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Evaluating the Air Quality, Climate & Economic Impacts of Biogas Management Technologies

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Evaluating the Air Quality, Climate & Economic Impacts of Biogas Management Technologies

UC Davis Biomass Collaborative (Davis, CA)
U.S. EPA Region 9 (San Francisco, CA)
& National Risk Management Research Lab
Office of Research and Development (Cincinnati, OH)

Table of Contents

Acknowledgements & Notice

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Foreword

The U.S. Environmental Protection Agency (EPA) is charged by Congress with protecting the Nation's land, air, and water resources. Under a mandate of national environmental laws, the Agency strives to formulate and implement actions leading to a compatible balance between human activities and the ability of natural systems to support and nurture life. To meet this mandate, EPA's research program provides data and technical support to solve environmental problems today and builds the science knowledge base necessary to manage our ecological resources wisely, understand how pollutants affect our health, and prevent or reduce environmental risks in the future.

The National Risk Management Research Laboratory (NRMRL) investigates technological and management approaches to prevent and reduce risks from pollution that threaten human health and the environment. The focus of the Laboratory's research program is to understand how pollution enters the environment by investigating emissions and releases to air, water, land, and sub-surfaces and to investigate technologies and approaches to prevent and control these sources of pollution. The research is designed to protect water quality in public water systems; remediate contaminated sites, sediments and ground water; prevent and control air pollutants in indoor and outdoor environments; and restore ecosystems. NRMRL collaborates with both public and private sector partners to foster technologies that reduce the cost of compliance and actively works to identify/anticipate emerging problems. NRMRL's research provides solutions to environmental problems by: developing and promoting technologies that protect and improve the environment; advancing scientific and engineering information to support regulatory and policy decisions; and providing the technical support and information transfer to ensure implementation of environmental regulations and strategies at the national, state, and community levels.

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Gary J. Foley, Acting Director of the Air Pollution Prevention and Control Division
National Risk Management Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency

Executive Summary

Anaerobic digestion is a natural biological process in which microorganisms break down organic materials in the absence of oxygen. When anaerobic microbes metabolize organic waste – i.e., the carbon-based remains of plants, animals and their waste products, e.g., animal manure, sewage sludge and food waste – they produce biogas. Biogas consists mainly of methane and carbon dioxide and can be used as a renewable energy fuel in a variety of applications. The costs and impacts of biogas generation and utilization processes differ, depending on the scale, technology, source material (e.g., sewage, manure, food processing waste, municipal solid waste), and end uses (e.g., on-site electricity generation, conversion to a vehicle fuel, injection into the natural gas pipeline).

This research was focused in California because it has unique air quality challenges that make it difficult to comply with National Ambient Air Quality Standards (NAAQS) without installing controls on a wide variety of sources.[1] These difficulties are "due to the combination of meteorology and topography, population growth and the pollution burden associated with mobile sources" (USEPA 2015a). However, with the strengthening of NAAQS for ground level-ozone, challenges unique to California could become more commonplace. As air quality regulators across the country consider limits on stationary sources, insights from the proverbial 'canary in the coal mine' may prove instructive.

Currently, many existing biogas producers [e.g., a Water Resource Recovery Facility (WRRF) or landfill] are located in ozone non-attainment areas in California where there is pressure to decrease stationary source emissions, especially from stationary reciprocating engines. Required to meet more stringent emissions rules, many organic waste managers, project owners and regulators alike lack sufficient information about the overall environmental and economic performance of available biogas management technologies. A more complete understanding of the environmental and economic performance of biogas-to-energy technologies will assist in identifying geographically appropriate and cost-effective biogas management options. This research attempts to advance that understanding through an evaluation of available biogas management technologies and related performance in California.

The focus of the research described in this report was to evaluate the impacts associated with biogas management technologies; specifically, to evaluate the emissions and costs associated with using biogas in particular end-use applications. Seven different technologies were evaluated in terms of their individual cost, efficiency and emissions — both greenhouse gas (GHG) and criteria air pollutant emissions. The technologies examined include: combustion in a

[1] In general, emission limits are more stringent and concomitant installation and operating costs are higher in California for these technologies. Forty-two California counties are designated non-attainment for the 8-hour ozone (2008) standard; seven of which are designated as Serious, Severe or Extreme (USEPA 2012b). Affected population is 34.6 million out of 39.1 million total state population (or 88% of total).

reciprocating engine; combustion in a gas turbine; combustion in a microturbine; conversion in a fuel cell; processing for pipeline injection; processing to create Compressed Natural Gas (CNG); and flaring.[2]

The scope of the analysis was at once broad and narrow. It was broad in that it did not consider differences in biogas composition, which vary considerably depending on the source material. The analysis was narrow in that the system boundary began with already-produced biogas and ended with on-site use or upgrading (Figure 1). It did not include the costs or emissions from upstream processes, such as biogas production, fugitive emissions or material handling and transportation costs.[3] Neither did it include downstream factors, such as the carbon temporarily sequestered by land-applying digestate or the carbon and criteria pollutants emitted by combusting CNG in a vehicle. Comprehensively, the analysis evaluated capital, operations, and maintenance costs, including those for biogas pre-treatment or conditioning (e.g., removing siloxanes and sulfur compounds) and exhaust gas treatment (i.e., for air pollution control equipment). Narrowly, it only evaluated costs pertaining to biogas management.

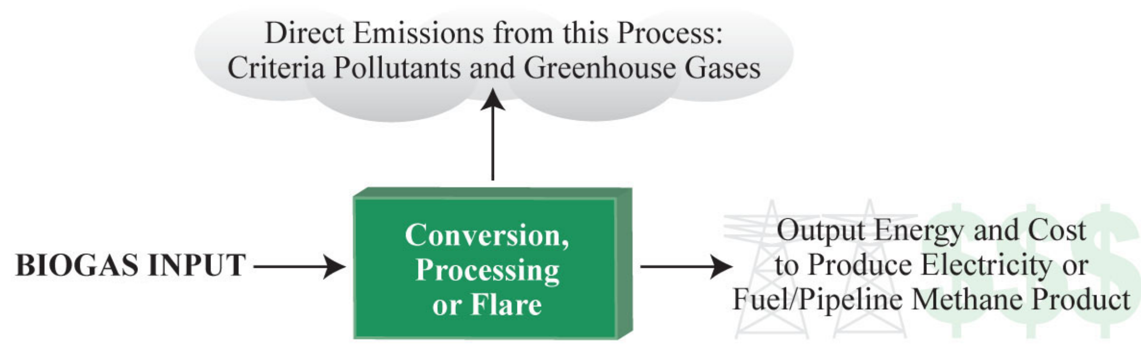

Figure 1. System boundary.

The characteristics evaluated and compared through this research project included the following:

- Conversion efficiency: percent energy efficiency for electricity production systems, higher heating value basis and percent yield for compressed renewable natural gas (RNG) and pipeline injection processes.[4]
- Levelized cost of energy (LCOE): dollar per kilowatt hour ($/kWh), dollar per million British thermal units ($/MMBtu) or $/gasoline gallon equivalent ($/GGE).
- On-site criteria pollutant and GHG emissions.[5]

Only California-based systems were evaluated. Source information included peer-reviewed and ‘gray’ literature, operating permits, source test reports, and expert and developer interviews. Cost

[2] Combined heat and power and direct use of biogas for heat or steam (boilers or furnaces) are not analyzed in this report but are a viable option if a facility can use the heat, e.g., to warm digesters.
[3] Although the cost of and emissions from processing wastes to generate biogas are significant factors in the economics and environmental impacts of waste-to-energy projects, they are not considered here given the availability of research focused on these issues and the limited resources available for this study.
[4] Electrical energy output / biogas energy input on a higher heating value (HHV) basis.
[5] Downstream emissions and costs for fuel and pipeline product are not included in this analysis.

and performance values in this report are suitable for comparing across technologies and for rough budgetary estimates. Detailed project costs and, to some extent, performance are site specific and would need to be assessed by a project developer.

Summary Cost Results

Costs required to process biogas varied from less than $1/MMBtu (input flow basis) for flare systems to $7-$25/MMBtu or more for upgrading the biogas for injection into the natural gas pipeline. Flaring appeared to be the lowest cost management option but would likely not be if energy savings, sales, or subsidies were included in a future analysis.

Fuel cell costs were similar to those of upgrading for pipeline injection. Costs for engines, microturbines and processing for CNG each fell below $5/MMBtu (input) for the upper end of the technology capacity range. Combustion turbine costs were relatively flat ($3-$4/MMBtu). Fuel cells, microturbines, processing to CNG and pipeline injection showed particularly strong economies of scale due to a combination of lower per-unit capital and operating costs, and higher efficiencies at larger scale. For situations where biogas is already available (e.g., landfills or WRRFs), management of biogas using microturbines, reciprocating engines, and gas turbines would compete with industrial and commercial electricity prices in CA.[6]

The LCOE for fuel cells ranged from ~$0.16/kWh at a small size (200 kW) to about $0.09/kWh at the 3 MW size. The LCOE for reciprocating engines varied from $0.09 to $0.05/kWh. Combustion turbines (gas turbines) had the lowest LCOE of about $0.04/kWh at large scale. CNG production with on-site fueling varied from about $18/MMBtu to about $4/MMBtu at the largest size. The CNG pathway was generally less costly than upgrading the gas for pipeline injection, which ranged upwards from $25/MMBtu at small scale to about $7/MMBtu at very large scale.

Summary Emissions Results

Criteria Pollutants[7]

Criteria pollutant emission factors, based on gas energy input (lb/MMBtu gas input), are calculated and summarized in the report. Reciprocating engines had the highest NO_x emission factor among the technologies that produce on-site electricity, while flares had the highest average NO_x emission factor over all. Of the stationary power applications, fuel cells, followed by gas turbines with selective catalytic reduction (SCR)-based NO_x control systems, had the lowest NO_x emission factors.[8]

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[6] Average California electricity prices for industrial and commercial customers are $0.123/kWh and $0.156/kWh respectively (EIA 2016). The expected Bioenergy Feed-in Tariff price floor is about $0.125/kWh.

[7] See methods and individual technology descriptions in main body of report for details on emission factors.

[8] Fuel cells employ an electrochemical method to produce electricity and therefore have very low air emissions. Those emissions come from the combustion or oxidation of the anode off gas, which contains unreacted hydrogen (H_2), CO and VOCs. Catalytic or surface burners are usually used for the anode off gas. These operate at a high enough temperature to oxidize the H_2, CO, and VOCs while producing very low NO_x emissions (ICF 2015).

The CNG and pipeline injection pathways produce on-site emissions but are responsible for additional emissions when the gas is used. Again, these downstream emissions are beyond the scope of this analysis.

The report summarizes output-based NO_x (lb/MWh of delivered electricity) for the electricity producing systems. The effect of conversion efficiency can be seen in the output-based emissions. Engines, gas turbines and microturbines all show decreasing output-based emissions as capacity (and efficiency) increases. The efficiency of fuel cells is approximately constant over the range of capacities modeled.

GHG

On-site emission factors for individual GHGs and output-based emissions in lb of CO_{2eq} per MWh were developed for each technology in the report. All devices emit small amounts of methane as "slip" (or unburned methane) from conversion devices or through leaks in processing equipment. The analysis used a methane slip factor that ranged from 0.2 – 2.0% depending on the device. The on-site CO_2 emissions include the CO_2 originally in the input biogas as well as those created by combusting methane. Both of these sources of CO_2 are biogenic.[9] There are no other CO_2 emissions considered in this report.

The CO_2 equivalent emission factors calculated in this report for biogas-fueled microturbines, gas turbines, reciprocating engines, and fuel cells are all considerably lower than the California electric grid average carbon footprint, which is 653 lb CO_{2eq} per MWh.[10]

Other Costs, Revenues & Policies

Recognizing the limited scope of the analysis and the important role of additional factors in evaluating a project's economic and environmental performance, the report includes a qualitative description of possible additional costs, such as acquiring a natural-gas powered fleet for the CNG pathway; it also reviews possible sources of revenue, such as savings from on-site energy use or income from off-site energy sales. Finally, the report provides an overview of major Federal and State policies and subsidies affecting biogas projects, including a compendium of grants & other financial incentives (Appendix B).

Relevance to other states or regions

While the biogas utilization technologies discussed in this report are in use throughout the U.S., the detailed emissions performance and costs are specific to California, where forty-two California counties are designated non-attainment for 8-hour ozone (2008). In general, emission limits are more stringent and concomitant installed and operating costs are higher in California

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[9] Biogenic CO_2 emissions are those related to the natural carbon cycle, as well as those resulting from the production, harvest, combustion, digestion, fermentation, decomposition, or processing of biologically based materials (USEPA 2016).

[10] See USEPA eGRID: https://www.epa.gov/energy/egrid. Biogenic CO_2 emissions are not counted in the EPA eGRID inventory. Biogenic CO_2 emissions from this analysis were not included in order to compare to eGRID. The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive source of data on the environmental characteristics of the electric power generated in the United States.

for these technologies. However, these results may soon have utility for many regions in the U.S. The number (and severity) of ozone non-attainment areas are expected to increase after implementing the more stringent 2015 ozone standard.

List of Figures

List of Tables

Acronyms & Abbreviations

ADC	Alternative daily cover
AFR	Air/fuel ratio
AD	Anaerobic digestion
ADWF	Average dry weather flow
BAAQMD	Bay Area Air Quality Management District
BACT	Best available control technology
B&V	Black and Veatch
BCF	Billion cubic feet
Btu	British thermal unit
CAPEX	Capital expenditure
CARB	California Air Resources Board
CEC	California Energy Commission
CI	Carbon intensity
CPUC	California Public Utilities Commission
CO_2	Carbon dioxide
CO_2eq	Carbon dioxide equivalent
CO	Carbon monoxide
CRNG	Coalition for Renewable Natural Gas
CHP	Combined heat and power
CNG	Compressed natural gas
CAFOs	Concentrated animal feedlot operations
DG	Distributed generation
DLN	Dry low-NO_x
EBMUD	East Bay Municipal Utility District
Eq	Equivalent
FIT	Feed-in tariff
GGE	Gasoline gallon equivalent
GW	Gigawatt
GWP	Global warming potential
GWP_{100}	100 year horizon GWP
GHG	Greenhouse gas
HHV	Higher heating value
h	Hour
H_2	Hydrogen
H_2S	Hydrogen sulfide
IEUA	Inland Empire Utilities Agency
IOU	Investor-owned utility
IPPC	Intergovernmental Panel on Climate Change
kWh	Kilowatt hour
LCA	Life-cycle analysis
LCOE	Levelized cost of energy
LNG	Liquefied natural gas
LCFS	Low carbon fuel standard
MW	Megawatt
MWh	Megawatt hour
CH_4	Methane
MM BDT	Million bone dry (short) tons

MMBtu	Million British thermal units
MGD	Million gallons per day
MCFC	Molten carbonate fuel cell
NAAQS	National Ambient Air Quality Standard
NO_x	Nitrogen oxides (or oxides of nitrogen)
N_2O	Nitrous oxide
NSCR	Nonselective catalytic reduction
ORD	Office of Research and Development
O&M	Operation and maintenance cost
O_2	Oxygen
O_3	Ozone
OPEX	Operations expense
PM	Particulate matter
ppm	Parts per million
ppmv	Parts per million by volume
lb	Pounds
PPA	Power purchasing agreement
PSA	Pressure swing adsorption
PAR	Proposed amended rule
POTW	Publicly owned treatment works
RICE	Reciprocating internal combustion engines
RAM	Renewable auction mechanism
REC	Renewable energy certificate
RFS	Renewable fuels standard
RIN	Renewable identification number
RNG	Renewable natural gas (also known as biomethane)
RPS	Renewable portfolio standard
RVO	Renewable volume obligation
SJVAPCD	San Joaquin Valley Air Pollution Control District
SCR	Selective catalytic reduction
SB	Senate bill
SLCP	Short-lived climate pollutants
SOFC	Solid oxide fuel cell
SCAQMD	South Coast Air Quality Management District
SCAP	Southern California Alliance of Publicly-Owned Treatment Works
SCFM	Standard cubic feet per minute
SO_2	Sulfur dioxide
SO_x	Sulfur oxide
TS	Total solids
EPA	U.S. Environmental Protection Agency
UCD	University of California, Davis
VOC	Volatile organic compounds
VS/TS	Volatile solids/Total solids
WRRF	Water resource recovery facility (a.k.a., WWTF)
WWTF	Wastewater treatment facility
y	Year

1. Introduction

Anaerobically digested (AD) organic waste produces biogas, a source of renewable energy. With ample volumes of organic waste, California could generate a significant amount of renewable energy. California biogas potential is estimated to be 93 billion cubic feet per year of methane or about 800 million gallons gasoline equivalent (GGE) if used as compressed Renewable Natural Gas (RNG), or CNG (Table 1) (Williams, Jenkins et al. 2015).

Table 1. Estimated biogas potential for California.

Feedstock	Amount Technically Available	Biomethane Potential (billion cubic feet)	Million gasoline gallon equivalent (GGE)
Animal Manure	3.4 MM BDT *	19.7	170
Landfill Gas	106 BCF *	53	457
Municipal Solid Waste (food, leaves, grass fraction)	1.2 MM BDT	12.6	109
Water Resource Recovery Facility[11] (WRRF)	11.8 BCF (gas)	7.7	66
Total		**93**	**802**

* MM BDT = million bone dry (short) tons, BCF = billion cubic feet.

Many biogas producers generate electricity on-site with reciprocating engines, gas turbines and microturbines, which emit ozone-forming criteria pollutants (i.e., nitrogen oxides or NO_x). The majority are located in ozone non-attainment air basins where strict regulation of criteria pollutants complicates the permitting of stationary sources (Figure 2).

Innovative alternatives such as upgrading biogas for injection into natural gas pipelines, fuel cells and the use of biogas as a transportation fuel can achieve cross-media environmental benefits, including: GHG emission mitigation, air and water quality improvements, odors and waste reduction, and fossil fuel displacement. However, organic waste managers and regulators alike lack sufficient information about the overall environmental and economic performance of available biogas management technologies.

[11] WRRFs are also known as Wastewater Treatment Facilities (WWTF).

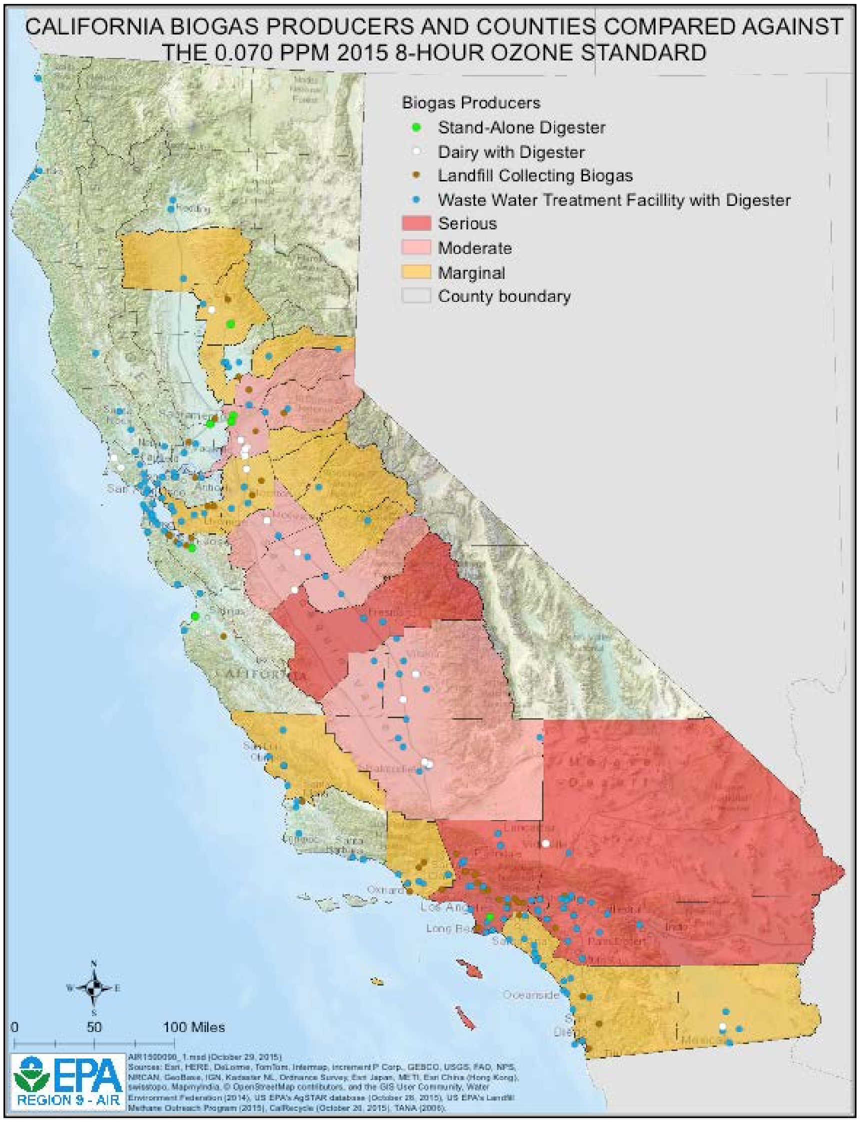

Figure 2. Ozone (O_3) attainment designations in California for 8-hour 2015 National Ambient Air Quality Standard (NAAQS) and biogas producers.

A more complete understanding of the environmental and economic performance of biogas-to-energy technologies will assist state and local governments, regulators, and potential project developers to identify geographically-appropriate and cost-effective biogas management options. This paper presents the economic and environmental performance of seven different biogas management technologies: flaring; combustion in a reciprocating engine; combustion in a gas turbine; combustion in a microturbine; conversion in a fuel cell; processing for natural gas pipeline injection or for CNG vehicle fuel.[12]

The analysis is limited to the environmental and economic performance associated with the biogas management technology (including biogas clean up and conditioning steps). It is not a comprehensive full system or life-cycle analysis. Upstream (e.g., the vehicle fuel consumed to transport material to the biogas facility) and downstream (e.g., the carbon temporarily sequestered by land-applying biosolids) sources and sinks are beyond the scope of this study.[13]

Rather, the analysis focuses on the point of use (conversion or upgrading), specifically the emissions and costs uniquely associated with each of the seven biogas management technologies. Figure 3 shows the stages of biogas production. As indicated by the shaded box within the figure, our cost and emissions analysis is limited to the biogas management stage.

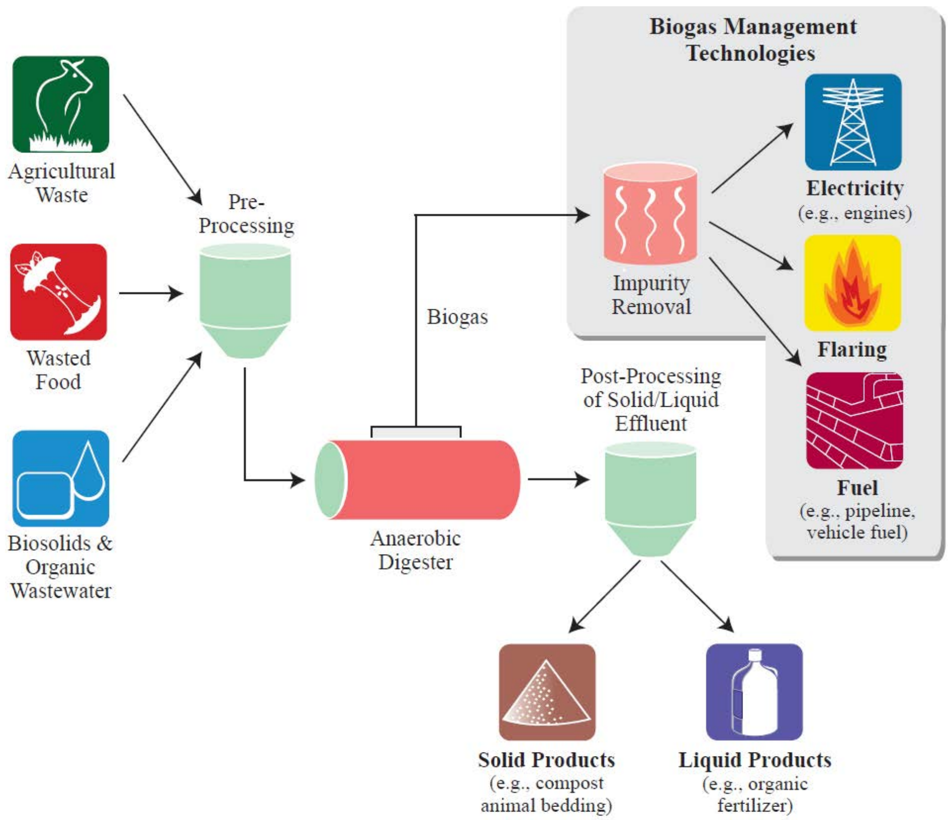

Figure 3. General biogas production and use pathway schematic.

[12] Combined heat and power and direct use of biogas for heat or steam (boilers or furnaces) are not analyzed in this report but can be a viable option when appropriate thermal load is available such as digester heating or nearby industrial furnaces.

[13] Although the cost of and emissions from processing wastes to generate biogas are significant factors in the economics and environmental impacts of waste-to-energy projects, they are not considered here given the availability of research focused on these issues and the limited resources available for this study.

This research also includes a qualitative description of additional costs and revenue beyond the scope of the quantitative analysis. The "Policy Pipeline" section provides an overview of major Federal and State policies affecting biogas projects. Appendix B details the grants & other financial incentives that could support biogas projects.

2. Methods & Results

The analysis evaluates and compares the cost and performance of seven different biogas management technologies— both in terms of emissions and operating efficiency. The investigated technologies include the following: combustion in a reciprocating engine; combustion in a gas turbine; combustion in a microturbine; conversion in a fuel cell; processing for pipeline injection; processing to create CNG to fuel vehicles; and flaring. Combined heat and power and direct use of biogas for heat or steam (boilers or furnaces) are not analyzed in this report but can be a viable option when appropriate thermal load is available, such as digester heating or nearby industrial furnaces.[14, 15]

The analysis does not include the costs and emissions associated with biogas production upstream, such as trucking, material handling, and digester construction costs; downstream, such as the carbon temporarily sequestered by land-applying digestate; or off-site, such the combustion of CNG in a vehicle or of RNG once drawn from the pipeline. In other words, the boundary of the analyzed technologies starts with already-produced biogas and examines the cost and performance of on-site use or upgrading (Figure 4).

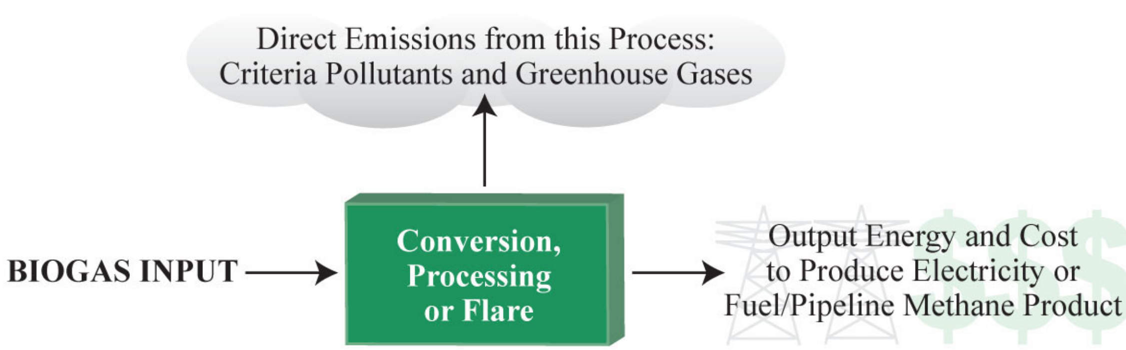

Figure 4. System boundary.

[14] U.S. EPA Landfill Methane Outreach Program: https://www3.epa.gov/lmop/projects-candidates/operational.html
[15] U.S. DOE CHP Technical Assistance Partnerships, Pacific Region: http://www.pacificchptap.org/aboutchp

The properties and characteristics evaluated and compared include the following:

- Conversion efficiency: percent energy efficiency for electricity production systems, higher heating value basis and percent yield for compressed RNG and pipeline injection processes.[16]
- Levelized cost of energy (LCOE): dollar per kilowatt hour ($/kWh), dollar per million British thermal units ($/MMBtu) or $/gasoline gallon equivalent ($/GGE).
- On-site criteria pollutant and GHG emissions.[17]

Source information included peer-reviewed and 'gray' literature,[18] operating permits and source test reports and expert and developer interviews.

Assumptions

Biogas Composition

Methane content in biogas ranges from 40-65% in landfill gas and 50-75% in digester gas (Mintz, Han et al. 2010, Rapport, Zhang et al. 2012). Raw biogas also contains water vapor and typically includes hydrogen sulfide (H_2S) and possibly siloxanes.[19] Hydrogen sulfide is corrosive, can contribute to sulfur oxide (SO_x) emissions and can damage catalysts used in air pollution control systems and most fuel cells. Siloxanes are problematic because they can lead to deposits of silicon compounds (such as SiO_2) in an engine or turbine when the biogas is combusted as well as damage to emissions control catalysts. Consequently, raw biogas often needs to be cleaned or treated to lower H_2S and siloxane content to acceptable levels (GTI 2014).

In this report, methane content of biogas is assumed to be 60% (with balance of carbon dioxide). The cost evaluations include those associated with removing biogas impurities (e.g., siloxanes and sulfur compounds) for the respective application.

Cost of Energy

Capital and operating costs for the biogas technologies are taken from literature and discussions with developers; those costs reflect California costs or "adders" to U.S. average costs. Costs of raw biogas cleanup (H_2S and siloxane reduction) are included for all biogas technologies. Cost of air pollution control equipment is included for reciprocating engines and gas turbines; air pollution control equipment is presumed not needed for microturbines, fuel cells, fuel and pipeline pathways, and flares. The CNG fueling pathway cost includes on-site fueling equipment. The upgrade to pipeline injection pathway includes interconnection or injection costs. Year 2015 dollars are used.

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[16] Electrical energy output / biogas energy input on a higher heating value (HHV) basis.
[17] Downstream emissions and costs for fuel and pipeline product are not included in this analysis.
[18] http://www.greynet.org/home/aboutgreynet.html
[19] Siloxanes are synthetic organo-silicon compounds used in the manufacturing of personal hygiene, health care and industrial products. Their prevalence results in the lower molecular weight siloxanes being released into landfill gas and some wastewater treatment digester gas.

The LCOE was estimated for each technology by dividing the total annual cost by the annual amount of energy produced to arrive at cost per unit of energy: $/kWh, $/GGE, or $/MMBtu. Total annual cost is the sum of the annualized capital cost and annual operation and maintenance (O&M) costs. The capital cost was amortized over 20 years using 6% annual interest to determine the annualized capital cost.

The LCOE represents the required revenue per unit of energy for the project to break even. Note that the analysis assumed the infrastructure needed to produce the biogas already existed (or was already paid for) and so biogas enters the economic calculation at zero cost.[20]

Criteria Pollutants

A large number of operating air permits and approximately 54 emission source test reports were obtained from air districts throughout California. Criteria pollutant emission factors based on fuel-energy input [i.e., pounds of pollutant per MMBtu input (lb/MMBtu)] were derived from a review of source test reports for microturbines, combustion turbines and flares (Table 2 and Appendix C).

For reciprocating engines, the nitrous oxide (NO_x) emission factor is based on the South Coast Air Quality Management District (SCAQMD) Rule 1110.2. Volatile organic compounds (VOC) and carbon monoxide (CO) emission factors are based on source test data for engines with SCR and catalytic oxidation (CatOx) exhaust treatment. These engine emission factors, therefore, represent expected performance for new installations (or emissions retrofits) for the SCAQMD and possibly other air districts at risk for meeting ambient ozone standards.

U.S. EPA AP-42 was used as the particulate matter (PM) emissions factor for reciprocating engines and gas turbines. Source test data was used for PM otherwise.

Source test averages were used for oxides of sulfur (SO_x) emission factors. Sulfur content in biogas is highly variable and directly affects SO_x emissions. The values shown here include the influence of the biogas sulfur. Additionally, most catalysts used in emissions control equipment are sensitive to sulfur and will fail quickly if most of the sulfur is not removed before it reaches the catalyst. The SO_x emission factors for those systems (SCR/CatOx) are therefore low.

Fuel cell emissions are based on permit values and one source test report.

On-site criteria pollutant emissions from producing compressed RNG and pipeline quality gas are based on flaring the tailgas, a process byproduct gas which contains some methane that needs to be destroyed. Downstream emissions also occur when the upgraded biogas is used, as a vehicle fuel or as pipeline natural gas. Those downstream emissions are not included in this analysis.[21]

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[20] If the biogas did not yet exist, e.g., a digester needed to be built, the economics would be different and the LCOE likely higher.

[21] These "downstream" emissions are important but there are too many possible factors (devices) to account for in this analysis.

Table 2. Number of source tests reviewed by application type.

Application*	No. of Source Tests Reviewed	Biogas Source Type	Source Test Air District
Reciprocating Engine	35	6 @ Landfill, 26 @ WRRF, 3 @ Dairy Digester	– South Coast – Bay Area – San Joaquin Valley – Yolo-Solano – Mojave Desert
Microturbine	4	1 @ WRRF, 3 @ Food Waste Digester	– South Coast – Bay Area
Combustion Turbine	10	5 @ Landfill, 5 @ WRRF	– South Coast – Bay Area – San Joaquin Valley
Fuel Cells	3 (2 permits)	3@ WRRF	– South Coast – San Joaquin Valley
Flare	4	1 @ Landfill, 3 @ WRRF	– South Coast – San Joaquin Valley

* Also see Appendix C.

Emission factors combined with conversion efficiencies were used to develop emissions per unit of energy output (i.e., lb/MWh) for electricity producing technologies.

Greenhouse Gas Emissions

GHG emissions include methane (CH_4) slip or fugitive emissions, nitrous oxide (N_2O) and carbon dioxide (CO_2) emissions.

Methane slip (or unburned methane) from combustion devices is small but significant ranging from 0.2 – 2.0% depending on the device (Mintz et al., 2010, SCS 2007). For the biomethane pathways (compressed RNG and pipeline injection), 1% fugitive methane is assumed in the upgrading process (Han, Mintz et al. 2011).

The N_2O emissions are taken from source-specific literature when found. Otherwise, default N_2O emission factors for stationary combustion in the energy industry were used from Table 2.2 in the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

The CO_2 emissions are calculated based on stoichiometric combustion of biogas where 1 gram of methane produces 2.75 grams of carbon dioxide when burned (or 2.75 lb/lb). Emissions include the CO_2 present in the incoming biogas, which passes through the combustion process unchanged, and the CO_2 produced when methane is combusted. For biogas with 60% methane content, the CO_2 emission factor is 0.115 lb CO_2 per cubic foot of biogas (or 191.3 lb/MMBtu).[22] All engine types, flaring, and other stationary applications that burn the same biogas type will have equivalent CO_2 emission factors. While there are fewer **on-site** CO_2 emissions associated with upgrading biogas to be used as a vehicle fuel or injected into the natural gas pipeline, once combusted, the total CO_2 emissions (on-site + off-site) would be the same as they are for engines and for flaring.

No matter the end-use, CO_2 emissions from combusting biogas are biogenic. The EPA defines biogenic CO_2 emissions as those related to the natural carbon cycle, as well as those resulting from the production, harvest, combustion, digestion, fermentation, decomposition, or processing of biologically based materials (USEPA 2016). The CO_2 emissions associated with all of the biogas management technologies evaluated herein are biogenic. There are no other CO_2 emissions considered in this report.

The report compares the CO_2 equivalent (CO_{2eq}) emission factors for biogas-fueled microturbines, gas turbines, reciprocating engines, and fuel cells to the California electric grid carbon footprint, which is 653 lbs CO2eq per MWh, according to the EPA's eGRID. Consistent with eGRID, biogenic CO_2 emissions were not used to calculate CO_{2eq} emissions. [23]

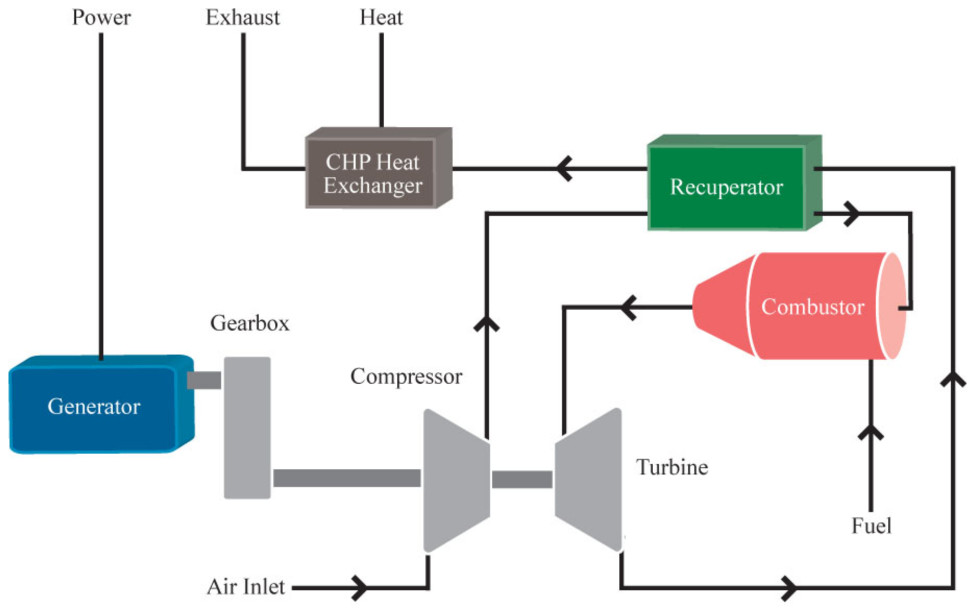
Results

Microturbine

Microturbines are small combustion turbines available in capacities ranging from 30 kW to 333 kW for individual units and up to multiple megawatt (MW) facility sizes if units are combined. Electricity conversion efficiency ranges from about 22% to 27% (Figure 12). With biogas fuel, NO_x emissions are typically lower than 9 parts per million by volume (ppmv).

Like the larger combustion turbine, the microturbine operates on the Brayton Cycle (thermodynamic cycle) where inlet air is first compressed followed by injection of gaseous or liquid fuel and then burned in the combustor. The hot high-pressure combustion gas expands through a turbine which provides shaft power to run the compressor and the electric generator (Figure 5).

[22] Emission factor of fossil natural gas is ~ 115 - 125 lb CO_2eq/MMBtu, (https://www.eia.gov/environment/emissions/co2_vol_mass.cfm)
[23] USEPA eGRID assigns zero CO_2 emissions to electric generation carbon footprint from the combustion of all biomass (including biogas) because these organic materials would otherwise release CO_2 (or other greenhouse gases) to the atmosphere through decomposition: https://www.epa.gov/sites/production/files/2015-10/documents/egrid2012_technicalsupportdocument.pdf.



(adapted from FlexEnergy)

Figure 5. Microturbine schematic.

Efficiency

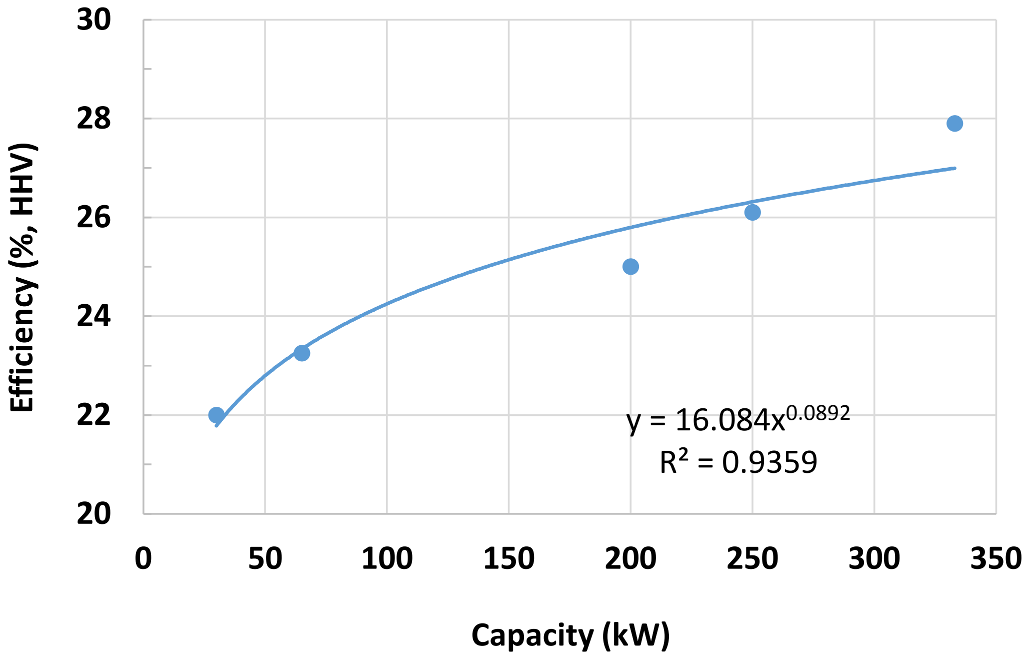
Electrical conversion efficiencies for microturbines (with recuperators) fueled on biogas range from about 22% to 27% [higher heating value (HHV) basis] (Itron 2011, Darrow, Tidball et al. 2015, FlexEnergy). Table 3 displays nominal electrical conversion efficiencies and corresponding gas energy input flows for typical microturbines.[24] Efficiency versus capacity is plotted in Figure 6 and includes the curve fit through the individual data.

Table 3. Microturbine input flows and efficiency.

Capacity			Efficiency, HHV basis	
kW	Gas Flow input (SCFM)*	Gas Flow input (MMBtu/h)	(%)	Heat Rate (Btu/kWh)*
30	13.1	0.47	22	15,700
65	26.4	0.95	23	14,600
200	73.5	2.6	26	13,200
250	90.0	3.2	26	13,000
333	116.9	4.2	27	12,600

* Note: SCFM = Standard cubic feet per minute. Heat Rate is Btu input energy per kWh electricity out

[24] Sea level and ambient air temperature at 60 °F. Input flow calculations assume biogas is 60% methane or has energy content of 600 Btu per cubic foot.



Sources: (Itron 2011, Darrow et al., 2015, FlexEnergy)

Figure 6. Microturbine efficiency curve.

Microturbine efficiency is sensitive to the density of air at point of use. Conversion efficiency and power output decrease as ambient temperature or elevation increases (due to lower air density – less oxygen per cubic foot available for combustion).

Emissions

Criteria Pollutants

Uncontrolled emissions from natural gas-fired microturbines typically range 3-9 ppm for NO_x, VOC and CO (Darrow, Tidball et al. 2015). Source tests from microturbines in the Bay Area Air Quality Management District (BAAQMD) and the SCAQMD were reviewed (Appendix C). Both were for Ingersoll Rand (now FlexEnergy) 250 kW microturbines with no exhaust gas aftertreatment. Criteria pollutant emission factors (lb/MMBtu) for microturbines were derived from source test averages (Table 4).

Table 4. Microturbine emission factors: criteria pollutants.

Pollutant	(lb/MMBtu)	Associated Concentration (PPM @15% O_2)
NO_x	0.016	4.2
CO	0.017	7.2
VOC	0.008	5.8
PM (total)	0.001	not indicated as concentration
SO_x	0.067	13

Using the emission factors in Table 4 and the conversion efficiencies in Table 3, representative output-based emissions estimates for microturbines of different capacities are shown in Figure 7.

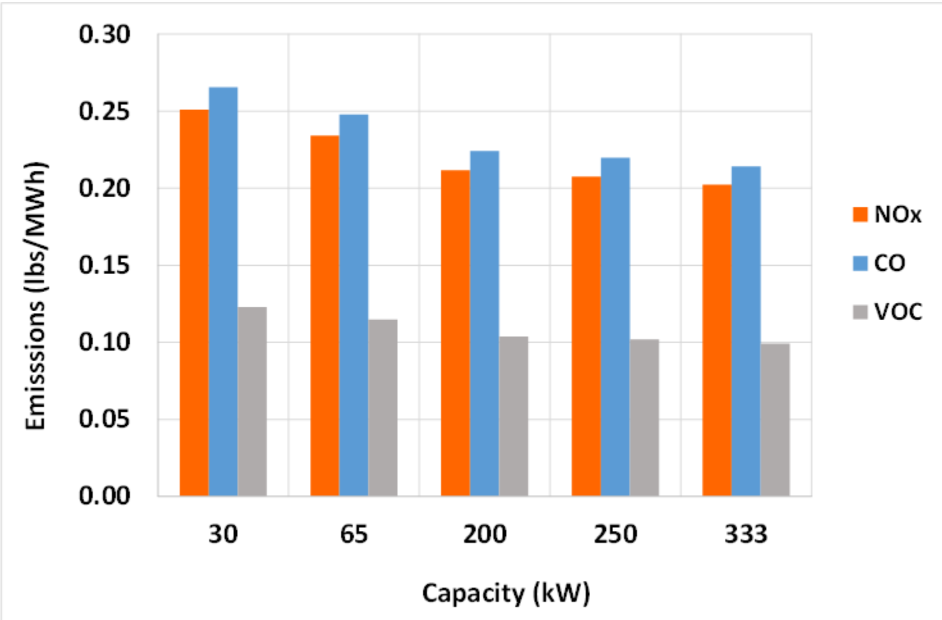


Figure 7. Emissions vs. capacity for microturbines.

Prior to 2013, a number of biogas fueled microturbines were certified to meet the California Air Resources Board (CARB) distributed generation (DG) emission standards (0.5, 6, and 1 lb/MWh for NO_x, CO and VOC, respectively). After January 2013, the DG emission standard for biogas fueled devices, including microturbines, became stricter (Table 5).[25] There are currently no biogas fueled devices certified to meet the DG standard.[26] Biogas devices can still be permitted through local air districts (and local regulations and emission limits).

Table 5. CARB DG emission standards for biogas.

Pollutant	Emission Standard (lb/MWh)	
	Jan. 1, 2008 to Dec. 31, 2013	After Jan. 1, 2013
NO_x	0.5	0.07
CO	6	0.1
VOC	1	0.02

[25] See: http://www.arb.ca.gov/energy/dg/eo/eo-expired.htm
[26] http://www.arb.ca.gov/energy/dg/eo/eo-current.htm

GHG

The GHG emission factors for microturbines are shown in Table 6. The methane emission factor is based on a destruction efficiency of 99.6% [average of turbine source tests from (SCS 2007) and default value in (CAR 2011)]. The emission factor for N_2O is derived from IPCC guidelines (IPCC 2006). The CO_2 emission factor is calculated assuming stoichiometric combustion of biogas (60% methane). The CO_2 emissions are biogenic.

Table 6. GHG emission factors – microturbines.

GHG Emission Factors (lb/MMBtu)		
CH_4	CO_2	N_2O
0.167	191.3	0.00026

Output based on GHG emissions [lb CO_2eq/MWh] are estimated by microturbine size in Table 7. These are based on the emission factors in Table 6, conversion efficiencies (Table 3) and the appropriate 100 year horizon global warming potentials (GWP_{100}).[27]

Table 7. Output based GHG emissions - microturbines.

Capacity (kW)	GHG (lb CO_2eq/MWh)		
	CH_4	CO_2*	N_2O
30	88.8	3,000	1.19
65	82.9	2,800	1.11
200	75.0	2,530	1.01
250	73.5	2,480	0.99
333	71.7	2,420	0.96

*Biogenic CO_2 emissions

[27] GWP_{100} = 34, 298 and 1 for CH_4, N_2O, and CO_2, respectively, based on the IPCC Fifth Assessment Report (AR5) [IPCC 2013].

Cost

Biogas fueled microturbines have installed costs that range from more than $6,800/kW for a 30 kW unit to about $3,610/kW for the 333 kW size (Table 8). Estimated LCOE ranges from $126/MWh to $64/MWh for the 30 kW and 333 kW sizes respectively (Table 8 and Figure 8).

Table 8. Microturbine cost analysis and LCOE.

Capacity (kW)	Electricity Production (kWh/y)[a]	Installed Cost		Total Capital		Annual Debt & Interest ($)[d]	Capital Cost ($/kWh)	Turbine O&M ($/kWh)[e]	Clean up O&M ($/kWh)	LCOE ($/kWh)
		Turbine, w/o gas cleanup ($/kW)[b]	Gas Cleanup ($/kW)[c]	($/kW)	Total ($)					
30	223,000	4,300	2,590	6890	207,000	18,000	0.081	0.02	0.026	**0.126**
65	484,000	3,220	1,930	5150	335,000	29,200	0.060	0.018	0.016	**0.094**
200	1,490,000	3,150	1,250	4400	880,000	76,700	0.052	0.017	0.008	**0.076**
250	1,860,000	2,720	1,150	3870	968,000	84,400	0.045	0.016	0.007	**0.068**
333	2,480,000	2,580	1,030	3610	1,200,000	105,000	0.042	0.016	0.006	**0.064**

Notes:

a. At 85% capacity factor.

b. Darrow, K., R. Tidball, J. Wang and A. Hampson (2015). Catalog of Combined Heat and Power (CHP) Technologies. ICF, EPA CHP Partnership.

c. Gas Cleanup Cap Cost – Based on cleanup equipment costs for two recent microturbine projects in CA.

d. 20 years @ 6% annual interest rate (or cost of money).

e. Based on average of service maintenance contracts for natural gas fueled units in ICF (2008). Catalog of CHP Technologies, EPA CHP Partnership.

Capital costs are based on installed costs for natural gas fired systems (Darrow, Tidball et al. 2015) plus gas cleaning costs for biogas fueled microturbines (Tourigny 2014). Total installed costs ($) are annualized over 20 years at 6% interest rate. O&M costs are derived from (ICF 2008, GTI 2014).

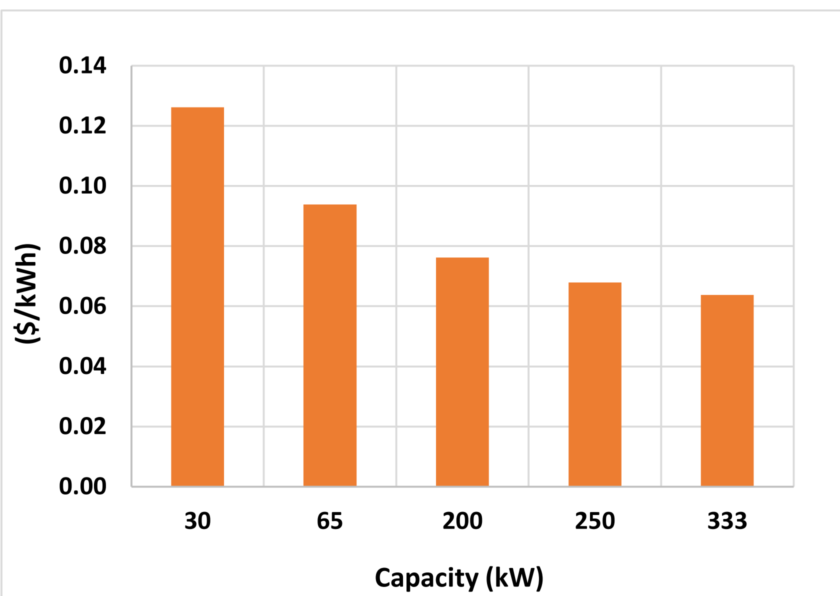
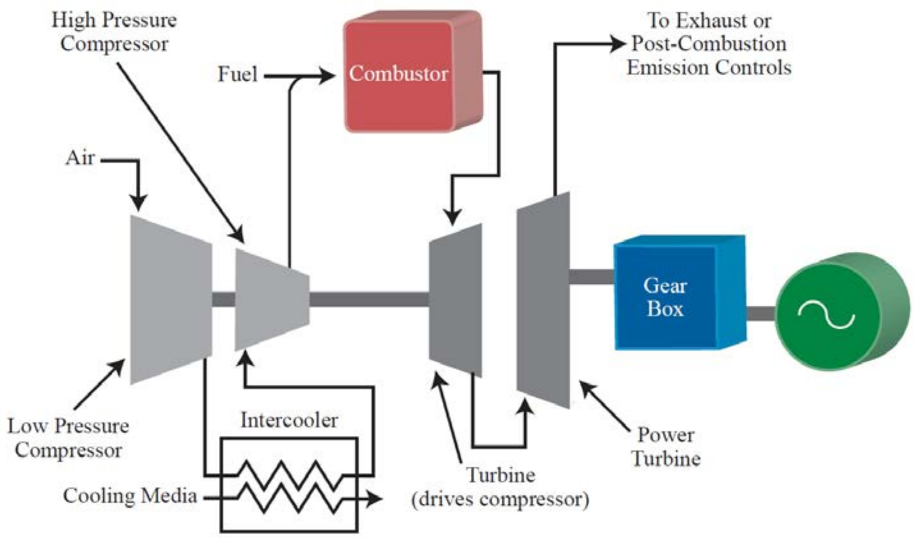


Figure 8. LCOE for microturbines.

Gas Turbines

Gas turbines (or combustion turbines) operate on the same thermodynamic cycle as microturbines (Brayton Cycle) but their larger capacities range from about 1 MW (1,000 kW) to 500 MW for a single unit (Figure 9). Systems used for biogas applications range up to about 7.9 MW. Electricity conversion efficiency, for simple-cycle application, ranges from about 21% to 31%.

Biogas fueled combustion turbines in California include two at the Altamont landfill (3 MW each), two at the Fresno-Clovis water resource recovery facility (~3.5 MW each), three at the Calabasas landfill (~4 MW each), four at Brea-Olinda Landfill (5.6 MW each), five at Sunshine Gas Producers, LLC Sylmar (4.9 MW each), two at Amaresco Chiquita Energy, Landfill Valencia (Castaic) (4.6 MW each) and one at East Bay Municipal Utility District (EBMUD) wastewater facility (4.5 MW).



(Adapted from Energy Solutions Center http://www.understandingchp.com)

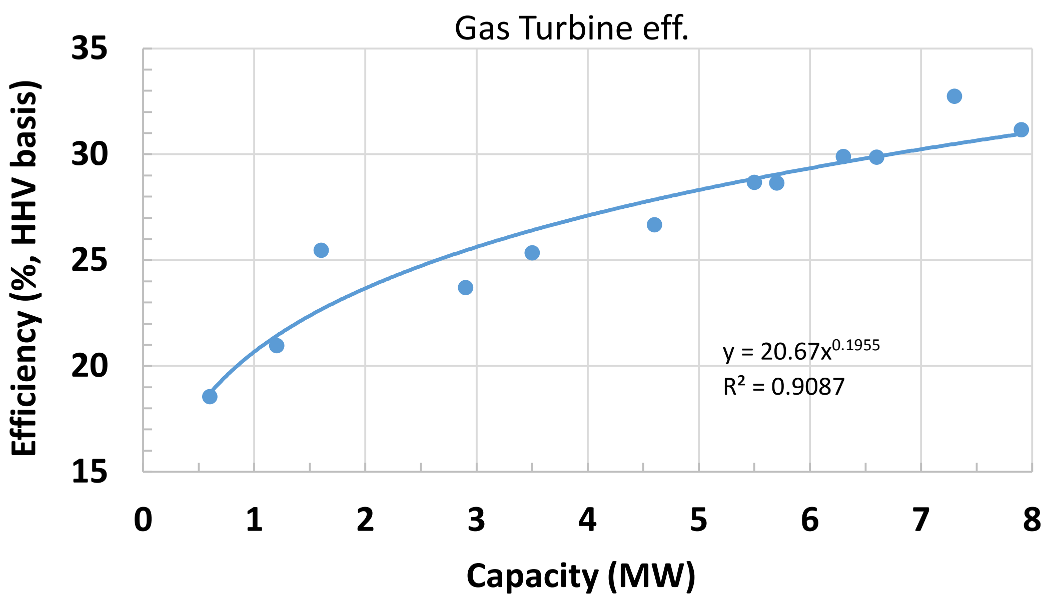
Figure 9. Gas turbine schematic.

Efficiency

Electrical conversion efficiencies for gas turbine generators fueled on biogas range from about 21% to 31% (HHV basis, 60 °F ambient air temperature) (Itron 2011, Kawasaki_Gas_Turbines 2015, Solar_Turbines 2015). Energy inputs range from about 20 MMBtu/h to 87 MMBtu/h for 1,200 kW and 7,900 kW respectively (Table 9). Efficiency versus capacity is plotted in Figure 10 and includes the curve fit through the individual data. As with microturbines, efficiency and output decreases as ambient temperature or site elevation increases.

Table 9. Gas turbine input flows and efficiency.

Capacity			Efficiency, HHV basis	
kW	Gas Flow in (SCFM)	Gas Flow in (MMBtu/h)	(%)	Heat Rate (Btu/kWh)
1200	540	19.5	21	16,300
3500	1310	47.1	25	13,500
4600	1630	58.8	27	12,800
5700	1890	67.9	29	11,900
6300	2000	71.9	30	11,400
7900	2400	86.5	31	10,900



Sources: (Itron 2011, Solar Turbines 2015, Kawasaki Gas Turbines 2015)

Figure 10. Gas turbine efficiency curve.

Emissions

Criteria Pollutants

Uncontrolled emissions from natural gas-fired combustion turbines typically range 15-25 ppm for NO_x, 25-50 ppm for CO and ~5 ppm for VOC (Darrow, Tidball et al. 2015). Source tests from biogas fueled gas turbines in the San Joaquin Valley Air Pollution Control District (SJVAPCD), BAAQMD and SCAQMD were reviewed (see Appendix C). Turbines with lean pre-mix combustor designs [Dry Low-NO_x or (DLN)] had average NO_x emissions of 8 ppm. Systems with selective catalytic reduction (SCR) NO_x control averaged 2.9 ppm NO_x (Table 10). Emission factors (lb/MMBtu), based on source test averages are also displayed in Table 10.

Table 10. Gas turbine emission factors: criteria pollutants.

	Low-NO_x Combustor Design		SCR NO_x Control		Uncontrolled*
	(lb/MMBtu)	ppm (@15% O_2)	(lb/MMBtu)	ppm (@15% O_2)	(lb/MMBtu)
NO_x	0.031	8.0	0.011	2.9	0.16
CO	0.004	1.5	0.013	5.4	0.44
VOC	0.007	5.3	0.001	0.5	0.013
PM (total)	0.012	not measured	0.012	not measured	0.023
SO_x	0.063	12.2	0.005	1.0	Depends on input

*Source: US EPA AP-42, Chapter 3.

Output-based emissions (i.e., pounds pollutant per MWh output) for biogas combustion turbines with low-NO_x burners and with SCR NO_x control are displayed in Figure 11 and Figure 12. The output-based emissions were estimated using the emission factors in Table 10, and conversion efficiencies in Table 9.

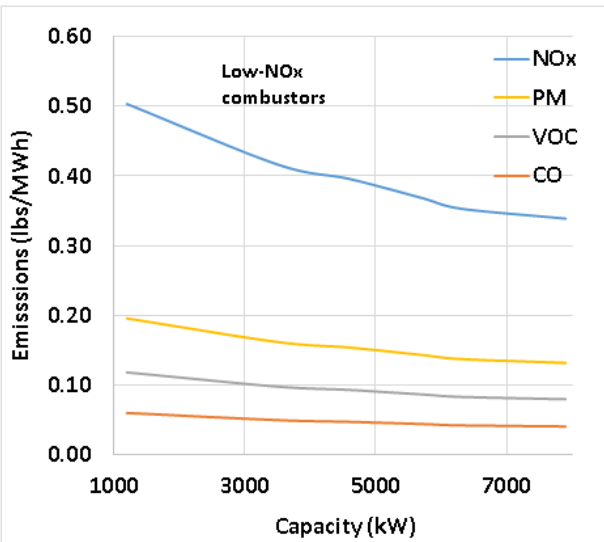


Figure 11. Emissions, “Low-NO_x” combustion turbines.

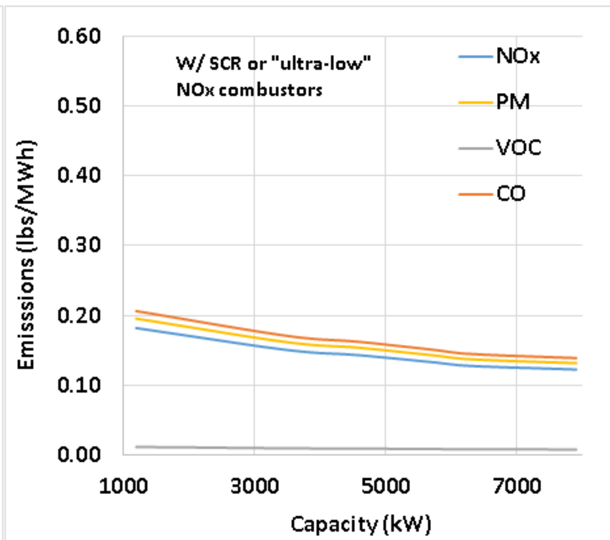


Figure 12. Emissions, combustion turbines w/ SCR NO_x control.

GHG

Emission factors for GHGs are assumed to be the same as for microturbines (Table 6).

Output based GHG emissions (lb CO_2eq/MWh) for gas turbines are estimated using the GHG emission factors, conversion efficiencies and respective GWP_{100}.[28]

[28] GWP_{100} = 34, 298 and 1 for CH_4, N_2O, and CO_2, respectively.

Table 11. Output based GHG emissions- gas turbines.

kW	Greenhouse Gases (lb CO_2eq/MWh)		
	CH_4	CO_2*	N_2O
1200	92.3	3,110	1.24
3500	76.3	2,580	1.03
4600	72.5	2,450	0.98
5700	67.5	2,280	0.91
6300	64.7	2,180	0.87
7900	62.1	2,090	0.83

*Biogenic CO_2 emissions

Cost

Installed cost for the combustion turbines ranges from $5,300/kW for the 1,200 kW size to about $2,500/kW for 7,900 kW (Table 12). Estimated LCOE ranges from $80/MWh to $42/MWh for the capacities reviewed (Table 12 and Figure 13).

Table 12. Combustion turbine cost analysis and LCOE.

Capacity (kW)	Electricity Production (kWh/y)[a]	Component Costs: Turbine system ($/kW)[b]	Component Costs: Gas Cleanup ($/kW)[c]	Component Costs: Emissions Control ($/kW)[d]	Total Capital ($/kW)	Total Capital: Total Installed ($)	Annual Debt & Interest ($)[e]	Capital Cost ($/kWh)	Turbine O&M ($/kWh)[f]	Clean up O&M ($/kWh)[g]	LCOE ($/kWh)
1200	8,935,000	4,390	310	624	5320	6,384,000	557,000	0.062	0.015	0.0028	**0.080**
3500	26,060,000	2,990	148	333	3470	12,150,000	1,060,000	0.041	0.013	0.0014	**0.055**
4600	34,250,000	2,710	122	284	3120	14,350,000	1,250,000	0.036	0.012	0.0011	**0.050**
5700	42,440,000	2,510	104	250	2860	16,300,000	1,420,000	0.034	0.012	0.0010	**0.047**
6300	46,910,000	2,420	96	236	2750	17,330,000	1,510,000	0.032	0.012	0.0009	**0.045**
7900	58,820,000	2,230	82	207	2520	19,910,000	1,740,000	0.029	0.012	0.0008	**0.042**

Notes:

a. At 85% capacity factor.

b. Darrow, K., R. Tidball, J. Wang and A. Hampson (2015). Catalog of CHP Technologies. ICF, EPA CHP Partnership.

c. Gas Cleanup Cap Cost – siloxane removal curve fit 35064 $X^{0.375}$, Figure 11 from: GTI (2014). Conduct a Nationwide Survey of Biogas Cleanup Technologies and Costs, Final Report, SCAQMD Contract #13432.

d. ICF (2012). Combined Heat and Power Policy Analysis and 2011-2030 Market Assessment, Consultant Report to the California Energy Commission (CEC). CEC-200-2012-002.

e. 20 years @ 6% annual interest rate (or cost of money).

f. Based on average of service maintenance contracts for natural gas fueled units in ICF (2008). Catalog of CHP Technologies, EPA CHP Partnership.

g. Cleanup O&M Cost – siloxane removal curve fit $2047X^{0.3988}$, Figure 12 from: GTI (2014). Op. Cit.

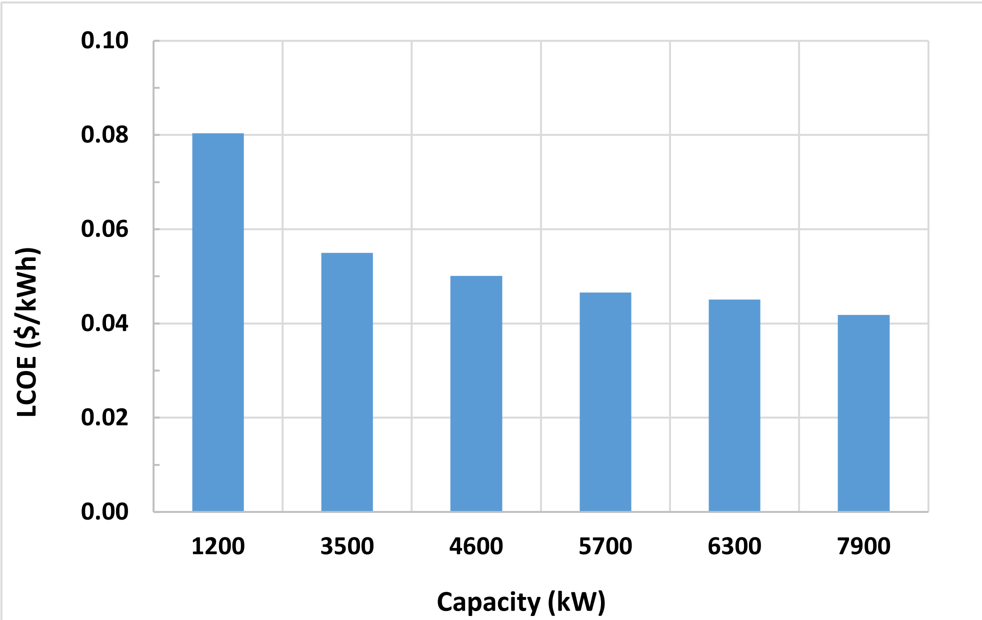


Figure 13. LCOE for combustion turbines.

Reciprocating Engines

Reciprocating internal combustion engines (RICE) are used extensively throughout the world for stationary power generation with some 12 million units produced in 2014 (237 million engines were produced for all applications) (Huibregtse 2014). Reciprocating engine-generators are typically the lowest cost systems for capacities from < 100 kW to approximately 10 MW. Reciprocating engines for biogas applications have been used extensively throughout California. Untreated exhaust emissions from reciprocating engines, especially NO_x, are among the highest of the biogas utilization technologies.

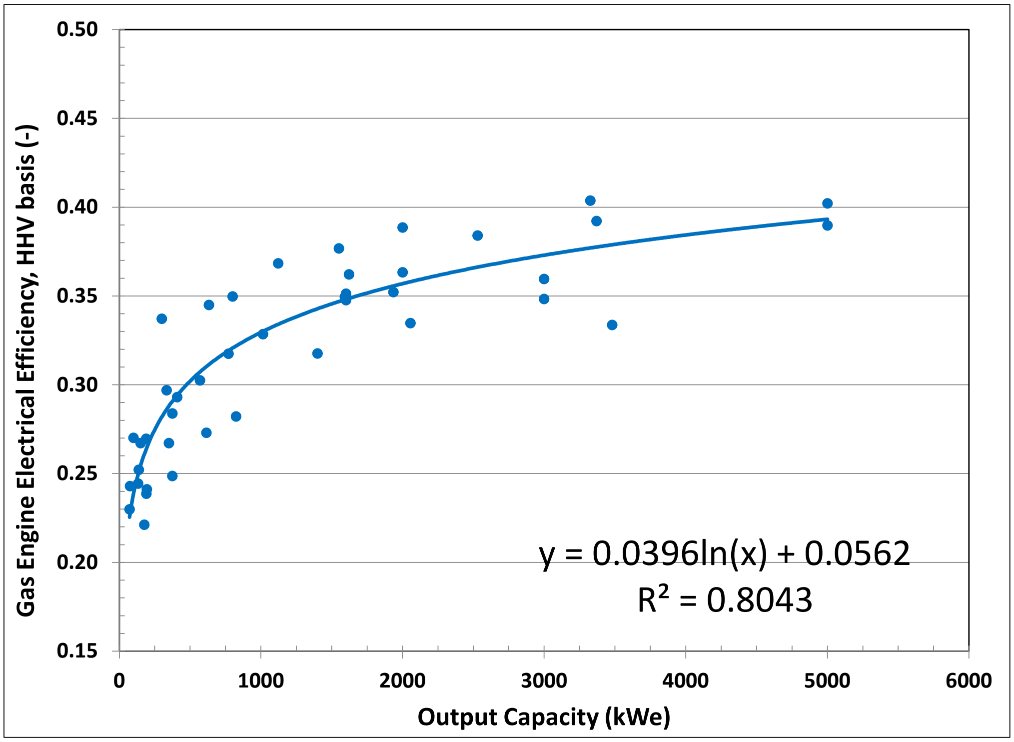
Biogas fueled engines are usually adapted from natural gas engines which operate on the 4-stroke, spark-ignited Otto cycle. There are two general classes of this type of engine; rich-burn and lean-burn.

Rich-burn engines, sometimes called stoichiometric engines, operate on an air fuel ratio (AFR) that is nearly stoichiometric, or exactly enough air to completely burn the fuel. Compared to lean-burn, rich-burn engines generally produce lower hydrocarbon emissions but higher NO_x emissions. Rich-burn engines are required for use with the basic three-way (NO_x, CO, hydrocarbons) nonselective catalytic reduction (NSCR) catalyst system used in most gasoline-fueled automotive applications.

Lean-burn engines use up to twice the amount of air needed for fuel combustion. This results in lower peak combustion temperatures which translates into lower NO_x production but can have higher products of incomplete combustion (hydrocarbons or VOC) compared to rich-burn. Lean-burn engines can have slightly higher fuel efficiency. Lean-burn engines must use selective catalytic reduction with urea injection for further NO_x reduction and oxidation catalysts for CO and VOC reduction. A new LFG-to-energy project at the Bowerman landfill in Orange County, CA is being commissioned. Seven Caterpillar CG260 3.37 MW lean-burn reciprocating engine-generators with SCR NO_x control and oxidation catalyst for VOC and CO control are installed (23.5 MW nameplate capacity) [SCAQMD 2014b].

Efficiency

Efficiency of biogas-fueled stationary engine-generator systems varies from about 25% for 100 kW units to 40% at the –4-5 MW size (Figure 14). Efficiency data were accumulated from several sources and charted below. A logarithmic curve fit to the data was used for efficiency values when analyzing engine output-based emissions (Table 13).



Sources; (ICF 2012, Rutgers 2014, Caterpiller 2015)

Figure 14. Reciprocating engine efficiency curve.

Table 13. Reciprocating engine input flows and efficiency.

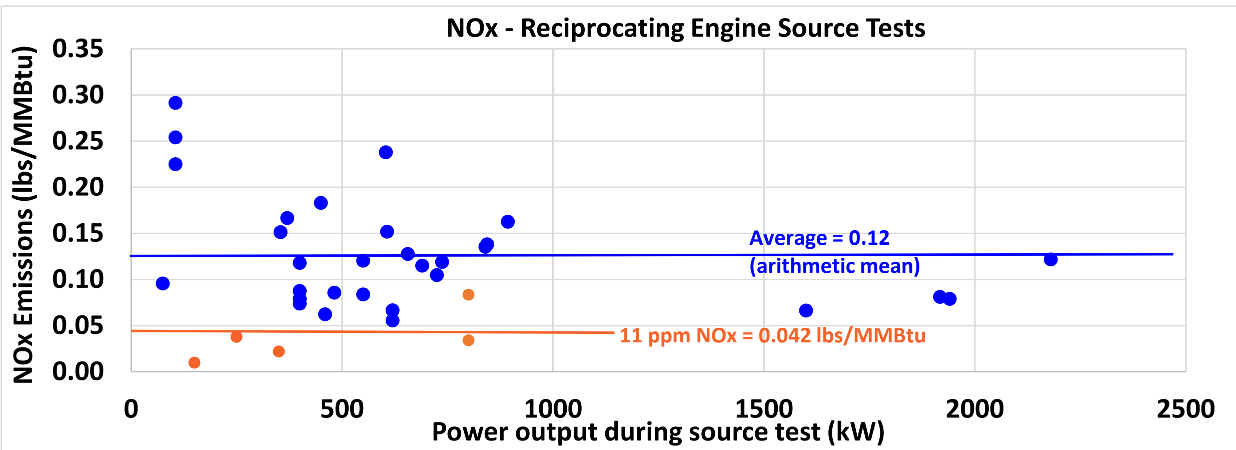
Capacity			Energy Efficiency, HHV basis	
kW	Biogas Flow input (SCFM)	Gas Flow input (MMBtu/h)	(%)	Heat Rate (Btu/kWh)
100	40	1.4	24	14,300
150	56	2.0	26	13,400
190	68	2.5	26	12,900
220	77	2.8	27	12,600
300	100	3.6	28	12,100
420	130	4.9	30	11,600
600	180	6.6	31	11,000
800	240	8.5	32	10,600
1000	290	10.3	33	10,300
1550	420	15.2	35	9,800
2000	530	19.1	36	9,600
3000	760	27.4	37	9,100

Emissions

Criteria Pollutants

Some thirty-one source tests for biogas fueled reciprocating engines in California were reviewed. Most were located in the BAAQMD and SJVAPCD and were permitted for 65-70 ppm NO_x. Also reviewed were three years of source tests for an engine permitted for 11 ppm NO_x at a dairy in the SJVAPCD that uses SCR for NO_x reduction. Emission factor data for the reciprocating engine source tests appear in Figure 15 through Figure 17 for NO_x, CO and VOC respectively (lb/MMBtu).

The average NO_x emission factor for engines permitted in the 60-70 ppm NO_x range is 0.128 lb-NO_x/MMBtu (33 ppm) (Figure 15).



Note: Orange data points from engines with SCR and CatOx emission control systems (next two figures as well).

Figure 15. NO_x emission factor: engine source tests.

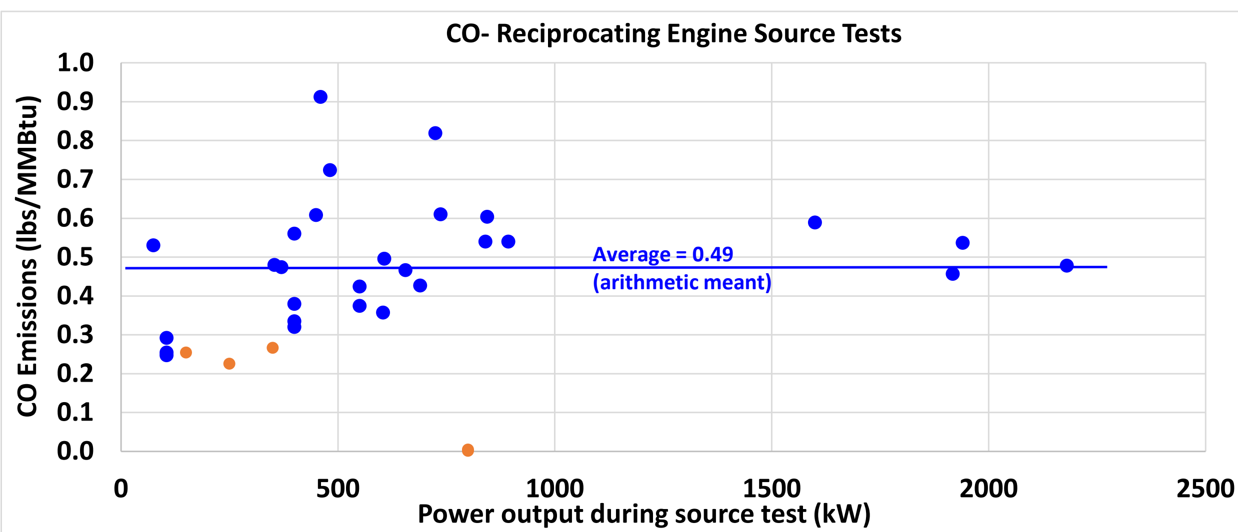


Figure 16. CO emission factor: engine source tests.

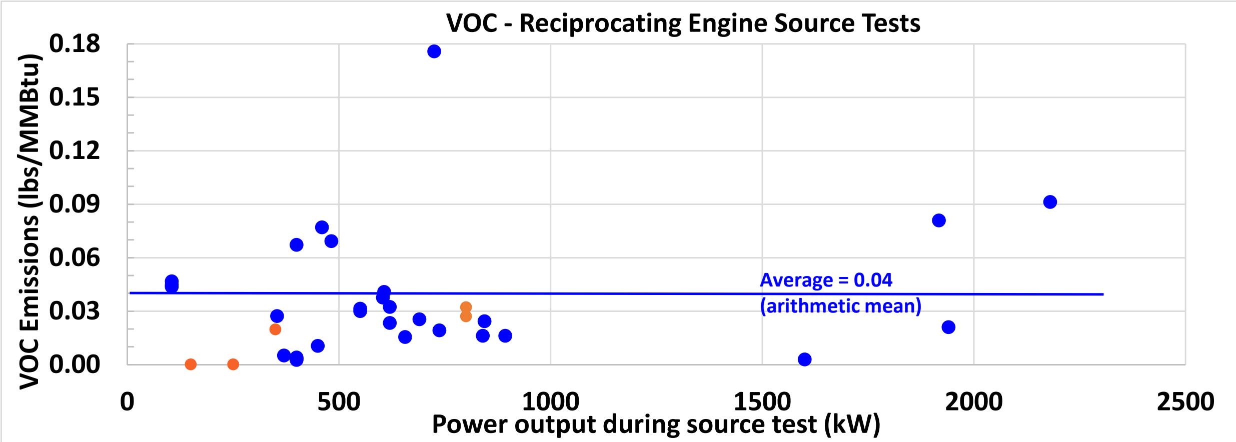


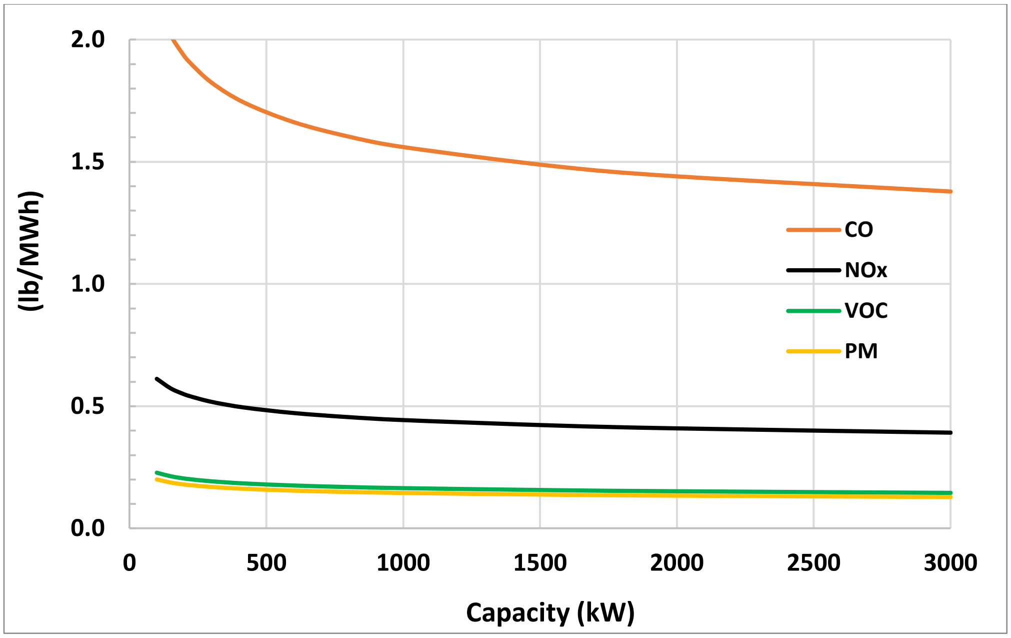
Figure 17. VOC emission factor: engine source tests.

The SCAQMD has been working on an amendment to its rule for emissions for stationary engines for several years (Rule 1110.2). The amended rule specifies new emission limits for biogas-fueled engines effective January 1, 2017 of 11 ppm NO_x, 250 ppm CO and 30 ppm VOC (SCAQMD 2015). These limits are equivalent to 0.043, 0.59 and 0.041 lb/MMBtu for NO_x, CO and VOC respectively (Table 14). For purposes of engine emission factors for the side-by-side comparisons with other technologies in this report, Rule 1110.2 limits for NO_x, CO and VOC are used, along with the average source-test sulfur dioxide (SO_2) value and the PM value from EPA AP-42 (Table 14). Output-based emissions (lb/MWh vs Capacity) for engines are displayed in Figure 18. Rule 1110.2 levels for NO_x, VOC and CO are used in Figure 18.

Table 14. Emission factors: reciprocating engines.

	(lb/MMBtu)				
	NO_x	**CO**	**VOC**	**SO_2**	**PM**
Source test averages (Pre-Rule 1110.2)	0.128	0.49	0.038	0.037	insuff.*
Source test averages (Engines w/ SCR & OxCat)	0.037	**0.151**	**0.016**	**0.003**	insuff.
SCAQMD Rule 1110.2 (implements 1 January 2017)	**0.043**	0.59	0.041	n/a*	n/a
EPA AP – 42	n/a	n/a	n/a	n/a	**0.014**
Emission Factors used in side-by-side comparison – this report	**0.043**	**0. 151**	**0.016**	**0.003**	**0.014**

*Notes: insuff. => insufficient number of source tests had PM results to use for average
n/a=> not applicable or not used



Note: NO_x based on Rule 1110.2, CO and VOC from SCR & CatOx equipped source tests, PM from AP-42.

Figure 18. Emissions vs. capacity for reciprocating engines.

GHG

The greenhouse gas emission factor for methane, summarized in Table 15, is the average of source tests from (Mintz, Han et al. 2010) and (SCS 2007). This is a methane destruction efficiency of 98%. The CO_2 emission factor is calculated assuming stoichiometric combustion of biogas (60% methane). The CO_2 emissions are biogenic. The N_2O emission factor is from (Mintz, Han et al. 2010), a life-cycle analysis of landfill gas based energy pathways.

Table 15. GHG emission factors – reciprocating engines.

GHG Emission Factors (lb/MMBtu)		
CH_4	CO_2	N_2O
0.838	191.3	0.00192

Output-based GHG emissions (lb CO_2eq/MWh) for engines (Table 16) are estimated using the emission factors in Table 15, conversion efficiencies (from Table 13) and respective GWP_{100}.[29]

[29] GWP_{100} = 34, 298 and 1 for CH_4, N_2O, and CO_2, respectively.

Table 16. Output based GHG emissions- reciprocating engines.

kW	Greenhouse Gases (lb CO_2eq/MWh)		
	CH_4	CO_2*	N_2O
100	408	2,740	8.2
150	382	2,560	7.7
190	368	2,470	7.4
220	360	2,420	7.2
300	345	2,310	6.9
420	329	2,210	6.6
600	314	2,110	6.3
800	303	2,030	6.1
1000	295	1,980	5.9
1550	280	1,880	5.6
2000	272	1,830	5.5
3000	261	1,750	5.2

*Biogenic CO_2 emissions

Cost

Installed cost for reciprocating engines ranges from $4,114/kW for the 100 kW size to about $2,289/kW for 3,000 kW (Table 17). Estimated LCOE ranges from $90/MWh to $48/MWh for the capacities reviewed (Table 17 and Figure 19).

Table 17. Reciprocating engine cost analysis and LCOE.

Capacity (kW)	Electricity Production (MWh/y)[a]	Component Costs			Total Capital		Annual Debt & Interest ($)[e]	Capital Cost ($/kWh)	O&M (engine & emiss.) $/kWh)[f]	Clean up O&M ($/kWh)[g]	LCOE ($/kWh)
		Engine system ($/kW)[b]	Gas Cleanup ($/kW)[c]	Emissions Reduction ($/kW)[d]	($/kW)	Total Installed ($)					
100	745	3,100	340	672	4110	411,000	35,800	0.048	0.030	0.012	**0.090**
150	1,120	2,970	340	574	3880	582,000	50,700	0.045	0.028	0.009	**0.083**
190	1,410	2,890	340	523	3750	713,000	62,100	0.044	0.028	0.008	**0.079**
220	1,640	2,840	340	494	3670	807,000	70,400	0.043	0.027	0.007	**0.077**
300	2,230	2,740	340	438	3520	1,060,000	92,100	0.041	0.026	0.006	**0.073**
420	3,130	2,620	340	384	3340	1,400,000	122,000	0.039	0.025	0.005	**0.069**
600	4,470	2,510	340	334	3180	1,910,000	166,000	0.037	0.024	0.004	**0.065**
800	5,960	2,410	340	299	3050	2,440,000	213,000	0.036	0.023	0.003	**0.062**
1000	7,450	2,340	293	274	2910	2,910,000	254,000	0.034	0.023	0.003	**0.059**
1550	11,500	2,190	219	231	2640	4,090,000	357,000	0.031	0.021	0.002	**0.054**
2000	14,900	2,100	184	209	2490	4,980,000	434,000	0.029	0.021	0.002	**0.052**
3000	22,300	1,970	141	178	2290	6,870,000	599,000	0.027	0.019	0.001	**0.048**

Sources and Notes:

a. At 85% capacity factor.

b. Basic Installed Cost (no gas cleaning, no after treatment). ICF 2012, Darrow, K., R. Tidball, J. Wang and A. Hampson (2015). Catalog of CHP Technologies. ICF, EPA CHP Partnership. Using this curve fit: $/kW = -332.9ln(x) + 4635.

c. Cleanup Cap Cost – siloxane removal curve fit 35064 $X^{0.375}$, Figure 11 from: GTI (2014). (GTI Study, then constant at 340 for < 200 scfm).

d. After treatment cost ($/kW) (Hybrid 2gCenergy & ICF 2012 data).

e. 20 years @ 6% annual interest rate (or cost of money).

f. EPA 2012 x 1.25 for after treatment.

g. Cleanup O&M Cost - siloxane removal curve fit 2047$X^{0.3988}$, Figure 12 from: GTI (2014). Op. Cit.

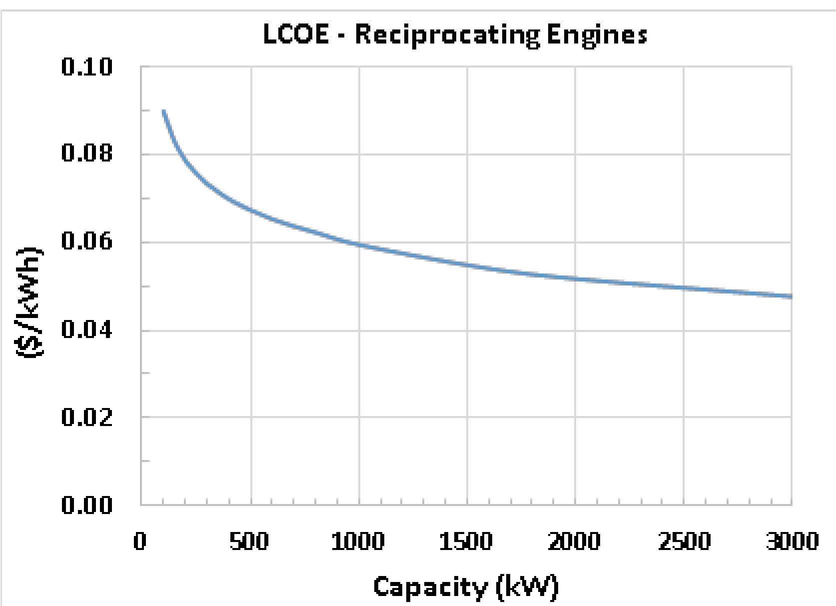
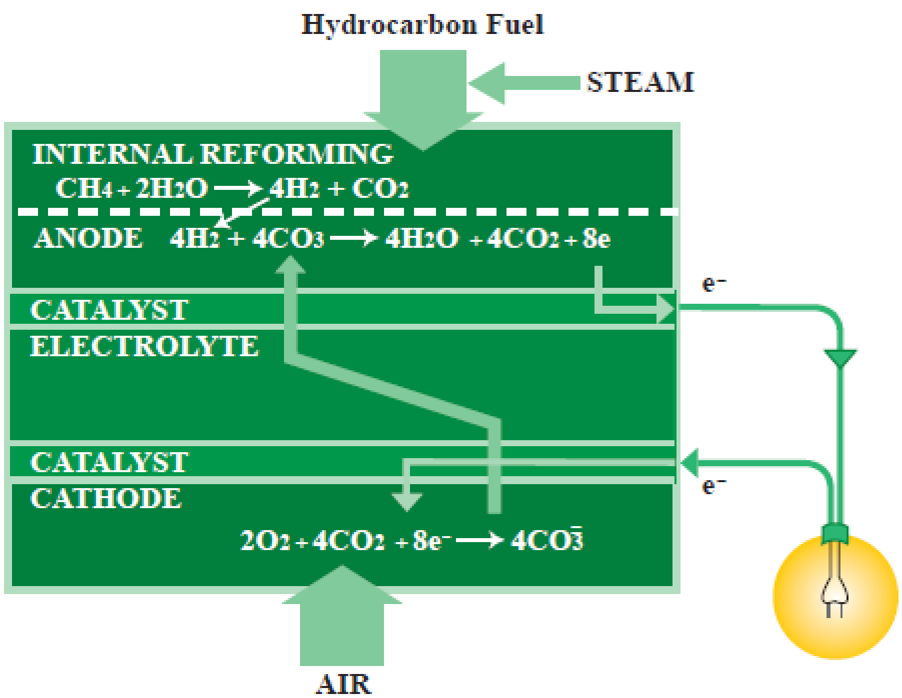


Figure 19. LCOE for reciprocating engines.

Fuel Cell

Fuel cells produce direct current power through an electrochemical process, rather than a combustion-to-mechanical energy process that turns an electrical generator. This electrochemical process also generates far lower criteria pollutant emissions, which in some cases are considered to be zero.

Stationary fuel cells that operate on natural gas or biogas are usually the high temperature "internal reforming" type which includes molten carbonate fuel cells (MCFC) and solid oxide fuel cells (SOFC). Because of the high internal temperature, MCFC and SOFC fuel cells can internally reform methane with steam to produce the hydrogen necessary for the electrochemical reaction (Figure 20).



Adapted from: http://www.fuelcellenergy.com/

Figure 20. Schematic - internal reforming molten-carbonate fuel cell.

There are some 400 stationary fuel cells in California for a total installed capacity of approximately 180 MW (SelfgenCa 2015). Eleven are fueled by biogas (installed capacity of ~ 10 MW) (ORNL 2015, SelfgenCa 2015).

The company FuelCell Energy is active in the biogas fuel cell market in California, offering 300 kW, 1.4 MW, 2.8 MW and larger units. Bloom, Doosan, LG Fuel Cell Systems, and GE also offer stationary fuel cell products that work with natural gas or extensively pre-treated and cleaned biogas.

Efficiency

Electrical conversion for internal-reforming fuel cells ranges from 42-54% net, HHV basis (Trendewicz and Braun 2013, FuelCell_Energy 2015, ICF 2015). For this analysis, 45% efficiency is used. Table 18 displays gas input flow (volume and energy basis) for a range of fuel cell capacities.

Table 18. Fuel cell capacities and associated biogas input flows.

Capacity (kW)	Biogas Flow input*	
	(SCFM)	(MMBtu/h)
200	42	1.5
300	63	2.3
500	110	3.8
800	170	6.1
1000	210	7.6
1400	290	10.6
6000	1260	45.5

**Assumes 60% methane in biogas*

Emissions

Criteria Pollutants & GHG

One of the most attractive features of fuel cells is that they have extremely low emissions. Those emissions come from the combustion or oxidation of the anode off gas which contains unreacted hydrogen, CO and VOCs. Catalytic or surface burners are usually used for the anode off gas, which operates at high enough temperature to oxidize the hydrogen (H_2), CO, and VOCs while producing very low NO_x emissions (ICF 2015).

Emission factors for fuel cells are derived from review of two permits, both for FuelCell Energy systems, one in the SJVAPCD and the other in the SCAQMD. The higher of the two permit levels was used for each criteria pollutant in Table 19.

GHG emissions and emission factors are also displayed in Table 19. The emission factors (lb/MMBtu) for N_2O and CH_4 are derived from IPCC guidelines (IPCC 2006). The CO_2 emission factor is calculated assuming stoichiometric oxidation of biogas (60% methane). The CO_2 emissions are biogenic.

Table 19. Criteria pollutant and GHG emissions from fuel cells.

Emissions	Criteria Pollutants					GHG		
	NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O
(lb/MWh)	0.02	0.070	0.01	0.06	0.001	0.019	1450	0.002
(lb/MMBtu)	0.0026	0.0092	0.0013	0.008	0.0001	0.0026	191.3	0.00026
(lb CO_2eq/MWh)	n/a					0.66	1450	0.58

*biogenic CO_2 emissions

Cost

Cost information for biogas fuel cells is derived from a number of sources including:

- (Trendewicz and Braun 2013) which modeled techno-economic performance of biogas SOFC fuel cells in California wastewater treatment facilities,
- (Horn 2013), a United States Court of Federal Claims opinion which examined project costs for the Anaergia fuel cell at the Inland Empire Utilities Agency (IEUA) Water Recycling Facility (RP-1) in Ontario, California,
- (USEPA 2013) describing a fuel cell project at the Palmdale Water Reclamation Plant in LA County, and
- (FuelCells.org 2011), a case study on multiple fuel cells installed at the Tulare WRRF. The installed costs analyzed here include gas cleaning equipment, engineering, permitting, etc.

Installed costs for fuel cells are high, ranging from nearly $8,000/kW (250 – 300 kW size) to about $3,800/kW (6,140 kW size) (see Table 20). A curve was fit through the literature costs (using year 2015 $), used to model costs for analysis in this report (see note 5 below Table 20).

Table 20. Fuel cell capital costs from literature.

Literature Source	kW	Installed Cost ($/kW) [yr. 2015 $]	
		Literature value	Curve-fit Value[5]
Trendewicz[1]	330	6,261	6,990
Trendewicz[1]	1530	4,239	5,020
Trendewicz[1]	6140	3,879	3,720
Anaergia[2]	1400	5,714	5,120
EPA Fact Sheet[3]	250	7,600	7,430
Tulare[4]	300	7,967	7,140

Sources and Note:

1. Trendewicz, A. A. and R. J. Braun (2013). "Techno-economic analysis of solid oxide fuel cell-based on CHP systems for biogas utilization at wastewater treatment. (Trendewicz and Braun 2013).
2. Horn (2015). Anaergia - RP1 Fuel Cell LLC et al v. USA. Reported Opinion, Judge Marian Blank Horn. 2013cv00552, United States Court of Federal Claims. (Horn 2013).
3. U.S. EPA (2013). Renewable Energy Fact Sheet: Fuel Cells. http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P100IL86.txt (USEPA 2013).
4. FuelCells.Org (2011). Case Study: Fuel Cell System Turns Waste into Electricity at the Tulare Wastewater Treatment Plant. http://www.fuelcells.org/uploads/TulareCaseStudy.pdf (FuelCells.org 2011).
5. Derived curve fit is: Installed Cost ($/kW) = $24475x^{-0.216}$, where x capacity in kW.

The O&M costs are based on a $500k per year maintenance contract for a 1,400 kW MCFC which includes five-year stack replacement (Remick and Wheeler 2010). Linear scaling (extrapolation) was used to adjust O&M costs (maintenance contract) for other capacities in the analysis. LCOE for biogas fuel cells varies from $0.164/kWh for the 200 kW size to $0.079/kWh for 6,000 kW (Table 21 & Figure 21).

Table 21. Fuel cell cost analysis and LCOE.

Capacity (kW)	Electricity Production (MWh/y)[a]	Installed Cost ($/kW)	Installed Cost Total Installed ($)	Annual Debt & Interest ($)[b]	Cap Cost ($/kWh)	O&M Cost ($/kWh)[c]	LCOE ($/kWh)
200	1.5	7,790	1,560,000	136,000	0.091	0.073	**0.164**
300	2.2	7,140	2,140,000	187,000	0.084	0.067	**0.150**
500	3.7	6,390	3,200,000	279,000	0.075	0.060	**0.135**
800	6.0	5,780	4,620,000	403,000	0.068	0.054	**0.122**
1000	7.4	5,500	5,500,000	480,000	0.064	0.052	**0.116**
1400	10.4	5,120	7,170,000	625,000	0.060	0.048	**0.108**
2800	20.8	4,410	12,300,000	1,070,000	0.052	0.041	**0.093**
6000	44.7	3,740	22,400,000	1,950,000	0.044	0.035	**0.079**

Sources and Notes:
a. At 85% capacity factor.
b. 20 years @ 6% annual interest rate (or cost of money).
c. Based on a $500k/y maintenance contract for a 1,400 kW MCFC that includes five-year stack replacement. Assumed linear scaling for other capacities. From: Remick, R. and D. Wheeler (2010). Molten Carbonate and Phosphoric Acid Stationary Fuel Cells: Overview and Gap Analysis. NREL/TP-560-49072L.

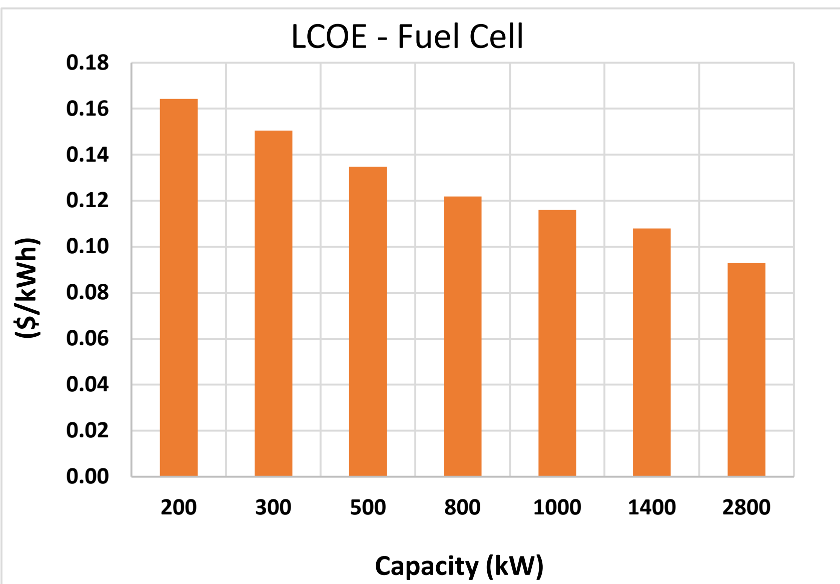


Figure 21. LCOE - fuel cell.

Compressed RNG (on-site fuel)

Biogas can be cleaned and upgraded to be suitable for a vehicle fuel, such as CNG or Liquefied Natural Gas (LNG). For this biogas use pathway, we only looked at renewable CNG, but not LNG (even though we realize that LNG is being used at some biogas facilities, like the Waste Management project at the Altamont Landfill)[30]. Renewable CNG pathway cost and

[30] For those interested in the Altamont LF LNG project: http://altamontlandfill.wm.com/green-energy/index.jsp

performance analysis is based on Unison Solutions (BioCNG) upgrading and fueling station for biogas input flows of 50-200 scfm and a large system (1,600 scfm biogas input) consisting of a Unison Solutions H_2S removal system, a Guild pressure swing adsorption (PSA) separation unit and an ANGI CNG fueling station.

Efficiency

The Unison Solutions' (BioCNG) equipment is installed at several sites in California, including the CleanWorld digester facility at Sacramento and the Blue Line RNG facility in South San Francisco. The equipment for the smaller capacity system uses a single-pass membrane technology for CO_2/CH_4 separation. About 70% of incoming methane is upgraded to fuel with the rest exiting the system with the CO in the tailgas (Figure 22) (BioCNG 2015).

The larger capacity system consisting of the Guild PSA system has a higher methane recovery rate of 85% or higher (Santos, Grande et al. 2011, Wu, Zhang et al. 2015). This analysis uses 70% recovery rate for systems < 200 scfm biogas input (BioCNG model) and 85% methane recovery for the large facility (1600 scfm) (Figure 22 and Table 22).

The tailgas cannot be vented (i.e. released untreated into the atmosphere). It can possibly be burned in an engine. This analysis assumes it is burned in a flare.

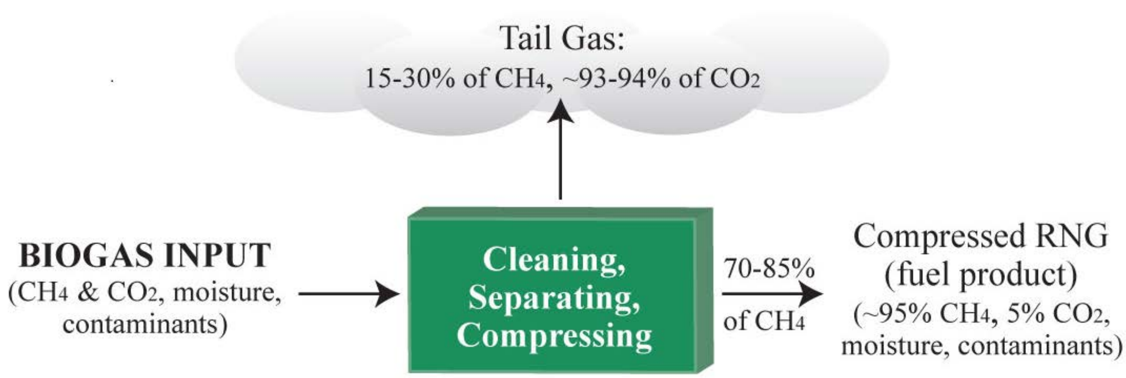


Figure 22. RNG process schematic.

Simple volume and energy flows for representative systems are tabulated below (Table 22).

Table 22. RNG input and output flow and energy.

Biogas Flow input		Methane recovery (%)	RNG Fuel Product Output		
(SCFM)	(MMBtu/h)		(SCFM)	(MMBtu/h)	(GGE/day)
50	1.8	70	22.1	1.3	241
100	3.6	70	44	2.5	482
200	7.2	70	88	5	963
1600	57.6	85	860	49	9,360

Emissions

Criteria Pollutants

An important feature of biogas upgrading for RNG fuel or pipeline injection is that on-site criteria pollutant emissions can be much lower than some of the combustion-based engines. Criteria pollutants will occur when and where the product gas is used in amounts that depend on those ultimate uses, such as vehicle emissions, natural gas power plants, in-home gas appliances, etc.

For the RNG pathway analyzed here, only on-site criteria pollutants are evaluated. The RNG upgrading process creates a tailgas (or byproduct gas) that contains a portion of the methane input to the process (Figure 23). Because the methane is a significant GHG if discharged into the atmosphere, the tailgas must be processed to reduce or eliminate the unrecovered or byproduct methane.

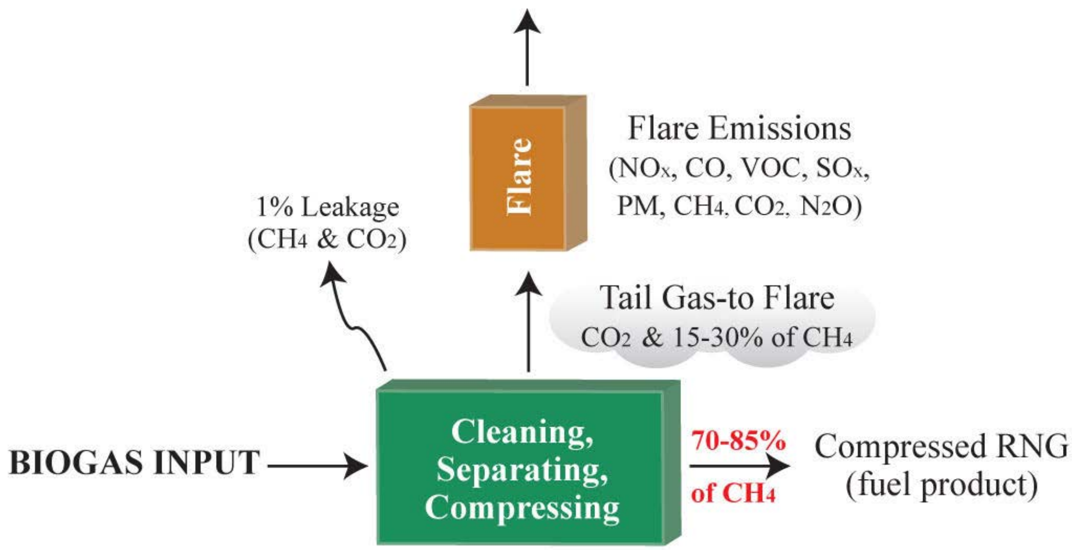


Figure 23. RNG process schematic with tailgas flare.

It may be possible in certain cases to burn the tailgas in an engine or turbine as a primary or co-fired fuel input which will oxidize the methane to CO_2. This analysis assumes the tailgas is burned in a flare for purposes of methane destruction (Figure 23). Emissions for tailgas burned in a flare are tabulated below (Table 23) and are based on the same flare emission factors discussed in the flare section.

Table 23. RNG on-site criteria pollutant emissions.

Biogas Flow input		Methane recovery (%)‡	RNG Fuel Product Output	Emissions (lb/day)*				
(SCFM)	(MMBtu/h)		(MMBtu/h)	NO_x	CO	PM	VOC	SO_x
50	1.8	70	1.3	0.71	0.59	0.15	0.08	0.50
100	3.6	70	2.5	1.43	1.18	0.31	0.16	1.01
200	7.2	70	5	2.86	2.36	0.62	0.31	2.02
1600	57.6	85	49	11.04	9.13	2.39	1.21	7.79
				Emission Factor (lb/MMBtu input to process)				
		70% Methane Recovery		**0.0165**	**0.0137**	**0.0036**	**0.0018**	**0.0117**
		85% Methane Recovery		**0.008**	**0.007**	**0.002**	**0.001**	**0.006**

‡Methane recovery = Yield or the portion of incoming methane that is recovered in the product. The unrecovered methane exits the upgrade process in the tailgas and is assumed burned in a flare in this analysis.
*Based on flare emission factors of 0.057, 0.0472, 0.01236, 0.0062 and 0.0403 lb/MMBtu for NO_x, CO, PM, VOC and SO_x respectively (See Flare section).

GHG

GHG emission factors include assumed 1% methane (biogas) leakage from the upgrading process (Han, Mintz et al. 2011)[31], methane slip through the tailgas flare and N_2O emissions from the flare (Mintz, Han et al. 2010). The CO_2 emission factor includes that in the incoming biogas that is separated from the methane in the upgrading process and then passes through the flare plus the product of methane combustion from tailgas burned in the flare as well as the small amount in the 1% leakage assumption mentioned above. The CO_2 emissions are biogenic (Table 24 and Figure 23).

Table 24. RNG process GHG emissions.

Gas Flow Input to RNG System		Greenhouse Gases (lb/day)			Greenhouse Gases (lb CO_2eq/day)		
(SCFM)	(MMBtu/h)	CH_4	CO_2 *	N_2O	CH_4	CO_2 *	N_2O
50	1.8	18.9	4,600	0.03	642	4,600	9
100	3.6	37.8	9,200	0.06	1,280	9,200	18
200	7.2	75.5	18,400	0.12	2,570	18,400	36
1600	57.6	590	122,000	0.47	20,100	122,000	140
		(lb/MMBtu into process)			**GWP_{100}**		
		CH_4	CO_2 *	N_2O	CH_4	CO_2 *	N_2O
70% CH_4 Recovery		**0.44**	**106.5**	**0.00070**			
85% CH_4 Recovery		**0.43**	**88.3**	**0.00034**	**34**	**1**	**298**

*Biogenic CO_2 emissions

31 1% methane leakage from the upgrading process is a default assumption used by GREET in Han, Mintz et al. (2011). [An Argonne National Lab report]

Cost

RNG pathway costs are estimated using installed capital and operating costs and methane recovery efficiency derived from BioCNG project information and consultant reports (Geosyntec 2013, BioCNG 2015, Kemp 2015, Polo 2015). Cost of capital is based on 20-year capital loans at 6% annual interest and includes fuel dispensing equipment and nominal gas storage (approximately half to one day of gas storage). RNG production cost is estimated to vary from about $2.42 per GGE [$18.30/MMBtu] at small scale to about $0.50/GGE [$4.00/MMBtu] at large scale (Table 25 and Figure 24).

Table 25. RNG costs.

Input-(scfm biogas)[2]	Fuel Output			RNG Equipment Cost (MM $)[1]	Flare Cost ($)[3]	Total Capital ($)	Annualized Capital ($/y)[4]	O&M CNG ($/GGE)[1]	CNG O&M ($/y)	O&M (CNG + Flare) ($/y)	**$/GGE**	$/MMBtu (output)
	RNG (scfm, 95% CH_4)	GGE/day	GGE/year									
50	22.1	240	83,500	1.2	69,800	1,270,000	111,000	1.06	88,000	91,000	**$2.42**	$18.30
100	44.2	480	167,000	1.5	116,000	1,620,000	141,000	0.82	137.000	142,000	**$1.69**	$12.79
200	88.4	960	334,000	2.0	192,000	2,190,000	191,000	0.64	214,000	221,000	**$1.23**	$9.34
1600	860	9400	3,250,000	6.54	511,000	7,050,000	615,000	0.34	1,090,000	1,110,000	**$0.53**	$4.02

Sources and Notes:

1. Based on BioCNG project sheets, conference presentations, Geosyntec report to Flagstaff Landfill and personal communication, Jay Kemp and Christine Polo, Black and Veatch. 70% methane recovery for single-pass membrane system (BioCNG 50-200 scfm input) and 85% methane recovery for PSA system (1600 scfm input).
2. 60% methane in biogas.
3. Tailgas (methane slip) is flared in this scenario. Added flare capital and operating costs using data from flare scenario.
4. 6% APR, 20-year financing of capital - $0.12/kWh electricity cost.

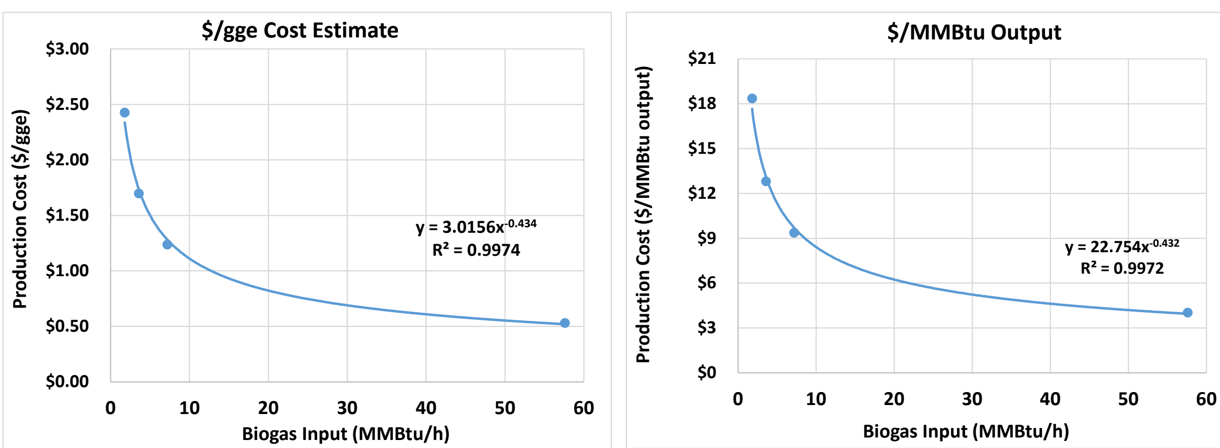


Figure 24. RNG production cost estimates.

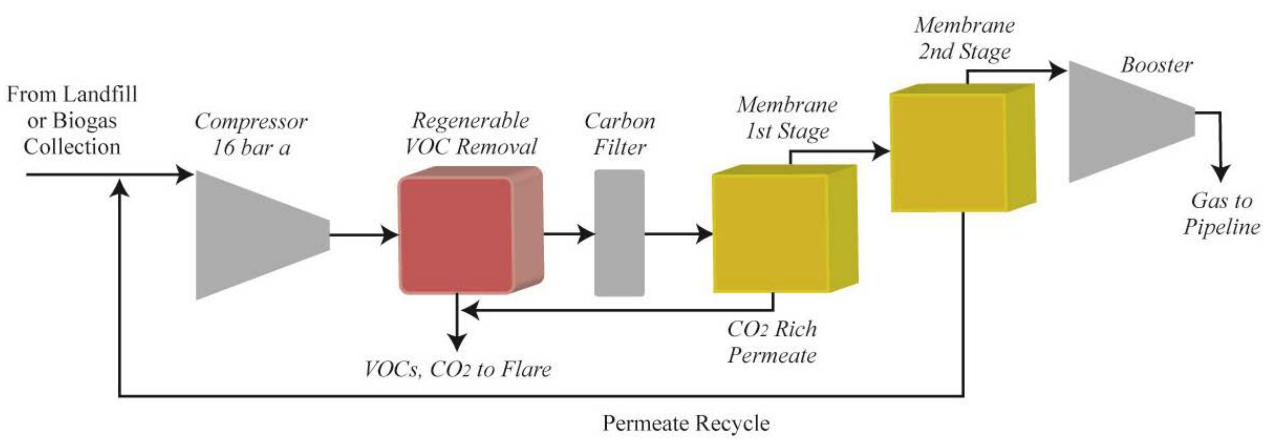
Upgrade & Pipeline Injection

Biogas can be upgraded and then injected into the pipeline. Upgrading to pipeline quality RNG involves cleaning the raw biogas (remove sulfur, siloxane, usually water vapor), separating the methane from the carbon dioxide and delivering a product that meets the local gas utility gas standard or tariff.[32] There are more than eighty biogas upgrading to pipeline injection facilities in Europe (IEA 2015). In the U.S., there are approximately fifty such facilities, including landfills and WRRFs (Escudero 2016). In California, there is one: at the Point Loma Water Resource Recovery Facility.

There are a variety of technologies available to upgrade biogas (separating CO_2 from methane) including (Ryckebosch, Drouillon et al. 2011, IEA 2014):

- physical/chemical absorption (water or amine scrubbers) [~ 65% of systems in Europe]
- permeable membrane systems [11% of systems in Europe]
- adsorption (i.e., pressure swing adsorption) [23% of systems in Europe]

BioFuels Energy, LLC is upgrading digester gas from the Point Loma Water Resource Recovery Facility near San Diego. It uses a two-stage permeable membrane system provided by Air Liquide (Figure 25) which recovers about 85-87% of input methane (Frisbie 2015).



Adapted from Air Liquid: http://www.medal.airliquide.com/en/biogaz-systems.html

Figure 25. Schematic - two-stage-membrane upgrade system.

[32] For example, see Southern California Gas Company, Rule 30 "Transportation of Customer-Owned Gas". https://www.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf.

Efficiency

Achievable methane recovery or yield for commercially available upgrading technologies is reported to be in the 96-99% range (Petersson and Wellinger 2009, Ryckebosch, Drouillon et al. 2011, Bauer, Hulteberg et al. 2013, IEA 2014). Methane recovery for the BioFuels Energy, LLC facility at Point Loma, California is reported to be 85-87% (Frisbie 2015). For upgrading to biomethane for pipeline injection in this analysis, a 90% methane recovery is used.

Basic volume and energy flows for a range of biogas upgrade-to-pipeline-injection capacities are tabulated below (Table 26). Methane concentration (or content) in the product gas is 98% in order to meet the required heating value (990 Btu ft^{-3}) for pipeline gas.[33]

Table 26. Upgrade-to-pipeline-injection input and product yield.

Biogas Flow Input			Product Gas Flow*	
(SCFM)	(MMBtu/h)		(SCFM)	(MMBtu/h)
50	1.8		27.5	1.6
75	2.7		41	2.4
100	3.6		55	3.2
150	5.4		83	4.9
300	10.8		165	9.7
600	21.6		331	19.4
1200	43.2		661	38.9
2300	82.8		1267	74.5

*Assumes 90% methane yield and 98% methane content in product gas (990 Btu ft^{-3}, HHV)

Emissions

Criteria Pollutants

On-site criteria pollutant emissions for biogas upgrading for RNG fuel or pipeline injection are relatively low because most of the methane is moved off-site and used (burned) elsewhere. Depending on where the product methane is used, such as at high efficient central station power production or in low-emission CNG vehicles, total emissions (on-site plus off-site) can be lower than most stationary engines, some turbine applications or flaring.

For the upgrading-to-pipeline-injection pathway analyzed here, only on-site criteria pollutants are evaluated. These consist of flare emissions from burning the tailgas to destroy process methane slip (Figure 26).

[33] "Recovery rate" and "methane content in product gas". Recovery rate describes how much of the methane in the incoming biogas is turned into product ("yield" could be used here as well). Methane content in final product is simply a concentration value, or physical property of final product.

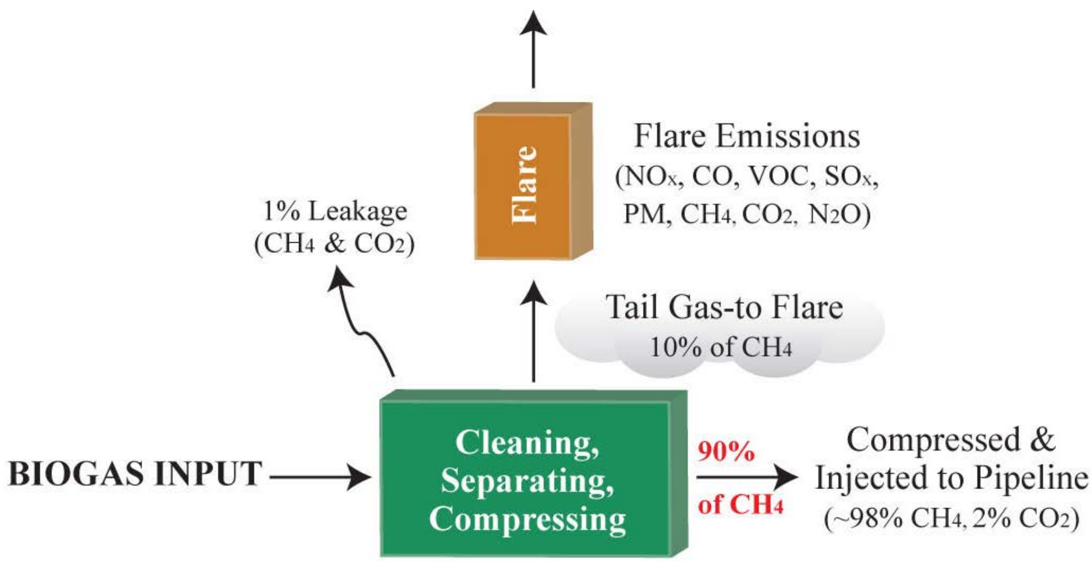


Figure 26. Upgrade-to-pipeline process schematic with tailgas flare.

Emissions for tailgas burned in a flare are tabulated below (Table 27) and are based on the same flare emission factors discussed in the flare section below.

Table 27. Upgrade-to-pipeline injection on-site criteria pollutant emissions.

Biogas Flow Input		Product Gas Flow	Emissions* (lb/day)				
(SCFM)	(MMBtu/h)	(MMBtu/h)	NO_x	CO	PM	VOC	SO_x
50	1.8	1.6	0.22	0.18	0.05	0.02	0.16
75	2.7	2.4	0.33	0.28	0.07	0.04	0.23
100	3.6	3.2	0.44	0.37	0.10	0.05	0.31
150	5.4	4.9	0.67	0.55	0.14	0.07	0.47
300	10.8	9.7	1.3	1.1	0.3	0.1	0.9
600	21.6	19.4	2.7	2.2	0.6	0.3	1.9
1200	43.2	38.9	5.3	4.4	1.2	0.6	3.8
2300	82.8	74.5	10.2	8.4	2.2	1.1	7.2
			Emission Factor (lb/MMBtu input to process)				
			0.0051	**0.0042**	**0.0011**	**0.0006**	**0.0036**

*Based on flare emission factors of 0.057, 0.0472, 0.01236, 0.0062 and 0.0403 lb/MMBtu for NO_x, CO, PM, VOC and SO_x respectively. (See Flare section.)

GHG

GHG emission factors include 1% methane (biogas) leakage from the upgrading process (Han, Mintz et al. 2011), methane slip through the tailgas flare and N_2O emission from the flare

(Mintz, Han et al. 2010). The CO_2 emission factor includes that in the incoming biogas that is separated from the methane in the upgrading process and then passes through the flare plus the product of methane combustion from tailgas burned in the flare as well as the small amount in the 1% leakage assumption mentioned above. The CO_2 emissions are biogenic (Table 28 and Figure 26).

Table 28. Upgrade-to-pipeline-injection process GHG emissions.

Biogas Flow Input		Greenhouse Gases (lb/day)				Greenhouse Gases (lb CO_2eq/day)		
(SCFM)	(MMBtu/h)	CH_4	CO_2 *	N_2O		CH_4	CO_2 *	N_2O
50	1.8	18.8	3,720	0.009		640	3,720	3
75	2.7	28.2	5,580	0.014		960	5,580	4
100	3.6	37.7	7,440	0.019		1,280	7,440	6
150	5.4	56.5	11,200	0.028		1,920	11,200	8
S300	10.8	113	22,300	0.057		3,840	22,300	17
600	21.6	226	44,700	0.113		7,680	44,700	34
1200	43.2	452	89,300	0.226		15,400	89,300	67
2300	82.8	866	171,000	0.434		29,400	171,000	129
		(lb/MMBtu input to process)				GWP_{100}		
		CH_4	CO_2 *	N_2O		CH_4	CO_2 *	N_2O
		0.4358	**86.1**	**0.00022**		**34**	**1**	**298**

*Biogenic CO_2 emissions

Cost

Because there are so few operating facilities (one known in California), biogas upgrading and injection costs are derived from a consultant report that modeled these costs as part of a financial evaluation of an RNG program proposed for gas utilities in Ontario, Canada (Electrigaz 2011). For the purposes of this study, the Electrigaz analysis was updated to year 2015 U.S. dollars with injection (i.e., interconnection) capital and O&M also modified to reflect expected higher costs in California (Table 29).

Table 29 shows installed capital and O&M costs for four project sizes (2.6, 9.2, 21.5 and 72.3 MMBtu/h product output).[34] Capital costs were annualized over a 20-year project life at 6% annual interest (or cost of money). Based on an evaluation of industry comments submitted to California Public Utilities Commission (CPUC) Proceeding R1302008, interconnect capital expenditure (CAPEX) and operations expenditure (OPEX) multipliers are 1.7 and 8, respectively. These were applied to the Electrigaz interconnect values (increases of ~$1-3 million

[34] These are the capacities analyzed in the Electrigaz study.

CAPEX and $50-100k OPEX).[35] Note that even with these interconnection cost increases, the upgrading portion still dominates at 75-90% of total production cost (Table 29).

Table 29. Upgrade and injection cost modeling.

Input Flow (SCFM, 60% CH_4)	72.7	265.6	621.5	2071.0
Product Methane (SCFM)	42.8	151.7	355.0	1192.9
Product Methane (MMBtu/h)	2.6	9.2	21.5	72.3
Upgrading Installed Capital	2,180,000	4,860,000	8,460,000	13,500,000
Injection, piping, compression* (*includes the 1.7x California Multiplier)	968,000	1,260,000	2,710,000	3,500,000
Total Capital	**3,148,000**	**6,120,000**	**11,170,000**	**17,000,000**
[20-year amortization, 6% interest]				
Upgrading Capital (annualized, $/y))	190,000	424,000	738,000	1,177,000
Injection Capital (annualized, $/y)	84,400	110,000	236,000	305,000
Annual Capital Expense ($/y)	274,400	534,000	974,000	1,480,000
O&M - Upgrading ($/y)	218,200	619,100	1,185,000	3,222,000
O&M - Injection ($/y)** (**includes the 8x California Multiplier)	41,100	48,700	108,300	113,700
Annual ($/Y)	**533,700**	**1,202,000**	**2,267,000**	**4,816,000**
Upgrading Cost ($/MMBtu)	17.98	12.95	10.20	6.95
Injection Cost ($/MMBtu)	5.52	1.97	1.83	0.66
Total Production Cost ($/MMBtu)	**23.50**	**14.92**	**12.03**	**7.61**

Notes:
Base upgrading and injection costs derived from: Electrigaz (2011). Biogas plant costing report: Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario, Prepared for Union Gas.
California injection CAPEX and OPEX "Multipliers" from industry comments to CPUC Proceeding R1302008 - Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements.

Figure 27 displays cost curves derived from the Electrigaz study (Electrigaz 2011) including a curve estimating costs for meeting California pipeline and interconnection standards (curve labeled "Electrigaz study w/ California adder" in the figure). Also shown for comparison purposes are:

[35] CPUC Proceeding R1302008 - Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, pipeline Open Access Rules, and Related Enforcement Provisions. Presiding Commissioner: Carla Peterman: http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:56:7166425933242::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1302008

- Two existing projects: a landfill-gas-to-pipeline-injection project in Texas (Williams 2015) and BioFuels Energy, LLC facility at the Point Loma Water Resource Recovery Facility (Frisbie 2015);
- Proposed upgrading and injection facility at Los Angeles County Sanitation Districts (Boehmke 2015); and
- Estimated high and low cost estimate in Waste Management comments to CPUC (Waste_Management 2014).

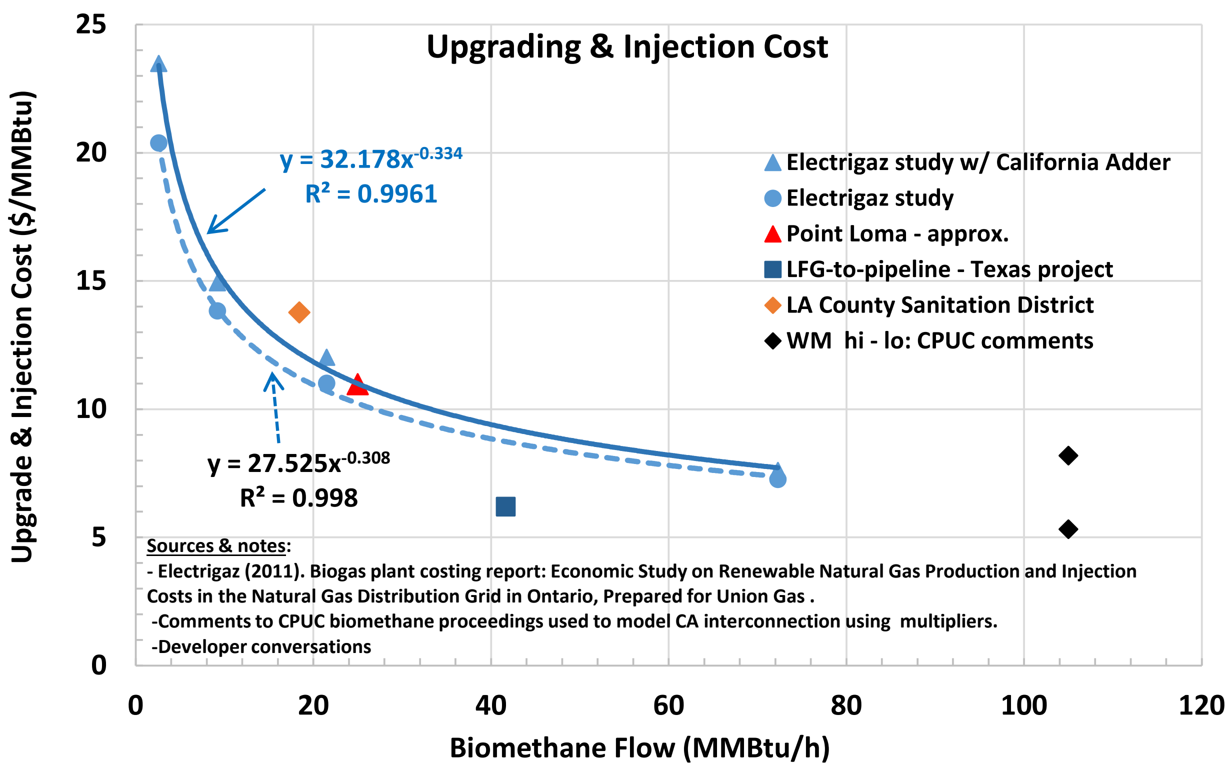


Figure 27. Upgrade and injection cost vs. capacity.

Flare

Flaring biogas without energy recovery is one method for disposing both methane and VOCs by burning and converting the vast majority of these emissions to CO_2. Flaring is assumed to be a default biogas application when intentional discharge or venting of biogas into the atmosphere is prohibited.

Criteria pollutant emission factors appear in the lower portion of Table 30 and are derived from weighted average source test emissions from three digester gas flares and one landfill gas flare (SCAQMD and SJVAPCD). (See Appendix C.) Criteria pollutant mass flows (lb/day) are also estimated in Table 30 for a range of flow rates. Emission factors for N_2O and CH_4 are taken from (Mintz, Han et al. 2010).

Table 30. Flare emissions and emission factors.

Gas Flow Input (MMBtu/h)	Emissions (lb/day)								Greenhouse Gases (lb CO_2eq/day)		
	NO_x	CO	PM	VOC	SO_x	Greenhouse Gases					
						CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
0.6	0.82	0.68	0.18	0.090	0.58	1.0	2,760	0.03	34	2,760	10.4
1	1.37	1.13	0.30	0.150	0.97	1.7	4,590	0.06	57	4,590	17.3
2	2.74	2.26	0.59	0.300	1.93	3.3	9,180	0.12	114	9,180	34.7
5	6.85	5.66	1.48	0.749	4.83	8.4	23,000	0.29	284	23,000	86.7
7	9.58	7.92	2.08	1.049	6.76	11.7	32,100	0.41	398	32,100	121
10	13.7	11.3	2.97	1.499	9.66	16.7	45,900	0.58	568	45,900	173
15	20.5	17.0	4.45	2.248	14.49	25.1	68,900	0.87	853	68,900	260
20	27.4	22.6	5.93	2.998	19.32	33.4	91,800	1.16	1,140	91,800	347
30	41.1	34.0	8.90	4.496	28.98	50.2	138,000	1.75	1,710	138,000	520
	Emission Factor (lb/MMBtu)					**Emission Factor (lb/MMBtu)**					
	NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O	**GWP_{100}**		
	0.057	**0.047**	**0.0123**	**0.0062**	**0.0403**	**0.07**	**191.3**	**0.0024**	**34**	**1**	**298**

*Biogenic CO_2 emissions

Cost

Flare costs are derived from (ICF 2013) with an estimated gas disposal cost of about \$1.25/MMBtu at small scale to less than \$0.50/MMBtu at the largest flow size as shown in Table 31.

Table 31. Flare gas disposal cost.

Gas Flow		**Installed Cost (\$)**	**O&M Cost (\$/y)**	**Gas Disposal Cost (\$/MMBtu)**
Biogas (SCFM)	**MMBtu/h**			
17	0.6	51,700	2,070	**1.25**
28	1.0	75,800	3,030	**1.10**
56	2.0	128,000	5,120	**0.93**
140	5.0	254,000	10,200	**0.74**
190	7.0	326,000	13,000	**0.68**
280	10.0	426,000	17,000	**0.62**
420	15.0	578,000	23,100	**0.56**
560	20.0	717,000	28,700	**0.52**
830	30.0	972,000	38,900	**0.47**

3. Results and Discussion

Primary Technology Costs

Cost or revenue required to process biogas varies from less than $1/MMBtu (input flow basis) for flare systems to $7-$25/MMBtu or more for upgrading the biogas for pipeline injection. Fuel cell costs are similar to pipeline injection. Engines, microturbines and compressed RNG fuel each fall below $5/MMBtu (input) for larger system sizes. Compressed RNG fuel processing is above $10/MMBtu for small capacities. Combustion turbine costs are relatively flat ($3-$4/MMBtu) (Figure 28). There are economies of scale for all processes investigated with fuel cells, microturbines and gas upgrading to RNG or pipeline injection showing strong economies of scale.

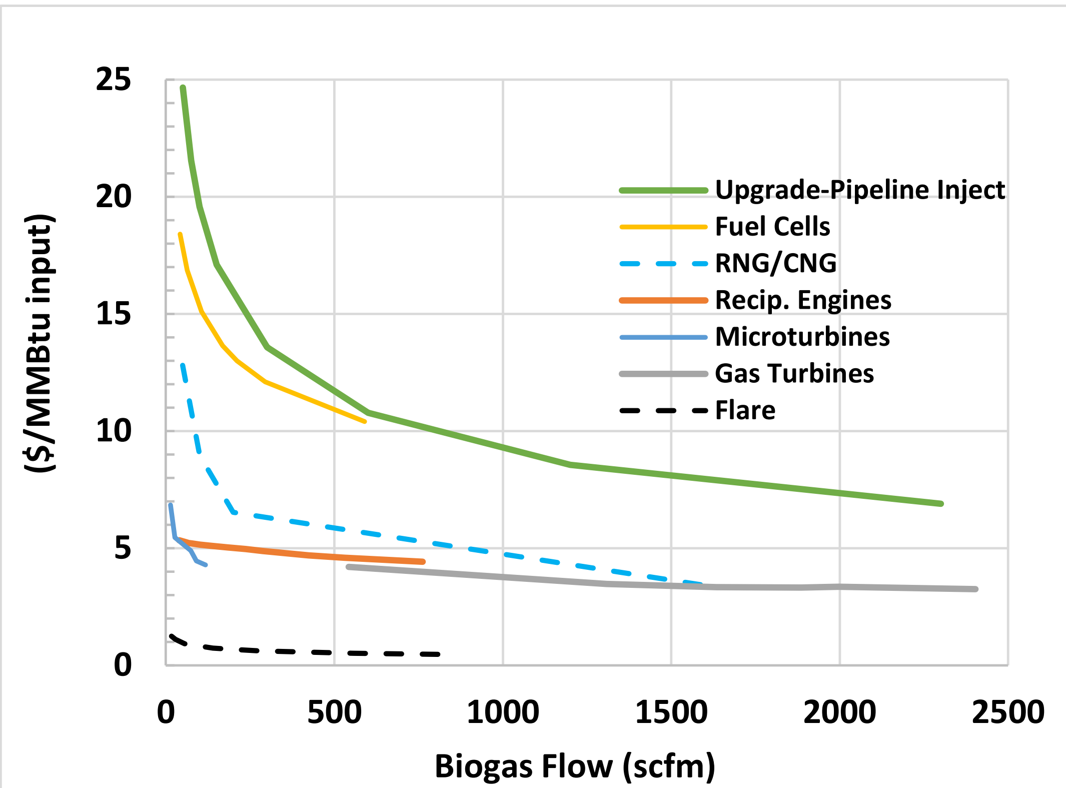


Figure 28. Biogas processing costs.

The LCOE for fuel cells ranges from ~$0.16/kWh at small size to about $0.09/kWh at the 3 MW size. Reciprocating engine LCOE varies from $0.09 to $0.05/kWh. Combustion turbines (gas turbines) have the lowest LCOE of about $0.04/kWh at large scale (Figure 29).

Average California electricity prices for industrial and commercial customers [$0.123/kWh and $0.156/kWh respectively (EIA 2016)], as well as the expected Bioenergy Feed-in Tariff price floor (about $0.125/kWh), are shown on Figure 29 for comparison.

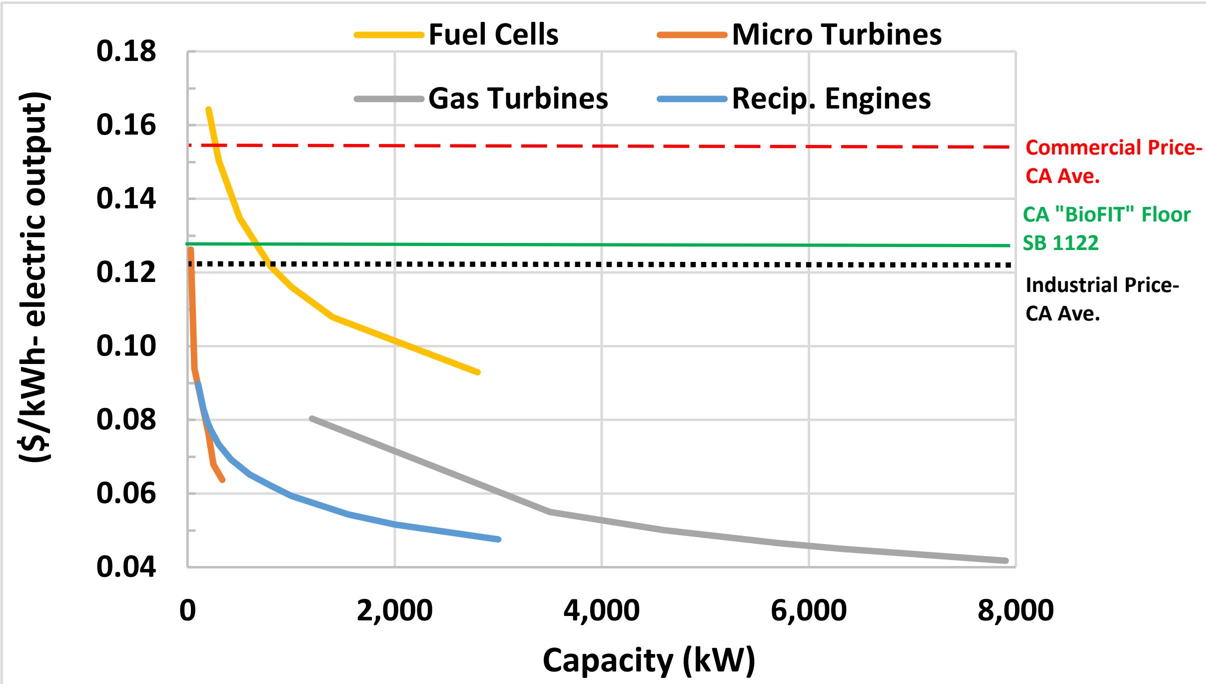
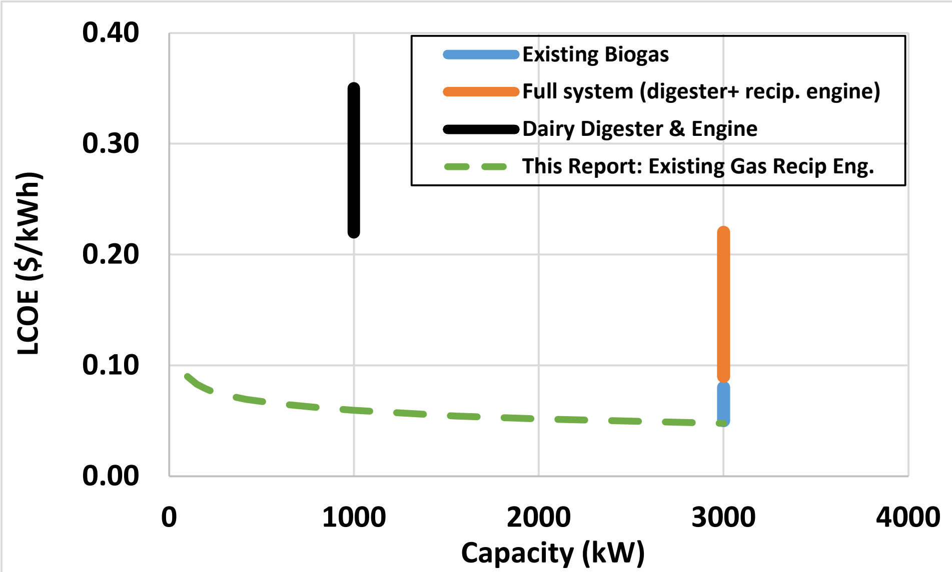


Figure 29. LCOE comparison.

As a reminder, costs in this study are for the biogas conversion or upgrading technology only. Costs for producing the raw biogas (i.e., constructing digesters, feedstock handling, etc.) are not included. Black and Veatch (B&V) analyzed expected LCOE for California bioenergy projects for the CPUC during rulemaking for Senate Bill (SB) 1122 (California's Bioenergy Feed-in-Tariff) (Black and Veatch 2013). They estimated LCOE for existing biogas, using California reciprocating engines, and found it ranges from $0.05 to $0.08 per kWh for a 3 MW project. Cost for a full 3 MW system (gas production plus engine-generator) ranges from $0.09 to $0.22 per kWh (Figure 30). LCOE for a 1 MW dairy digester system ranges from $0.22 to $0.35 per kWh. Also shown for comparison in Figure 30 is the LCOE curve for reciprocating engines developed in this report. This agrees with the low end of the B&V estimate for existing biogas.

For situations where biogas is already available (e.g., landfills with gas extraction systems or existing wastewater treatment anaerobic digesters), management of biogas using microturbines, reciprocating engines, and gas turbines would compete with industrial and commercial electricity prices in CA.



Sources: Black and Veatch (2013). Small-Scale Bioenergy: Resource Potential, Costs, and Feed-in Tariff Implementation Assessment, Prepared for the California Public Utilities Commission. R.11-05-005 AES/sbf/lil, and this report.

Figure 30. B&V LCOE estimates for biogas compared to this report.

Compressed RNG with on-site fueling varies from about $18/MMBtu produced (small scale) to about $4/MMBtu at the largest size (or about $2.40 - $0.50 per gallon gasoline equivalent) and is generally less costly than upgrading biogas for pipeline injection, which can be higher than $25/MMBtu at small scale to about $7/MMBtu at very large scale (Figure 31).

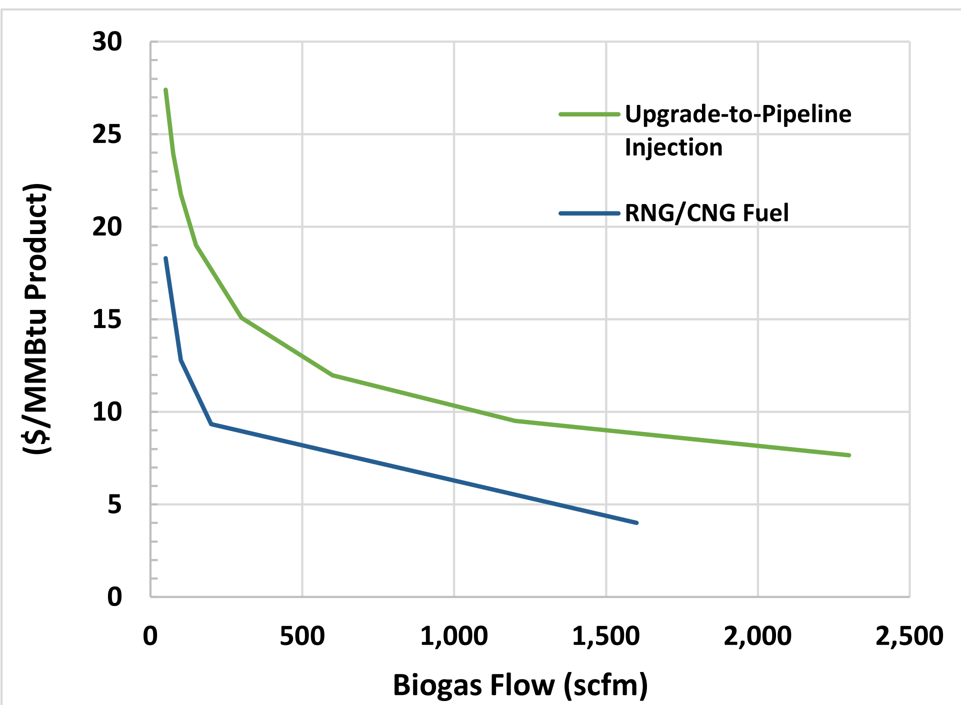


Figure 31. Biomethane product cost.

Energy revenues from electricity sales are expected to be about $0.125/kWh based on the Bioenergy Feed-in-Tariff “floor” or starting price.[36] RNG must compete with the current low natural gas prices and will require additional value offered by Low Carbon Fuel Standard (LCFS) and Renewable Identification Number (RIN) credits for fuel applications or value from other renewable attributes for RNG injected to the pipeline.

Criteria Pollutant Emissions

Criteria pollutant emission factors (lb/MMBtu gas input) are summarized in Table 32 and Figure 32. Reciprocating engines (even those based on Rule 1110.2 limits) have the highest NO_x emission factor among the on-site electricity prime movers. Flares have the highest average NO_x emission factor of all the analyzed applications (Figure 32). Fuel cells, followed by gas turbines with SCR-based NO_x control have the lowest NO_x emission factors (for stationary power applications).

The RNG fuel and pipeline injection pathways have emissions that occur both on-site and when the gas is used elsewhere. The off-site mobile and stationary source emissions are beyond the scope of this analysis.

Table 32. Emission factor comparisons: criteria pollutants.

	Emission Factor (lb/MMBtu input) [Source Test Averages, permit values, or AP-42]				
	NO_x	**CO**	**PM**	**VOC**	**SO_x**
Reciprocating Engines	0.043	0.151	0.014	0.016	0.003
Micro-Turbines	0.016	0.017	0.001	0.008	0.067
Gas Turbines - Low NO_x	0.031	0.004	0.012	0.007	0.063
Gas Turbines - SCR	0.011	0.013	0.012	0.0007	0.0046
Fuel Cells	0.003	0.009	0.001	0.008	0.0001
Upgrade to Pipeline	0.0051	0.0042	0.0011	0.0006	0.0036
RNG-CNG 70% Recovery	0.0165	0.0137	0.0036	0.0018	0.0117
RNG-CNG 85% Recovery	0.0080	0.0066	0.0017	0.0009	0.0056
Flare	0.057	0.047	0.012	0.006	0.040

Output-based criteria pollutants (lb/MWh) for the electricity producing systems appear in Figure 33 through Figure 35. For comparison, California central-station power plant best available control technology (BACT) is also shown (CARB 2007).

[36] CPUC Decision D.15-09-004: http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&DocID=154488509

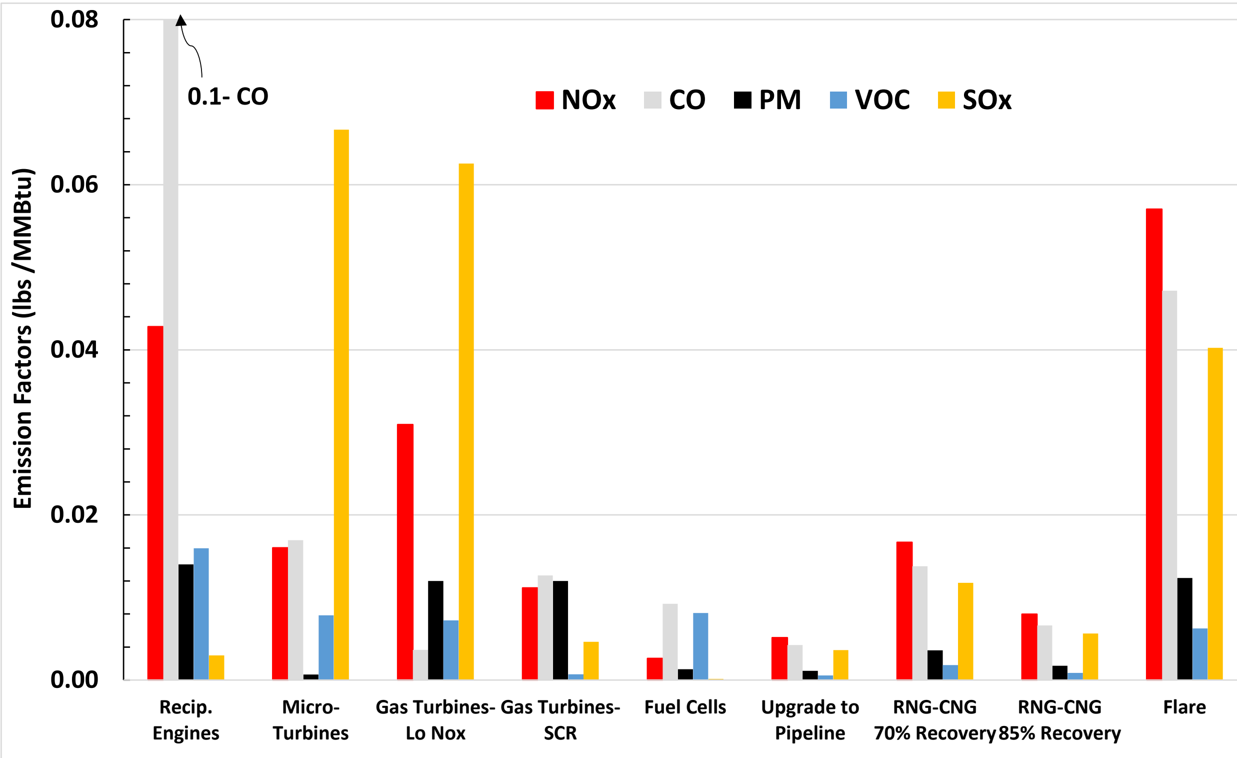


Figure 32. Emission factors by technology.

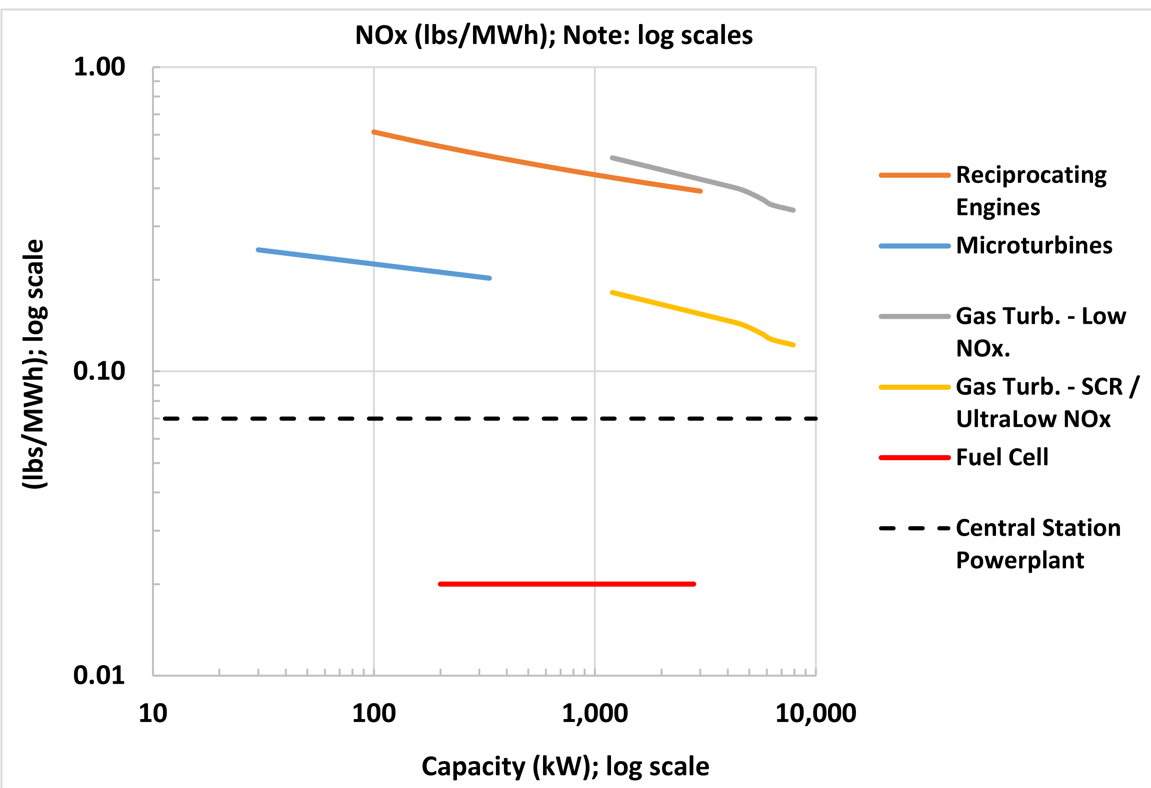


Figure 33. NO_x emissions (lb/MWh).

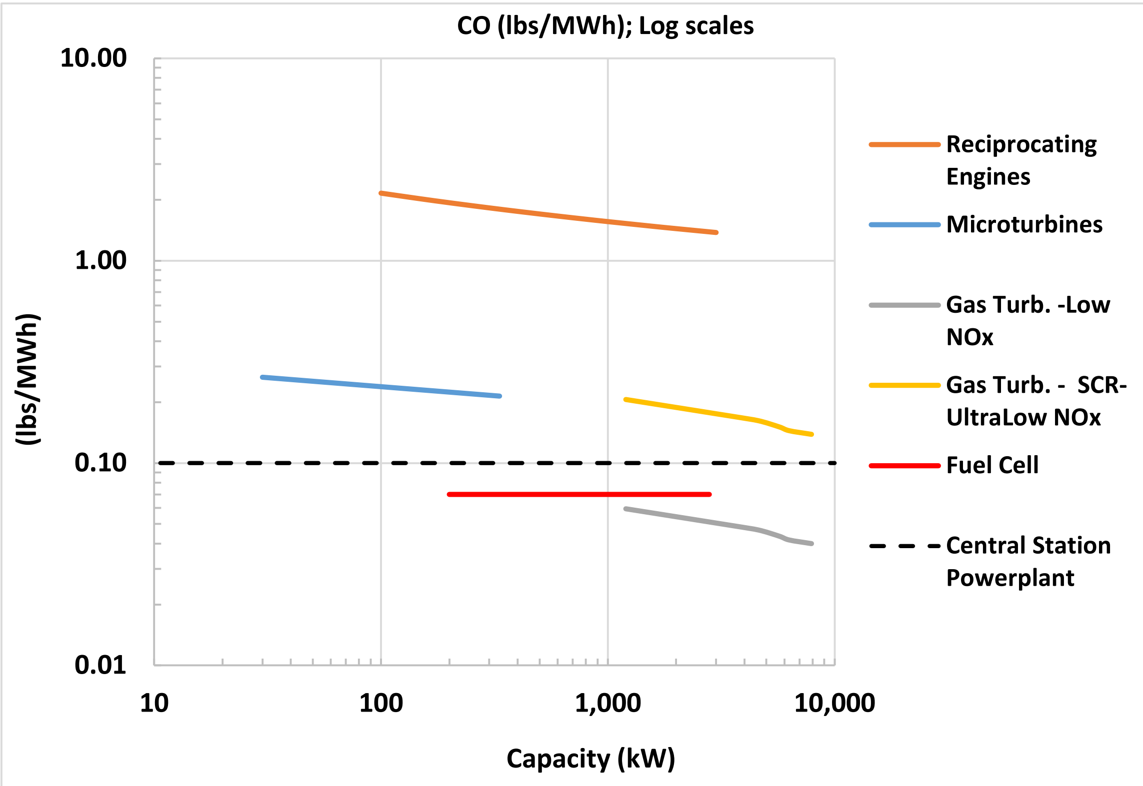


Figure 34. CO emissions (lb/MWh).

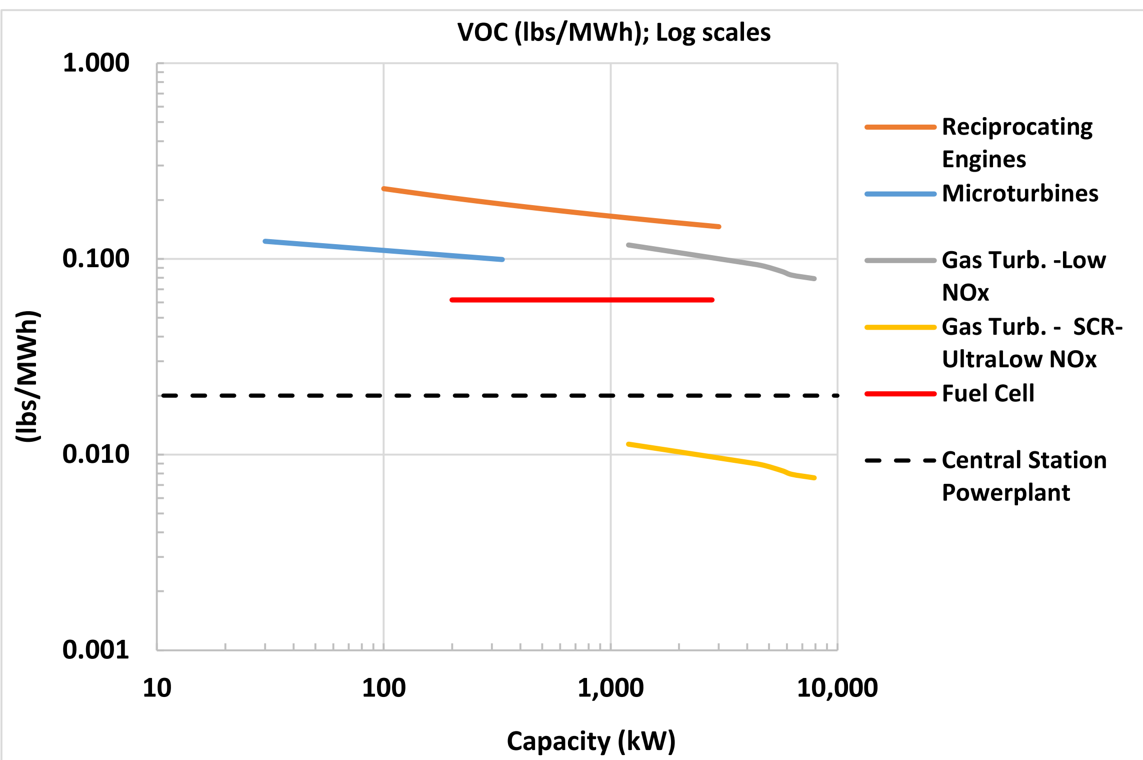


Figure 35. VOC emissions (lb/MWh).

GHG Emissions

On-site GHG emission factors for conversion or processing are summarized for all systems in Table 33 and Figure 36. Recall, upstream and downstream sources and sinks are beyond the scope of this analysis.

All devices emit small but significant amounts of methane as "slip" (or unburned methane) from conversion devices or through leaks in processing equipment, ranging from <1% to as much as 5% of the incoming methane in the fuel or biogas (CAR 2011), (Han, Mintz et al. 2011).

N_2O emissions are generally taken from (IPCC 2006) and are rather small for these systems, even when accounting for its large 100-year GWP of 278.

On-site CO_2 emissions include those originally in the input biogas (40% CO_2 content was used for calculation purposes in this report) and those produced through the combustion of methane in the conversion device. The CO_2 emissions are biogenic.

Table 33. GHG emission factor summary.

Technology	GHG Emission Factor[37] (lb/MMBtu)			Notes
	CH_4	N_2O	CO_2	
Recip. Engines	0.838	1.92E-03	191.3	Average of SCS (2007) & Mintz (ANL)*, N_2O & ~ 97.99% CH_4 destruction efficiency (2% slip)
Micro-Turbines	0.167	2.56E-04	191.3	Average SCS (2007) & CAR (2011): CH_4 99.6% destruction efficiency, N_2O Emission Factor from Table 2.2 in 2006 IPCC Guidelines
Gas Turbines	0.167	2.56E-04	191.3	Average SCS (2007) & CAR (2011): CH_4 99.6% destruction efficiency, N_2O Emission Factor from Table 2.2 in 2006 IPCC Guidelines
Fuel Cell	0.003	2.56E-04	191.3	CH_4 & N_2O Emission Factor from 2006 IPCC Guidelines
Flare	0.07	2.43E-03	191.3	Mintz et al., (2010) CH_4 99.8% destruction efficiency, N_2O also from Mintz (2010).
RNG/CNG (70% recovery)	0.437	7.03E-04	106.5	1% CH_4 leakage in upgrade process + flare emissions from tailgas combustion. No vehicle or downstream combustion emissions included.
RNG/CNG (85% recovery)	0.427	3.40E-04	88.3	
Upgrade-Injection	0.436	2.18E-04	86.1	

[37] Units are lb/MWh of CH_4, CO_2 and N_2O. They are not displayed in (or converted to) CO_2eq.

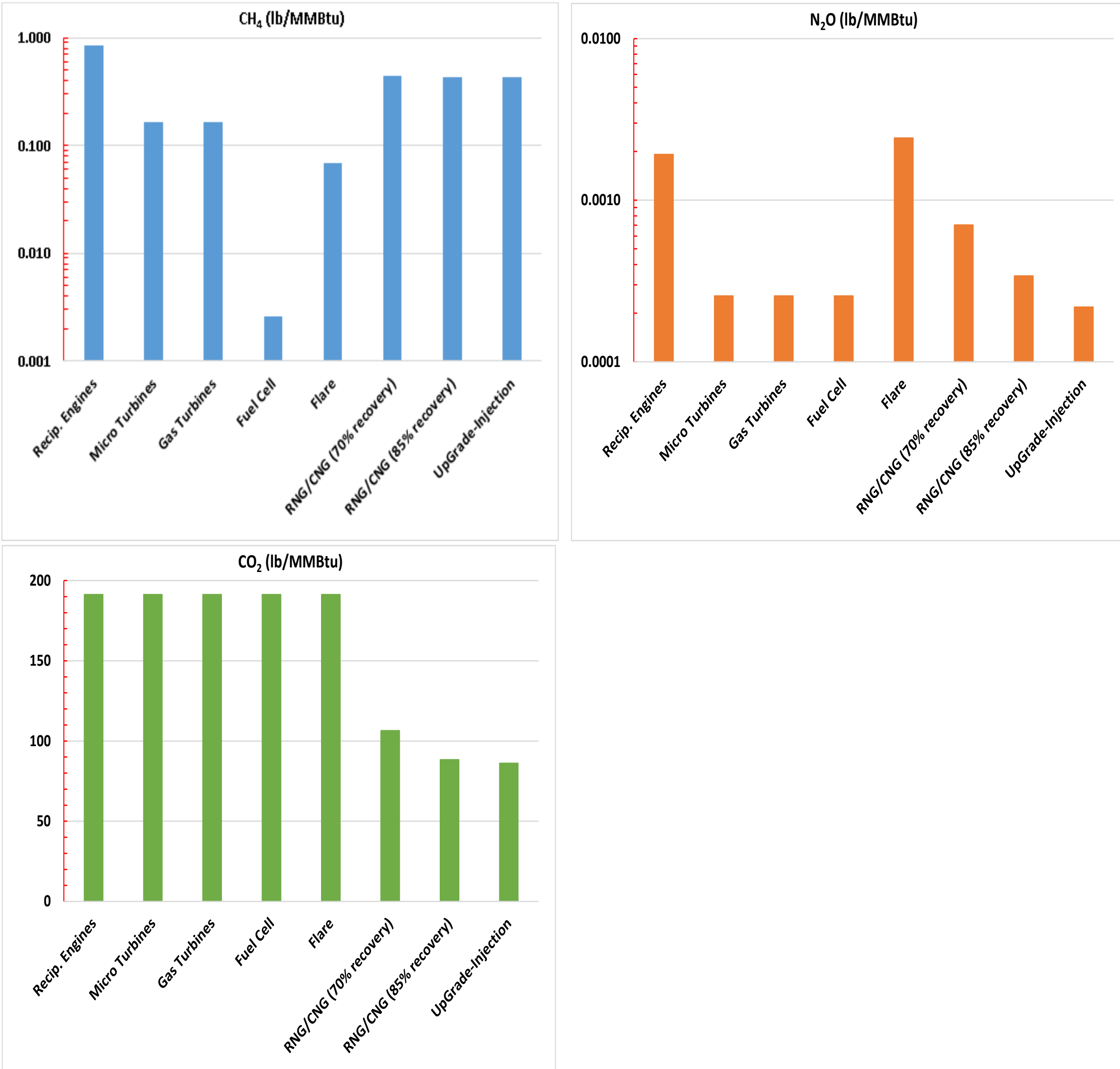


Figure 36. GHG emission factor summary (lb/MMBtu input).

Comparison to eGRID

The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive source of data on the environmental characteristics, including GHG emissions, of nearly all electric power generated in the United States. Average output based (i.e., lb/MWh) methane and nitrous oxide emissions for the electricity generating technologies are plotted in Figure 37 and Figure 38, respectively. Also shown are average California grid emissions (CA eGRID) from (USEPA 2012).

For engines, microturbines and gas turbines, average methane emissions are about two orders of magnitude larger than the CA eGRID factor (0.03 lb CH_4 per MWh) (Figure 37). This is primarily due to relatively large methane slip compared to that of the overall California grid. The N_2O emissions for microturbines, gas turbines, and fuel cells were about half that of the CA grid

(CA eGRID factor is 0.006 lb N_2O per MWh). Reciprocating engine N_2O emissions are about four times the California grid average (Figure 38).

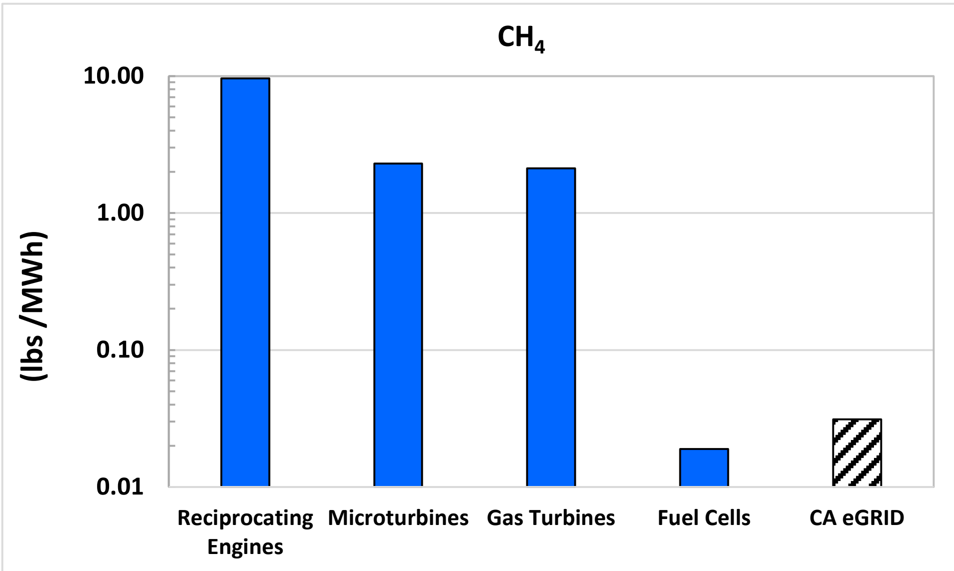


Figure 37. Average methane emissions, bio-power technologies & CA eGRID.

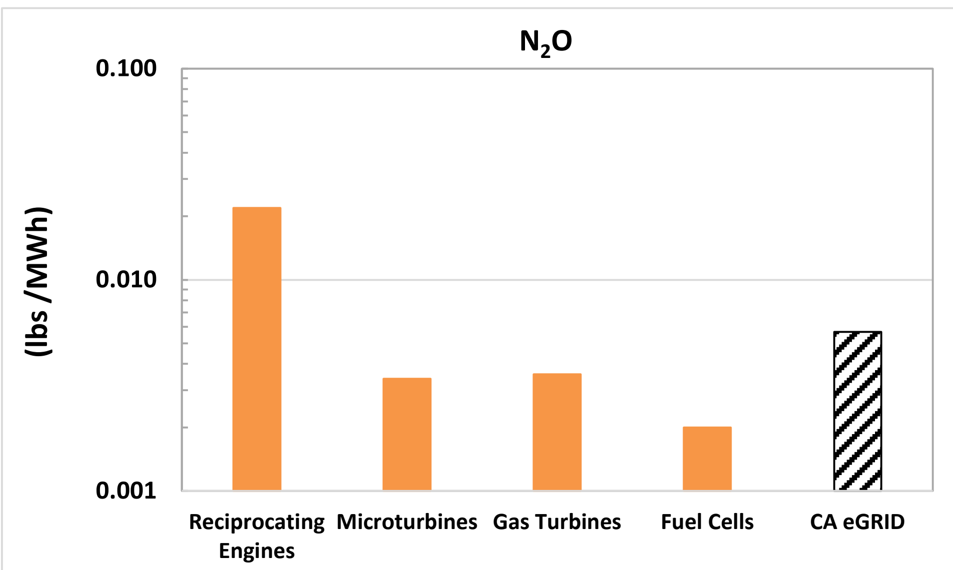


Figure 38. Average N_2O emissions, bio-power technologies & CA eGRID.

All the devices also emit significant amounts of CO_2, resulting in overall CO_2eq emissions factors that would appear higher than the CA eGRID factor of 653 lb CO_2eq per MWh output.[38]

[38] eGRID uses GWP_{100} values from the IPCC Second Assessment Report (IPCC 1995). When applying the GWP_{100} from the Fifth Assessment Report (AR5 or IPCC 2013), the CA eGRID CO_2eq value increases by 0.05%.

However, “eGRID assigns zero CO_2 emissions to generation from the combustion of all biomass (including biogas) because these organic materials would otherwise release CO_2 (or other greenhouse gases) to the atmosphere through decomposition” (USEPA 2015d). To compare to eGRID’s emission factor for CO_2eq, biogas CO_2 emissions for the devices in this report are not counted in the carbon intensity calculation. Therefore, the CO_2eq equivalent emission factors for microturbines, gas turbines, reciprocating engines, and fuel cells are all considerably lower than the CA eGRID factor of 653 lb CO_2eq per MWh output (Figure 39).

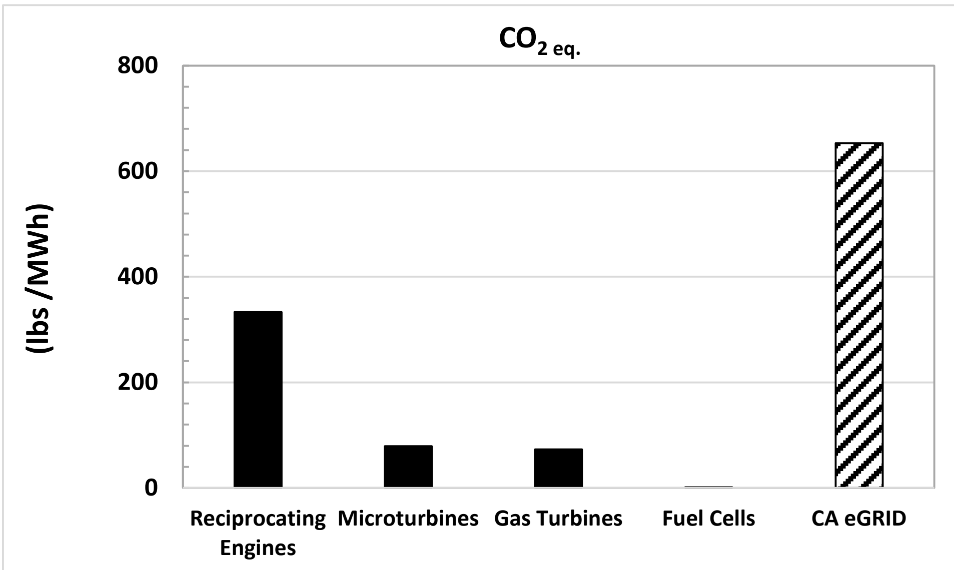


Figure 39. CO_2eq emissions for the bio-power technologies & CA eGRID.

Additional Costs

Stationary Engines: Pre-Treatment

Before being combusted, biogas is typically “pre-treated” to remove water and other trace contaminants. Depending on the biogas source and the emission requirements of the local air district, additional treatment may be necessary. For example, biogas engines operating in the SCAQMD will need to comply with Rule 1110.2, which restricts the NO_x from stationary engines to 11 ppm. By January 2017, biogas engine operators will have to invest in cleaner technologies (e.g., fuel cells) or after-gas treatment technologies (e.g., SCR systems). As both are highly sensitive to siloxanes and sulfur — exposure can deactivate SCR catalysts in a matter of hours — facilities must additionally invest in treatments that can remove contaminants to a very high degree. Sulfur treatment is a higher priority for fuel cells.

While the present analysis did not directly investigate such pretreatment costs, it used costs estimated by a recent study sponsored by the SCAQMD. To help biogas facilities in their jurisdiction comply with Rule 1110.2, the SCAQMD conducted a nationwide survey of biogas cleanup technologies and costs (GTI 2014). SCAQMD completed an extensive literature and internet search to identify and obtain information on biogas cleanup systems, corroborated findings with vendor surveys, and compared the costs of various systems. Based on the findings, SCAQMD developed an Excel-based calculation spreadsheet that estimates capital (equipment) costs, annual operation and maintenance costs and annualized cost for a siloxane removal system based on user input data (SCAQMD 2014).[39]

The SCAQMD may be one of the first air districts with such strict NO_x and VOC emission limits, but it will likely not be the last. To meet the EPA's 2015 standard for ozone, other jurisdictions may similarly focus on reducing NO_x and VOCs from stationary engines.

Compressed RNG: Scale & Demand

Scale affects project costs. The greater the flow rate, the smaller the per-unit cost ($/GGE). The smallest-scale system analyzed (the BioCNG 50 system) is sized for an average biogas input flow of 50 SCFM — or 72,000 cubic feet per day. There are few existing digesters in California equipped to generate biogas at the 50 scfm rate. More than half of the state's WRRFs with anaerobic digesters, for example, treat less than 7 MGD; processing only wastewater, these facilities would appear unlikely to produce enough biogas to justify the investment.[40] And yet public agencies (e.g., the Janesville WRRF and St. Landry Parish landfill) have been willing to invest in smaller-scale projects, provided the project meets expected rates of return and adheres to calculated payback horizons. Outside support (e.g., grants) and outside wastes (i.e., co-digestion) would make any project, particularly smaller projects, more economical. Additional research on co-digestion and project scale would provide valuable insight.

Another critical factor in the cost equation is the current status and planned expansion of natural gas vehicles within an organization's fleet. A viable CNG project requires vehicles to use the fuel. Some facilities — such as the Joint Water Pollution Control Plant in Carson (CA), which sells approximately 1,000 GGE/day to district vehicles, buses, and other commercial and public users — could dedicate biogas to producing compressed RNG, but will not until there is adequate demand (Boehmke 2015). Similarly, the Janesville (WI) WRRF has the capacity to dedicate more biogas to CNG, but, until it acquires additional dual-fuel vehicles, will prioritize electricity and heat (Ely and Rock 2014). The present analysis did not consider the cost of acquiring and/or converting and maintaining CNG vehicles. Nor did it consider the relationship between economies of scale and fleet size (i.e., that larger volumes of CNG will require a larger fleet, the acquisition and maintenance of which will require a larger investment). Here too, additional research would assist future projects.

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[39] The Biogas Cleanup System Cost Estimator Toolkit is available here: http://www.aqmd.gov/home/regulations/rules/support-documents. It can be found under the heading, Rule 1110.2.

[40] According to data collected from EPA Region 9's annual biosolids reports, 76 of California's WRRFs with anaerobic digesters have an Average Dry Weather Flow (ADWF) of less than 7.2 million gallons per day (MGD). Assuming a wastewater flow of 1 MGD could produce 10,000 cubic feet of biogas (USEPA 2011), a facility treating 7.2 MGD could produce 72,000 cubic feet per day.

Pipeline Injection: Scale, Clean-Up & Interconnection

Scale also influences pipeline injection project economics. Upgrading biogas to CNG vehicle fuel can be competitive with diesel in many cases, making it an attractive transportation fuel; whereas upgrading and injecting biogas into the pipeline is more expensive than conventional gas, making injection a costly alternative (Gorrie 2014). Produced in smaller quantities than natural gas and requiring more expensive processing, the production cost of biogas is inherently higher than fossil fuel gas (Boehmke 2015). Additionally, natural gas prices are at a decade-low (EIA 2015). For these reasons, scale is a significant consideration. Additional research on the size and costs of existing U.S. and European biomethane pipeline projects would provide valuable insight.

Perhaps even more significant for California biogas facilities are the costs associated with meeting the CPUC biomethane quality standards and the interconnection fees charged by the state's Investor Owned Utility (IOUs). California Assembly Bill 1900 (Chapter 602, Statutes of 2012) required the CPUC to develop standards for constituents in biogas to protect human health and pipeline integrity. The resulting January 2014 rule requires testing, monitoring and controlling for 17 constituents of concern, as well as a heating content requirement of 990 Btu. Industry advocates have described the requirements as "cost-prohibitive" (Levin, Mitchell et al. 2014). Relatedly, the cost of interconnecting a biogas facility to the common carrier pipeline is high, according to the State's IOUs, over a million dollars (CPUC 2015).

The Coalition for Renewable Natural Gas (CRNG) estimates the initial cost of a pipeline biomethane project in California to be between $2 and $3.8 million, with annual costs exceeding $400,000 (CRNG 2015). These California-specific costs for biomethane into the pipeline are included in this report's cost estimates, presented earlier in Table 29 & Figure 27. As additional projects come on-line in California, a close examination of project economics, including the role of federal and state subsidies, would be useful. The present analysis did not consider how grants and incentives would affect pipeline injection project costs.

Collecting & Processing High Strength Organic Wastes

For facilities handling high strength organic wastes—ranging from source-separated organics via municipal collection programs to food processing facility discards—managers will need to invest in infrastructure to collect and process the material. Methods employed to collect high strength organic wastes will differ depending on the facility type, size and location. Inasmuch, collection costs will vary.

Generally, processing high strength organic wastes involves chopping, grinding, and screening the material to create a *slurry* which is fed into the digesters. In <u>Food Waste to Energy</u>, Ely and Rock (2014) describe the processing protocols of six WRRFs and include various projects costs. Costs for constructing food waste receiving stations ranged from $800,000 to $5,000,000. Needless to say, processing costs also vary depending on unique facility characteristics.

While significant, the costs associated with collecting and processing high strength organic wastes are not included in this analysis.

Managing Digestate

In California, the land application of biosolids is heavily regulated, and, in some counties, effectively banned. Inasmuch, the cost of managing biosolids varies, depending on the management option, tipping fees, and travel distance. According to the 2014 Southern California Alliance of Publicly-Owned Treatment Works (SCAP) survey, the average cost for managing biosolids for Southern Californian Publicly Owned Treatment Works (POTWs) was $53.94/ton, ranging from a low of $5.40/ton for landfill Alternative Daily Cover (ADC) to a high of $89.50 for deep well injection (SCAP 2015). Table 34 summarizes the results of the SCAP survey, showing the range and average costs for several different biosolids management strategies.

Table 34. Range and average costs of different biosolids management strategies.

Biosolids Management Strategy	**Range ($/ton)**	**Average ($/ton)**
Composting	$29.41 to $84.00	$56.75
Landfill Alternative Daily Cover	$5.40 to $61.76	$31.72
Deep Well Injection	$89.50	$89.50
Land Application	$39.00 to $57.00	$47.13
Landfill, Direct Burial	$45.00 to $52.50	$50.41

Source: (SCAP 2015)

Depending on the digester type (i.e., wet or dry), the proximity of a composting facility (to cure the solid digestate), and the end-use (land application, ADC, etc.), the cost of managing digestate from a stand-alone digester will vary considerably. As many stand-alone digesters are relatively new operations, much remains to be seen regarding overall project operation and maintenance costs. Case studies examining the economics of stand-alone digester systems, including the costs and revenues associated with co-products such as digestate can be found in the literature (Ghafoori, Flynn et al. 2007, Gebrezgabher, Meuwissen et al. 2010, Golkowska, Vazquez-Rowe et al. 2014, Monlau, Sambusiti et al. 2015) but are, for the most part, based in Europe. Similar U.S. and California case studies are needed.

Unlike digestate from water resource recovery facilities and stand-alone digesters, dairy digestate can be used on-site. Depending on its water content, digestate can be spray-applied to crops as a fertilizer supplement or replacement, used as compost material or livestock bedding material (ESA 2011). Digestate management typically does not cost a dairy much, it may even generate a small revenue; see the additional sources discussion in the Primary Revenue section below.

Also omitted from this analysis are the environmental costs associated with managing digestate. For example, the emissions analysis did not consider the fuel that would be consumed by trucks hauling material to a land-application site; nor did it consider the potential N_2O that would be emitted if the digestate were improperly managed.

Primary Revenue: Energy Savings, Sales & Subsidies

Biogas facilities can generate significant sources of revenue, which are dependent on the biogas end use, as well as federal, state and local regulations, policies and incentives. Global cumulative revenue from investment in biogas production capacity is expected to reach $25.8 billion between 2015 and 2024, according to Navigant Research (Navigant 2015). Revenues include cost savings from on-site energy operating costs, such as waste heat recovery and electricity use on-site, as well as off-site sales, including exporting the electricity to the grid or producing RNG to fuel vehicles or inject in the natural gas utility pipeline. Additionally, biogas-to-energy projects are eligible for local, state and federal subsidies, which can play an important role in project financing. However, current low natural gas prices make biogas projects difficult to finance. This analysis did not take into consideration energy savings, sales, and subsidies when evaluating project economics. These factors could substantially lessen costs.

Offsetting Heat & Power Costs

Biogas combusted in engines — including reciprocating engines, microturbines, turbines and fuel cells — produces both electricity and heat. Producing heat and electricity on-site has a number of benefits, including generating power at a cost below retail electricity rates and displacing purchased fuels for thermal needs. For those biogas facilities with considerable power expenses, on-site generation is particularly attractive. For WRRFs, energy bills can be ~30% of total O&M costs (Carns 2005), usually representing a facility's second or third biggest expense. The electric power produced by combusting biogas in an engine can offset all or most of a WRRF's power demand, and the thermal energy produced by the CHP system can be used to meet digester heat loads and, in some cases, for space heating (USEPA 2011).

Selling Excess Energy

Biogas can also be exported and sold off-site, either as pipeline quality biomethane, a vehicle fuel, or electricity. To sell electricity to a utility or nearby facility, a biogas facility can interconnect. Once interconnected, a facility can sell to a third party by developing a Power Purchase Agreement (PPA) or to the local electric utility by establishing a net metering agreement. Net metering credits renewable energy generators that deliver to the grid. The local utility tracks each kWh consumed and received. When a biogas facility generates more electricity than it consumes, the electric utility credits the excess delivered to the grid. These credits can, in turn, be used to offset the cost of power purchased from the utility when the biogas facility consumes more than it generates.

In California, the major electric utilities must offer net metering to all eligible facilities (1 MW or less solar, wind, fuel cell or biogas systems) until the facilities reach a legislated limit (DSIRE 2015). Larger capacity systems are eligible for other renewable energy procurement programs. Systems under 3 MW may participate in California's Feed-in Tariff (FIT) program (CPUC 2014a); systems greater than 3 MW and less than 20 MW may participate in the Renewable Auction Mechanism (RAM) program (CPUC 2014b). Unlike net-metering, the FIT and RAM programs do not commit utilities to purchasing the electricity at full retail value; rather, as with PPAs, the utilities commit to buying electricity at a predetermined rate over a predetermined time period.

Renewable Energy Certificates (RECs)

A biogas system producer may also sell the on-site generated electricity in the form of a REC. In California, as with other states, RECs are used to show compliance with the Renewable Portfolio Standard (RPS) and can be traded in voluntary markets (Green and Koostra 2015). A state's RPS requires IOUs, electric service provides and community choice aggregators to increase procurement from eligible renewable energy resources. California's current RPS goal is to procure 50% renewables by 2030 (De Leon 2015).

A REC is a certificate that represents the generation of one MWh of electricity from an eligible source of renewable energy and represents the property rights, in this case, to the non-power qualities of electricity generated from biogas. Because the RECs are not tied to the physical delivery of electrons, organizations are able to purchase green power from suppliers other than their local electricity provider. While RECs offer increased contracting convenience, they do not provide the same protection against price volatility as long-term contracts (USDOE 2010).

EPA's Renewable Fuel Standard & Renewable Identification Number (RIN) Credits

Managed by the U.S. EPA, the RFS program mandates that 36 billion gallons of renewable fuel be blended into the nation's transportation fuel by 2022 (USEPA 2016b). The RFS obligates producers of gasoline or diesel (including refiners, importers, and blenders) to meet the mandate, and established a trading program to ensure compliance. The trading program allows obligated parties to comply through a credit based program, with the credits being Renewable Identification Numbers (RINs).

A RIN is a 38-digit number generated by the production or import of qualifying renewable fuel; it uniquely identifies the fuel type, providing, among other details, information about the category of fuel it qualifies for under the program. RFS fuel categories include cellulosic biofuel, biomass-based diesel, advanced biofuels, and renewable fuel, commonly referred to as conventional biofuels. The obligated parties satisfy the RFS obligations for each category under the program by obtaining the necessary number and type of RINs. RINs are generated by the renewable fuel-producer and, once blended, the RINs are separated and can be banked, sold or traded amongst registered parties. These Renewable Volume Obligations (RVOs) change each year. Table 35 shows the 2016 RVOs associated with each fuel category (USEPA 2016b).

Table 35. 2016 Renewable Volume Obligations.

Fuel category	**2016 RVO Volumes (billion gallons)**	**2016 RVO Percentages (of total U.S. fuel produced)**
Cellulosic biofuels	0.23	0.128%
Biomass-based diesel	1.9	1.59%
Advanced biofuels	3.61	2.01%
Renewable fuel	18.11	10.10%

Biogas-derived fuels had been classified as advanced biofuels, but were reclassified to be cellulosic biofuels in the July 2014 Pathways II Final Rule (USEPA 2014). Biogas-derived fuels and electricity used in the transportation sector (to, for example, power an electric car) can now generate cellulosic RINs. RINs are traded in an open marketplace, and prices are controlled by supply and demand. The market will likely grow as RVOs increase.

CARB's LCFS Credits

California's adoption of the Global Warming Solutions Act of 2006 set in motion a series of policies to reduce GHG emissions in the state. The LCFS and Cap-and-Trade regulations established a market for proper capture and reuse of methane generated from AD projects, which can significantly reduce GHG emissions. The LCFS requires at least a 10% reduction of carbon intensity of California's transportation fuels by 2020. The carbon intensity of RNG is significantly lower than many other fuel pathways, which can be blended to maintain a price advantage over diesel while providing a net carbon saving. Thus, LCFS credits can generate substantial financial benefits. From August 2015 LCFS credit prices, the potential value of LCFS credits from dairies could be about $400 million per year.[41, 42]

California's Carbon Offset Credits & Greenhouse Gas Reduction Fund

California's GHG Reduction Fund was established to receive proceeds generated from the Cap-and-Trade auctions.[43] This Cap-and-Trade regulation allows for generation of offset credits by eligible biogas digester projects, in addition to the LCFS and RIN credits. The State of California determines carbon offset protocols for quantifying carbon reductions and manages the sale of offset credits.[44] Even flared biogas can generate verified carbon offsets. Environmental credits may provide financial returns yet their price greatly fluctuates. California's price in carbon has fluctuated from the peak of $23.00/ton CO_2eq in September 2011 near the launch of this program to $11.60/ton CO_2eq.[45]

Additional Revenues: Tipping Fees & Co-Products

In addition to the money saved by reducing on-site energy costs and the money earned by exporting energy, biogas facilities can generate additional revenue by diversifying their source portfolio. A WRRF or a dairy co-digesting with high-strength organic waste [i.e., organic waste with a high energy value, such as Fats, Oils and Grease (FOG)] can increase revenue by boosting biogas production and by charging tipping fees. While upgrading a facility to receive high strength organic wastes can require capital improvements, the benefits typically outweigh the costs.

Depending on the amount and type of material co-digested, biogas yields can improve significantly. Three facilities profiled in a recent EPA paper reported biogas increases of at least

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[41] Assumes California dairies produce 34% of national biogas potential from U.S. dairies, with a carbon intensity of -100 and an average August 2015 credit trading price of $57. http://www.arb.ca.gov/fuels/lcfs/lrtmonthlycreditreports.htm.

[42] Informa Economics (2013) National Market Value of Anaerobic Digester Products, Prepared for the Innovation Center for U.S. Dairy, February. http://www.usdairy.com/~/media/usd/public/nationalmarketvalueofanaerobicdigesterproducts.pdf.

[43] AB 1532 (Pérez, Chapter 807), SB 535 (De León, Chapter 830), and SB 1018 (Senate Budget Committee, Chapter 39) established the GHG Reduction Fund to receive Cap-and-Trade auction proceeds.

[44] For a list of protocols and offset projects, see: http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm.

[45] See https://www.theice.com/marketdata/reports/142, and http://calcarbondash.org/.

100%; one, the Sheboygan (WI) WRRF, observed a 300% increase (Ely and Rock 2014). A 700-cow dairy in northwest Washington co-digesting with 16% outside organic wastes more than doubled biogas production. Tipping fees too can bring in substantial revenues. Of the facilities profiled in the aforementioned EPA paper, the EBMUD facility in Oakland, CA earned $8 million in tipping fees in one year (Ely and Rock 2014). The co-digesting dairy in northwest Washington almost quadrupled annual digester revenues (Bishop and Shumway 2009, Frear, Liao et al. 2011).

Some biogas facilities could also generate revenue by recovering nutrients and selling enhanced fertilizer products. WRRFs such as the Hampton Roads Sanitation District recover and convert phosphorus and ammonia into a slow-release fertilizer, the revenues from which offset capital and operating costs (NACWA-WERF-WEF 2013). Concentrated Animal Feedlot Operations (CAFOs) are also recovering nutrients to create agricultural products. The Double A and Big Sky dairies in Jerome (ID), the Bio-Town facility in Reynolds (IN), and the Qualco Digester in Monroe (WA) are a few examples of dairy digester systems equipped to economically harvest phosphorus. The nutrient removal strategies of these and other CAFOs are reviewed in a recent study prepared for the Innovation Center for U.S. Dairy (Ma & Kennedy et al. 2013). Biogas facilities operating in regions with nutrient trading programs[46] may one day find nutrient recovery particularly lucrative.[47]

Whether or not processed to optimize nutrient recovery, the digestate from WRRFs and stand-alone digesters can be used as soil amendments, more often at a cost to the facility (see the Additional Costs section above). Dairies, on the other hand, can generate modest revenue by managing liquid and solid digestate on- and off-site. The effluent can be used on-site, reducing or eliminating the need for synthetic fertilizers. It can also be sold to adjacent farms. The solid digestate can also be used as a fertilizer on-site, dried and used as animal bedding, or sold commercially. The potential offset costs and earned profits are considered minor (ESA 2011).

While the economic benefits of land-applying digestate may be evolving, the environmental benefits are well established. Applying biosolids, manure, and/or cured digestate (i.e. compost) helps build healthy soils by providing nutrients, which reduce the need for synthetic fertilizers and pesticides; and by increasing organic matter, which has many benefits, including reducing erosion, sequestering carbon, supporting soil biodiversity, and, of course, retaining water. Increased Soil Organic Matter (SOM) helps to aggregate mineral particles, building a network of pore spaces that enables water to reach plant roots faster and to stay in the soil longer. Increased soil water results in greater drought tolerance for non-irrigated crops and less frequent irrigation for irrigated crops. Soil amendments also reduce evaporation of water from soils, further reducing irrigation demands (Brown 2014). As the California drought enters its fifth year, support for SOM is gaining even more ground through the Healthy Soils Initiative (CDFA 2016).

[46] e.g., the Laguna de Santa Rosa water quality credit trading programs, the Klamath Tracking and Accounting program, and the Lake Tahoe Clarity Crediting Program.

Markets for AD co-products, notably compost and soil amendments, need to be built out and strengthened. This would provide an important source of revenue, helping to finance biogas projects in the face of low natural gas prices and relatively few incentives. The future will likely see more enhanced fertilizer products including separated and concentrated nutrients (i.e., nitrogen, phosphorous, potassium, etc.) sold in liquid, pellet or dry form. The residual fibrous material may be incorporated into more valuable products that improve soil moisture retention and nutrient release; other prospects for fibers include plant boxes, land stabilization materials, pressboard for home construction, and additives to increase the strength of plastics (Gorrie 2014a). Whether or not the California drought persists, recycled effluent may also play a role in project financing.

Policy Pipeline

Government regulations and policies can drastically affect viability of biogas projects. Regulatory actions can expedite, but also hinder or all together halt, the development of projects. Various policies — which can include regulations, mandates, standards, incentives and tax credits — may have strong influence on success of a given biogas project. Due to the still nascent nature of these technologies and the biogas market as a whole, federal, state and local policies are constantly changing. The considerable uncertainty about these government actions causes significant market volatility, often leading to difficulties in securing project financing. For example, because of the volatility of RIN and LCFS credits, investors are often reluctant to provide the necessary financing for biogas digester projects. Strong longer term policies at various levels of government can help ensure the success and longevity of biogas projects.

Federal Policies

2015 NAAQS for Ground-Level Ozone

Ground level ozone is not emitted directly into the air, but is created by chemical reactions between NO_x, methane and VOCs in the presence of sunlight. Emissions from industrial facilities and electric utilities, motor vehicle exhaust, gasoline vapors, and chemical solvents are some of the major sources of NO_x and VOCs. Breathing ozone can trigger a variety of health problems, particularly for children, the elderly, and people of all ages who have lung diseases such as asthma (USEPA 2015).

In October 2015, EPA strengthened the NAAQS for ground-level ozone to 70 ppb. The benefits of meeting the standards in California are estimated at $1.2 to $2.1 billion annually after 2025. This includes the value of avoiding harmful health effects, such as premature deaths, missed work days and asthma-related emergency room visits. While beneficial, achieving the reductions in California will be difficult. The state has unique air quality challenges due to the combination of meteorology and topography, population growth and the pollution burden associated with mobile sources (USEPA 2015a).

The majority of California's NO_x emissions are generated by mobile sources. According to 2012 estimates, mobile sources (mainly, on-road motor vehicles) are responsible for nearly 83% of the 2,106 tons of NO_x emitted daily (CARB 2015). To reduce these emissions, California has spent billions of dollars on innovative technologies such as zero-emission trucks and buses, hybrid heavy-duty vehicles, and zero-emission freight equipment. In addition, CARB has adopted an optional low NO_x emission standard for on-road heavy-duty engines, encouraging engine manufactures to introduce new technologies to reduce emissions below the current mandatory emission standards for model years 2010 and later (CARB 2014).

Certification to lower optional standards could enable certified low- engines to become eligible for CARB incentive funding (CARB 2015c). As of February 2016, natural gas-fueled engines have been certified by both the EPA and CARB to meet CARB’s 0.02 grams per break-horsepower hour optional low NO_x emission standard, showing 90% lower NO_x emissions than EPA’s current 2010 standard (CARB 2016). Local air districts have also invested in mobile source reductions. The SCAQMD, for example, has funded projects to improve engine design, battery life, fuel cells and powertrains for electric vehicles.

Despite on-going state and local efforts to reduce mobile sources, nearly half of all California counties, representing roughly 80% of the state’s population, exceed the NAAQS for ground-level ozone. In Figure 40, the map at left, shows the California counties in nonattainment for the 2008 ozone standard of 75 ppb. The map on the right shows the counties expected to be in nonattainment for the 2015 ozone standard of 70 ppb. Air districts struggling to meet the ozone NAAQS are requiring further NO_x reductions from stationary sources (e.g., Rule 1110.2) even though, as with the SCAQMD, they represent less than 10% of total emissions (CARB 2015). As explained in South Coast’s Air Quality Management Plan, “the challenges are too great, the stakes too high, and the deadlines too soon” (SCAQMD 2013).

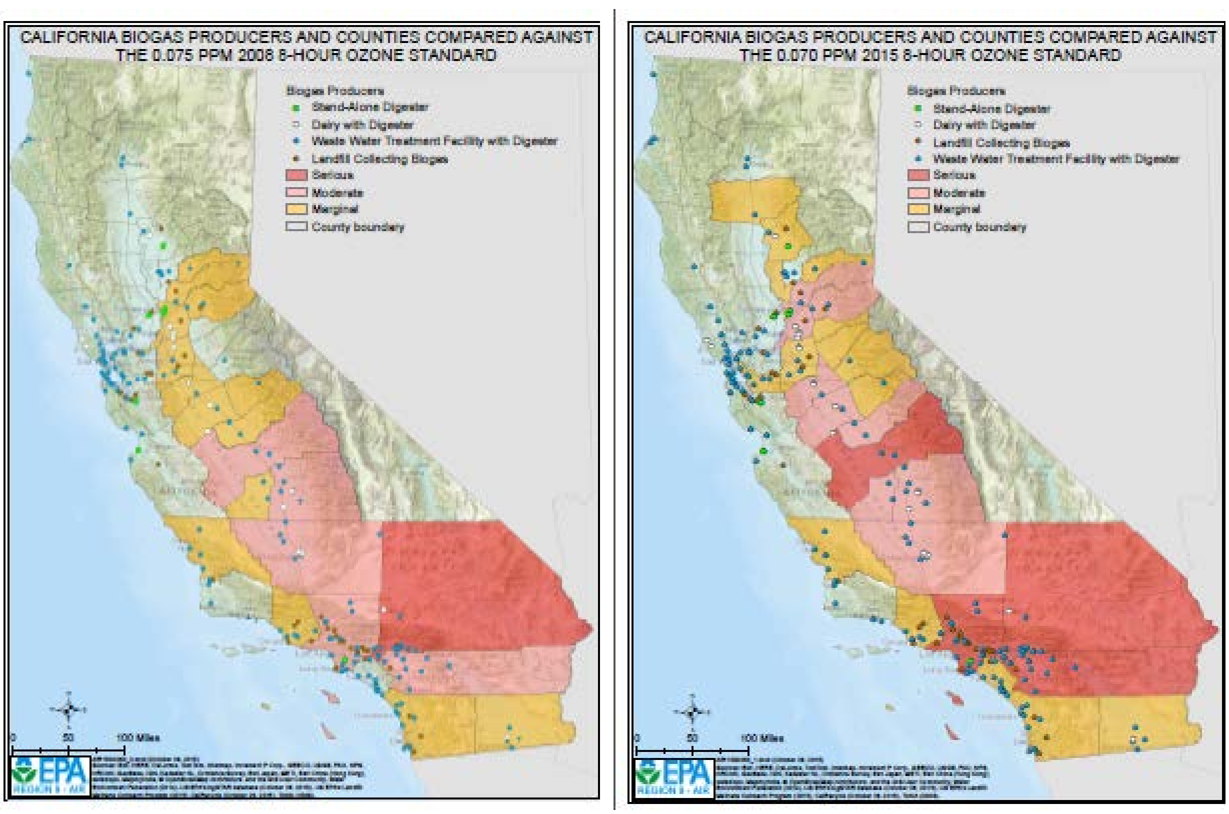

Figure 40. Biogas facilities and attainment designations for 2008 and 2015 ozone standard.

The biogas industry will be an important partner in reaching ozone reduction goals. Those counties exceeding the ozone standard are also the counties where the majority of the state's biogas producers reside. Nearly 60% of the landfills with gas capture systems, wastewater treatment facilities with anaerobic digesters, dairies with digesters and stand-alone digesters operated in counties exceeding 2008 ozone standard of 75 ppb. Nearly 70% of biogas producers operate in counties exceeding the 2015 standard of 70 ppb.

Clean Power Plan

EPA's Clean Power Plan establishes the first-ever national standards to limit carbon pollution from existing power plants and to a national reduce CO_2 emissions by 32% from 2005 levels by 2030. Under this rule, states can tailor implementation plans to meet their respective energy, environmental and economic needs and goals. EPA anticipates that renewable energy will be a significant strategy for states and existing sources (USEPA 2015b). On February 9, 2016, the U.S. Supreme Court stayed the Clean Power Plan pending judicial review. <u>The effect of the stay is that there is no obligation to comply with the Clean Power Plan, and states therefore have no obligation to develop state plans responsive to the Clean Power Plan.</u> The Court's decision was not on the merits of the rule. EPA firmly believes the Clean Power Plan will be upheld when the merits are considered because the rule rests on strong scientific and legal foundations. For the states that choose to continue to work to cut carbon pollution from power plants and seek the agency's guidance and assistance, EPA will continue to provide tools and support.

RFS Renewable Volume Obligations & RIN Classification

EPA's RFS has made significant changes in classifying RNG or biogas used as a transportation fuel from specified sources, as well as setting annual Renewable Volume Obligations (RVOs) or total amount of required renewable fuels. RNG generated from biogas sources was once classified as an advanced biofuel RIN renewable fuel category, yet EPA's July 2014 Pathways II Final Rule now lists RNG as a cellulosic biofuel. Since RIN credits are traded in an open marketplace, prices are controlled by supply and demand. Cellulosic RIN credits may become more valuable because: 1) they have been relatively rare, and obligated parties must meet RVOs; and 2) they are the "one-stop-shop" of the RIN credit marketplace, as they can be used to meet the RVOs of any RFS fuel category. In addition to this major policy change, which has led to increasing the value of RNG RIN credits, EPA's November 2015 final RFS rule set annual RVOs or total amounts of renewable fuel required for 2016 and a proposed 2017 RVO for biomass-based diesel. The final 2016 volumes shows a significant growth in renewable fuels, especially for cellulosic biofuel, which includes RNG, increasing seven times from 2014 market production levels.

State of California Policies

Cap-and-Trade Investment Plan for Auction Proceeds

The California State government determines the process for allocating auction proceeds generated from the Cap-and-Trade Program. The Investment Plan identifies near- and long-term GHG emission reduction goals and targets and recommended investments. These GHG reduction goals and funding levels provide signals on the state's priority and opportunities to reduce GHGs. Support for various biogas projects, used both for electricity generation and as RNG fuel, are included in the December 2015 Cap-and-Trade Auction Proceeds Revised Draft Second

Investment Plan (CARB 2015b). As the Governor and legislature are finalizing this Plan in 2016, biogas projects are likely to be eligible to receive significant levels of funding support during 2016-17.

LCFS Re-Certification

Similar to EPA's RFS, California's LCFS is regularly updated, which affects RNG. CARB periodically updates the LCFS (as with any of its programs) in order to make sure the regulatory program remains current with the latest science and technology. This can result in adjustments to the life-cycle analysis of some of the fuel pathways used to assign carbon intensity scores under the LCFS program. Any such adjustments may require a re-certification of the fuel pathway. The re-certification updates the carbon intensity values certified under the previous LCFS regulation. This re-certification may change how a fuel is classified or adjust its carbon intensity (CI) (CARB 2015e).

Bioenergy Feed-In-Tariff

California's Bioenergy FIT (per SB 1122 (Rubio 2012)) requires the CPUC to direct IOUs to procure 250 MW (cumulative, statewide) of new small biopower (less than 3 MW per project) in a separate IOU feed-in tariff program (Bioenergy Feed-in-Tariff). 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.

Renewable Portfolio & Golden State Standards

California's RPS and SB 350 (De León and Leno 2015), the Golden State Standards, set renewable energy consumption requirements. SB 350 increased the RPS, originally to 33% by 2020 to now 50% by 2030 (De Leon 2015). This new state standard will help increase the amount of electricity generated from biogas.

Governor Brown's Clean Energy Jobs Plan

Governor Brown's Clean Energy Jobs Plan calls for 20 gigawatts (GWs) of new renewable generation by 2020. The Plan calls for 8 GW from large scale facilities of 20 MW or higher and for 12 GW from distributed generation from facilities of less than 20 MW per project (Brown 2011).

Short-Lived Climate Pollutants

To meet the Governor's climate goals, significantly reducing Short-Lived Climate Pollutants (SLCP), such as methane, will be necessary. CARB is developing a comprehensive strategy to reduce these emissions (CARB 2015d). Capturing methane via biogas digesters is included in the state's draft strategy, which may include regulations, such as manure management practices (including digesters), on new dairies.

Natural Resources & Waste Diversion Targets & Goals

CalRecycle implements waste division strategies to cut GHG emissions, primarily methane, by reducing the amount of municipal solid waste disposed in landfills. California's 75% diversion and compositing goal by 2020 will greatly increase digester projects, anticipating the reduction of methane emissions by 40% from 2005 levels by 2030 (CalRecycle 2011). Utilizing organic waste through digesters will help California meet the State's RPS and bioenergy targets.

However, a significant investment in infrastructure to support resource recovery from organic waste will be needed.

Strong, long-term policies are greatly needed to help stabilize the market for biogas projects. These government actions serve as market drivers that can lead to greater certainty and reliability in the revenues generated from biogas end products, such as electricity or natural gas. Project investors often need long-term market certainty to finance high capital cost projects, such as digester projects. As states set higher standards for more renewable energy and fuel production, biogas projects will only increase.

Governor Brown's Goal of Fifty Percent Reduction in Petroleum Use

Additional funding under the Governor's Budget if made available to CARB under the Low Carbon Transportation Program and to the CEC under its Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) will also help incentivize the development of the state's indigenous biogas production resources. CARB is proposing to establish a $40 million Low Carbon Fuel Incentive Program as part of its *2016-17 Funding Plan for the Air Quality Improvement Program and Low Carbon Transportation Greenhouse Gas Reduction Fund Investments* (CARB 2016b). The Governor is also proposing to add an additional $25 million to the Alternative and Renewable Fuel and Vehicle Technology Program "…to provide incentives for in-state biofuel production through the expansion of existing facilities or the construction of new facilities" [Brown 2016 (pg. 97)].

Renewable Hydrogen and Fuel Cell Electric Vehicles

SB1505 (Lowenthal Chapter 877 Statutes of 2006) requires that at least 33% of hydrogen produced in California, in the aggregate, be produced from renewables. Auto-manufacturers have begun delivering the first production fuel cell electric vehicles (FCEV) to California and the industry expects to be delivering thousands of FCEVs within the next few years (CAFCP 2015). The resulting increased demand for renewable hydrogen to fuel these vehicles should help incentivize the market for the development of RNG production which can serve as a feedstock for the production of renewable hydrogen (Pyper 2014). California's ambitions to develop Advanced Clean Transit including the use of fuel cell electric buses will also add to the increased demand for RNG as a feedstock for renewable-hydrogen fuel (CAFCP 2013).

4. Conclusions

Economic performance

Not taking into consideration energy savings, sales or subsidies, flaring is the lowest cost biogas management option at less than \$1/MMBtu (input flow basis). In order of increasing cost are gas turbines, with costs ranging from \$3.25 to \$4.20/MMBtu; reciprocating engines, with costs ranging from \$4.42 to \$5.34/MMBtu; microturbines, with costs ranging from \$4.29 to \$6.85/MMBtu; upgrading and converting to CNG, with costs ranging from \$3.4 to \$12.8/MMBtu; fuel cells, with costs ranging from \$10.41 to \$18.41/MMBtu; and, upgrading the biogas for pipeline injection, with costs ranging from \$7 to \$25/MMBtu. (See Figure 34.) There are economies of scale for all of the processes investigated with fuel cells, microturbines and pipeline injection showing strong economies of scale.

For situations where biogas is already available (e.g., landfills or WRRFs), management of biogas using microturbines, reciprocating engines, and gas turbines would compete with industrial and commercial electricity prices in California, which ranged from \$0.12-\$0.16 per kwh in 2015 (EIA 2016). Those technologies also fall below the California “bioFIT” floor (\$0.125/kWh), suggesting they would be economic at the bioFIT price (Figure 35). Regarding the CNG pathway, the fuel production cost (for situations where biogas is already available) ranges from \$0.50/GGE for the 1600 SCFM system to \$2.40/GGE for the 50 SCFM system; these are lower than current California fuel prices and the \$2.51/gallon average of the last 20 years (CEC 2016).

As acknowledged throughout this report, our cost analysis is narrow in its scope. It only includes costs for the biogas conversion or upgrading technology. Costs for producing the raw biogas (i.e., digesters, feedstock handling, etc.) are not included. Conversely, the analysis does not consider those factors that would offset projects costs, including primary (i.e., energy sales, savings, and subsidies) and secondary (i.e., tipping fees and the sale of co-products) sources of revenue. Our analysis is one piece of a much bigger economic puzzle.

Environmental performance

The analysis compared the criteria pollutant (NO_x, CO, PM, VOC and SO_x) and greenhouse gas (CH_4, N_2O and CO_2) emissions associated with on-site use or upgrading. For criteria pollutants, in order of decreasing emissions, flares have the highest NO_x emissions (as lb/MMBtu gas input), followed by reciprocating engines (even those meeting 1110.2 limits), low NO_x gas turbines, CNG systems with only 70% recovery, microturbines, gas turbines with SCR, CNG systems with 85% recovery, pipeline injection, and fuel cells. The emissions factors for the other criteria pollutants analyzed do not all follow that same sequence (Figure 38).

Combusting biogas emits criteria pollutants that exacerbate California’s air quality challenges. While the majority of California’s NO_x emissions are generated by mobile sources, reducing criteria pollutant emissions from biogas sources is an important element in plans to improve air quality regionally, and statewide. Simultaneously, generating energy from biogas is key to attaining greenhouse gas reduction goals. Previous studies have demonstrated the relatively low carbon intensity of biogas-derived fuels, including several of the CARB LCFS pathways.

For greenhouse gas emissions, all devices emit small, but significant, amounts of methane as "slip" (or unburned methane) from conversion devices or through leaks in processing equipment, ranging from <1% to 2% of the incoming biogas. For biogas engines, microturbines and gas turbines, average methane emissions are about two orders of magnitude larger than the California eGRID factor (Figure 37). This is primarily due to relatively large methane slip compared to that of the overall California grid. The N_2O emissions for microturbines, gas turbines, and fuel cells were about half that of the California grid. Reciprocating engine N_2O emissions are about four times the California grid average (Figure 38).

To compare to eGRID, biogenic CO_2 emissions are not included in the CO_2eq emissions factor calculations. Therefore, the CO_2eq equivalent emission factors for biogas fueled microturbines, gas turbines, reciprocating engines, and fuel cells are all considerably lower than the California eGRID factor (Figure 41, which is same as Figure 39).

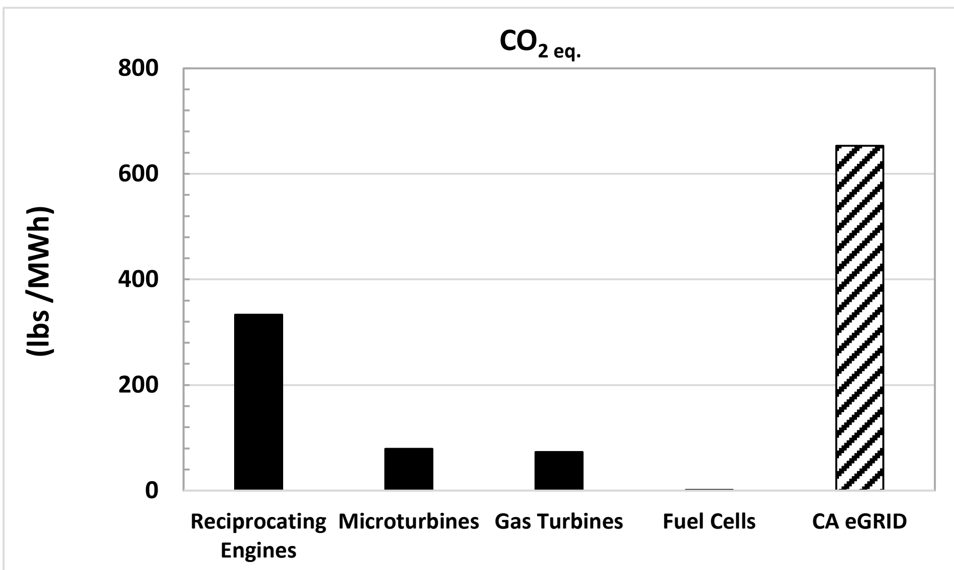

Figure 41. CO_2eq emissions for the bio-power technologies & CA eGRID.

As acknowledged throughout this report, the scope is limited and does not allow for a full system or life-cycle emissions accounting. The boundary of the analyzed technologies starts with already-produced biogas and examines only the emissions associated with on-site use or upgrading. Upstream emissions, such as hauling material to a digester, and downstream emissions, such as those from a biogas-fueled CNG vehicle, were not considered. Conversely, the analysis did not incorporate downstream sinks, such as the carbon temporarily sequestered by land-applying digestate. As with the economic analysis, our environmental analysis is one piece of a much bigger emissions puzzle.

Implications for Future Research and Policy

The narrow scope of our analysis helped to highlight the need for additional inquiries. Circumstances unique to particular facilities affect project costs in big and small ways. For example, how do differences in biogas quality affect cost? A source-specific analysis of project costs – one that addresses the economics of removing problematic trace contaminants – would provide greater and helpful insight.

Technology innovations and improvements that reduce costs or emissions are needed. With respect to fuel cells operating on biogas, increased durability of stack components would reduce operating costs while a larger number of installed and operating units would reduce installation costs (due to learning and lower equipment production cost).

Geography too influences costs. Consider, for example, the facility- and location-specific economics of flaring. Typically, landfills combusting biogas do not use waste heat; WRRFs do, requiring both heat and power. But how might these facilities manage biogas in a region where mountains and mobile sources interact to create the worst air quality in the nation? With stronger emission limits on stationary engines, would it be more economical for landfills to flare rather than upgrade? With greater on-site energy needs, what would flaring cost a WRRF? A more nuanced analysis taking into consideration unique geographic conditions would assess project costs with greater certainty.

A more encompassing and tailored accounting of what factors increase project costs is needed. So too is a clearer assessment of what factors offset projects costs. In this report, we have qualitatively described the federal and state grants and incentives available to support biogas projects. But, more information regarding the impact of these incentives is needed. Moreover, there is a need for quantitative information on the costs and benefits of secondary sources of revenue. A complete cost analysis should consider those factors that increase biogas production (e.g., co-digestion) and may otherwise boost the bottom-line (e.g., fertilizer sales).

For each opportunity there is to increase or offset costs, there seems an equal opportunity to fill knowledge gaps. Take, for example, co-digestion at a WRRF. There is a growing consensus that co-digestion improves project economics and can be the tipping point for investing in combined heat and power (WERF 2012). Yet, if an on-site energy analysis were to consider the costs and revenues associated with a prospective co-digestion effort, the analyst would lack essential data. Information regarding feedstock availability, for example, is scantly available. Quantifying organic waste volumes at scale is critical for an individual facility. Enabling the sector to do so may be critical for the state.

The California Association of Sanitation Agencies (CASA) estimates existing WRRFs possess the capacity to manage 75% of the food waste generated in California (CASA 2016). Given the state mandate to reduce the disposal of organic waste by 50% by 2020, CASA's estimate raises important policy questions. If WRRFs can manage such a large volume of California's food waste while also bringing the state closer to reaching renewable energy goals, should co-digestion projects be prioritized? Even if boosting biogas production emits criteria pollutants that exacerbate California's air quality challenges?

Evaluating impacts is no easy task. One approach can at once hinder and advance societal goals. Diverting organics from landfills and into digesters limits rogue methane emissions, reducing short-lived climate pollutants. Yet, combusting biogas in stationary engines can exacerbate local air quality problems. Digestate-based fertilizer products build healthier soils, sequestering carbon and increasing agricultural water efficiency. Yet, in some California counties, the land application of biosolids is effectively banned. The less money a WRRF spends on energy, the more it can invest in upgrades such as tertiary treatment, helping to expand local water supply during drought. Yet, emission limits on stationary engines increase operating costs, restraining WRRF budgets.

Some of these conflicts may be real, others perceived. Balancing state goals with local ordinances and industry preferences to advance the projects and policies with the greatest net-environmental benefit is a tall order. Future biogas research efforts could help lead the way by considering broader upstream and downstream impacts as they pertain to cross-media goals. How and at what cost can biogas projects realize clean energy, clean air, clean water, healthy soil and waste diversion goals?

A first task could be to identify how to economically reduce criteria emissions from stationary engines over a time period agreeable both to regulated facilities and local air districts. If after-gas treatment technologies (e.g., SCR) on reciprocating engines are an acceptable interim solution, how do we get there and what comes afterward? Our analysis and the SCAQMD assessment of after-gas cleanup technologies are first steps. What additional research, legislative action or funding solution will be next?

Our analysis has provided a side-by-side comparison, showing the environmental and economic performance of seven different biogas applications in California. While not exhaustive, it provides a bare bones synopsis. By doing so, we now have a generic baseline, a metric that can be used measure progress. Shrinking costs and emissions reductions can be used to indicate the efficacy of related technological and policy innovations. How these metrics change over the next 20 years will be telling.

Relevance to other states or regions

While the biogas utilization technologies discussed in this report are in use throughout the U.S., the detailed emissions performance and costs are specific to California. However, these results may soon have utility for a larger area in the rest of the U.S. There are approximately 170 counties (home to 86 million people) in the rest of the U.S. that are designated marginal or moderate non-attainment for 8-hour ozone (USEPA 2012b). The number (and severity) of ozone non-attainment areas in the U.S. is expected to increase after implementing the more stringent 2015 ozone standard (USEPA 2015c).[48]

[48] Final nonattainment area designations and classifications for the 2015 NAAQS ozone standard are expected in October 2017. https://www.epa.gov/ozone-pollution/2015-ozone-naaqs-timelines

Appendices

Appendix A- Technology Summary Results Data

Microturbines

Capacity			Efficiency, HHV basis		Levelized Cost ($/MWh)	Emissions (lb/MWh)				
kW	Gas Flow input (SCFM)	Gas Flow input (MMBtu/h)	(%)	Heat Rate (Btu/kWh)		NO_x	CO	PM	VOC	SO_x
30	13.1	0.47	22	15,700	**126**	0.251	0.266	0.010	0.123	1.044
65	26.4	0.95	23	14,600	**94**	0.234	0.248	0.010	0.115	0.975
200	73.5	2.6	26	13,200	**76**	0.212	0.224	0.009	0.104	0.882
250	90.0	3.2	26	13,000	**68**	0.208	0.220	0.009	0.102	0.864
333	116.9	4.2	27	12,600	**64**	0.202	0.214	0.008	0.099	0.842

Emission Factor (lb/MMBtu)				
NO_x	CO	PM	VOC	SO_x
0.0160	**0.0170**	**0.00067**	**0.0079**	**0.0667**

kW	Greenhouse Gases (lb/MWh)			Greenhouse Gases (lb CO_2eq/MWh)		
	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
30	2.6	3,000	0.004	88.8	3,000	1.19
65	2.4	2,800	0.004	82.9	2,800	1.11
200	2.2	2,530	0.003	75.0	2,530	1.01
250	2.2	2,480	0.003	73.5	2,480	0.99
333	2.1	2,420	0.003	71.7	2,420	0.96

Emission Factor (lb/MMBtu)			GWP_{100}		
CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
0.167	**191.3**	**0.00026**	**34**	**1**	**298**

* Biogenic CO_2 emissions

Gas Turbines

Capacity			Efficiency, HHV basis		Levelized Cost	Emissions (lb/MWh)								
						low-NO_x Combustor				SCR or ultra low NO_x				AP-42 (no control)
kW	Gas Flow input (SCFM)	Gas Flow input (MMBtu/h)	(%)	Heat Rate (Btu/kWh)	($/MWh)	NO_x	CO	VOC	SO_x	NO_x	CO	VOC	SO_x	PM
1200	542	19.5	21	16,300	80.4	0.50	0.059	0.12	1.018	0.18	0.21	0.011	0.075	0.20
3500	1309	47.1	25	13,500	55.0	0.42	0.05	0.10	0.842	0.15	0.17	0.009	0.062	0.16
4600	1634	58.8	27	12,800	50.1	0.40	0.05	0.09	0.800	0.14	0.16	0.009	0.059	0.15
5700	1886	67.9	29	11,900	46.6	0.37	0.04	0.09	0.745	0.13	0.15	0.008	0.055	0.14
6300	1997	71.9	30	11,400	45.0	0.35	0.04	0.08	0.714	0.13	0.14	0.008	0.053	0.14
7900	2402	86.5	31	10,900	41.8	0.34	0.04	0.08	0.685	0.12	0.14	0.008	0.051	0.13

Emission Factor (lb/MMBtu)								
NO_x	CO	VOC	SO_x	NO_x	CO	VOC	SO_x	PM
0.0309	**0.0037**	**0.0072**	**0.0626**	**0.0112**	**0.0127**	**0.0007**	**0.0046**	**0.01200**

kW	Greenhouse Gases (lb/MWh)			Greenhouse Gases (lb CO_{2eq}/MWh)		
	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
1200	2.7	3,113	0.0060	92.3	3,113	1.79
3500	2.2	2,576	0.0034	76.3	2,576	1.03
4600	2.1	2,447	0.0033	72.5	2,447	0.98
5700	2.0	2,279	0.0030	67.5	2,279	0.91
6300	1.9	2,183	0.0029	64.7	2,183	0.87
7900	1.8	2,095	0.0028	62.1	2,095	0.83

GHG Emission Factors (lb/MMBtu)			GWP_{100}		
CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
0.1668	**191.3**	**0.00026**	**34**	**1**	**298**

*Biogenic CO_2 emissions

Reciprocating Engines

Capacity			Efficiency, HHV basis		Levelized Cost	Emissions (lb/MWh)					Greenhouse Gases (lb/MWh)			Greenhouse Gases (lb CO_2eq/MWh)		
kW	Biogas Flow in (SCFM)	Gas Flow in (MMBtu/h)	(%)	Heat Rate (Btu/kWh)	($/MWh)	NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
100	40	1.4	23.9	14,300	89.8	0.61	2.16	0.20	0.23	0.0429	11.99	2,737	0.027	408	2,737	8.2
150	56	2.0	25.5	13,400	83.0	0.57	2.02	0.19	0.21	0.0402	11.23	2,564	0.026	382	2,564	7.7
190	68	2.5	26.4	12,900	79.5	0.55	1.95	0.18	0.21	0.0388	10.83	2,473	0.025	368	2,473	7.4
220	77	2.8	27.0	12,600	77.4	0.54	1.91	0.18	0.20	0.0379	10.60	2,420	0.024	360	2,420	7.2
300	101	3.6	28.2	12,100	73.3	0.52	1.82	0.17	0.19	0.0363	10.14	2,315	0.023	345	2,315	6.9
420	135	4.9	29.5	11,600	69.2	0.49	1.74	0.16	0.18	0.0347	9.68	2,210	0.022	329	2,210	6.6
600	184	6.6	31.0	11,000	65.2	0.47	1.66	0.15	0.18	0.0331	9.24	2,109	0.021	314	2,109	6.3
800	236	8.5	32.1	10,600	62.2	0.46	1.60	0.15	0.17	0.0319	8.91	2,034	0.020	303	2,034	6.1
1000	287	10.3	33.0	10,300	59.4	0.44	1.56	0.14	0.17	0.0310	8.67	1,980	0.020	295	1,980	5.9
1550	423	15.2	34.7	9,800	54.3	0.42	1.48	0.14	0.16	0.0295	8.24	1,881	0.019	280	1,881	5.6
2000	531	19.1	35.7	9,600	51.6	0.41	1.44	0.13	0.15	0.0287	8.01	1,828	0.018	272	1,828	5.5
3000	762	27.4	37.3	9,100	47.6	0.39	1.38	0.13	0.15	0.0274	7.66	1,749	0.018	261	1,749	5.2

* biogenic CO_2 emissions

	Emission Factor (lb/MMBtu)					**GHG Emission Factors (lb/MMBtu)**			**GWP_{100}**		
	Rule 1110.2	ST Aves. (SCR/CatOx)	(AP 42)	ST Aves. (SCR/CatOx)							
	NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
ST Aves. = Source Test Averages	**0.043**	**0.151**	**0.014**	**0.016**	**0.003**	**0.838**	**191.3**	**0.00192**	**34**	**1**	**298**

Fuel Cells

Capacity			Energy Efficiency (%, HHV basis)	Levelized Cost ($/MWh)	Emissions (lb/MWh)					GHG (lb/MWh)			GHG (lb CO_2eq/MWh)		
kW	Gas Flow in (SCFM)	Gas Flow in (MMBtu/h)			NO_x	CO	PM	VOC	SO_x	CH_4	CO_2 *	N_2O	CH_4	CO_2 *	N_2O
200	42	1.5	45.0	164	0.02	0.070	0.01	0.06	0.001	0.019	1451	0.002	0.66	1451	0.58
300	63	2.3	45.0	150	0.02	0.07	0.01	0.06	0.001	0.019	1451	0.002	0.66	1451	0.58
500	105	3.8	45.0	135	0.02	0.07	0.01	0.06	0.001	0.019	1451	0.002	0.66	1451	0.58
800	169	6.1	45.0	122	0.02	0.07	0.01	0.06	0.001	0.019	1451	0.002	0.66	1451	0.58
1000	211	7.6	45.0	116	0.02	0.07	0.01	0.06	0.001	0.019	1451	0.002	0.66	1451	0.58
1400	295	10.6	45.0	108	0.02	0.07	0.01	0.06	0.001	0.019	1451	0.002	0.66	1451	0.58
6000	1264	45.5	45.0	79	0.02	0.07	0.01	0.06	0.001	0.019	1451	0.002	0.66	1451	0.58
					Emission Factor (lb/MMBtu)					**Emission Factor (lb/MMBtu)**			**GWP_{100}**		
					NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
					0.0026	0.0092	0.00132	0.0081	0.0001	0.0026	191.3	0.00026	34	1	298

* Biogenic CO_2 emissions

RNG with On-site Fueling

Biogas Flow input (SCFM)	Biogas Flow input (MMBtu/h)	Methane recovery (%)	RNG Fuel Product Output (SCFM)	RNG Fuel Product Output (MMBtu/h)	RNG Fuel Product Output (GGE/day)	Levelized Cost ($/MMBtu gas input)	Levelized Cost ($/MMBtu output)	Levelized Cost $/gallons gasoline eq.	Levelized Cost $/gallons diesel eq.
50	1.8	70	22.1	1.3	241	12.8	18.3	2.42	2.75
100	3.6	70	44	2.5	482	9.0	12.8	1.69	1.92
200	7.2	70	88	5	963	6.5	9.3	1.23	1.40
1600	57.6	85	859	49	9,359	3.4	4.0	0.53	0.60

(SCFM)	Emissions (lb/day) NO_x	CO	PM	VOC	SO_x	Greenhouse Gases (lb/day) CH_4	CO_2*	N_2O	Greenhouse Gases (lb CO_2eq/day) CH_4	CO_2*	N_2O
50	0.71	0.59	0.15	0.08	0.50	18.9	4,599	0.03	642	4,599	9
100	1.43	1.18	0.31	0.16	1.01	37.8	9,197	0.06	1,280	9,197	18
200	2.86	2.36	0.62	0.31	2.02	75.5	18,395	0.12	2,570	18,395	36
1600	11.04	9.13	2.39	1.21	7.79	589.9	122,125	0.47	20,100	122,125	140

	Emission Factor (lb/MMBtu input to process) NO_x	CO	PM	VOC	SO_x	**(lb/MMBtu input to process)** CH_4	CO_2*	N_2O	**GWP_{100}** CH_4	CO_2*	N_2O
70% CH_4 Recovery:	**0.0165**	**0.0137**	**0.0036**	**0.0018**	**0.0117**	**0.44**	**106.5**	**0.00070**			
85% CH_4 Recovery:	**0.008**	**0.007**	**0.002**	**0.001**	**0.006**	**0.43**	**88.3**	**0.00034**	**34**	**1**	**298**

*Biogenic CO_2 emissions

Upgrade & Pipeline Injection

Biogas Flow Input		Product Gas Flow		Levelized Cost		Emissions (lb/day)					Greenhouse Gases (lb/day)			Greenhouse Gases (lb CO_2eq/day)		
(SCFM)	(MMBtu/h)	(SCFM)	(MMBtu/h)	($/MMBtu gas input)	($/MMBtu output)	NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
50	1.8	27.5	1.6	24.7	27.4	0.22	0.18	0.05	0.02	0.16	18.8	3,721	0.009	640	3,721	3
75	2.7	41	2.4	21.5	23.9	0.33	0.28	0.07	0.04	0.23	28.2	5,582	0.014	960	5,582	4
100	3.6	55	3.2	19.6	21.8	0.44	0.37	0.10	0.05	0.31	37.7	7,443	0.019	1,280	7,443	6
150	5.4	83	4.9	17.1	19.0	0.67	0.55	0.14	0.07	0.47	56.5	11,164	0.028	1,920	11,164	8
300	10.8	165	9.7	13.6	15.1	1.3	1.1	0.3	0.1	0.9	113	22,328	0.057	3,840	22,328	17
600	21.6	331	19.4	10.8	12.0	2.7	2.2	0.6	0.3	1.9	226	44,656	0.113	7,680	44,656	34
1200	43.2	661	38.9	8.6	9.5	5.3	4.4	1.2	0.6	3.8	452	89,313	0.226	15,400	89,313	67
2300	82.8	1267	74.5	6.9	7.7	10.2	8.4	2.2	1.1	7.2	866	171,182	0.434	29,400	171,182	129

Emission Factor (lb/MMBtu input to process)					**(lb/MMBtu input to process)**			**GWP_{100}**		
NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
0.0051	**0.0042**	**0.0011**	**0.0006**	**0.0036**	**0.4358**	**86.1**	**0.00022**	**34**	**1**	**298**

* Biogenic CO_2 emissions

Flare

Capacity		Levelized Cost	Emissions (lb/day)								Greenhouse Gases (lb CO_2eq/day)		
								Greenhouse Gases					
Gas Flow input (SCFM)	Gas Flow input (MMBtu/h)	($/MMBtu) Input	NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
17	0.6	1.25	0.8	0.7	0.2	0.1	0.6	1.0	2,755	0.03	34	2,755	10.4
28	1	1.10	1.4	1.1	0.3	0.1	1.0	1.7	4,592	0.06	57	4,592	17.3
56	2	0.93	2.7	2.3	0.6	0.3	1.9	3.3	9,184	0.12	114	9,184	34.7
139	5	0.74	6.8	5.7	1.5	0.7	4.8	8.4	22,961	0.29	284	22,961	86.7
194	7	0.68	9.6	7.9	2.1	1.0	6.8	11.7	32,145	0.41	398	32,145	121.4
278	10	0.62	13.7	11.3	3.0	1.5	9.7	16.7	45,922	0.58	568	45,922	173.4
417	15	0.56	20.5	17.0	4.5	2.2	14.5	25.1	68,883	0.87	853	68,883	260.2
556	20	0.52	27.4	22.6	5.9	3.0	19.3	33.4	91,844	1.16	1,140	91,844	346.9
833	30	0.47	41.1	34.0	8.9	4.5	29.0	50.2	137,766	1.75	1,710	137,766	520.3

Emission Factor (lb/MMBtu)					**Emission Factor (lb/MMBtu)**			**GWP_{100}**		
NO_x	CO	PM	VOC	SO_x	CH_4	CO_2*	N_2O	CH_4	CO_2*	N_2O
0.0570	**0.0472**	**0.01236**	**0.0062**	**0.0403**	**0.070**	**191.3**	**0.00243**	**34**	**1**	**298**

*Biogenic CO_2 emissions

Appendix B- Grants & Other Financial Incentives

Compilation of Key Funding Sources

- Guide to Federal Financing for Energy Efficiency and Clean Energy Development, September 2014
- Database of State Incentives for Renewable and Efficiency
- EPA Region 9's Sustainable Water Infrastructure

Federal & California Agency-Specific Funding

Funding Agency	Program Title
Bay Area Air Quality Management District	Grant Funding
Cal Recycle	Greenhouse Gas (GHG) Reduction Loan Program
Cal Recycle	Organics Grant Program
CALFED	CALFED Grants and Contracts
California Air Resources Board	Carl Moyer Memorial Air Quality Standards Attainment Program
California Air Resources Board	Low Carbon Transportation Investments and Air Quality Improvement Program (AQIP)
California Air Resources Board	Low Carbon Fuel Standard
California Air Resources Board	Cap and Trade Auction Proceeds
California Center for Sustainable Energy	California Center for Sustainable Energy - Self Generation Incentive Program
California Center for Sustainable Energy	California Center for Sustainable Energy - Border Energy Savings Program
California Dept. of Food and Agriculture	Dairy Digester Research and Development Program
California Energy Commission	California Energy Commission- Clean Energy Manufacturing Program
California Energy Commission	Energy Efficiency Financing (1% loans: PON 13-401)
California Energy Commission	Alternative and Renewable Fuel and Vehicle Technology Program (AB 118)
California Energy Commission	Electric Program Investment Charge (EPIC) Program
California Public Utilities Commission	California Public Utilities Commission - Solar Incentives
California Public Utilities Commission	California Public Utilities Commission Qualifying Facility Program
California Public Utilities Commission	Self-Generation Incentive Program
California Statewide Communities Development Authority	California First (PACE Financing)
Infrastructure Bank	Infrastructure State Revolving Fund Program
PG&E	Pacific Gas & Electric Self-Generation Incentive Program

Sacramento Metropolitan Air Quality Management District	Off- & On-Road Grant Programs
SJVAPCD	Grants and incentives
SJVAPCD	Technology Advancement Program
SDG&E	San Diego Gas & Electric Company Rebates and Incentives
SMAQMD	Grant program
SMUD	Sacramento Municipal Utility District Business Rebates and Incentives
SCAQMD	Grants and Bids
Southern California Edison	Southern California Edison Self-Generation Incentive Program
Southern California Gas Company	Southern California Gas Company Self-Generation Incentive Program
Southern California Gas Company	Southern California Gas Company Water Supply and Treatment
State Water Resource Control Board	Clean Water State Revolving Fund
U.S. Bureau of Reclamation	System Optimization Review Grants
U.S. Bureau of Reclamation	Water & Energy Efficiency Grants
U.S. Department of Agriculture	Advanced Biofuel Payment Program
U.S. Department of Agriculture	Biorefinery Assistance Program
U.S. Department of Agriculture	High Energy Cost Grant Program
U.S. Department of Agriculture	Repowering Assistance Program
U.S. Department of Agriculture	Rural Utilities Service Electric Program
U.S. Department of Agriculture	Water and Environmental Programs
U.S. Department of Agriculture	Rural Energy for America Program Renewable Energy Systems & Energy Efficiency Improvement Loans & Grants
U.S. Department of Energy	Federal Funding for State and Local Clean Energy Programs
U.S. Department of Energy	Loan Guarantee Program
U.S. Department of Energy	Renewable Energy Production Incentive
U.S. Department of Energy	Technical Assistance Program (TAP)
U.S. Environmental Protection Agency	Renewable Fuel Program
U.S. Environmental Protection Agency	Diesel Emissions Reduction Program
U.S. Internal Revenue Service	Renewable Electricity Production Tax Credit
U.S. Small Business Administration	Small Business Innovation Research

Appendix C- Source Test Data

Source Tests – Microturbines

Primemover	Emissions equip. notes	Source Test Date	AQMD	Power during test (kW)	Emissions (lbs/hr)				Emissions (lbs/MMBtu)			
					NOx	CO	SO2	VOC	NOx	CO	SO2	VOC
City of Millbrae 250 kW microturbine fueled w/ digester gas (2007)	-	Jan, 2007	BAAQMD	250	0.063	0.04		0.008	0.0167	0.0106		0.00212
Ralph's Groceries Ingersoll Rand 250 kW microturbine # 1	no post combustion emissions treatment	Feb., 2013	SCAQMD	250	0.058	0.088	0.23	0.06	0.0149	0.0221	0.0590	0.0154
Ralph's Groceries Ingersoll Rand 250 kW microturbine # 2	no post combustion emissions treatment	Feb., 2013	SCAQMD	250	0.06	0.092	0.27	0.03	0.0154	0.0231	0.0692	0.0077
Ralph's Groceries Ingersoll Rand 250 kW microturbine # 3	no post combustion emissions treatment	Feb., 2013	SCAQMD	250	0.061	0.093	0.27	0.07	0.0156	0.0233	0.0692	0.0179

Source Tests – Flares

Equipment Descriptions	Source Test Date	AQMD	Flow/Cap	Energy in Fuel (Btu/scf)	Fuel flow (SCFM)	MMBtu/h	Emissions (lbs/hr)					Emissions (lbs/MMBtu)				
							NOx	CO	SO2	VOC	PM	NOx	CO	SO2	VOC	PM
Eastern Muni / San Jacinto Valley Water Reclamation - Digester Gas Flare	Jan-08	SCAQMD	18 MMBtu	622	165	6.16	0.365	0.301	0.129	0.0425	0.092	0.059	0.049	0.021	0.007	0.015
Eastern Muni / Moreno Valley - Digester Gas Flare	May-12	SCAQMD	1.7 MMBtu	192	25	0.29	0.0032	0.003	0.09	0.0005	0.02	0.011	0.010	0.313	0.002	0.069
Tulare WPCF _Gigester gas flare	Sep-13	SJVAPC	12.4	631	37	1.40	0.09		0.28	0.003		0.064		0.200	0.002	
Lamb Canyon Landfill	May-07	sCAQMD		430	211	5.44	0.3		0.036	0.037	0.035	0.055		0.007	0.007	0.006

Source Tests – Fuel Cells

Emissions equip. notes	Source Test Date	AQMD	Capacity (kW)	Fuel flow (SCFM)	Emissions (lbs/hr)				Emissions (lbs/MMBtu)			
					NOx	CO	SO2	VOC	NOx	CO	SO2	VOC
Fuel Cell - Tulare City WWTP	Permit only	SJVAPCD	300	63	0.006	0.015	0.0003	0.006	0.0026	0.007	0.00013	0.003
Eastern Muni Water District (2 x 300 kW fuel cells)	Permit only	SCAQMD	600	126	0.0015	0.042	0.0006	0.08	0.00033	0.009	0.00013	0.018
Moreno Valley RWQRF Fuel Cell Energy DFC300MA	Mar-09	SCAQMD	250	53	0.005	0.005		0.008	0.0028	0.003		0.004

Source Tests – Gas Turbines

Primemover	Emissions equip. notes	Source Test Date	AQMD	Power during test (kW)	Emissions (lbs/hr)				Emissions (lbs/MMBtu)			
					NOx	CO	SO2	VOC	NOx	CO	SO2	VOC
OS-4529 Gas Turbine Altamont Landfill S-6	No apparent emission control, LFG	Feb-13	BAAQMD	3100	5.36	3.58	0.19	0.3	0.116	0.078	0.004	0.007
Altamont Turbine S-7	No apparent emission control, LFG	Feb-13	BAAQMD	3100	5.29	3.67	0.24	0.3	0.116	0.081	0.005	0.007
Calabasas Solar Mercury 50 recuperative, , 4.5 MW, Turbine A	"Low NOX", 2004 era, LFG	2010	SCAQMD	4095	1.5	0.177	3.1	0.6	0.031	0.004	0.064	0.012
Calabasas Solar Mercury 50 recuperative, , 4.5 MW, Turbine B	"Low NOX", 2004 era, LFG	2010	SCAQMD	4391	1.3	0.164	2.6	0.28	0.031	0.004	0.062	0.007
Calabasas Solar Mercury 50 recuperative, , 4.5 MW, Turbine C	"Low NOX", 2004 era, LFG	2010	SCAQMD	4391	1.3	0.143	2.6	0.17	0.031	0.003	0.062	0.004
Fresno/Clovis RWRF 2x 3.3 GT w/ ~1-2 MW steam turbine. Water injection and SCR equipped. ~ 36% volumetric fuel flow is natural gas. Digester gas is upgraded to about 950 Btu/scf	SCR, WWTP	2013 Turbine 1	SJVAPCD	4500	0.766	0.621	-	-	0.013	0.011		
Fresno/Clovis RWRF 2x 3.3 GT w/ ~1-2 MW steam turbine. Water injection and SCR equipped.	SCR, WWTP	2013 Turbine 2	SJVAPCD	4680	0.602	1.181	-	-	0.010	0.020		
Fresno/Clovis RWRF 2x 3.3 GT w/ ~1-2 MW steam turbine. Water injection and SCR equipped.	SCR, WWTP	2012 Turbine 1	SJVAPCD	3487	0.43	0.37			0.0095	0.008		
Fresno/Clovis	SCR, WWTP	2012 Turbine 2	SJVAPCD	4280	0.51	1.1			0.0092	0.020		
EBMUD Solar Mercury 50 Ultra-lean premix recuperative, "Low-NOx" burner, 4.5 MW, 44.5 MMBtu/h	"Advanced low-Nox burner", WWTP		BAAQMD	4500	0.59	0.2	0.2	0.03	0.014	0.005	0.005	0.001

Source Tests – Reciprocating Engines

Primemover	Emissions equip. notes	Source Test Date	AQMD	Power during	Emissions (lbs/hr)				Emissions (lbs/MMBtu)				Emissions (lbs/MWh)			
					NOx	CO	SO2	VOC	NOx	CO	SO2	VOC	NOx	CO	SO2	VOC
Reciprocating engine, 2980 hp, 13000 cu in, Co-generation, Multi-Fuel Cogeneration Engine #1 EBMUD S-37	No apparent emission control, WWTP digester gas	5/21/2013	BAAQMD	1940	1.5	10.2	0.3	0.4	0.079	0.537	0.016	0.021	0.77	5.26	0.15	0.21
Reciprocating engine, 2980 hp, 13000 cu in, Co-generation, Multi-Fuel Cogeneration Engine #3 EBMUD S-39	No apparent emission control, WWTP digester gas	6/12/2013	BAAQMD	1917	1.7	9.6	0.14	1.7	0.081	0.457	0.007	0.081	0.89	5.01	0.07	0.89
Reciprocating engine, 2980 hp, 13000 cu in, Co-generation, Multi-Fuel Cogeneration Engine #2 EBMUD S-38	No apparent emission control, WWTP digester gas	9/19/2013	BAAQMD	2180	2.8	11	0.78	2.1	0.122	0.478	0.034	0.091	1.28	5.05	0.36	0.96
Reciprocating engine, 706 hp, Waukesha, 3520 cu in 225, Cogen Engine-2, Dublin San Ramon Services District, Plant # 1371,	No apparent emission control, WWTP digester gas	7/25/2013	BAAQMD	400	0.39	2.5	0.021	0.3	0.087	0.561	0.005	0.067	0.98	6.25	0.05	0.75
Fairfield Suisun Sewer S-54 Reciprocating engine, 1268 hp, Waukesha, 7040 cu in 287 Cogen Engine #3 (Pad 4), Nat and Dig Gas, 900kW	No apparent emission control, WWTP digester gas	8/17/2012	BAAQMD	844	1.10	4.83	0.071	0.20	0.138	0.604	0.009	0.024	1.31	5.73	0.08	0.23
Fairfield Suisun Sewer S-54 Reciprocating engine, 1268 hp, Waukesha, 7040 cu in 287 Cogen Engine #3 (Pad 4), Nat and Dig Gas, 900kW	No apparent emission control, WWTP digester gas	8/15/2013	BAAQMD	725	0.74	5.80	0.154	1.25	0.105	0.819	0.022	0.176	1.02	8.01	0.21	1.72
Fairfield Suisun Sewer S-3, Reciprocating engine, 800 hp, 6597 cu in, Cogen Engine #2, Digester Gas Fired	No apparent emission control, WWTP digester gas	5/17/2012	BAAQMD	370	0.93	2.65	0.142	0.03	0.167	0.474	0.025	0.005	2.51	7.15	0.38	0.08
Fairfield Suisun Sewer S-3, Reciprocating engine, 800 hp, 6597 cu in, Cogen Engine #2, Digester Gas Fired	No apparent emission control, WWTP digester gas	5/28/2013	BAAQMD	354	0.81	2.57	0.317	0.15	0.1512	0.480	0.059	0.027	2.28	7.25	0.89	0.41
Sunnyvale Water Pollution Control S-15 Reciprocating engine, 1130 hp, Caterpillar, 5110 cu in 221, Engine/Generator No. 2	No apparent emission control, WWTP digester gas	2/28/2012	BAAQMD	690	1.05	3.9	0.533	0.23	0.1150	0.427	0.058	0.026	1.52	5.65	0.77	0.34
Sunnyvale Water Pollution Control S-15 Reciprocating engine, 1130 hp, Caterpillar, 5110 cu in 221, Engine/Generator No. 2	No apparent emission control, WWTP digester gas	2/10/2014	BAAQMD	604	1.77	2.66	0.8	0.28	0.238	0.357	0.107	0.038	2.93	4.40	1.32	0.46
Sunnyvale Water Pollution Control S-14 Reciprocating engine, 1130 hp, Caterpillar, 5110 cu in 221, Engine/Generator No. 1	No apparent emission control, WWTP digester gas	3/1/2012	BAAQMD	656	1.16	4.25	0.6	0.14	0.128	0.467	0.066	0.016	1.77	6.48		
Sunnyvale Water Pollution Control S-14 Reciprocating engine, 1130 hp, Caterpillar, 5110 cu in 221, Engine/Generator No. 1	No apparent emission control, WWTP digester gas	2/10/2014	BAAQMD	607	1.19	3.89	0.58	0.32	0.152	0.496	0.074	0.041	1.96	6.41		
San Leandro Water Pollution Control : S-14 - Reciprocating engine, 148 hp, MAN, 419 cu in, Co-generation-Biogas Fired IC Engine	No apparent emission control, WWTP digester gas	5/18/2010	BAAQMD	105	0.26	0.22		0.04	0.291	0.248	-	0.045	2.48	2.10		
San Leandro Water Pollution Control : S-15 - Reciprocating engine, 148 hp, MAN, 419 cu in, Co-generation-Biogas Fired IC Engine	No apparent emission control, WWTP digester gas	5/18/2010	BAAQMD	105	0.29	0.29		0.05	0.254	0.255	-	0.044	2.76	2.76		
San Leandro Water Pollution Control : S-16 - Reciprocating engine, 148 hp, MAN, 419 cu in, Co-generation-Biogas Fired IC Engine	No apparent emission control, WWTP digester gas	5/18/2010	BAAQMD	105	0.24	0.31		0.05	0.225	0.292	-	0.047	2.29	2.95		
SFPUC, S-26 Reciprocating engine, 773 hp, Waukesha, 3520 cu, Internal Combustion Engine Generator No. 1	No apparent emission control, WWTP digester gas	7/23/2012	BAAQMD	460	0.175	2.62		0.22	0.062	0.913	-	0.077	0.38	5.70		
SFPUC, S-26 Reciprocating engine, 773 hp, Waukesha, 3520 cu, Internal Combustion Engine Generator No. 2	No apparent emission control, WWTP digester gas	9/24/2013	BAAQMD	482	0.35	2.91	0.02	0.28	0.086	0.724	0.005	0.069	0.73	6.03		
Bakersfield WWTP: 577 BHP Waukesha digester gas lean burn engine #2		5/28/2013	SJVAPCD	400					0.079	0.380		0.003				
Bakersfield WWTP: 577 BHP Waukesha digester gas lean burn engine #2		6/10/2011	SJVAPCD	400					0.118	0.321		0.004				
Bakersfield WWTP: 577 BHP Waukesha digester gas lean burn engine #2		11/2/2009	SJVAPCD	400					0.074	0.335		0.003				
Visalia Landfill 1150 HP Lean Burn CAT G3516TA Landfill Gas. S-2890-1-6		12/14/2010	SJVAPCD	737	1.23	6.36		0.2	0.119	0.611		0.019	1.67			
Tulare Waste Water Plant 670 BHP WAUKESHA MODEL L5108GL BIOGAS-FIRED LEAN BURN IC ENGINE WITH H2S SCRUBBER POWERING AN ELECTRIC GENERATOR		12/3/2013	SJVAPCD	450					0.183	0.608		0.011				
Yolo County Landfill 550 kW Cat. E1, P-78-98	Air fuel ratio controller	3/26/2013	YSAQMD	550	0.761	3.92		0.14	0.084	0.425		0.032	1.38			
Yolo County Landfill 1306 BHP Cat. G-3516 900 kW E2 (4A, P-78-98	Air fuel ratio controller	3/6/2013	YSAQMD	893	2.259	7.63		0.12	0.163	0.540		0.016	2.53			
Yolo County Landfill 550 kW Cat. E4, P-78-98	Air fuel ratio controller	3/26/2013	YSAQMD	550	1.120				0.120	0.375		0.030	2.04			
Yolo County Landfill 840 kW	Air fuel ratio controller	2/28/2013	YSAQMD	840	1.340	5.37		0.08	0.135	0.540		0.016	1.60			
Davis WWTP 110 BHP digester gas Cat G342 -		3/20/2013	YSAQMD	75	0.1082				0.096	0.531			1.44			
HayRoad Landfill- 2233 BHP Cat G3520C- 1650 kW	Air fuel ratio controller		YSAQMD	1600	1.11	9.94		0.04	0.066	0.590		0.003	0.69			
Waukesha, VGF48GL (San Bernard. Water Dept. Cogen #1: at least 2 identical systems) 2005 or earlire appl. # 431476		2006	SCAQMD	620	0.450			0.22	0.066			0.032	0.73			0.35
Waukesha, VGF48GL (San Bernard. Water Dept. Cogen #2: at least 2 identical systems) 2005 or earlire appl. # 431477		2006	SCAQMD	620	0.380			0.16	0.056			0.023	0.61			0.26
Fiscalini Dairy: 1067 BHP Guascor SFGLD-560 Engine w SCR - -750 kW gen	SCR	2012	SJVAPCD	350	0.088	1.068		0.080	0.022	0.267		0.020	0.25	3.05		0.23
Fiscalini Dairy: 1067 BHP Guascor SFGLD-560 Engine w SCR - -750 kW gen	SCR / ox cat	2013	SJVAPCD	250	0.117	0.699		0.001	0.038	0.226		0.00027	0.47	2.79		0.00
Fiscalini Dairy: 1067 BHP Guascor SFGLD-560 Engine w SCR - -750 kW gen	SCR / ox cat	2014	SJVAPCD	150	0.015	0.395		0.000	0.010	0.255		0.00027	0.10	2.63		0.00
#1: MWM TCG 2016 V16 w/ SCR and Ox Catalyst	SCR / ox cat	2015	Mojave Desert	800	0.577	0.011	0.0002	0.222	0.084	0.002	0.00003	0.03223				
#1: MWM TCG 2016 V16 w/ SCR and Ox Catalyst	SCR / ox cat	2015		800	0.213	0.031	0.0002	0.17	0.034	0.005	0.00003	0.02721				

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