the basis for California Biomass Collaborative assessments since 2005. Tittmann et al (2008) used the data from the CALFIRE assessment and the Fuel Reduction Cost Simulator (Fight et al., 2006) to develop a high-resolution resource assessment that includes the cost of acquisition. These assessments over-estimate forest biomass because they do not account for limits on the industry capacity for implementing the prescriptions along with other factors. A national assessment of forest biomass by United States Forest Service (USFS) constrains the production of forest products based on historical activities within a county (Skog et al., 2008). The assessment results in estimates of biomass volume that is less than half the CALFIRE estimate but is only available at the county resolution. In the present study, the USFS resource assessment has been used but scaled it to a five kilometer grid using the high resolution data set from Tittmann. The downscaling of the assessment is particularly important in the California context where counties are large and irregularly shaped. Distributing the resource uniformly across a county would result in large estimates of forest availability in the Central Valley as counties from the Valley extend into the Sierras.

Figure 2: Forest Residue Estimate for California

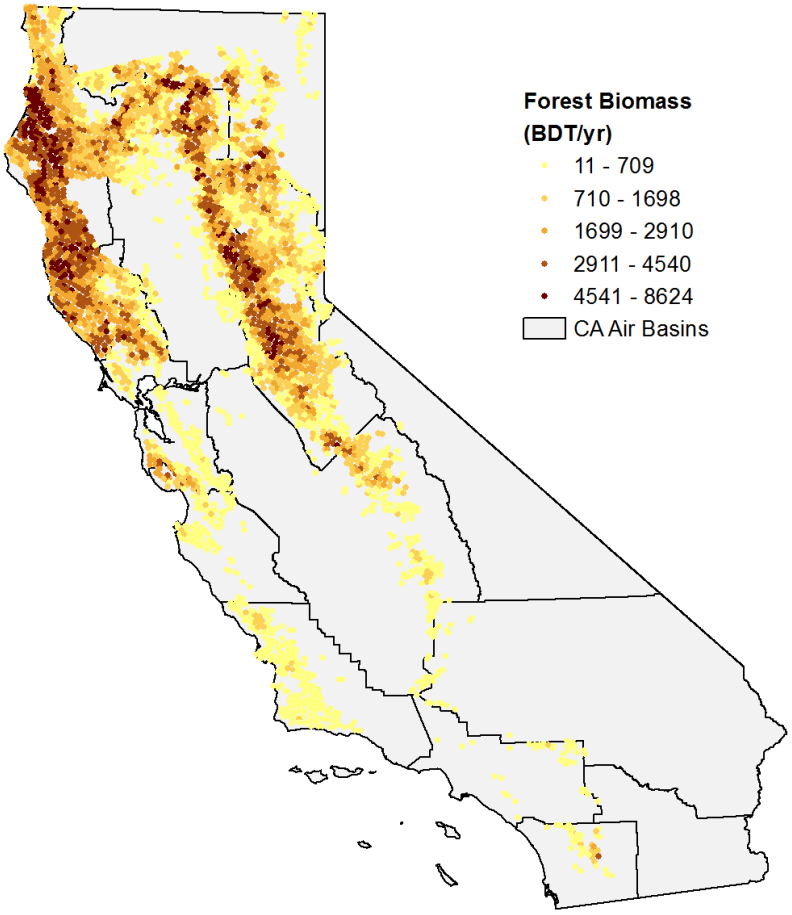


Figure 2Figure 2shows the estimate of forest residue that is available for less than $50/BDT at the forest landing.

3.1.3 Municipal Waste

The amount of California Municipal Solid Waste (MSW) disposed in landfills was 29.3 million tons in 2012 (31 million tons when green waste is used as alternative daily cover (ADC) (CalRecycle 2013b). Total and per-capita and waste disposal have decreased by about 30 percent since 2006, partly due to economic downturn and increased diversion.

The composition, amount, and higher heating value (HHV) from MSW assumed for this study is shown in Table 1. The biomass component of MSW includes construction and demolition wood, paper, grass and other green waste, food waste, and other organics not including plastics and tires. Only the landfilled biomass fraction is considered in the resource estimates reported here. The total biomass in MSW (landfilled and diverted) is estimated at 25 million BDT/y, or roughly 2/3 BDT biomass per person per year in the state.

Table 1: Composition and Properties of MSW*

Component	Landfilled (million tons, wet)	% of Total Wet MSW	Moisture (% wb)	Landfilled (million tons, dry)	Ash (% wb)	Ash (Million ton/yr)	HHV (MJ/kg, as received)	HHV contribution to composite (MJ kg^{-1} as received)	(HHV MJ/kg dry)
Biomass									
Paper/Cardboard	5.1	16.4	10	4.6	5.3	0.3	16	2.62	17.8
Food	4.5	14.7	70	1.4	5.0	0.2	4.2	0.62	14.0
Leaves and Grass	1.1	3.6	60	0.4	4.0	0.0	6	0.22	15.0
Other Organics	1.3	4.1	4	1.2	10.0	0.1	8.5	0.35	8.9
C&D Lumber	4.3	13.7	12	3.7	5.0	0.2	17	2.34	19.3
Prunings, trimmings, green ADC	2.4	7.8	40	1.4	3.6	0.1	11.4	0.89	19.0
Branches and stumps	0.2	0.6	40	0.1	3.6	0.0	11.4	0.06	19.0
Biomass Carbon Compounds - **Total**	**18.8**	**60.9**	**31.6**	**12.9**	**5.2**	**1.0**	**11.7**	**7.09**	**17.0**
Other Organics									
All non-Film Plastic	1.8	5.9	0.2	1.8	2.0	0.0	22	1.29	22.0
Textiles	1.6	5.1	10	1.4	7.0	0.1	17.4	0.89	19.3
Film Plastic	1.0	3.2	0.2	1.0	3.0	0.0	45	1.45	45.1
Non-Biomass Carbon Compounds - **Total**	**4.4**	**14.2**	**3.7**	**4.2**	**4.0**	**0.2**	**25.6**	**3.63**	**26.5**
Inorganic									
Other C&D	1.6	5.2	-	1.6	100	1.6	-	-	-
Metal	1.3	4.4	-	1.3	100	1.3	-	-	-
Other Mixed and Mineralized	4.3	14.0	-	4.3	100	4.3	-	-	-
Glass	0.4	1.3	-	0.4	100	0.4	-	-	-
Mineral **Total**	**7.7**	**24.9**	-	**7.7**			-	-	-
Total Landfilled MSW	**31**	**100**	**20**	**25**	**29.2**	**9.0**	**10.7**	**10.7**	**13.4**

*Total disposal shown here includes 1.6 million tons of green waste used as ADC, which is included in the 'Prunings, trimmings, green ADC' row.

HHV: higher heating value

Source: 2008 California waste stream composite data (http://www.calrecycle.ca.gov/Publications/Detail.aspx?PublicationID=1346) & California Solid Waste Generation and Diversion (http://www.calrecycle.ca.gov/LGCentral/GoalMeasure/DisposalRate/Graphs/Disposal.htm)

Figure 3: Disposal of Biomass by Landfill Location

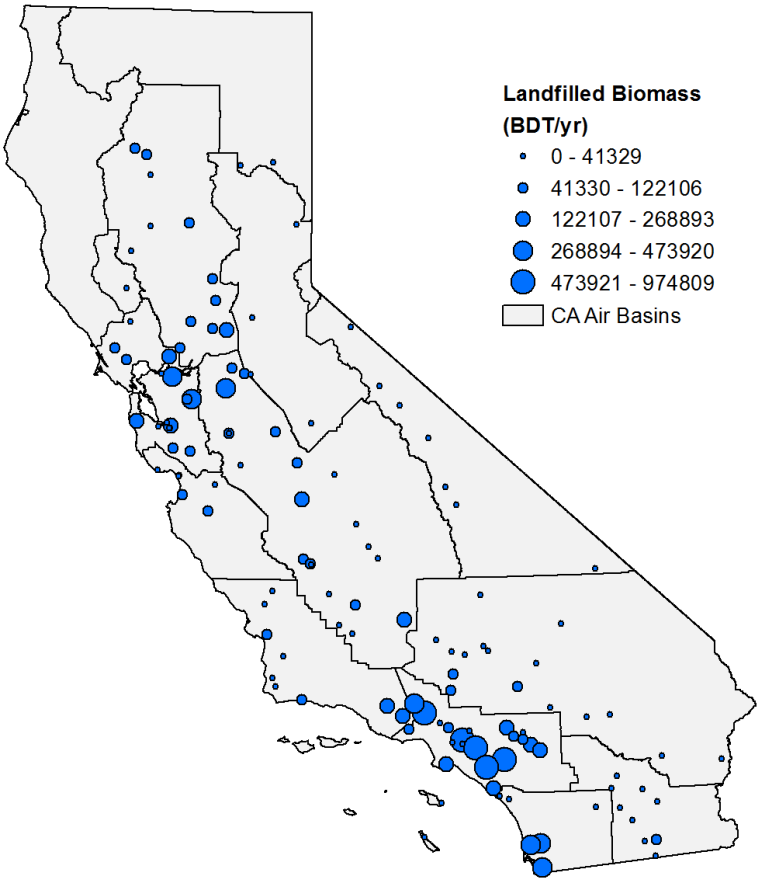


Figure 3 presents the location of landfills in California and their capacity. Resource quantities by biomass type were computed for the fraction disposed in landfills. CalRecycle does not track composition of diverted MSW.

3.2 Power Generation Scenarios from Biomass Resources

3.2.1 Background and Policy Basis for Utilization Scenarios

Instate bioenergy production contributes about 5.8 TWh/y to California's total system power (which is 17 percent of in-state renewable power and 2 percent of the full California power mix).[1] There are some 175 operating biopower generation facilities in California with a combined total capacity of about 938 MW (Table 2). There may be sufficient in-state 'technically recoverable' biomass to support another 2,800 MW of capacity or 21 TWh/y of electricity (Williams, et al., 2015).[2]

[1] http://energyalmanac.ca.gov/electricity/total_system_power.html

[2] Technical biomass resource is that which can be sustainably recovered with minimal impacts to erosion, riparian zones, soil organic matter and other agronomic factors. No economic filter is applied resource.

The California Renewable Portfolio Standard (RPS), requiring 33 percent of all retail electricity sales be renewable by 2020, is the main policy driver for renewable electricity in the state. The RPS is resource and technology neutral using a "least-cost, best-fit" approach for ranking renewable purchase contracts.

A 2006 executive order (S-06-06, Governor Schwarzenegger) set a target for biopower to remain at 20 percent of the state's renewable energy portfolio (biopower accounted for approximately 20 percent of California's renewable power in the mid-2000s). The executive order, though not withdrawn by the current governor, is not likely to be supported going forward as the California Public Utilities Commission (CPUC) expects the 2020 RPS obligation to be met by increasing contributions from wind, photo-voltaic and thermal solar with decreasing contributions from geothermal and biopower.[3] Consistent with this outlook, the California Energy Commission 2012 Bioenergy Action Plan does not contain biopower production goals.

Two other policy instruments provide some basis for biopower modeling scenarios: Senate Bill 1122 (Rubio, 2012) and Governor Brown's Clean Energy Jobs Plan. SB 1122 requires the CPUC to direct Investor Owned Utilities (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. The 250 cumulative MW is allocated by resource type; 110 MW urban biogas, 90 MW agricultural bioenergy (including dairies), and 50 MW from material from sustainable forest management.

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, or < 20 MW per project).

Table 2: Summary of Biopower in California

Facility Type	Net (MW)	Facilities
Solid Fuel (woody& ag.)	575	27
Landfill Gas Projects	270	79
Wastewater Treatment Plant Facilities	88	56
Farm Anaerobic Digestion (AD)	3.8	11
Food Process/Urban AD	0.7	2
Solid Fuel (MSW)	63	3
Totals	1001	178

3.2.2 Biopower Scenarios

A total of nine scenarios were established and evaluated and include the existing biopower baseline and one that examines repowering the existing solid fuel and biogas fleet, and scenarios that incorporate the existing policy or goals. In particular, Scenarios 3a and 3b are distributed generation scenarios modeling the impact of SB 1122 and an alternative where the maximum capacity constraint is increased to 20MW, and Scenarios 4-8 assume the governor's

[3]See, for instance, Figure 2 in the CPUC Q4 2012 RPS quarterly report: http://www.cpuc.ca.gov/NR/rdonlyres/4F902F57-78BA-4A5F-BDFA-C9CAF48A2500/0/2012_Q3_Q4RPSReportFINAL.pdf

20 GW goal is implemented and model new biomass facilities to meet 20 percent of 8 GW (1.6 GW) of large scale renewables (>20 MW). Table 3 presents a matrix showing the prime movers (technologies) and feedstocks used for the scenarios.

3.2.2.1 Biopower Scenarios List

Scenario 1. Baseline:
Existing biopower fleet including upstream biomass collection systems.

Scenario 2. Repower Existing Fleet:
Repowering of existing fleet for efficiency and emissions improvement while holding the capacity constant. Solid fuel systems are upgraded to biomass-integrated-gasifier-combined-cycle (BIGCC) and biogas engines upgraded to fuel.

Scenario 3. SB 1122 Implementation

a) Distributed Generation: 250 MW of new small scale (< 3MW per project) biopower with three subcategories:

- 110 MW urban biogas,
- 90 MW agricultural bioenergy,
- 50 MW forest bioenergy.

The existing fleet is included as a competitive demand for biomass.

b) Distributed Generation: A larger maximum capacity (<20MW) than specified in SB 1122. The same subcategory targets as SB 1122 are met.

Scenario 4. BIGCC:
1.6 GW of new large-scale BIGCC capacity to be sited on a least cost basis using forest residues, agricultural cellulosic biomass, and urban wood wastes.

Scenario 5. Renewable Synthetic Natural Gas (RSNG):
RSNG conversion facilities with pipeline injection for consumption at central station natural gas power plants (displacing natural gas fuel) using the same resources as in Scenario 4. Can be considered new renewable generation but does not add any new capacity to system. The target for electricity generation in this scenario is 1.6 GW.

Scenario 6. Competition between BIGCC & RSNG:
Economic competition between the two technologies in Scenarios 4 and 5.

Scenario 7. Thermal Conversion of MSW:
MSW to power facilities using thermal conversion. The gasification and solid fuel combustion technologies are indistinguishable on an economic comparison so generic thermal conversion is modeled.

Scenario 8. Large Adoption of Distributed Generation (~20MW):
A combined 2 GW of new capacity from 20 MW facilities with 284 MW from large-scale (~20 MW) biogas facilities from a combination of MSW anaerobic digestion,

wastewater treatment plant (WWTP), agricultural and rural biogas sources and the remainder from 20MW facilities using forest residues, agricultural cellulosic biomass, and urban wood wastes. The sources are chosen on a least cost basis.

The primary modeling outputs are point source emissions [e.g., NOx and speciated volatile organic compounds (VOC)] using appropriate emission factors as inputs, and costs for modeled bioenergy scenarios. The Geospatial Bioenergy System Model (GBSM) optimizes siting for Scenario 3 facilities including the technology mix for some of those scenarios.

3.2.3 Biopower Technologies

Several types of biopower technologies and/or energy pathways are modeled as part of each scenario. The prime movers range from conventional systems that comprise the existing bioenergy fleet in the state (i.e., solid fuel combustion-steam-Rankine cycles, gas engines, microturbines, combustion turbines and fuel cells) to advanced or even developmental technologies (i.e., gasifier-to-fuel cell, synthetic natural gas via gasification, etc.) that are expected to have improved emissions and energy performance though at potentially higher cost. Energy performance and cost estimates (technology costs) are described for the biopower technologies below. Emission factors are discussed in the following section.

Table 3: Scenario Prime Mover and Feedstock Matrix

Prime Mover	Scenarios	SCENARIOS 1	2	3a	3b	4	5	6	7	8
		Baseline - model existing biopower fleet	Repower Existing Fleet	Distributed Generation-Implement SB1122 (<3 MW/project)†	Distributed Generation-Upto 2.4 GW new DG (<20MW/project??)††	Biomass-Integrated-gasifier-combined-cycle (BIGCC)*	Renewable synthetic natural gas (RSNG)**	Combinations of BIGCC & RSNG (using best economic cases(s)	Thermal Conversion of MSW	Large scale biogas
						1.6 GW of new large scale bioenergy ; > 20MW/project (1200 MW thermal conversion and 400 MW large biogas)				
Solid-fuel Combustion - Steam Rankine Cycle		Woody waste: Forest, ag. and urban			Woody&herbaceous: Forest, ag. and urban					
Reciprocating Engine (biogas) New ReciP-I : Dairy Recip-II: MSW AD Recip-III: WWTP		Existing digester and landfill gas								
	+ digester and gas conditioning			Urban biogas & ag bioenergy (food/FOG/green waste, manure)	food/FOG/green waste, manure					
Micro (gas) turbine (biogas) New Micro-I : Dairy Micro-II: MSW AD Micro-III: WWTP		Existing digester and landfill gas	Upgrade from existing recip. engines							
	+ digester and gas conditioning			Urban biogas & ag bioenergy (food/FOG/green waste, manure)	food/FOG/green waste, manure					
Gas turbine (biogas) New GT-I : Dairy GT-II: MSW AD GT-III: WWTP		Existing digester and landfill gas	Upgrade from existing recip. engines							
	+ digester and gas conditioning			Urban biogas & ag bioenergy (food/FOG/green waste, manure)	food/FOG/green waste, manure					food/FOG/green waste, manure
Fuel Cell (biogas) New FC-I : Dairy DC-II: MSW AD FC-III: WWTP		Existing digester and landfill gas	Upgrade from existing recip. engines							
	+ digester and gas conditioning			Urban biogas & ag bioenergy (food/FOG/green waste, manure)	food/FOG/green waste, manure					
Biomass integrated gasifier-combined-cycle (BIGCC)*			Woody waste: Forest, ag. and urban			Woody&herbaceous: Forest, ag. and urban		Woody&herbaceous: Forest, ag. and urban		
Gasifier with reciprocating engine				Ag. & Forest bioenergy (woody & herbaceous)	Woody&herbaceous: Forest, ag. and urban					
Gasifier with Fuel Cell				Ag. & Forest bioenergy (woody & herbaceous)	Woody&herbaceous: Forest, ag. and urban					
Pipeline-to-Central Station natural gas power plant	RSNG production**						Woody&herbaceous: Forest, ag. and urban	Woody&herbaceous: Forest, ag. and urban		
	+ digester and gas conditioning									food/FOG/green waste, manure
MSW Gasifiers									MSW and/or ofMSW‡	
MSW solid -fuel Combustion									MSW and/or ofMSW‡	
Biorefinery										

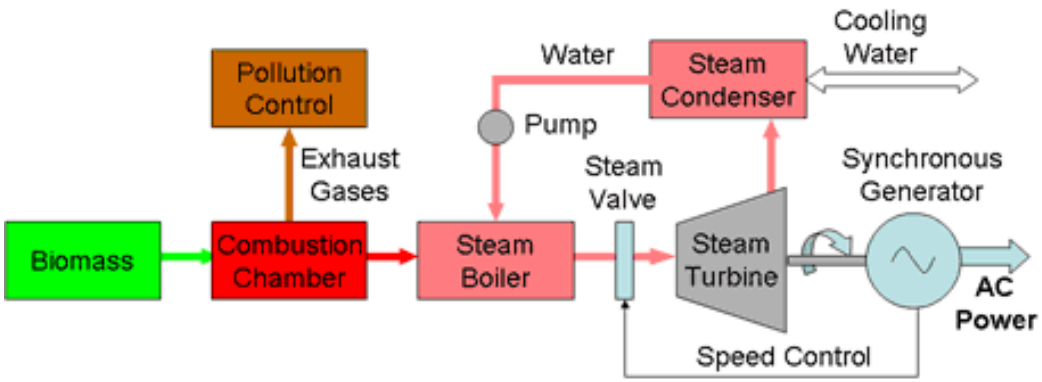
3.2.3.1 Solid Fuel Thermal Conversion, Woody Biomass- Larger Scale

These technologies include the woody biomass solid fuel combustion systems used throughout California (steam-Rankine cycle) and biomass-integrated-gasifier-combined-cycle (BIGCC) technology assumed in Scenarios 2, 4 and 6. Scale or capacity is generally above about 10 MW. Scenario feedstocks include woody and herbaceous biomass residues from forest, agricultural and urban resources.

3.2.3.2 Conventional Solid Fuel Combustion (Steam Cycle)

This is the standard steam Rankine cycle, which consists of a boiler or furnace where solid fuel is burned to generate superheated steam that is expanded through a steam turbine-generator to produce electricity (Figure 4).

Figure 4: Schematic Biomass Steam Cycle Power Plant



Source: Electropaedia: http://www.woodbank.com/

Three furnace or boiler technologies are used in California: grate with mechanical stoker, bubbling fluid bed (BFB), and circulating fluid bed (CFB). Energy performance for these boiler types [Higher Heating Value (HHV basis)], based on USEPA eGRID[4] , range from about 22% (stoker) to about 26% for BFB (Table 4
Table 4).

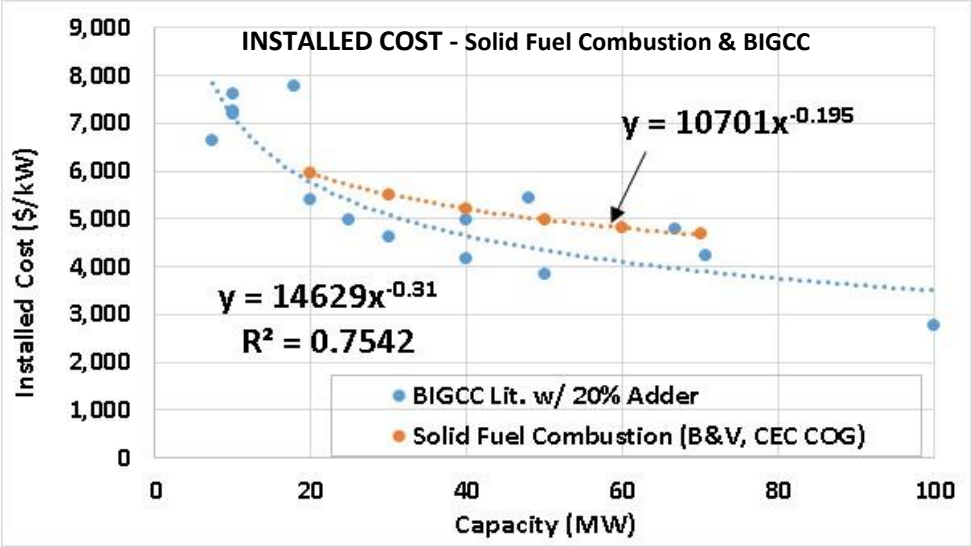
Table 4: Biomass Steam Cycle Efficiency by Boiler Type

Boiler Type	Efficiency (%, HHV basis)	Heat Rate (Btu/kWh)
Stoker	21.7	15724
Circulating Fluidized Bed	22.2	15369
Bubbling Fluidized Bed	26	12827

[4] http://cfpub.epa.gov/egridweb/

Installed and operating costs for solid fuel combustion are based on a cost model from Black and Veatch (B&V) and a recent Cost of Generation Report from the California Energy Commission (Rhyne and Klein, 2014). Installed cost varies from about $4800/kW for 70 MW facilities to $6000/kW for 20 MW (Figure 5). Operating costs also vary with scale and are summarized in the technology cost matrix in Table 8.

Figure 5: Installed Cost vs. Capacity for Solid Fuel Combustion and BIGCC Technologies

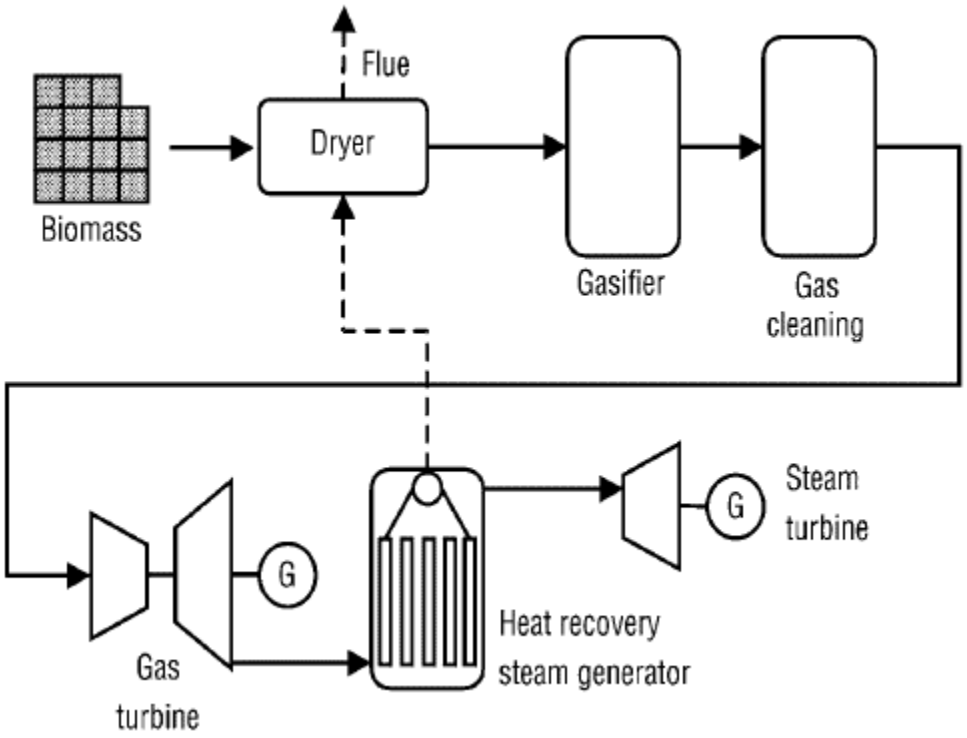


3.2.3.3 Biomass-Integrated-Gasifier-Combined-Cycle

Biomass-based integrated gasification combined cycle (BIGCC) here means a gas turbine-generator fueled by product gas from a biomass gasifier combined with a heat recovery steam generator using gas turbine exhaust to raise steam for a Rankine bottoming cycle (Figure 6). The system is attractive for biomass power production because it offers higher net efficiencies than simple steam cycles and may have improved emissions performance.

Though there are some coal fired IGCC facilities operating in North America, there are no biomass (BIGCC) units commercially operating in the world. A small (6 MWe) BIGCC demonstration project operated at Värnamo, Sweden in the late 1990's (Stahl, 1998) and a number of other demonstration projects were built or considered in the 1990's to early 2000's, but none operated in full combined cycle mode (Bhattacharya, 2011;Williams, 2005). A 5 MW BIGCC system that used reciprocating engine-generators followed by a steam Rankine cycle has been demonstrated in China (Wu, 2008).

Figure 6: Simple Schematic of BIGCC system (Gas Turbine–Steam Cycle)



Source: Larson, 2001

Net efficiency (electrical energy / fuel input energy) of BIGCC systems vary from about 33% at 20 MW to 40% at 70 MW in this study.[5]

Cost and performance data for BIGCC are taken from the literature (in some cases converting Euros to US$ and inflating to year 2014 $US. Installed cost are modeled in Figure 5 above and summarized with operating costs in Table 8. BIGCC installed costs are lower than conventional combustion installed costs above 20 MW, which is counter-intuitive given the added complexity of BIGCC compared to conventional systems. The BIGCC costs are based on estimates from literature while the conventional combustion costs derived from actual built or proposed projects.

3.2.3.4 Solid Fuel Thermal Conversion, Woody Biomass- Smaller Scale

Technologies in this category are a gasifier with engine-generator and a gasifier-to-fuel cell generator. Scale ranges from <1 MW to about 10 MW. Scenario feedstocks include woody and herbaceous biomass residues from forest, agricultural and urban resources.

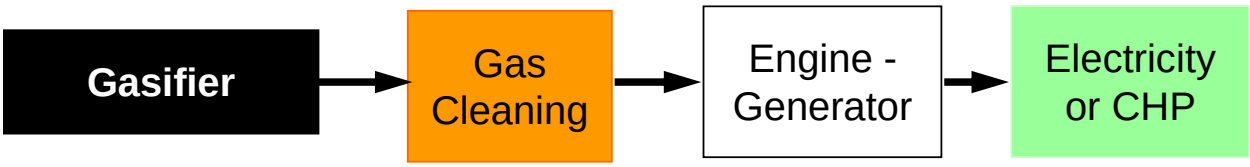
3.2.3.5 Gasifier with Reciprocating Engine

This technology is available to Scenarios 3a and 3b (distributed energy scenarios). The typical technology consists of a gasifier reactor where substoichiometric oxidation of solid feedstock

[5] BIGCC Efficiency (%-HHV basis) = 5.549xln(MW_{Cap}) + 17.014

occurs creating a fuel gas that normally requires cleaning and conditioning before used as fuel for the reciprocating engine generator (Figure 7).

Figure 7: Gasifier to Engine-generator Schematic



Capital and operating cost assumptions are from the report Black & Veatch did for the California Public Utilities Commission on the SB 1122 feed-in tariff assessment. Efficiency (at 24%, wood to power) is taken from Francois et al. (2013) (Table 8).

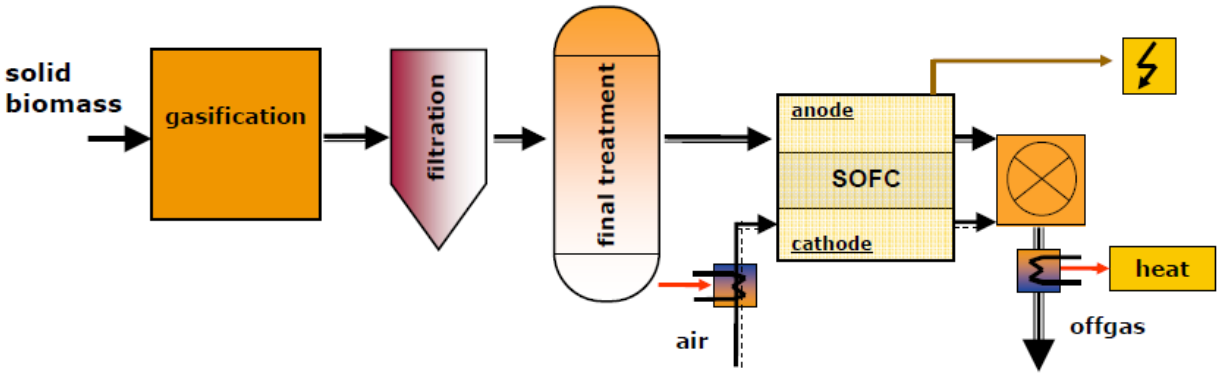
3.2.3.6 Gasifier to Fuel Cell

This technology also is available to Scenarios 3a and 3b (distributed energy scenarios) and would access woody and herbaceous biomass residues from forest, agricultural and urban resources (Figure 8).

Biomass gasifiers integrated with fuel cells for power production (BIGFC) offer potentially higher overall electricity conversion efficiencies than gasifier-to-engine systems and with reduced emissions. BIGFC systems are developmental. Essentially only lab scale operation of solid oxide fuel cell (SOFC) with biomass producer gas has been demonstrated (Nagel et al., 2011).

The SOFC would appear to be the most promising fuel cell type for this application because of its tolerance to relatively low fuel gas quality and its capability, via internal reforming, of oxidizing carbon monoxide and light hydrocarbon fuels.

Figure 8: Integrated Biomass Gasifier Fuel Cell Concept

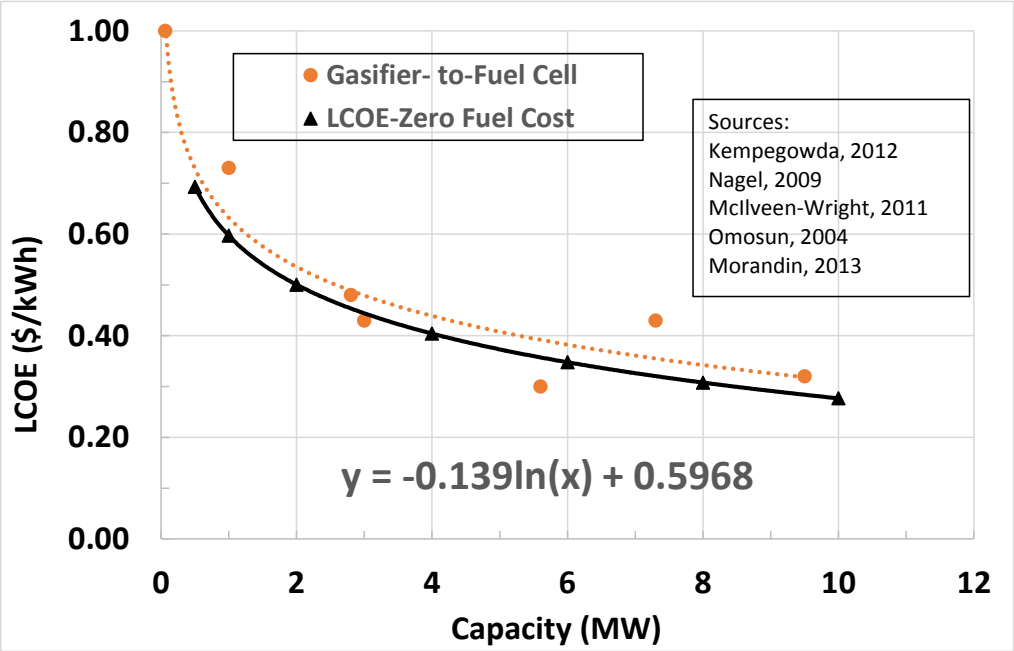


Source: Kleinhappl 2012

Electricity conversion efficiencies for this concept would be 20 -40 % (Kempegowda et al., 2012). For this study, 30% HHV efficiency is used.

A survey of conceptual and techno-economic modelling studies for BIGFC in the literature was completed and a levelized cost of energy (LCOE) curve for zero feedstock cost was developed for use in modeling the scenarios (Figure 9).

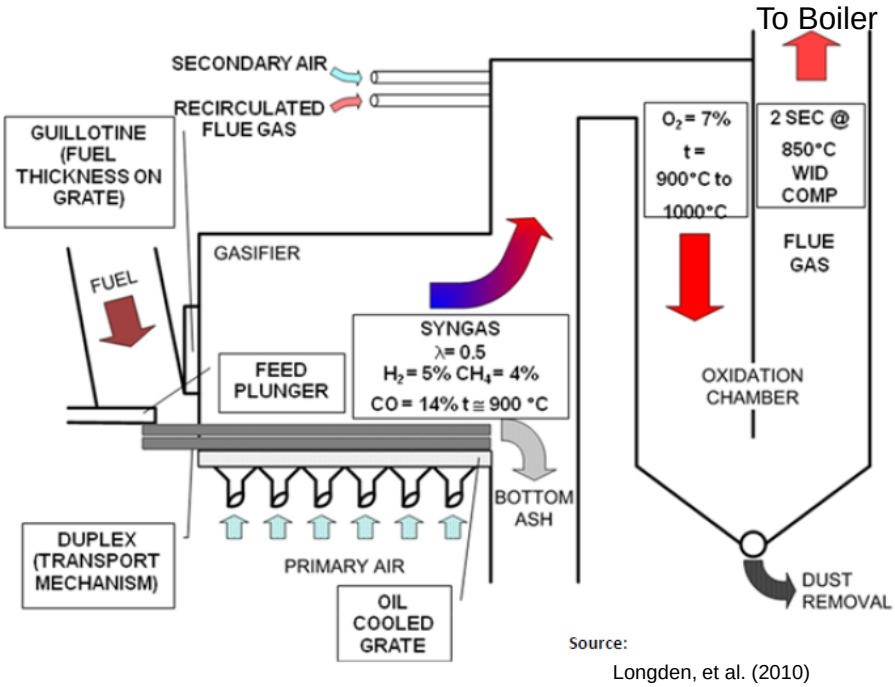
Figure 9: LCOE Curve for Gasifier with Fuel Cell Technology



3.2.3.7 Municipal Solid Waste Thermal Conversion

This technology is utilized in Scenario 7 consuming the biogenic fraction of MSW currently being disposed in landfills (i.e., not material that is currently diverted or recycled). The technology modeled is modern solid waste combustion or solid waste gasification. The cost and performance parameters are lumped into a single "MSW thermal conversion" technology. The two are lumped together or considered the same for this study since the majority of operating MSW gasification projects are staged, or close-coupled combustion and not unlike modern MSW combustion systems in terms of performance and cost (Figure 10) (Williams and Zhang, 2013).

Figure 10: Schematic of a Typical MSW Gasifier-close-coupled-combustion System (Energos)



Source:
Longden, et al. (2010)

Energy performance of this technology class is defined as 600 kWh/ wet ton or 850 kWh/ dry ton (either biomass fraction or total MSW, they are roughly similar) (Williams et al., 2015). Cost curves were developed from recent consultant reports and conference papers detailing actual or proposed projects (See Table 8 for cost curves and source information).

3.2.3.8 Biogas Systems

There are approximately 145 biogas-to-electricity facilities in the state with a combined capacity of about 360 MW. There is a large potential for more biogas energy production from landfills, wastewater treatment facilities that add new or additional digester capacity, and conversion of feedstocks such as food and green waste, animal manures, etc.

Technologies modeled for biogas-to-electricity scenarios include reciprocating and gas turbine engine-generators, fuel cells and upgrading and pipeline injection for conversion at central station plants.

Existing biogas systems appear in the base case scenario (Scenario 1). Cost and performance assumptions for new biogas installations are described below.

3.2.3.9 Existing Biogas with Gas Flaring: Dairies, Wastewater treatment, Landfills

For cases where biogas is already produced but is not utilized (i.e., is flared), costs to produce electricity are comparatively low and derive primarily from installation and operation of a prime mover (i.e., presumes digester, landfill, gas collection costs are already paid for).

Costs for adding a reciprocating engine facility to an un-used biogas (existing) facility, including gas cleaning, air emissions reduction equipment, and all required infrastructure are $2,681/kW installed with $180/kW-yr O&M (Table 6). These values are taken from the B&V SB 1122 Feed-In Tariff Implementation Assessment Report to the CPUC (B&V, 2013).

Gas turbine, microturbine, and fuel cell installed costs are derived from literature sources and are modeled as incremental to reciprocating engine-generator costs (i.e., microturbine costs are $500/kW plus recip. engine cost: Table 5).

Gas-to-electricity conversion efficiency assumptions are also listed in Table 5.

Table 5: Biogas Conversion Technology Cost and Performance Assumptions

Biogas conversion properties	Biogas to electricity net efficiency (%, HHV)	Installed Cost Adder ($/kW)*	Fixed O&M ($/kW-yr)*
Recip Engine & Gas Turbine	30	Base	180
MicroTurbine (30-250 kW)	25	500	180
Fuel Cell	43	3500	260

Based on review of: Trendewicz, (2013), US EPA (2008a), (2008b), and (2008c).

3.2.3.10 New Biogas: Dairies, Wastewater treatment

New biogas to power installations from dairies or wastewater treatment plants are modeled in Scenarios 3a and 3b (DG scenarios). Feedstocks include certain urban and agricultural resources: food/FOG/green waste and manure.

Cost assumptions for new dairy or wastewater treatment digester installations with reciprocating engine-generators are taken from the B&V the B&V SB 1122 Feed-In Tariff Implementation Assessment Report to the CPUC (B&V, 2013) and appear in Table 6.

For new biogas using microturbines or fuel cells, the model adds the incremental costs (to the engine base costs) (Table 5).

Table 6: Biogas Reciprocating Engine Costs

Biogas: Reciprocating Engine		Capacity Range (MW)	Capital Cost ($/kW)*	Fixed O&M ($/kW-yr)*	Variable (non-fuel) O&M ($/MWh)
Existing Digester/Landfill but biogas not utilized	LF, WWTP	0.2 - 3	2,681	180	(included in Fixed O&M)
Including Digester Costs	Dairy	0.2-2 (+)	10,900	950	
Including Digester Costs	WWTP	0.5 - 4	9,700	490	

* Midpoint values, B&V SB 1122 Report

(http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M081/K583/81583311.PDF)

3.2.3.11 New Biogas from MSW Anaerobic Digestion

Biogas produced from anaerobic digestion of the organic fraction of MSW (instead of sending to landfill) is modeled the DG Scenarios (3a and 3b) and possibly could appear in the large biogas scenario (7).

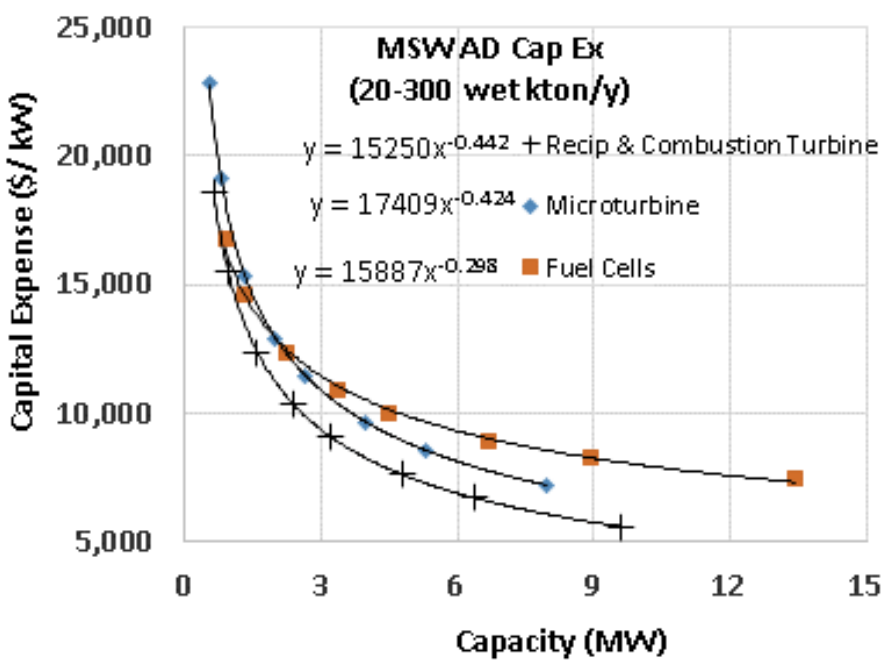
Performance of MSW Anaerobic Digester (AD) systems, in terms of net kWh per ton of input feedstock, is derived from Williams et al. (2015) and shown in Table 7.

Capital and operating cost of a generic MSW digester system was modeled using Tsilemou (2006) and Rapport et al., (2008) and inflating to year 2014 dollars. Capital cost curves for MSW AD systems using different prime movers (engines, microturbines, fuel cells) are shown in Figure 11. Costs are summarized in Table 8.

Table 7: MSW AD Technology Performance

Biogas conversion properties	Biogas to electricity net efficiency (%, HHV)	kWh/wet ton of food, leaves, grass	kWh/wet ton biomass fraction MSW	kWh/BDT biomass fraction MSW
Recip Engine & Gas Turbine	30	280	85	124
MicroTurbine (30-250 kW)	25	233	71	104
Fuel Cell	43	420	128	187

Figure 11: Installed Cost Curves, MSW AD Systems



3.2.3.12 Biogas upgrade and injection to pipeline

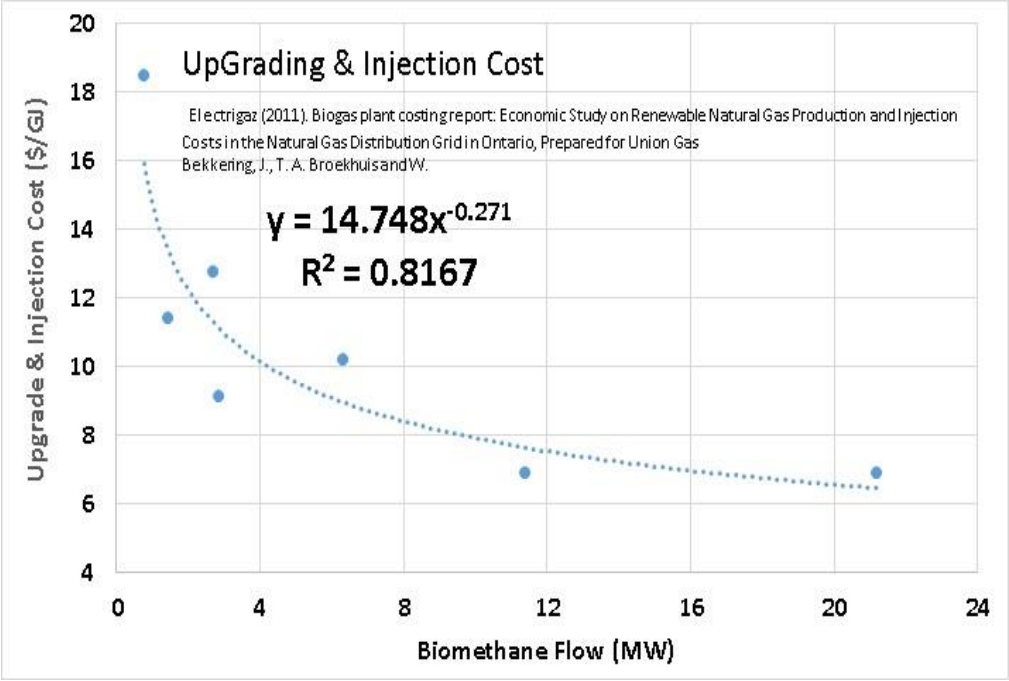
Biogas upgrading for pipeline injection is one pathway within Scenario 8 for large scale biogas systems. Biogas projects, instead of using the gas onsite for power production, would upgrade the gas to pipeline quality and inject into the natural gas pipeline system. Biomethane consumed in a central station, combined cycle gas power plant would produce electricity at approximately 50% thermal efficiency for the power plant alone.

Table 8: Summary of Technology Cost and Performance Estimates

Prime Mover	Capacity Range (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable (non-fuel) O&M ($/MWh)	Comments	Sources
Solid-fuel Combustion - Steam Cycle	15 - 70	$10701x(MW_{cap})^{-0.195}$	$3626.9x(MW_{cap})^{-0.862}$	$10.538x(MW_{cap})^{-0.05}$		B&V (2014) Rhyne (2014)
BIGCC	10 - 80	$14629x(MW_{Cap.})^{-0.31}$	Same as solid fuel combustion	Same as solid fuel combustion	Efficiency (%) 5.549xln(MWCap) + 17.014	Brown et al., (2009) Kalina (2012) Tsakomakas (2012) Upadhyay (2012) Klimantos (2009) KEMA (2009)
Gasifier & recip. engine	0.2-5 MW	6,000	553	(included in Fixed O&M)	24% Net efficiency (to power)	B&V (2013) Francois et al. (2013)
Gasifier with Fuel Cell	0.5-10	See comments	See comments	See comments	LCOE ($/kWh) = -0.139x ln(MW Cap.) + 0.5968 30% HHV basis	Kempegowda,(2012) Nagel, (2009) McIlveen-Wright, (2011) Omosun, (2004) Morandin,(2013)
MSW Thermal Conversion	5 - 70 MW	$42186x(MW_{cap})^{-0.338}$	$1379.5x(MW_{cap})^{-0.29}$	(included in Fixed O&M)	600 kWh/ wet ton; 850 kWh/ dry ton (biomass fraction or total MSW, roughly similar)	CDM-Smith (2014) Rodriquez, (2011) Schauer,(2012) Stantec (2011) Stueck, W. (2013) Tsilemou,(2006) Turkel, T. (2012)
Non Utilized Existing Biogas: Install Power Project	0.2-10+ (may use multiple prime movers)	Recip. 2,681 MT 3,181 FC 6,181	Recip. 180 MT 180 FC 260	(included in Fixed O&M)		B&V (2013) US EPA (2008) Trendewicz, (2013)
New Biogas (recip. engines)		Dairy 10,900 WWTP 9,700	Dairy 950 WWTP 490	(included in Fixed O&M)	microturbines or fuel cells, use incrmt costs	B&V (2013)
MSW AD	0.5 - 15	Recip. $15250x(MW_{Cap.})^{-0.442}$ MT $17409x(MW_{Cap.})^{-0.424}$ FC $15887x(MW_{Cap.})^{-0.298}$	$1589.3x(MW_{Cap.})^{-0.296}$ $1770.5x(MW_{Cap.})^{-0.304}$ $1380.5x(MW_{Cap.})^{-0.257}$	(included in Fixed O&M)		Tsilemou (2006) Rapport et al., (2008)
Upgrade Biogas & Inject in Pipeline					RNG upgrading& inject. $/GJ = 14.748(MW biometh flow)^{-0.271}$	Electrigaz (2011) Bekkering, et al., (2010)
RSNG (thermal pathway)	20-100				($/GJ)=112.91x(1000 BDT/y)$^{-0.362}$ 65% eff. Wood-to-SNG.	Zwart et al., (2006) Mensingre et al., (2011) Hactoglu, et al., (2010) Cozens &Whitton, (2010) Aranda et al., (2014)

Electrigaz (2011) and Bekkering, et al. (2010) were used to derive gas upgrading and injection costs as a function of scale (Figure 12). Costs to produce the raw biogas would need to be added to account for full system costs.

Figure 12: Cost for Biogas Upgrading and Injection to A Natural Gas Pipeline

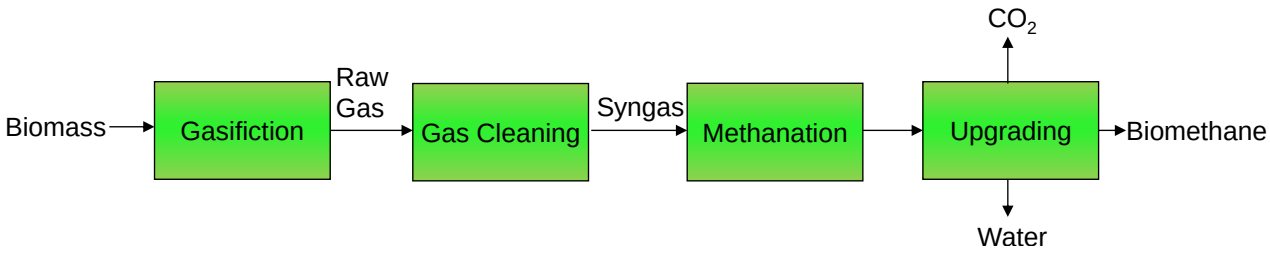


3.2.3.13 Synthetic Natural Gas (Thermal Pathway to Biomethane)

Biomass derived methane (biomethane) is normally produced from biogas created by anaerobic fermentation (anaerobic digestion) of appropriate substrates. Gas production potential from anaerobic digestion depends on feedstock characteristics. Materials with high starch and/or lipid and low lignocellulose content produce relatively large amounts of biogas (methane) compared to high lignin, low carbohydrate substrates. Bulk mixed wastes that include lignocellulosic components convert to biogas with energy efficiencies of 20-40% (energy in biogas divided by energy in substrate) (McMcKendry, 2002).

Biomethane can also be produced via thermal gasification with appropriate raw gas cleaning and reforming to a synthesis gas followed by methanation and upgrading to biomethane (Figure 13). Methane synthesized via this thermal gasification / methanation route is sometimes called synthetic natural gas (SNG) and renewable SNG (RSNG) if derived from biomass. Overall efficiency to RSNG could be as high as ~ 65% for commercial scale facilities (Kopyscinski et al., 2010; Mensinger et al., 2011; Aranda et al., 2014). Overall thermal efficiency to electricity would be approximately 30-33% if burned in a combined cycle natural gas power plant (assumes 50% efficient combined cycle power plant).

Figure 13: RSNG Process Schematic

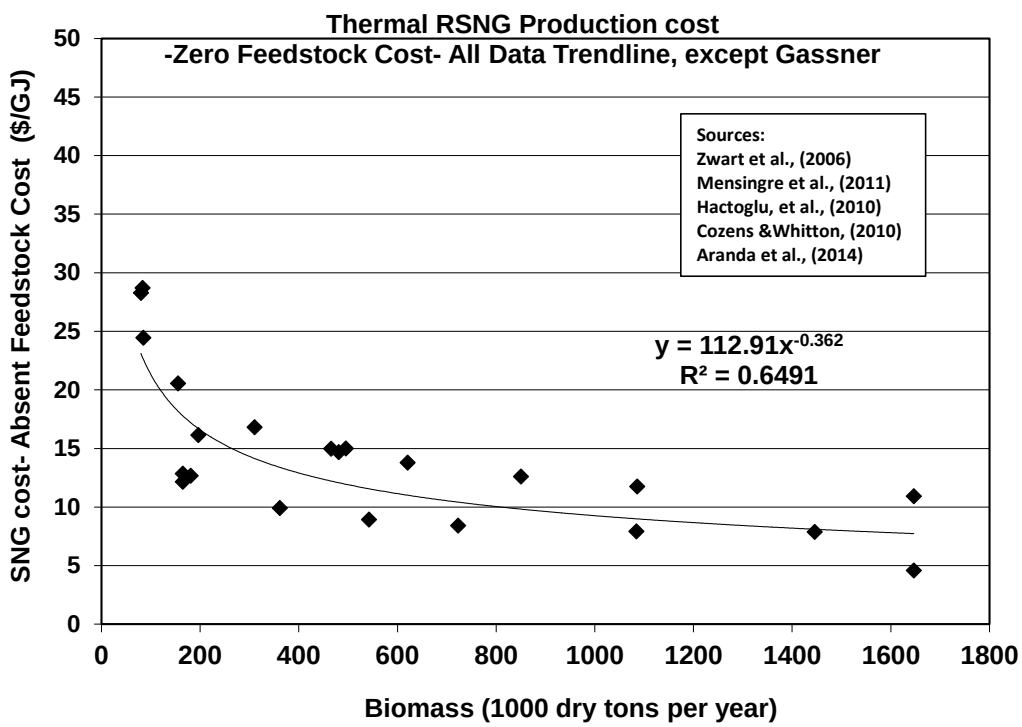


A commercial scale RSNG demonstration project is being commissioned in Sweden (GoBiGas). Gas production capacity is 20 MW_{SNG} (~68 MMBtu/hr). An 80 -100 MW SNG Phase II facility is planned. An allothermal gasification technology by Repotec is used (Göteborg Energi 2012).

Installed gas production costs (including injection to pipeline) were derived from review of techno-economic studies in the literature. Values were transformed to year 2014 US$ using CPI inflation factors and $1.40 per Euro. RSNG production cost estimates range widely from $45/GJ to about $12/GJ depending on scale, feedstock costs and technology or other assumptions.

Gas production cost without feedstock cost vs. scale was developed from the literature (Figure 14 and summarized in Table 8).

Figure 14: Production Cost ($0 Feedstock)



3.2.4 Technology Emission Factors

Emissions factors for NOx and VOC (lb/MWh) for biopower scenarios are listed in Table 9. Baseline emission factors for solid fuel combustion (Scenario 1) are based on individual facility air permit limits (Appendix C).

Table 9: Emission Factors

Technology	Emission Factors (lb/MWh)		Notes
	NOx	VOC	
Recip. Engines (biogas and producer gas)	0.5	0.2	NOx is based on 11 ppm (SCAMD Rule 1110.2) & 30% HHV eff.VOC is achieved by OCSD w/ oxidation catalyst --[Rule 1110.2 permit level 30 ppmv would be ~ 0.42 lb/MWh]
Microturbines (biogas)	0.24	0.12	Source test: Microturbines MT250 Ingersall Rand, Ralph's Groceries (there are no CARB Certified DG microturbines meeting 0.07 & 0.02 lb/MWh emissions factor for NOx and VOC respectively http://www.arb.ca.gov/energy/dg/eo/eo-current.htm
Combustion Turbines, simple cycle (biogas)	0.26	0.1	Source test averages for combustion turbines at Calabasas Landfill and Fresno/Clovis waste water treatment plant
Fuel Cells (biogas and producer gas)	0.02	0.02	Permit: FuelCell Energy, DFC300MA [3 x 300] (Eastern Muni, Perris)
Pipeline-to-Central Station natural gas power plant	*	*	* Natural Gas Combined Cycle Emfacs used for estimate of total emissions but zero emissions at the conversion site.
MSW Thermal Conversion (combustion or gasifiers, SCRNOx control)	0.15	0.11	Based on 5 ppmv NOx (7% O2) in City of LA Waste-to-energy proposal document [2.1 ppmvd NOx @ 15% O2] Very aggressive!
Biomass-Integrated-Gasifier-Combined-Cycle (BIGCC)	0.09	0.03	Adjusted upwards from NG CC due to Fuel N and lower CC efficiency
New Solid Fuel Combustion (Rankine)	0.54	0.002	DTE Stockton Source test (essentially new plant)
For Reference:			
Natural Gas Combined Cycle	0.055	0.02	Based on 2 -2.5 ppmvd NOx and 2 ppmvd VOC at 15% O2 (BACT) and 7300 Btu/kWh heat rate (~47% HHV eff.)
Current Solid Fuel Combustion (Rankine), CA weighted average Permits	2.3	0.8	Capacity-weighted average permitted values

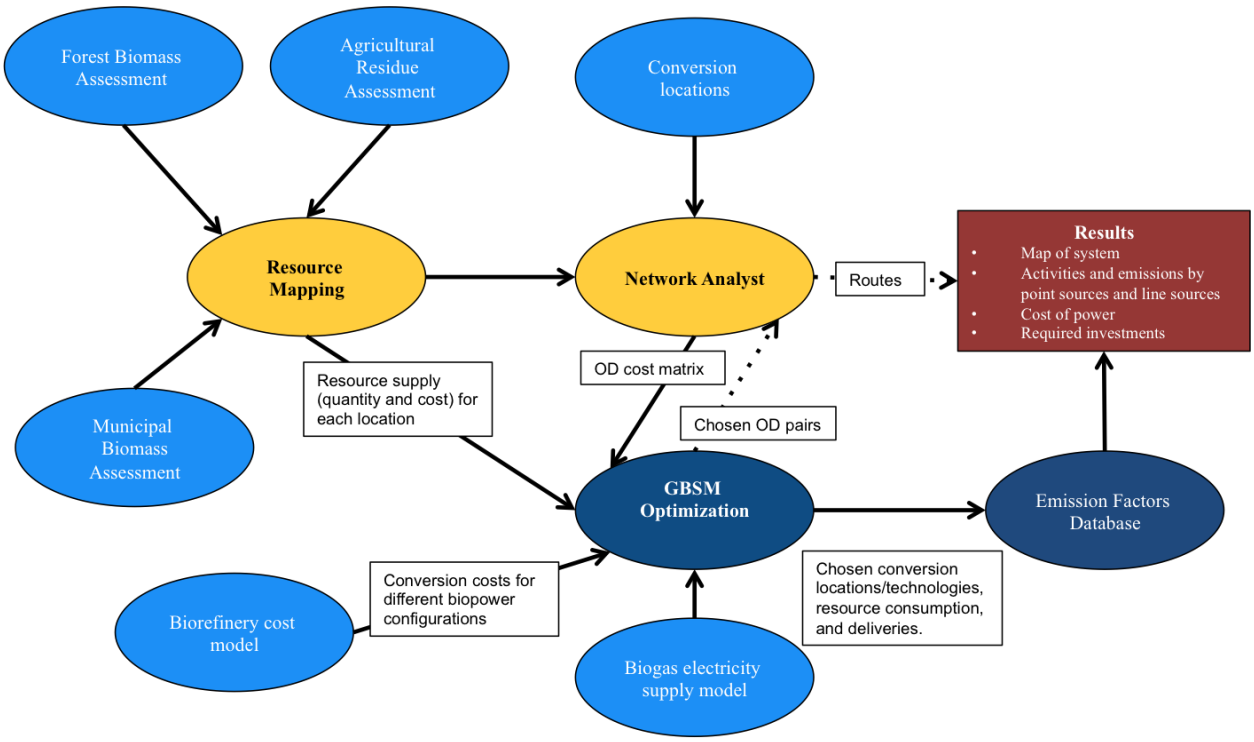
3.3 Integration of GBSM and Air Quality Model

3.3.1 Description of Geospatial Bioenergy System Model (GBSM)

The Geospatial Bioenergy System Model (GBSM) provides the basis for producing scenarios of the biopower industry. It was originally developed with previous funding from the California Energy Commission to predict optimal bioenergy supply chain configurations given spatial

distributions of biomass resources, product markets and technology costs (Parker et al 2010; Tittmann et al, 2010; Parker, 2011). It is built on an integrated geospatial database containing geographic and cost data for all aspects of the bioenergy production chain. The GBSM uses the geographic and cost data as input to a Mixed Integer Linear Program (MILP) that optimizes geographic location and size for biorefineries along with the allocation of resources to the biorefineries. The MILP optimizes the production system based upon the feedstock procurement supply curve, feedstock and fuel transport costs calculated from a geographic transportation network, and costs for conversion of biomass into products. The model includes a broad range of technologies as options for utilizing biomass resources for fuels and electricity production. The GBSM uses a profit-maximizing objective for the industry as a whole for finding the optimal industry design. Figure 15 shows a schematic of the GBSM.

Figure 15: Schematic of Geospatial Bioenergy System Model



Several modifications were made to the GBSM for this project to produce results that are useful for air quality modeling. First, the spatial resolution of the model was modified to provide results at a resolution that matches the air quality model. This involved the spatial mapping of the resources described above, improving the transportation network model, and updating the set of potential locations. Second, new technologies were added. Third, post-processing of the results was incorporated to estimate spatial emissions inventory.

For this work, the technology options for producing electricity have been expanded to include the technologies listed above using forest, urban and agricultural biomass excluding manures, wastewater treatment, and landfills. These three biogas sources were treated as point sources of

supply in the model with their cost of production externally calculated using the size of individual facilities and the cost curves presented above. They were then included as electricity supply options in the model to compete with the other technologies for market share.

3.3.1.1 Biomass Transportation Costs and Emissions

Some forms of biomass require aggregation from their point of generation to the biopower plants or potential locations for biopower facilities. This aggregation allows for economies of scale to be exploited but at the cost of transporting the biomass. Biomass transport costs are estimated in this work assuming truck transportation along the California road network. The least cost path between each biomass source point and each existing or potential biopower facility location is found using the Network Analyst function in the ArcGIS 10.3 software. The cost function is defined as the cost of moving a fully loaded 25 ton truck (80,000 lb. gross vehicle weight) between the two locations and incorporates loading/unloading costs and cost of movement with both time and distance dependent components (Tittmann et al, 2008).

The California road network used in the routing algorithm is simplified from the actual road network. The network includes class 1-3 roads throughout the state. Many of the resource supply points do not lie directly on this simplified road network. Connections between the supply points and the road network were made by adding straight-line connectors to the nearest point on the road network. These connectors were given additional length by applying a turtosity factor of 1.3 as the real road network will not typically provide the shortest path to the major roads. The process of selecting potential locations for new biopower facilities is described in the next section. were at least 25 km from each other (50 km in the case of a national model of large-scale biorefineries). One of the challenges for matching GBSM with the air quality model was to select potential locations that are more representative of actual biorefinery locations. Locating in the middle of a population center is both unlikely and leads to a higher exposure rates than locating outside of the urban areas. For this reason we chose to select only potential locations outside of urban areas (with the exception of landfills and wastewater treatment plants, which are included regardless of location). For new potential locations we have used electric substations outside of urban areas. This gives 1196 locations (shown in Figure 18). The set was further reduced by clustering the locations that were too close together to be resolved in the modeling work. This gives 443 potential location throughout the state plus 131 landfill locations for a total of 574 possible locations for siting new biopower facilities.

Figure 16 shows the road network in California and the addition of connectors. The Network Analyst function in ArcGIS minimizes the delivery cost as it finds the routes between all supply points and potential biopower facility locations. This cost has both time and distance components. The time component is calculated using the posted speed limits on the roads and 15 MPH speed on the connectors.

The transportation network is used in the modeling in two ways. First, the network is used to create a cost matrix that gives the cost of moving one wet ton of biomass between each supply point to each potential location. This information is used by the optimization model to determine the spatial layout of the chosen supply chains for each scenario. After the optimization provides the layout, the network model is again used to create a spatial

description of the truck travel in service of the industry. An example of the routing results is given in Figure 17.

3.3.1.2 Potential Locations for New Biopower Facilities

The location of new biopower facilities is a major factor in the air quality impacts projected in this work. The GBSM uses a discrete set of user defined potential locations in choosing where to locate facilities. These locations are meant not as prescriptive locations but to be representative of the surrounding area. In previous work these potential locations were chosen as all towns having the infrastructure to support a facility and then reduced to locations that were at least 25 km from each other (50 km in the case of a national model of large-scale biorefineries). One of the challenges for matching GBSM with the air quality model was to select potential locations that are more representative of actual biorefinery locations. Locating in the middle of a population center is both unlikely and leads to a higher exposure rates than locating outside of the urban areas. For this reason we chose to select only potential locations outside of urban areas (with the exception of landfills and wastewater treatment plants, which are included regardless of location). For new potential locations we have used electric substations outside of urban areas. This gives 1196 locations (shown in Figure 18). The set was further reduced by clustering the locations that were too close together to be resolved in the modeling work. This gives 443 potential location throughout the state plus 131 landfill locations for a total of 574 possible locations for siting new biopower facilities.

Figure 16: Road Network for California Showing the Base Network (left) and the Connections (right)

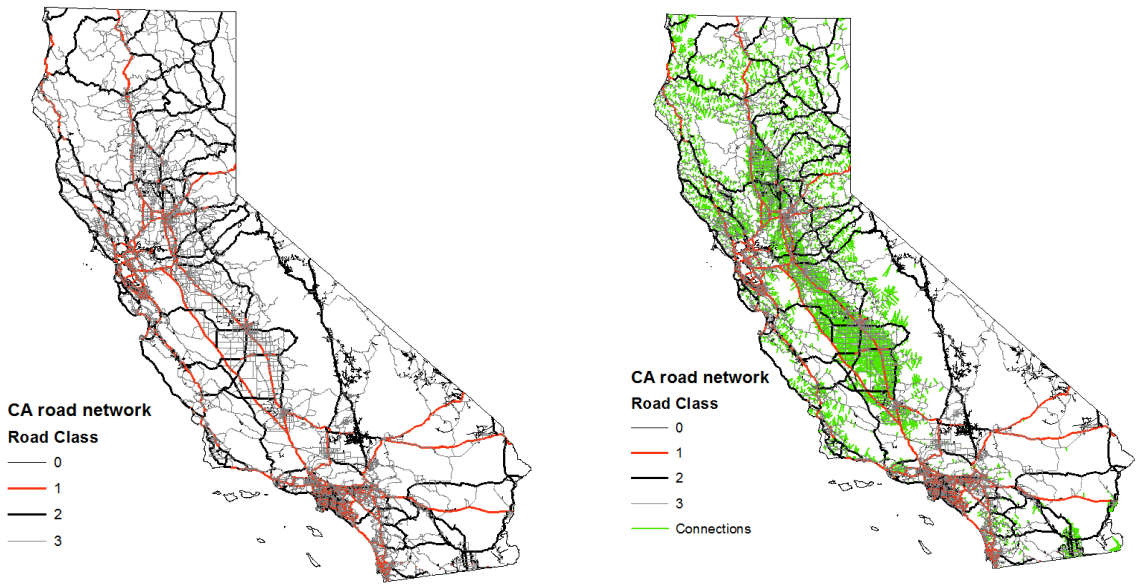
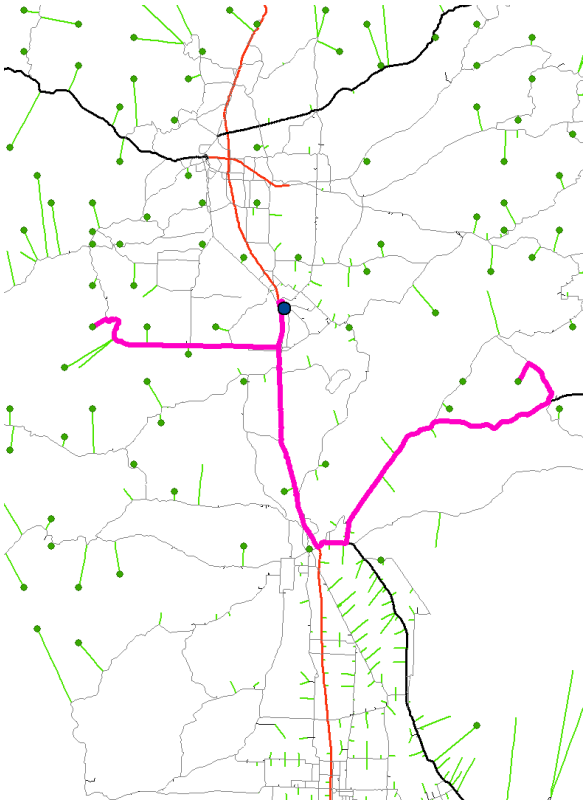
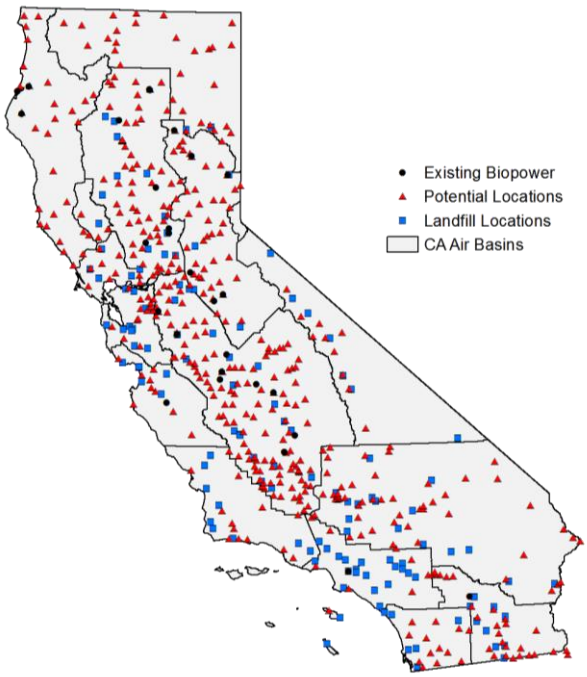


Figure 17: Example of Mapping of Truck Travel in Service of a Biopower Facility



Legend: Road class: class 1 in red, class 2 in thick black, class 3 in think black; Procurement sites shown by green dots; Connectors shown by straight green lines; Bioenergy plant shown by a filled circle. Examples of transportation route from procurement sites to bioenergy plant shown in pink.

Figure 18: Potential Locations for New Biopower Facilities and Existing Solid Fuel Combustion Facilities



3.3.2 Air Quality Modeling

3.3.2.1 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:

$$\frac{\partial Q_m^k}{\partial t} = -\nabla \cdot \left(uQ_m^k\right) + \nabla \cdot \left(K\nabla Q_m^k\right) + \left(\frac{Q_m^k}{\partial t}\right)_{sources/sinks} + \left(\frac{Q_m^k}{\partial t}\right)_{aerosol} + \left(\frac{Q_m^k}{\partial t}\right)_{chemi} \quad (1)$$

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.

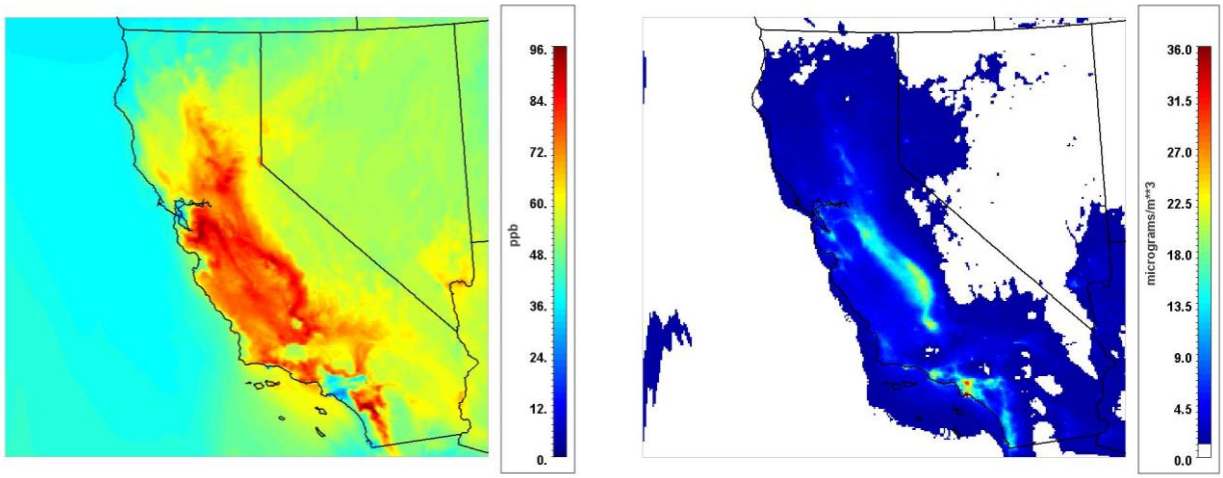
The CMAQ model (Byun and Ching, 1999) is a comprehensive air quality modeling system developed by the United States Environmental Protection Agency (US EPA) and is used in many regulatory air quality applications such as studying tropospheric ozone, particulate matter, acid deposition and visibility (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 were 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.

3.3.2.2 Air Quality Modeling Performance

This section discusses air quality resulting from modeling the Summer Baseline and the Winter Baseline cases. 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 that are used regularly to validate simulation models. Annual emissions were spatially and temporally disaggregated by SMOKE to approximate hourly emissions over the simulation domain. Figure 19 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, 2005, 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 19a).

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 19b).

Figure 19: Ambient air Concentrations for July 13, 2005: (a) 8-hour Average Ozone, (b) 24-hour Average $PM_{2.5}$.



(a) (b)

Figure 22 shows simulated 8-hour ozone concentrations and 24-hour PM2.5 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 PM2.5 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 PM2.5 concentrations higher than the 35 μg/m3 federal EPA standard.

Figure 23 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 24 presents modeled and observed 24-hour average PM2.5 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 PM2.5, are -27.8% and 29.3%, respectively.

Figure 20 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 2 and 3. 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).

$$\mathrm{MNB}=\frac{1}{N}\sum_{i=1}^{N}\frac{C_M(x_i,t)-C_O(x_i,t)}{C_O(x_i,t)} \tag{2}$$

$$\mathrm{MNGE}=\frac{1}{N}\sum_{i=1}^{N}\frac{|C_M(x_i,t)-C_O(x_i,t)|}{C_O(x_i,t)}, \tag{3}$$

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 ith 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).

Figure 21 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.

Figure 22 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 μg/m^3 federal EPA standard.

Figure 23 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 24 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.

Figure 20: Modeled and Observed Hourly Ozone Concentrations for July 13, 2005 at Selected Locations

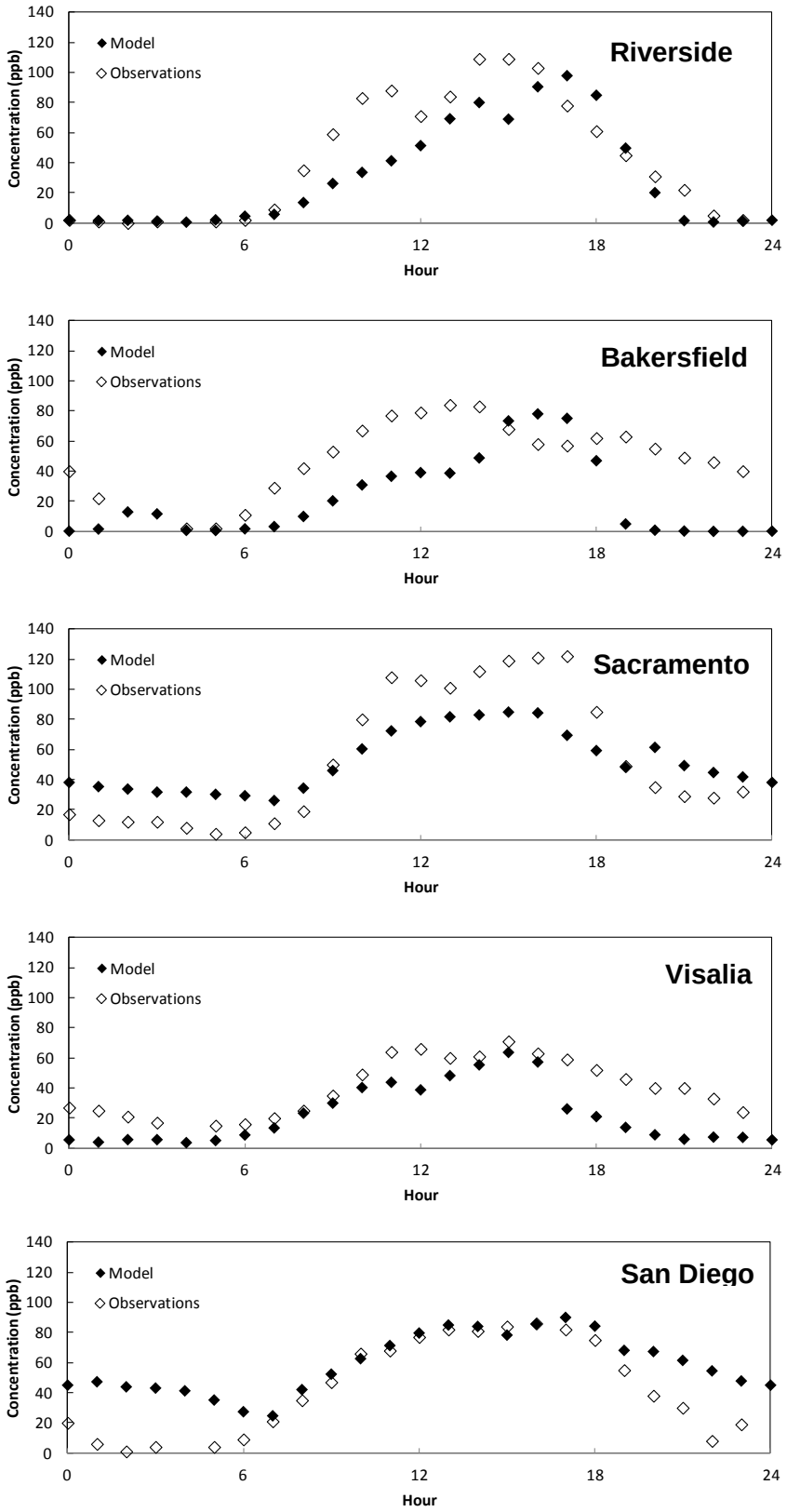


Figure 21: Modeled and Observed 24-Hour Average $PM_{2.5}$ Concentrations for July 13, 2005 at Selected Locations

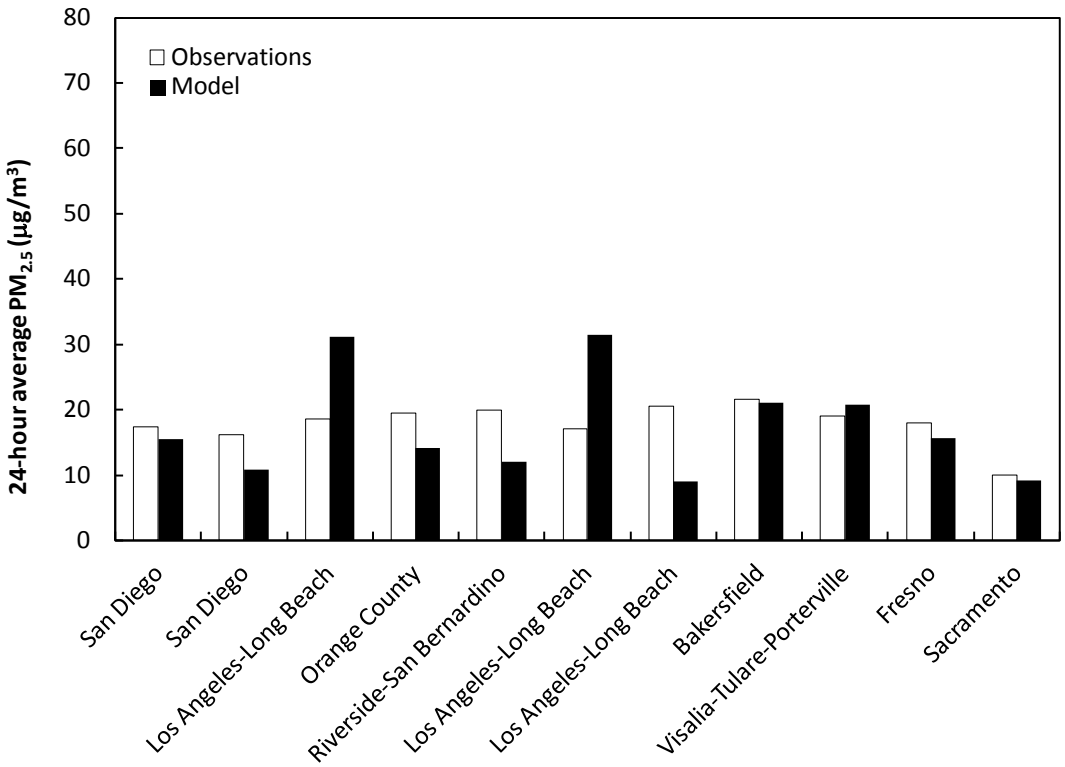
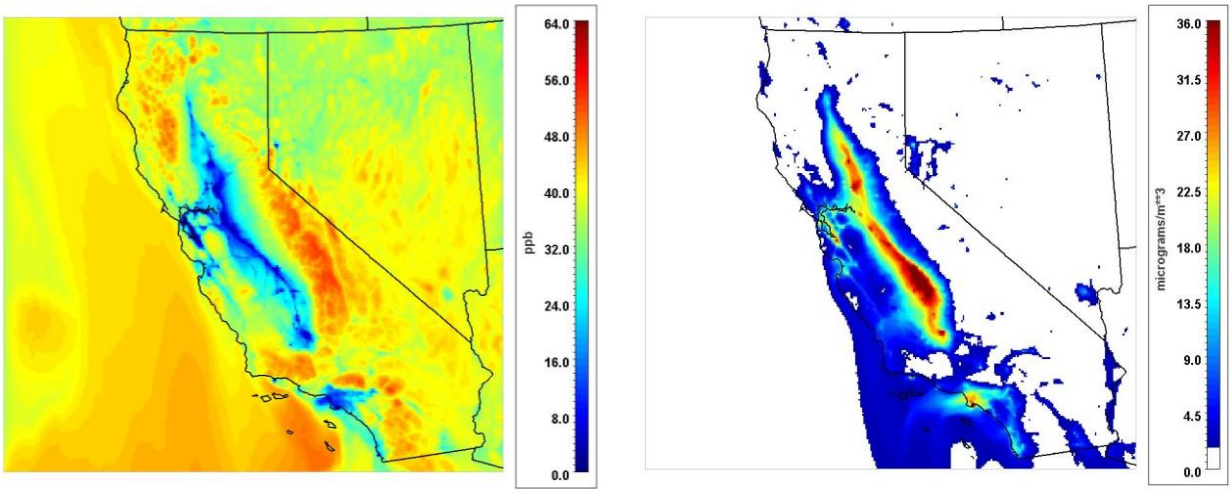


Figure 22: Modeled Pollutant Concentrations for December 7, 2005: (a) 8-hour Average Ozone, (b) 24-hour Average $PM_{2.5}$.



(a) (b)

Figure 23: Modeled and Observed Hourly Ozone Concentrations for December 7, 2005 at Selected Locations

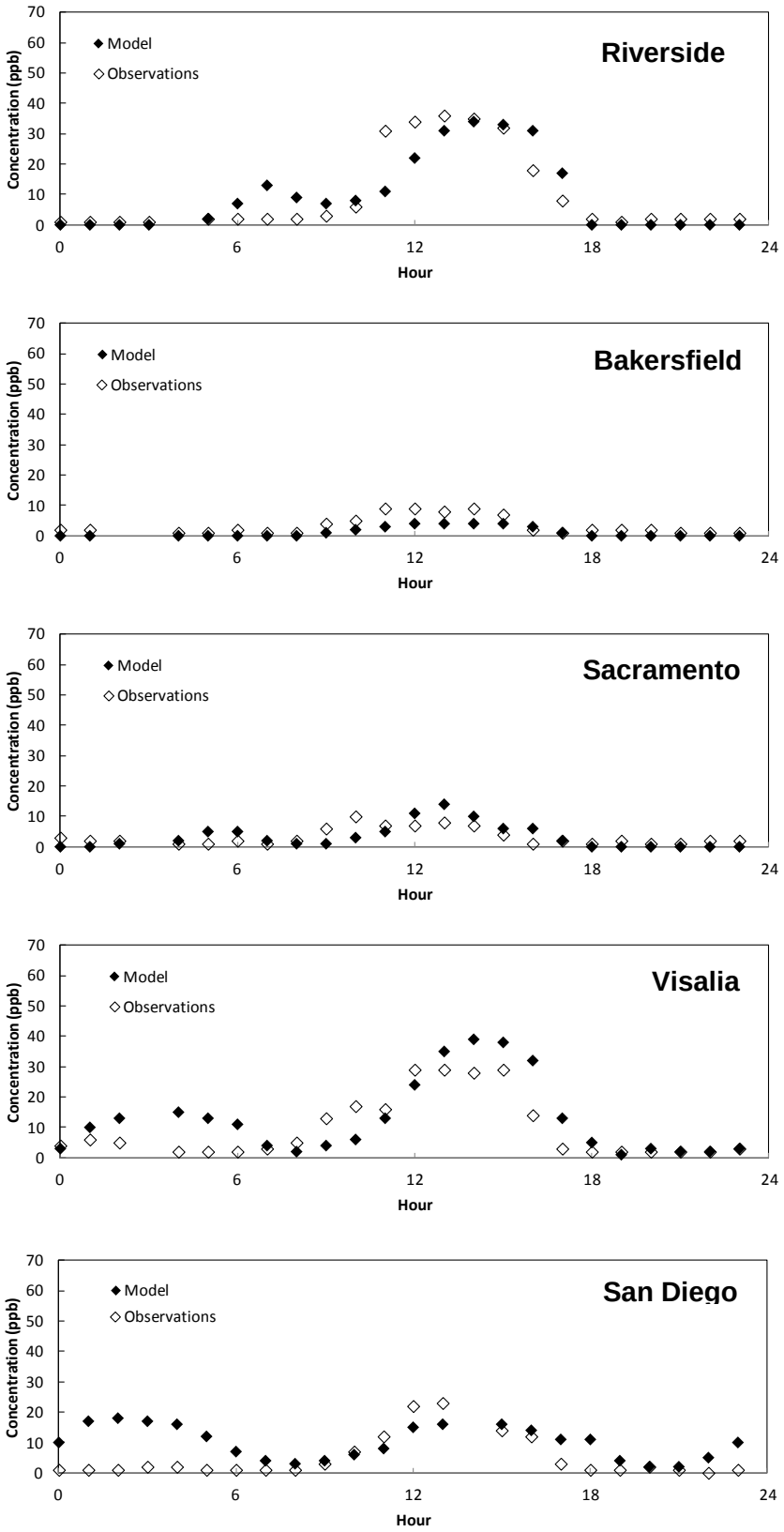
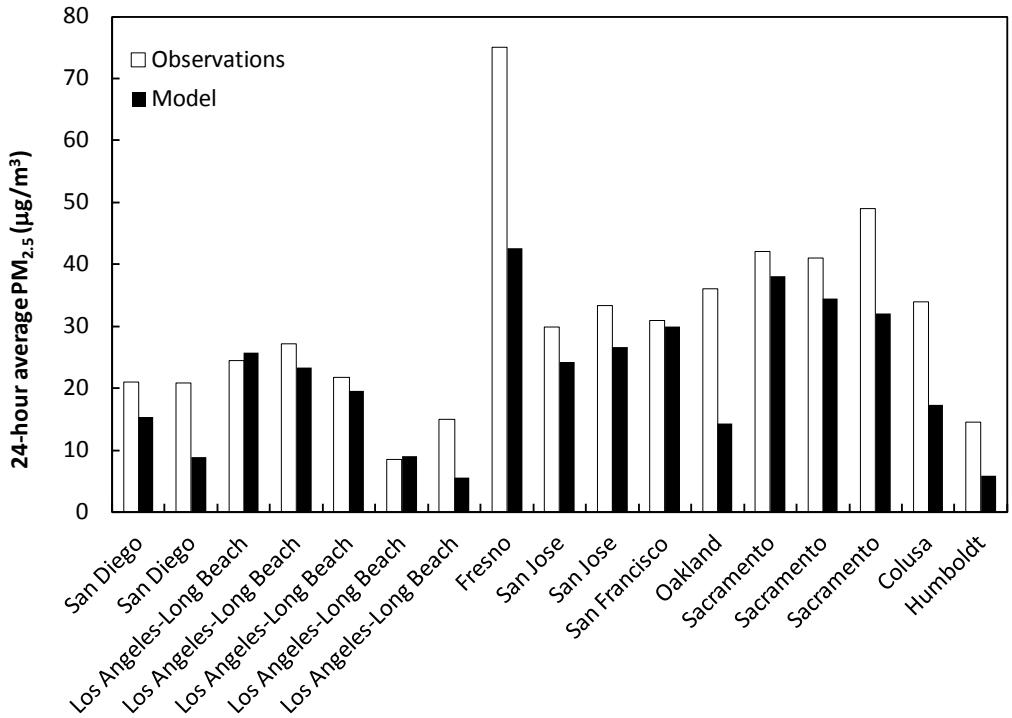


Figure 24: Modeled and Observed 24-hour Average $PM_{2.5}$ Concentrations for December 7, 2005 at Selected Locations



3.3.3 Air Quality Impacts of Biomass Scenarios

3.3.3.1 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.

Ozone:

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:

$$NO_2 + h\nu \rightarrow NO + O \qquad \text{(R1)}$$

$$O + O_2 \rightarrow O_3 \qquad \text{(R2)}$$

$$NO + O_3 \rightarrow NO_2 + O_2 \qquad \text{(R3)}$$

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:

$$O_3 + H_2O + h\nu \rightarrow O_2 + 2\,OH \qquad (R4)$$

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 reaction R5 to form H_2O and an alkyl radical R, which then reacts with NO to reform NO_2 by reaction R6.

$$R\text{-}H + OH \rightarrow R + H_2O \qquad (R5)$$

$$R + NO + O_2 \rightarrow RO + NO_2 \qquad (R6)$$

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).

$$OH + NO_2 \rightarrow HNO_3 \qquad (R7)$$

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.

3.3.4 Integration of Models

Integration of GBSM and CMAQ comprises three steps: (1) gridding of emissions, (2) chemical speciation of air pollutants and (3) temporal resolution of emissions.

Gridding of emissions requires processing ArcGIS shapefiles, which includes point files for procurement and conversion of biomass, and line files for the location of transportation corridors. The conversion from GIS to gridded emissions is accomplished by defining the air quality modeling domain of 4 km by 4 km resolution, and using GIS spatial analysis tools to redistribute line segments and point sources into the grid (as shown in Figure 25 and Figure 26).

Chemical speciation is required to disaggregate lumped species like NOx, PM and VOC, into their constituents. For NOx, we assume a constant breakdown of 90% NO and 10% NO2. On the other hand, speciation for VOC and PM depend on the technology considered for biomass collection and conversion. The speciation profiles are obtained from US EPA SPECIATE database, which is then used in the emissions processing tool SMOKE. These more specific chemical species are required for the photochemical model in order to simulate detailed atmospheric chemistry. The profiles used for biomass conversion facilities are shown in Figure 27.

Figure 25: Example of GIS Shapefile Display (top) and zoom-in with the Modeling Grid Overlay (bottom)

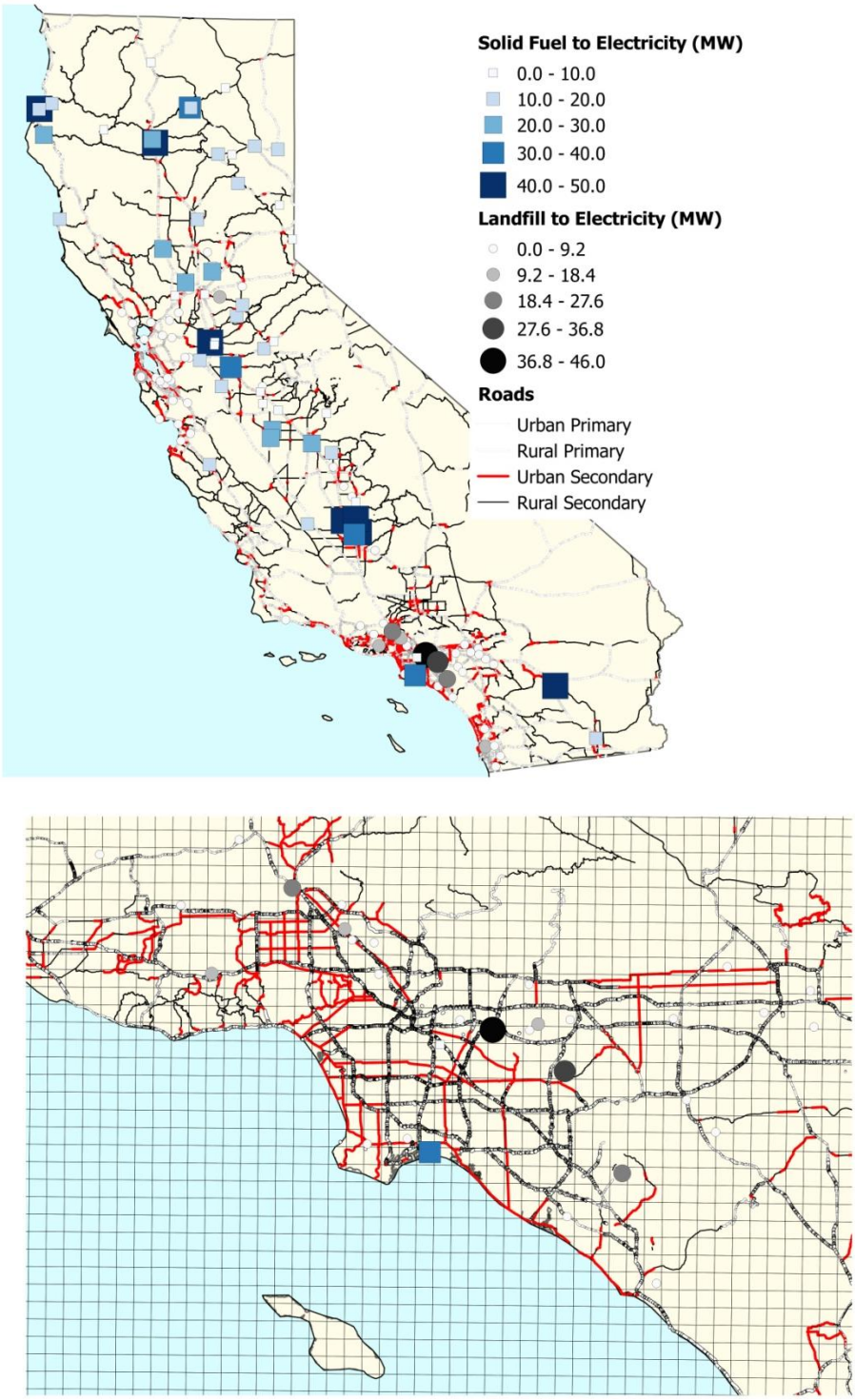
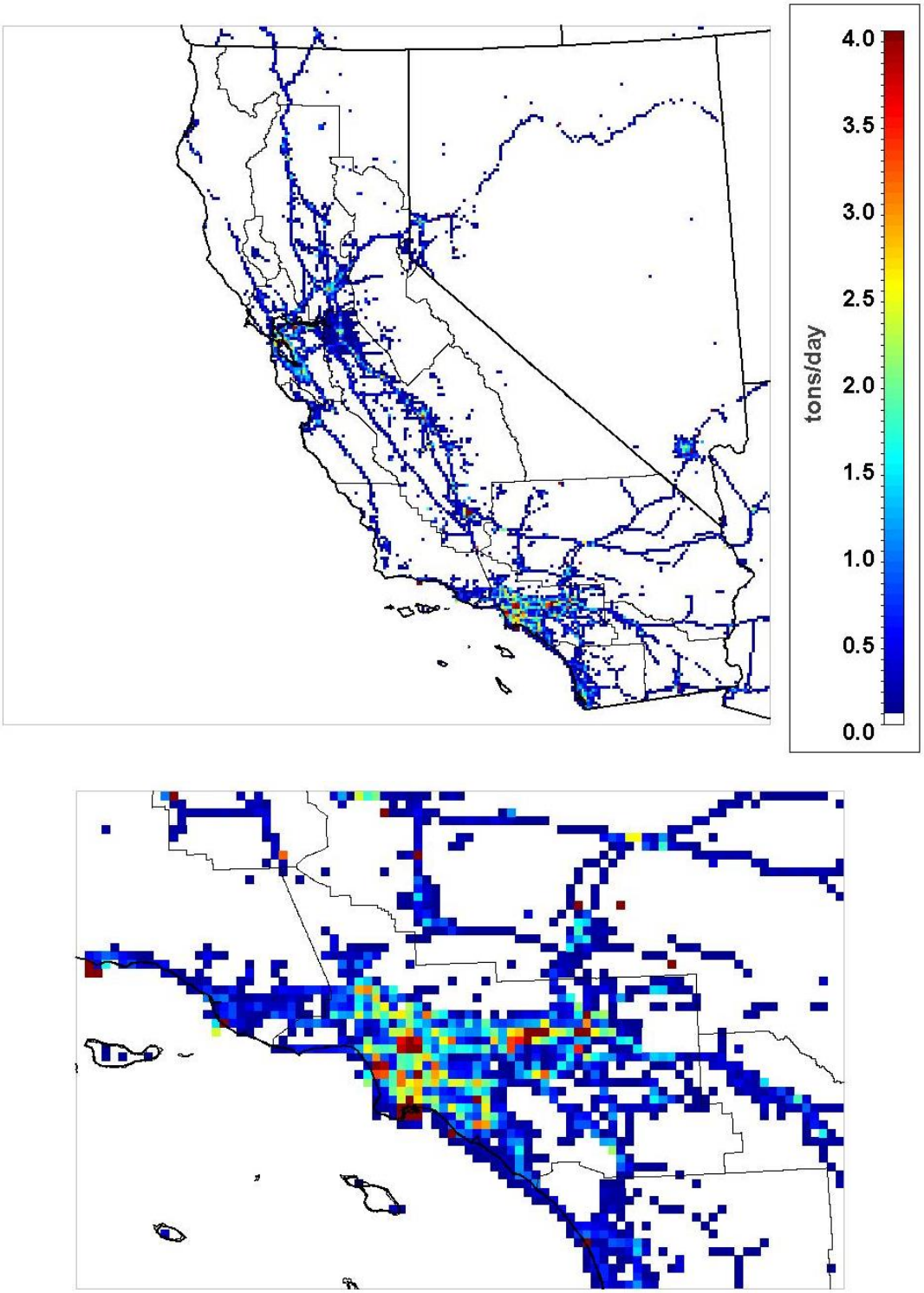
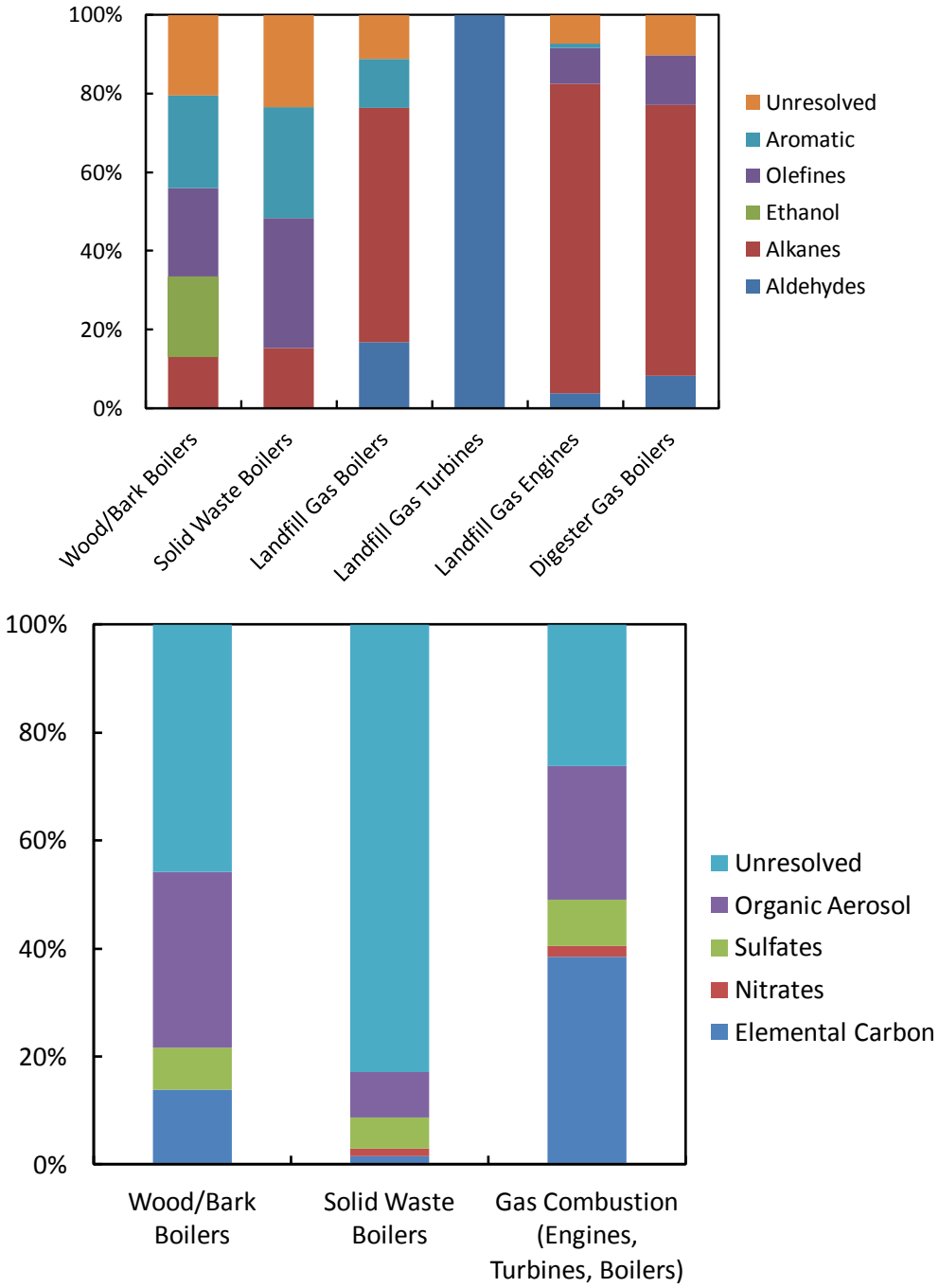


Figure 26: Gridded Emissions Required by CMAQ (top) and Zoom-in of Emissions showing 4 km by 4 km Resolution (bottom)



The air quality model requires hourly temporal resolution. Even though some of the agricultural and forestry residues present seasonal variability, this study assumes constant availability throughout the year, based on annual average potentials for biomass collection. Collection and transport of biomass is assumed to occur in a 10-hour period, from 8 am to 6 pm.

Figure 27: Chemical Profiles for VOC (top) and PM (bottom) for Various Biomass Conversion Technologies



3.4 Emissions

Air quality impacts of biomass use are driven by the intensity of emissions and their spatial distribution. There are three major sources of emissions from biomass use: conversion of biomass in a facility, procurement of biomass, and transport of biomass from the procurement site to the conversion facility.

Table 10 presents the values for total power produced, biomass collected and total miles travelled by biomass trucks. This study assumes no change in transportation and procurement technology among scenarios. Namely, emission factors for procurement and transport of biomass remain constant. As a result, emissions from procurement and transport of biomass depend only on the total biomass collected and total miles transported. In contrast, technology for biomass conversion varies among scenarios. For example, Scenario 2 and Scenario 4 assume that BIGCC system is used to produce power, which has lowest NO_x emissions (0.09 lb/MWh) and highest efficiency among biopower technologies for solid biomass. Scenario 3a and 3b assume the use of reciprocating engines, which has the highest NO_x emissions per unit of power produced (0.5 lb/MWh). Scenario 5 assumes no emissions from conversion of biomass, whereas Scenario 7 assumes thermal conversion of MSW, with an intermediate value for NO_x emissions per unit of power produce (0.15 MWh). In conclusion, emissions from conversion vary among the scenarios as a function of the technology used for biomass conversion, in addition to varying due to the amount of biomass converted.

Table 11 presents the emissions from the biomass scenarios. Scenario 1 generated 25.9 tons per day of NOx and 9.2 tons per day of VOCs. Approximately 91% of NOx and 99% of VOC emissions occurred at the conversion facility. Large reductions in emissions are possible through repowering the existing fleet with BIGCC technology, as assumed in Scenario 2. Improved efficiency also reduces emissions from the procurement and transportation of biomass. The repowering scenario achieves a 93% reduction in NOx and a 96% reduction in VOC emissions. Note that Scenario 1 and 2 also include emissions from biogas installations.

Scenario 3a assumes slightly higher procurement and comparable transport of biomass relative to Scenario 1. In contrast, Scenario 3a does not include biogas facilities, and results in slightly lower emissions than Scenario 1. Scenario 8 assumes the largest procurement of biomass and requires the longest transport. In addition, Scenario 8 includes a significant market share of reciprocating engines, which results in higher emissions than the other large scale deployment scenarios. As a result, Scenario 8 produces the highest NOx and VOC emissions amongst the scenarios. The larger scale facilities allowed in Scenario 8 make the food waste AD technology relatively more attractive, which results in more production within the South Coast air basin. This result suggests further exploring the cost of emissions within areas of extreme non-attainment.

For large deployments of biopower, the NOx and VOC emissions were less than one quarter of the baseline emissions on a per kWh basis. The BIGCC technology assumed in Scenario 4 proved to be more economically attractive than the synthetic natural gas technology assumed in

Scenario 5. Therefore Scenarios 4 and 6 are identical. The emissions are similar for the two technologies as well.

Table 10: Summary of Biomass Procurement and Power Generation from the Biomass Scenarios

	Total Biomass Power (MW)	Additional Power from Biomass Facilities (MW)	Procurement (BDT/day)	Transport (VMT)
Scenario 1	966*	0	12,049	52,195
Scenario 2	966*	0	7,748	28,345
Scenario 3a	918	248	16,445	50,761
Scenario 3b	920	250	17,578	53,848
Scenario 4 and 6	3670	3000	40,650	108,562
Scenario 5	1970	1300	28,867	106,674
Scenario 7	1971	1301	14,948	204,774
Scenario 8	2830	2160	52,908	212,729

*Includes existing biogas facilities

Table 11: Summary of Emissions for the Biomass Scenarios

	Pollutant Emissions (tons/day)				
	NO_X	SO_X	CO	VOC	$PM_{2.5}$
Scenario 1	25.9	1.2	34.4	9.2	2.7
Scenario 2	1.8	0.2	2.3	0.4	0.8
Scenario 3a	19.9	1.1	25.6	6.8	2.4
Scenario 3b	20.1	1.1	25.7	6.8	2.4
Scenario 4 and 6	25.2	2.0	18.1	7.8	5.9
Scenario 5	20.4	2.8	22.6	6.5	6.4
Scenario 7	21.3	1.3	11.5	8.0	3.6
Scenario 8	36.7	2.6	189.0	12.1	5.9

In the case of BIGCC and synthetic natural gas technologies, the conversion emissions are low enough that the procurement and transportation of biomass become significant contributors to the total supply chain emissions. This highlights the importance of mobile source and off road emissions in driving down total emissions as better technology is used in the conversion.

3.5 Results

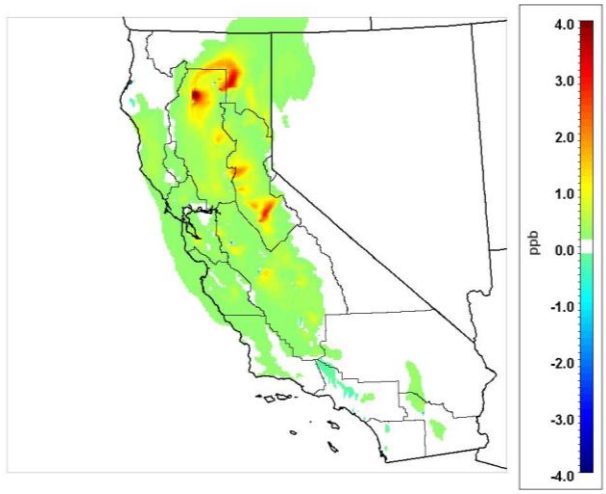
3.5.1 Air Quality Results

The air quality results are discussed by assigning Scenario 1 – which assumes the current biomass installations – as the reference case. Scenario 1 is first compared to the baseline for 2020, which assumes no biomass-related emissions. Air quality impacts are expressed as the difference between a study cases minus the reference 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.

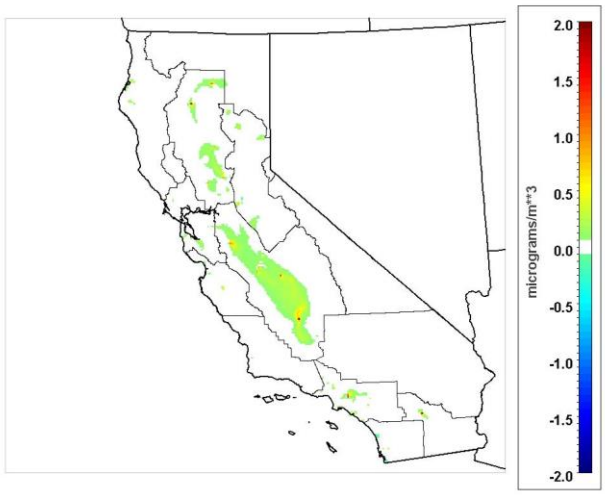
Figure 28 presents the impacts on ozone and $PM_{2.5}$ of the current biomass facilities with respect to the case with no biomass (Scenario 1). This illustrates the contribution of current biomass facilities to air pollution levels. There are large biomass facilities in the northern part of the state that use forest and agricultural residue. Those facilities cause increases in ozone of up to 4 ppb. Facilities in the San Joaquin Valley also contribute to small increases of less than 2 ppb of ozone, and increases in $PM_{2.5}$ concentrations of up to 2 $\mu g/m^3$. Wintertime $PM_{2.5}$ is more sensitive to changes in emissions, and as a result, the winter impacts of biomass on $PM_{2.5}$ are generally higher than in the summer.

When analyzing the magnitude of the impacts on ozone and PM concentrations, it is important to identify the regions that are typically affected by high pollutant concentrations. Regions such as the South Coast, the Sacramento Valley, and the San Joaquin Valley suffer from high levels of pollution throughout the year, and hence, even small changes in pollutant concentrations are important. To illustrate the sensitive regions in the state, Figure 29 presents shaded in gray the areas with ozone concentrations higher than 70 ppb and 24-hour average PM concentrations higher than 20 $\mu g/m^3$. Ozone is particularly high in the San Joaquin Valley, South Coast, and parts of the Central Coast and Mojave Desert basins. $PM_{2.5}$ peaks near the port of Los Angeles in the summer, but in the winter, PM concentrations are particularly high in the San Joaquin and Sacramento Valleys. It is in those shaded areas that even small increases in air pollutants can worsen already bad conditions for air quality. Conversely, increases in air pollutants in the northernmost part of the State, where some biomass facilities exist, do not pose a critical problem regarding air quality standards.

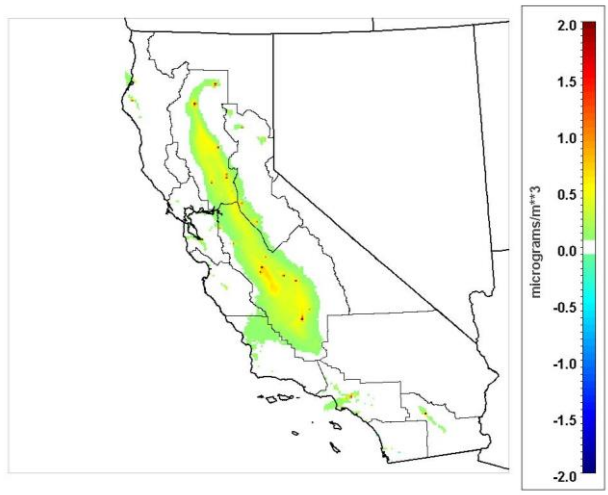
Figure 28: Air Quality Impacts of Scenario 1: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average PM2.5 in the Summer, (c) Impact on 24-hour Average PM2.5 in the Winter



(a)

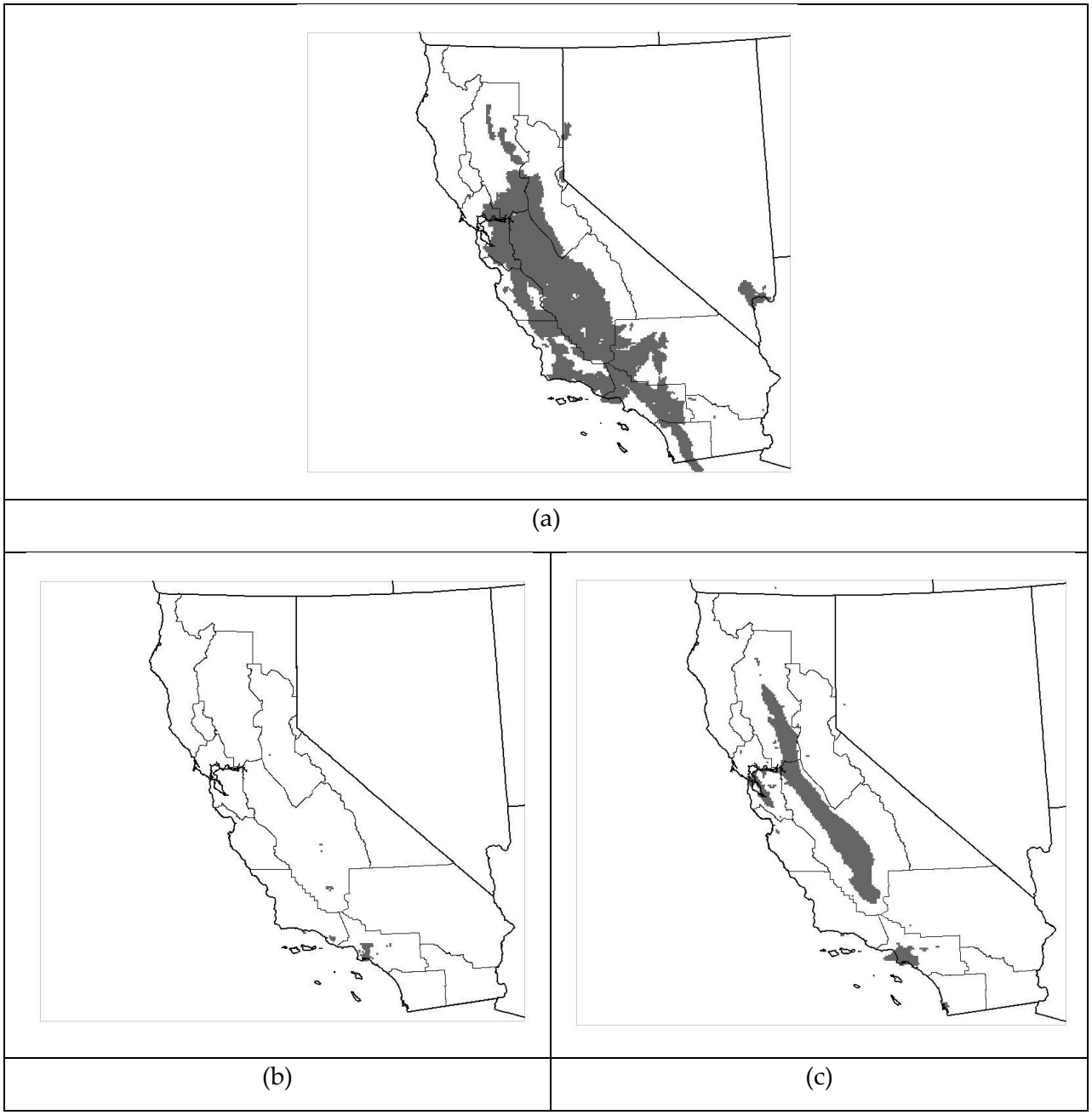


(b)



(c)

Figure 29: Areas Sensitive to Changes in Air Pollutants: (a) Areas with Ozone Concentrations Higher than 70 ppb, (b) Areas with 24-hour Average $PM_{2.5}$ Higher than 20 $\mu g/m^3$ in the Summer, (c) Areas with 24-hour Average $PM_{2.5}$ Higher than 20 $\mu g/m^3$ in the Winter



In general, the higher the increases in emissions from biomass use, the greater the increases in ozone and particulate matter are, and vice versa. For example, Scenario 2 produces the lowest emissions among all scenarios and, as a result, presents the largest decreases in ozone and $PM_{2.5}$ concentrations with respect to Scenario 1 (Figure 30). And Scenario 3a (Figure 31), which results in emissions that are comparable to Scenario 1, presents small changes in air pollutant concentrations with respect to Scenario 1. On the other extreme, Scenario 8 produces the

greatest emissions among the scenarios, which results in some of the greatest increases in ozone and PM in the Central Valley (Figure 32). However, Scenarios 4 (Figure 33) and Scenario 5 (Figure 34), with substantially lower emissions than Scenario 8, also cause large increases of ozone in the Sacramento Valley because of concentration of procurement and transport in that particular area. This result stresses the importance of spatially-resolved analysis of emissions and air quality. Even though scenario 4 and Scenario 5 produce impacts on ozone concentration that are higher than Scenario 8, these impacts occur in areas that are less sensitive. On the other hand, increases in $PM_{2.5}$ occur in the San Joaquin Valley, which is an area already impacted by high particulate matter formation. Figure 35 presents the air quality impacts of scenario 7. Scenario 7 assumes a high penetration of MSW conversion facilities, which have the largest concentration around Los Angeles metropolitan area. Because the South Coast air basin is typically less sensitive to changes in emissions due to already high levels of air pollutant emissions, the quality impacts of Scenario 7 are less intense than other scenarios with comparable total pollutant emissions.

One should note that the emission factors from biomass conversion in Scenario 4 and 5 are the lowest, and that there is a significant contribution from procurement and transport that needs to be accounted for. This underscores the importance of the emissions from procurement and transport in scenarios with high volumes of biomass collection.

Figure 30: Air Quality Impacts of Scenario 2: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average $PM_{2.5}$ in the Summer, (c) Impact on 24-hour Average $PM_{2.5}$ in the Winter

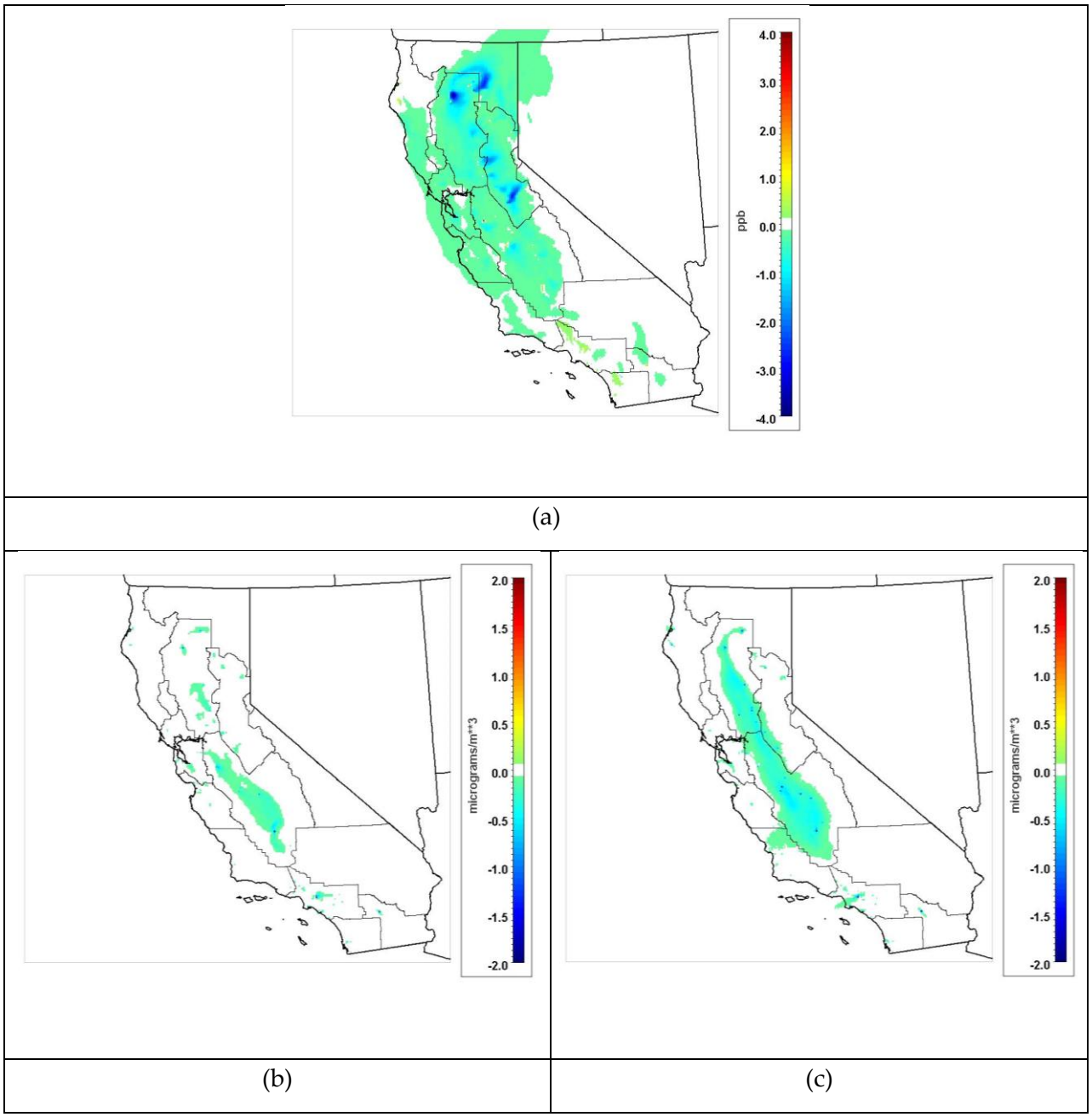


Figure 31: Air quality Impacts of Scenario 3a: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average $PM_{2.5}$ in the Summer, (c) Impact on 24-hour Average $PM_{2.5}$ in the Winter

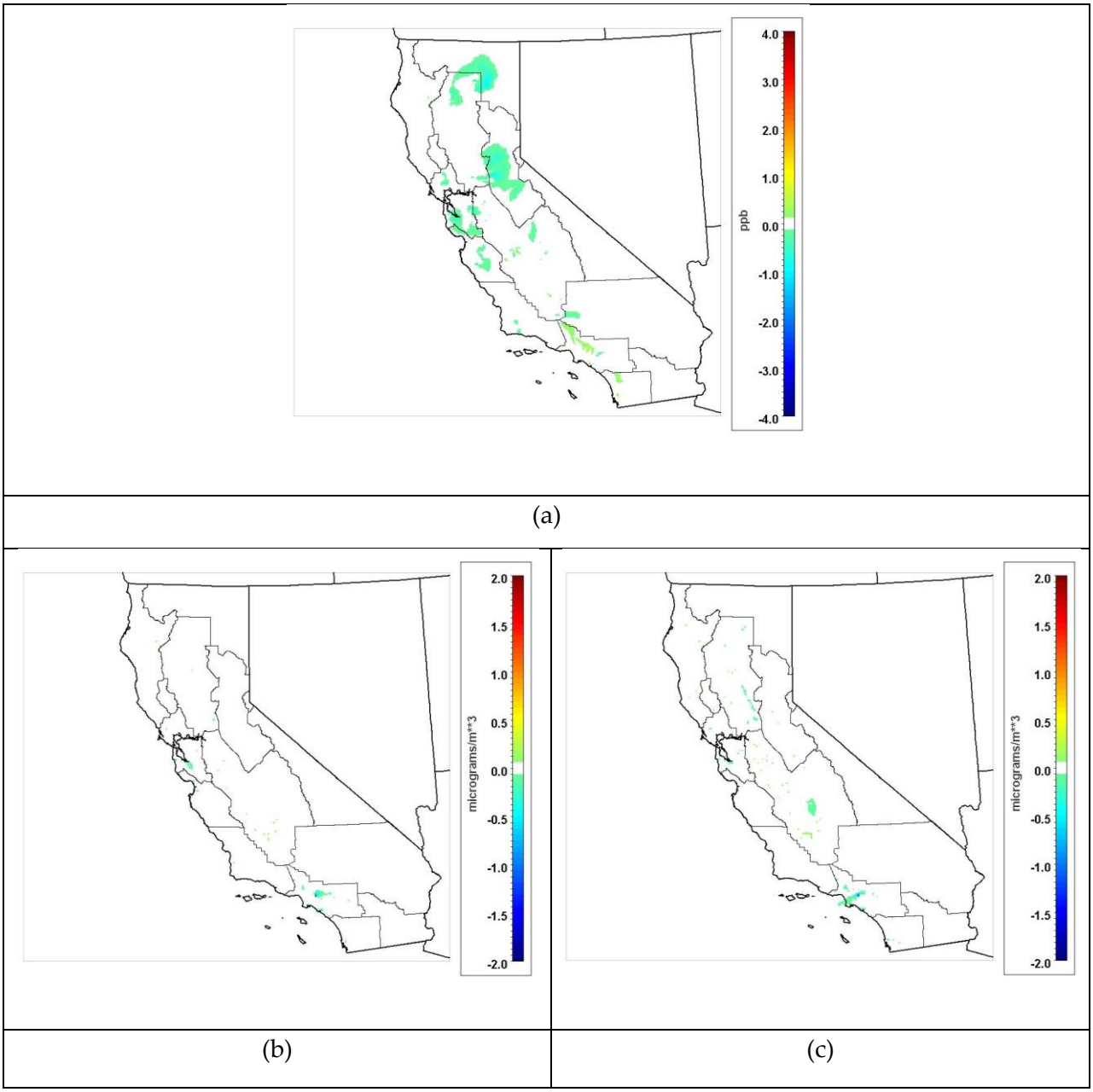
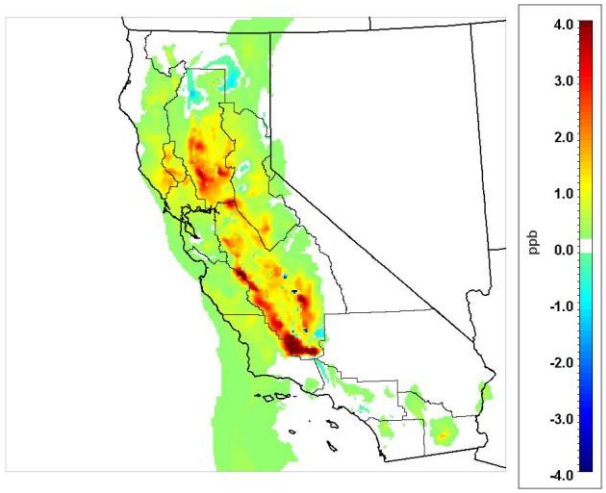
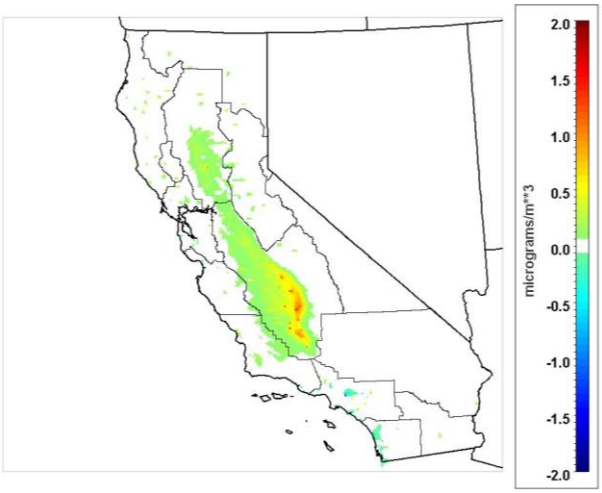


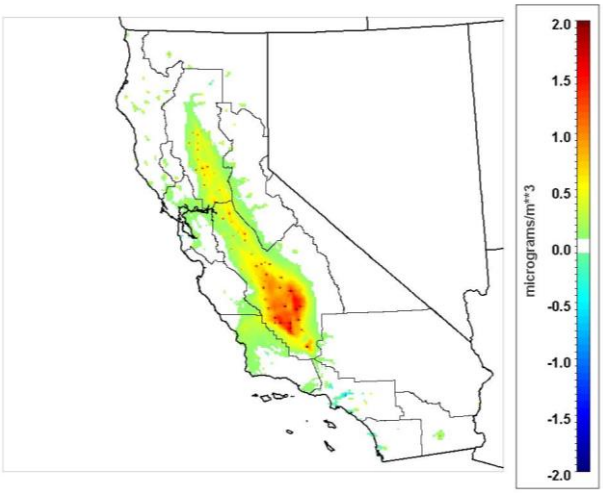
Figure 32: Air Quality Impacts of Scenario 8: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average $PM_{2.5}$ in the Summer, (c) Impact on 24-hour Average $PM_{2.5}$ in the Winter



(a)



(b)



(c)

Figure 33: Air Quality Impacts of Scenario 4: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average $PM_{2.5}$ in the Summer, (c) Impact on 24-hour Average $PM_{2.5}$ in the Winter

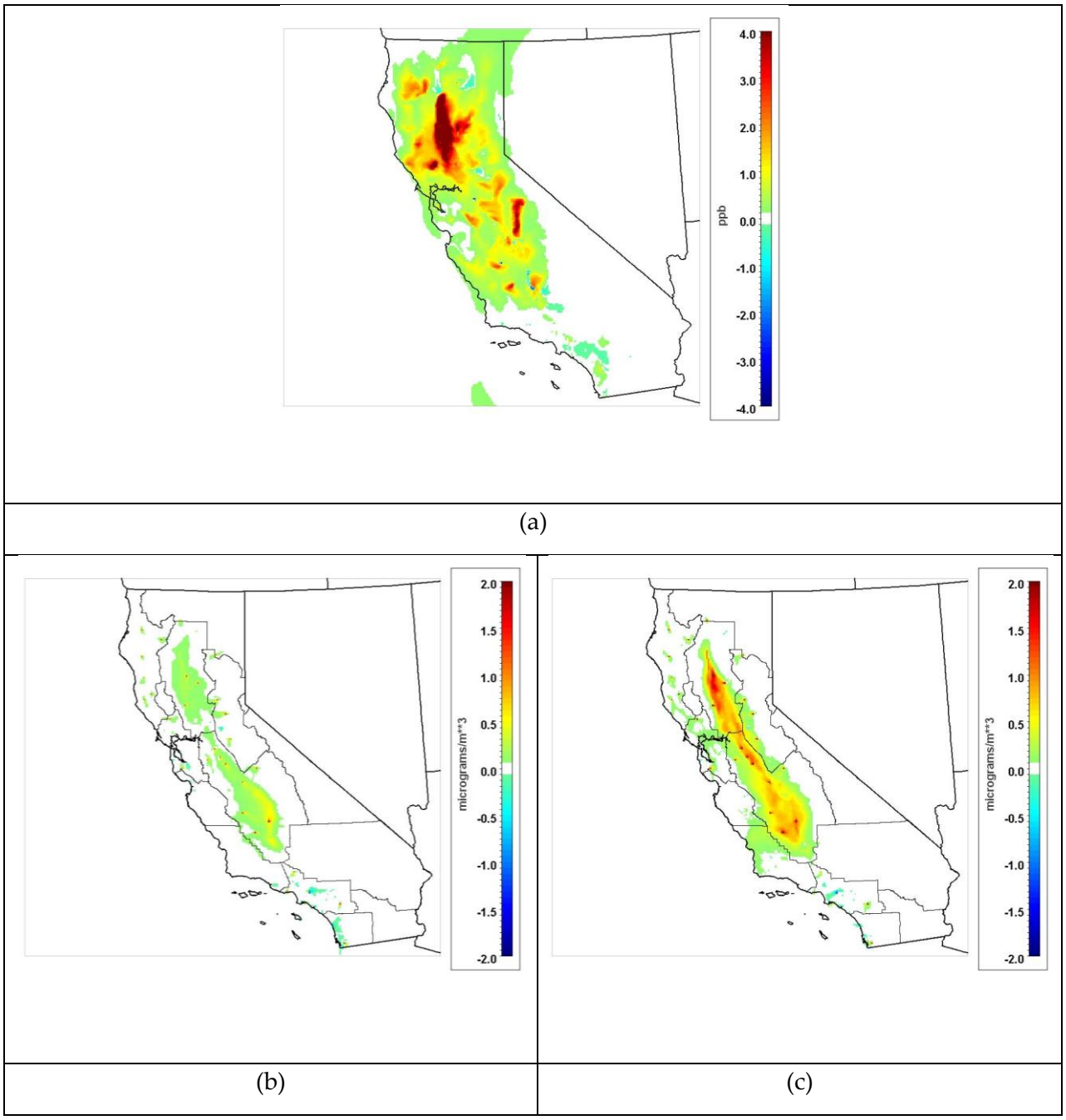
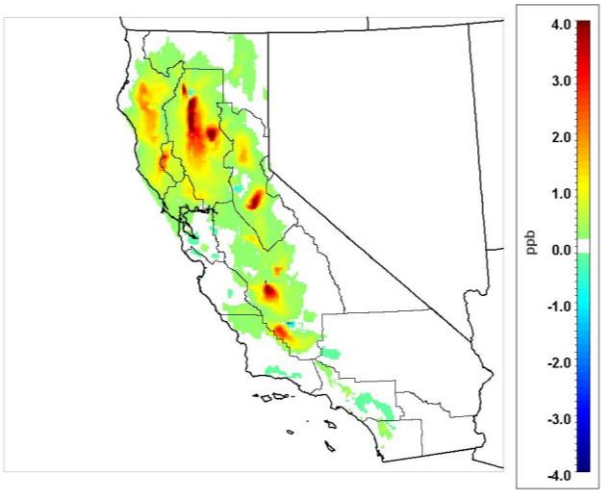
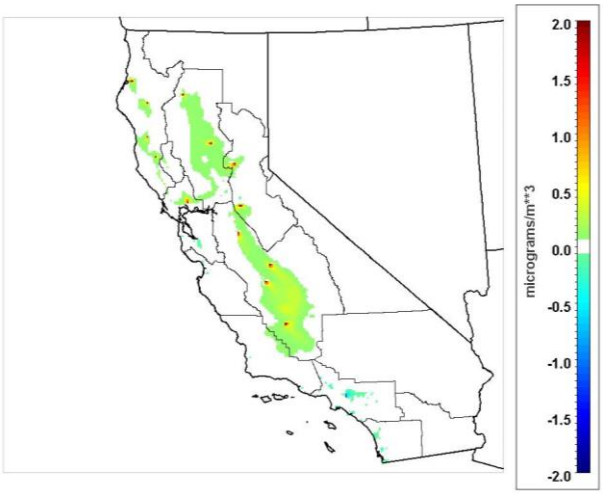


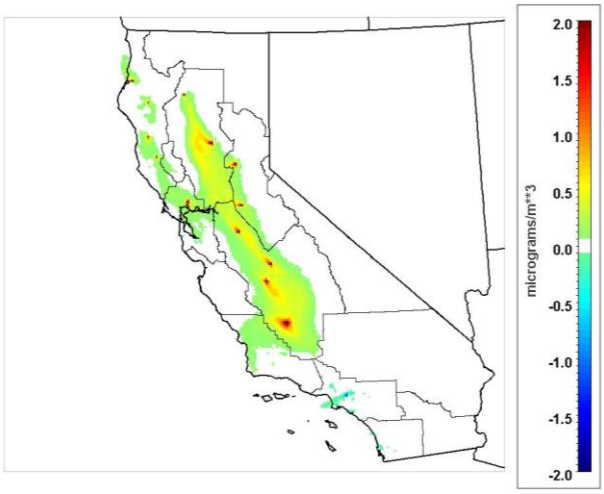
Figure 34: Air Quality Impacts of Scenario 5: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average $PM_{2.5}$ in the Summer, (c) Impact on 24-hour Average $PM_{2.5}$ in the Winter



(a)

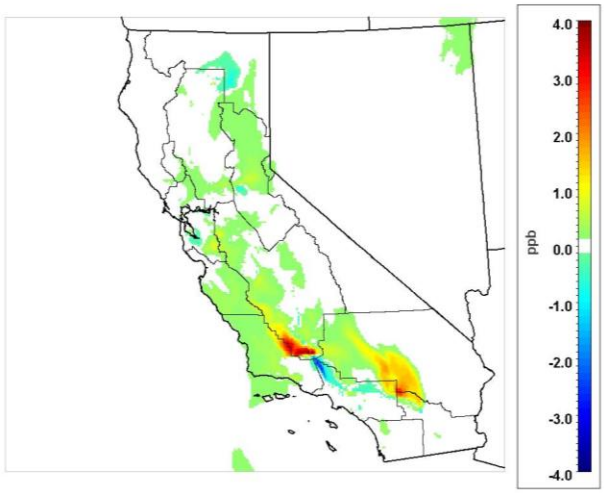


(b)

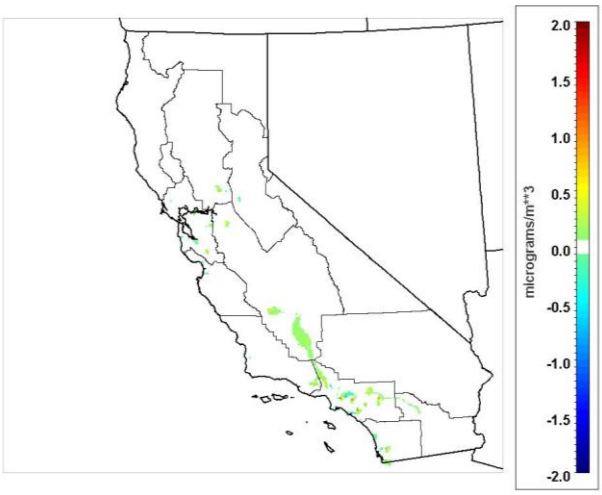


(c)

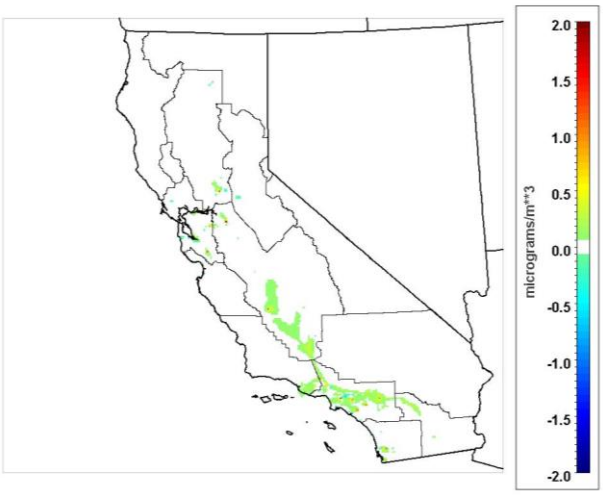
Figure 35: Air Quality Impacts of Scenario 7: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average $PM_{2.5}$ in the Summer, (c) Impact on 24-hour Average $PM_{2.5}$ in the Winter



(a)



(b)



(c)

3.5.2 Economic Analyses

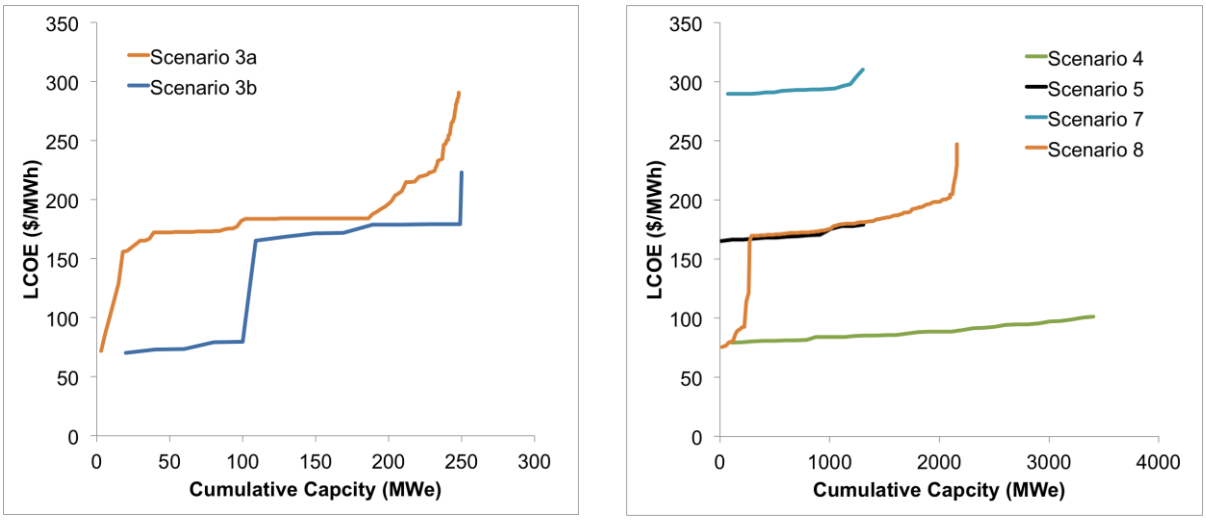
The baseline scenario requires the lowest electricity price for economic operations at $0.06/kWh. The repowering scenario requires an investment of 3.56 billion dollars in order to achieve the emissions reductions and improved efficiency but requires $0.10/kWh more than the baseline in order to pay for the capital investment and higher non-feedstock operational costs. If the BIGCC technology is deployed without being constrained to existing facility sites and capacities, the technology performs better. Scenario 4 gives the lowest selling price for electricity of all the expansion scenarios. This is achieved through large optimally sited facilities that consume most available woody biomass resources. Table 12 summarizes the costs of each scenario.

Table 12: Economic Summary of Biomass Scenarios

	Capacity (MW)	Additional Power from Biomass Facilities (MW)	# of new facilities	Capital (billion $)	Req'd Price ($/kWh)
Scenario 1	670	0	-	-	$0.06
Scenario 2	685	15	27	$3.57	$0.16
Scenario 3a	918	248	122	$1.87	$0.29
Scenario 3b	920	250	14	$1.34	$0.22
Scenario 4 and 6	3,670	3,000	31	$10.64	$0.10
Scenario 5	1,970	1,300	14		$0.18
Scenario 7	1,971	1,301	19	$13.13	$0.31
Scenario 8	2,830	2,160	133	$12.54	$0.25

The scenarios generate an industry design with as many as 133 new facilities. The LCOE for each facility can be plotted against cumulative capacity to give a supply curve for each scenario. These supply curves are instructive to show where constraints in resources have led to high required prices and suggest less ambitious goals in some cases and more ambitious goals in others. Figure 36(a) shows the supply curves generated from scenarios 3a and 3b. A significant fraction of the supply for Scenario 3a is available at costs between $0.15 and $0.20/kWh but that the mandate on the urban subcategory is difficult to fully meet driving costs up to $0.29/kWh. In scenario 3b, the capacity constraint is relaxed from less than 3 MW to less than 20 MW, allowing the urban subcategory to be met more easily and reducing the overall costs. The agricultural subcategory is met completely with small-scale gasifiers with reciprocating engines utilizing orchard/vineyard prunings and food processing wastes. Dairy digesters do not come into the solution unless the price of electricity is at least $0.26/kWh.

Figure 36: Supply Curves for Small-Scale Biopower Scenarios (a) 3a and 3b, (b) 4, 5, 7, 8



(a) (b)

The large-scale biopower scenarios have flatter supply curves than the small-scale biopower scenarios. This reflects low variation in the feedstock costs at the point of generation and the effect of fully exploiting economies of scale. Where the small-scale scenarios had some facilities below the maximum allowable scale the large-scale scenarios mostly maximized facility size. Scenario 4 is the most economic and demonstrates little increase in the expected cost as the industry size increases. Scenario 6 matches Scenario 4 exactly so it is not shown.

CHAPTER 4:
California Biogas Power Generation Assessment

While the analysis for biomass described in Chapter 3 uses the Geospatial Bioenergy System Model to determine the power generation, the economics, and the emissions related to each scenario, the biogas assessment described in this chapter follows a different process. The biogas assessment looks at the current biogas produced in California in landfills and anaerobic digesters from water resource recovery facilities (i.e., wastewater treatment plants, WWTP). The biogas analysis uses separate methods for power generation potential, economics, and air quality impacts for each of the scenarios. The different scenarios look at the additional power generation potential from the amount of biogas produced at landfills and wastewater treatment plants. The economic model uses a modified cost of generation module from the Holistic Grid Resource Integration and Deployment (HiGRID) model, which focuses on the cost of biopower generation from biogas. The air quality impacts from each scenario are analyzed through same air quality model described in the previous chapter.

4.1 Biogas Resources in California

Biogas produced at landfills and WWTP contain a blend of methane and carbon dioxide that can be used to produce power. Currently, 20 percent of the landfills and 12.5 percent of WWTP in California power waste-to-energy projects through biogas. For the landfills and wastewater treatment plants that currently do not have a waste-to-energy project, the unused biogas needs to be collected and discarded either through flaring or another process. However, this renewable resource can be used to increase power production or produce transportation fuel rather than emitting it to the atmosphere.

An inventory was aggregated for the biogas produced within California using databases from the Landfill Methane Outreach Program, the California Biomass Collaborative, the California Water Boards' California Integrated Water Quality System Project, and other agencies. The inventory includes annual amount of biogas produced from landfills and wastewater treatment plants, current available biogas for future projects, and locations of sites.

4.1.1 Landfill Gas Inventory

Municipal Solid Waste generation increased from 88.1 million tons annually in 1960 to 250.4 million tons annually in 2010. Also, waste generation per capita has increased from 2.68 lb/person/day in 1960 to 4.40 lb/person/day in 2010. The amount of municipal solid waste being landfilled has oscillated around 120 million tons annually from 1975 to present due to the combination of different recycling, combustion with energy recovery, and composting projects that have been implemented. Overall, these projects have increased steadily over the decades steadily and reduced the tons of waste discarded into landfills (U.S. Environmental Protection Agency, 2011).

The Environmental Protection Agency (EPA) Landfill Methane Outreach Program (LMOP) creates partnerships between state agencies, energy consumers and producers, the landfill gas industry and communities to promote waste to energy projects for landfills throughout the

United States. LMOP's mission is "to reduce methane emissions by lowering barriers and promoting the development of cost-effective and environmentally beneficial landfill gas (LFG) energy projects" (U.S. Environmental Protection Agency, 2013).

Existing landfill databases were consulted to develop a biogas inventory for the state of California. The main landfill databases consulted are listed below with its respective data

- EPA LMOP: 314 municipal solid waste landfills; 1.35 billon tons of waste in place.
- CalRecycle Solid Waste Information System (SWIS): 240 permitted solid waste landfills; upper bound of 1.6 billon tons in place (actual tonnage unknown because of data gaps).
- California Biomass Collaborative Facilities Database (CBC): 370 solid waste landfills; 1.4 billion tons in place.

The EPA LMOP database was selected as the main source for the inventory based on the following criteria:

- Comprehensive data on current landfill gas to energy projects, project type, MW capacity, start date, shutdown date (if applicable), and emissions reductions.
- Landfills are classified by project status, including operational, construction, shutdown, candidate, and potential.
- The LMOP database has the least amount of missing data on waste in place, year landfill opened, landfill closure year and landfill owner organization.

Table 13 summarizes the number of landfills categorized by project status. If a landfill currently has an operational LFG project, it falls under the operational category even if there are additional projects in construction or has previously shutdown.

Annual waste in place for a landfill was determined by dividing the total amount of waste in place (tons) by the number of years the landfill has been open, as shown below.

$$MSW\ per\ year = \frac{'Waste\ in\ Place'}{2012 - 'YearLandfill\ Opened'}$$

If the landfill closed prior to 2012 and stopped receiving waste, a modified formula was use.

$$MSW\ per\ year = \frac{'Waste\ in\ Place'}{'Landfill\ Closure' - 'YearLandfill\ Opened'}$$

Table 13: EPA LMOP Database Information Summary

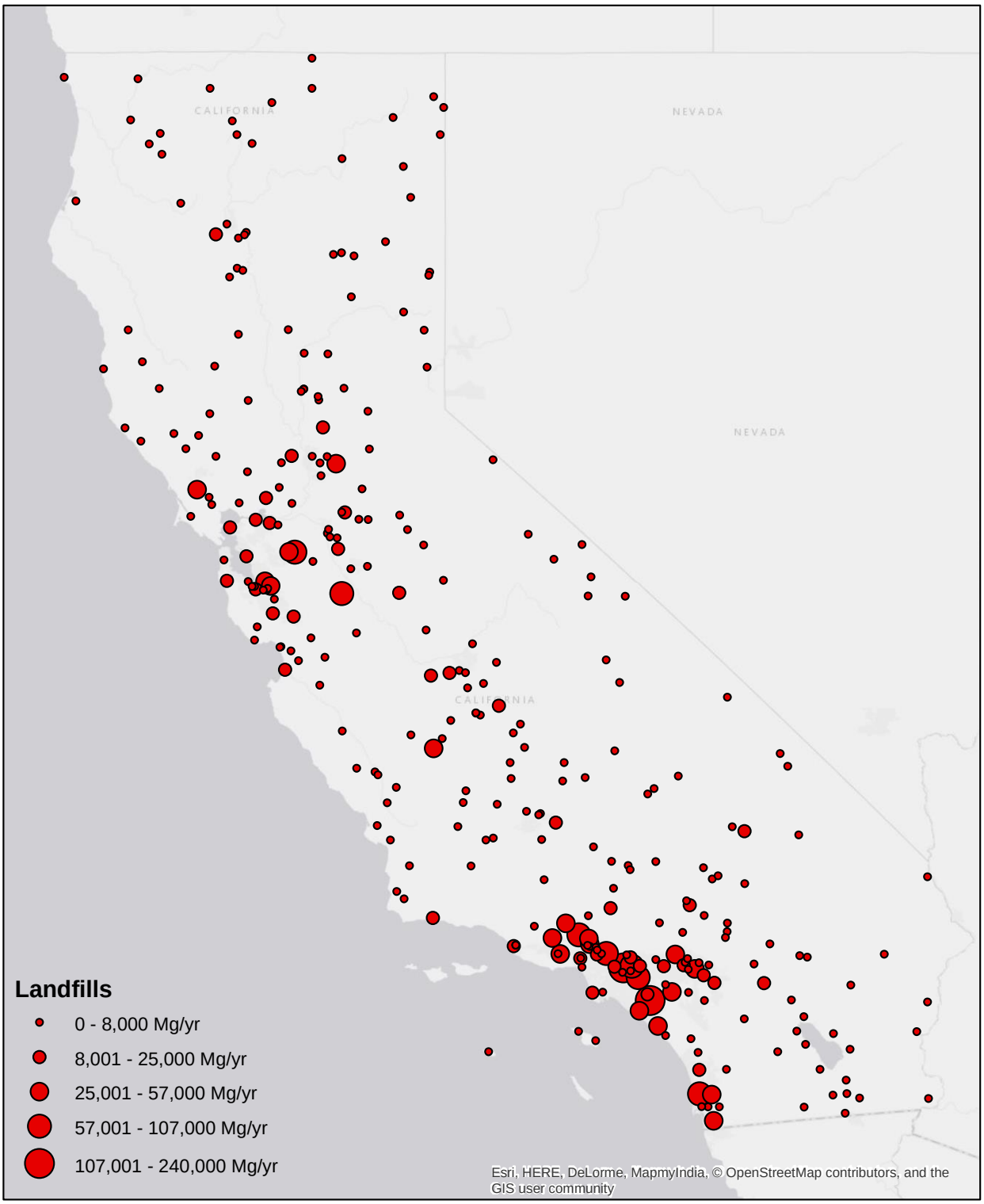
	Number of Landfills	Waste in Place (tons)	Current MW Capacity	Description
Total Operational	65	910, 793, 188	298	Landfill has operational LFG project
Total Construction	5	31, 976, 218	53	Landfill has LFG project in construction
Total Shutdown	14	108, 540, 854	81	Landfill has LFG project that has been shutdown
Total Candidate	32	160, 166, 741	0	Landfill accepting waste or has been closed for ≤ 5 years. Landfill has at least 1,000,000 tons of waste in place and does not have an operational or under-construction project.
Total Potential	198	143, 861, 864	0	Landfill does not meet any of the above criteria
Aggregate Total	314	1, 355, 338, 865		

Source: EPA Landfill Methane Outreach Program 2013

Annual biogas production per landfill was calculated using the EPA Landfill Gas Emissions Model (LandGEM) tool. LandGEM uses the annual waste set in place at a landfill and calculates the annual amount of biogas produced. The average waste set in place per year for each landfill worked as an input for the LandGEM model. The LandGEM model takes into consideration factors like waste composition and the decrease in methane percentage over time as waste anaerobically digests. Appendix A displays the first order decomposition rate equation used within LandGEM and its inputs. Based on the annual waste in place, landfill opening year and landfill closing year, LandGEM outputs the amount of biogas and biomethane produced in megagrams per year (Mg/year) at each landfill.

Figure 37 shows a map of California landfills locations with their respective average methane produced. California produced 2,410,000 Mg in 2013 from landfills based on the data from the LMOP database and LandGEM outputs. However, the LMOP database reports that 352 MW of power is produced from current landfill projects in California. Therefore, the actual potential biomethane available for projects is 1,479,738 Mg/year, which is 60% of the calculated annual biomethane production. This study utilizes the available biomethane per landfill and the information from the LMOP database for each of the scenarios investigated.

Figure 37: California Landfills with Biomethane Production



4.1.2 Anaerobic Digester Gas Inventory

In parallel, WWTP databases were consulted to quantify wastewater flow and determine the biogas produced. Biogas is produced in the anaerobic digesters at wastewater treatment plants. The sludge exiting the WWTP system is piped to the anaerobic digester where a mixture of gases often referred as biogas, which include methane and carbon dioxide, is produced from microorganisms breaking down solids in the absence of oxygen. (Chai Wong, 2011) The two main databases consulted for the production of biogas from WWTP were the California Biomass Collaborative Facilities Database (CBC) and the California Water Board – California Integrated Water Quality System (CIWQS). Table 14 summarizes the data extracted from the databases.

Table 14: WWTP Recorded under CBC and CIWQS Database

CBC Database		CA Integrated Water Quality System	
WWTP with Anaerobic Digesters	140	All WWTP	303
Aggregate Flow (MGD)	2,500	Aggregate Flow (MGD)	3,700
MW capacity	85		

The CBC database includes WWTPs with anaerobic digesters as well as information on gross MW capacity, net MW capacity, cogeneration operations, project status, influent flow, average dry weather flow, power generation technology, and plant location.

A detailed version of the CIWQS data was provided by the California Water Board and includes monthly flow data for all wastewater released in California from 2010 to 2013. Using the data acquired, average million gallons per day (MGD) of influent flow for each wastewater treatment plant was calculated. The CIWQS database average flow rates were selected to calculate biomethane potential since the database includes data on both WWTPs with and without anaerobic digesters. Additionally, the three-year timeframe of the data accounts for intra-annual seasonality and inter-annual variability.

Table 15 shows that the majority of wastewater flow comes from power plants and only 25% of wastewater flow travels to wastewater treatment plants. This project focuses on the 303 wastewater treatment plants from the CIWQS database because of their ability to pipe sludge to anaerobic digesters and produce biogas and biomethane.

Potential biomethane production calculated for the inventory is based on the method outlined in Metcalf and Eddy's "Wastewater Engineering: Treatment and Resource Recovery" (Tchobanoglous, 2014). This method was selected based on available information. The two main formulas shown below were used to calculate biomethane production.

Table 15: Summary of CIWQS Database Influent Flow per Day.

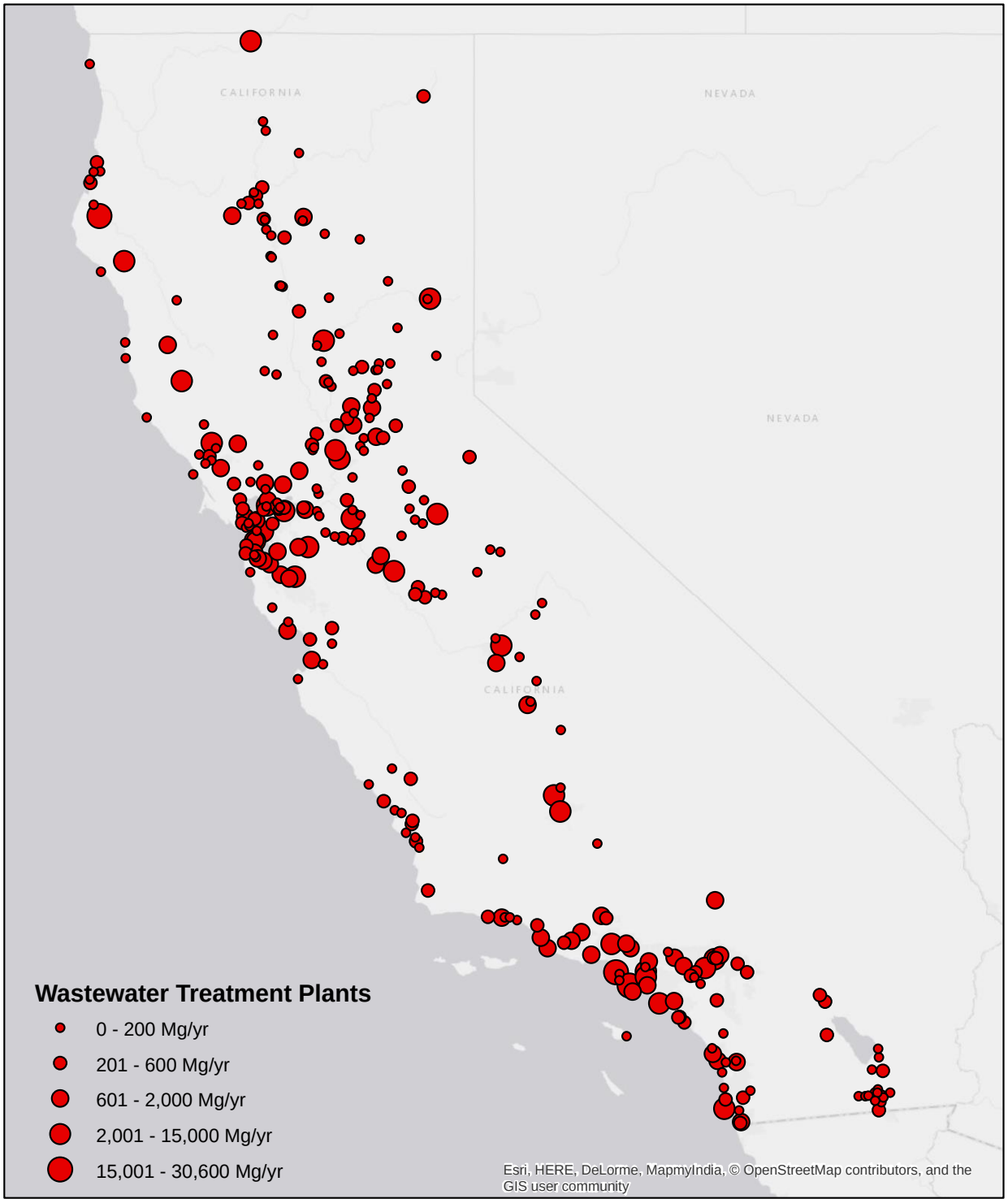
	Number of plants	Total MGD
CIWQS	352	15634
CIWQS WWTP only	303	3771
CIWQS WWTP > 1 MGD	205	3741
CIWQS > 5MGD	119	3542
CBC	140	2552
1MGD < WWTP < 5MGD	86	199

$$V_{CH_4} = (0.35)\left[(S_o - S)(Q)\left(10^{-3}\frac{g}{kg}\right)\right] - 1.42\,P_x$$

$$P_x = \frac{\left[YQ(S_o - S)10^{-3}\frac{g}{kg}\right]}{[1 + k_d(SRT)]}$$

Appendix A includes the inputs and assumptions used in the equations listed above. The calculated volume of biomethane produced per day was converted to megagrams (Mg) of biomethane per year and used for scenario development. In total, the 303 WWTP in the CIWQS database produces 313, 300 Mg of biomethane per year, which is 12.5 percent of the annual biomethane production potential of California landfills. Figure 38 shows the locations of WWTP in California considered in the analysis with the potential biomethane production at each location. However, as in Figure 37, the amount of biomethane shown does not include the usage of biogas currently utilized in projects at the facilities. The biomethane gas available for the projects is 247, 957 Mg of biomethane per year, which is 80 percent of the biomethane produced. The different utilization scenarios use the available biomethane for this study. Appendix A lists the location of landfills and wastewater treatment plants used in the analysis.

Figure 38: Wastewater Treatment Plants in California with Biomethane Production



4.2 Biogas Power Generation and Transportation Fuel Scenarios

Current projects across California landfills and wastewater treatment plants utilize biogas to produce energy, supply heat, or produce transportation fuel. The Sanitation District of Los Angeles County uses the biogas to produce power through steam turbines and reciprocating engines. ("Renewable Energy and Clean Fuels," 2015) Biogas from the Altamont Landfill in Livermore produces 13,000 gallons of liquefied natural gas (LNG) per day from the landfill gas captured ("CASE STUDY: Altamont Landfill and Resource Recovery Facility," 2011). Technologies used to generate power with natural gas can also be used with biogas, such as fuel cells, microturbines, and combined cycles. However, the biogas has to be processed and cleaned as required by the technology used to generate power.

Most often biogas projects use a reciprocating engine either by itself or in a combined heat and power system due to its fuel flexibility. However, a reciprocating engine requires additional emission reduction technologies to be able to meet emission standards. Fuel cells can also be used with biogas to generate power. The Eastern Municipal Water District (EMWD) currently powers a 900 kW fuel cell at the Moreno Valley Water Reclamation Facility with the produced biogas. The power generated from the fuel cell provides 40 percent of the facility's energy requirements ("Eastern Municipal Water District Agengy Profile," 2015). These technologies along with other power generation technologies suitable for biogas were considered when forming utilization scenarios to analyze the best technical and economically feasible scenarios to maximize environmental benefits and power generation. The biogas supply chains considered in this analysis are listed in Table 16.

Table 16: Potential Biogas Supply Chains

Electricity	• Onsite reciprocating combustion • Onsite gas turbine combustion • Onsite fuel cell • Onsite tri-generation • Pipeline injection for central electricity generation
Heat	• Onsite direct-fired boiler • Onsite combined heat and power system • Onsite tri-generation
Transportation	• Onsite CNG production • Onsite Liquefied Natural Gas (LNG) production • Onsite tri-generation • Onsite steam methane reformation (SMR) • Pipeline injection for central CNG, LNG, or SMR

The utilization scenarios adopted for this study are listed in Table 17 and described below. Each scenario adopts a biogas supply chain candidate from Table 16 and establishes an application with the associated additional power, heat, and transportation production based on the available biogas. For example, in Scenario 5, a fuel cell is not installed at a WWTP or land-fill with a capacity less than 1.4 MW.

- Scenario 1: Onsite combined cycle combustion
  Models the usage of the available biogas to fuel an onsite combined cycle system at landfills and wastewater treatment plants. A combined cycle is only considered when sufficient biogas is available to support a 3 MW system. Combined cycle systems are among the most efficient systems since they use the combination of a gas turbine and a steam turbine to generate power. The combined cycle electrical efficiency is assumed to be 50 percent. The biogas from the landfill and wastewater treatment plant needs to be processed before entering the combined cycle system in order to reduce emissions and extend the equipment lifetime. However, additional equipment may need to be installed to be able to meet emissions standards.

Table 17: Utilization Scenarios for Biogas

Scenario	Description
1	Onsite combined cycle combustion
2	Onsite reciprocating engine
3	Onsite reciprocating engine combined heat and power system or onsite combined cycle system if available biogas would support 3 MW of combined cycle capacity
4	Onsite microturbine combined heat and power system or onsite combined cycle system if available biogas would support 3 MW of combined cycle capacity
5	Onsite fuel cell combined heat and power system
6	Onsite fuel cell combined heat and power system or onsite combined cycle system if available biogas would support 3 MW of combined cycle capacity
7	Onsite fuel cell tri-generation system (power, heat, and hydrogen production)
8	Onsite Compressed Natural Gas (CNG) production
9	Onsite Liquefied Natural Gas (LNG) production
10	Pipeline injection of biomethane (Sized for 1 million scfd of available biomethane)
11	Pipeline injection for central CNG production
12	Pipeline injection for combined cycle electricity generation
13	Onsite direct-fired boiler
14	Onsite hydrogen production using steam methane reformation (SMR)
15	Onsite microturbine
16	Onsite gas turbine combustion

- Scenario 2: Onsite reciprocating engine
  Models the usage of the available biogas to fuel a reciprocating engine onsite at landfills and wastewater treatment plants. The installment of a reciprocating engine is considered when sufficient biogas is available to support a 1 MW engine. Installing a combined heat and power (CHP) system with the reciprocating engine can increase the efficiency of the overall system. The installation of a CHP system is considered only at wastewater treatment plants because landfills do not have a direct use for the exhaust heat produced. The electrical efficiency of the reciprocating engine is 32 percent and the heat recovery efficiency of the CHP system is 35 percent. Reciprocating engines have high emissions and need additional emission reducing

equipment in order to meet emission standards, but are the most popular installations for biogas projects because of the fuel flexibility and low cost.

- Scenario 3: Onsite reciprocating engine combined heat/Combined Cycle
  Models the usage of available biogas to fuel either a reciprocating engine or a combined cycle system onsite at landfills and wastewater treatment plants. The combination of these technologies would allow for power generation at higher efficiencies for locations with a higher amount of biogas and can support a 3 MW system. For locations that produce a lower amount of biogas, but can still support a reciprocating engine but not a combined cycle, a 1 MW reciprocating engine is considered. The efficiencies for each system are the same as the ones considered in scenario 1 and 2. A CHP system with the reciprocating engine is considered only at wastewater treatment plants where a reciprocating engine is installed.

- Scenario 4: Onsite microturbine combined heat and power/Combined Cycle
  Models the usage of available biogas to fuel either a microturbine or a combined cycle onsite at landfills and wastewater treatment plants. The combined cycle would be installed where enough biogas is produced to support a 3 MW combined cycle system. The system will have an electrical efficiency of 50 percent. For locations where a combined cycle cannot be supported, a 130 kW microturbine with 29 percent efficiency is considered instead. For wastewater treatment locations a CHP system coupled with a microturbine at a heat-recovery efficiency of 26 percent is considered only at wastewater treatment plants.

- Scenario 5: Onsite fuel cell combined heat and power system
  Models using a fuel cell onsite at landfills and wastewater treatment plants to generate power. Solid oxide fuel cell (SOFC) and molten carbonate fuel cell (MCFC) types allow biogas to be used as the primary fuel due to their fuel flexibility and operation temperatures. The high operating temperatures allow the exhaust heat to be used for fuel reforming and operations. The scenario looks at the application of a 1.4 MW fuel cell performing at a 44 percent electrical efficiency. As in the previous scenarios, the fuel cell is coupled with a CHP system at a heat-recovery efficiency of 24 percent when the location is a wastewater treatment plant, while at landfills only the fuel cell is installed.

- Scenario 6: Onsite fuel cell combined heat and power system/Combined Cycle
  Models using the available biogas to fuel either a fuel cell or a combined cycle onsite at landfills and wastewater treatment plants. The combined cycle will be installed at locations generating enough biogas to support a 3 MW combined cycle system with an electrical efficiency of 50 percent. For locations where not enough biogas is produced to support the combined cycle a 1.4 MW fuel cell with an electrical efficiency of 44 percent is considered. A CHP system coupled with a fuel cell is installed at wastewater treatment plants.

- Scenario 7: Onsite fuel cell tri-generation system
  Models using the biogas to generate power and transportation fuel. The installation is only considered when there is sufficient biogas available to support the capacity of the 1.4 MW fuel cell. For landfill locations the fuel cell generates power at an electrical efficiency of 44 percent and hydrogen fuel onsite at a generation efficiency of 20 percent. At a wastewater treatment plant location, a fuel cell generates power, heat, and hydrogen fuel. The electricity, heat recovery, and hydrogen generation efficiencies are 41, 24, and 20 percent, respectively.

- Scenario 8: Onsite Compressed Natural Gas (CNG) production
  Models using the biogas from landfills and wastewater treatment plants to produce compressed natural gas (CNG) onsite. The biogas is cleaned and upgraded to CNG at the landfill or wastewater treatment plant. Analysis takes into consideration the losses related to the upgrading and compression process while producing CNG at a smaller scale.

- Scenario 9: Onsite Liquefied Natural Gas (LNG) production
  Models using the biogas from landfills and wastewater treatment plants to produce liquefied natural gas (LNG). The biogas is cleaned and upgraded to LNG at the landfill and wastewater treatment locations. The analysis takes into consideration the losses related to upgrading and converting the biogas to LNG at a smaller scale.

- Scenario 10: Pipeline injection of biomethane
  Models using the biogas from landfills and wastewater treatment plants and upgrading it to pipeline standards for use mostly in residential areas. The scenario analysis takes into consideration the transportation and upgrading losses of producing renewable natural gas.

- Scenario 11: Pipeline injection for central CNG production
  Models using the biogas from landfills and wastewater treatment plants to produce CNG at centralized plants. The scenario consists of cleaning and upgrading the biogas to pipeline quality and injecting it to the California natural gas pipeline to have an end-use of producing CNG at centralized plants. Before injecting the renewable natural gas into the pipeline, the biogas is cleaned and upgraded to meet pipeline quality standards. The analysis considers the losses of methane from the production and transportation of the renewable natural gas to the centralized plants as well as the higher efficiency of CNG production at centralized plants.

- Scenario 12: Pipeline injection for combined cycle electricity generation
  Models using the biogas from landfills and wastewater treatment to produce electricity at a central plant. The scenario considers cleaning and upgrading the biogas to meet pipeline standards and injecting the renewable natural gas to the natural gas pipeline. The end-use of the injected renewable natural gas is producing electricity at a centralized natural gas power plant. The analysis factors the losses related to the upgrading and the transportation of the renewable natural gas to the

natural gas pipeline. The electricity production from a natural gas plant performs more efficiently than if it were produced at a smaller scale.

- Scenario 13: Onsite direct-fired boiler
  Models using biogas from landfills and wastewater treatment plants to generate heat onsite using a direct-fired boiler. The boiler operates at an efficiency of 71 percent. The heat produced can be used to provide heat to the anaerobic digester in wastewater treatment plants or other industrial processes.

- Scenario 14: Onsite hydrogen production using steam methane reformation
  Models using the biogas from landfills and wastewater treatment plants to produce hydrogen fuel onsite for vehicles. The hydrogen is produced through steam methane reformation. The process includes the cleaning and processing of the methane to produce hydrogen fuel. The scenario assumes the hydrogen production occurs at the landfills and wastewater treatment locations. The hydrogen produced would support a fueling station for hydrogen fuel cell vehicles.

- Scenario 15: Onsite microturbine
  Models using the biogas from landfills and wastewater treatment plants to generate power through a microturbine. A 130 kW microturbine with an electrical efficiency of 29 percent generates power at landfills. A CHP system with a heat recovery efficiency of 26 percent is installed with a microturbine at wastewater treatment plant locations. The microturbine installment is considered only when there is enough biogas to support a 130 kW microturbine.

- Scenario 16: Onsite gas turbine combustion
  Models using the biogas from the landfills and wastewater treatment plants to power a 5.5 MW gas turbine. The gas turbine would only be installed when there is sufficient biogas produced to support the capacity of the gas turbine. The gas turbine operates with an electrical efficiency of 30 percent. Only power is generated at the landfill locations, while at wastewater treatment plants the gas turbine is coupled with a CHP system at a heat recovery efficiency of 35 percent to provide both heat and power. Due to the high emissions of gas turbines, emission reduction technology would need to be added in order to meet emission standards.

As noted from the scenario descriptions, any heat exhaust from the power generation is not captured at landfills. Landfills typically do not have the ability to process heat; therefore, exhaust heat from the technology installed is vented to the atmosphere rather than being collected and used in another process. Some projects exist where heat produced at landfills from power generation supplies heat to adjoining locations. However, all the scenarios studied assume heat to be a by-product for landfill locations. In the case of wastewater treatment plants, the heat produced can be used to supply heat to the anaerobic digesters or other processes within the plant; therefore, heat generation is considered in the analysis.

Each utilization scenario looks at the methane amount recovered from the biogas as the starting point. The amount of power, heat, and transportation fuel produced is based on the annual

methane available from the landfills and wastewater treatment plants. Related efficiency factors, conversion losses, and leakages are included in the analysis to determine the amount of power, heat, and transportation fuel generated.

The utilization scenarios are designed to provide insight into the biopower capacity available from biogas produced in landfills and wastewater treatment plants. Biopower results are shown alongside the economic and air quality modeling results in Section 4.5.

4.3 Economic Model

The Biopower Economic Module calculates the levelized cost of energy ("LCOE") for the biogas supply chains shown in Table 16 and for the utilization scenarios in Table 17, which consist of these supply chains alone or in combination.

4.3.1 Methodology

The Biopower Economic Module calculates the LCOE for each WWTP and LFG facility in California for each of the utilization scenarios shown in Table 17. The starting point for each LCOE calculation is the annual amount of available biomethane remaining at each facility after existing equipment at that facility has been fully utilized. For each facility and utilization scenario, the heat rate of the primary equipment determines the amount of megawatts (MW) of capacity the equipment could support based on the available biomethane. The total MW of supportable capacity determines the number of full-load units of the primary equipment and the fractional capacity supported by one marginal unit. The LCOE of a full-load unit is calculated based on the default cost and operating values for the primary equipment. These default values used to calculate the LCOE of a full-load unit are contained in a main matrix, the "G Matrix", of the module and may be changed by the user either directly within the matrix or by over-writing them within the Biopower Module code. Appendix B shows the default values within the main matrix for each piece of equipment included in the HiGRID Biopower Module.

The fractional capacity supportable by the one marginal unit establishes the capacity factor of the marginal unit used to calculate the LCOE for the marginal unit. If the fractional capacity is less than the threshold percent as specified by the user, no marginal unit is installed. The default threshold percent is 50 percent, but this can be changed within the Biopower Module code. If a facility's available biomethane is not enough to support even one piece of equipment at a 50 percent load factor, no equipment will be installed at that facility for the utilization scenario. In the case when considering that all of the biomethane is used at each WWTP and LFG facility, co-firing of natural gas needs to be considered. Within the model an on-off toggle is available to enable co-firing with natural gas. Natural gas makes up the balance of the fuel required to make the capacity factor of the marginal unit equal to the default capacity factor of a full-load unit. The module includes heat recovery units for WWTPs for combined heat and power configurations while LFG facilities do not. To calculate the weighted average LCOE for each scenario, the number of full-load units is multiplied by the LCOE of each full-load unit and added to the LCOE of the marginal unit. Afterwards, the resultant total LCOE "cost" is divided by the lifetime production of all units and all equipment.

4.3.1.1 Biogas Cleanup Costs

The default variable operating and maintenance (VOM) costs in the main matrix for each piece of equipment increases to reflect different levels of biogas cleanup required for each piece of equipment. The Biopower Module includes two levels of biogas cleanup. The first level cleans the biogas for use in engines, and the second level is for upgrading the biogas to pipeline quality for use in CNG, LNG, and SMR production and for pipeline injection. The costs associated with the two levels of biogas cleanup are as follows:

- The cost of biogas cleanup for use in engines is specified by the user. The biogas cleanup costs are set at $1.764/MMBtu (HHV) for WWTPs and at $1.56/MMBtu (HHV) for LFG facilities.
- The cost of upgrading biogas to pipeline quality is based on a multiple of the cost of biogas cleanup. The multiplier is set at 1.33 for WWTPs and at 1.25 for LFG facilities.
- The cost of biogas cleanup for use in fuel cells is assumed to be 1.33 times greater than the cost of biogas cleanup for use in engines. This multiplier is specified by the user and reflects the fact that the electrochemical process used by the molten carbonate fuel cell or the solid oxide fuel cell is more sensitive to contaminants than a combustion engine.

4.3.1.2 Selective Catalytic Reduction Costs

To meet California air quality regulations, it is often necessary to add selective catalytic reduction (SCR) equipment to combustion engines. The Biopower Module adds $75/kW in capacity costs and $3.80/MWh in VOM costs for reciprocating engines, microturbines, gas turbines, and combined cycle equipment to reflect the costs of the required SCR equipment and its impact on operating costs.

4.3.1.3 Calculation of Utilization Scenario LCOE Values

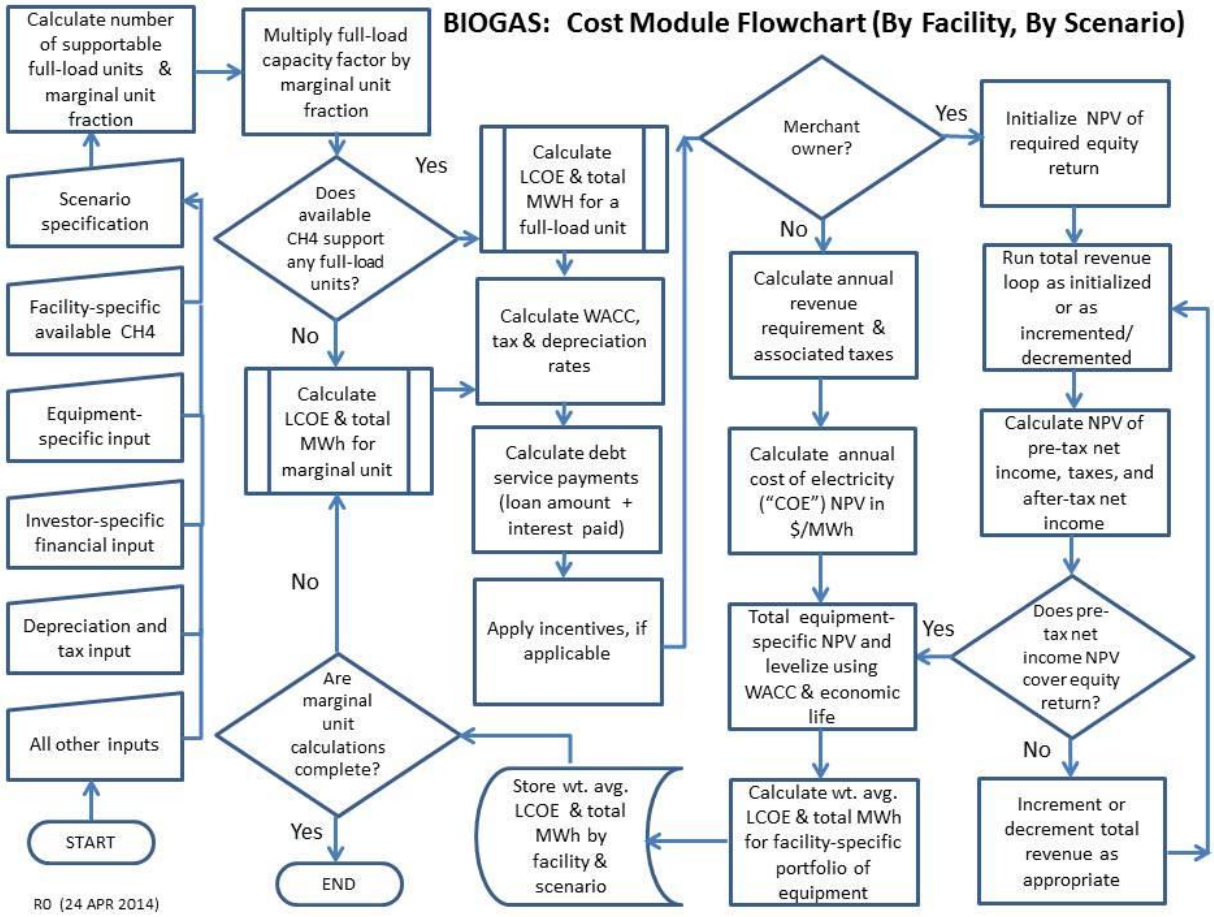
All LCOE calculations are performed using a discounted cash flow model that calculates the LCOE based on a lifetime analysis of the portfolio of equipment associated with each biogas supply chain or utilization scenario. The default cost, financial, and operating parameters associated with each piece of equipment in the portfolio include energy penalties and losses associated with operating each piece of equipment.

The LCOE for each full-load unit of equipment is calculated using the cost, financial, and operating parameters associated with that piece of equipment. These LCOE values are common to all utilization scenarios that include full-load units of that equipment. The LCOE for each marginal unit of that same equipment is calculated based on parameters specific to each facility and each utilization scenario. Standard conversion factors are used to convert all units to equivalent megawatts ("MW") and megawatt-hours ("MWh") prior to the LCOE calculations being performed.

There is no analysis of the upstream costs associated with the production of the available biomethane at each facility since the biogas would typically be vented. Figure 39 illustrates how the characteristics for the full-load units and the marginal unit of each piece of equipment

included in each utilization scenario flow through the model to calculate the weighted average LCOE for each utilization scenario.

Figure 39: Economic Model Flowchart



4.3.1.4 Output of Results

The Biopower Module output consists of a series of matrices that contain facility-by-facility results by utilization scenario. This output can be used to inform other parts of the biogas project (e.g., air quality modeling) by identifying the incremental LCOE cost associated with choosing one utilization scenario over another for any given WWTP or LFG facility. Additionally, the LCOE associated with each scenario looks at the average LCOE.

The Biopower Module produces the following results for each facility for each utilization scenario:

- Identification of the primary equipment
- Number of full-load units
- Lifetime units of fuel used by each full-load unit
- Lifetime units of production of each full-load unit

- LCOE of each full-load unit
- Capacity factor of the marginal unit
- Lifetime units of fuel used by the marginal unit
- Lifetime units of production of the marginal unit
- LCOE of the marginal unit
- Total lifetime units of production for all units
- Total lifetime MMBtu of fuel used by all units
- Weighted average LCOE for all units (i.e., full-load units plus the marginal unit). The weighted average LCOEs are reported (in $/MWh) for each facility and each utilization scenario
- Total capital expenditure required for all units installed in millions

The economic results from the biopower module are shown in Section 4.5 along with the results of the power generation and the air quality effects. The economics will give insight into the economic feasibility of each biopower scenario studied.

4.4 Emissions

Emissions released into the atmosphere and the effects they cause on air quality must be considered when planning for new power installations. Emissions produced from power generation technology are dependent on various factors like fuel composition, the technology used for the energy production, and the efficiency of the technology. The fuel considered is biogas and it is assumed that the composition of the fuel resembles that of the natural gas mix. The biogas has been processed so that biogas has a low concentration of carbon dioxide while methane concentration is high. Emissions were calculated through the use of emission factors established by the EPA technology characterization catalog and emission factors for air pollutants under AP-42 (EPA, 2015). Table 18 shows the emission factors applied to the estimated energy production based on the available gas at landfills and wastewater treatment plants. These emission factors are used for the scenarios that are producing power onsite and are applied to each location to determine the amount of emission developed onsite for the power produced.

Table 18: Emission Factors for Technologies Used in Scenarios

	Emissions Factors [lb/MWh]				
Technology	**PM**	**NOx**	**SOx**	**CO**	**VOC**
Reciprocating Engine	0.000263	0.070	0.002	0.200	0.100
Microturbine	0.005780	0.060	0.003	0.060	0.020
Fuel Cell	0.000020	0.010	0.000	0.020	0.020
Combined cycle	0.035000	0.083	0.013	0.102	0.049
Gas Turbine	0.078000	0.477	0.153	1.500	0.044
Direct-Fired Boiler	0.025400	0.334	0.002	0.281	0.018

For the transportation fuel cases, onsite emissions to produce transportation fuels are assumed to be low and have low to no effect on air quality with the exception of hydrogen production through steam methane reformation. Emissions per kilogram of hydrogen produced onsite are shown in Table 19.

Table 19: Emissions from Onsite Hydrogen Production

	PM	**NOx**	**SOx**	**CO**	**VOC**
Steam Methane Reformation	.022 g/kg H_2	.8979 g/kg H_2	0 g/kg H_2	.0798 g/kg H_2	0 g/kg H_2

Source: (Spath & Mann, 2001)

However, tailpipe emissions must be considered when looking at the effects on air quality when increasing the vehicle miles traveled of alternative fuel vehicles. Emissions in these scenarios are accounted by considering the vehicle miles traveled that CNG, LNG or hydrogen vehicles are replacing light duty gasoline vehicles. Emissions related to transportation are reduced assuming a certain percentage of the miles traveled are powered by renewable fuels. Table 20 shows the percentage of miles driven based on the amount of alternative fuel recovered from biogas. The percentage change shows the change in miles driven from light duty gas vehicles to those of one powered by either hydrogen, CNG or LNG.

Table 20: Percentage of Annual Miles Driven by Alternative Fuel

Utilization Scenario	Description	Landfills	WWTP	Total
7	Trigeneration	3.12 %	0.486 %	3.606 %
8	CNG Production	6.07 %	1.24 %	7.31 %
9	LNG Production	5.91 %	1.22 %	7.13 %
11	Pipeline Injection for Central CNG Production	5.98 %	1.22 %	7.2 %
14	Hydrogen by SMR	18 %	2.53 %	20.53 %

Figure 40 through Figure 44 show the emissions related to producing power on the landfills and wastewater treatment sites. From the figures it can be seen that the scenarios producing the least amount of emissions are those where only fuel cells are installed to produce power. Comparing scenarios where either a combined cycle or another technology is installed to the scenarios where only that technology is installed shows that combined cycle plants produce higher emissions. However, combined cycle plants work at higher efficiencies than the rest of the technologies considered and are able to produce more power. The emissions presented in these figures are spatially resolved and used in the air quality model described in the previous chapter to analyze their effects throughout California.

Figure 40: PM Emissions of Onsite Power Production Scenarios

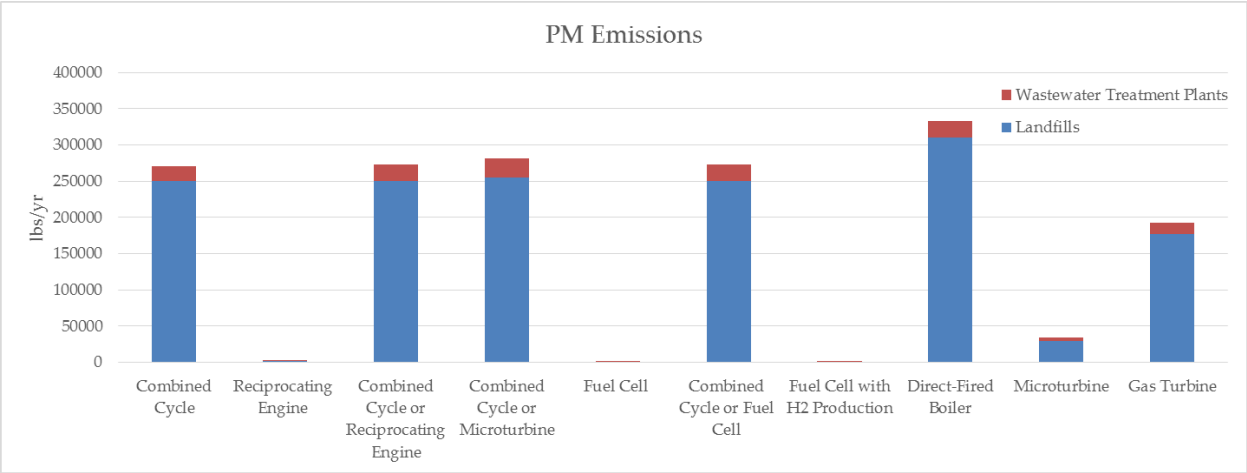


Figure 41: NO_x Emissions of Onsite Power Production

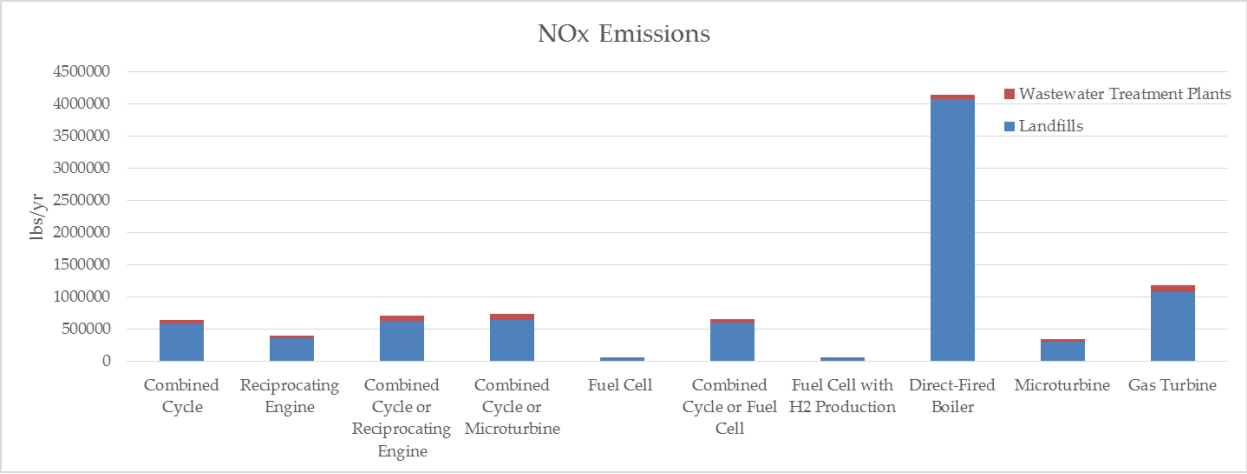


Figure 42: SO_x Emissions of Onsite Power Production

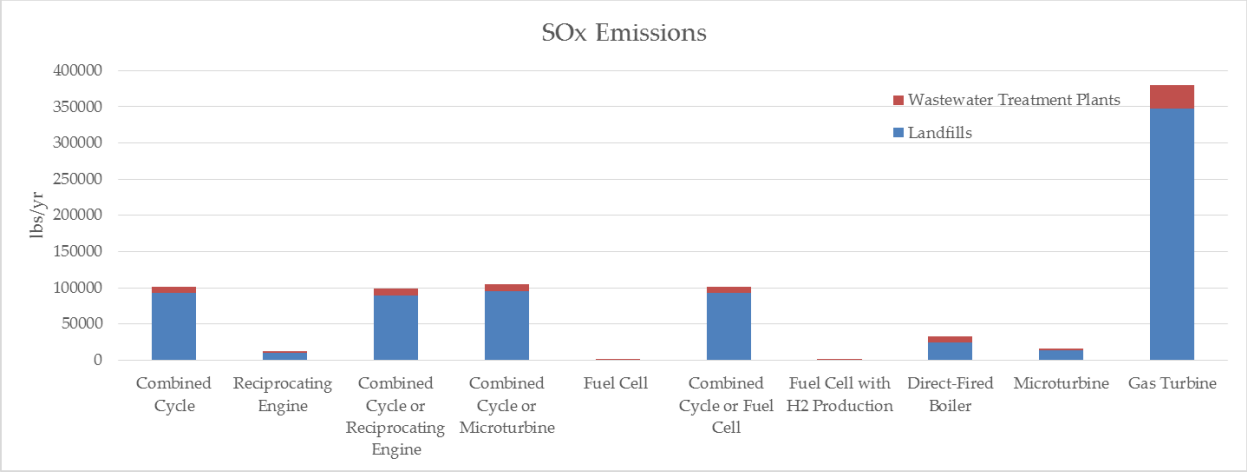


Figure 43: CO Emissions of Onsite Power Production

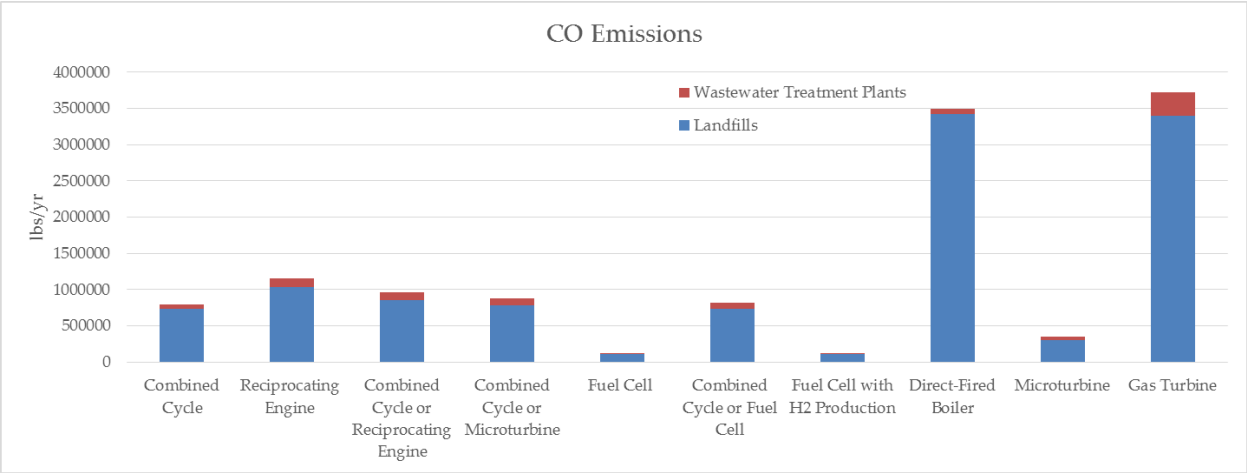
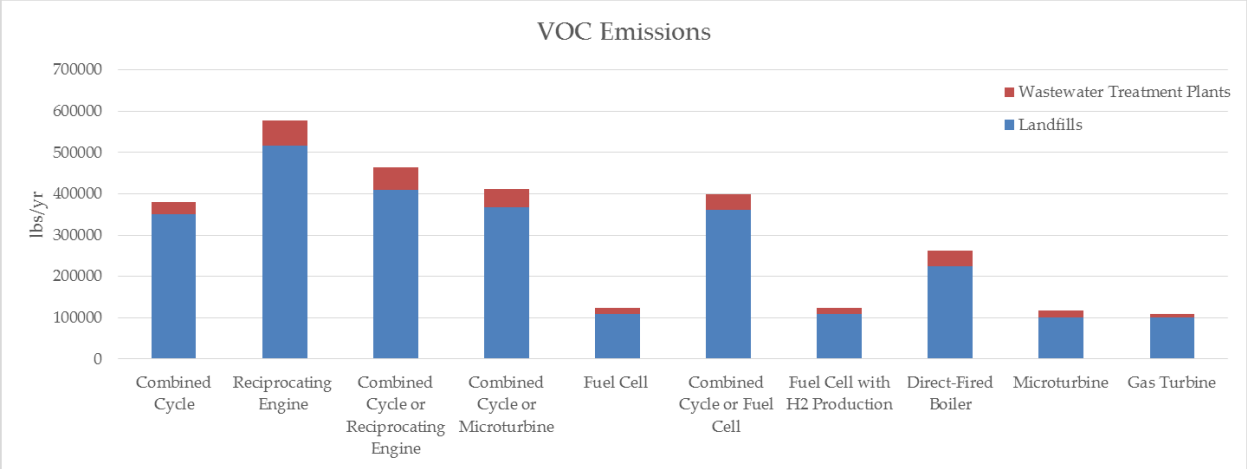


Figure 44: VOC Emissions of Onsite Power Production



4.4.1 Greenhouse Gases

Methane is the second most abundant greenhouse gas (GHG) in the atmosphere and lives in the atmosphere for about 20 years. Methane resides in the atmosphere for a shorter amount of time than carbon dioxide; however methane traps radiation from the atmosphere more efficiently and has greater global warming potential than carbon dioxide. To reduce greenhouse gas emissions, landfills and wastewater treatment plants collect the methane produced and destroy it mainly through flaring if it is not used for waste-to-energy projects.

Over the course of time the CO_2 and methane from biological waste in landfills and wastewater treatment plants is naturally released into the atmosphere. Harvesting methane produced from waste sites and using it to generate power or transportation fuel can offset the GHG emissions from energy fossil fueled plants or transportation fuels derived from fossil fuels. Producing CNG and LNG from anaerobic digester gas has lower well-to-wheel greenhouse gas emissions than transportation fuel derived from fossil reserves (Han, Mintz, & Wang, 2011).

The GHG emissions related to onsite power generation consist on the combustion of the collected methane. Since there is no additional collection or transportation of the methane produced at landfills and WWTP, there are no additional GHG emissions from collection of biogas. The emissions considered are those related to the production of power from the additional equipment installed at landfill and WWTP. Figure 45 and Figure 46 show the emissions of GHG in megagrams of CO2 equivalent (Mg CO2eq) from the additional power generation at landfills and wastewater treatment plants, respectively. These positive emissions are related to the generated emissions onsite, while the negative emissions shown in blue are the savings from the power produced that would be displaced by the California power mix. Using the current GHG emission factor from the Emissions & Generation Resource Integrated Database (eGRID) and the amount of electricity produced per scenario gives the emission saving from the biopower produced. For California, eGRID shows that 613 lb CO2 eq/ MWh (eGRID 2015). The GHG emissions are related to the amount of power generated, so scenarios

generating more power also exhibit more GHG emissions. For both landfills and WWTPs, power generation from the installation of gas turbines produces the lowest amount of GHG emissions onsite.

Figure 45: GHG Emissions for Additional Onsite Power Generation at Landfills

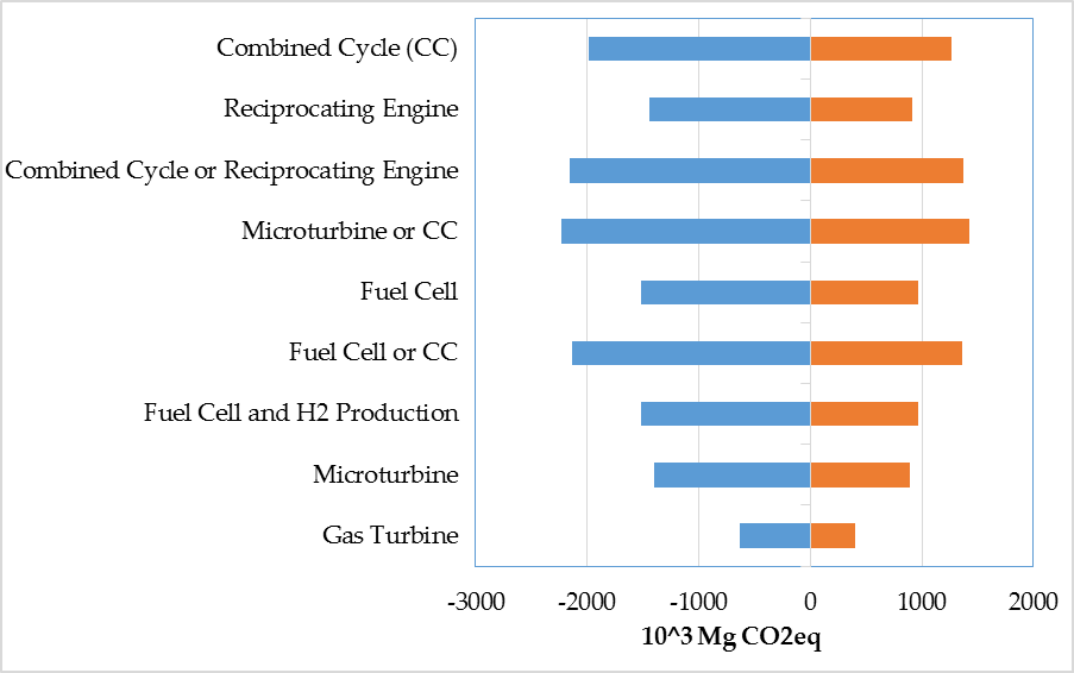
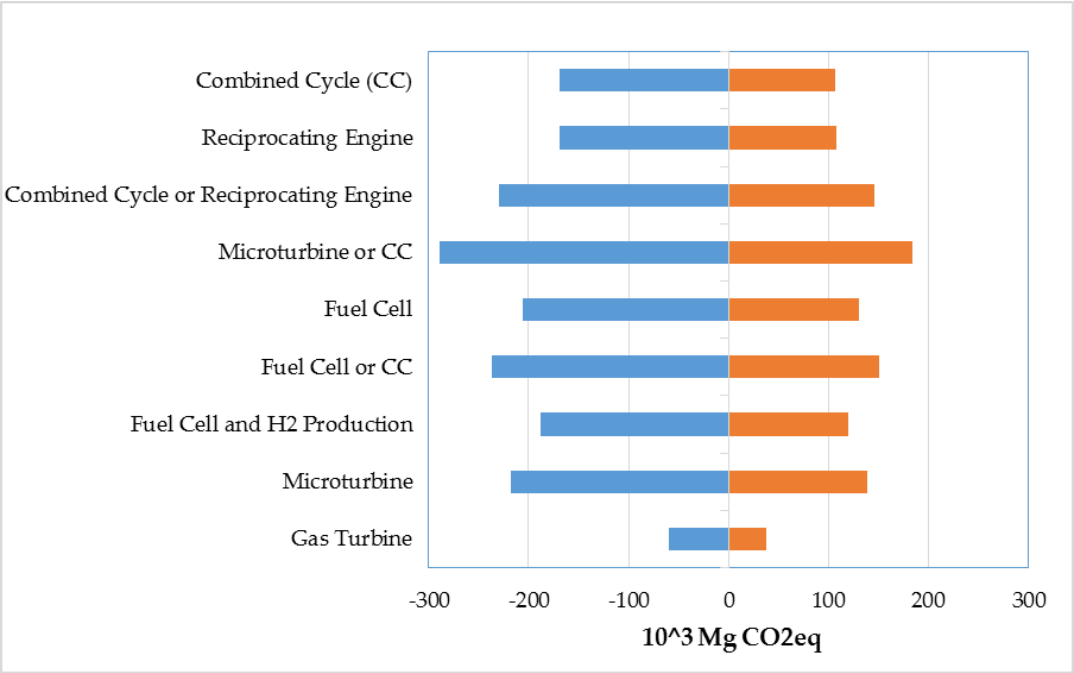


Figure 46: GHG Emissions from Additional Onsite Power Generation at WWTP



4.5 Results

4.5.1 Biopower

Table 21 summarizes the results of the power, heat and transportation fuel generation results for each scenario. Scenarios 10 and 12, which consider the production of renewable natural gas and injection to the natural gas pipeline, produce the greatest amount of power. Scenarios 10 and 12 consider the available biogas from the sites to be processed and conditioned to meet natural gas pipeline standards and injected into the natural gas pipeline to be used as renewable natural gas. Since conversion efficiencies increase when converting biogas to either power or transportation fuel at centralized facilities there is a higher yield. Scenario 4 produces the greatest amount of power when focusing on generating power at each landfill and WWTP. This scenario considers the available biogas for the installation of a combine cycle or microturbine. In this scenario, combined cycles are installed in sites where 3 MW combined cycle systems can be supported and for the rest of the sites microturbines are installed. Figure 47 and Figure 48 shows the net GHG emissions savings from landfills and WWTP, respectively. These figures show that using biogas to generate power causes an overall GHG reduction than if the power where to be generated from the California power mix and supplied to the grid. The using a combined cycle to generate power increases the amount of electricity available and therefore increases the amount of GHG savings.

Figure 47: Net GHG Emissions from Onsite Power Generation at Landfills

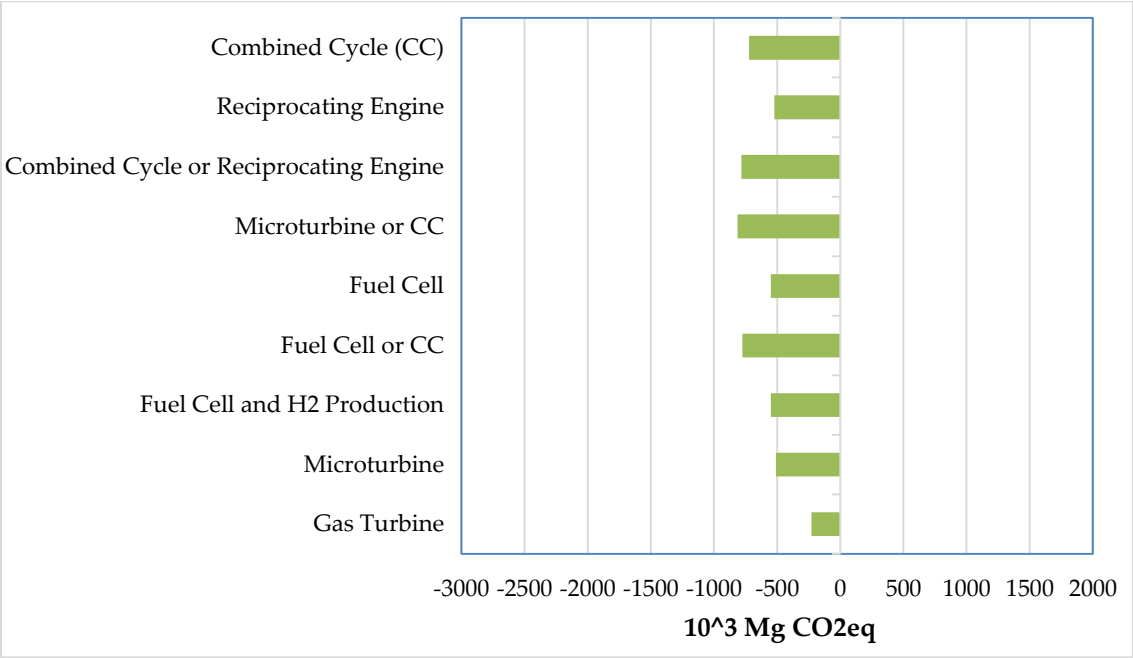
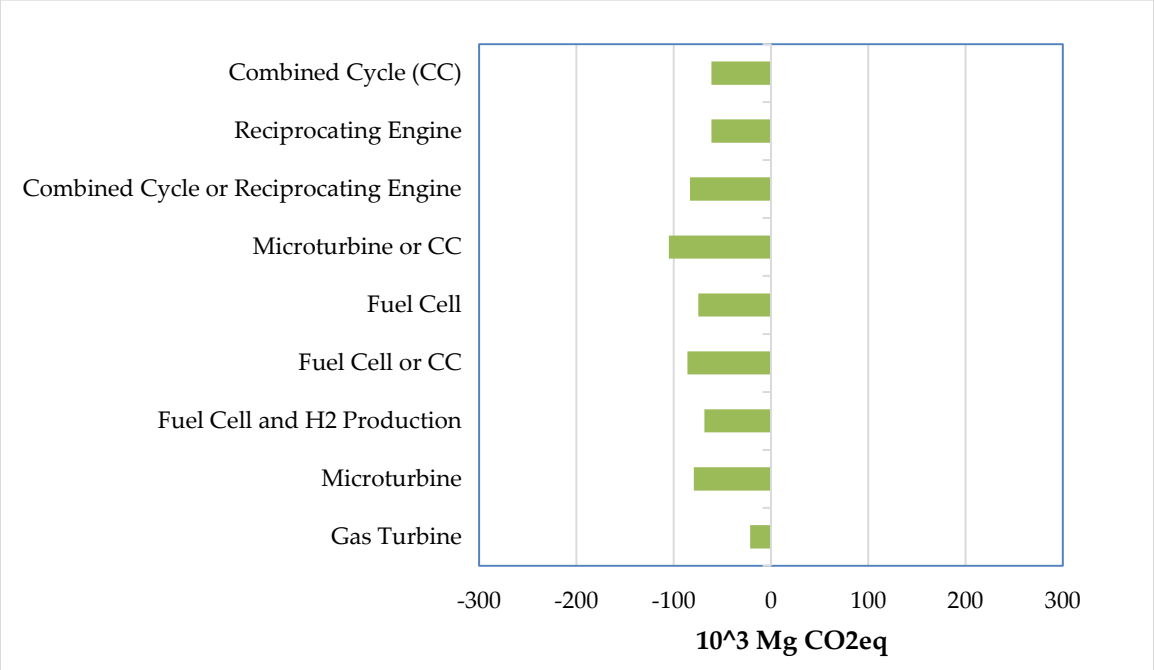


Figure 48: Net GHG Emissions from Additional Onsite Power Generation at WWTP



As for the production of transportation fuel, producing compressed natural gas (CNG) onsite rather than producing at a central plant shows to be more efficient. The decrease in loses when generating onsite allows for a greater yield in distributed CNG. Additionally, utilizing the biogas to produce CNG rather than LNG or Hydrogen fuel generates more transportation fuel on a per mas basis. However, the emissions from CNG fuel production and vehicle utilization has greater impacts then if Hydrogen fuel where produced. The increase in emissions is concerned with the tailpipe emissions from CNG vehicles, which hydrogen fuel cell vehicles do not have.

Table 21: Summary of Power, Heat, and Transportation Fuel Generation from Biogas

Scenario	Landfills				Wastewater Treatment Plants				
	Additional MW capacity	CNG (Mg)	LNG (Mg)	H2 (Mg)	Additional MW capacity	Heat (MW) capacity	CNG (Mg)	LNG (Mg)	H2 (Mg)
1	815				69				
2	590				69	76			
3	883				101	27			
4	917				132	45			
5	621				85	46			
6	875				104	16			
7	687			*105024*	78	34			16348
8		*932300*					189685		
9			*862341*					178013	
10	923				184				
11		*918317*					186839		
12	923				171				
13	579				94				
14				*606428*					85253
15	575				90	44			
16	258				24	28			

4.5.2 Economic Results

The economic model was run for all of the utilization scenarios using both anaerobic digester gas from WWTP and landfill gas. The model simulated the economics at each landfill or WWTP in the state and the cost related to the installation of new equipment at each site. An example of the full results for each WWTP is shown in Figure 49 for utilization scenario 1. In general, the LCOE increases as the potential biogas availability decreases. This is the result of a decrease in the capacity factor of the marginal unit, which can also be observed in Figure 49. The left panel shows the total WWTP facilities, which are a total of 304, with their respective LCOE. The facilities are numbered so that facility 1 has the largest amount of available biogas and facility 304 has the smallest or amount of available biogas. Therefore, for facilities that do not have enough biogas to support the technology there is no LCOE since it is not considered in the analysis. In Figure 49 these correspond to the facilities numbered 30 or higher. The right panel shows a zoomed in version of the left panel, which focuses on the locations where enough biogas supports a 3 MW combined cycle. The right panel displays that as the amount of full load units installed increases the LCOE for the facility decreases.

Figure 49: Utilization Scenario 1 – 3 MW Combined Cycle WWTPs

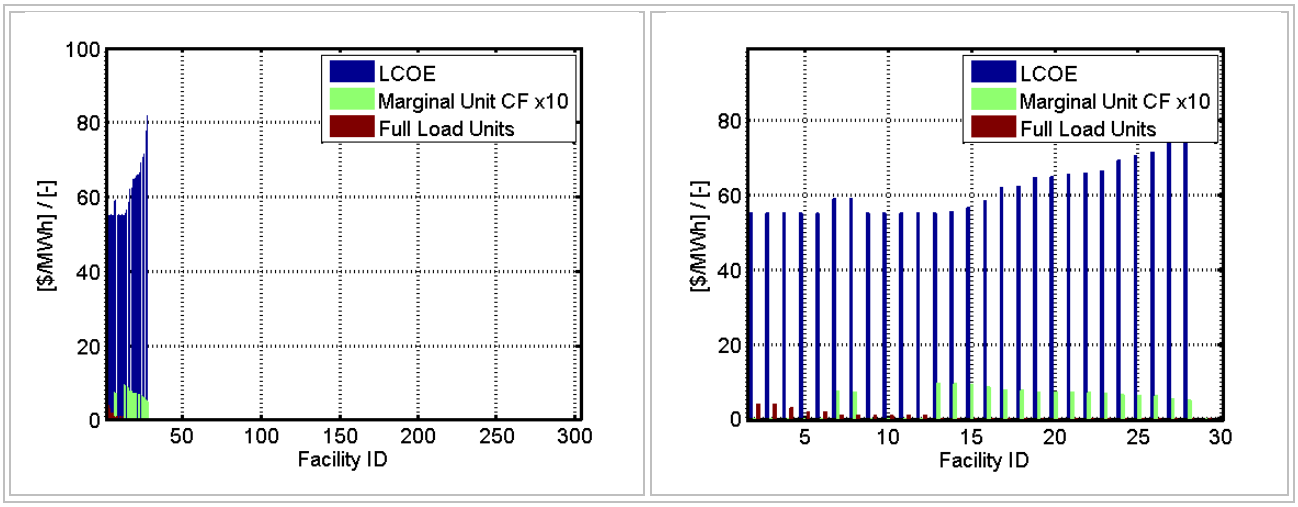


Figure 50 shows the overall LCOE for all the power generation utilization scenarios for the WWTPs with no co-firing and no attribution of cost to the biogas. The lowest cost power generation utilization scenario is the scenario where smaller WWTPs install 1 MW reciprocating engines and large WWTPs install 3 MW combined cycles. This results from combining the low installed cost combined cycles that are too large for many WWTPs with the reciprocating engines that allow utilization of more biogas at the smaller WWTPs. It is interesting to note that including CHP or hydrogen co-production decreases the LCOE of a facility. The increase of utilization per biogas available allows for the cost reduction since more energy is utilized for the same amount of equipment as shown by comparing the 1.4 MW FC case with the 1.4MW FC Tri-generation case. Figure 51 shows the results for the pipeline injection and hydrogen utilization scenarios at WWTPs with no co-firing and no attributed biogas cost. The figure shows the most cost effective scenario for biogas utilization at WWTPs to be the production of CNG fuel onsite. Figure 52 and Figure 53 show results for the utilization scenarios for landfills with no co-firing and no attribution of cost to the biogas. Comparing the results from the landfill gas to the WWTP biogas shows that utilization scenarios at landfills have lower LCOE than the WWTP utilization scenarios. As with the WWTP, the scenario considering the installation of either a combined cycle or a microturbine at landfill site have the lowest LCOE. Scenario 3, which considers either a CC or a reciprocating engine, has the lowest LCOE of $55.45/kWh. However, Scenario 4, which is similar to Scenario 3 but considers a microturbine instead of a reciprocating engine, has a LCOE of $55.89/kWh, which is very close.

Figure 54, Figure 55, Figure 56, and Figure 57 show results that consider the ability of co-firing natural gas with the biogas at landfills and WWTP. The figures show how the addition of co-firing increases the cost of the system; nonetheless, the scenarios with the lowest LCOE remain the same as if there was no co-firing.

Figure 50: Economic Model Results for Power Generation Utilization Scenarios at WWTP with no Co-Firing and no Biogas Cost

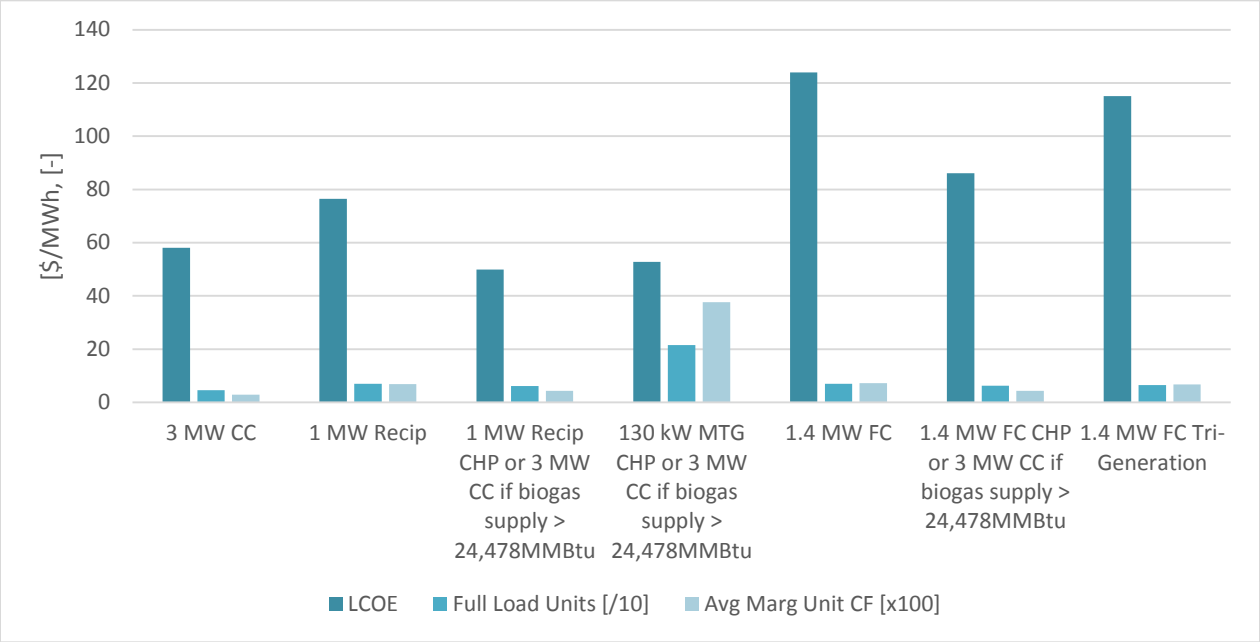


Figure 51: Economic Model Results for Pipeline Injection and Hydrogen Utilization Scenarios at WWTP with no Co-Firing and no Biogas Cost

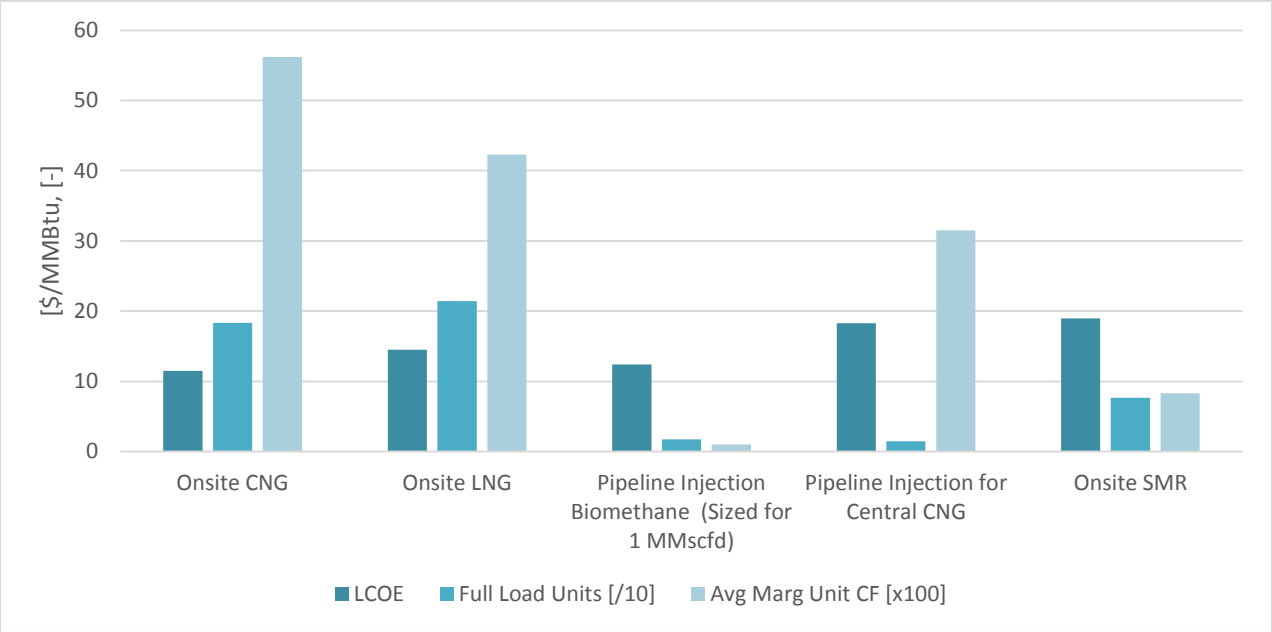


Figure 52: Economic Model Results for Power Generation Utilization Scenarios at Landfills with no Co-Firing and no Biogas Cost

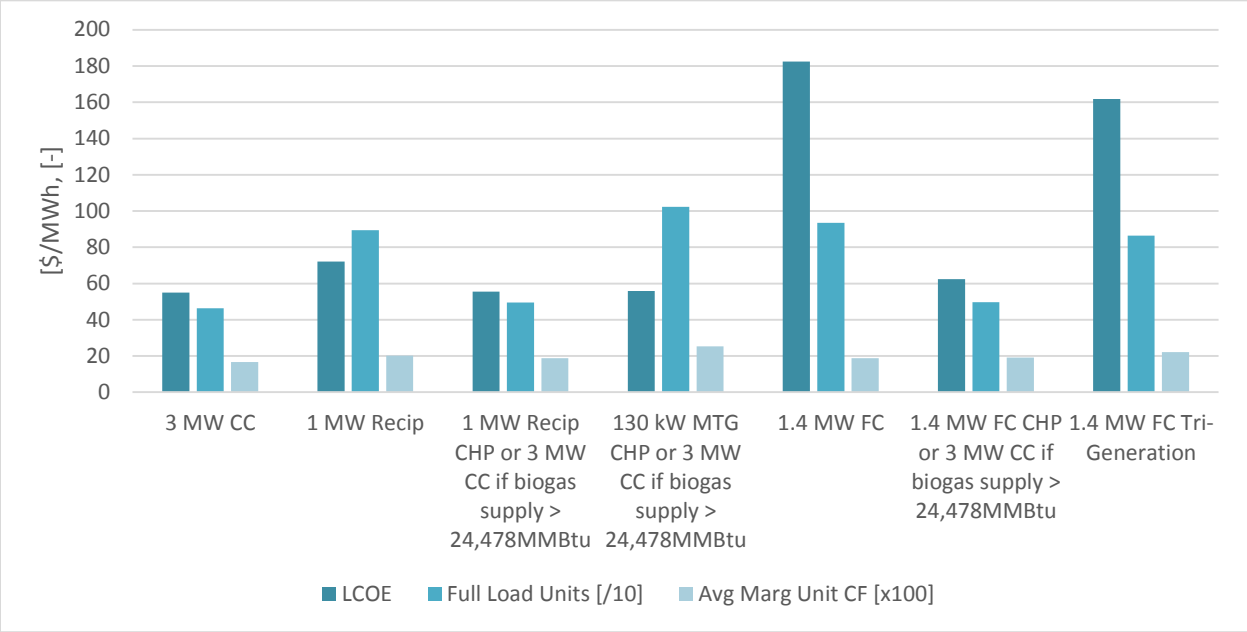


Figure 53: Economic Model Results for Pipeline Injection and Hydrogen Utilization Scenarios at Landfills with no Co-Firing and no Biogas Cost

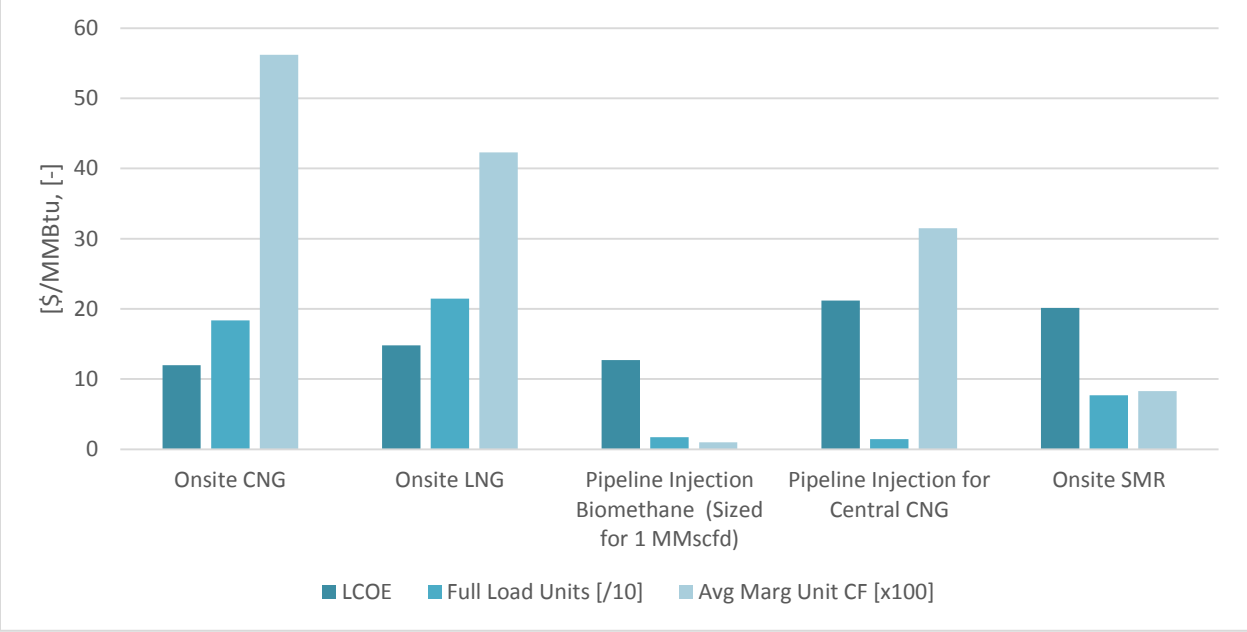


Figure 54: Economic Model Results for Power Generation Utilization Scenarios at WWTPs with Co-Firing and no Biogas Cost

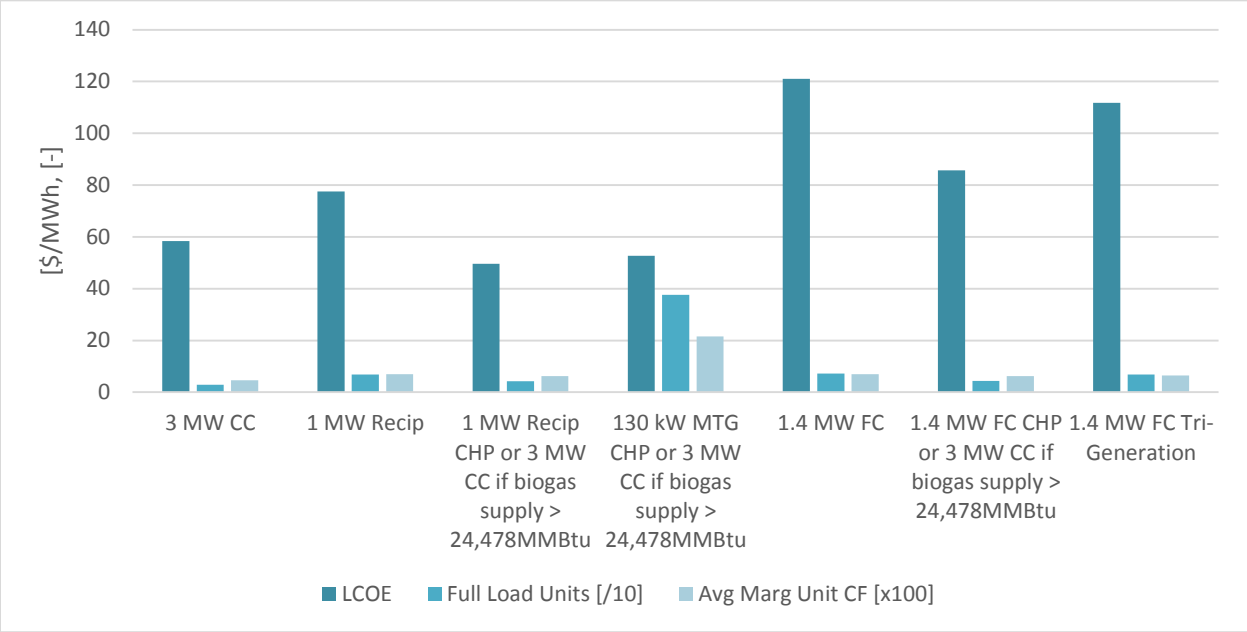


Figure 55: Economic Model Results for Pipeline Injection and Hydrogen Utilization Scenarios at WWTPs with Co-Firing and no Biogas Cost

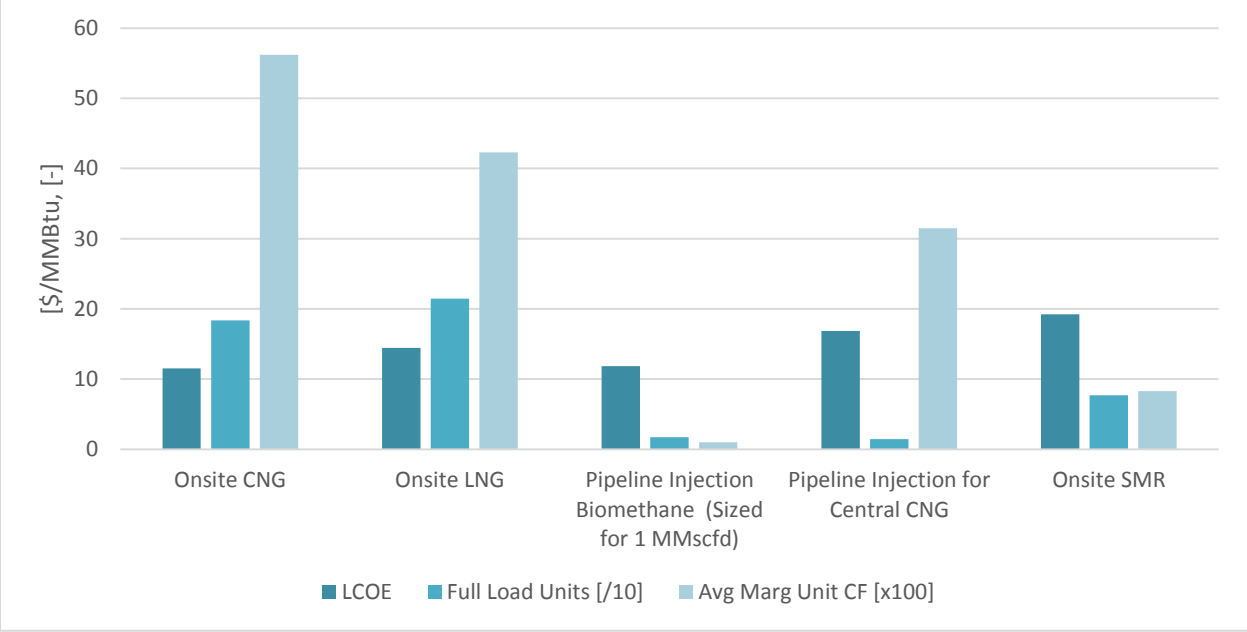


Figure 56: Economic Model Results for Power Generation Utilization Scenarios at Landfills with Co-Firing and no Biogas Cost

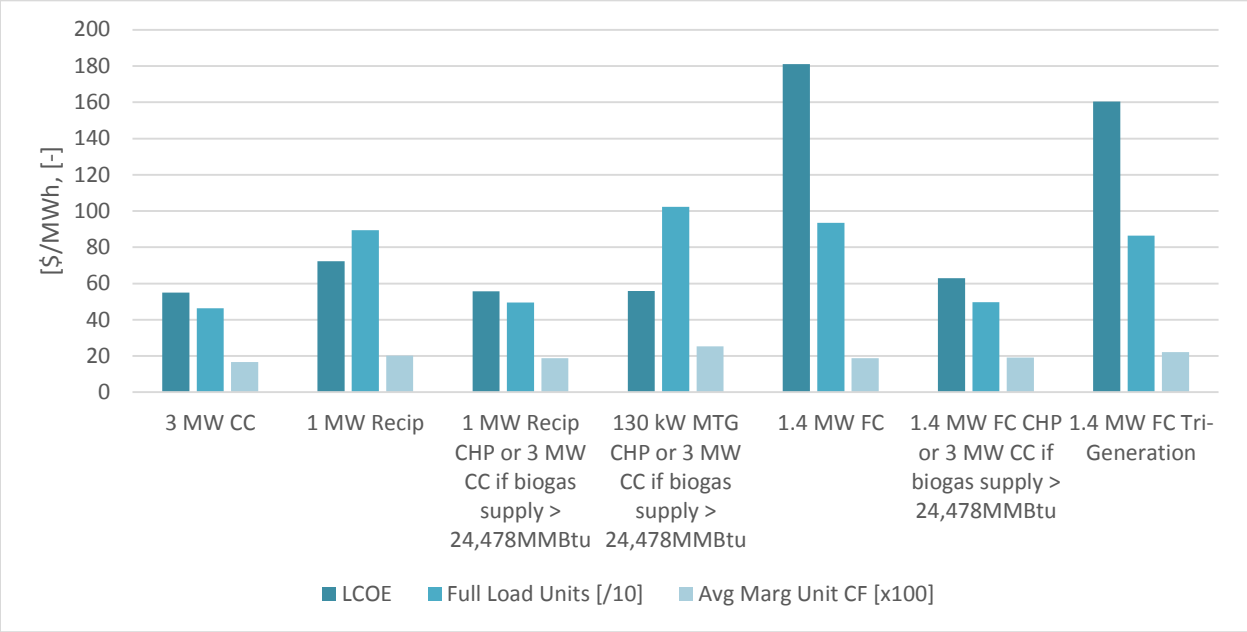


Figure 57 Economic Model Results for Pipeline Injection and Hydrogen Utilization Scenarios at Landfills with Co-Firing and no Biogas Cost

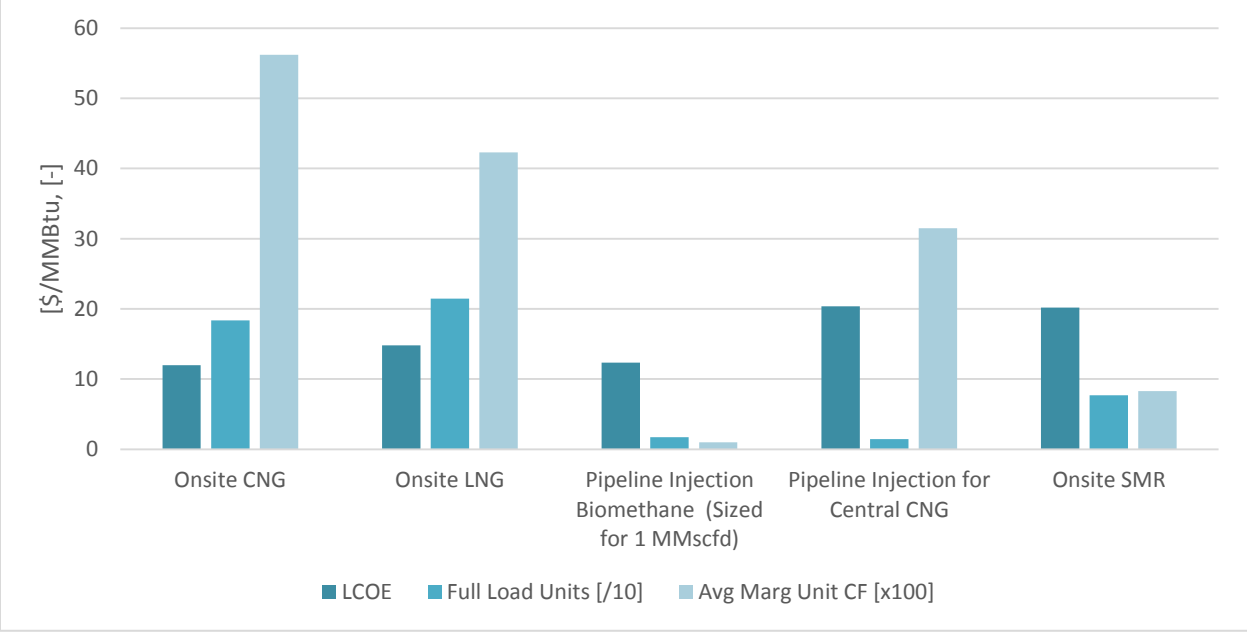


Figure 59, Figure 60, and Figure 61 show the economic modeling results with the attribution of cost to the biogas itself. The cost for biogas in the model is considered to be the same as the cost of natural gas. The figures show that LCOEs are now much higher than the previous two sets of results (no co-firing, co-firing). The scenarios showing the lowest LCOE in both landfills and WWTP are those which include the installation of a combined cycle plant either by itself or in combination with another technology. As for production of transportation fuel or renewable natural gas, both scenarios have the lowest LCOE for the production and injection into the pipeline for use as renewable natural gas.

Figure 58: Economic Model Results for Power Generation Utilization Scenarios at WWTPs with no Co-Firing and Biogas Cost

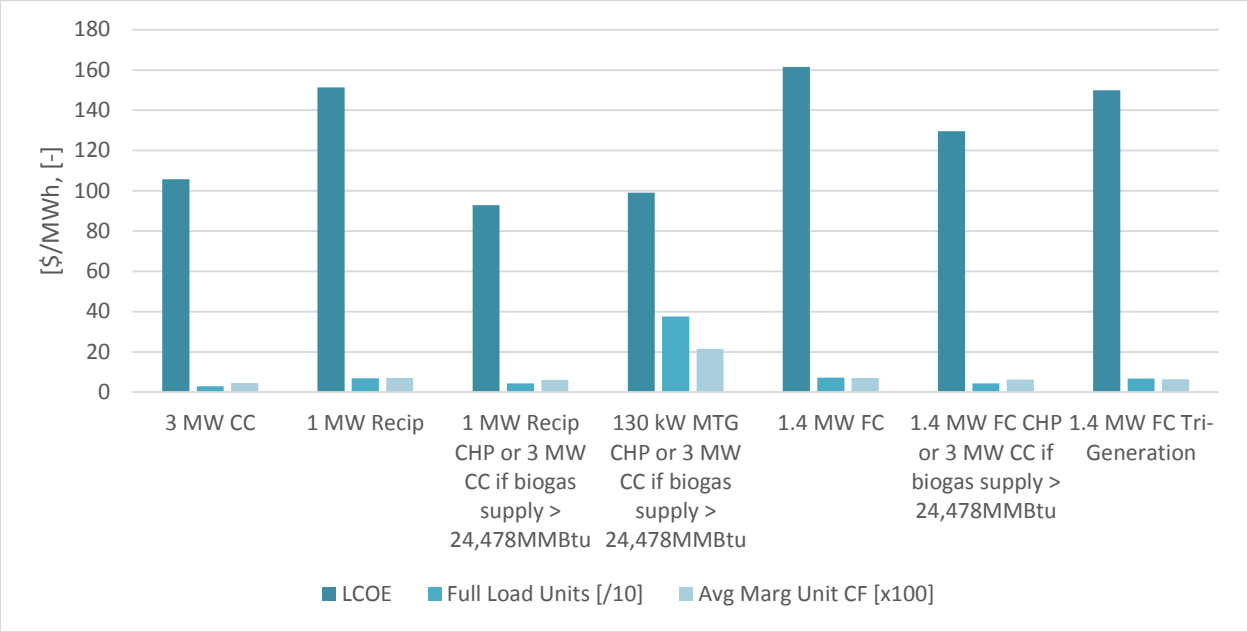


Figure 59: Economic Model Results for Pipeline Injection and Hydrogen Utilization Scenarios at WWTPs with Co-Firing and Biogas Cost

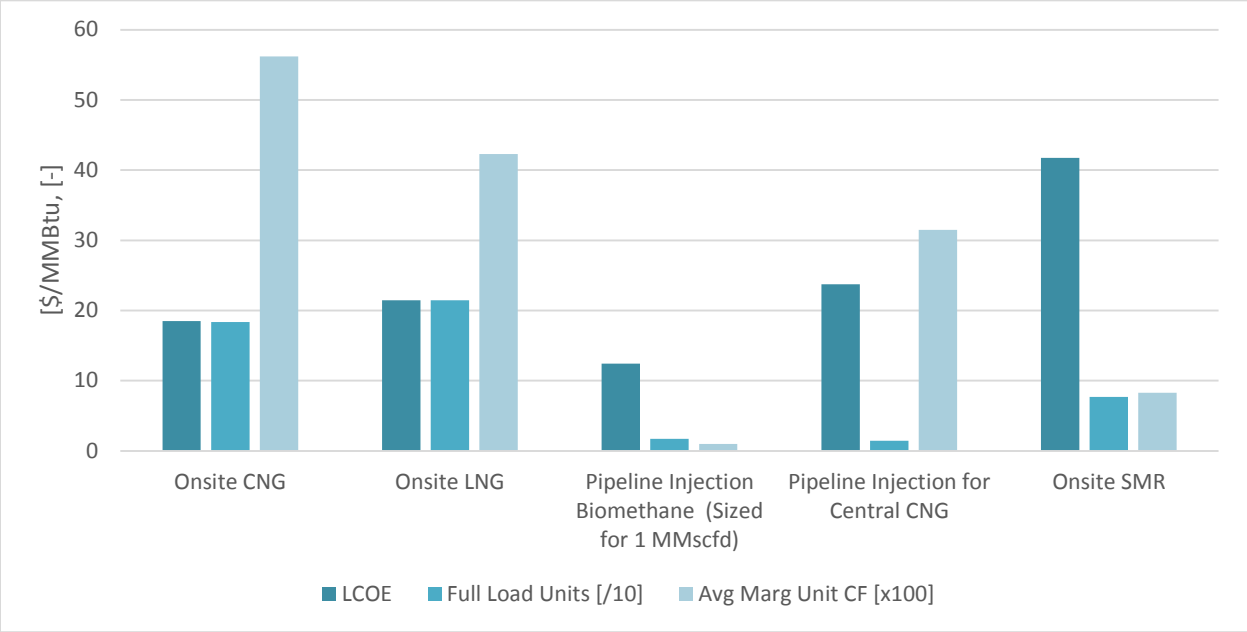


Figure 60: Economic Model results for Power Generation Utilization Scenarios at Landfills with no Co-Firing and Biogas Cost

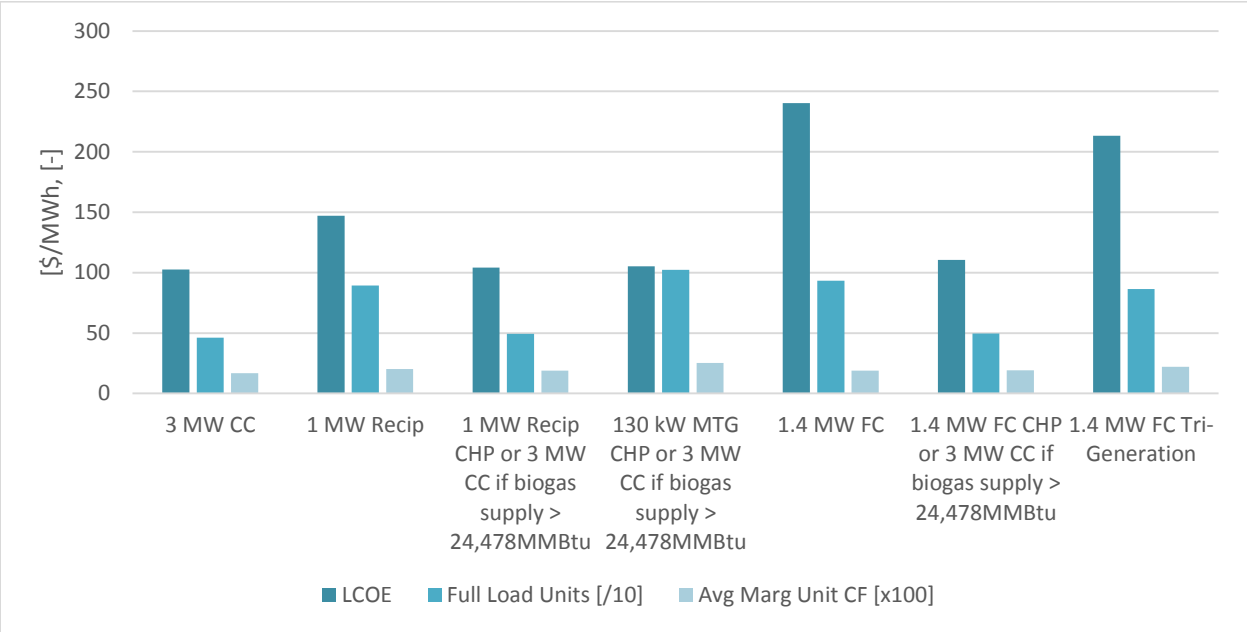
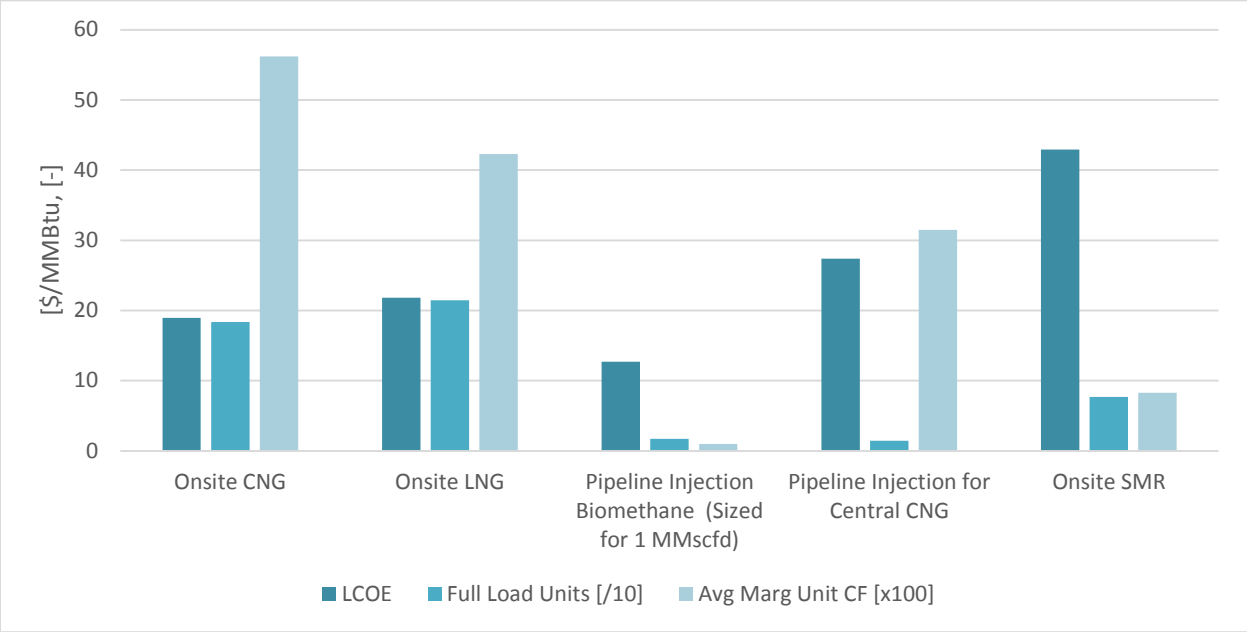


Figure 61: Economic Model Results for Pipeline Injection and Hydrogen Utilization Scenarios at Landfills with Co-Firing and Biogas Cost



4.5.3 Air Quality Results

Scenario emissions from the previous section were spatially and temporally allocated with the air quality model to study the effects of increasing biopower in California. The air quality model looks at the base case of 2020 and takes into account emissions related to increasing alternative transportation fuel and power from biogas. The model provides concentration changes in ozone and particulate matter with a width of 2.5 microns or less (PM 2.5) for each scenario. The additional power generated from biogas resources is a very small percentage in comparison to total power generation within California or the amount of biomass power generated. Scenarios modeled from power generation are those that would cause the greatest effect in air quality and are most likely to be implemented at landfill and WWTP locations. These scenarios include the installation of reciprocating engines, combined cycles or microturbines, and fuel cell installations. The transportation fuel scenarios modeled include the production of CNG, LNG, and hydrogen fuel for light duty vehicles.

The air quality simulation results are presented in these figures:

- Figure 62: Scenario 2 (reciprocating engines in landfills and wastewater treatment plants)
- Figure 63: Scenario 4 (combined cycle or microturbine onsite)
- Figure 64: Scenario 6 (either a fuel cell or combined cycle)
- Figure 65: Scenario 7 (generating power and production of hydrogen fuel using a fuel cell)

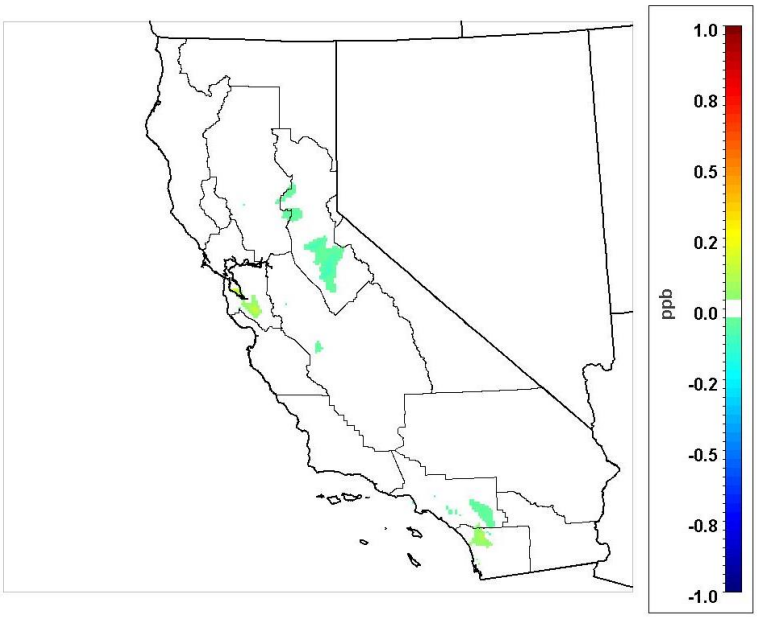
- Figure 66: Scenario 8 (production of CNG onsite)
- Figure 67: Scenario 14 (production of hydrogen through steam methane reformation)

Each case shows the impact on peak ozone in the summer as well as the 24-hr average $PM_{2.5}$ in the summer and winter cases. As mentioned above, $PM_{2.5}$ impacts are more sensitive in the winter season than summer and accordingly PM cases are worse in the winter, but still at very low concentrations compared to the baseline case.

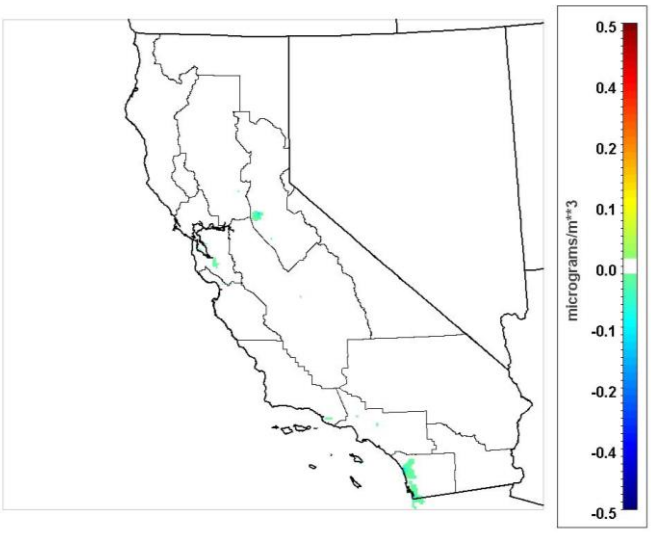
Examining the air quality impacts from Figure 62 through Figure 67 shows that the effect of using biogas to generate power and produce transportation fuel has a small impact on air quality throughout the state. In some cases, the scenario modeled shows an impact so small that it is negligible. The air quality results from Scenario 4, which produced the greatest amount of emissions, show an increase of about .2 ppb of ozone concentration in the San Francisco Air Basin and the San Diego County Air Basin while other air basins show a small decrease. Similar responses can be seen in the air quality results from the other scenarios modeled. However, in the power and hydrogen production from the installation of a fuel cell (Figure 65), ozone decreases over a large area of the basins while there is a slight increase in the San Francisco Air Basin and the San Diego County Air Basin.

Apart from looking at the ozone concentration change, the air quality model also estimates the change in $PM_{2.5}$. Similar to the change in ozone concentration, Scenario 4 (Figure 63) shows the greatest increase among the air quality impacts. Scenario 7 (Figure 65) shows the greatest overall effect on air quality. Using a fuel cell to produce power while at the same time generating hydrogen for transportation shows a decrease in $PM_{2.5}$ over a large area in the basins and a small change of less than .25 micrograms per meter cubed in the basins.

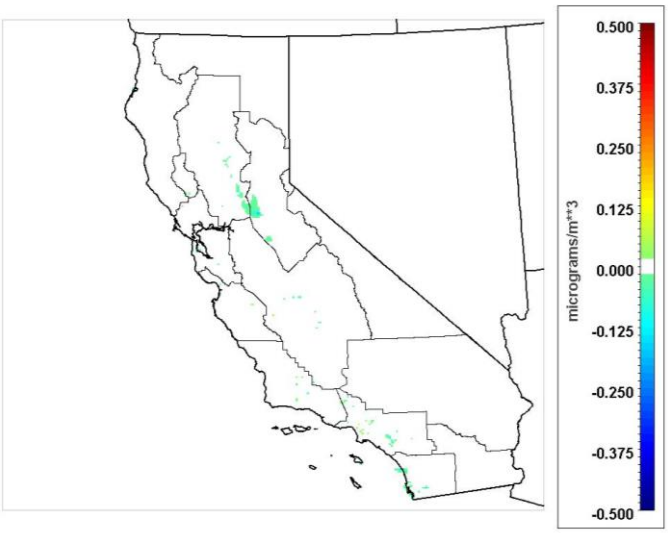
Figure 62: Air Quality Impacts of Biogas Scenario 2: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average PM2.5 in the Summer, (c) Impact on 24-hour Average PM2.5 in the Winter



(a)

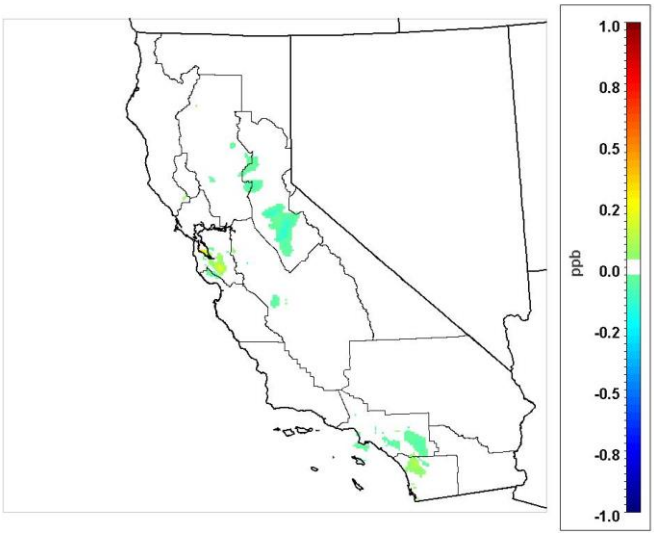


(b)

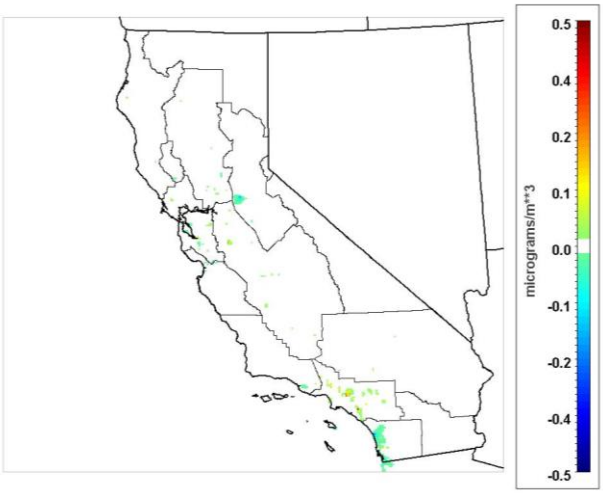


(c)

Figure 63: Air Quality Impacts of Biogas Scenario 4: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average PM2.5 in the Summer, (c) Impact on 24-hour Average PM2.5 in the Winter



(a)



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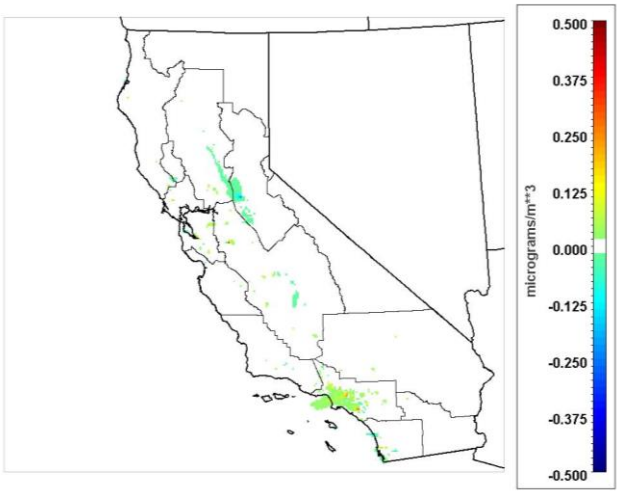
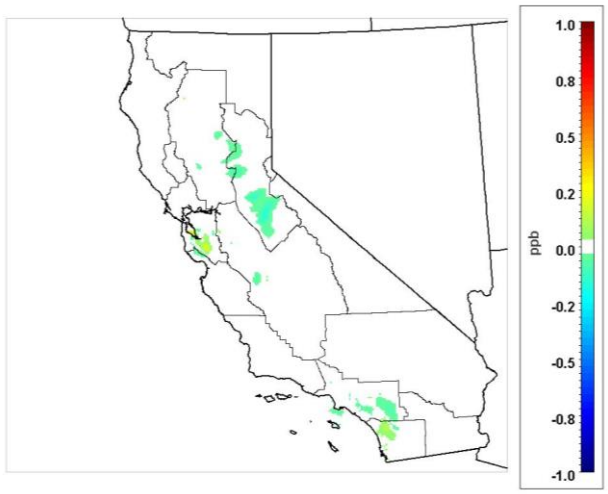
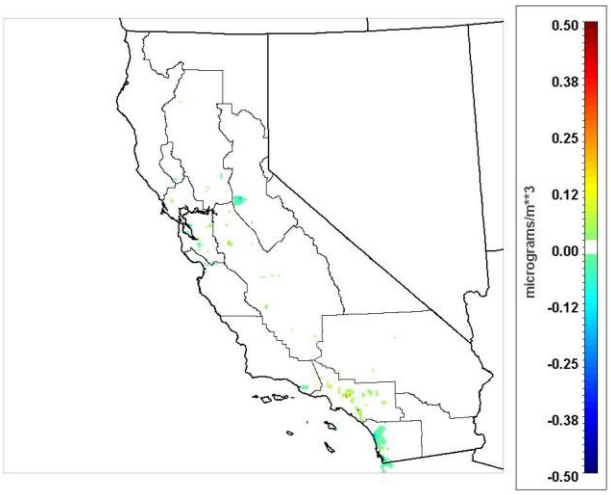


(c)

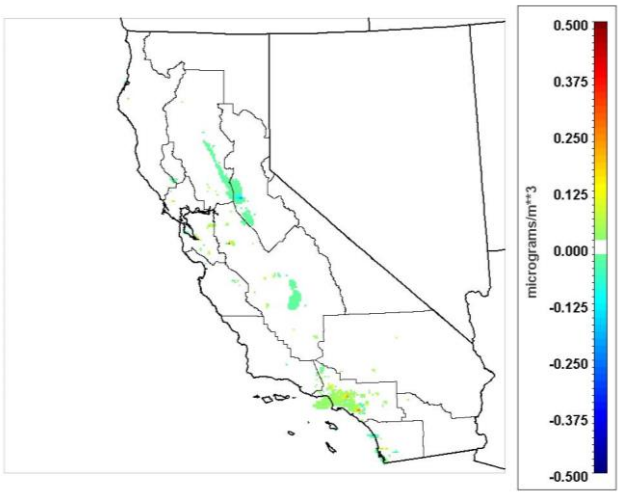
Figure 64: Air Quality Impacts of Biogas Scenario 6: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average PM2.5 in the Summer, (c) Impact on 24-hour Average PM2.5 in the Winter



(a)

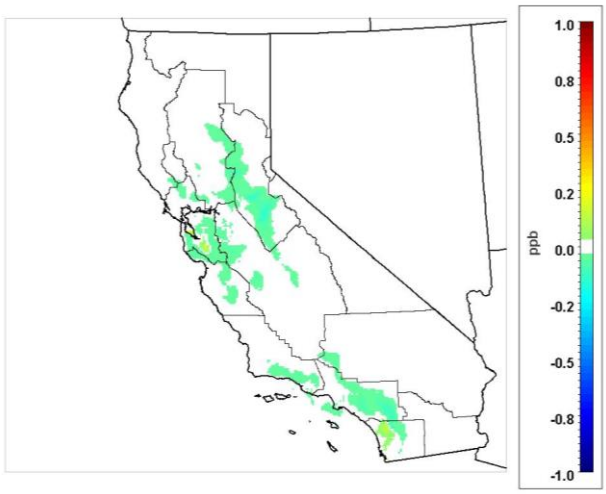


(b)

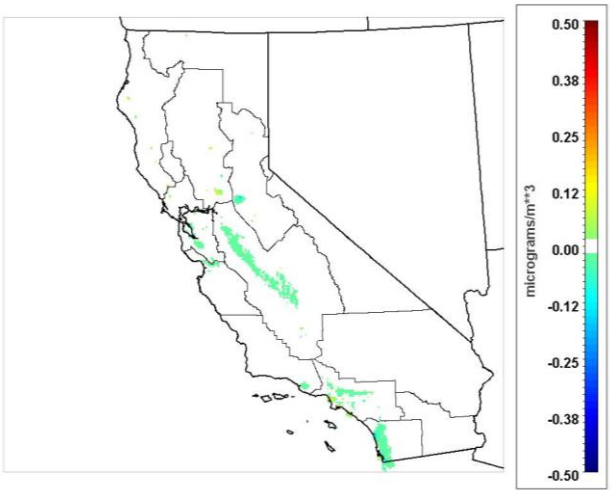


(c)

Figure 65: Air Quality Impacts of Biogas Scenario 7: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average PM2.5 in the Summer, (c) Impact on 24-hour Average PM2.5 in the Winter



(a)



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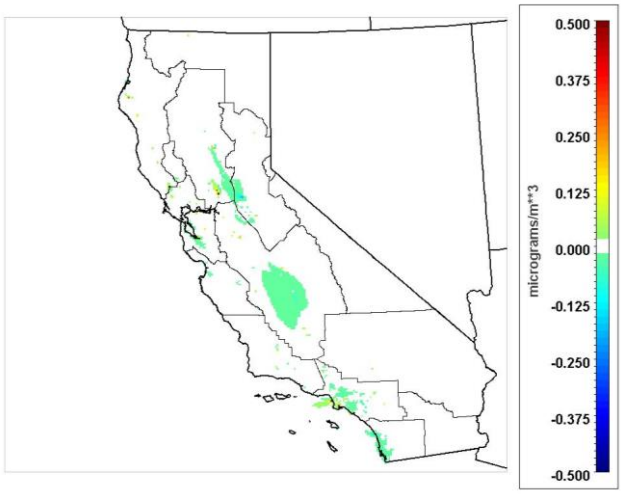
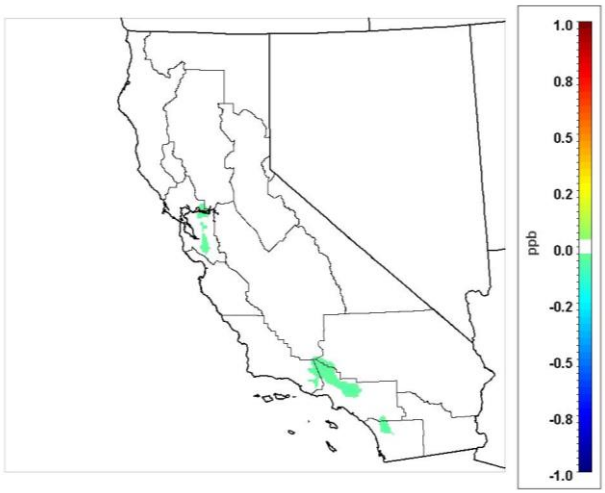
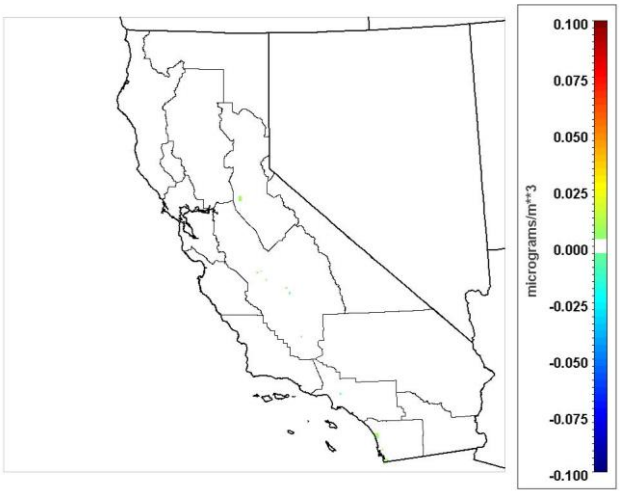


(c)

Figure 66: Air Quality Impacts of Biogas Scenario 8: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average PM2.5 in the Summer, (c) Impact on 24-hour Average PM2.5 in the Winter



(a)



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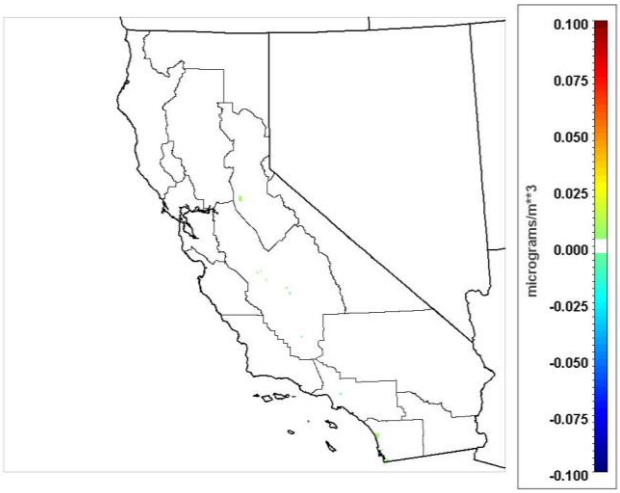
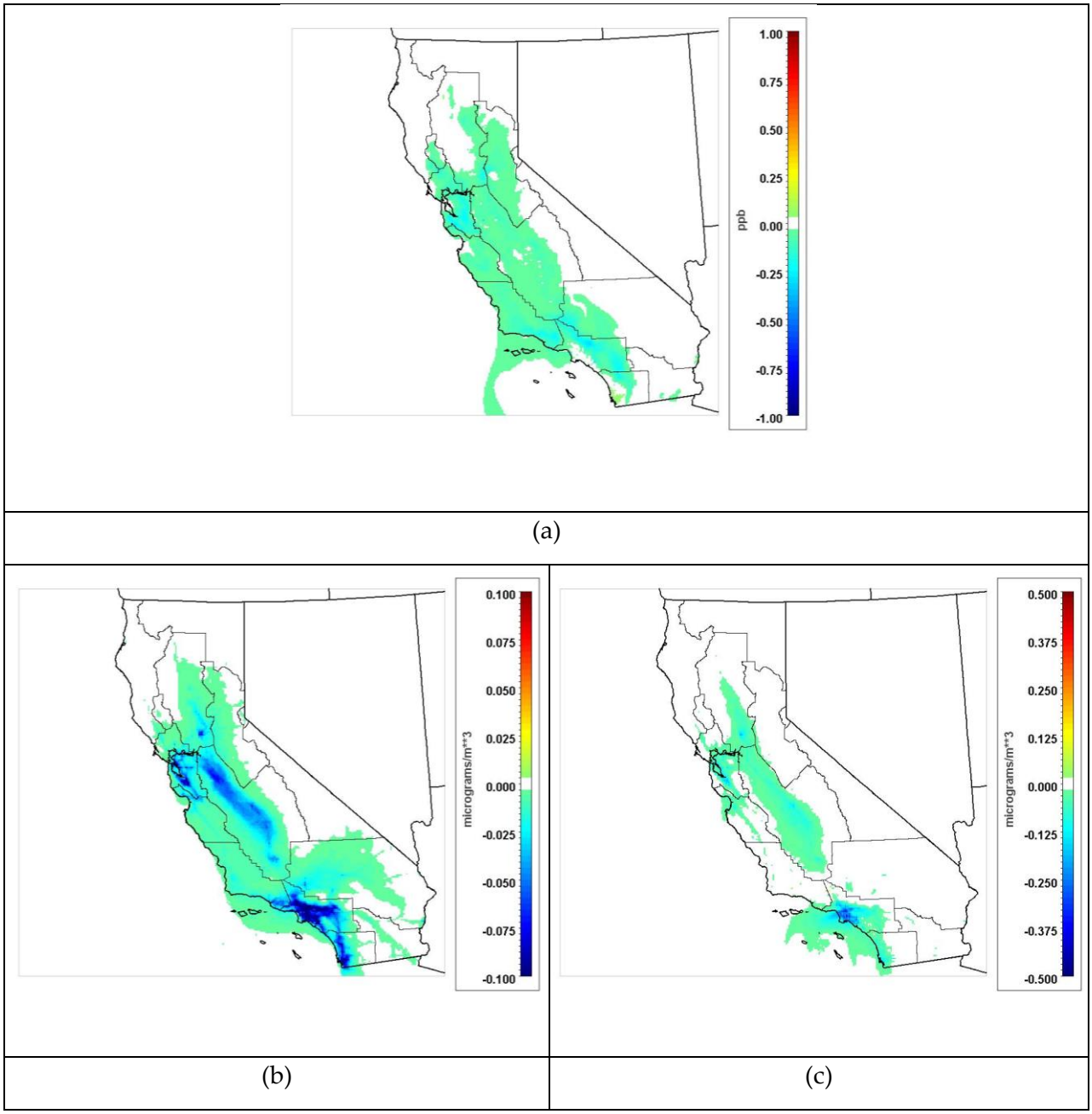


(c)

Figure 67: Air Quality Impacts of Biogas Scenario 14: (a) Impact on Peak Ozone in Summer, (b) Impact on 24-hour Average PM2.5 in the Summer, (c) impact on 24-hour Average PM2.5 in the Winter



Positive impacts in the air quality can be noted when using biogas to produce transportation fuel. Utilizing biogas to produce CNG, the air quality model showed that there will not be a significant change. The greatest difference in the 24-hour average difference was less than 0.025 micrograms per meter cubed throughout the scenarios modeled. Using biogas to produce hydrogen fuel decreases both ozone concentration and PM. Using biogas to produce hydrogen for vehicles shows a greater improvement in air quality compared to biogas for CNG

production. Overall air quality results show that using biogas for either power or transportation fuel causes only a small difference in the air quality or in some case improve air quality. Additionally, air quality results show that using biogas as a transportation fuel, specifically hydrogen, is more beneficial for air quality than using it to produce power.

4.6 Biogas Infrastructure Recommendation

The following recommendations take into the consideration the inventory gathered on biogas availability in California, the different possible uses and their maximum capacity, the economics related to each application, and the effects of implementing new power generation or transportation fuel on air quality.

4.6.1 Use biogas for transportation fuel to maximize air quality effects

Biogas produced from landfills and wastewater treatment plants can be utilized to generate power or transportation fuel. The high methane content of biogas allows for it to be able to produce power from technologies such as reciprocating engines, fuel cell, microturbines, gas turbines, and combined cycles. The composition of biogas also allows for transportation fuel to be produced such as CNG, LNG, and hydrogen fuel. Utilizing biogas to create transportation fuel onsite for onsite fueling stations would increase the fueling infrastructure for CNG, LNG, or hydrogen, while at the same time having a positive effect on air quality. The air quality modeling of the biogas scenarios show how the production of hydrogen fuel from biogas causes an overall reduction in ozone and PM2.5 concentrations. With the increase in fuel infrastructure the annual vehicle mileage traveled in the state can increase CNG, LNG, or hydrogen up to 7.3 percent, 7.1 percent, and 20.5 percent, respectively. As seen in Figure 62 through Figure 67, the effects of alternative fuel production have a better effect on air quality than using biogas for power generation only. The use of biogas to produce hydrogen fuel is the most favorable to air quality. Additionally, the criteria pollutant emissions from conventional vehicles are also avoided since hydrogen fuel cell vehicles have virtually zero tailpipe emissions of criteria.

4.6.2 Reduction in greenhouse gases from biogas use

Using biogas over conventional natural gas already in its own proves a reduction in GHG. Whereas natural gas needs to be extracted and is energy intensive, biogas is generated from landfills and WWTP and minimal energy is needed to transport it to be utilized onsite. Biogas scenarios producing transportation fuel from biogas exhibit the greatest reduction in GHG rather than used to generate power. Combusting the biogas continues to emit GHG and criteria emissions, but GHG emissions are converted to carbon dioxide emissions rather than methane and its effect is reduced in the atmosphere.

Transportation fuel derived from renewables have overall less GHG emission than fuels derived from fossil fuels (Han et al., 2011). However, GHG emissions from tailpipe are not removed since the vehicle performance does not change if it is fueled by renewable CNG or conventional CNG. The production of hydrogen from biogas allows for the greatest reduction in GHG since fuel cell vehicles operating on hydrogen have no GHG from their tailpipe emissions. However, producing hydrogen through steam methane reformation emits carbon

dioxide. In order to reduce carbon dioxide emissions from steam methane reformation a carbon capture system would need to be installed.

4.6.3 Fossil fuel reduction from using biogas

Biogas utilization can replace fossil fuel used for power generation or transportation fuel usage. Fossil fuel usage has a negative impact in both air quality and GHG emissions and thus its reduction will decreases has a positive effect in GHG emissions and air quality. The utilization of biogas to produce hydrogen transportation fuel can reduce the reduction in fossil fuel. When considering the reduction in fuel from producing power the greatest reduction will be in biogas scenarios where the greatest amount of power is produced. The fuel used to power a combined cycle is replaced with renewable natural gas. Fuel used by power plants within California will be reduced and displaced by renewable natural gas. The production of CNG allows for the reduction of fossil fuel since CNG is produced at a higher yield than LNG or hydrogen fuel

4.6.4 Install fuel cell technology for clean power generation

Fuel cell installations produce power while meeting emission standards without the addition of emission reduction equipment. A fuel cell installation at a WWTP can provide part of the electricity needed to operate the plant while providing heat to the anaerobic digester on site. The installation of fuel cells has the potential to generate a greater megawatt capacity than a reciprocating engine, but with 78- 92 percent reduction in emissions of PM, NOx, SOx, CO, and VOC pound per MWh. LFG and WWTP are located in high population areas. Therefore, it is important to consider the emissions related to power generation and its effect in air quality. With the addition of a fuel cell over a reciprocating engine, the efficiency of the system is increased while emissions are reduced.

CHAPTER 5:
Biogas and Biomass Power Generation

Various legislative and regulatory initiatives in place support the increase of biomass and biogas resources in California to address California's renewable power portfolio and meet California energy and climate goals. Previous chapters focused on the potential power production from either biomass or biogas. This chapter compares and evaluates both biomass and biogas resources.

5.1 Electric Power Generation

The maximum additional electric power production from the biomass scenarios is the development of new BIGCC facilities (Biomass Scenario 4) with the potential to generate 3000 MW. The maximum additional electric power production from the biogas scenarios is a combination of installations of either a combined cycle or microturbines at landfills and WWTPs (Biogas Scenario 4) with a potential to generate 1049 MW.[6] Therefore, the maximum biopower that can be produced from the biomass and biogas scenarios studied is 4719 MW. When considering installing new biopower facilities and maximizing the potential of biopower to generate electricity, these two scenarios are the most effective.

The minimum additional electric power production from the biomass scenarios is the use of municipal solid waste to power facilities by thermal conversion (Biomass Scenario 7). This biomass scenario generates 1301 MW with 19 new facilities installed (Table 12). The minimum additional electric power production from the biogas scenarios is the use of relatively low-efficiency reciprocating engines (compared to combined cycles of fuel cell applications) represented by Biogas Scenario 2. This scenario produced a total of 659 MW additional power (590 + 69MW, Table 21).

5.2 Transportation Fuel

The composition of biogas and ease of extraction from landfills and WWTPs allows biogas to be used to produce a transportation fuel in addition to generating electricity. When comparing the two uses, transportation fuel production benefits outweigh those of power production. Transportation fuel from biogas allows for the reduction of GHG emissions and improvement in air quality, and it is more economically viable. The production of power from biogas requires the conditioning of the biogas and installment of new equipment at landfills and wastewater treatment plants for power production. Transportation fuel production requires less cost related to equipment installation and operation since it only needs the cleanup system and fuel processing.

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[6] The biogas utilization scenarios adopt the power rating for commercially viable technology today. As an example, for Scenario 5, 1.4MW is adopted for commercially viable product. The analysis precludes the deployment of fuel cells to WWTP and landfills with capacities lower than 1.4MW. If fuel cells were able to be deployed to ALL WWTP and landfills, Scenario 5 would result in the maximum power generated.

5.3 Air Quality

Biomass use can significantly degrade air quality whereas the impact of biogas is marginal to none. Emissions from biomass contribute significantly to the formation of ozone and PM in the Central Valley where levels of ozone ad PM are a major target for reduction. Using biomass resources requires longer traveling distances for trucks, whereas biogas is generated onsite and no additional transportation is required. The impacts of biopower are dominated by biomass power generation. Consequently, while low-emitting and highly efficient technologies will reduce the burden of biomass use, emissions associated with the collection transport must be substantially curtailed.

Biogas resources from landfills and wastewater treatment plants are centered on urban regions of California like the Bay Area and Los Angeles regions. The use of biogas for electric power generation increases ozone and $PM_{2.5}$ concentrations, albeit small. As noted above, the scenarios using biogas to power a combined cycle produces the maximum power production. However, this scenario also produces the highest emissions and air quality impact. If fuel cells with nameplate power below 1.4 MW were deployed at bio resources with capacities less than 1.4 MW, maximum power production would increase and air quality would improve.

Using biogas for the production of transportation fuels (CNG, LNG, and hydrogen) produces the lowest emissions among the biogas scenarios. The use of bio-derived CNG and LNG to replace gasoline in combustion vehicles results in a measurable but relatively small reduction in criteria pollutant emission. While the production of hydrogen via SMR produces emissions of criteria pollutants, the levels are more than offset by the displacement of gasoline combustion vehicles by hydrogen fuel cell vehicles. In contrast to CNG and LNG, hydrogen production achieves the largest air pollutant emission reduction and the largest decrease in ozone (< 1 ppb) and particulate matter (< 0.5 ug/m3) concentrations.

5.4 Greenhouse Gas Emissions

The GHG emissions from power production must also be considered when introducing new electric power generation from bio resources. Using biomass and biogas reduces greenhouse gases compared to using conventional methods. The carbon found in biologically based materials overtime degrade and are released to the atmosphere as carbon dioxide. The use of these waste products from biomass and biogas allows for harvesting the energy that would otherwise be slowly emitted over time. For biogas resources specifically, the emissions related to the extraction and transport of natural gas from petroleum wells and shale gas deposits are avoided.

Producing a transportation fuel from biogas can substantially reduce GHG emissions from vehicles. If biogas were to be used to produce hydrogen fuel, a substantial reduction in GHG since savings occur from the production of fuel as well as zero carbon tailpipe emissions from the fuel cell vehicles. Overall, the benefits of producing transportation fuel from biogas exceed those of generating electric power from biogas resources.

5.5 Economics

When comparing economics of using biomass to produce renewable synthetic natural gas (RSNG) over large-scale power production from a biomass-integrated-gasifier-combined-cycle (BIGCC) system, BIGCC was found to be more economic than RSNG. The required price for RSNG is $0.18/kWh where, for a BIGCC, it is $0.10/kWh. Therefore, biomass resource utilization is lower in cost when used to generate power in comparison to synthetic natural gas.

The economic results from the biogas scenarios favor the utilization of a combination of a reciprocating engine or a combined cycle to generate power onsite, and the onsite production of CNG. The economic analysis included co-firing of natural gas in order to install equipment at the locations. Where the cost for co-firing was considered, results still show that the installation of a reciprocating engine onsite and onsite production of CNG are the most cost effective. When considering a cost for biogas and co-firing, the most cost effective scenario is generating power onsite using a reciprocating engine and injecting the biomethane produced from the biogas to the natural gas pipeline for general use.

The lowest LCOE for electric power generation from biogas is approximately $53/MWh. The cost for fuel production from landfill gas is $11.85/MMBtu, $14.82/MMBtu, and $20.15/MMBtu for onsite production of CNG, LNG, and hydrogen fuel, respectively. For WWTP, the cost of fuel production is $11.50/MMBtu, $14.48/MMBtu, and $18.96/MMBtu for onsite production of CNG, LNG, and hydrogen fuel, respectively. In comparison to electric power generation, the least expensive production of a transportation fuel is $11.50/MMBtu (approximately $39.25/MWh). As a result, the economic impacts of biogas favor the production of renewable transportation fuel.

CHAPTER 6: Summary

Renewable energy sources provide 19.64 percent of the power generated in California. Biomass and biogas resources contribute more than 3 percent of the total energy generation mix (California Energy Commision, 2013). Biomass and biogas resources portend a key opportunity for California to expand the renewable energy portfolio. In addition to the current power generated from biogas and biomass, an additional 2,800 megawatts (MWs) are available from recoverable biomass and biogas resources (Williams et al., 2008). The question is what technologies, and what utilization scenarios are the most effective use of the biopower resources from an air quality, greenhouse emission, and economic perspective.

To address this question, this project addressed using these additional biopower resources to generate electric power and produce transportation fuels for a variety of utilization scenarios. The scenarios adopt the power rating for commercially viable technology today and deploy the technology only where the bio source has the capacity to support the power rating of the technology. As an example, for Biogas Scenario 5, a 1.4MW fuel cell is adopted for the commercially viable product. The scenario analysis allows only the deployment of fuel cells to WWTP and landfills with capacities greater than 1.4MW.

The results of the study reveal that the deployment of additional biomass and biogas resources in California to generate electric power or produce a transportation fuel result in (1) different effects and air quality and greenhouse gas emissions, and (2) different economic impacts depending on the scenario analyzed.

Biomass resources included forestry, agricultural and municipal solid waste. Technologies for biomass scenarios included current boilers, advanced gasification systems that can be integrated with a combined cycle or can be operated in conjunction with gas engines. RSNG production was also considered. For solid biomass, additional costs and emissions associated with collection and transport of biomass was included in the analysis.

Emissions from biomass generation and utilization were found to contribute significantly to the formation of ozone and PM in the Central Valley where elevated levels of pollutants occur throughout the year. Consequently, there is the need to identify scenarios to minimize the impacts associated with the use of biomass. Low-emitting highly efficient technologies for conversion of biomass to power can reduce the burden of biomass use. A key is to manage and control the emissions associated with the transport of biomass.

Biogas resources included the gas produced from landfills and anaerobic digesters in wastewater treatment plants. The biogas scenarios included the use of biogas to (1) generate electric power from microturbines, reciprocating engines, fuel cells, combined cycles, and gas turbines, and (2) produce transportation fuels (compressed natural gas, liquefied natural gas, and compressed hydrogen gas). Air quality simulations revealed that power generation from biogas sources results in little to no effect in the air quality due to the small amount of power generation. For the production of transportation fuels, the results showed that using biogas to

produce CNG, LNG, and hydrogen to be the most beneficial to not only air quality but also in the cost of fuel production and utilization. Producing transportation fuel from biogas also results in reducing greenhouse gases through the avoidance of greenhouse gas emissions from fossil fuels.

In summary, all scenarios studied lead to a reduction in GHG emissions, the degree to which depended on the scenario. In contrast, air quality impacts varied from unfavorable to favorable, again depending on the scenario. Overall, using biomass for electric power generation can produce unfavorable air quality impacts from the emissions associated with (1) the transmission of biomass from the source to the point of processing, and (2) the processing. Using biogas resources, in contrast, has marginal to no impact on air quality with biogas for a transportation fuel being the most attractive. Using fuel cells for both biomass and biogas provide the most favorable opportunity to maximize electric power generation, minimize air quality impacts, and reduce greenhouse gas emissions. For transportation, producing hydrogen from biogas for use in fuel cell vehicles provides the most favorable opportunity to improve air quality and lower carbon with viable economics.

Using renewable biosources provides California with a potential, in principle, to more effectively achieve its climate and air quality goals. The degree of effectiveness and overall economic benefit is directly associated with the technology selected and the utilization scenario employed. The results of this study provide key insights to inform this process.

GLOSSARY

Term	Definition
AB 32	Assembly Bill 32
AD	Anaerobic Digester
ADC	Alternative Daily Cover
BDT	Bone Dry Ton
BIGCC	Biomass-integrated-gasifier-combined-cycle
CAFE	Corporate Average Fuel Economy
CALFIRE	California Department of Forestry and Fire Protection
CC	Combined Cycle
CMAQ	Community Multiscale Air Quality Modeling System
CPUC	California Public Utilities Commission
DG	Distributed Generation
eGRID	Emissions & Generation Resource Integrated Database
EPA NAAQS	Environmental Protection Agency, National Ambient Air Quality Standards
GBSM	Geospatial Bioenergy System Model
GHG	Greenhouse Gases
GWh	Gigawatt-hour
HHV	Higher Heating Value
HiGRID	Holistic Grid Resource Integration and Deployment
LandGEM	Landfill Gas Emissions Model
LCFS	Low Carbon Fuel Standard
LCOE	Levelized cost of electricity
LF	Landfill
LFG	Landfill Gas
LMOP	Landfill Methane Outreach Program (LMOP)

LNG	Liquefied Natural Gas
MSW	Municipal Solid Waste
MW	Megawatt
PUR	Pesticide Use Report
RPS	Renewable Portfolio Standard
RSNG	Renewable Synthetic Natural Gas
SB 1122	Senate Bill 1122
SB 1505	Senate Bill 1505
SMR	Steam Methane Reformations
SNG	Synthetic Natural Gas
SOFC	Solid Oxide Fuel Cell
USFS	United States Forest Service
VOC	volatile organic compounds
WWTP	Wastewater Treatment Plant
ZEV	Zero Emission Vehicle

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APPENDIX A:
Biogas Inventory

LandGEM first order rate decomposition equation

$$Q_{CH_4} = \sum_{i=1}^{n} \sum_{j=0.1}^{1} kL_o \left(\frac{M_i}{10} \right) e^{-kt_{ij}}$$

LandGEM inputs:

Q_{CH4} = annual methane generation in the year of the calculation (*m^3/year*)

i = 1-year time increment

n = (year of the calculation) - (initial year of waste acceptance)

j = 0.1-year time increment

k = methane generation rate (*$year^{-1}$*)

L_o = potential methane generation capacity (m^3/*Mg*)

M_i = mass of waste accepted in the ith year (*Mg*)

t_{ij} = age of the jth section of waste mass M_i accepted in the ith year (*decimal years*, e.g., 3.2 years)

Model Parameters from User Inputs:

k =	0.050	*$year^{-1}$*
L_o =	170	*m^3/Mg*

WWTP Methane Calculation Methods

$$V_{CH_4} = (0.35)\left[(S_o - S)(Q)\left(10^{-3}\frac{g}{kg}\right)\right] - 1.42\,P_x$$

V_{CH4}	Volume of methane produced at standard conditions, 0C and 1 atm	
0.35	Theoretical conversion factor for the amount of methane produced, m^3, from conversion of 1 kg of bCOD at 0C (conversion factor at 35C = 0.40)	
Q	Flowrate m^3/day	
S_o	bCOD in influent mg/L	300/.65
S	bCOD in effluent mg/L	20
P_x	Net mass of cell tissue produced per day	

$$P_x = \frac{\left[YQ(S_o - S)10^{-3}\frac{g}{kg}\right]}{[1 + k_d(SRT)]}$$

Y = yield coefficient	0.5
kd = endogenous coefficient	0.6
SRT = solid retention time	

California Landfill Inventory

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
1	Puente Hills LF	57.80	109195.95
2	Frank R. Bowerman SLF		88884.31
3	Fink Road LF	0.00	62903.26
4	Sunshine Canyon Landfill		60180.83
5	West Miramar SLF	9.90	54956.16
6	Altamont SLF	8.90	41537.13
7	BKK Landfill-Phases I & II	10.90	37009.03
8	Scholl Canyon SLF	8.00	35562.05
9	Bradley Landfill	6.75	33384.98
10	Tri-Cities Landfill	0.00	29015.97
11	Avenal LF	0.00	28481.32
12	Chiquita Canyon SLF	6.00	27911.01
13	El Sobrante SLF	4.05	27417.27
14	Olinda Alpha SLF	35.60	26956.68
15	Vasco Road SLF	0.00	24116.11
16	Otay LF	8.20	22630.46
17	San Timoteo Sanitary Landfill	0.00	22547.44
18	Mid-Valley Sanitary LF	2.52	21014.64
19	Simi Valley LF	2.70	20573.61
20	Kiefer LF	15.00	20467.42
21	American Avenue Disposal Site	0.00	20346.62
22	Sycamore SLF	1.50	19912.03
23	Victorville Sanitary Landfill	0.00	19521.57
24	Central Disposal Site (Sonoma) - Phases I, II, & III	7.50	19367.85
25	Calabasas SLF	13.80	19004.46
26	Lamb Canyon Disposal Site		18268.02
27	Bakersfield Metropolitan SLF (BENA)	1.60	17353.67
28	Chateau Fresno LF	0.00	16557.35
29	Prima Deshecha SLF	5.50	16092.37

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
30	Newby Island SLF Phases I, II, & III	6.50	15684.84
31	Santiago Canyon SLF	2.00	15501.42
32	Operating Industries, Inc. LF (OII)	0.40	14745.22
33	West Contra Costa LF	2.00	14375.76
34	San Marcos LF	1.70	13470.06
35	Kirby Canyon Recycling & Disposal Facility	0.00	12338.84
36	Lopez Canyon SLF	6.00	11668.08
37	Fort Irwin Sanitary Landfill	0.00	11039.64
38	Austin Road Landfill	0.80	10453.02
39	North County Recycling Center and Sanitary LF	0.00	10432.89
40	Tajiguas SLF	3.10	10355.94
41	Milliken SLF	2.20	10318.90
42	Antelope Valley Public LF	0.00	9969.18
43	Highway 59 Disposal Site	0.00	9899.50
44	Yolo County Central LF	1.75	9812.09
45	Edom Hill Disposal Site	0.00	8360.57
46	Azusa Land Reclamation Company, Inc.	0.00	8181.54
47	Acme LF	2.20	8164.03
48	West Central LF	0.00	7731.39
49	Guadalupe Sanitary Landfill	2.68	7220.31
50	Davis Street LF		7078.36
51	Penrose LF		6547.54
52	Shafter-Wasco SLF	0.00	6292.26
53	Colton Sanitary Landfill	1.20	6118.62
54	Arvin SLF	0.00	5954.94
55	Badlands Disposal Site	1.10	5893.19
56	Ridgecrest-Inyokern SLF	0.00	5880.83
57	Monterey Peninsula SLF	4.60	5773.55
58	Shoreline LF at Mountain View	3.00	5458.19
59	Toyon Canyon LF	3.00	5432.64
60	Toland Road SLF	0.07	5346.59

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
61	Lancaster Landfill	0.00	5184.53
62	Bailard LF	1.70	4979.18
63	Keller Canyon LF	3.80	4926.61
64	Visalia Disposal Site	1.50	4852.49
65	China Grade SLF	0.00	4798.63
66	Double Butte Disposal Site	0.00	4740.15
67	Foothill Sanitary Landfill, Inc.	0.00	4491.28
68	Western Regional LF	2.40	4356.07
69	Spadra LF	8.50	4297.15
70	Geer Road SLF	0.00	4249.90
71	Cold Canyon LF Solid Waste Disposal Site		4116.24
72	Sacramento City LF		3982.54
73	Coachella Sanitary Landfill	0.00	3918.56
74	Landers Sanitary Landfill	0.00	3863.24
75	Palo Alto LF		3810.81
76	Barstow Sanitary Landfill	0.00	3609.91
77	Woodville Disposal Site	0.60	3472.32
78	Tehachapi SLF	0.00	3451.41
79	Bonzi SLF	0.00	3396.35
80	L & D Landfill Company	0.00	3270.12
81	Burbank LF Site No. 3	0.55	3198.92
82	American Canyon SLF	1.00	3196.89
83	Taft SLF	0.00	2938.35
84	Santa Cruz City SLF	1.60	2919.59
85	Mead Valley Disposal Site	0.00	2913.86
86	Harney Lane SLF	0.00	2883.07
87	Teapot Dome Disposal Site	0.00	2833.88
88	Highgrove SLF	0.00	2814.72
89	Sheldon-Arleta LF		2776.51
90	Red Bluff Landfill	0.00	2748.81
91	Ox Mountain SLF	11.40	2739.15
92	Ponderosa SLF	0.00	2564.14
93	South Chollas Landfill	0.00	2388.72

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
94	Yuba-Sutter Landfill	0.00	2342.15
95	Palos Verdes Landfill	6.00	2336.66
96	McCourtney LF	0.00	2277.74
97	Fresno Sanitary Landfill	0.00	2266.34
98	City of Santa Clara LF	0.75	2122.95
99	Ascon & Desser Landfills		2122.85
100	Hanford SLF	0.00	2122.08
101	City of Ukiah Solid Waste Disposal Site	0.00	2083.51
102	Mojave-Rosamond SLF	0.00	2049.32
103	Anderson Solid Waste Disposal Site	0.00	2009.79
104	Mission Canyon Landfill	0.00	2007.32
105	Fairmead Solid Waste Disposal Site	0.00	1963.05
106	City of Corona LF	0.60	1875.64
107	City of Lompoc SLF		1803.02
108	City of Clovis LF	0.00	1796.39
109	Oro Grande LF	0.00	1772.59
110	Watsonville City Solid Waste Disposal Site	0.00	1740.03
111	City of Paso Robles LF	0.00	1727.11
112	Mariposa County SLF	0.00	1715.54
113	Ostrom Road Landfill	3.20	1696.67
114	Pacheco Pass SLF	0.00	1692.84
115	Allied Imperial Landfill	0.00	1691.70
116	Desert Valley Monofill Landfill	0.00	1639.88
117	Redwood SLF		1635.88
118	Zanker Road (Nine Par) SLF	0.00	1587.70
119	Ramona LF	0.00	1583.00
120	Yuba-Sutter Disposal Area	0.00	1556.95
121	Camp Roberts Solid Waste Disposal Site	0.00	1459.65
122	Hillside Solid Waste Disposal Site	0.00	1429.93
123	Neal Road LF	2.16	1415.43
124	Rock Creek LF	0.00	1379.23

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
125	Cummings Road Landfill	0.00	1329.75
126	Union Mine Disposal Site	0.21	1326.96
127	John Smith Road Solid Waste Disposal Site	0.00	1277.87
128	Coalinga Disposal Site	0.00	1236.20
129	Southeast Regional Solid Waste Disposal Site	0.00	1227.75
130	University of California at Davis SLF	0.00	1201.82
131	Vandenberg Air Force Base LF	0.00	1158.87
132	Amador County SLF	0.00	1147.16
133	McFarland-Delano SLF	0.00	1141.86
134	Industry Hills Sheraton Resort	0.50	1127.12
135	Billy Wright Disposal Site	0.00	1106.81
136	Tuolumne County Central SLF	0.00	1061.98
137	City of Santa Maria Refuse Disposal Site	1.00	1054.33
138	Eastlake SLF	0.00	1015.33
139	Blythe Disposal Site	0.00	1005.19
140	Glenn County LF Site	0.00	1002.17
141	Duarte LF		1001.60
142	Eastern Regional LF	0.00	995.44
143	Boron SLF	0.00	959.31
144	Johnson Canyon Landfill	0.00	949.96
145	Orange Avenue Disposal Inc.	0.00	948.12
146	Calexico Solid Waste Disposal Site	0.00	943.43
147	Las Pulgas LF	0.00	936.01
148	Ben Lomond Solid Waste Disposal Site	0.00	930.46
149	Bishop Sunland	0.00	913.60
150	San Onofre LF	0.00	895.33
151	Chicago Grade LF	0.00	881.42
152	Crescent City SLF	0.00	847.55
153	Healdsburg Landfill	0.00	843.38
154	Marsh Road LF	1.58	807.39
155	Arizona Street LF	0.00	773.57

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
156	Chestnut Avenue SLF	0.00	761.55
157	Yreka Solid Waste LF	0.00	751.74
158	Central Contra Costa SLF		735.38
159	Corral Hollow LF	0.00	734.01
160	Mitsubishi Cement Plant Cushenbury LF	0.00	729.79
161	U.S.M.C. 29 Palms Disposal Site	0.00	728.19
162	Hesperia Refuse Disposal Site	0.00	663.39
163	Apple Valley Disposal Site	0.00	633.03
164	Bass Hill LF	0.00	627.68
165	Earlimart Disposal Site	0.00	593.59
166	Edwards Air Force Base-Main Base LF	0.00	556.76
167	Jamacha Landfill	0.28	545.14
168	Exeter Disposal Site	0.00	538.31
169	City of Redding/Benton LF	0.00	499.41
170	Twentynine Palms Disposal Site	0.00	498.63
171	Big Bear Refuse Disposal Site	0.00	497.89
172	NAS, Lemoore SLF	0.00	496.04
173	Brawley Disposal Site	0.00	430.65
174	Lenwood-Hinkley Refuse Disposal Site	0.00	428.32
175	Lewis Road SLF	0.00	410.88
176	Phelan Refuse Disposal Site	0.00	401.43
177	Trona-Argus Refuse Disposal Site	0.00	375.93
178	Benton Crossing SLF	0.00	375.84
179	Santa Clara LF	0.85	340.56
180	Imperial Waste Site	0.00	322.65
181	French Camp Landfill	0.00	319.03
182	Lebec SLF	0.00	312.46
183	Gopher Hill SLF	0.00	306.86
184	Casa Grande Site	0.00	295.43
185	Anza Disposal Site	0.00	288.50
186	Beale Air Force Base SLF	0.00	281.05
187	Yucaipa Refuse Disposal Site	0.00	274.70

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
188	Independence Disposal Site	0.00	252.80
189	Caspar Refuse Disposal Site	0.00	250.71
190	Twin Bridges LF	0.00	234.60
191	Holtville Disposal Site	0.00	229.17
192	Needles Solid Waste Disposal Site	0.00	227.24
193	Big Oak Flat LF	0.00	223.51
194	Benton SLF	0.00	205.55
195	Sierra Army Depot	0.00	199.98
196	Kern Valley LF	0.00	199.55
197	Chalfant SLF	0.00	187.94
198	Walker SLF	0.00	187.94
199	Borrego Landfill	0.00	183.95
200	City of Willits Disposal Site	0.00	180.42
201	Oasis Disposal Site	0.00	179.64
202	Lost Hills SLF	0.00	171.86
203	Dixon Pit LF	0.00	171.32
204	Upland LF		170.22
205	California Street LF	1.00	168.43
206	Baker Refuse Disposal Site	0.00	161.86
207	Tecopa Disposal Site	0.00	160.45
208	Chester SLF	0.00	146.57
209	Black Butte Solid Waste Disposal Site	0.00	146.13
210	Lone Pine Disposal Site	0.00	140.90
211	Buttonwillow SLF	0.00	138.13
212	Pumice Valley SLF	0.00	135.57
213	Cloverdale LF	0.00	131.96
214	Evans Road LF	0.00	130.60
215	Brand Park LF	0.00	129.60
216	Loyalton LF	0.00	126.93
217	Portola LF	0.00	125.10
218	Jolon Road SLF	0.00	122.11
219	Foxen Canyon SLF	0.00	116.90
220	Mecca LF II	0.00	104.64

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
221	West Marin Sanitary Landfill, Inc.	0.00	102.79
222	Westwood Disposal Facility	0.00	102.78
223	Hay Road Landfill, Inc.	1.60	97.78
224	Salton City Cut & Fill Site	0.00	89.82
225	Palo Verde Cut & Fill Site	0.00	81.79
226	Herlong Disposal Facility	0.00	77.85
227	Hot Spa Cut & Fill Site	0.00	77.10
228	Alturas SLF	0.00	70.87
229	Tulelake SLF	0.00	66.11
230	Morongo Disposal Site	0.00	62.15
231	Niland Cut & Fill Site	0.00	61.52
232	Coastal LF	2.55	58.95
233	Rio Vista SLF	0.00	56.20
234	Lucerne Valley Disposal Site	0.00	56.05
235	Bridgeport SLF	0.00	55.30
236	Shoshone Disposal Site	0.00	54.42
237	South Coast Refuse Disposal	0.00	48.13
238	Santa Monica Landfill	0.00	47.70
239	North Belridge Solid Waste Disposal Site	0.00	47.31
240	Pitchess Honor Rancho LF	0.00	42.15
241	Stonyford Disposal Site	0.00	37.59
242	Valley Tree & Construction Disposal Site	0.00	36.28
243	Camp San Luis Obispo LF	0.00	36.08
244	New Cuyama SLF	0.00	36.08
245	Furnace Creek	0.00	34.32
246	Desert Center LF	0.00	33.43
247	McCloud Community Services District LF	0.00	32.65
248	Annapolis LF	0.00	29.57
249	Laytonville Refuse Disposal Site	0.00	29.54
250	Berryessa Garbage Service Disposal Site	0.00	28.10
251	Bieber Disposal Facility	0.00	28.10

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
252	Glennville LF	0.00	27.90
253	Ocotillo Cut & Fill	0.00	26.92
254	San Nicolas Island LF	0.00	26.73
255	Intermountain Landfill, Inc.	0.00	23.93
256	Kennedy Meadows Disposal Site	0.00	23.17
257	California Valley LF	0.00	20.01
258	Weed Solid Waste Disposal Site	0.00	16.33
259	Two Harbors LF Site	0.00	14.77
260	Yermo Disposal Site	0.00	13.46
261	Newberry Springs Disposal Site	0.00	12.09
262	San Antonio South Shore Disposal Site	0.00	9.62
263	Ravendale Disposal	0.00	8.38
264	Cecilville Disposal Site	0.00	7.26
265	Madeline Disposal Facility	0.00	7.22
266	Balance Rock Disposal Site	0.00	7.06
267	Cedarville LF - East	0.00	6.90
268	Happy Camp Solid Waste Disposal site	0.00	6.86
269	Hotelling Gulch Disposal Site	0.00	6.53
270	Lava Beds Disposal Site	0.00	6.53
271	Rogers Creek	0.00	6.53
272	Kelly Gulch Solid Waste Disposal Site	0.00	6.21
273	Goldstone Deep Space Comm Complex	0.00	6.16
274	Eagleville Disposal Site	0.00	5.91
275	Fort Bidwell LF	0.00	5.91
276	Lake City LF	0.00	5.91
277	Clipper Creek	0.00	5.09
278	Oroville LF	0.00	3.85
279	Metro Water District - Iron Mountain	0.00	0.89
280	Simpson Paper Company Landfill	0.00	0.10
281	Buena Vista Disposal Site	3.18	-2237.08

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
282	Coyote Canyon SLF	21.00	-4999.14
283	Crazy Horse Landfill	1.40	-487.84
284	Mission Hills	7.50	-582.26
285	Savage Canyon LF	2.00	-1189.02
286	Sunnyvale LF	1.20	-587.43
287	Potrero Hills SLF	9.60	-2538.74
288	Bakersfield Sanitary Landfill		0.00
289	Bonsall Landfill		0.00
290	CWMI - KHF (MSW Landfill B-19)	0.00	0.00
291	Forward Inc. Landfill	0.00	0.00
292	Aerojet Liquid Rocket Company LF	0.00	0.00
293	Calaveras Cement-Division of Flintkote Company	0.00	0.00
294	City of Palo Alto Refuse Disposal Site	0.00	0.00
295	Clover Flat Landfill	0.00	0.00
296	Collins Pine Company Landfill	0.00	0.00
297	Deep Springs College Disposal Site	0.00	0.00
298	Diamond LF	0.00	0.00
299	E.O.D. #2	0.00	0.00
300	Edwards Air Force Base-Rocket Propulsion LF	0.00	0.00
301	Hanford Recycling Disposal Site	0.00	0.00
302	Harold James Inc. Tire Disposal Site	0.00	0.00
303	Louisiana-Pacific Disposal Site	0.00	0.00
304	Montecito Memorial Park	0.00	0.00
305	Owens Fiberglas Co.	0.00	0.00
306	Picacho Cut and Fill Site	0.00	0.00
307	Red Hill SLF	0.00	0.00
308	Santa Fe Energy Resources, Inc. LF	0.00	0.00
309	Santa Rosa Geothermal Company LF	0.00	0.00
310	Speckertt Disposal Area	0.00	0.00
311	Tennant Solid Waste Disposal Site	0.00	0.00

ID No.	Landfill Name	Current MW Capacity	Unused Mg CH_4/year
312	Texaco Oil Disposal Site "C"	0.00	0.00
313	Weaverville LF Disposal Site	0.00	0.00
314	West Seventh Street Disposal Site	0.00	0.00

Californa Wastewaster Treatment Plant Inventory

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
1	Hyperion WWTP	0.00	30581.48
2	Rio Dell City WWTF	0.00	15598.12
3	Healdsburg City WWTP	0.00	14271.75
4	Sac City Combined WW Collection/TRT Sys	0.00	11141.38
5	Sacramento Regional WWTP	4.30	10003.52
6	Ukiah City WWTP	0.00	8165.62
7	Point Loma WWTP & Ocean Outfall	4.50	7374.37
8	Oroville WWTP	0.00	6134.92
9	Clovis WWTF	0.00	5273.83
10	Redway POTW	0.00	4944.83
11	OCSD Plant 1~/~OCSD Plant 2	6.98	4460.69
12	Joint Water Pollution Control Plant, Carson	18.00	4294.02
13	Sonora Regional WWTP	0.00	3969.54
14	Turlock WWTP	1.20	3701.52
15	San Jose Creek Water Reclamation Plant	0.00	3567.28
16	Donald C. Tillman WWRP	0.00	3335.54
17	PRODUCED WATER RECL PROJECT	0.00	3224.36
18	CENTRAL CONTRA COSTA SD WWTP	0.00	3048.92
19	SF-SE Water Pollution Control Plant, N-Point & Bayside	2.00	2788.94
20	CDF&W Iron Gate Hatchery WWTS	0.00	2765.19
21	CAWELO RESERVOIR B	0.00	2738.96
22	City of Livermore Water Reclamation Plant~/~DUBLIN SAN RAMON SD WWTP~/~EBDA COMMON OUTFALL~/~HAYWARD WPCF~/~ORO LOMA/CASTRO VALLEY SD WPCP~/~Raymond A. Boege Alvarado WWTP (Union SD)~/~SAN LEANDRO WPCP	0.00	2564.27
23	Phillips 66 (formerly ConocoPhillips) San Francisco Refinery, Rodeo	0.00	2522.61
24	Colton/San Bernadino STP, RIX	0.00	2506.31
25	Los Coyotes WRP	0.00	2468.03
26	Portola WWTP	0.00	2318.54
27	Stockton Regional WW Control Facility	0.00	2209.04
28	Modesto WQCF WW Land Disposal (secondary trtmt)	0.00	1947.16
29	Santa Rosa Subregional Water Reclamation Facility	0.00	1813.83
30	Modesto Water Quality Control Facility (primary trtmt)	0.00	1742.18
31	Margaret H. Chandler WWRF	0.00	1736.45
32	EBMUD WPCP	4.30	1645.13

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
33	South Bay International WTP	0.00	1629.03
34	Long Beach WRP	0.00	1600.33
35	Lincoln City WWTF	0.00	1574.86
36	Los Angeles-Glendale WWRP	0.00	1501.76
37	Terminal Island Water Reclamation Plant	0.00	1479.67
38	MRWPCA REG TRTMT & OUTFALL SYS	0.00	1443.94
39	Valencia Water Reclamation Plant	0.00	1415.56
40	BUENA SD, SHADOWRIDGE WRP~/~CARLSBAD WRF~/~ENCINA WPCF~/~Encina Ocean Outfall~/~VALLECITOS WD MEADOWLARK WRP	0.00	1323.18
41	Malaga CWD WWTF	0.00	1293.97
42	FSSD SUBREGIONAL WWTP	0.00	1282.49
43	Willits City WWTP	0.00	1264.47
44	Riverside City WWRF	1.05	1261.79
45	PALO ALTO REGIONAL WQCP	0.00	1252.23
46	SBSA WWTP	0.00	1083.05
47	Calistoga City Dunaweal WWTP	0.00	1066.75
48	SAN MATEO WWTP	0.00	1040.74
49	VICTOR VALLEY MUNI WTP	0.00	892.24
50	Simi Valley WWRP	0.00	848.14
51	City of Livermore Water Reclamation Plant~/~EBDA COMMON OUTFALL	0.00	839.99
52	VISALIA WWTF	0.00	838.33
53	Pomona Water Reclamation Plant	0.00	833.00
54	Auburn WWTP	0.00	820.52
55	Ventura WRF	0.00	797.23
56	NAPA SD WWTP (Soscol Water Recycling Facility)	0.00	762.25
57	Dry Creek WWTP	0.00	760.66
58	Millseat Facility	0.00	753.24
59	DELTA DIABLO SD WWTP	0.00	748.50
60	Whittier Narrows Water Reclamation Plant, El Monte	0.00	743.94
61	Burbank WWRP	0.00	722.13
62	Clear Creek WWTP	0.00	689.45
63	VALLEJO SFCD WWTP	0.00	663.14
64	Michelson WWRF	0.00	662.12
65	Easterly WWTP	0.00	656.14
66	Oxnard Wastewater Treatment Plant	1.00	646.93
67	IEUA Carbon Canyon WWRF~/~IEUA Regional Plant No. 1~/~IEUA Regional Plant No. 4~/~IEUA Regional Plant No. 5	0.00	643.23
68	El Dorado Hills WWTP	0.00	624.04

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
69	Tapia WRF	0.00	616.77
70	Pleasant Grove WWTP	0.00	569.40
71	McKinleyville WWTP	0.00	555.58
72	NORTH SAN MATEO COUNTY SANITATION DISTRICT WWTP	0.00	546.57
73	Forestville Water District	0.00	544.50
74	Lake of the Pines WWTP	0.00	522.86
75	RICHMOND REFINERY	0.00	516.46
76	HARRF DISCH to San Elijo Ocean Outfall	0.36	508.08
77	CALEXICO CITY WWTP	0.00	506.19
78	SCRWA WWTP	0.00	502.85
79	Saugus Water Reclamation Plant	0.00	502.28
80	South San Francisco-San Bruno WQCP	0.41	491.54
81	SWA Mountain Gate Limestone Quarry	0.00	491.47
82	SeaWorld, San Diego	0.00	485.00
83	SHELL MARTINEZ REFINERY WWTP	0.00	478.81
84	Yuba City WWTF	0.03	478.12
85	PETALUMA ELLIS CREEK WATER RECYCLING FACILITY (NPDES Permit)	0.00	477.60
86	RICHMOND WPCP~/~WEST COUNTY AGENCY OUTFALL~/~WEST COUNTY WW DISTRICT WPCP	0.19	468.34
87	Tracy WWTP	0.00	459.08
88	Alturas Municipal WWTP	0.00	457.26
89	Golden Eagle Refinery WWTP	0.00	456.17
90	Shasta Lake WWTF	0.00	445.88
91	Manteca WW Quality Control Facility	0.00	435.95
92	CENTRAL MARIN SAN. AGCY. WWTP	0.29	427.61
93	WRCRWA Regional WWRF	0.00	426.54
94	USS POSCO Industries - NPDES/SUB15	0.00	424.66
95	Merced WWTF	0.00	422.94
96	Colton WRF	0.00	416.92
97	NOVATO AND IGNACIO WWTP	0.03	407.55
98	BURLINGAME WWTP	0.20	402.44
99	South Bay WRP	0.00	401.73
100	Eureka City Elk River WWTP	0.00	398.11
101	Woodland Water Pollution Control Facility	0.00	395.19
102	CITY OF SAN CLEMENTE WRP~/~City of San Clemente Segunda Deshecha Runoff Plant~/~LATHAM WWP~/~SCWD GW Recovery Facility~/~SMWD OSO CREEK WRP~/~SMWD-CHIQUITA WRP~/~SOCWA 3A RP~/~SOCWA San Juan Creek Ocean Outfall~/~San Juan Capistrano	0.00	393.92

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
	GW TP		
103	Deer Creek WWTP	0.00	386.44
104	Corona WWRF No. 1	0.00	382.33
105	EVMWD Regional WWRF	0.00	375.67
106	EL TORO WD WRP~/~IRWD LOS ALISOS WRP~/~Irvine Desalter Project Potable WT System~/~Irvine Desalter Project Shallow GW Unit~/~SOCWA Aliso Creek Ocean Outfall~/~SOCWA COASTAL TP~/~SOCWA Regional TP	0.00	368.00
107	Chico Water Pollution Control Plant	0.14	364.46
108	GOLETA SD WWTP	0.00	357.21
109	Crystal Creek Aggregate	0.00	334.16
110	EBMUD Orinda Filter Plant	0.00	333.29
111	Dales Facility	0.00	333.25
112	San Andreas WWTP	0.00	331.36
113	CALERA CREEK WATER RECYCLING PLANT	0.00	322.13
114	EL TORO WD WRP~/~IRWD LOS ALISOS WRP~/~Irvine Desalter Project Potable WT System~/~Irvine Desalter Project Shallow GW Unit~/~SCWD Aliso Creek Water Harvesting Project~/~SOCWA Aliso Creek Ocean Outfall~/~SOCWA COASTAL TP~/~SOCWA Regional TP	0.00	321.78
115	Lake Wildwood WWTP	0.00	320.41
116	Brawley City WWTP	0.00	302.48
117	Henry N. Wochholz WWRF	0.00	301.49
118	PASO ROBLES WWTP	0.00	300.02
119	Coachella SD WWTP	0.00	297.04
120	Stillwater WWTF	0.00	294.27
121	California Men's Colony WWTP	0.00	291.07
122	Davis WWTP	0.08	287.90
123	El Centro City WWTP	0.00	284.01
124	Hill Canyon WWTP	0.42	280.30
125	ATWATER WWTF (5C240100001)	0.00	278.55
126	LOMPOC REGIONAL WRP	0.00	275.46
127	Abalone Farm, The	0.00	274.35
128	South San Luis Obispo SD WWTP	0.00	272.84
129	City of PINOLE WWTP	0.00	271.68
130	COACHELLA VALLEY WD WWTP	0.00	267.50
131	Sterling Caviar LLC, Elverta	0.00	263.67
132	SF - OCEANSIDE Water Pollution Control Plant	1.00	243.81
133	Valley SD WWTP	0.00	243.18

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
134	Camarillo WRP	0.00	233.20
135	White Slough Water Pollution Control Facility	0.00	227.49
136	SASM WWTP	0.00	225.26
137	Bear Valley WWTP	0.00	222.15
138	Hangtown Creek WRF	0.00	220.55
139	ATWATER REGIONAL WWTF	0.00	218.44
140	Beaumont WWTP No. 1	0.00	208.01
141	Ojai Valley WWTP	0.00	202.98
142	SCWA Graton CSD	0.00	194.45
143	Aerojet Interim GW Extraction & Treatment System	0.00	194.38
144	SONOMA VALLEY COUNTY SD WWTP	0.00	193.57
145	SUNNYVALE WPCP	0.75	190.32
146	Imperial ID El Centro GS	0.00	190.17
147	Ironhouse WWTF	0.00	188.34
148	Brentwood WWTP	0.00	177.92
149	LAS GALLINAS WWTP	0.05	177.10
150	Southern Region Tertiary Treatment Plant	0.00	175.61
151	GET H-B and SGSA Groundwater Extraction and Treatment System	0.00	175.60
152	Galt WWTP & Reclamation Facility	0.00	161.23
153	Windsor Town WWTP	0.00	157.40
154	Arcata City WWTF	0.00	157.18
155	Jackson City WWTP	0.00	153.71
156	Edward C. Little Water Recycling Plant	0.00	149.36
157	Volta Facility	0.00	149.28
158	Placer Cnty SMD No 1 WWTP	0.00	149.01
159	Planada WWTF	0.00	148.11
160	CARPINTERIA SD WWTP	0.00	146.56
161	Grass Valley City WWTP	0.00	138.26
162	SAUSALITO MARIN CITY STP	0.00	136.79
163	SAM WWTP (Sewer Authority Mid-Coastside Wastewater Treatment Plant)	0.00	134.57
164	PISMO BEACH WWTP	0.00	134.37
165	Red Bluff WW Reclamation Plant	0.00	133.80
166	SAN LUIS OBISPO WWTP	0.24	133.46
167	J.F. Enterprises Worm Farm	0.00	131.19
168	Ray Stoyer Water Recycling Facility	0.00	128.82
169	Olivehurst WWTP	0.00	125.59
170	Discovery Bay WWTP	0.00	124.83
171	UC Davis Main WWTP	0.00	122.40
172	CA DEPT OF CORRECTIONS CENTINELA WWTP	0.00	121.76

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
173	MT. VIEW SANITARY DISTRICT WWTP	0.00	121.26
174	Crescent City WWTP	0.00	116.58
175	North Fresno WWRF	0.00	113.62
176	Fallbrook Public Water District Plant 1	0.00	111.97
177	Mount Shasta WWTP	0.00	108.05
178	Imperial City WWTP	0.00	103.21
179	Pactiv Molded Pulp Mill	0.00	101.19
180	Anderson WPCP	0.00	100.54
181	CALIPATRIA CITY WWTP	0.00	95.74
182	Calmat Sanger Plant	0.00	95.22
183	Linda Cnty Water District WWTP	0.00	94.56
184	MORRO BAY/CAYUCOS WWTP	0.00	94.38
185	Montecito SD WWTP	0.00	90.36
186	CUTLER-OROSI WWTF	0.00	90.27
187	Scotts Valley WWTP	0.00	87.58
188	Royal Mountain King Mine	0.00	87.53
189	AMERICAN CANYON WWTP	0.00	86.13
190	Mariposa WWTP	0.00	85.49
191	Placer Cnty SMD No 3	0.00	84.71
192	Biggs WWTP	0.00	80.69
193	San Elijo Water Reclamation Facility	0.09	80.26
194	Fortuna City WWTP	0.00	76.84
195	WAWONA WWTF	0.00	75.80
196	RODEO Sanitary District WWTP	0.00	62.50
197	Lee Lake WD WWRF	0.00	61.76
198	Willows Wastewater Treatment Plant	0.00	61.11
199	Corning WWTP	0.00	60.21
200	Live Oak City WWTP	0.00	60.00
201	SF ARPRT MEL LEONG TP-SANITARY WASTE	0.00	56.25
202	MARIN CSD 5 - TIBURON WWTP	0.00	52.98
203	Bell Carter Industrial WWTP	0.00	52.82
204	Cloverdale City WWTP	0.00	51.13
205	Quincy WWTP & Collection System	0.00	51.02
206	UC Davis, Bodega Marine Lab (NPDES)	0.00	49.09
207	Sweetwater Authority Groundwater Demin	0.00	48.95
208	SCWA Russian River CSD	0.00	47.82
209	BALSAM MEADOWS HYDRO PROJECT	0.00	47.64
210	SPX Marley Cooling Technologies (on Wagner)	0.00	47.10
211	SAN JOSE/SANTA CLARA WPCP	8.80	46.76
212	Holtville City WWTP	0.00	45.84

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
213	Fort Bragg City WWTP	0.00	45.52
214	Mountain House WWTP	0.00	44.20
215	Heber PUD WWTP	0.00	43.80
216	YOUNTVILLE / CA VETS HOME WWTP	0.00	39.31
217	Williams WWTP	0.00	38.19
218	Paradise WTP	0.00	37.35
219	Colusa WWTP	0.00	36.24
220	Nevada City WWTP	0.00	36.23
221	Rio Vista Beach WWTF	0.00	36.07
222	Kiefer Landfill GW Extraction & Treatment Plant	0.00	34.88
223	Avalon WWTF	0.00	34.15
224	Angels City WWTP	0.00	34.07
225	Sierra Pacific Industries - Arcata Division Sawmill	0.00	33.50
226	El Portal WWTF	0.00	33.26
227	McVan Area Poso Creek Oil Field	0.00	33.19
228	VALERO BENICIA REFINERY	0.00	33.11
229	Palomar Energy Center	0.00	32.75
230	Deuel Vocational Institution	0.00	31.64
231	EL ESTERO WWTP NPDES	0.70	29.97
232	Corona WWRF No. 3	0.00	29.94
233	Cottonwood WWTP	0.00	29.18
234	Empire Mine State Historic Park	0.00	28.11
235	TREASURE ISLAND WWTP/DOD	0.00	27.84
236	Collins Pine Chester Sawmill	0.00	24.32
237	Occidental CSD	0.00	23.56
238	CARMEL AREA WWTP	0.12	23.02
239	Temporary Ocean Water Desalination Demonstration Project	0.00	23.01
240	Bella Vista WTP	0.00	22.69
241	Clear Creek WTP	0.00	22.28
242	Donner Summit PUD WWTP	0.00	20.23
243	GENERAL ELECTRIC GWCS	0.00	19.88
244	Colfax WWTP	0.00	19.87
245	Klondike, Dutch & Telegraph Tunnel Mines	0.00	18.68
246	WESTMORLAND CITY WWTP	0.00	18.05
247	Lincoln Village Center GWT System	0.00	17.75
248	Copper Cove WWRF	0.00	17.35
249	Center for Aquatic Biology and Aquaculture	0.00	16.98
250	Dunsmuir STP	0.00	16.72
251	Thunder Valley Casino WWTP	0.00	16.14

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
252	Miners Ranch WTP	0.00	15.65
253	US Navy Naval Air Facility WWTP	0.00	15.42
254	Northwest WWTF	0.00	15.24
255	San Juan Bautista WWTP	0.00	14.19
256	DG Fairhaven Power	0.00	14.05
257	Covelo POTW	0.00	13.93
258	Lake California WWTP	0.00	13.24
259	Scripps Institution Of Oceanography	0.00	12.30
260	HERITAGE RANCH WWTP	0.00	12.09
261	SUMMERLAND WWTP	0.00	10.84
262	IMPERIAL ID GRASS CARP HATCHERY	0.00	9.91
263	Bell Carter Plant 1	0.00	9.56
264	RHODIA INC - NON15, NPDES, SLIC	0.00	8.72
265	Hammonton Gold Village WWTP	0.00	8.69
266	SEELEY CWD WWTP	0.00	8.39
267	Shelter Cove POTW	0.00	8.06
268	Treatment Plant #1	0.00	7.50
269	UNI-KOOL ABBOTT ST	0.00	7.17
270	ROCKWELL INTERNATIONAL GROUNDWATER CLEANUP SYSTEM	0.00	6.79
271	Mendocino City CSD	0.00	6.49
272	LA SALINA WWTP, OCEANSIDE OCEAN OUTFALL~/~Mission Basin Desalting Facility~/~Oceanside Ocean Outfall~/~SAN LUIS REY WRF	0.56	6.02
273	Mineral WWTP	0.00	5.58
274	AVILA WWTP	0.00	5.45
275	Stallion Springs WWTF	0.00	5.42
276	Niland SD WWTP	0.00	5.26
277	Delleker WWTP	0.00	5.09
278	Sierra Conservation Center WTP (NPDES)	0.00	5.03
279	Country Life MHPRV Asset Partners LP WWTP	0.00	3.50
280	Pico Rivera Facility	0.00	3.32
281	CHEVRON ESTERO MARINE TERMINAL	0.00	3.09
282	SAN SIMEON WWTP	0.00	2.83
283	Indian Springs Geothermal Project	0.00	2.70
284	CUYAMA CSD WWTP	0.00	2.62
285	BIG BASIN WWTP	0.00	2.11
286	Imperial CCD WWTP	0.00	1.91
287	Peter M Ormand Date Gardens MHP	0.00	1.48
288	Shasta Lake WTP	0.00	1.24

ID No.	WWTP	Current MW Capacity	Unused Mg CH_4/yr
289	MARIN CSD 5 PARADISE COVE WWTP	0.00	1.18
290	Cascade Shores WWTP	0.00	1.14
291	BIG CREEK POWERHOUSE NO 1 WWTF	0.00	0.92
292	Mendocino Cnty WWD#2-Anchor Bay	0.00	0.44
293	McCabe USD WWTP	0.00	0.34
294	DUBLIN SAN RAMON SD WWTP	1.50	0.00
295	SANTA CRUZ WWTP	1.32	0.00
296	WATSONVILLE WWTP	0.67	0.00
297	Rialto WWRF	0.90	0.00
298	HAYWARD SHORELINE MARSH~/~Raymond A. Boege Alvarado WWTP (Union SD)	0.50	0.00
299	BENICIA WWTP	1.00	0.00
300	MILLBRAE WWTP	0.25	0.00
301	ENCINA WPCF~/~Encina Ocean Outfall~/~VALLECITOS WD MEADOWLARK WRP	0.75	0.00
302	Phillips 66 Company, Santa Maria Refinery (formerly ConocoPhillips)	0.40	0.00
303	Visalia Cleanup-Snyder General	0.50	0.00

APPENDIX B:
Economic Model

		48	49	50	51	52	53	54	55	56	57	58	59
		1.06 MW Recip	130 kW Microturbine	Small GT (5.5MW)	3 MW Conventional Combined Cycle (CC)	1.4 MW Fuel Cell	Heat Recovery Unit (Marginal	H2 Production (FC; Marginal Impact Only)	Natural Gas Boiler	Onsite CNG Production	Onsite LNG Production	Onsite SMR (500 kg H2/ day)	Pipeline Injection
1	Gross Capacity	1.06	0.13	5.5	3	1.4	1	0.2775	2.1	0.61	0.256	0.82	12.2
2	Annual Capacity Factor	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
3	Instant Cost ($/kW)	1900	3800	2400	1500	3300	50	1830	40	450	600	1450	305
4	FOM ($/kW-yr)	30	20	25	14.44	150	3	90	5	25	30	10	20
5	VOM ($/MWh)	18	22	12	15	10	1	0	1	15	20	25	20
6	HR (MMBtu/MWh)	11.221	13.5	12	7.85	8.06	0	5.2177	3.412	3.412	3.412	11.919	0
7	HR Degradation	0.0024	0.0024	0.001	0.0024	0.009	0.05	0.009	0.05	0.0024	0.0024	0.0024	0.0024
8	Capacity Degradation	0.0024	0.0024	0.001	0.0024	0.009	0.001	0.009	0.001	0.0024	0.0024	0.0024	0.0024
9	Debt Term (Yrs)	12	12	12	12	20	10	20	10	12	12	10	20
10	Economic Life (Yrs)	20	20	20	20	20	20	20	20	20	20	10	20
11	Federal Tax Life (Yrs)	20	20	15	20	10	10	10	15	20	20	20	20
12	State Tax Life (Yrs)	20	20	15	20	20	15	20	15	20	20	10	20
13	Ad Valorem Tax Rate	0.01098	0.01098	0.01098	0.01098	0.01098	0.01098	0.01098	0.01098	0.01098	0.01098	0.01098	0.01098
14	Annual Starts	25	25	150	25	4	0	0	0	0	0	25	0
15	Start-Up Fuel (MMBtu/MW)	2.8	2.8	2.8	2.8	10	0	0	0	0	0	2.8	0
16	Plant Losses	0	0	0.034	0	0.0693	0	0	0	0.0693	0.0693	0	0.0693
17	TX Losses	0	0	0	0	0	0	0	0	0.033	0.0925	0	0.033
18	Transformer Losses	0	0	0	0	0	0	0	0	0	0	0	0
19	TX Cost ($/MWh)	0	0	0	4.3	0	0	0	0	0	0	0	0
20	Fuel Type	1	1	1	1	1	7	0	8	1	1	1	6
21	GDA Eligibility	0	0	0	0	0	0	0	0	0	0	0	0
22	CSI PBI Eligibility	0	0	0	0	0	0	0	0	0	0	0	0
23	Ownership Type	0	0	0	0	0	0	0	0	0	0	0	0
24	Annual Starts	25	25	150	25	25	0	25	0	0	0	0	0
25	CO2 Emission factors (tons CO2/MMBTU fuel)	0.0585	0.0585	0.0585	0.058	0.0585	0	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585
26	CO2 released (tons CO2)	0	0	0	0	0	0	0	0	0	0	0	0
27	Renewable Resource Percent	0	0	0	0	0	0	0	0	0	0	0	0

APPENDIX C:
Solid Fuel Combustion Emission Factors

PlantName	Capacity GrossMW	Capacity Net MW	NOx (lb/MWh)	VOC/ ROG/ NMHC (lb/MWh)	Technology	County	Latitude	Longitude
Fairhaven (Dry season)	21	18	2.81	0.30	Stoker - Grate	Humbolt	40.79946	-124.20309
Fairhaven (Wet season)	21	18	2.81	0.30	Stoker - Grate	Humbolt	40.79946	-124.20309
Woodland Biomass Power	29	25	1.05	0.70	CFB	Yolo	38.691	-121.736
Rio Bravo Fresno	28	25	1.10	0.42	CFB	Fresno	36.68882	-119.72341
Mendota Biomass	28	25	1.11	0.39	CFB	Fresno	36.7559	-120.36527
Desert View	53	47	1.15	0.43	CFB	Riverside	33.58649	-116.08791
Rio Bravo Rocklin	28	25	1.40	0.42	CFB	Placer	38.83183	-121.3136
Delano Energy	57	49	1.46	0.29	BFB	Kern	35.7191	-119.23459
Tracy Biomass	23	18.5	1.47	0.69	Stoker - Grate	San Joaquin	37.71999	-121.48845
Chowchilla II	12.5	10	1.48	0.09	BFB	Madera	37.10715	-120.24887
Buena Vista Biomass	18	16	1.48	0.33	BFB	Amador	38.27792	-120.91376
Dinuba	13	11.5	1.55	1.16	BFB	Tulare	36.57	-119.419
Madera	28	25	2.00	0.96	BFB	Madera	36.862	-120.339
Blue Lake Power	14	11	2.52		Stoker - Grate	Humboldt	40.87769	-123.99461
Chinese Station	23	20	2.92	1.82	BFB	Tuolumne	37.87464	-120.47755
Wheelabrator Shasta	55	50	3.05	1.78	Stoker - Grate	Shasta	40.42959	-122.27824
Commerce Refuse-to-Energy Facility	11.5	10	3.44	0.24	Stoker - Grate	Los Angeles	33.995	-118.151
Stanislaus Resource Recovery	22.5	20	4.71	0.20	Stoker - Grate	Stanislaus	37.397	-121.141
Soledad	15	13.5	1.46		NA	Monterey	36.41698	-121.31562
SPI Loyalton	20	18	2.82		Stoker - Grate	Sierra	39.66994	-120.23941
Pacific Oroville Power	20	18	2.41		Stoker - Grate	Butte	39.481	-121.56557
Sierra Power	11	9.5	1.79	1.19	Stoker - Grate	Tulare	35.95393	-119.04631
Burney Forest Power	35	31	1.85	1.54	Stoker - Grate	Shasta	40.88	-121.72
SPI Burney	20	16	3.13	1.79	Stoker - Grate	Shasta	40.87676	-121.7019
SPI Lincoln	18	10	3.76	0.55	Stoker - Grate	Placer	38.90268	-121.3096
Collins Pine	13.3	12	4.58	2.75	Stoker - Grate	Plumas	40.30284	-121.24409
Eel River	34	28	5.04		Stoker - Grate	Humbolt	40.48134	-124.10463