MAY

2018

FINAL

SAN BERNARDINO WATER RECLAMATION PLANT

DIGESTER GAS BENEFICIAL USE STUDY

carollo

Engineers...Working Wonders With Water®

San Bernardino Municipal Water Department
San Bernardino Water Reclamation Plant

DIGESTER GAS BENEFICIAL USE STUDY

FINAL | May 2018

Project# 11036A.00

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Abbreviations

AACE	American Association of Cost Engineering
AQMD	Air Quality Management District
BACT	Best Available Control Technology
BTU	British thermal unit
CARB	California Air Resources Board
Carollo	Carollo Engineers, Inc.
CEMS	Continuous Emission Monitoring Systems
cfd	cubic feet per day
cfm	cubic feet per minute
CH_4	methane
City	City of San Bernardino
CNG	compressed natural gas
CO	Carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalence
cu ft	cubic feet
D3	RIN classification for cellulose derived fuel
DG	Digester Gas
DGE	diesel gallon equivalents
EPA	Environmental Protection Agency'
ESCO	Energy Service Companies
EVWD	East Valley Water District
F	Fahrenheit
FCE	Fuel Cell Energy
GGE	gasoline gallon equivalents
GHG	greenhouse gas
GR/SCF	Grams per standard cubic feet
GWP	Global Warming Potential
H_2S	hydrogen sulfide
HFC	hydrofluorocarbons
HHV	higher heating value
HP	horsepower

ICE	Internal Combustion Engines
kg	kilograms
kW	kilowatt
kWh	Kilowatt per hour
lbs	pounds
LCFS	low-carbon fuel standard mandate
LHV	Lower heating value
mgd	million gallons per day
MMBTU	Million British thermal units
mol	Molecular concentration
MT	Microturbines
MW	megawatt
MWe	MW electric
MW/H	megawatt per hour
N_2O	nitrous oxide
NG	natural gas
NOx	Nitrogen oxides
O&M	operation and maintenance
P3	Public Private Partnership
PPA	Power Purchase Agreement
PFC	perfluorocarbons
POGT	Partial Oxidation Gas Turbine
Ppb	Parts per billion
ppd	pounds per day
ppm	parts per million
Ppmv	Parts per million by volume
Ppmvd	Parts per million by dry volume
psi	pounds per square inch
Psig	Pounds per square inch gauge
R&D	Research and Development
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RNG	renewable natural gas
RTU	remote terminal unit

SBMWD	San Bernardino Municipal Water District
SCAQMD	Southern California Air Quality Management District
SCE	Southern California Edison
scf	standard cubic feet
Scfd	Standard cubic feet per day
SCR	Selective Catalytic Reduction
SF_6	sulfur hexafluoride
SO_2	sulfur dioxide
VOC	volatile organic compound
WRP	Water Reclamation Plant
µg	micrograms

Conversions:

MMBtu: 1,000,000 British thermal units

Therm: 1 therm equals 100,000 Btu, or 0.10 MMBtu

Section 1

INTRODUCTION

The City of San Bernardino Municipal Water Department (SBMWD) owns and operates the Water Reclamation Plant (WRP) located at 399 Chandler Place, San Bernardino, CA. Carollo Engineers (Carollo) was retained to evaluate beneficial digester gas use options for this facility. The objective of this study is to evaluate proven technologies for beneficial uses of the digester gas based on current and anticipated economic and environmental criteria. Also, a realistic implementation schedule for each option is presented in order to meet the Air Quality Management District's (AQMD's) compliance with Rule 1110.2.

The purpose of this study was to complete a high level evaluation and select the most feasible technology for beneficial digester gas use and provide recommendations. The basis of design and technology and equipment selection would be completed during the detailed design phase.

The following alternatives were reviewed and evaluated based on capital and life cycle costs as well as environmental and operational considerations:

- **Alternative 1: Cogeneration of Heat and Power (CHP) in Internal Combustion Engines with digester gas pretreatment and exhaust post-treatment.** This option will include installation of a gas conditioning system, internal combustion engines and exhaust treatment with catalytic reduction (Figure 1).

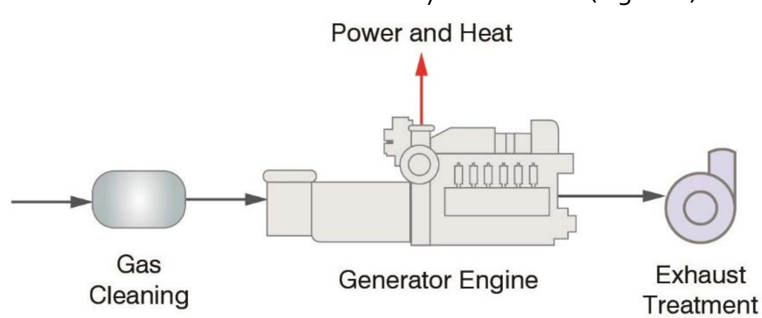


Figure 1 Simplified Schematic for Alternative 1

- **Alternative 2: Cogeneration of Heat and Power (CHP) in Microturbines (MTs) with digester gas pretreatment.** This option includes installation of a gas conditioning system and addition of MTs for cogeneration - no exhaust treatment is required (Figure 2)

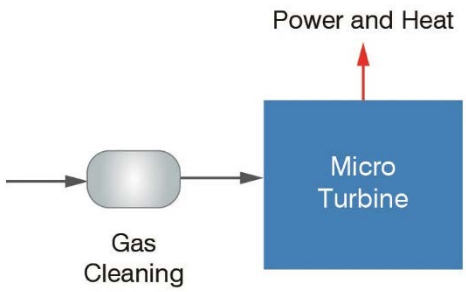


Figure 2 Simplified Schematic for Alternative 2

- **Alternative 3: Cogeneration of Heat and Power (CHP) in Fuel Cells with digester gas pretreatment.** This option includes installation of a digester gas conditioning system and a power generation system using Fuel Cells under a Power Purchase Agreement (Figure 3).

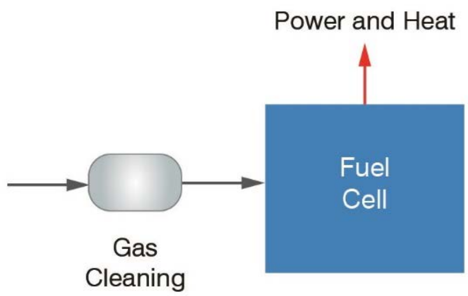


Figure 3 Simplified Schematic for Alternative 3

- **Alternative 4: Conversion of biogas to compressed natural gas (CNG) for pipeline injection.** The pipeline injection option includes installation of a gas conditioning system to convert the plant's biogas into pipeline quality CNG. The CNG would be sold to the market to generate renewable credits (Figure 4).

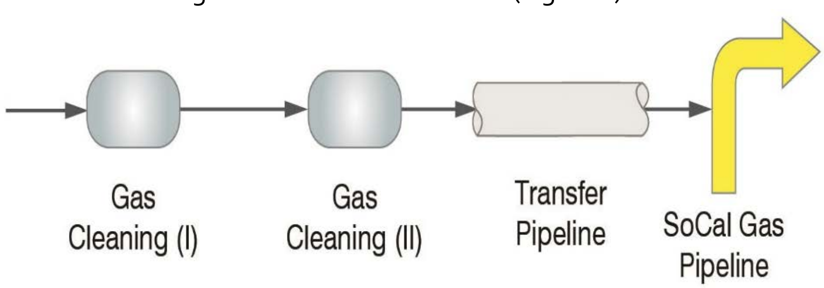


Figure 4 Simplified Schematic for Alternative 4

- **Alternative 5: Conversion of biogas to CNG for vehicle fueling.** A vehicle fueling option would include a gas conditioning system to convert the plant's biogas into vehicle fuel quality natural gas (CNG) for onsite use by SBMWD and WRP vehicles. Alternatively, a 1.5-mile pipeline from the WRP to the City of San Bernardino's (City) existing fueling station could be built to connect to the City's CNG system that already has a large established fleet of CNG vehicles (Figure 5).

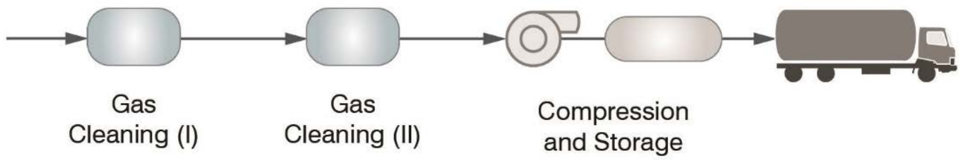


Figure 5 Simplified Schematic for Alternative 5

Section 2

BASIS OF DESIGN

2.1 Estimated Digester Gas Production

The WRP is currently operating with an influent flow of 22 million gallons per day (mgd). The daily digester gas (DG or "biogas") production at the facility for the year 2017 and up until February 2018 is presented in Figure 6. Based on the operating data, the daily gas production varies between 260,000 and 528,000 cubic feet per day (cfd) with an annual average of 417,000 cfd. A portion of the DG, around 43,000 cfd or ten percent (10 percent), is used in the WRP's boilers to heat the anaerobic digesters. The majority of the DG is currently compressed, then used in engine driven blowers and pumps and the remainder of the DG is flared. The WRP also has an existing cogeneration plant equipped with two 999 horsepower (HP) Waukesha digester gas engines. However, this facility has been out of service since 2015 because the engines are unable to meet the exhaust nitrogen oxides (NOx) limits.

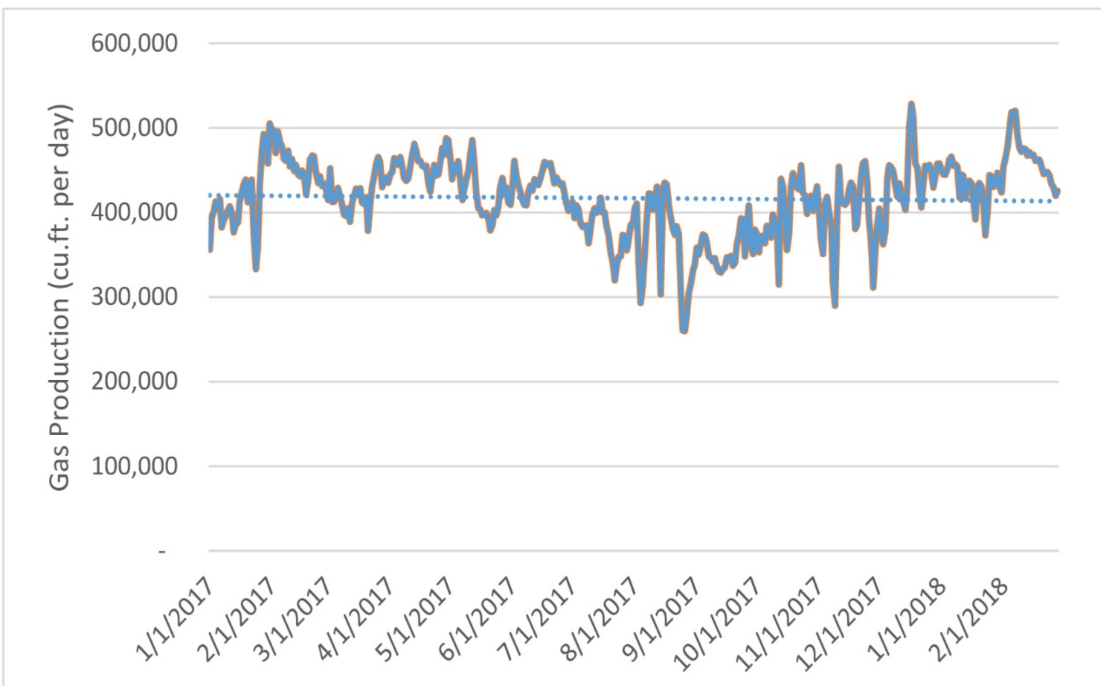


Figure 6 Historical Biogas Production

The future DG generation was calculated based on an assumed growth of 2 percent of the average day annual influent load. SBMWD is presently undertaking a sewer system master plan that will generate future flow and load projections for the WRP. These projections can be used to update the projections shown in this report, as and when needed. Currently, East Valley Water District (EVWD) is in the process of planning a wastewater treatment plant. This plant would divert approximately 6-mgd of sewer flow away from the WRP owned and operated by SBMWD. EVWD is in negotiations with SBMWD to potentially send solids to the WRP for treatment and biosolids disposal. However, agreement on such a solids transfer arrangement has not yet been reached and therefore for the purpose of this study it is assumed that EVWD will take 6 mgd of flow but no solids from EVWD will be treated at the WRP. This approach provides a conservative estimate of future gas production.

Once the EVWD plant is on line, the digester gas production would decline from about 417,000 to about 303,000 standard cubic feet per day (scfd). It was assumed that thereafter a moderate annual gas flow increase of 2 percent would occur, see Figure 7. By 2037 the digester gas production is projected to reach about 407,000 cu ft per day. In order to enhance gas production, food waste substrate could be introduced to increase the digester gas production after implementation of a beneficial digester gas use project. There is an increasing regional trend to use available municipal digester capacity to treat food waste, driven by the recent CalRecycle regulations.

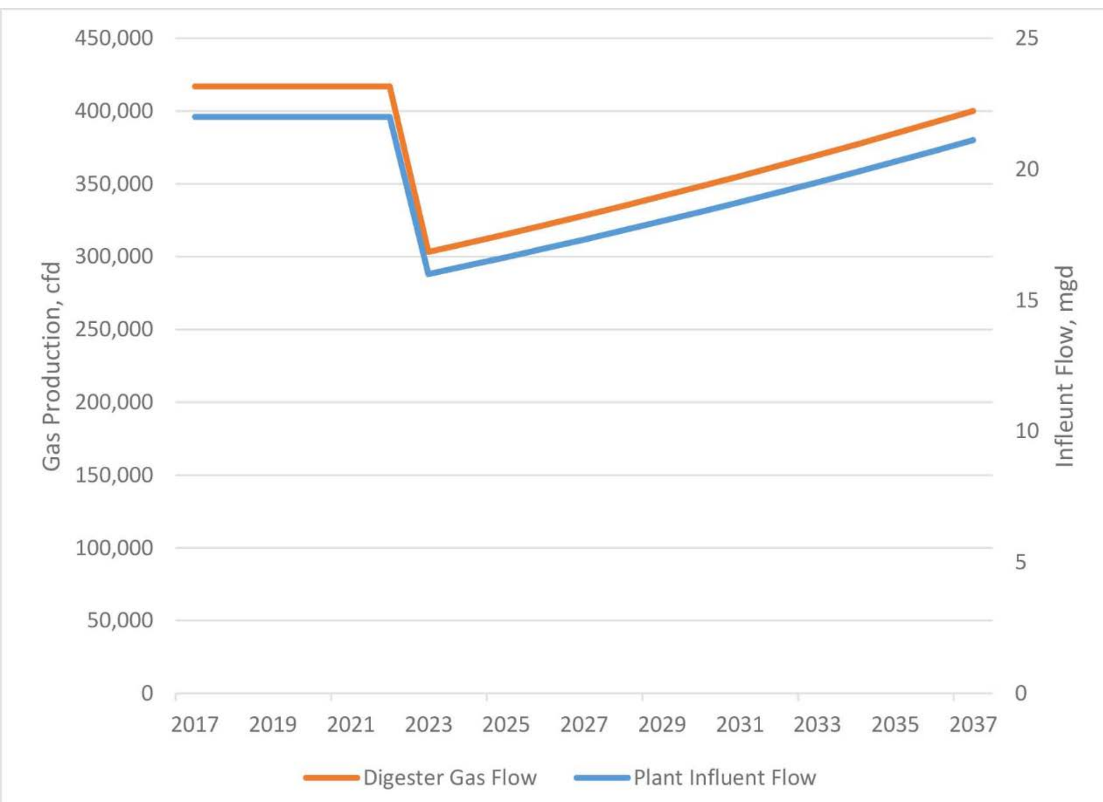


Figure 7 Influent and Biogas Flow Projections (based on an assumed 2% annual growth rate)

2.1.1 Digester Gas Used for Digester Heating

As mentioned, an average DG flow of 30 standard cubic feet per minute (scfm) or 43,200 scfd is currently used in the boilers for digester heating. These gas flows correspond to a heating demand of 25.9 million British thermal unit (BTU) per day. This DG demand is expected to continue and the net available digester gas flow rates are shown in Table 1. Note that there will be a period of transition for this DG beneficial use project during the reduction in flow from EVWD SNRC. The DG flow projection will be further evaluated during the design phase of this project.

Table 1 Digester Gas Production and Available Flows for Beneficial Uses

	Production Year 2017	Projected Production Year 2023(2)	Projected Net Production Year 2023(1)(2)
Average (scfm)	290	211	181
Minimum (scfm)	260	190	160
Maximum (scfm)	528	391	361

Notes:
(1) Projected gas flows available for beneficial use. These net available DG flows take into consideration the DG used for boilers.
(2) The projections are based on the assumption that the EVWD SNRC will come online with the effective date of 2023.

2.2 Digester Gas Quality

The quality of the DG will determine the level of treatment required for the various alternatives evaluated in this report and the associated operating costs. The SBMWD provided historical biogas quality data including methane (CH_4), carbon dioxide (CO_2), hydrogen sulfide (H_2S) and siloxane concentrations, and the data are summarized in Table 2.

Table 2 Biogas Quality

	CH4 (%)	CO2 (%)	H2S (ppm)	Siloxane (µg/L)	Heating value (BTU/scf)(1)
Average (2)	63	36	94.9	8	570
Maximum (2)	70	48	143	9	630
Minimum (2)	52	30	20	<4	470

Notes:
Abbreviations: ppm - parts per million; scf - standard cubic feet; µg – micrograms.
(1) The values used in this analysis are adjusted downwards by 10 percent to account for moisture in the biogas to calculate the lower heating value LHV.
(2) Values calculated based on SBWRP data from January 2017 to February 2018.

2.3 Cost Analysis

The assumptions used for the life cycle cost analysis for the alternatives considered in this report are presented in Table 3.

Table 3 Financial Assumptions for Life Cycle Analysis

Criteria	Assumption Used
Inflation Rate for capital and Operation and Maintenance (O&M) Costs (fuel, electricity) per year	3%
Gross Discount Rate per year	4%
Gas Conditioning System Availability Percentage	96% (2)
O&M Cost for Dual Pass Gas Conditioning System , $/GGE	$0.54
Natural gas cost, $/therm	$0.53
RIN Credit, $/RIN (1)	$2.50
LCFS Credit ($/MMBTU)	$5
CNG Sale Price $/GGE	$1.75

Notes:
Abbreviations: GGE - gasoline gallon equivalents; LCFS - low-carbon fuel standard mandate; RIN - Renewable Identification Number; MMBTU – million British thermal units.
(1) RIN based on current values up until the year 2022.
(2) Depending on the technology of gas treatment and the system availability could be lower.

Section 3

BACKGROUND

3.1 Air Quality Regulations

The following section describes the current air quality regulations within the Southern California Air Quality Management District (SCAQMD), which are impacting the digester gas use options in cogeneration plants, emission control devices, and the operation of ultralow emission flares.

3.2 Internal Combustion Engines - Rules 1110.2 and 218

The emission limits for digester gas fired Internal Combustion Engines (ICEs) are based on SCAQMD Rule 1110.2 and the limits are listed in Table 4. Due to this rule existing or new ICEs will need to be equipped with exhaust gas treatment systems to reduce the concentrations of NOx, volatile organic compound (VOC's) and carbon monoxide (CO).

Table 4 Emission Limits for Biogas Fueled Process Engines and ICEs

Regulated Parameters	NOx (1)	VOC(2)	CO(1)
Concentration Limits for Process Engines (blowers, pumps)(3)	36-45	250	2000
Previous Concentration Limits for ICE (ppm)	39	56.7	269.9
New Concentration Limits for ICE (ppm)	11	30	250

Notes:
(1) Parts per million by volume, corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
(2) Parts per million by volume, measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over the sampling time required by the test method.
(3) Converted emission limits.

The SCAQMD Rule 1110.2 and Rule 218 regulate the requirements for Continuous Emission Monitoring Systems (CEMS), which are required to monitor emission levels after exhaust gas treatment. It should be noted that this is for ICEs only; neither Fuel Cells nor MTs require a CEMS or periodic emission source testing, because Fuel Cells are classified as a zero emission technology. SCAQMD air permits are required for the pre-heating system. However, Fuel Cells do require a permit for the preheater, which has become an issue on some other projects due to permitting delays.

3.3 Flares - Rule 1118.1

The conditions for the operation of digester gas flares per SCAQMD Rule 1118.1 are currently being amended with the goal to achieve further NOx emission reductions. Only flares operating less than 200 hours per year (low use) or low emitting flares (less than one pound NOx per day) and plants with a minimum percent beneficial use of 85 percent by July 1, 2019 (or 90 percent by July 1, 2022) are exempt from the new emission limits (Figure 8). The percentage for beneficial use is still subject to review and discussions and could be changed in the final version of the Rule. Please refer to the AQMD workshop held on March 8th, 2018 and additional information published on their web-site (http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1118.1/2018-03-08_pr1118-1_wg4.pdf?sfvrsn=6).

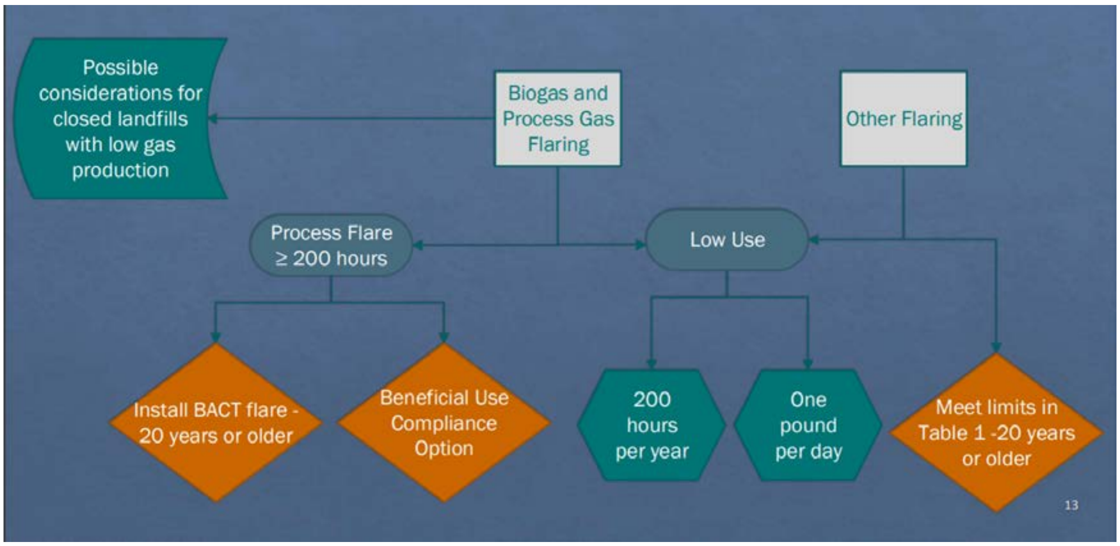


Figure 8 Rule Concepts Overview (Early Draft of SCAQMD Proposed Amended Rule 1118.1)

3.4 Replacement of Digester Gas Fueled Engine Driven Blowers and Arrowhead Pump Station Gas Fueled Pump

SBMWD is operating digester gas fueled ICE driven aeration blowers, which will need to be replaced by electrically driven blowers to reduce emissions per SCAQMD requirements. Also, the Arrowhead pump station is equipped with a DG fueled ICE driven pump which will be retrofitted with an electric drive motor. A centralized aeration blower would be rated at 750 HP and the new electrical motor for the Arrowhead pump station will be rated at 200 HP. The estimated increase in power demand at the WRP is 656 kilowatt (kW), made up as follows:

- New blower: 750 HP x 0.90 x 0.746 kW/HP / 0.95 (motor efficiency) = 530 kW.
- Pump station: 200 HP x 0.80 x 0.746 kW/HP / 0.95 (motor efficiency) = 126 kW.

3.4.1 Flare Replacement Project

The SBMWD is planning to replace the current single flare with a duty and backup flare compliant with the Rule 1118.1. The schedule for the full-scale installation of the beneficial use project would depend on the completion of the flare replacement project, which includes all related permitting tasks.

3.5 Background Partial Oxidation Gas Turbine (POGT)

In a 2012 Working Group Meeting for Then-Proposed Amended Rule (PAR) 1110.2, SBMWD Staff was approached by a private entity (herein referred to fictitiously as RESEARCH INSTITUTE) with a potential research-level project. The potential project contemplated the collaboration of RESEARCH INSTITUTE, SCAQMD, and a host wastewater treatment plant (SBMWD) to demonstrate a theoretical approach to meeting the PAR 1110.2. At the time, the Best Available Control Technology (BACT) (and only technology) to comply with PAR 1110.2 was to implement an ICE cogeneration system with gas pretreatment and Selective Catalytic Reduction (SCR) exhaust treatment. Most mid-sized wastewater treatment plants (such as the WRP) could not implement this technology in a realistic manner that was less costly than wasting to flare all of the renewable DG and purchasing a source of utility energy to drive all of the process equipment.

If demonstrated, the new proprietary technology could more cost-effectively achieve the proposed emissions limits while continuing to benefit from the use of the renewable DG energy source and maintaining low process electrical usage. As a key stakeholder in the industry, SBMWD committed to help drive this proposed technology from 2012 through the present day. SBMWD initially served as the host site and provided co-funding for the project. Due to extensive problems and cost overruns (exhausting funding from other sources), as well as the need to see this technology work, SBMWD expanded its commitment to funding the demonstration project.

Despite the best efforts and funding from SBMWD, the problems persisted. Since 2012, numerous other technologies have become prevalent, each with varying levels of success and cost effectiveness for other public agencies. For calendar-year 2018, SBMWD is paying the Compliance Flexibility Fee to comply with Adopted Rule 1110.2. This option is only available until December 31, 2018. In February 2018, the research project was deemed not commercially viable at the time and was forced to evaluate the best path forward. As a result, SBMWD discontinued its portion of funding of RESEARCH INSTITUTE (and ancillary providers also funded by SBMWD in order to keep the project moving forward) toward the research project. Instead, SBMWD met with SCAQMD and proposed to proceed with a proven technology in order to comply with Adopted Rule 1110.2. The SBMWD remains committed to the contemplated technology and is willing to continue to serve as the host site for the research as this technology, if and when proven, would be greatly beneficial for the industry.

3.6 Power Demand

Currently SBWMD is procuring utility power from Southern California Edison (SCE). To supplement this source of procured power to drive all of the plant processes with beneficially-used renewable DG, the Department installed in 2005 two (2) 750 kilowatt, 999 horsepower cogeneration Waukesha ICEs ("Cogen #1" and "Cogen #2"). Both ICEs were de-tuned to 704 kW to remain at 999 HP. Cogen #1 and #2 were used as prime power providers through 2012, when both were discontinued based on emissions limitations. Cogen #1 was operated occasionally for testing purposes through 2015, then incorporated into the POGT Project.

Based on a review of the electricity bills for the year 2017, as well as statements of SBMWD Staff, the power demand peaks in the summer months, July and August. As shown in Figure 9 the annual average power demand was 2,200 kW and the maximum monthly power demand was 2,704 kW (includes meter readings for Hoffman Building, Service Accounts 3-000-0019-54 and Service at WRP, 3-000-8294-72). The rates vary between summer on-peak rates (7.5 cents per kWh) and winter mid-peak rates (4.5 cents/ kilowatt per hour (kWh)). The monthly power costs ranged from $110,646 in April to $182,000 in July and August. The total annual power cost for the year 2017 was $1,628,145.

As stated earlier the future electrical load is expected to increase by 656 kW for new blower and pump motor additions. This would lead to an average annual power demand of 2,860 kW, a maximum demand of 3,360 kW and an annual projected power cost of up to $2,917,448 (actual costs will depend on Tier structures and peak demand charges for each meter location).

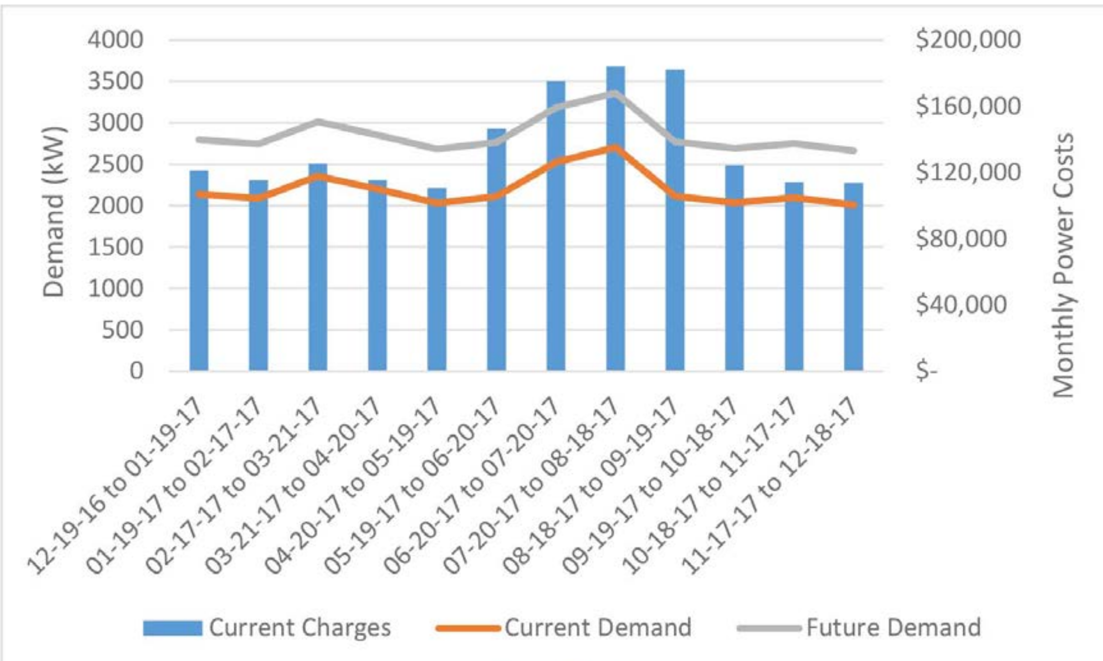


Figure 9 Current Power Demand and Costs and Projected Power Demand

3.6.1 Potential Solar Project

The increase in power demand for the aeration blower and Arrowhead pump described above may partially be off-set by the installation of a future solar photovoltaic system, which is currently being considered by SBMWD. The existing net metering devices installed for the cogeneration plant and for interconnection with the SCE grid could potentially become available for potential re-use in the solar project depending on the type of DG use alternative selected.

Section 4

IDENTIFICATION OF ALTERNATIVES

4.1 Alternative 1: Power and Heat - Cogeneration Engines with Pretreatment and Post-treatment

4.1.1 Process Flow Diagram

A process flow diagram for the digester gas pre-treatment system and for the internal combustion engine is presented in Figure 10.

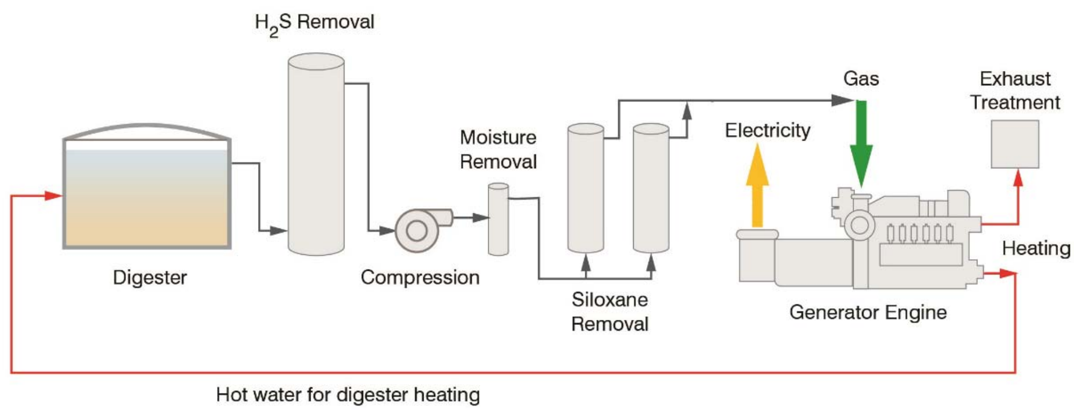


Figure 10 Engine Cogeneration System Process Flow Chart

4.1.2 Design Criteria

Methane (CH_4) and carbon dioxide (CO_2) are the two main chemical compounds present in DG. Depending on the performance of the anaerobic digesters, methane is typically present between 50 percent and 70 percent, and between 30 percent and 50 percent for carbon dioxide. The remaining percentage contains different chemical substances that can be detrimental to the treatment plant. Hydrogen Sulfide, or H_2S, a gas detectable in very low concentrations (parts per billion) and notable for both its toxicity and its ability to corrode various materials used in the treatment plant, is one of these minor substances. Siloxane (measured in micrograms per liter or ppm) is an organic silicon compound commonly detected in the DG. Siloxane results from entry of many different silicon-based chemicals in the wastewater stream (cosmetic products, detergents, chelating agents, paint products, and other cleaning products). In the combustion of DG containing siloxanes, the gaseous silicon compounds are transformed into oxides, which precipitate as solids on the inside of the piston, combustion chambers and in the exhaust treatment system.

The design criteria for H_2S and siloxane removal are based on the need to meet the emission limits for sulfur dioxide (SO_2) and NOx and to protect the cogeneration system to convert DG to power and heat (Figure 10). A siloxane DG pre-treatment system is required for all combustion or electrochemical reaction technologies considered (ICEs, Fuel Cell, or MT) to protect the engine combustion chambers from siloxane build-up. In addition, an exhaust treatment system for lean burning engines is needed to meet AQMD requirements. For this purpose a Selective Catalytic Reduction (SCR) is commonly applied using urea for selective conversion of NOx to Nitrogen. Oxidation Catalysts are used to reduce CO and VOC emissions. These catalysts will be subject to siloxane scaling and therefore any DG needs be treated to meet Siloxane levels to below 1 ppb as the cost for the replacement of a fouled SCR catalyst following siloxane breakthrough would range from \$50,000 to \$100,000. Due to the lack of instantaneous testing methods, a duty and backup DG pretreatment system, plumbed in series would be required to prevent H_2S or siloxane breakthrough.

The sizing of the ICEs for SBMWD will be based on the available DG and the plant's power needs and the heating demand for the digesters. Consideration for any reuse of Cogen #1 or Cogen #2 engines would occur during a detailed design process. The typical engine sizes range from approximately 350 to 1200 kW provided by the ICE manufacturers GE Jenbacher, GE Waukesha or Caterpillar.

The WRP's combined annual average power demand was 2.2 MW based on the Edison bills from the year 2017. The future total average load would be 2.85 MW after the addition of the electric driven aeration blower and the electrically driven pump at the Arrowhead pump station. Any reduction in power demand resulting from downsized equipment to account for any cessation of flow from an EVWD facility would occur slowly over time as individual components were replaced with smaller units.

Table 5 describes the required DG feed flow rate for ICEs, electrical power and heat output after deducting the DG flows used for boilers as a back-up heating system would need to be maintained. At least two ICEs rated at 848 kW would be required based on the DG flow rates. The minimum digester gas flow of 181 cubic feet per minute (cfm) would support one ICE operating at 85 percent load. At the maximum digester gas flow of 361 cfm two ICEs would be operated. The engine selection and configuration will be subject to review during the detailed design phase and could change.

Table 5 Digester Gas Requirements and Emission Calculations for IC Engines

Parameters	Units	Values
Biogas LHV	(BTU/cu ft)	570
Two Jenbacher JMS 316 GS-B.L	(kW)	848
Energy input	(MMBTU/hr)	7558
DG flow input required	(cfm)	209 each
Average DG flow (range)	(cfm)	260 (181-361)
Electrical efficiency	%	40
Exhaust gas flow	(cfm)	2183
Baseline NOx emissions without SCR at 30 ppm (1)	(ppd)	11.28
	(tons per year)	2.06
NOx Emissions with SCR	(ppd)	3.38
	(tons per year)	0.6

Notes:
Abbreviations: ppd – pounds per day; LHV - lower heating value.
(1) The NOx emissions can be less than 30 ppm and the mass emission will depend on the hours of operation.

4.1.3 Life Cycle Costs

The costs for the cogeneration alternative with ICEs include the capital and installation costs for the gas treatment system, the actual ICEs, and the exhaust treatment system with SCR and CO catalyst (Table 6).

The operations and maintenance costs include the carbon media replacement, periodic maintenance for the ICEs, and catalyst and urea costs for the SCR. The value of the power costs avoided is based on the power purchased from SCE.

The initial capital investment is estimated to be $12,450,000 for two new Jenbacher engines (rated at 848 kW each), DG pre-treatment and exhaust treatment systems.
The total 20-year net present value Life Cycle cost is estimated to be $26.5 Million.

Table 6 Net Present Life Cycle Costs for Alternative 1 - IC Engines

Alternative 1- IC Engines	Cost Estimate (1)
Estimated Project Cost	($12,450,000)
Annual (Costs)/Revenues	
• Base Cost for Electricity	($2,115,000)
• Saved Costs through Power Generation	$1,203,000
• Gas Cleaning O&M Costs	($146,000)
• Engine O&M Costs	($106,000)
• SCR Costs (Catalyst and Urea)	($55,000)
20-Year Present Value of (Costs)/Revenues	
• Base Cost for Electricity	($25,379,000)
• Saved Costs through Power Generation	$14,425,000
• Gas Cleaning O&M Costs	($1,153,000)
• Engine and SCR O&M Costs	($1,932,000)
Total 20-Year Net Present Life Cycle Cost	**($26,488,000)**

Notes:
(1) Detailed breakdown of capital costs are presented in Appendix B.

4.1.4 Schedule and Implementation Plan

The conventional delivery method using a design, bid, build approach is estimated to take 2.5 years for the completion of the project. The project schedule is shown below in Figure 11.

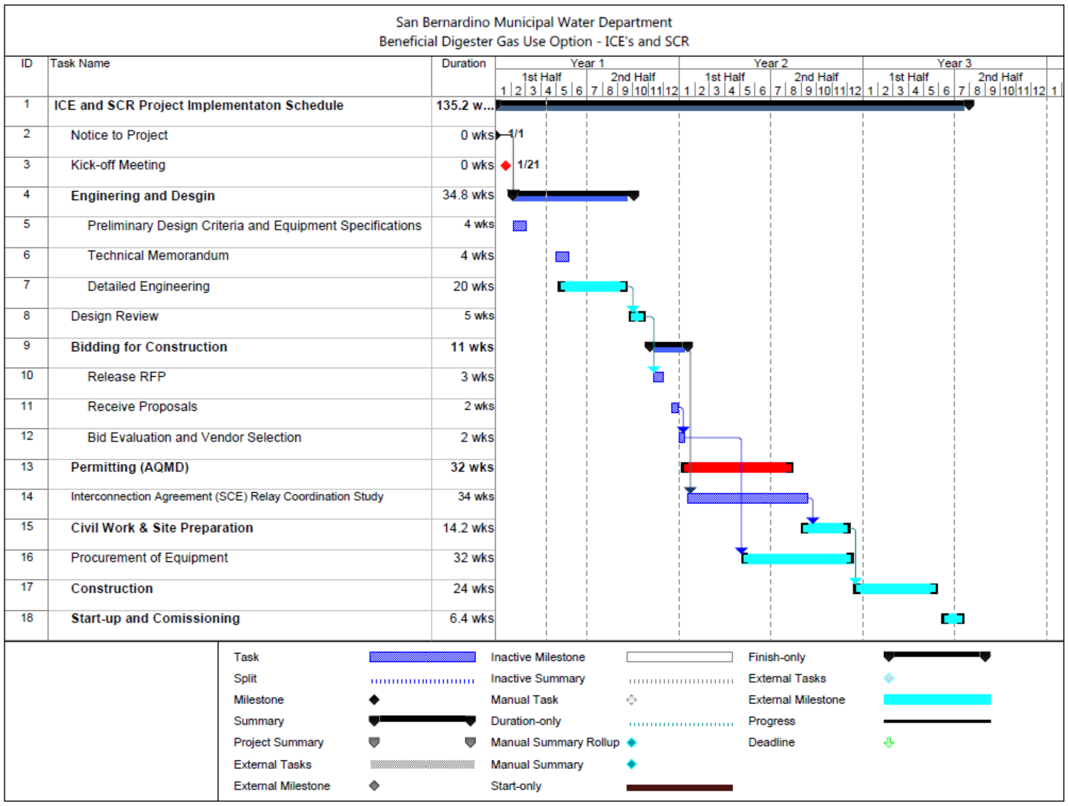


Figure 11 Schedule for Alternative 1 - Cogeneration with ICE

4.1.5 Public Private Partnership Feasibility

Private energy contracting companies Energy Service Companies (ESCO's) are offering operations and service agreements for internal combustion engines equipped with both DG pretreatment systems and exhaust post-treatment (SCR). A list of vendors and private partners with active projects in southern California is provided below:

- Amaresco.
- Anaergia.
- CH_4 Energy.
- Generate Capital.
- GI Energy.
- Quasar Energy.

When procuring the power through a Public Private Partnership (P3) option or a Power Purchase Agreement (PPA), there is still a risk that the private operator can go out of business. Also, depending on the size of the plant the costs can be 30 percent higher compared to the SBMWD owning and operating the cogeneration facility. However, the advantage of a P3 option is that the SBMWD does not have to hire staff to operate the power plant.

It is recommended to include a mandatory flare in the scope of the contract for any PPA to ensure that the DG can be flared by the P3 provider in case of equipment down-time for maintenance.

4.1.5.1 Key Stake Holders

For the Interconnection Agreement with SCE the primary contact would be SBMWD, which would act as the applicant or the host site, if a third party applies under a PPA.

4.1.6 Incentives and Grants

Incentives for the installation of cogeneration systems (ICE, MT or fuel cell) operating on digester gas are available through SCE or the Gas Company under the Self Generation Incentive Program (SGIP). The first 50 percent of the grant is paid out after completion of the installation. The remaining 50 percent of the grant is performance based; the electrical generation is metered and reported to Edison by an independent third party.

In addition, through the BioMAT program, the export of green power to the grid is incentivized through a power purchase rate. The BioMAT is an adjustable tariff for biogas derived green power. Utilities are required to procure a certain amount of biopower from wastewater plants and diaries. The current bid posted by SCE offers 12 cents per kWh for a period of 20 years for digester gas generated in wastewater plants.

The grants would be paid out to the operating entity. Under a PPA, these grants would be paid to the private operator. No grants were included in the financial models of this report as the incentives offered by SCE or other agencies vary dramatically over time.

4.2 Alternative 2: Power from DG - Microturbines (CHP) with DG Pretreatment

4.2.1 Process Flow Diagram

A process flow diagram for the digester gas treatment system and for the MT is presented in Figure 12.

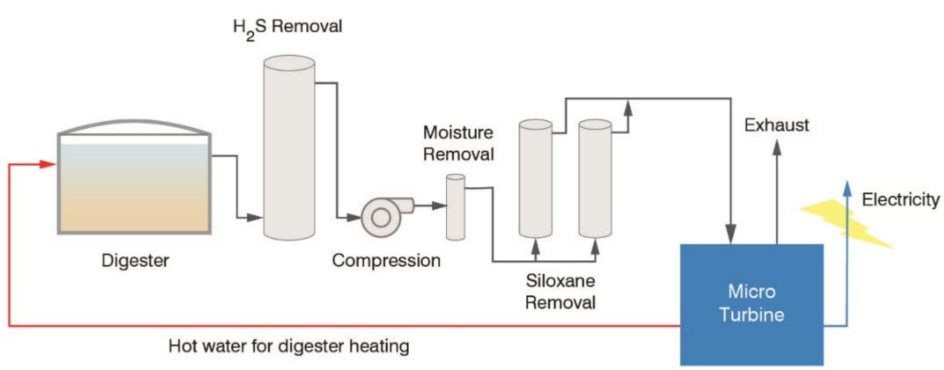


Figure 12 MT Cogeneration System Process Flow Chart

4.2.2 Design Criteria

For the MT cogeneration system (Figure 12) the same H_2S and siloxane pre-treatment criteria apply as described for the ICE alternative. However, a breakthrough of siloxane contaminants would not immediately result in a fatal failure of the MT. The manufacturers recommended maximum siloxane concentrations is 3 ppb. Also, the MT does not require an exhaust post-treatment step as required for an ICE, which would be affected by siloxane fouling. For the MT option the recommendation would be to install a containerized system with five MTs rated at 200 kW each (Table 7). For all five units in operation the required DG flow is 316 cfm. With an average DG flow rate of 260 cfm four turbines would be operated and one MT would be on stand-by.

Per SCAQMD Rule 219 micro-turbines, with a rated maximum heat input capacity of 3,500,000 British thermal units (Btu) per hour or less, are exempt from written permits, if the cumulative power output of all such engines at a facility is less than two megawatts, and that the engines are certified at the time of manufacture with CARB.

Table 7 Digester Gas Requirements and Emission Calculations for MTs

Parameters	Units	Values
Biogas LHV	(BTU/cu ft)	570
MT 5 x 200 kW (4 duty, 1 standby)	(kW)	max. 1000
Energy input	(MMBTU/hr)	10.3
DG flow input required (available)	(cfm)	316 (181-260)
Inlet pressure	psig	75 - 80
Electrical efficiency	(%)	29
Compressor parasitic load	(kW)	100
Net power output	(kW)	900
Average net power output	(kW)	750
Exhaust gas flow	(cfm)	10,892
Exhaust gas temperature	(F)	535
NOx emissions at <9 ppmvd	ppd	16.89
	(tons per year)	3.08

Notes:
Abbreviations: psig – pounds per square inch gauge; ppmvd – parts per million by dry volume.

4.2.3 Life Cycle Costs

The costs factors for the MT project are the capital and installation costs for the gas treatment system, a gas compressor, and the actual MT. There is no need for exhaust treatment systems or emission monitoring devices. The existing DG compression system requires further evaluation and potential replacement. The operations and maintenance costs include the DG pretreatment media replacement and periodic maintenance for the MT. Media replacement is estimated at $150,000 per year (assuming H_2S will be reduced below 50 ppm with ferric injection into the digesters), otherwise these costs will be higher.

The value of the power purchase costs avoided is based on the power purchased from SCE. A slightly lower electrical efficiency of the MT results in a lower net power generation. In addition, a gas compressor is needed thus increasing the parasitic load.

Initial capital investment including installation costs was estimated to be $11.5 Million for a MT cogeneration system rated at 1000 kW (Table 8). With a net output of 750 kW including loss of efficiency at higher ambient temperatures, compression and other parasitic loads this will result in a greater demand of imported energy compared with ICEs.

The total 20-year net present value life cycle cost is estimated to be $30.5 million.

Table 8 Net Present Value Summary for MTs

Alternative 2 - MTs	Cost Estimate
Estimated Project Capital Cost	($11,500,000)
Annual (Costs)/Revenues	
• Base Cost for Electricity	($2,115,000)
• Savings through Power Generation	$810,000
• Gas Cleaning O&M Costs	($146,000)
• MT O&M Costs	($181,000)
20-Year Present Value of (Costs)/Revenues	
• Base Costs for Electricity	($25,379,000)
• Savings through Power Generation	$9,706,000
• Gas Cleaning O&M Costs	($1,153,000)
• MT O&M Costs	($2,166,000)
Total 20-Year Net Present life cycle Cost	**($30,500,000)**

4.2.4 Schedule and Implementation Plan

A conventional delivery method using a design, bid, build approach is estimated to take up to 2 years for the completion of the project. The project sequence for MT implementation is similar to that for the IC Engines shown in Figure 11.

4.2.5 Public Private Partnership Feasibility

A number of private companies ESCO's are offering operations and service agreements for a MT including DG pre-treatment system. No exhaust post-treatment is required for a MT. P3 projects would not be executed through the manufacturer but through a third party leasing company. The two vendors for MT projects are Capstone and FlexEnergy (using MT from Ingersoll Rand).

4.2.6 Incentives and Grants

Similar to ICEs the installation of MTs operating on digester gas is supported by grants such as SGIP. The power export under the BIOMAT program is also an option. The grants would be paid out to the operating entity and under a PPA these grants would be paid out to the private operator.

4.3 Alternative 3: Power from DG - Fuel Cells (CHP) with DG pretreatment

4.3.1 Process Flow Diagram

A process flow diagram for the Fuel Cell and digester gas pre-treatment system is shown in Figure 13.

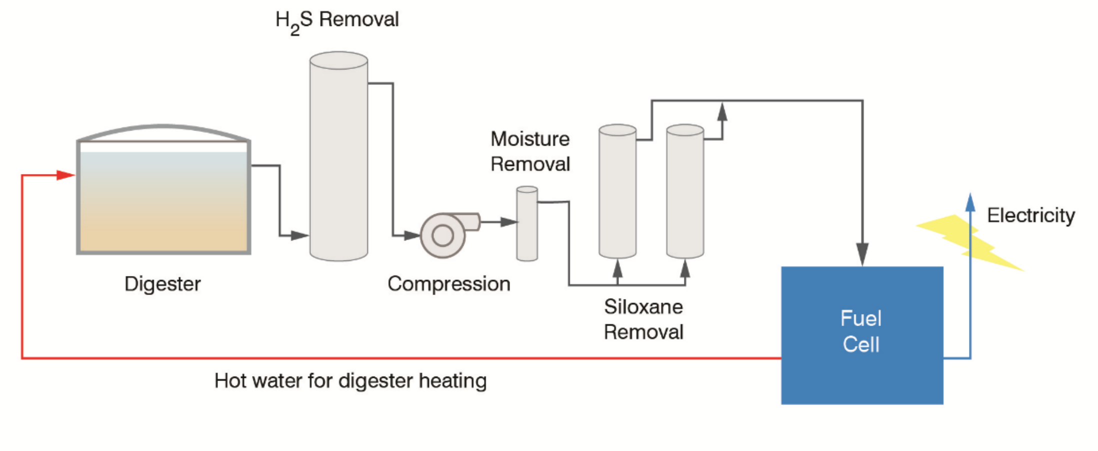


Figure 13 Fuel Cell Cogeneration System Process Flow Chart

4.3.2 Design Criteria

For Fuel Cells the DG pre-treatment design criteria for H_2S and siloxane removal are similar to the other cogeneration technologies. Experience has shown that there is little room for error and that DG cleaning is even more important for fuel cells in order to protect the membrane stacks from fouling with sulfides or siloxanes. The costs for the fuel cell stack replacement would be very high as it is one of the major costs of the overall system.

Based upon the experience of similarly-situated agencies, the design of the gas treatment system and the maintenance and operation of the fuel cell is best handled by a single Fuel Cell system vendor as part of a maintenance contract or PPA. The DG will be treated by addition of Ferric Chloride in the digester to achieve an H_2S level below 50 ppm and conditions like these would be negotiated in the PPA in more detail.

4.3.3 Life Cycle Costs

The addition of a DG holder to provide a constant DG flow rate to the Fuel Cells is required and the project cost was estimated to be $1.9 Million. Due to the complexity of the DG treatment and maintenance requirements for the Fuel Cell no purchase or capital costs for the fuel cell were obtained. Instead the manufacturer Fuel Cell Energy (FCE) provided a preliminary verbal estimate for electrical rates under a PPA including selling power back to SBMWD at 8.5 cents per kWh. A 20-year contract with FCE would be subject to further review of the SCE electrical bills and 15-min interval power demands. Based on the current SCE rates of 11.2 cents the average annual power savings at Present Value would be $195,685 per year. The total 20-year net present value Life Cycle Cost is estimated to be $23.4 Million.

Table 9 Present Life Cycle Cost, Power Output and PPA for Fuel Cells

Alternative 3 - Fuel Cells	Cost Estimates
Estimated Project Costs for DG Holder	($1,937,000)
Annual (Costs)/Revenues	
• Cost of Electricity Purchased from SCE	($1,073,000)
• Net Power Generation (MWh)	6,414
• Cost of Power with PPA	($723,000)
Total 20-year Net Present Life Cycle Cost	**($23,402,000)**

Notes:
Abbreviations: MW/h – megawatts per hour

4.3.4 Schedule and Implementation Plan

The vendor Fuel Cell Energy estimates that the implementation of the Fuel Cell including permits, design, and construction would take around 1 to 2 years. All responsibilities for permits, design and construction would be with the vendor under the PPA.

The first step for implementation would be the negotiation of a contract term sheet which includes conditions for digester gas quality and flow rate. The second step would be the actual agreement which defines how SBWMD is protected during fuel cell equipment down-times and to make sure that the vendor provides a flare in case that the fuel cell is not operational.

No AQMD permits for the Fuel Cells are required. However, the interconnection agreement with SCE would need to be initiated right away as this will take from 6 to 12 months to obtain.

4.3.5 Public Private Partnership Feasibility

For the Fuel Cell alternative, the only reasonable approach is via a PPA to outsource the operation of the digester gas treatment and fuel cell operations and purchase the generated power from the manufacturer or operator. The only vendors currently offering a PPA for this technology are Fuel Cell Energy and Bloom Energy. FCE is the only supplier for DG operated fuel cells at municipal wastewater plants. Bloom Energy is in the process of entering the DG market with a newly developed DG cleaning system.

The following business model is being applied at the Tulare Wastewater plant and would be a possible alternative for consideration by SBMWD. Fuel Cells are operated on NG to generate power to cover the electrical demand of the WWTP. The power is procured under a PPA with FCE at a low rate (e.g., 5-6 cents per kWh). The digester gas is sold to FCE in a P3 arrangement so that FCE can export the green power to the gird under the BIOMAT at a rate above 12 cents per kWh. The agreement would need to be structured so that both parties get a share of the revenues.

4.3.6 Incentives and Grants

Similar to ICE, the installation of Fuel Cells operating on digester gas is supported by the SGIP grant program. The grant would be paid out to the operating entity. Under a PPA, these grants would be paid to the private operator. AQMD has highlighted the potential availability of financial incentives to support the implementation or demonstration of novel Fuel Cell technologies operating on treated DG.

The power export under the BIOMAT program is an option because SBMWD is a SCE customer.

4.4 Alternative 4: Gas Sale - DG Purification and Renewable Natural Gas (RNG) Pipeline Injection

4.4.1 Process Flow Diagram

A process flow diagram for the digester gas purification system and digester gas pipeline injection is presented in Figure 14.

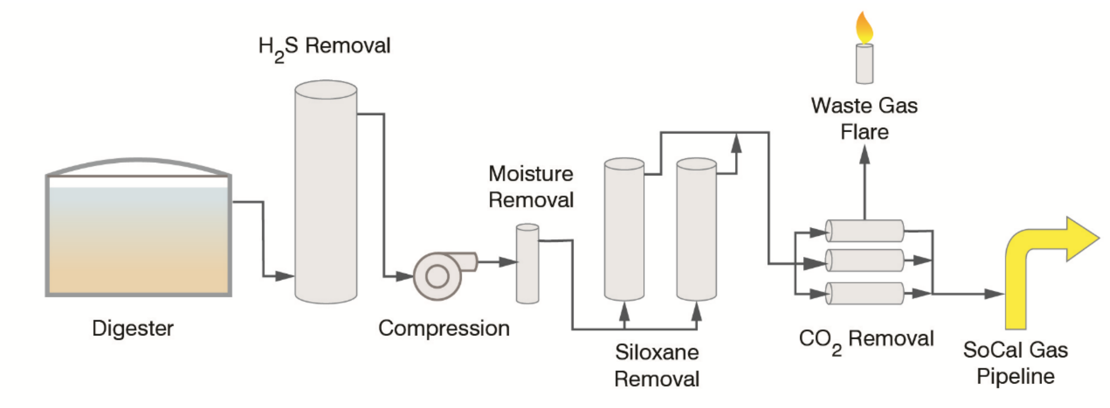


Figure 14 Treatment Train for Upgrading DG for Pipeline Injection

4.4.2 Design Considerations

The RNG alternative requires gas conditioning treatment to remove impurities such as H_2S and siloxane compounds, followed by removal of the CO_2 as shown in Figure 14. California legislation for pipeline injection under Rule 39 requires further enrichment of Methane to greater than 99 percent CH_4 and, if needed, Propane addition to achieve 1100 BTU/cu ft (Table 10).

The gas conditioning systems use well-proven technologies to remove the undesired constituents. Storage is not required for the pipeline injection alternative, since RNG would be injected into the pipeline at the same rate it is produced. Pipeline injection requires a similar treatment of the gas as CNG for vehicles, but would require an additional treatment step (an additional set of membranes) for additional CO_2 removal. This process would also require a thermal oxidizing flare or similar technology for disposal of the very low BTU waste gas, since it contains mostly CO_2. Figure 15 shows the potential location of a future gas treatment skid located near the WRP.

Table 10 RNG Biogas Quality Requirements

Constituents/Properties	Units	Limit
Higher Heating Value (HHV)	BTU/scf	965-1,100
Wobble (based on HHV)		1,185-1,285
Carbon Dioxide (mol %)	mol %	3.0
Oxygen	mol %	2.0
Total Inerts	mol %	14.3
H2S	gr/scf (ppmv)	0.25 (4)
Total Sulfur	gr/scf (ppmv)	5.0 (85)
Hydrocarbon Dew Point Cricondentherm	degrees F	15
Water Vapor Content	lb/MMscf	3
Dust, Dirt, Scum, and Other Solids		Free of
Water and Hydrocarbons in Liquid Form		Free of
Temperature	degrees F	32-110
Siloxanes	ppb	<1

Notes:
Abbreviations: mol – molecular concentration; gr/scf – grams per standard cubic feet; lb/MMscf – pounds per million standard cubic feet; ppmv – parts per million by volume, degrees F – Fahrenheit.

SCG requires RNG monitoring equipment prior to injection into their system, including a gas chromatograph, flowmeter, regulator, remote terminal unit (RTU), gas odorizer, emergency shut-off valve, and other ancillary equipment. The installed cost of the equipment was estimated to be $1,050,000. This equipment would be maintained by SCG and the connecting party has to pay maintenance costs of $15,000 per year.

The principal benefit of pipeline injection is that 100 percent of the generated biogas can be sold instead of being limited by the demands of the energy production equipment.

Figure 15 Proposed Site Plan for Gas Conditioning Skid

The Gas Company publishes maps showing existing high pressure gas lines in the nearby service area. After a review of these maps and the site specific conditions an interconnection with the nearby high pressure gas pipeline was found to be feasible. The distance from the WRP to the nearest high pressure natural gas line located in the North near West Mill Street is approximately 1.5 miles. A Capacity Study would need to be completed by the Gas Company to get confirmation about the gas pressure, gas demands, and flows in that line to evaluate the feasibility of pipeline gas injection. Figure 16 provides an indication of where the high pressure line is located relative to the WRP.

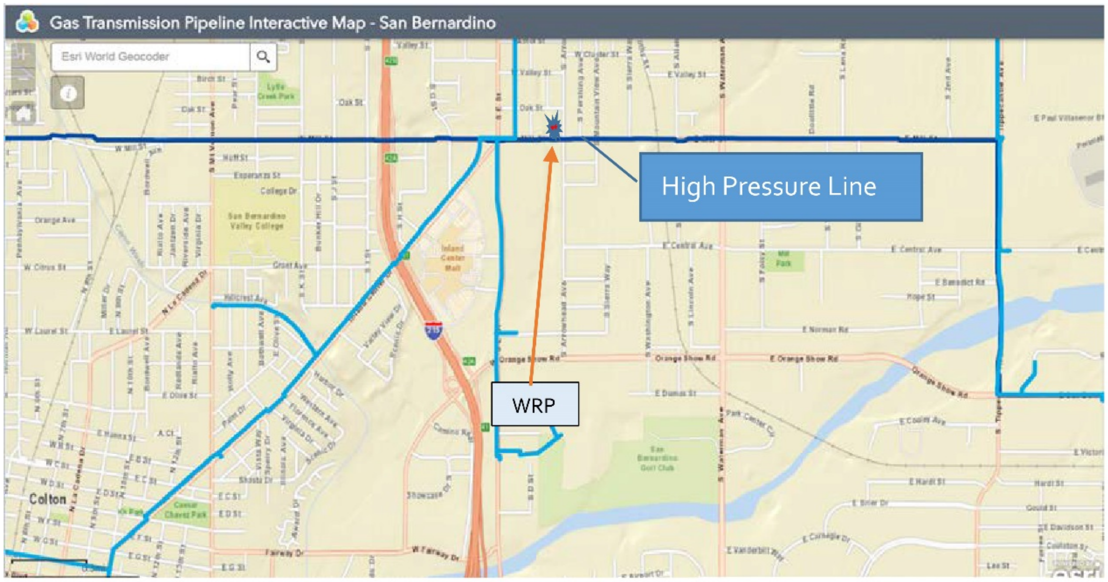


Figure 16 High Pressure Gas Line Point of Connection on West Mill Street, San Bernardino

4.4.3 Life Cycle Costs

The life cycle costs for this alternative include the capital and operating costs for the digester cleaning and upgrading system to achieve the RNG quality requirements. Other cost factors taken into consideration are the costs to purchase the electricity and NG costs for digester heating, if the digester gas is used for vehicle fueling or RNG (Table 11).

The total 20-year net present value life cycle cost is estimated to be $29.9 Million.

Table 11 Net Present Life Cycle Cost

Alternative 4 - RNG Pipeline Injection	Cost Estimates
Estimated Project Capital Cost	($10,556,000)
(Costs)/Revenues	
• Cost for Electricity	($2,127,000)
• Revenue for CNG Sale to Pipeline	$174,000
• Revenue for RIN/LCFS Credits	$369,000
• Cost for NG for Digester Heating	($46,000)
• O&M Costs	($736,000)
20-Year Present Value of (Costs)/Revenues	
• Cost for Electricity	($26,140,000)
• Revenue for CNG Sale to Pipeline	$2,089,000
• Revenue for RIN /LCFS Credit	$3,540,000
• Cost for NG for Digester Heating	($552,000)
• O&M Costs	($8,839,000)
Total 20-Year Net Present Life Cycle Cost	**($29,901,000)(1)**

Notes:
(1) RIN credits under the Renewable Fuel Standard (RFS) federal program are set to expire after the year 2022 and LCFS credits under the State program are set to expire in 2030, if no legislative action is taken. It is possible that these credits will continue, which would improve the financial position of this alternative. However, for the purpose of this evaluation it was assumed that RIN credits would not be available after 2022 and LCFS would not be available after 2030.

4.4.4 Schedule Implementation Plan

In order to take advantage of the legally mandated RIN quotas through 2022, this project would need to be started as quickly as possible (i.e., reduce the time to market). Figure 17 shows a general schedule, with the major required activities and coordination items spelled out. One critical activity that has been identified is the Capacity Study and coordination of the interconnection agreement with SoCal Gas. Carollo contacted SoCal Gas representative for RNG to inquire about the timeline for interconnection and based on experience, this can take up to 2 years. If the project is completed in 2020 and with the expiration of the Renewable Fuel Standard (RFS) program after year 2022 the project would only receive 2 years of RIN credits under the most conservative assumption.

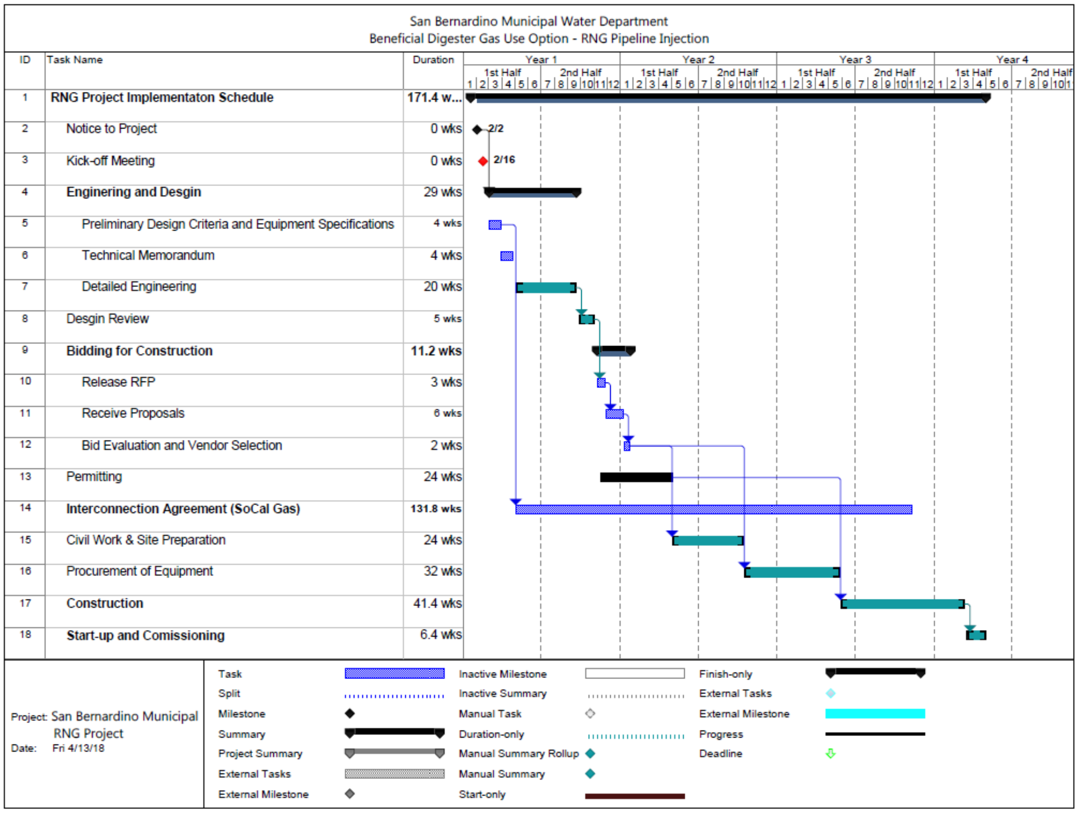


Figure 17 Implementation Schedule for the RNG Alternative

Additional steps shown in the schedule include:

- Approvals and securing of funding.
- Developing a contract with the design engineer.
- Performing the engineering design.
- Procuring the biogas conditioning equipment.
- Developing a request for proposals to obtain a RIN broker.
- Construction.
- RIN certification.

4.4.5 Public Private Partnerships

For the pipeline option there will not be acceptable payback and therefore no P3 opportunity based on the relatively low digester flow rates and the high capital investments for the transfer pipe, the NG pipeline interconnection and the monitoring system. Based on discussions with private developers banks would only be able to provide financing for RIN credits valued at $12 per MMBTU for a duration of 5 years, because the current RFS program has not been extended beyond 2022.

4.4.6 Incentives for Digester Gas Use as RNG

With increasing public pressure to reduce the country's reliance on non-renewable vehicle fuels, several programs, and incentives have been designed to offset fossil fuel use and decrease greenhouse gas (GHG) emissions.

4.4.6.1 Environmental Protection Agency's Renewable Fuel Standard Program

The Environmental Protection Agency's (EPA) Renewable Fuel Standard (RFS) Program was created under the Energy Policy Act of 2005, (https://www.epa.gov/renewable-fuel-standard-program), and established the first renewable fuel volume mandate in the United States. The program requires oil and gas producers to purchase specified amounts of fuel credits each year to increase the amount of renewable fuel used. Each 77,000 BTUs of gas used for vehicle fuel generates a renewable credit with a specific identification number, named the Renewable Identification Number (RIN).

The RFS program defines four types of renewable fuels: cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuel. As of 2014, the RFS program allows digester biogas from municipal wastewater treatment facility digesters as a transportation fuel feedstock. The biogas is designated as a "cellulosic" (D3) feedstock, which carries the greatest RIN value of the four categories.

The mandated quantities of renewable fuel volumes have been set through 2022, as shown in Figure 18. Beyond 2022, fuel volume mandates will be set by the EPA administrator.

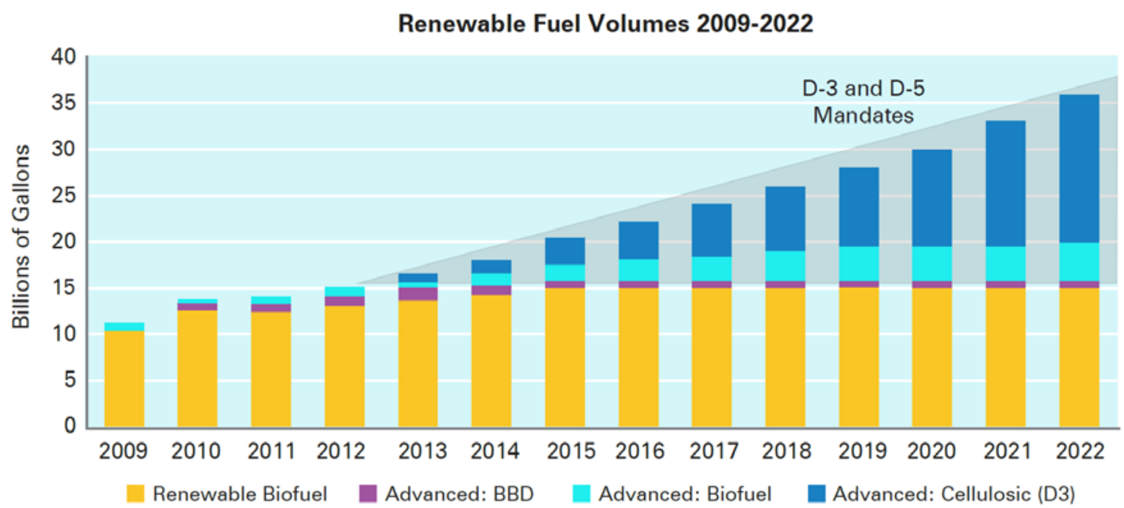


Figure 18 Renewable Fuel Volume Mandates

RINs are traded on the open market, and their value is dependent upon the price of oil and the renewable volume obligation, which is the amount of RINs obligated parties have to purchase. When D3 RINs were first introduced into the market 3 years ago, they had a value of approximately $1.00 per RIN. D3 RINs are currently trading for $2.50, with a 3-year historical average of $1.78. If demand for RIN credits associated with cellulosic biofuels grows, RINs can have an increasing market value over time. For the purposes of this evaluation, the currently traded value of $2.50 was used until 2022. Figure 19 presents the historical average RIN value for D3 RINs from 2015 through present day. The RIN credits are set to expire after 2022 unless legislation is passed to extend this federal program. For project financing purposes developers assume that the RIN values are expected to be reduced by 70 percent.

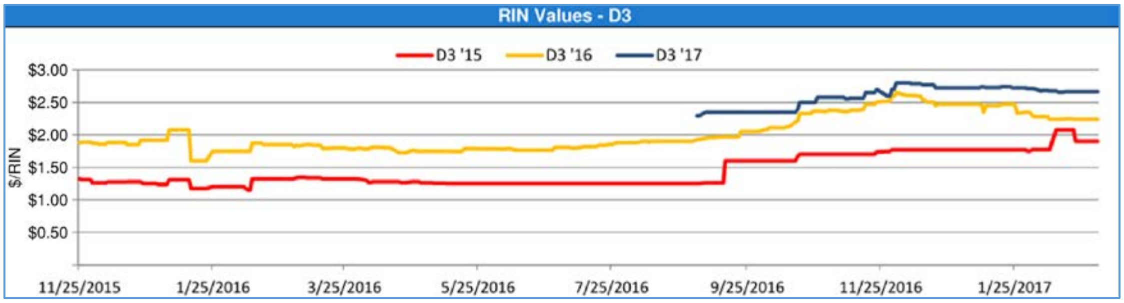


Figure 19 Historical D3 RIN Values

In order to become a RIN producer, the generator must be certified with the EPA. This is typically done by a third-party carbon offset broker. Carbon offset brokers can provide RIN registration and ongoing reporting and management. The carbon offset broker also handles the sale of RINs to producers. In exchange, they receive a management fee based on an agreed upon percentage of the RIN value, anticipated to be 20 percent for this size of project. For pipeline injection projects, the carbon offset brokers also manage the sale of the injected CNG.

Another option is for an obligated party (i.e., oil and gas producer) to purchase the RINs directly from the generator.

Both options result in the sale of the CNG and RIN credits, and would include similar amounts of work for SBMWD. Differences could include the length of contract, contractual obligations, and pricing structure.

4.4.6.2 California Low-Carbon Fuel Standard

In California the Low-Carbon Fuel Standard (LCFS) was enacted in 2007, with specific eligibility criteria defined by the California Air Resources Board (CARB) in April 2009 but taking effect in January 2011. The LCFS requires oil refineries and distributors to ensure that the mix of fuel they sell in the Californian market meets the established declining targets for GHG emissions measured in CO_2-equivalent grams per unit of fuel energy sold for transport purposes. The LCFS directive calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. At this time the value of the LCFS for RNG from digester gas is guaranteed until 2030 at a value of $5 per MMBTU.

4.5 Alternative 5: Gas Sale as Vehicle Fuel - DG Purification and CNG Fueling Station

4.5.1 Process Flow Diagram

A process flow diagram for the digester gas purification system and gas storage is present in Figure 20.

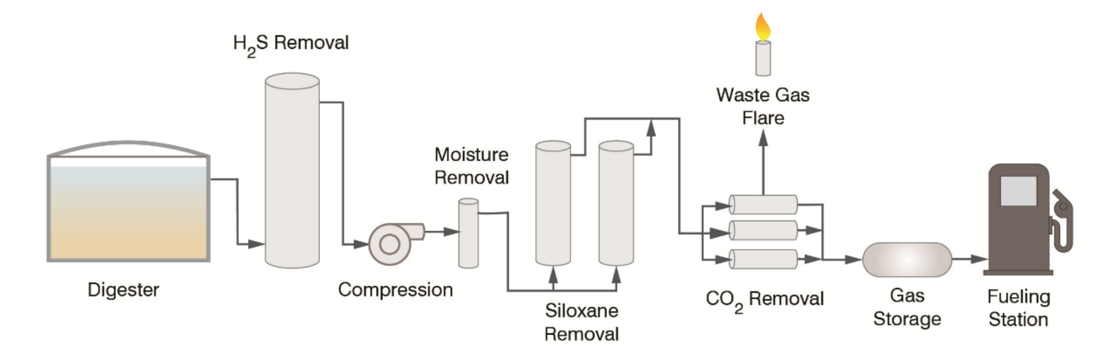


Figure 20 Treatment Train for Upgrading DG for Use in a CNG Fueling Station

4.5.2 Design Considerations

Both RNG and CNG alternatives require gas conditioning treatment to remove impurities such as H_2S and siloxane compounds, followed by removal of the majority of the CO_2, resulting in greater than 95 percent CH_4 in the gas for CNG. The guidelines from the engine manufacturers association define the methane content and sulfide levels. The gas conditioning systems use well-proven technologies to remove the undesired constituents. A typical gas treatment schematic for CNG treatment is presented in Figure 20.

Treatment processes for biogas typically fall into two groups: physical or chemical/biological removal. Water vapor, CO_2, and particulates are removed by physical processes, while VOC, halogenated organics, H_2S, and siloxane compounds are removed by either chemical or biological treatment.

4.5.2.1 Carbon Dioxide

The most commonly used and recommended CO_2 removal treatment is a membrane separation system. The gas is pressurized and the CH_4 is retained on the membrane while the CO_2 passes through as tail gas. Some CH_4 also passes through into the tail gas, which means the gas needs to be flared. This process requires a thermal oxidizer flare since the waste gas does not have a high enough BTU value to be burned in a traditional flare.

4.5.2.2 Summary of Manufacturers

Table 12 summarizes the constituents in the raw biogas and the manufacturers that provide the recommended equipment required to remove them.

Table 12 Summary of Conditioning Equipment Manufacturers

Constituent	Recommended Treatment Method	Removal Equipment Manufacturers
H_2S	Adsorption	Varec, Clean Methane Systems, ESC, Marcab, MV Technologies, Unison, Biorem, Venture
Moisture	Refrigeration	Clean Methane Systems, ESC, Parker, Perennial Energy, Unison, Venture
Siloxane	Adsorption	Clean Methane Systems, ESC, Marcab, Theia Air, Unison, Venture
CO_2	Membrane Separation	Air Liquide, Unison

4.5.2.3 Biogas Storage

Storage for CNG systems is often required due to the constant production of biogas and intermittent fueling periods. For a fast-fill station, high-pressure storage is required in order to have CNG on-demand. A larger amount of storage results in higher utilization, because overnight production can be stored for daytime dispensation (or vice-versa for slow-fill stations). Otherwise, gas would have to be flared when the storage is full. Figure 21 shows an example bank of high pressure storage tubes that would be included for the CNG fueling alternative.

Figure 21 High Pressure Storage Tubes for CNG

A storage vessel or bank of storage vessels containing roughly half of the SBMWD's production, 800 diesel gallon equivalents (DGE), is recommended for the CNG option. This will maximize the utilization of biogas use by storing gas produced during the night and dispense the gas required to fuel the trucks during the day. If the demand at the nearby CNG station for fueling City buses and trash trucks is 6,000 DGE per day this RNG project would cover 30 percent of the daily demand (Table 13). For fueling vehicles on-site at the WRP the current fleet consists of 3 CNG vehicles and in the future up to 10 vehicles, which is still too small to take advantage of the total available CNG volumes. Therefore, either a connection to the City's off-site CNG station, about 1.5 miles away, would be needed to fully utilize the CNG produced at the WRP, or alternatively (and less costly), the City's fleet could be encouraged to come to the filling station at the WRP.

Table 13 Biogas Production Equivalents

Year	Biogas Production, scfd	MMBTU Generated/Day (1)	DGEs/Day	Equivalent Vehicle Miles/Day (2)	DGE/day Demand at CNG station Pershing Ave.	SBMWD Usage DGE/day
2017	417,000	231	1,780	3,560	6,000	<500 (3)
2019	315,000	173	1,335	2,670	6,000	<500 (3)

Notes:
(1) Assumes 550 BTU/cu ft, 129,500 BTU/DGE, and 95 percent efficiency of dual pass biogas conditioning system and 96 percent availability.
(2) Assumes CNG sanitation vehicles achieve a fuel efficiency of 2 miles per DGE.
(3) Assumes future addition of vehicles to total 10 CNG trucks.

4.5.3 Vicinity to City of San Bernardino CNG facility

The City operates a CNG facility located at 187 S. Pershing Ave, San Bernardino, CA 92408. This CNG fueling station was installed in 2007 and is 1.5 Miles north of the WRP. The City provided the following information about equipment and client base:

1. Above Ground Horizontal Tank Capacity: 15,000 gallons.
2. Filling Stations: Two (2) hose 3,000 and 3,600 pounds per square inch (psi) hoses.
3. Future demand: Expandable with an additional 2 filling stations.
4. Client Base:
    a. City of San Bernardino: (Cars, Trucks) Fifty-two (52).
    b. Durham: (School Buses) Forty-seven (47) (Fleet includes 280 buses).
    c. Burrtec (Trash Trucks).
    d. AT&T (Trucks).
    e. Yellow and Bell Cab (Taxi Cars).
    f. CalTrans (Street Sweepers, Trucks).
    g. Global Environmental.
    h. CleanStreet (Street Sweepers).

Figure 22 shows photos of the fueling posts and equipment installed at the existing fueling station. As mentioned, re-directing some of the above client base to a WRP-operated CNG fueling station would benefit both the City and SBMWD.

Figure 22 CNG Fueling Equipment Located on Pershing Ave., San Bernardino

4.5.4 OmniTrans CNG Facility

The OmniTrans CNG Facility located on 599 W. Rialto Ave, San Bernardino, CA 92410 was installed in December 2017 and is equipped with three (3) Compressors to produce an equivalent of 6,500 gallons each day. The client base consists of OmniTrans buses with a fleet of 176 buses.

4.5.5 Sewer Combo and City Truck Fleet

- SBMWD operates the following CNG vehicles:
  - Number of CNG vehicles in the current fleet: 3.
  - Diesel fleet converted to CNG: immediately 1 vehicle and in the future additional: 2-10.

4.5.6 Life Cycle Costs

The life cycle costs include the capital and operating costs for the digester gas upgrading system. An additional cost factor taken into consideration is the missed opportunity to avoid future peak power charges at the wastewater plant, if the digester gas is used for vehicle fueling and not available for electrical power generation onsite. As mentioned above incremental power costs will be a result of the new load coming from the new electric aeration blower and Arrowhead pump (Table 14). The Total 20-Year Net Present Life Cycle Cost for this option was estimated to be $29.3 Million.

Table 14 Net Present Value Summary for Alternative 5 - CNG for Vehicle Fuel

Alternative 5 - CNG for Vehicle Fuel	Cost Estimates
Estimated Project Capital Cost	($7,247,000)
Annual (Costs)/Revenues	
• Cost for Electricity Purchased	($2,178,000)
• Revenue for CNG Sale	$167,000
• Revenue for RIN/LCFS Credits	$94,000
• Natural Gas Costs for Digester Heating	($298,000)
• O&M Costs	($299,000)
20-Year Present Value of (Costs)/Revenues	
• Cost for Electricity Purchased	($26,140,000)
• Revenue for CNG Sale	$2,013,000
• Revenue for RIN/LCFS Credit	$1,329,000
• Natural Gas Costs for Digester Heating	($3,594,000)
• O&M Costs	($3,638,000)
Total 20-Year Net Present Life Cycle Cost	**(29,334,000)**

4.5.7 Schedule and Implementation Plan

The conventional delivery method using a Design, Bid, Build approach is estimated to take up to 2 years for the completion of the project. The project sequence is similar to RNG pipeline project schedule shown above (Figure 17). However, this project does not require an interconnection permit if the filling station remains on the WRP, and less stringent gas quality standards will also help in expediting the project implementation.

4.5.8 Public Private Partnership Feasibility

A number of private companies are offering operations and service agreements for CNG Fueling stations including DG pre-treatment systems. Vendors with active projects in California are DirectCNG and Cornerstone BioCNG. The limiting factor is the client base for the CNG fueling station. As discussed, if the fleet is limited to the vehicles at the WRP, then not all the gas will be utilized. However, working with the City to redirect some clientele to the WRP to obtain CNG could be a win-win situation. Alternatively a pipeline and connection to the existing off-site CNG stations could be considered. However, this approach will add considerable cost (for the pipeline) and add considerable complexity for permitting the gas line outside the WRP property. For private developers the challenge would be the uncertainty of the RFS program set to expire in 2022. A P3 would only be able to get financing for RIN credits valued at $12 per MMBTU for a duration of 5 years.

4.5.9 Incentives for Biogas to Transportation Fuel

The EPA RFS Program and the California LCFS described above apply also for the RNG used in on-site CNG stations.

4.6 Other Alternatives - Digester Gas Conversion to Bioplastics

The Company Newlight, Inc. in Costa Mesa is utilizing digester gas from industrial food processors wastewater plants and transporting the gas in tube trailers to their processing plant in Bakersfield. There the DG is used as a feed substrate in a biological process to convert both CO_2 and methane to biopolymers. However, this option is currently not available for municipal wastewater plants.

Section 5

COMPARISON OF ALTERNATIVES

The following alternatives were evaluated for the WRP based on a preliminary assessment of capital and life cycle costs as well as environmental considerations.

- Alternative 1: Power from DG - Cogeneration (CHP) with pretreatment and post-treatment:
  - This option includes installation of a new gas conditioning system, new engines and new exhaust treatment with SCR and CO catalysts.
- Alternative 2: Power from DG - MTs (CHP) with DG pretreatment:
  - This option includes installation of a new gas conditioning system and addition of the MTs. Now exhaust treatment system is required.
- Alternative 3: Power from DG - Fuel Cells with DG pretreatment:
  - This option includes installation of a new gas conditioning system with Fuel Cells. This option would most likely be provided as part of a Power Purchase Agreement.
- Alternative 4: Conversion of biogas to CNG for pipeline injection:
  - A pipeline injection project includes installation of a new gas conditioning system to convert the plant's biogas into pipeline quality RNG. The RNG would be sold to the market and used to generate and sell renewable credits.
- Alternative 5: Conversion of biogas to CNG for vehicle fueling:
  - A vehicle fueling project includes a new gas conditioning system to convert the plant's biogas into vehicle fuel quality natural gas (CNG) for on-site vehicle fueling. Alternatively, an approximately 1-mile pipeline running from the SBMWD to the existing City CNG station on Pershing could be built to convey the gas.

5.1 Capital Cost Evaluation

Carollo's cost estimating software was utilized to develop capital cost estimates for the alternatives listed above and represents a Class 5 Estimate based on the American Association of Cost Engineering (AACE) classification. Equipment quotes were provided by Unison and DMT, manufacturers of gas conditioning and CNG upgrading systems.

Capital costs presented herein are escalated to the mid-point of construction (assumed to be middle of 2019). Assumptions and allowances for the capital costs are presented in Table 15 and are based on total direct costs.

Table 15 Design Criteria and Financial Assumptions

Criteria	Assumption Used
Escalation rate per year	3%
Contractor General Conditions	15%
Contingency	30%
General Contractor Overhead, Profit	15%
Engineering, Legal, and Administrative Fees	15%

5.2 Life Cycle Cost Evaluation

A life cycle cost for five options was developed, which evaluated the costs and revenues for each option over the estimated life of the equipment (assumed to be 20 years).

To evaluate the benefits and costs of each alternative, the projected capital cost, O&M costs, and anticipated revenues were calculated. The total 20-year net present value was then calculated for each alternative. A summary table presenting the life cycle cost for each alternative is shown in Table 16. **Note that all of the 20-year Net Present Value life cycle costs are negative, meaning that none of these projects will pay for themselves**. Detailed project cost estimates are provided in Appendix B.

The 20-year Life Cycle costs for the Fuel Cell option under a PPA is based on an electrical power purchase rate of 8.5 cents per kWh provided by FCE and will need to be confirmed and negotiated. The capital costs for the Fuel Cell under a PPA will require SBMWD to add a DG holder to provide a continuous feed flow rate to the fuel cell and the project costs are included in Table 16. The rate under the PPA option might include SGIP grants from SCE, which is possibly the reason that the power purchase rate is at 8.5 cents per kWh. It should be noted that potential benefits from SGIP grants are also possible for the other options but were not taken into consideration in this analysis.

The capital costs savings for using the existing Waukesha engines and retrofitting them with SCR are estimated to be $4,000,000. However, assuming the existing engines efficiency of 33%, the NPV cost of reusing the existing engines will only be about $2 million lower than the new cogeneration engines; approximately $24.5 million. In addition, other SGIP grants and incentives may result in additional savings.

Table 16 Project Costs and Net Present Value for Alternatives

Alternative	Project Costs ($)	20-Year Net Present Life Cycle Costs ($)
0. Flaring	2,077,000	(27,778,000)
1. Cogeneration - ICE with SCR	12,450,000	(26,488,000)(2)
2. Cogeneration - MT	11,500,000	(30,492,000)
3. Cogeneration - Fuel cells	1,937,000(1)	(23,402,000)
4. Pipeline Injection	10,556,000	(29,902,000)
5. CNG Vehicle Fuel	7,247,000	(29,327,000)

Notes:
(1) No capital costs were provided, but power purchase rates under a PPA. The project costs include project costs for the addition of a DG holder
(2) Cost is expected to drop by about $2 million if existing engines are used at an assumed efficiency of 33% and a remaining life of 20-years

5.3 Maximum Average Cost Effectiveness for NOx Reduction (AQMD)

The Maximum Average Cost Effectiveness for NOx abatement was used as a baseline per Table 5 in Part C of the Best Available Control Technology (BACT) Guidelines and this value is $27,359 per ton (based on 1st Quarter 2017 Marshall and Swift equipment index). SCAQMD stated in the 2016 Air Quality Management Plan or (AQMP) that cost effectiveness for emission reductions from non-refinery flares and related beneficial use projects was estimated to be less than $20,000 per ton of NOx and VOC's removed.

NOx Emissions for each alternative are listed in Table 17. MTs have low NOx concentrations, but the exhaust gas flow rates are much higher compared to ICEs. The daily NOx mass emissions are therefore higher for the MT compared to an ICE (without SCR). Digester gas conversion to CNG for truck fueling or for RNG pipeline injection has the lowest NOx emissions costs of all options considered.

Table 17 NOx Emissions for Each Alternatives

Alternative	Exhaust Gas Flow (scfm)	NOx (ppm)	NOx (ppd)	NOx (tons per year)
0. Existing Cogeneration ICE	2,183	30	11.28	2.06
1. Cogeneration - ICE with SCR	2,183	9	3.38	0.6
2. Cogeneration - MT	10,892	9	16.89	3.08
3. Cogeneration - Fuel cells	2,895	0.3(2)	0.19	0.034
4. Pipeline Injection	-	N/A(1)	N/A(1)	N/A(1)
5. CNG Vehicle Fuel	-	N/A(1)	N/A(1)	N/A(1)

Notes:
(1) Emissions in vehicles off-site will vary depending on type of vehicles and engines.
(2) Calculatations based on Manufacturers Data Sheet for 1.4 MW; NOx Emissions = 0.01 lb/MW/h.

5.4 Non-economic Considerations

Other non-economic considerations not included in this section such as public acceptance, noise, visual impacts or Environmental Justice concerns and permitting issues will be discussed and considered as part of the Final Report.

5.4.1 Greenhouse Gas Emissions

GHG emission reduction can come from directly reducing GHG emissions by consuming less, or from increasing GHG offsets, which provide a positive contribution to net GHG emissions. Quantifying GHG emissions allows utilities the opportunity to plan the most cost-effective means of managing and reducing GHG emissions (or increasing offsets) while minimizing fossil fuel-based energy use and maximizing resource recovery.

Six GHGs have been prioritized for GHG inventory purposes, based on each gas' capacity to absorb and reradiate heat, and thus contribute to climate change. These GHGs include CO_2, CH_4, nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6). Of these, CO_2, CH_4, and N_2O are considered relevant for wastewater treatment emissions and are the focus of the inventory. To account for the variation in the ability for each gas to absorb and reradiate heat, Global Warming Potentials (GWP) is used to relate gases to CO_2 on a mass basis (e.g., carbon dioxide equivalence or CO_2e). An assumption of the time horizon must be made to generate meaningful emissions estimates when selecting GWPs. The typical time horizon selected is 100 years. Based on this time horizon, CH_4 and N_2O are estimated to have 25 and 298 times the capacity to absorb and reradiate heat relative to CO_2, respectively. In addition to the GWPs, a combination of widely accepted, peer-reviewed protocols and emission factors were used to estimate the GHG emissions, as summarized in Table 18.

Table 18 Factors Used to Calculate GHG Emissions from Biogas Production and Reuse

Description	Units	Value	Source
Biogas LHV	BTU/scf	570	SBMWD
Average Natural Gas HHV	BTU/scf	1,060	U.S. Energy Information Administration, 2015
Biogas Combustion	kg CO_2/MMBTU	52.07	40 CFR 98.33 and Subpart C
	kg CH_4/MMBTU	0.0032	
	kg N_2O /MMBTU	0.00063	
Natural Gas Combustion	kg CO_2/MMBTU	53.06	40 CFR 98.33 and Subpart C
	kg CH_4/MMBTU	0.001	
	kg N_2O /MMBTU	0.0001	
DGEs	BTU/DGE	129,500	NAFA Fleet Management Association, 2010

Notes:
Abbreviations: kg – kilograms.

GHG emissions and offsets were evaluated for the RNG (pipeline) and CNG station options described above and compared against the project baseline. The project DG used for heat provides an offset of 1,539 metric tons of CO_2e annually. Repurposing biogas to fuel vehicles increases GHG offsets to 5,386 metric tons of CO_2e annually. If the biogas is sent to pipeline injection, GHG emission offsets increase even further to 6,855 metric tons of CO_2e per year. A comparison of these offsets is shown in Figure 23.

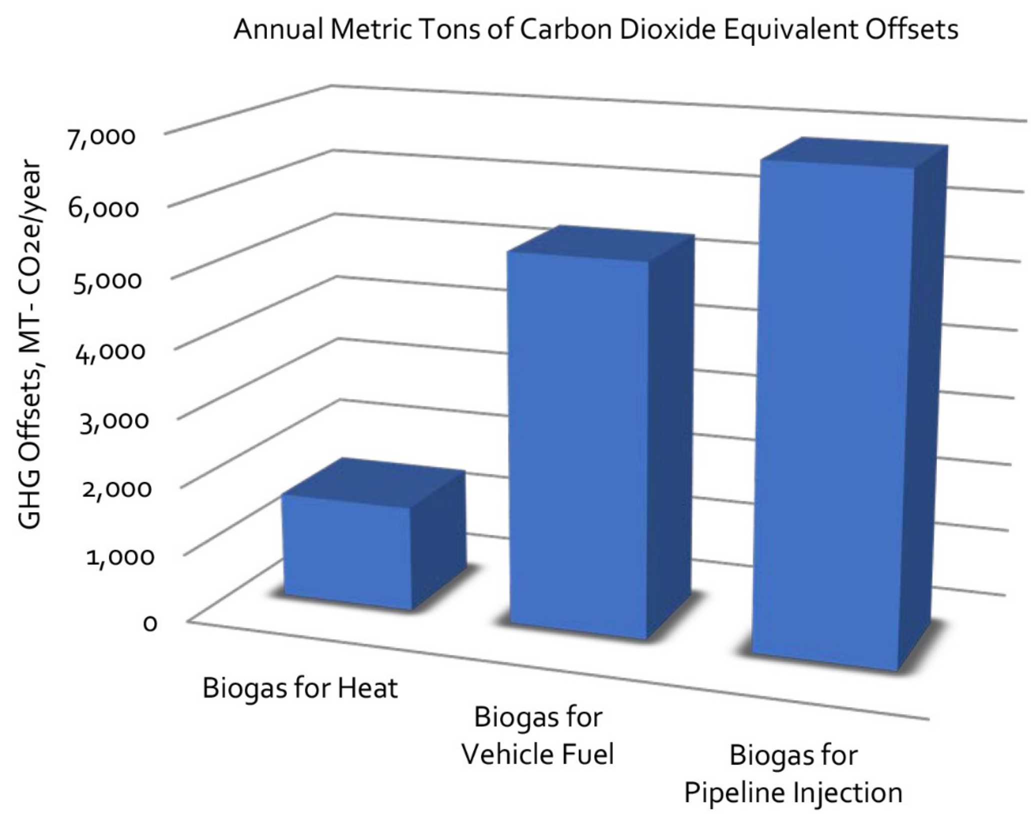


Figure 23 GHG Offsets Based on Type of Project

5.4.2 Advantages and Disadvantages

The alternatives were evaluated against the project goals and selected non-economic criteria to determine the best fit for the SBMWD. Table 19 presents non-economic advantages and disadvantages for each alternative.

Table 19 Non-Economic Comparison of Alternatives

Alternative	Advantages	Disadvantages
Cogeneration with ICEs	• Highest operational experience. • PPA arrangement is feasible.	• High life cycle costs for new plant. • Requires DG pre-treatment and exhaust treatment (SCR and CO).
Cogeneration with MTs	• Lower capital costs. • Lower emissions - no exhaust treatment is required. • PPA arrangement is feasible.	• Limited local operational experience at Wastewater plants. • Derating at high ambient temperatures and lower electrical efficiency. • Shorter life span.
Cogeneration with FCs	• Lowest emission technology supported by AQMD • Life cycle cost manageable under a PPA arrangement. • P3 arrangement is feasible.	• Limited operational success and only under certain conditions. • Only to be considered under a PPA arrangement.
Conversion of Biogas to CNG for Pipeline Injection	• Development of renewable energy product. • Higher utilization of biogas as compared to vehicle fueling.	• Project risks associated with pipeline routing off-site. • Requires higher DG volumes to be feasible. • More stringent gas quality requirements as compared to vehicle fueling.
Conversion of Biogas to CNG for Vehicle Fueling	• Development of renewable energy product. • Creation of a regional partnership to benefit members of the community.	• Project risks associated with pipeline routing off-site. • Project risks associated with marketing the CNG or contracting with other entity for DG sale.

Table 20 includes the Ranking Score for each Alternative based on a low point score of 0 points and the highest ranking with 5 points. The weighted total for both IC Engines and Fuel Cells (PPA) are the same, but as mentioned above, the Fuel Cell (PPA) approach may have included some benefit from available incentives, resulting in a lower overall 20-year Life Cycle Cost, which were not applied to the other alternatives. Details of the make-up of the PPA cost would be available during negotiations with the supplier if this alternative is selected as the preferred approach for the Department.

Table 20 Advantages and Disadvantages for Each Alternative

	Scoring (0 - 5, low to high benefit)				
Criteria/Alternatives	**IC Engines with SCR**	**MTs**	**Fuel Cells (PPA)**	**RNG pipeline**	**CNG onsite fueling**
NOx emissions (tons/year)	2.06 (3)	2.8 (2)	0.19 (5)	0 (5)	0 (4)
20-year Life Cycle Costs (million)	$26.5 (3)	$30.5 (0)	$23.4 (4)	$30 (0)	$34 (0)
Operational Experience and Success rate	high (4)	variable (2)	only with PPA (1)	growing (1)	growing (3)
Weighted Total	**10**	**4**	**10(1)**	**6**	**7**
Suitability for P3	yes (4)	yes (4)	yes (5)	no (0)	yes (2)
Flare Rule > 85% beneficial use requirement met	(5)	(4)	(5)	(5)	limited demand (1)
Electrical/Conversion Efficiency	Medium (2)	Low (1)	Higher (3)	High (4)	High (4)
Capital Costs (million)	$12.5 (1)	$11.5 (2)	$1.9 (5)	$10.5 (2)	$7.2 (3)

Note:
(1) The rate under the PPA option might include SGIP grants from SCE, which were not taken into consideration for the ICE & SCR option.

5.4.3 Meeting with AQMD

During the meeting with AQMD to discuss the preliminary findings of this study, Staff encouraged SBMWD to consider the technology with the lowest emissions. For the Fuel Cell option AQMD wanted to make sure, that all possible vendors had been appropriately considered. The selection of a Fuel Cell technology with lowest emissions would prompt the need for financial incentives for the continued operational success of this technology or to demonstrate the newest developments in Fuel Cell technologies operating on DG. AQMD staff highlighted the availability of grants and their support for such a project.

Section 6

CONCLUSIONS

For the CNG and Pipeline Gas alternatives the economic evaluations can only be based on current incentives and this takes into consideration the possible expiration of the RIN's after the year 2022. It should be noted, that upcoming legislative changes in favor of biomethane projects are underway in California with ARB extending the LCFS credits so that the LCFS credit were applied in this model. Based on communication with a Gas Company Representative additional support is expected through SB-1440, which would require that utilities purchase biomethane from wastewater plants or dairy digesters. The Gas Company noted more interest in RNG pipeline injection projects, but a pipeline injection project of this size with less than 1 million cu ft per day would not be economically viable.

Therefore, based on the current legislative conditions and considering the expected increase in power demand and electricity bills at the WRP the power cogeneration alternatives appear to be more financially attractive.

During the meeting with AQMD, Staff encouraged SBMWD to consider the technology with the lowest emissions. The selection of a Fuel Cell technology with lowest emissions would prompt the need for financial incentives for the successful and on-going operation of this technology. AQMD highlighted the availability of grants and incentives.

After evaluating both economic and non-economic considerations, including the more heavily weighted NOx emissions reduction and life cycle costs, it is concluded that SBMWD consider power generation using a Fuel Cell under a PPA, if the rate provided by the vendor can be confirmed. Otherwise, Internal Combustion Engines with SCRs would be ranked as the next most economically favorable alternative. Such a project could be implemented either through a SBMWD project or through a Public Private Partnership (under a PPA).

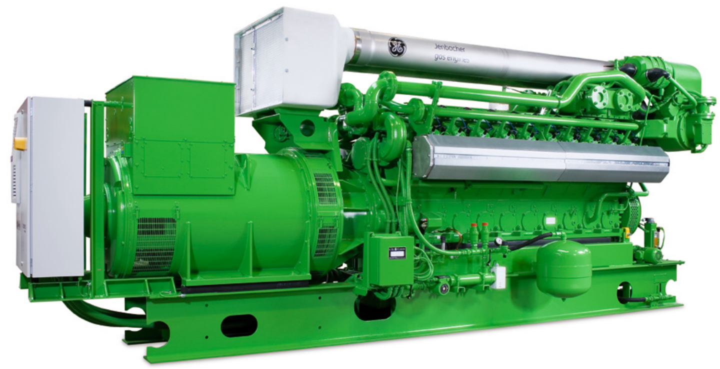
The PPA route would reduce the risk associated with the operation of the gas treatment skid and would protect the investment in the cogeneration plant. It would also allow for a quicker project implementation schedule compared to a conventional Design, Bid, Build approach. However, this risk is offset somewhat by the potential for the P3 provider to discontinue business and leave SBMWD without a means of treating its DG. In this case AQMD staff would potentially be able to be flexible or provide support for the success of the DG project.

Any potential new gas conditioning skid and cogeneration plants could be installed to the West of the current digesters and cogeneration engine room.

Appendix A

EQUIPMENT DATA SHEETS

Jenbacher type 3



Efficient, durable, reliable

Long service intervals, maintenance-friendly engine design and low fuel consumption ensure maximum efficiency in our type 3 engines. Enhanced components prolong service life even when using non-pipeline gases such as landfill gas. The new type 3D generation offers an outstanding service interval with up to 80,000 operating hours until the major overhaul. This engine type stands out in its 400 to 1,100 kW power range due to its technical maturity and high degree of reliability.

Reference installations

J312 Containerized solution Landfill site; Cavenago, Italy

Fuel	Engine type	Electrical output	Thermal output	Commissioning
Landfill gas	2 x J312	1,202 kW	5,102 MBTU/hr	09/1999

Every system has its own landfill gas feeder line and exhaust gas treatment line. The generated electricity is used on-site, excess power is fed into the public grid. The employment of the CL.AIR* system ensures the purification of the exhaust gas to meet stringent Italian emission requirements. As a special feature, at this plant the thermal energy is used for landfill leachate treatment, as well as for greenhouse heating.

J316 Profusa, producer of coke; Bilbao, Spain

Fuel	Engine type	Electrical output	Thermal output	Commissioning
Coke gas and natural gas	12 x J316	5,642 kW (a), 6,528 kW (b)	-	11/1995

a) with coke gas b) with 60 % coke gas and 40 % natural gas, or 100 % natural gas

This installation designed by GE's Jenbacher product team enables Profusa to convert the residual coke gas with a hydrogen content of approximately 50 % into valuable electrical energy. Beginning 2008, the 12 engines reached a combined total of one million operating hours.

J320 Ecoparc I; Barcelona, Spain

Fuel	Engine type	Electrical output	Thermal output	Commissioning
Biogas and natural gas	5 x J320	5,240 kW	10,040 MBTU/hr (a) 10,263 MBTU/hr (b)	12/2001 to 01/2002

a) with biogas b) with natural gas

In Ecoparc I, organic waste is processed into biogas, which serves as energy source for our gas engines. The generated electricity is used on-site as well as fed into the public power grid. A portion of the thermal energy is used as process heat in the digesters, and the excess heat is bled off in the air coolers.

J320 Amtex Spinning Mills; Faisalabad, Pakistan

Fuel	Engine type	Electrical output	Thermal output	Commissioning
Natural gas	12 x J320	12,072 kW	-	11/2002 (a), 04/2003 (b), 03/2003 (c), 04/2004 (d), 04/2005 (e), 03/2008 (f)

a) 1st–2nd engine b) 3rd engine c) 4th–7th engine d) 8th engine e) 9th, 10th engine f) 11th, 12th engine

The natural gas-driven units generate electricity for spinning mills in one of Pakistan's most important textile centers. Special features of this Jenbacher plant allow for high ambient temperature, dusty inlet air, and operation in island mode.

Technical data

Configuration	V 70°
Bore (inch)	5.31
Stroke (inch)	6.69
Displacement / cylinder (cu.in)	148.5
Speed (rpm)	1,800 (60 Hz)
Mean piston speed (in/s)	402
Scope of supply	Generator set, cogeneration system, generator set / cogeneration in container
Applicable gas types	Natural gas, flare gas, propane, biogas, landfill gas, sewage gas. Special gases (e.g., coal mine gas, coke gas, wood gas, pyrolysis gas)

Engine type	J312	J316	J320
No. of cylinders	12	16	20
Total displacement (cu.in)	1,782	2,376	2,970

Dimensions l x w x h (inch)		
Generator set	J312	190 x 70 x 90
	J316	210 x 70 x 90
	J320	230 x 70 x 100
Cogeneration system	J312	190 x 90 x 90
	J316	210 x 90 x 90
	J320	230 x 80 x 90
Container	J312	480 x 100 x 110
	J316	480 x 100 x 110
	J320	480 x 100 x 110

Weights empty (lbs)		
Generator set	J312	18,740
	J316	22,490
	J320	29,770
Cogeneration system	J312	21,830
	J316	24,910
	J320	30,870

Outputs and efficiencies

Natural gas	**1,800 rpm | 60 Hz**					
NOx <	**Type**	**Pel (kW)[1]**	**ηel (%)[1]**	**Pth (MBTU/hr)[2]**	**ηth (%)[2]**	**ηtot (%)**
1.0 g/bhp.hr	J312	633	38.1	2,837	50.0	88.1
	J316	849	38.3	3,796	50.2	88.5
	J320	1,062	39.1	4,658	50.3	89.4
0.5 g/bhp.hr	J312	633	36.8	3,053	51.9	88.7
	J316	849	37.0	4,047	51.6	88.6
	J320	1,062	38.2	4,836	51.0	89.2

Biogas	**1,800 rpm | 60 Hz**					
NOx <	**Type**	**Pel (kW)[1]**	**ηel (%)[1]**	**Pth (MBTU/hr)[2]**	**ηth (%)[2]**	**ηtot (%)**
1.0 g/bhp.hr	J312	633	38.1	2,764	48.8	86.9
	J316	849	38.3	3,699	48.9	87.3
	J320	1,062	39.1	4,507	48.6	87.8
0.6 g/bhp.hr	J312	633	36.8	2,934	49.9	86.7
	J316	849	37.0	3,914	49.9	86.9
	J320	1,062	37.0	4,951	50.5	87.5

1) Technical data according to ISO 3046
2) Total heat output with a tolerance of +/- 8 %, exhaust gas outlet temperature 120°C, for biogas gas outlet temperature 180°C

All data according to full load and subject to technical development and modification.

Further engines versions available on request.

Find your local support online:
www.gepower.com/distributedpower

GEA-32390US

C1000S Megawatt Power Package

Digester Gas

The Signature Series Microturbine provides 1MW of reliable electrical power in one small, ultra-low emission, and highly efficient package.

- Ultra-low emissions
- Accepts sour gas fuels with up to 5,000 ppm H_2S
- One moving part – minimal maintenance and downtime
- Patented air bearings – no lubricating oil or coolant
- Integrated utility synchronization – no external switchgear
- Compact modular design allows for easy, low-cost installation
- High electrical efficiency over a very wide operating range
- High availability – part load redundancy
- Remote monitoring and diagnostic capabilities
- Proven technology with tens of millions of operating hours
- Various Factory Protection Plans available

C1000S Power Package

Electrical Performance[1]

Electrical Power Output	1000kW
Voltage	400/480 VAC
Electrical Service	3-Phase, 4 Wire Wye
Frequency	50/60 Hz
Electrical Efficiency LHV	33%

Fuel/Engine Characteristics[1]

Digester Gas HHV	20.5–32.6 MJ/m^3 (550–875 BTU/scf)
H_2S Content	<5,000 ppm
Inlet Pressure	517–551 kPa gauge (75–80 psig)
Fuel Flow HHV	12,000 MJ/hr (11,400,000 BTU/hr)
Net Heat Rate LHV	10.9 MJ/kWh (10,300 BTU/kWh)

Exhaust Characteristics[1]

NOx Emissions @ 15% O_2	< 9 ppmvd (18 mg/m^3)
Exhaust Mass Flow	6.7 kg/s (14.7 lbm/s)
Exhaust Gas Temperature	280°C (535°F)

Dimensions & Weight[2]

Width x Depth x Height[3]	3.0 x 9.1 x 2.9 m (117 x 360 x 114 in)
Weight - Grid Connect Model	17,100 kg (37,700 lbs)
Weight - Dual Mode Model	20,650 kg (45,500 lbs)

Reliable power when and where you need it. Clean and simple.

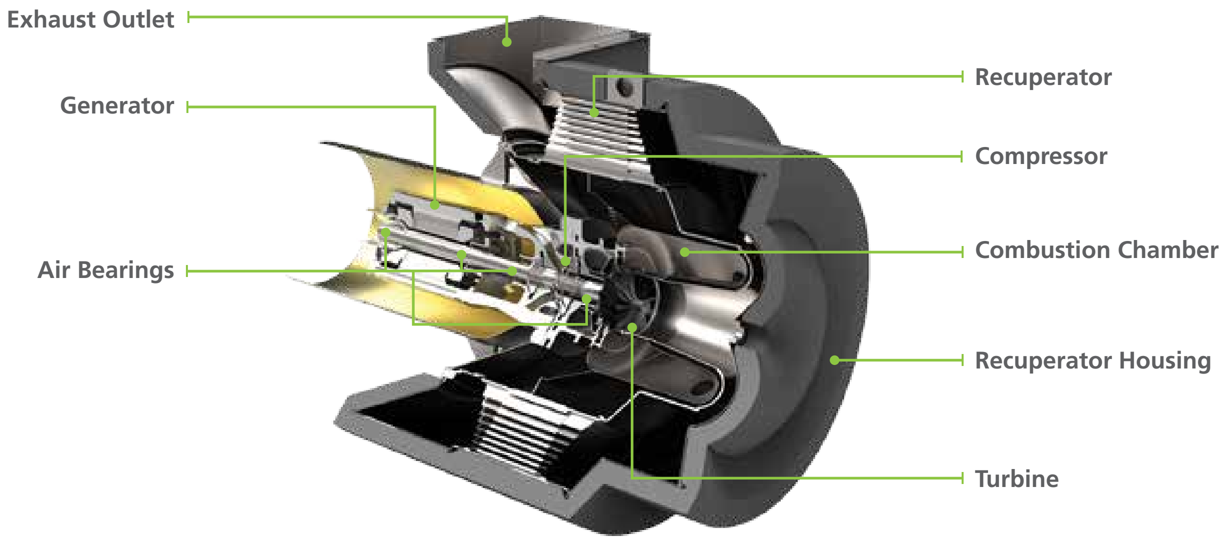
Minimum Clearance Requirements[4]

Horizontal Clearance	
Left	1.5 m (60 in)
Right	0.0 m (0 in)
Front	1.7 m (65 in)
Rear	2.0 m (80 in)

Certifications

- UL 2200 Listed
- CE Certified
- Certified to the following grid interconnection standards: UL 1741, VDE, BDEW and CEI 0-16
- Compliant to California Rule 21

C200 Engine Components



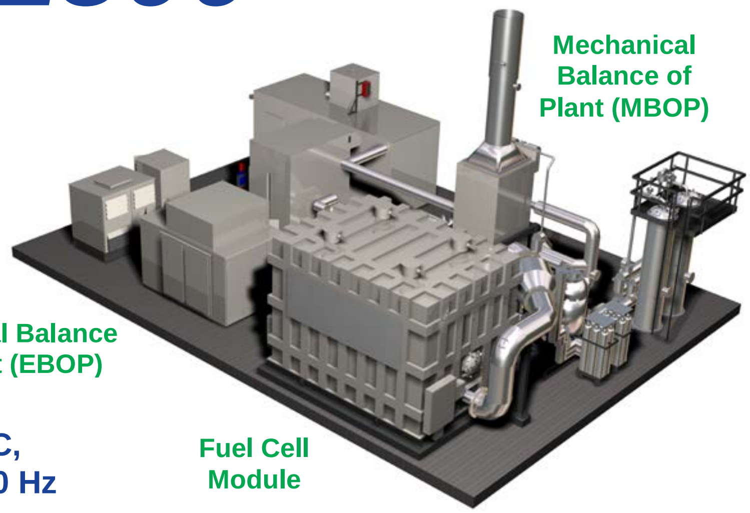
(1) Nominal full power performance at ISO conditions: 15˚C (59˚F), 14.696 psia, 60% RH
(2) Approximate dimensions and weights
(3) Height dimensions are to the roofline. Exhaust outlet extends at least 127 mm (5 in) above the roofline
(4) Clearance requirements may increase due to local code considerations
Specifications are not warranted and are subject to change without notice.

SureSource 1500

1.4 MEGAWATTS

KEY FEATURES

- Continuous Power
- Highly Efficient
- Fuel Flexible
- Ultra-Clean
- Scalable
- Modest Footprint
- Quiet Operation



APPLICATIONS

Featuring ultra-low emissions, quiet operation and minimal space requirements (about the size of a tennis court), the SureSource 1500 is suitable for locations where combustion-based traditional power generation technologies are not feasible or desirable such as next to buildings or in space-constrained urban locations. This solution is ideal for on-site power generation for large installations requiring continuous power and value high-quality steam for facility heating and/or absorption chilling; including industrial facilities, hospitals, universities and wastewater treatment plants.

PERFORMANCE

Gross Power Output	
Power @ Plant Rating	1,400 kW
Standard Output AC voltage	480 V
Standard Frequency	60 Hz
Optional Output AC Voltages	By Request
Optional Output Frequency	50 Hz

Efficiency	
LHV	47 +/- 2 %

Available Heat	
Exhaust Temperature	700 +/- 50 ºF
Exhaust Flow	18,300 lb/h
Allowable Backpressure	5 iwc

Heat Energy Available for Recovery	
(to 250 ºF)	2,216,000 Btu/h
(to 120 ºF)	3,730,000 Btu/h

Fuel Consumption	
Natural gas (at 930 Btu/ft3)	181 scfm
Heat rate, LHV	7,260 Btu/kWh

Water Consumption	
Average	4.5 gpm
Peak during WTS backflush	15 gpm

Water Discharge	
Average	2.25 gpm
Peak during WTS backflush	15 gpm

Pollutant Emissions	
NOx	0.01 lb/MWh
SOx	0.0001 lb/MWh
PM10	0.00002 lb/MWh

Greenhouse Gas Emissions	
CO2	980 lb/MWh
CO2 (with waste heat recovery)	520-680 lb/MWh

Sound Level	
Standard	72 dB(A) at 10 feet

SPECIFICATIONS
SureSource 1500

WEIGHTS

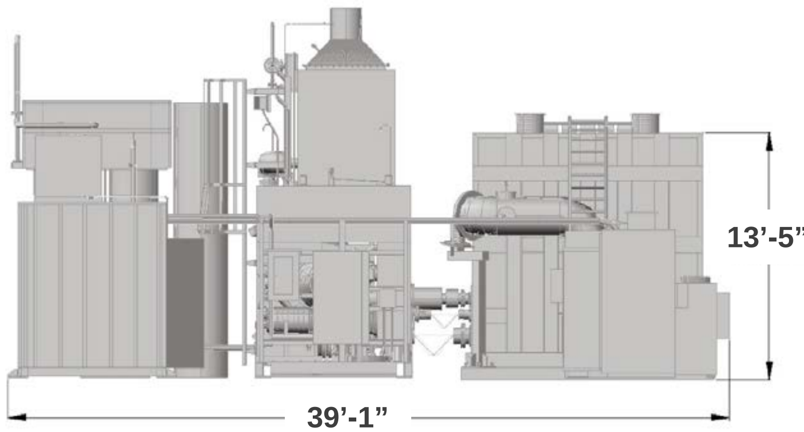
Water Treatment Skid
20,000 lb

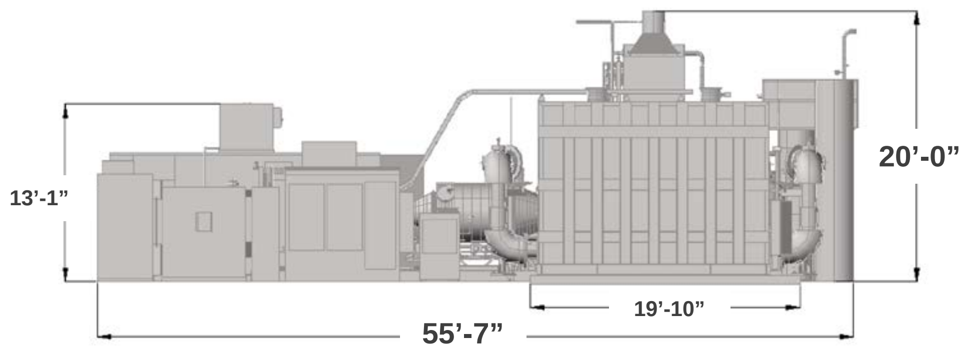
Main Process Skid
50,000 lb

Desulfurization
15,000 lb

Electrical Balance of Plant
26,500 lb

Fuel Cell Module
107,000 lb





ABOUT FUELCELL ENERGY

FuelCell Energy (NASDAQ: FCEL) delivers efficient, affordable and clean solutions for the supply, recovery and storage of energy. We design, manufacture, undertake project development, install, operate and maintain megawatt-scale fuel cell systems, serving utilities, industrial and large municipal power users with solutions that include both utility-scale and on-site power generation, carbon capture, local hydrogen production for transportation and industry, and long duration energy storage. With SureSource installations on three continents and millions of megawatt hours of ultra-clean power produced, FuelCell Energy is a global leader with environmentally responsible power solutions.

Vehicle Fuel Systems

Vehicle Fuel Systems

BioCNG™
Vehicle fuel for a green future

Unison Solutions is the co-inventor of a biogas conditioning system that economically produces BioCNG, a biogas based fuel to power vehicles designed for compressed natural gas (CNG). This fuel is approximately 95% methane and meets SAE J1616 fuel specifications.

How does it work?

- Biogas is piped to the BioCNG system from the landfill or anaerobic digester
- Hydrogen Sulfide (H_2S), Moisture (H_2O), Siloxanes, Volatile Organic Compounds (VOC) and Carbon Dioxide (CO_2) are removed
- Fuel is routed to a CNG fueling system and compressed for use in CNG vehicles

Model	Biogas Inlet Flow (scfm)	Fuel Production (GGE/day)	Fuel Production (DGE/day)
BioCNG 50	50	185-300	160-260
BioCNG 100	100	370-600	320-520
BioCNG 200	200	740-1200	640-1040
BioCNG 400	400	1480-2400	1280-2080

Appendix B

CAPITAL COST ESTIMATES

Engineers...Working Wonders With Water®

PROJECT SUMMARY

Project:	**Biogas Use Applications**	**Estimate Class:**	**5**
Client:	**San Bernardino MWD**	**PIC:**	**GJG**
Location:	**San Bernardino, CA**	**PM:**	**RD**
Zip Code:	**92408**	**Date:**	**March 2018**
Carollo Job #	**11036A.00**	**By:**	**CT**
		Reviewed:	**RD**

NO.	DESCRIPTION	TOTAL
01	Internal Combustion Engines and SCR	$12,456,593
02	Microturbine	$11,461,169
03	PPA (Digester Gas Holder)	$1,936,573
04	RNG to Pipeline	$10,556,317
05	Vehicle Fueling with on-site CNG Station	$7,247,471
0	Flaring	$2,076,090

The cost estimate herein is based on our perception of current conditions at the project location. This estimate reflects our professional opinion of accurate costs at this time and is subject to change as the project design matures. Carollo Engineers have no control over variances in the cost of labor, materials, equipment; nor services provided by others, contractor's means and methods of executing the work or of determining prices, competitive bidding or market conditions, practices or bidding strategies. Carollo Engineers cannot and does not warrant or guarantee that proposals, bids or actual construction costs will not vary from the costs presented as shown.

DETAILED COST ESTIMATE

Project: Biogas Use Applications
Client: San Bernardino MWD
Location: San Bernardino, CA
Element: 0 Flaring

Date : March 2018
By : CT
Reviewed: RD

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	700	CY	$9.40	$6,577	
	Total					**$6,577**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	100	CY	$339	$33,938	
	Total					**$33,938**
	Division 11 - Equipment					
11000	Flare enclosed	1	EA	$550,000	$550,000	
	Auxiliiary			$94,000	$94,000	
	Total					**$644,000**
	Division 15 - Mechanical					
15267	Piping	20%	LF	$644,000	$128,800	
	Total					**$128,800**
	Division 16 - Electrical					
16000	EI&C Allowance	20%	% Div 11	$772,800	$154,560.00	
	Total					**$154,560**
	Contingency	30%	EA	$967,874	$290,362.29	
	General Contractor Overhead, Profit, and Risk	15%	EA	$967,874	$145,181	
	Escalation to Mid-Point (2018)	5%	EA	$967,874	$48,394	
	General Conditions	15%	EA	$967,874	$145,181.15	
	Total Estimated Construction Cost					**$1,596,993**
	Engineering, Legal, and Administrative Fees	30%	EA	$1,596,993	$479,097.78	
	Total Project Cost					**$2,076,090**

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DETAILED COST ESTIMATE

Project: Biogas Use Applications
Client: San Bernardino MWD
Location: San Bernardino, CA
Element: 01 Internal Combustion Engines with SCR

Date : March 2018
By : CT
Reviewed: RD

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	2,000	CY	$9.40	$18,790	
	Total					**$18,790**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	2,500	CY	$339	$848,443	
	Total					**$848,443**
	Division 11 - Equipment					
11000	DG Treatment for H2S	1	EA	$1,200,000	$1,200,000	
11000	Jenbacher Engines 3 Series 848 kW	2	EA	$950,000	$1,900,000	
11000	SCR Exhaust Gas Treatment (JM)	2	EA	$250,000	$500,000	
11000	Auxilliary	1	EA	$200,000	$200,000	
	Total					**$3,800,000**
	Division 15 - Mechanical					
15267	Piping	20%	LF	$3,800,000	$760,000	
	Total					**$760,000**
	Division 16 - Electrical					
16000	EI&C Allowance	20%	% Div 11	$4,560,000	$912,000.00	
	Total					**$912,000**
	Contingency	30%	EA	$6,339,233	$1,901,769.91	
	General Contractor Overhead, Profit, and Risk	15%	EA	$6,339,233	$950,885	
	Escalation to Mid-Point (2018)	5%	EA	$6,339,233	$316,962	
	General Conditions	15%	EA	$6,339,233	$950,884.96	
	Total Estimated Construction Cost					**$10,459,735**
	Engineering, Legal, and Administrative Fees	30%	EA	$6,656,195	$1,996,858.41	
	Total Project Cost					**$12,456,593**

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DETAILED COST ESTIMATE

Project: Biogas Use Applications
Client: San Bernardino MWD
Location: San Bernardino, CA
Element: 02 Microturbine

Date : March 2018
By : CT
Reviewed: RD

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	700	CY	$9.40	$6,577	
	Total					**$6,577**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	280	CY	$339	$95,026	
	Total					**$95,026**
	Division 11 - Equipment					
11000	DG Treatment for H2S	1	EA	$1,500,000	$1,500,000	
11000	Capstone Microturbine 1000 kW	1	EA	$1,540,000	$1,540,000	
11000	Heat Recovery	1	EA	$500,000	$500,000	
11000	Auxilliary	1	EA	$100,000	$100,000	
	Total					**$3,640,000**
	Division 15 - Mechanical					
15267	Piping	20%	LF	$3,640,000	$728,000	
	Total					**$728,000**
	Division 16 - Electrical					
16000	EI&C Allowance	20%	% Div 11	$4,368,000	$873,600.00	
	Total					**$873,600**
	Contingency	30%	EA	$5,343,202	$1,602,960.66	
	General Contractor Overhead, Profit, and Risk	15%	EA	$5,343,202	$801,480	
	Escalation to Mid-Point (2018)	5%	EA	$5,343,202	$267,160	
	General Conditions	15%	EA	$5,343,202	$801,480.33	
	Total Estimated Construction Cost					**$8,816,284**
	Engineering, Legal, and Administrative Fees	30%	EA	$8,816,284	$2,644,885.08	
	Total Project Cost					**$11,461,169**

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DETAILED COST ESTIMATE

Project: Biogas Use Applications
Client: San Bernardino MWD
Location: San Bernardino, CA
Element: 03 Digester Gas Holder for Fuel Cell

Date : March 2018
By : CT
Reviewed: RD

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	600	CY	$9.40	$5,637	
	Total					**$5,637**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	290	CY	$339	$98,572	
	Total					**$98,572**
	Division 11 - Equipment					
11000	DG Holder Dystor 90 ft (incl. controls, fans, anchors, safety equipm)	1	EA	$550,000	$550,000	
11000	Auxilliary	1	EA	$50,000	$50,000	
	Total					**$600,000**
	Division 15 - Mechanical					
15267	Piping	20%	LF	$600,000	$120,000	
	Total					**$120,000**
	Division 16 - Electrical					
16000	EI&C Allowance	20%	% Div 11	$720,000	$144,000.00	
	Total					**$144,000**
	Contingency	30%	EA	$962,572	$288,771.62	
	General Contractor Overhead, Profit, and Risk	15%	EA	$962,572	$144,386	
	Escalation to Mid-Point (2018)	5%	EA	$962,572	$48,129	
	General Conditions	15%	EA	$962,572	$144,385.81	
	Total Estimated Construction Cost					**$1,489,672**
	Engineering, Legal, and Administrative Fees	30%	EA	$1,489,672	$446,901.56	
	Total Project Cost					**$1,936,573**

QUANTITY TAKEOFF WORKSHEET

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Project: Biogas Use Applications
Client: San Bernardino MWD
Location: San Bernardino, CA
Zip Code: 92408
Element: 04 Pipeline Injection

Date: March 2018
By : CT
Reviewed: RD

SPEC NO.	DRAWING # / DESCRIPTION	# of PLACES	Resulting UNIT	LENGTH in Feet	WIDTH, HEIGHT or DEPTH	THICKNESS in Feet	DIAMETER in Feet	LBS per LF	TOTAL QTY		NOTES	Item No. (Carollo Code)
DIVISION 02												
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	1.00	CY	90.00	55.00	3.00			550.00	CY		0230021009
DIVISION 03												
03300	8" Flat Non-Formed S.O.G.	1.00	CY	85.00	45.00	0.67			94.92	CY		0330020009
DIVISION 11												
11000	BioCNG 400 DP	1.00	EA						1.00	EA		11000XX007
11000	BioCNG Control Panel	1.00	EA						1.00	EA		11000XX003
11000	BioCNG 400 DP Winterization	1.00	EA						1.00	EA		11000XX009
11000	BioCNG Thermal Oxidizing Flare	1.00	EA						1.00	EA		11000XX011
11000	RNG Quality Monitoring Equipment	1.00	EA						1.00	EA		11000XX013
DIVISION 15												
15286	6" Sch 40S Buttwelded 316L Sst Pipe In A Bldg To 12' Ht.	1.00	LF	200.00					200.00	LF		1528680003
15267	4" Sdr 11 Hdpe Pipe In Open Trench	1.00	LF	2,500.00					2,500.00	LF		1526711007
DIVISION 16												
16000	EI&C Allowance	1.00	EA						1.00	EA		16000XX001
ADD ON												
17000	Contingency	1.00	EA						1.00	EA		17000XX001
17000	General Contractor Overhead, Profit, and Risk	1.00	EA						1.00	EA		17000XX003
17000	Escalation to Mid-Point (2018)	1.00	EA						1.00	EA		17000XX005
17000	Engineering, Legal, and Administrative Fees	1.00	EA						1.00	EA		17000XX007

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DETAILED COST ESTIMATE

Project: Biogas Use Applications
Client: San Bernardino MWD
Location: San Bernardino, CA
Element: 04 Pipeline Injection

Date : March 2018
By : CT
Reviewed: RD

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	550	CY	$9.40	$5,167	
	Total					**$5,167**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	95	CY	$339	$32,214	
	Total					**$32,214**
	Division 11 - Equipment					
11000	BioCNG 400 DP	1	EA	$2,041,491	$2,041,491	
11000	BioCNG Control Panel	1	EA	$45,000	$45,000	
11000	BioCNG 400 DP Winterization	1	EA	$266,000	$266,000	
11000	BioCNG Thermal Oxidizing Flare	1	EA	$341,900	$341,900	
11000	RNG Quality Monitoring Equipment	1	EA	$1,050,000	$1,050,000	
	Total					**$3,744,391**
	Division 15 - Mechanical					
15267	4" Sdr 11 Hdpe Pipe In Open Trench	15,000	LF	$54	$806,250	
15286	6" Sch 40S Buttwelded 316L Sst Pipe In A Bldg To 12' Ht.	200	LF	$116	$23,273	
	Total					**$829,523**
	Division 16 - Electrical					
16000	EI&C Allowance	15%	% Div 11	$3,744,391	$561,658.64	
	Total					**$561,659**
	Contingency	30%	EA	$5,172,953	$1,551,886	
	General Contractor Overhead, Profit, and Risk	15%	EA	$6,724,839	$1,008,726	
	Escalation to Mid-Point (2018)	5%	EA	$7,733,565	$386,678	
	General Conditions					
	Total Estimated Construction Cost					**$8,120,244**
	Engineering, Legal, and Administrative Fees	30%	EA	$8,120,244	$2,436,073	
	Total Project Cost					**$10,556,317**

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QUANTITY TAKEOFF WORKSHEET

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Project: Biogas Use Applications
Client: San Bernardino MWD
Location: San Bernardino, CA
Zip Code: 92408
Element: 05 City Vehicle Fleet CNG

Date: March 2018
By : CT
Reviewed: RD

SPEC NO.	DRAWING # / DESCRIPTION	# of PLACES	Resulting UNIT	LENGTH in Feet	WIDTH, HEIGHT or DEPTH	THICKNESS in Feet	DIAMETER in Feet	LBS per LF	TOTAL QTY		NOTES	Item No. (Carollo Code)
	(Leave this row blank)											
DIVISION 02												
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	1.00	CY	90.00	55.00	3.00			550.00	CY		0230021009
DIVISION 03												
03300	8" Flat Non-Formed S.O.G.	1.00	CY	80.00	45.00	0.67			89.33	CY		0330020009
DIVISION 11												
11000	BioCNG 400	1.00	EA						1.00	EA		11000XX001
11000	BioCNG Control Panel	1.00	EA						1.00	EA		11000XX003
11000	BioCNG Auxiliary Equipment	1.00	EA						1.00	EA		11000XX005
11000	CNG Storage	1.00	EA						1.00	EA		11000XX015
DIVISION 15												
15286	6" Sch 40S Buttwelded 316L Sst Pipe In A Bldg To 12' Ht.	1.00	LF	200.00					200.00	LF		1528680003
15267	4" Sdr 11 Hdpe Pipe In Open Trench	1.00	LF	5,000.00					5,000.00	LF		1526711007
15000	Pipe Tunnelling under Streets	1.00	LF	120.00					120.00	LF		15000XX001
DIVISION 16												
16000	EI&C Allowance		EA						0.00	EA		16000XX001
ADD Ons												
17000	Contingency		EA						0.00	EA		17000XX001
17000	General Contractor Overhead, Profit, and Risk		EA						0.00	EA		17000XX003
17000	Escalation to Mid-Point (2018)		EA						0.00	EA		17000XX005
17000	Engineering, Legal, and Administrative Fees		EA						0.00	EA		17000XX007

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DETAILED COST ESTIMATE

Project: Biogas Use Applications
Client: San Bernardino MWD
Location: San Bernardino, CA
Element: 05 City Vehicle Fleet CNG

Date : March 2018
By : CT
Reviewed: RD

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	550	CY	$9.40	$5,167	
	Total					**$5,167**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	89	CY	$339	$30,317	
	Total					**$30,317**
	Division 11 - Equipment					
11000	BioCNG 400	1	EA	$1,750,000	$1,750,000	
11000	BioCNG Control Panel	1	EA	$45,000	$45,000	
11000	BioCNG Auxiliary Equipment	1	EA	$175,000	$175,000	
11000	CNG Storage	1	EA	$750,000.00	$750,000	
	Total					**$2,720,000**
	Division 15 - Mechanical					
15000	Pipe Tunnelling under Streets	120	LF	$800	$96,000	
15267	4" Sdr 11 Hdpe Pipe In Open Trench	5,000	LF	$54	$268,750	
15286	6" Sch 40S Buttwelded 316L Sst Pipe In A Bldg To 12' Ht.	200	LF	$116	$23,273	
	Total					**$388,023**
	Division 16 - Electrical					
16000	EI&C Allowance	15%	of Div 11	$2,720,000	$408,000	
	Total					**$408,000**
	Contingency	30%	EA	$3,551,507	$1,065,452.04	
	General Contractor Overhead, Profit, and Risk	15%	EA	$4,616,959	$692,543.83	
	Escalation to Mid-Point (2018)	5%	EA	$5,309,503	$265,475	
	General Conditions	15%	EA	$3,551,507	$532,726	
	Total Estimated Construction Cost					**$6,107,704**
	Engineering, Legal, and Administrative Fees	30%	EA	$5,574,978	$1,672,493	
	Total Project Cost					**$7,247,471**

San Bernardino MWD
Beneficial Digester Gas Uses
Carollo Engineers, Inc.
Forcasting Assumptions

Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Process Data											
Average plant flow (million gallons/day)	22.0	22.0	22.0	16.0	16.3	16.6	17.0	17.3	17.7	18.0	18.4
Average digester gas available (scf/day)	417000	417000	417000	303273	309338	315525	321835	328272	334838	341534	348365
Average Digester gas heating value (million Btu/hr)	9.9	9.9	9.9	7.2	7.3	7.5	7.6	7.8	8.0	8.1	8.3
Average plant heat load (million Btu/hr)	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Peak plant heat load (million Btu/hr)	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9
Plant electrical cons. Baseload, ann. average (kw-hr/day)	39,953	39,953	39,953	29,057	29,638	30,231	30,835	31,452	32,081	32,723	33,377
Plant electrical demand, ann. average (kw)	1,665	1,665	1,665	1,211	1,235	1,260	1,285	1,310	1,337	1,363	1,391
Plant electrical demand, ann. peak (kw)	3,300	3,300	3,300	2,400	2,448	2,497	2,547	2,598	2,650	2,703	2,757
Gas flow to boilers, cfd	31,273	31,273	31,273	22,744	23,199	23,663	24,136	24,619	25,111	25,613	26,125
Gas flow to boilers, mBTU/yr	6,506	6,506	6,506	4,732	4,826	4,923	5,021	5,122	5,224	5,329	5,435
Heat Transfer in boilers mBTU/yr	5,205	5,205	5,205	3,785	3,861	3,938	4,017	4,098	4,179	4,263	4,348

Cost Data			**Year**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Electricity ($/MWh)			1.00	122.385	126.057	129.839	133.734	137.746	141.878	146.135	150.519	155.034
PPA Electricity ($/MWh)			1.00	85.000	87.550	90.177	92.882	95.668	98.538	101.494	104.539	107.675
Natural Gas ($/MMBtu)			1.00	5.97	6.14	6.33	6.52	6.71	6.92	7.12	7.34	7.56
Electricity ($/kWh)	0.112	$/kWh in 2017		0.122	0.126	0.130	0.134	0.138	0.142	0.146	0.151	0.155
PPA Electricity ($/kWh)	0.085	$/kWh in 2017		0.085	0.088	0.090	0.093	0.096	0.099	0.101	0.105	0.108
Natural Gas ($/MMBtu, LHV)	5.30	$/MMBtu in 2017		5.97	6.14	6.33	6.52	6.71	6.92	7.12	7.34	7.56
Digester Gas Pipeline ($/MMBtu, LHV)	2.00	$/MMBtu		1.86	1.91	1.97	2.03	2.09	2.15	2.22	2.28	2.35
CNG Sale Price ($/GGE)	1.75											

Comments:
All operational data are assumed to be proportional to the plant flows: electrical demand and digester heating

Table of Current Plant Data with Projection in 2019

	Current 2017	2023	2038
Plant flow, mgd	22.0	16.0	21.5
AA Gas prod., scfd	417,000	303,273	408,165
AA Gas prod., scfm	290	211	283
Ave. heat, million Btu/hr	0.82	0.59	0.80
Peak heat, million Btu/hr	1.07	0.78	1.05
Gas flow to boilers, cfd	43,000	31,273	42,089
Elect usage, kWh/d	39,953	29,057	39,106
Average elect demand, kW	1,665	1,211	1,629
Peak elect demand, kW	2,700	3,300	2,643
Ave. elect cost, $/kWhr	0.1120	From SCE bills	
PPA Electrical cost, $/kWhr	0.0850	2020 1st year	
NG cost, $/therm, HHV	0.5300		

43,000 cfd 1.02 million BTU/hr From Joseph (plant data)

From SCE bills

San Bernardino MWD
Beneficial Digester Gas Uses
Carollo Engineers, Inc.
Forcasting Assumptions

Year	**2020**	**2021**	**2022**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	AVERAGE
												20-Year
Process Data												
Average plant flow (million gallons/day)	22.0	22.0	22.0	18.7	19.1	19.5	19.9	20.3	20.7	21.1	21.53	19.3
Average digester gas available (scf/day)	417000	417000	417000	355332	362439	369688	377082	384623	392316	400162	408165	365,573
Average Digester gas heating value (million Btu/hr)	9.9	9.9	9.9	8.4	8.6	8.8	9.0	9.1	9.3	9.5	9.7	8.7
Average plant heat load (million Btu/hr)	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.7
Peak plant heat load (million Btu/hr)	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9
Plant electrical cons. Baseload, ann. average (kw-hr/day)	39,953	39,953	39,953	34,044	34,725	35,420	36,128	36,851	37,588	38,340	39,106	35,026
Plant electrical demand, ann. average (kw)	1,665	1,665	1,665	1,419	1,447	1,476	1,505	1,535	1,566	1,597	1,629	1,459
Plant electrical demand, ann. peak (kw)	3,300	3,300	3,300	2,812	2,868	2,926	2,984	3,044	3,105	3,167	3,230	2,893
Gas flow to boilers, cfd	31,273	31,273	31,273	26,648	27,181	27,725	28,279	28,845	29,422	30,010	30,610	27,416
Gas flow to boilers, mBTU/yr	6,506	6,506	6,506	5,544	5,655	5,768	5,883	6,001	6,121	6,244	6,368	5,704
Heat Transfer in boilers mBTU/yr	5,205	5,205	5,205	4,435	4,524	4,614	4,707	4,801	4,897	4,995	5,095	4,563

Cost Data			**Year**	**2020**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2041**	**2042**
Electricity ($/MWh)			1.00	122.385	159.685	164.476	169.410	174.492	179.727	185.119	190.673	196.393	227.673	234.503
PPA Electricity ($/MWh)			1.00	85.000	110.906	114.233	117.660	121.190	124.825	128.570	132.427	136.400	158.125	162.869
Natural Gas ($/MMBtu)			1.00	5.97	7.78	8.02	8.26	8.50	8.76	9.02	9.29	9.57	11.10	11.43
Electricity ($/kWh)	0.112	$/kWh in 2017		0.122	0.160	0.164	0.169	0.174	0.180	0.185	0.191	0.196	0.228	0.235
PPA Electricity ($/kWh)	0.085	$/kWh in 2017		0.085	0.111	0.114	0.118	0.121	0.125	0.129	0.132	0.136	0.158	0.163
Natural Gas ($/MMBtu, LHV)	5.30	$/MMBtu in 2017		5.97	7.78	8.02	8.26	8.50	8.76	9.02	9.29	9.57	11.10	11.43
Digester Gas Pipeline ($/MMBtu, LHV)	2.00	$/MMBtu		1.86	2.42	2.50	2.57	2.65	2.73	2.81	2.89	2.98	3.45	3.56
CNG Sale Price ($/GGE)	1.75													

Comments:
All operationa

Table of Current Plant Data with Projection in 2019

	Current 2017	2023	2038
Plant flow, mgd	22.0	16.0	21.5
AA Gas prod., scfd	417,000	303,273	408,165
AA Gas prod., scfm	290	211	283
Ave. heat, million Btu/hr	0.82	0.59	0.80
Peak heat, million Btu/hr	1.07	0.78	1.05
Gas flow to boilers, cfd	43,000	31,273	42,089
Elect usage, kWh/d	39,953	29,057	39,106
Average elect demand, kW	1,665	1,211	1,629
Peak elect demand, kW	2,700	3,300	2,643
Ave. elect cost, $/kWhr	0.1120	From SCE bills	
PPA Electrical cost, $/kWhr	0.0850	2020 1st year	
NG cost, $/therm, HHV	0.5300		

San Bernardino MWD 3/18/2018 = Lastest revision
Beneficial Digester Gas Uses
Carollo Engineers, Inc.

Input data for Life Cycle Cost Analysis

GENERAL ASSUMPTIONS

The annual average plant heating load for digesters, the electrical demand, and the gas production are ratioed based on the influent plant flow rate for duration of this analysis.
These financial assumptions are used on other worksheets.

FINANCIAL ASSUMPTIONS		Value	Source:
Current Year of Analysis		2017	
First year of operation		2020	
Project duration, years		20	
Inflation (capital costs)		3.0%	Based on ENR index over past 20 years
Inflation (fuel and electricity costs)		3.0%	Based on ENR index over past 20 years
Inflation (O&M costs)		3.0%	Based on ENR index over past 20 years
Gross discount rate		4.0%	
Digester Gas LHV, Btu/scf		570	
Cogen engine availability percentage		95%	
BioCNG availability percentage		96%	BioCNG quotes as an average of 23 hours/day
BioCNG treatment efficiency		70%	Correspondence with BioCNG
BioCNG DP treatment efficiency		95%	Correspondence wih BioCNG
BioCNG utilization percentage		30%	sold to vehicles
Plant heat usage percentage of masterplan value		100%	Input in order to modify heating requirements
O&M cost for new engine alternatives $/kWh	$	0.015	$0.008 - .010/kWh per David Gall at Jenbacher, higher based on previous data from Cat and Cummins
O&M cost for new microturbine alternatives $/kWh	$	0.025	
O&M rate for boiler alternatives $/MMBtu	$	0.250	Assumed boiler O&M (not used for LE)
O&M rate for fuel treatment system $/million Btu	$	0.900	O&M for cogen gas treatment (not use for LE)
O&M cost for BioCNG system $/GGE	$	0.75	Quoted from BioCNG
O&M rate for DP BioCNG system $/GGE	$	0.85	Quoted from BioCNG
Parasitic Power for Engines (% of Capacity)		8.5%	Assumed parasitic energy to run cogen (not used for LE)
Green Power Credit $/kWh	$	0.005	Federal incentive for cogen (not used for LE)
RIN Price $/RIN	$	2.50	3-yr historical average http://www.progressivefuelslimited.com/web_data/PFL_RIN_Recap.pdf
RIN Energy (BTU)		77,000	https://cleancities.energy.gov/files/u/news_events/document/document_url/84/2_-Session_0_-_RIN_101_-_FINAL.pdf slide 21
GGE Energy (BTU/GGE)		114,000	"FUEL ECONOMY IMPACT ANALYSIS OF RFG" EPA, August 1995
DGE Energy (BTU/DGE)		129,500	DGE =~ GGE/0.88 per NAFA Fleet Managers Assn, https://web.archive.org/web/20100615153419/http://nafa.org/Template.cfm?Section=Energy_Equivalents
RIN Credit $/GGE	$	3.70	Equation determines value based on RIN price
RIN Accounting percent		70%	Blue Source fee for RINs in the range of 500,000 - 1,000,000 RINs/year, based on conversations with Will Overly
LCFS Credit $/MT CO2e	$	25.00	
CNG Sale Price $/GGE	$	1.75	Using costs for Riverside region: CNG station on Acorn, Riverside

Grant Incentive (1 = yes, 0 = no)	1	Not used for LE
NG Usage (when appropriate) (1 = yes, 0 = no)	0	Used for Cogen option, not LE

San Bernardino MWD
Beneficial Digester Gas Uses
Carollo Engineers, Inc.
Forcasting Assumptions

Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Process Data											
Average plant flow (million gallons/day)	22.0	22.0	22.0	16.0	16.3	16.6	17.0	17.3	17.7	18.0	18.4
Average digester gas available (scf/day)	417000	417000	417000	303273	309338	315525	321835	328272	334838	341534	348365
Average Digester gas heating value (million Btu/hr)	9.9	9.9	9.9	7.2	7.3	7.5	7.6	7.8	8.0	8.1	8.3
Average plant heat load (million Btu/hr)	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Peak plant heat load (million Btu/hr)	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9
Plant electrical cons. Baseload, ann. average (kw-hr/day)	39,953	39,953	39,953	29,057	29,638	30,231	30,835	31,452	32,081	32,723	33,377
Plant electrical demand, ann. average (kw)	1,665	1,665	1,665	1,211	1,235	1,260	1,285	1,310	1,337	1,363	1,391
Plant electrical demand, ann. peak (kw)	3,300	3,300	3,300	2,400	2,448	2,497	2,547	2,598	2,650	2,703	2,757
Gas flow to boilers, cfd	31,273	31,273	31,273	22,744	23,199	23,663	24,136	24,619	25,111	25,613	26,125
Gas flow to boilers, mBTU/yr	6,506	6,506	6,506	4,732	4,826	4,923	5,021	5,122	5,224	5,329	5,435
Heat Transfer in boilers mBTU/yr	5,205	5,205	5,205	3,785	3,861	3,938	4,017	4,098	4,179	4,263	4,348

Cost Data			**Year**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Electricity ($/MWh)			1.00	122.385	126.057	129.839	133.734	137.746	141.878	146.135	150.519	155.034
PPA Electricity ($/MWh)			1.00	85.000	87.550	90.177	92.882	95.668	98.538	101.494	104.539	107.675
Natural Gas ($/MMBtu)			1.00	5.97	6.14	6.33	6.52	6.71	6.92	7.12	7.34	7.56
Electricity ($/kWh)	0.112	$/kWh in 2017		0.122	0.126	0.130	0.134	0.138	0.142	0.146	0.151	0.155
PPA Electricity ($/kWh)	0.085	$/kWh in 2017		0.085	0.088	0.090	0.093	0.096	0.099	0.101	0.105	0.108
Natural Gas ($/MMBtu, LHV)	5.30	$/MMBtu in 2017		5.97	6.14	6.33	6.52	6.71	6.92	7.12	7.34	7.56
Digester Gas Pipeline ($/MMBtu, LHV)	2.00	$/MMBtu		1.86	1.91	1.97	2.03	2.09	2.15	2.22	2.28	2.35
CNG Sale Price ($/GGE)	1.75											

Comments:
All operational data are assumed to be proportional to the plant flows: electrical demand and digester heating

Table of Current Plant Data with Projection in 2019

	Current 2017	2023	2038
Plant flow, mgd	22.0	16.0	21.5
AA Gas prod., scfd	417,000	303,273	408,165
AA Gas prod., scfm	290	211	283
Ave. heat, million Btu/hr	0.82	0.59	0.80
Peak heat, million Btu/hr	1.07	0.78	1.05
Gas flow to boilers, cfd	43,000	31,273	42,089
Elect usage, kWh/d	39,953	29,057	39,106
Average elect demand, kW	1,665	1,211	1,629
Peak elect demand, kW	2,700	3,300	2,643
Ave. elect cost, $/kWhr	0.1120	From SCE bills	
PPA Electrical cost, $/kWhr	0.0850	2020 1st year	
NG cost, $/therm, HHV	0.5300		

43,000 cfd 1.02 million BTU/hr From Joseph (plant data)

From SCE bills

San Bernardino MWD
Beneficial Digester Gas Uses
Carollo Engineers, Inc.
Forcasting Assumptions

Year	**2020**	**2021**	**2022**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	AVERAGE
												20-Year
Process Data												
Average plant flow (million gallons/day)	22.0	22.0	22.0	18.7	19.1	19.5	19.9	20.3	20.7	21.1	21.53	19.3
Average digester gas available (scf/day)	417000	417000	417000	355332	362439	369688	377082	384623	392316	400162	408165	365,573
Average Digester gas heating value (million Btu/hr)	9.9	9.9	9.9	8.4	8.6	8.8	9.0	9.1	9.3	9.5	9.7	8.7
Average plant heat load (million Btu/hr)	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.7
Peak plant heat load (million Btu/hr)	0.8	0.8	0.8	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9
Plant electrical cons. Baseload, ann. average (kw-hr/day)	39,953	39,953	39,953	34,044	34,725	35,420	36,128	36,851	37,588	38,340	39,106	35,026
Plant electrical demand, ann. average (kw)	1,665	1,665	1,665	1,419	1,447	1,476	1,505	1,535	1,566	1,597	1,629	1,459
Plant electrical demand, ann. peak (kw)	3,300	3,300	3,300	2,812	2,868	2,926	2,984	3,044	3,105	3,167	3,230	2,893
Gas flow to boilers, cfd	31,273	31,273	31,273	26,648	27,181	27,725	28,279	28,845	29,422	30,010	30,610	27,416
Gas flow to boilers, mBTU/yr	6,506	6,506	6,506	5,544	5,655	5,768	5,883	6,001	6,121	6,244	6,368	5,704
Heat Transfer in boilers mBTU/yr	5,205	5,205	5,205	4,435	4,524	4,614	4,707	4,801	4,897	4,995	5,095	4,563

Cost Data			**Year**	**2020**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2041**	**2042**
Electricity ($/MWh)			1.00	122.385	159.685	164.476	169.410	174.492	179.727	185.119	190.673	196.393	227.673	234.503
PPA Electricity ($/MWh)			1.00	85.000	110.906	114.233	117.660	121.190	124.825	128.570	132.427	136.400	158.125	162.869
Natural Gas ($/MMBtu)			1.00	5.97	7.78	8.02	8.26	8.50	8.76	9.02	9.29	9.57	11.10	11.43
Electricity ($/kWh)	0.112	$/kWh in 2017		0.122	0.160	0.164	0.169	0.174	0.180	0.185	0.191	0.196	0.228	0.235
PPA Electricity ($/kWh)	0.085	$/kWh in 2017		0.085	0.111	0.114	0.118	0.121	0.125	0.129	0.132	0.136	0.158	0.163
Natural Gas ($/MMBtu, LHV)	5.30	$/MMBtu in 2017		5.97	7.78	8.02	8.26	8.50	8.76	9.02	9.29	9.57	11.10	11.43
Digester Gas Pipeline ($/MMBtu, LHV)	2.00	$/MMBtu		1.86	2.42	2.50	2.57	2.65	2.73	2.81	2.89	2.98	3.45	3.56
CNG Sale Price ($/GGE)	1.75													

Comments:
All operationa

Table of Current Plant Data with Projection in 2019

	Current 2017	2023	2038
Plant flow, mgd	22.0	16.0	21.5
AA Gas prod., scfd	417,000	303,273	408,165
AA Gas prod., scfm	290	211	283
Ave. heat, million Btu/hr	0.82	0.59	0.80
Peak heat, million Btu/hr	1.07	0.78	1.05
Gas flow to boilers, cfd	43,000	31,273	42,089
Elect usage, kWh/d	39,953	29,057	39,106
Average elect demand, kW	1,665	1,211	1,629
Peak elect demand, kW	2,700	3,300	2,643
Ave. elect cost, $/kWhr	0.1120	From SCE bills	
PPA Electrical cost, $/kWhr	0.0850	2020 1st year	
NG cost, $/therm, HHV	0.5300		

Biogas Gas Use Applications
Alternative 1
New 2 x 848 kW Engine Generator Facility

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Operation Data								
Average Digester Gas Available (million Btus)	72,255	82,419	82,419	82,419	59,941	61,140	62,363	63,610
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	72,255	82,419	82,419	82,419	59,941	61,140	62,363	63,610
Total Fuel Consumed (million Btus)	72,255	82,419	82,419	82,419	59,941	61,140	62,363	63,610
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	72,255	82,419	82,419	82,419	59,941	61,140	62,363	63,610
Natural Gas Percentage	0%	0%	0%	0%	0%	0%	0%	0%
Flared Digester Gas (million Btus)	-	-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)	32,515	37,089	37,089	37,089	26,973	27,513	28,063	28,624
Peak Electricity Required by Plant (kW)	2,893	3,300	3,300	3,300	2,400	2,448	2,497	2,547
Average Electricity Required by Plant (kW)	1,459	1,665	1,665	1,665	1,211	1,235	1,260	1,285
Net Electrical Generation (kW)	873	1,017	1,017	1,017	700	717	734	752
Parasitic Electrical Usage (kW)	144	144	144	144	144	144	144	144
Net Electricity Generated (MW-hrs)	7,268	8,460	8,460	8,460	5,825	5,966	6,109	6,255
Electricity Purchased (MW-hrs)	5,516	6,123	6,123	6,123	4,780	4,852	4,925	5,000
Required plant heat - (million Btus)	6,155	5,205	5,305	5,405	5,505	5,605	5,705	5,805
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	0.92	0.78	0.79	0.81	0.82	0.84	0.85	0.87
Cogen heating capacity, million Btu/hr	3.71	4.23	4.23	4.23	3.08	3.14	3.20	3.27
Excess (Boiler make up) peak day, million Btu/hr	2.79	3.46	3.44	3.43	2.26	2.30	2.35	2.40
Costs/(Revenues) for project								
Base Cost for electricity	$ 2,114,710	$ 1,784,723	$ 1,838,264	$ 1,893,412	$ 1,418,338	$ 1,490,106	$ 1,565,505	$ 1,644,720
Revenue for generated electricity	$ (1,203,488)	$ (1,035,347)	$ (1,066,407)	$ (1,098,399)	$ (779,044)	$ (821,769)	$ (866,755)	$ (914,119)
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities	$ 146,354	$ 81,055	$ 83,487	$ 85,992	$ 64,416	$ 67,675	$ 71,099	$ 74,697
O&M costs for engine generator facilities	$ 161,181	$ 138,662	$ 142,822	$ 147,107	$ 104,336	$ 110,058	$ 116,083	$ 122,427
Total Cost / (Revenue)	**$ 1,218,758**	**$ 969,094**	**$ 998,167**	**$ 1,028,112**	**$ 808,045**	**$ 846,070**	**$ 885,933**	**$ 927,724**
Intial Capital Cost Investment = $12,450,000								
Total Annual Costs (Revenues)	$ 1,168,446	$ 969,094	$ 998,167	$ 1,028,112	$ 808,045	$ 846,070	$ 885,933	$ 927,724
Present Worth of Annual Costs (Revenues)	$ 701,901	$ 861,521	$ 853,237	$ 845,033	$ 638,610	$ 642,944	$ 647,342	$ 651,807
TOTAL PRESENT VALUE $ 26,488,014								
Annualized Total Project Capital Cost	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926
Annualized Total Project Benefit	$ 2,116,372	$ 1,917,020	$ 1,946,092	$ 1,976,037	$ 1,755,971	$ 1,793,996	$ 1,833,859	$ 1,875,650
Jenbacher Engine Generator 848 kW per unit								
Number of Units		2	2	2	2	2	2	2
Number of Units Operating		2	2	2	2	2	2	2
Fuel rate, Btu/kW-hr		8,533	8,533	8,533	8,533	8,533	8,533	8,533
Cogeneration heat recovery/fuel input		45%	45%	45%	45%	45%	45%	45%
Cogeneration electricity recovery/fuel input		40%	40%	40%	40%	40%	40%	40%
Power output, kW		1,696	1,696	1,696	1,696	1,696	1,696	1,696
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322	8,322
Capital cost estimate	$12,450,000	$12,450,000	$0	$0	$0	$0	$0	$0
Grant	$0	$0						
Net Capital Costs	$12,450,000							

Biogas Gas Use Applications
Alternative 1
New 2 x 848 kW Engine Generator Facility

Year	**Average**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Operation Data								
Average Digester Gas Available (million Btus)	72,255	64,882	66,180	67,503	68,853	70,231	71,635	73,068
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	72,255	64,882	66,180	67,503	68,853	70,231	71,635	73,068
Total Fuel Consumed (million Btus)	72,255	64,882	66,180	67,503	68,853	70,231	71,635	73,068
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	72,255	64,882	66,180	67,503	68,853	70,231	71,635	73,068
Natural Gas Percentage	0%	0%	0%	0%	0%	0%	0%	0%
Flared Digester Gas (million Btus)	-	-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)	32,515	29,197	29,781	30,377	30,984	31,604	32,236	32,881
Peak Electricity Required by Plant (kW)	2,893	2,598	2,650	2,703	2,757	2,812	2,868	2,926
Average Electricity Required by Plant (kW)	1,459	1,310	1,337	1,363	1,391	1,419	1,447	1,476
Net Electrical Generation (kW)	873	770	788	806	826	845	865	885
Parasitic Electrical Usage (kW)	144	144	144	144	144	144	144	144
Net Electricity Generated (MW-hrs)	7,268	6,404	6,557	6,712	6,870	7,031	7,196	7,364
Electricity Purchased (MW-hrs)	5,516	5,076	5,153	5,232	5,313	5,395	5,479	5,564
Required plant heat - (million Btus)	6,155	5,905	6,005	6,105	6,205	6,305	6,405	6,505
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	0.92	0.88	0.90	0.91	0.93	0.94	0.96	0.97
Cogen heating capacity, million Btu/hr	3.71	3.33	3.40	3.47	3.54	3.61	3.68	3.75
Excess (Boiler make up) peak day, million Btu/hr	2.79	2.45	2.50	2.56	2.61	2.67	2.72	2.78
Costs/(Revenues) for project								
Base Cost for electricity	$ 2,114,710	$ 1,727,942	$ 1,815,376	$ 1,907,234	$ 2,003,740	$ 2,105,130	$ 2,211,649	$ 2,323,559
Revenue for generated electricity	$ (1,203,488)	$ (963,985)	$ (1,016,482)	$ (1,071,748)	$ (1,129,925)	$ (1,191,164)	$ (1,255,623)	$ (1,323,470)
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities	$ 146,354	$ 78,477	$ 82,448	$ 86,619	$ 91,002	$ 95,607	$ 100,445	$ 105,527
O&M costs for engine generator facilities	$ 161,181	$ 129,105	$ 136,136	$ 143,538	$ 151,329	$ 159,531	$ 168,164	$ 177,251
Total Cost / (Revenue)	**$ 1,218,758**	**$ 971,539**	**$ 1,017,477**	**$ 1,065,643**	**$ 1,116,147**	**$ 1,169,104**	**$ 1,224,634**	**$ 1,282,866**

Intial Capital Cost Investment = $12,450,000

	Average	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Total Annual Costs (Revenues)	$ 1,168,446	$ 971,539	$ 1,017,477	$ 1,065,643	$ 1,116,147	$ 1,169,104	$ 1,224,634	$ 1,282,866
Present Worth of Annual Costs (Revenues)	$ 701,901	$ 656,337	$ 660,934	$ 665,598	$ 670,329	$ 675,128	$ 679,996	$ 684,933
TOTAL PRESENT VALUE **$ 26,488,014**								
Annualized Total Project Capital Cost	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926
Annualized Total Project Benefit	$ 2,116,372	$ 1,919,465	$ 1,965,403	$ 2,013,569	$ 2,064,073	$ 2,117,030	$ 2,172,560	$ 2,230,792

Jenbacher Engine Generator 848 kW per unit

		2027	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Number of Units		2	2	2	2	2	2	2
Number of Units Operating		2	2	2	2	2	2	2
Fuel rate, Btu/kW-hr		8,533	8,533	8,533	8,533	8,533	8,533	8,533
Cogeneration heat recovery/fuel input		45%	45%	45%	45%	45%	45%	45%
Cogeneration electricity recovery/fuel input		40%	40%	40%	40%	40%	40%	40%
Power output, kW		1,696	1,696	1,696	1,696	1,696	1,696	1,696
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322	8,322
Capital cost estimate	$12,450,000	$0	$0	$0	$0	$0	$0	$0
Grant	$0							
Net Capital Costs	$12,450,000							

Biogas Gas Use Applications
Alternative 1
New 2 x 848 kW Engine Generator Facility

Year	**Average**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Operation Data							
Average Digester Gas Available (million Btus)	72,255	74,529	76,020	77,540	79,091	80,673	80,576
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	72,255	74,529	76,020	77,540	79,091	80,673	80,576
Total Fuel Consumed (million Btus)	72,255	74,529	76,020	77,540	79,091	80,673	80,576
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	72,255	74,529	76,020	77,540	79,091	80,673	80,576
Natural Gas Percentage	0%	0%	0%	0%	0%	0%	0%
Flared Digester Gas (million Btus)	-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)	32,515	33,538	34,209	34,893	35,591	36,303	36,259
Peak Electricity Required by Plant (kW)	2,893	2,984	3,044	3,105	3,167	3,230	3,226
Average Electricity Required by Plant (kW)	1,459	1,505	1,535	1,566	1,597	1,629	1,627
Net Electrical Generation (kW)	873	905	926	948	970	992	991
Parasitic Electrical Usage (kW)	144	144	144	144	144	144	144
Net Electricity Generated (MW-hrs)	7,268	7,535	7,710	7,888	8,070	8,255	8,244
Electricity Purchased (MW-hrs)	5,516	5,652	5,741	5,832	5,924	6,019	6,013
Required plant heat - (million Btus)	6,155	6,605	6,705	6,805	6,905	7,005	7,105
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	0.92	0.99	1.00	1.02	1.03	1.05	1.06
Cogen heating capacity, million Btu/hr	3.71	3.83	3.91	3.98	4.06	4.14	4.14
Excess (Boiler make up) peak day, million Btu/hr	2.79	2.84	2.90	2.97	3.03	3.10	3.08
Costs/(Revenues) for project							
Base Cost for electricity	$ 2,114,710	$ 2,441,131	$ 2,564,652	$ 2,694,423	$ 2,830,761	$ 2,973,998	$ 3,059,534
Revenue for generated electricity	$ (1,203,488)	$ (1,394,880)	$ (1,470,036)	$ (1,549,132)	$ (1,632,371)	$ (1,719,969)	$ (1,769,128)
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities	$ 146,354	$ 110,867	$ 116,477	$ 122,370	$ 128,562	$ 135,068	$ 138,952
O&M costs for engine generator facilities	$ 161,181	$ 186,814	$ 196,880	$ 207,473	$ 218,621	$ 230,353	$ 236,937
Total Cost / (Revenue)	**$ 1,218,758**	**$ 1,343,932**	**$ 1,407,973**	**$ 1,475,135**	**$ 1,545,573**	**$ 1,619,450**	**$ 1,666,296**
Intial Capital Cost Investment = $12,450,000							
Total Annual Costs (Revenues)	$ 1,168,446	$ 1,343,932	$ 1,407,973	$ 1,475,135	$ 1,545,573	$ 1,619,450	$ 1,666,296
Present Worth of Annual Costs (Revenues)	$ 701,901	$ 689,939	$ 695,015	$ 700,162	$ 705,380	$ 710,669	$ 703,102
TOTAL PRESENT VALUE $ 26,488,014							
Annualized Total Project Capital Cost	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926	$ 947,926
Annualized Total Project Benefit	$ 2,116,372	$ 2,291,858	$ 2,355,899	$ 2,423,061	$ 2,493,499	$ 2,567,376	$ 2,614,221

Jenbacher Engine Generator 848 kW per unit		**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Number of Units		2	2	2	2	2	2
Number of Units Operating		2	2	2	2	2	2
Fuel rate, Btu/kW-hr		8,533	8,533	8,533	8,533	8,533	8,533
Cogeneration heat recovery/fuel input		45%	45%	45%	45%	45%	45%
Cogeneration electricity recovery/fuel input		40%	40%	40%	40%	40%	40%
Power output, kW		1,696	1,696	1,696	1,696	1,696	1,696
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322
Capital cost estimate	$12,450,000	$0	$0	$0	$0	$0	$0
Grant	$0						
Net Capital Costs	$12,450,000						

San Bernardino WRP
Biogas Gas Use Applications
Alternative 2
New 1 MW Microturbine Generation Facility

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Operation Data								
Average Digester Gas Available (million Btus)	72,255	82,419	82,419	82,419	59,941	61,140	62,363	63,610
Boiler Fuel Consumed (million Btus)	-	-	-	-	-	-	-	-
New Cogen Fuel Consumed (million Btus)	72,255	82,419	82,419	82,419	59,941	61,140	62,363	63,610
Total Fuel Consumed (million Btus)	72,255	82,419	82,419	82,419	59,941	61,140	62,363	63,610
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	72,255	82,419	82,419	82,419	59,941	61,140	62,363	63,610
Natural Gas Percentage	0%	0%	0%	0%	0%	0%	0%	0%
Flared Digester Gas (million Btus)	-	-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)	28,902	32,968	32,968	32,968	23,976	24,456	24,945	25,444
Peak Electricity Required by Plant (kW)	2,893	3,300	3,300	3,300	2,400	2,448	2,497	2,547
Average Electricity Required by Plant (kW)	1,459	1,665	1,665	1,665	1,211	1,235	1,260	1,285
Net Electrical Generation (kW)	588	692	692	692	462	474	487	499
Parasitic Electrical Usage (kW)	150	150	150	150	150	150	150	150
Net Electricity Generated (MW-hrs)	4,891	5,755	5,755	5,755	3,845	3,947	4,051	4,157
Electricity Purchased (MW-hrs)	7,893	8,828	8,828	8,828	6,761	6,871	6,984	7,098
Required plant heat - (million Btus)	6,155	5,205	5,305	5,405	5,505	5,605	5,705	5,805
Excess boiler heat req'd (million Btus)	-	-	-	-	-	-	-	-
Daily peak heat demand, million Btu/hr	0.92	0.78	0.79	0.81	0.82	0.84	0.85	0.87
Cogen heating capacity, million Btu/hr	3.30	3.76	3.76	3.76	2.74	2.79	2.85	2.90
Excess (Boiler make up) peak day, million Btu/hr	2.38	2.99	2.97	2.96	1.91	1.95	2.00	2.04
Costs/(Revenues) for project								
Base Cost for electricity	$ 2,114,710	$ 1,784,723	$ 1,838,264	$ 1,893,412	$ 1,418,338	$ 1,490,106	$ 1,565,505	$ 1,644,720
Revenue for generated electricity	$ (810,290)	$ (704,301)	$ (725,430)	$ (747,193)	$ (514,187)	$ (543,643)	$ (574,694)	$ (607,422)
Natural gas costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities	$ 146,354	$ 81,055	$ 83,487	$ 85,992	$ 64,416	$ 67,675	$ 71,099	$ 74,697
O&M costs for MT facilities	$ 180,868	$ 157,210	$ 161,926	$ 166,784	$ 114,774	$ 121,349	$ 128,280	$ 135,585
Total Cost / (Revenue)	**$ 1,631,642**	**$ 1,318,687**	**$ 1,358,247**	**$ 1,398,995**	**$ 1,083,341**	**$ 1,135,486**	**$ 1,190,190**	**$ 1,247,580**
Intial Capital Cost Investment = $11,500,000								
Total Annual Costs (Revenues)	$ 1,581,330	$ 1,318,687	$ 1,358,247	$ 1,398,995	$ 1,083,341	$ 1,135,486	$ 1,190,190	$ 1,247,580
Present Worth of Annual Costs (Revenues)	$ 949,599	$ 1,172,308	$ 1,161,036	$ 1,149,872	$ 856,180	$ 862,876	$ 869,660	$ 876,533
TOTAL PRESENT VALUE $ 30,491,986								
Annualized Total Project Capital Cost	$ 875,594	$ 875,594	$ 875,594	$ 875,594	$ 875,594	$ 875,594	$ 875,594	$ 875,594
Annualized Total Project Benefit	$ 2,456,924	$ 2,194,281	$ 2,233,841	$ 2,274,589	$ 1,958,935	$ 2,011,080	$ 2,065,785	$ 2,123,174
Capstone MT 200 kW per unit								
Number of Units		5	5	5	5	5	5	5
Number of Units Operating		5	5	5	5	5	5	5
Fuel rate, Btu/kW-hr		11,769	11,769	11,769	11,769	11,769	11,769	11,769
Cogeneration heat recovery/fuel input		40%	40%	40%	40%	40%	40%	40%
Cogeneration electricity recovery/fuel input		29%	29%	29%	29%	29%	29%	29%
Power output, kW		1,000	1,000	1,000	1,000	1,000	1,000	1,000
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322	8,322
Capital cost estimate	$11,500,000	$11,500,000	$0	$0	$0	$0	$0	$0
Grant	$0	$0						
Net Capital Costs	$11,500,000							

San Bernardino WRP
Biogas Gas Use Applications
Alternative 2
New 1 MW Microturbine Generation Facility

Year		**Average**		**2027**		**2028**		**2029**		**2030**		**2031**		**2032**		**2033**
Operation Data																
Average Digester Gas Available (million Btus)		72,255		64,882		66,180		67,503		68,853		70,231		71,635		73,068
Boiler Fuel Consumed (million Btus)		-		-		-		-		-		-		-		-
New Cogen Fuel Consumed (million Btus)		72,255		64,882		66,180		67,503		68,853		70,231		71,635		73,068
Total Fuel Consumed (million Btus)		72,255		64,882		66,180		67,503		68,853		70,231		71,635		73,068
Natural Gas Consumed (million Btus)		-		-		-		-		-		-		-		-
Digester Gas Consumed (million Btus)		72,255		64,882		66,180		67,503		68,853		70,231		71,635		73,068
Natural Gas Percentage		0%		0%		0%		0%		0%		0%		0%		0%
Flared Digester Gas (million Btus)		-		-		-		-		-		-		-		-
Cogen Heat Generated (million Btus)		28,902		25,953		26,472		27,001		27,541		28,092		28,654		29,227
Peak Electricity Required by Plant (kW)		2,893		2,598		2,650		2,703		2,757		2,812		2,868		2,926
Average Electricity Required by Plant (kW)		1,459		1,310		1,337		1,363		1,391		1,419		1,447		1,476
Net Electrical Generation (kW)		588		512		526		539		553		567		581		596
Parasitic Electrical Usage (kW)		150		150		150		150		150		150		150		150
Net Electricity Generated (MW-hrs)		4,891		4,265		4,375		4,487		4,602		4,719		4,838		4,960
Electricity Purchased (MW-hrs)		7,893		7,215		7,335		7,456		7,580		7,707		7,836		7,968
Required plant heat - (million Btus)		6,155		5,905		6,005		6,105		6,205		6,305		6,405		6,505
Excess boiler heat req'd (million Btus)		-		-		-		-		-		-		-		-
Daily peak heat demand, million Btu/hr		0.92		0.88		0.90		0.91		0.93		0.94		0.96		0.97
Cogen heating capacity, million Btu/hr		3.30		2.96		3.02		3.08		3.14		3.21		3.27		3.34
Excess (Boiler make up) peak day, million Btu/hr		2.38		2.08		2.13		2.17		2.22		2.27		2.31		2.37
Costs/(Revenues) for project																
Base Cost for electricity	$	2,114,710	$	1,727,942	$	1,815,376	$	1,907,234	$	2,003,740	$	2,105,130	$	2,211,649	$	2,323,559
Revenue for generated electricity	$	(810,290)	$	(641,915)	$	(678,267)	$	(716,574)	$	(756,938)	$	(799,469)	$	(844,279)	$	(891,486)
Natural gas costs	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
O&M costs for fuel treatment facilities	$	146,354	$	78,477	$	82,448	$	86,619	$	91,002	$	95,607	$	100,445	$	105,527
O&M costs for MT facilities	$	180,868	$	143,285	$	151,399	$	159,949	$	168,959	$	178,453	$	188,455	$	198,992
Total Cost / (Revenue)	**$**	**1,631,642**	**$**	**1,307,789**	**$**	**1,370,956**	**$**	**1,437,230**	**$**	**1,506,764**	**$**	**1,579,721**	**$**	**1,656,270**	**$**	**1,736,592**
Intial Capital Cost Investment = $11,500,000																
Total Annual Costs (Revenues)	$	1,581,330	$	1,307,789	$	1,370,956	$	1,437,230	$	1,506,764	$	1,579,721	$	1,656,270	$	1,736,592
Present Worth of Annual Costs (Revenues)	$	949,599	$	883,495	$	890,547	$	897,689	$	904,923	$	912,249	$	919,668	$	927,181
TOTAL PRESENT VALUE **$** **30,491,986**																
Annualized Total Project Capital Cost	$	875,594	$	875,594	$	875,594	$	875,594	$	875,594	$	875,594	$	875,594	$	875,594
Annualized Total Project Benefit	$	2,456,924	$	2,183,383	$	2,246,550	$	2,312,824	$	2,382,358	$	2,455,315	$	2,531,865	$	2,612,186

Capstone MT 200 kW per unit		2027	2028	2029	2030	2031	2032	2033
Number of Units		5	5	5	5	5	5	5
Number of Units Operating		5	5	5	5	5	5	5
Fuel rate, Btu/kW-hr		11,769	11,769	11,769	11,769	11,769	11,769	11,769
Cogeneration heat recovery/fuel input		40%	40%	40%	40%	40%	40%	40%
Cogeneration electricity recovery/fuel input		29%	29%	29%	29%	29%	29%	29%
Power output, kW		1,000	1,000	1,000	1,000	1,000	1,000	1,000
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322	8,322
Capital cost estimate	$11,500,000	$0	$0	$0	$0	$0	$0	$0
Grant	$0							
Net Capital Costs	$11,500,000							

San Bernardino WRP
Biogas Gas Use Applications
Alternative 2
New 1 MW Microturbine Generation Facility

Year		**Average**		**2034**		**2035**		**2036**		**2037**		**2038**		**2039**
Operation Data														
Average Digester Gas Available (million Btus)		72,255		74,529		76,020		77,540		79,091		80,673		80,576
Boiler Fuel Consumed (million Btus)		-		-		-		-		-		-		-
New Cogen Fuel Consumed (million Btus)		72,255		74,529		76,020		77,540		79,091		80,673		80,576
Total Fuel Consumed (million Btus)		72,255		74,529		76,020		77,540		79,091		80,673		80,576
Natural Gas Consumed (million Btus)		-		-		-		-		-		-		-
Digester Gas Consumed (million Btus)		72,255		74,529		76,020		77,540		79,091		80,673		80,576
Natural Gas Percentage		0%		0%		0%		0%		0%		0%		0%
Flared Digester Gas (million Btus)		-		-		-		-		-		-		-
Cogen Heat Generated (million Btus)		28,902		29,812		30,408		31,016		31,636		32,269		32,230
Peak Electricity Required by Plant (kW)		2,893		2,984		3,044		3,105		3,167		3,230		3,226
Average Electricity Required by Plant (kW)		1,459		1,505		1,535		1,566		1,597		1,629		1,627
Net Electrical Generation (kW)		588		611		626		642		658		674		673
Parasitic Electrical Usage (kW)		150		150		150		150		150		150		150
Net Electricity Generated (MW-hrs)		4,891		5,084		5,211		5,340		5,472		5,606		5,598
Electricity Purchased (MW-hrs)		7,893		8,102		8,240		8,379		8,522		8,667		8,659
Required plant heat - (million Btus)		6,155		6,605		6,705		6,805		6,905		7,005		7,105
Excess boiler heat req'd (million Btus)		-		-		-		-		-		-		-
Daily peak heat demand, million Btu/hr		0.92		0.99		1.00		1.02		1.03		1.05		1.06
Cogen heating capacity, million Btu/hr		3.30		3.40		3.47		3.54		3.61		3.68		3.68
Excess (Boiler make up) peak day, million Btu/hr		2.38		2.42		2.47		2.52		2.58		2.64		2.62
Costs/(Revenues) for project														
Base Cost for electricity	$	2,114,710	$	2,441,131	$	2,564,652	$	2,694,423	$	2,830,761	$	2,973,998	$	3,059,534
Revenue for generated electricity	$	(810,290)	$	(941,217)	$	(993,603)	$	(1,048,782)	$	(1,106,901)	$	(1,168,112)	$	(1,201,386)
Natural gas costs	$	-	$	-	$	-	$	-	$	-	$	-	$	-
O&M costs for fuel treatment facilities	$	146,354	$	110,867	$	116,477	$	122,370	$	128,562	$	135,068	$	138,952
O&M costs for MT facilities	$	180,868	$	210,093	$	221,786	$	234,103	$	247,076	$	260,739	$	268,167
Total Cost / (Revenue)	**$**	**1,631,642**	**$**	**1,820,874**	**$**	**1,909,312**	**$**	**2,002,115**	**$**	**2,099,499**	**$**	**2,201,693**	**$**	**2,265,267**
Intial Capital Cost Investment = $11,500,000														
Total Annual Costs (Revenues)	$	1,581,330	$	1,820,874	$	1,909,312	$	2,002,115	$	2,099,499	$	2,201,693	$	2,265,267
Present Worth of Annual Costs (Revenues)	$	949,599	$	934,788	$	942,490	$	950,289	$	958,184	$	966,177	$	955,842
TOTAL PRESENT VALUE $ 30,491,986														
Annualized Total Project Capital Cost	$	875,594	$	875,594	$	875,594	$	875,594	$	875,594	$	875,594	$	875,594
Annualized Total Project Benefit	$	2,456,924	$	2,696,468	$	2,784,906	$	2,877,709	$	2,975,093	$	3,077,287	$	3,140,861
Capstone MT 200 kW per unit														
Number of Units				5		5		5		5		5		5
Number of Units Operating				5		5		5		5		5		5
Fuel rate, Btu/kW-hr				11,769		11,769		11,769		11,769		11,769		11,769
Cogeneration heat recovery/fuel input				40%		40%		40%		40%		40%		40%
Cogeneration electricity recovery/fuel input				29%		29%		29%		29%		29%		29%
Power output, kW				1,000		1,000		1,000		1,000		1,000		1,000
Operating hours per year				8,322		8,322		8,322		8,322		8,322		8,322
Capital cost estimate		$11,500,000		$0		$0		$0		$0		$0		$0
Grant		$0												
Net Capital Costs		$11,500,000												

San Bernardino WRP
Biogas Gas Use Applications
Alternative 3
Fuel Cell Cogeneration with PPA

Life Cycle Present Worth of Annual Costs

Year		**Average**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Operation Data								
Average Digester Gas Available (million Btus)		72,255	82,419	82,419	82,419	59,941	61,140	62,363
Boiler Fuel Consumed (million Btus)		7,694	6,506	6,631	6,756	6,881	7,006	7,131
Fuel Cell - Fuel Consumed (million Btus)		64,561	75,913	75,788	75,663	53,060	54,134	55,231
Total Fuel Consumed (million Btus)		72,255	82,419	82,419	82,419	59,941	61,140	62,363
Natural Gas Consumed (million Btus)		-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)		72,255	82,419	82,419	82,419	59,941	61,140	62,363
Natural Gas Percentage		0%	0%	0%	0%	0%	0%	0%
Flared Digester Gas (million Btus)		-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)		-	-	-	-	-	-	-
Peak Electricity Required by Plant (kW)		2,893	3,300	3,300	3,300	2,400	2,448	2,497
Average Electricity Required by Plant (kW)		1,459	1,665	1,665	1,665	1,211	1,235	1,260
Net Electrical Generation (kW)		771	1,083.72	1,064	1,045	685	689	693
Parasitic Electrical Usage (kW)		119	119	119	119	119	119	119
Electricity Generated (MW-hrs)		6,414	9,019	8,855	8,693	5,700	5,734	5,769
Electricity Purchased (MW-hrs)		6,370	5,564	5,728	5,890	4,906	5,083	5,265
Required plant heat - (million Btus)		6,155	5,205	5,305	5,405	5,505	5,605	5,705
Excess boiler heat req'd (million Btus)		6,155	5,205	5,305	5,405	5,505	5,605	5,705
Daily peak heat demand, million Btu/hr		0.92	0.78	0.79	0.81	0.82	0.84	0.85
Cogen heating capacity, million Btu/hr		-	-	-	-	-	-	-
Excess (Boiler make up) peak day, million Btu/hr		(0.92)	(0.78)	(0.79)	(0.81)	(0.82)	(0.84)	(0.85)
Costs/(Revenues) for project								
Cost for electricity purchased from SCE		$ 1,073,100	$ 680,967	$ 722,089	$ 764,720	$ 656,062	$ 700,206	$ 746,946
Cost for electricity purchased from PPA		$ 723,427	$ 766,588	$ 775,214	$ 783,908	$ 529,421	$ 548,607	$ 568,511
Natural gas costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities		$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for engine generator facilities		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost / (Revenue)		**$ 1,796,526**	**$ 1,447,555**	**$ 1,497,303**	**$ 1,548,627**	**$ 1,185,483**	**$ 1,248,813**	**$ 1,315,458**
Intial Capital Cost Investment =	$1,937,000							
Total Annual Costs (Revenues)		$ 1,796,526	$ 1,447,555	$ 1,497,303	$ 1,548,627	$ 1,185,483	$ 1,248,813	$ 1,315,458
Present Worth of Annual Costs (Revenues)		$ 1,073,242	$ 1,286,871	$ 1,279,901	$ 1,272,859	$ 936,905	$ 948,995	$ 961,192
TOTAL PRESENT VALUE	**$ 23,401,831**							
Annualized Total Project Capital Cost		$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481
Annualized Total Project Benefit		$ 1,944,007	$ 1,595,036	$ 1,644,784	$ 1,696,108	$ 1,332,964	$ 1,396,293	$ 1,462,938

FCE Fuel Cell	1,400 kW per unit							
Number of Units			1	1	1	1	1	1
Number of Units Operating			1	1	1	1	1	1
Fuel rate, Btu/kW-hr			7,584	7,698	7,814	7,931	8,050	8,171
Cogeneration heat recovery/fuel input			0%	0%	0%	0%	0%	0%
Cogeneration electricity recovery/fuel input			45%	44%	44%	43%	42%	42%
Power output, kW			1,400	1,400	1,400	1,400	1,400	1,400
Operating hours per year			8,322	8,322	8,322	8,322	8,322	8,322
Capital cost estimate		$1,937,000	$1,937,000					
Grant		$0	$0					
Net Capital Costs		$1,937,000						

San Bernardino WRP
Biogas Gas Use Applications
Alternative 3
Fuel Cell Cogeneration with PPA

Year		**Average**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Operation Data										
Average Digester Gas Available (million Btus)		72,255	63,610	64,882	66,180	67,503	68,853	70,231	71,635	73,068
Boiler Fuel Consumed (million Btus)		7,694	7,256	7,381	7,506	7,631	7,756	7,881	8,007	8,132
Fuel Cell - Fuel Consumed (million Btus)		64,561	56,354	57,501	58,673	59,872	61,097	62,349	63,629	64,936
Total Fuel Consumed (million Btus)		72,255	63,610	64,882	66,180	67,503	68,853	70,231	71,635	73,068
Natural Gas Consumed (million Btus)		-	-	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)		72,255	63,610	64,882	66,180	67,503	68,853	70,231	71,635	73,068
Natural Gas Percentage		0%	0%	0%	0%	0%	0%	0%	0%	0%
Flared Digester Gas (million Btus)		-	-	-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)		-	-	-	-	-	-	-	-	-
Peak Electricity Required by Plant (kW)		2,893	2,547	2,598	2,650	2,703	2,757	2,812	2,868	2,926
Average Electricity Required by Plant (kW)		1,459	1,285	1,310	1,337	1,363	1,391	1,419	1,447	1,476
Net Electrical Generation (kW)		771	698	702	706	711	715	720	724	729
Parasitic Electrical Usage (kW)		119	119	119	119	119	119	119	119	119
Electricity Generated (MW-hrs)		6,414	5,805	5,841	5,877	5,914	5,951	5,988	6,026	6,065
Electricity Purchased (MW-hrs)		6,370	5,450	5,639	5,832	6,030	6,232	6,438	6,648	6,863
Required plant heat - (million Btus)		6,155	5,805	5,905	6,005	6,105	6,205	6,305	6,405	6,505
Excess boiler heat req'd (million Btus)		6,155	5,805	5,905	6,005	6,105	6,205	6,305	6,405	6,505
Daily peak heat demand, million Btu/hr		0.92	0.87	0.88	0.90	0.91	0.93	0.94	0.96	0.97
Cogen heating capacity, million Btu/hr		-	-	-	-	-	-	-	-	-
Excess (Boiler make up) peak day, million Btu/hr		(0.92)	(0.87)	(0.88)	(0.90)	(0.91)	(0.93)	(0.94)	(0.96)	(0.97)
Costs/(Revenues) for project										
Cost for electricity purchased from SCE		$ 1,073,100	$ 796,427	$ 848,803	$ 904,236	$ 962,895	$ 1,024,961	$ 1,090,624	$ 1,160,082	$ 1,233,546
Cost for electricity purchased from PPA		$ 723,427	$ 589,162	$ 610,586	$ 632,812	$ 655,869	$ 679,789	$ 704,602	$ 730,342	$ 757,043
Natural gas costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for engine generator facilities		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost / (Revenue)		**$ 1,796,526**	**$ 1,385,589**	**$ 1,459,389**	**$ 1,537,048**	**$ 1,618,764**	**$ 1,704,750**	**$ 1,795,226**	**$ 1,890,424**	**$ 1,990,589**
Intial Capital Cost Investment =	$1,937,000									
Total Annual Costs (Revenues)		$ 1,796,526	$ 1,385,589	$ 1,459,389	$ 1,537,048	$ 1,618,764	$ 1,704,750	$ 1,795,226	$ 1,890,424	$ 1,990,589
Present Worth of Annual Costs (Revenues)		$ 1,073,242	$ 973,497	$ 985,911	$ 998,437	$ 1,011,075	$ 1,023,829	$ 1,036,698	$ 1,049,685	$ 1,062,792
TOTAL PRESENT VALUE	**$ 23,401,831**									
Annualized Total Project Capital Cost		$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481
Annualized Total Project Benefit		$ 1,944,007	$ 1,533,070	$ 1,606,870	$ 1,684,528	$ 1,766,245	$ 1,852,230	$ 1,942,706	$ 2,037,904	$ 2,138,070
FCE Fuel Cell	1,400 kW per unit									
Number of Units			1	1	1	1	1	1	1	1
Number of Units Operating			1	1	1	1	1	1	1	1
Fuel rate, Btu/kW-hr			8,293	8,418	8,544	8,672	8,802	8,934	9,068	9,204
Cogeneration heat recovery/fuel input			0%	0%	0%	0%	0%	0%	0%	0%
Cogeneration electricity recovery/fuel input			41%	41%	40%	39%	39%	38%	38%	37%
Power output, kW			1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Operating hours per year			8,322	8,322	8,322	8,322	8,322	8,322	8,322	8,322
Capital cost estimate		$1,937,000								
Grant		$0								
Net Capital Costs		$1,937,000								

San Bernardino WRP
Biogas Gas Use Applications
Alternative 3
Fuel Cell Cogeneration with PPA

Year	**Average**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Operation Data							
Average Digester Gas Available (million Btus)	72,255	74,529	76,020	77,540	79,091	80,673	80,576
Boiler Fuel Consumed (million Btus)	7,694	8,257	8,382	8,507	8,632	8,757	8,882
Fuel Cell - Fuel Consumed (million Btus)	64,561	66,273	67,638	69,034	70,459	71,916	71,694
Total Fuel Consumed (million Btus)	72,255	74,529	76,020	77,540	79,091	80,673	80,576
Natural Gas Consumed (million Btus)	-	-	-	-	-	-	-
Digester Gas Consumed (million Btus)	72,255	74,529	76,020	77,540	79,091	80,673	80,576
Natural Gas Percentage	0%	0%	0%	0%	0%	0%	0%
Flared Digester Gas (million Btus)	-	-	-	-	-	-	-
Cogen Heat Generated (million Btus)	-	-	-	-	-	-	-
Peak Electricity Required by Plant (kW)	2,893	2,984	3,044	3,105	3,167	3,230	3,226
Average Electricity Required by Plant (kW)	1,459	1,505	1,535	1,566	1,597	1,629	1,627
Net Electrical Generation (kW)	771	733	738	743	748	753	737
Parasitic Electrical Usage (kW)	119	119	119	119	119	119	119
Electricity Generated (MW-hrs)	6,414	6,104	6,143	6,182	6,222	6,263	6,133
Electricity Purchased (MW-hrs)	6,370	7,083	7,308	7,537	7,772	8,011	8,123
Required plant heat - (million Btus)	6,155	6,605	6,705	6,805	6,905	7,005	7,105
Excess boiler heat req'd (million Btus)	6,155	6,605	6,705	6,805	6,905	7,005	7,105
Daily peak heat demand, million Btu/hr	0.92	0.99	1.00	1.02	1.03	1.05	1.06
Cogen heating capacity, million Btu/hr	-	-	-	-	-	-	-
Excess (Boiler make up) peak day, million Btu/hr	(0.92)	(0.99)	(1.00)	(1.02)	(1.03)	(1.05)	(1.06)

Costs/(Revenues) for project		Average	2034	2035	2036	2037	2038	2039
Cost for electricity purchased from SCE		$ 1,073,100	$ 1,311,239	$ 1,393,394	$ 1,480,257	$ 1,572,088	$ 1,669,161	$ 1,743,289
Cost for electricity purchased from PPA		$ 723,427	$ 784,741	$ 813,471	$ 843,272	$ 874,183	$ 906,245	$ 914,168
Natural gas costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for fuel treatment facilities		$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M costs for engine generator facilities		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost / (Revenue)		**$ 1,796,526**	**$ 2,095,979**	**$ 2,206,864**	**$ 2,323,528**	**$ 2,446,271**	**$ 2,575,406**	**$ 2,657,457**
Intial Capital Cost Investment =	$1,937,000							
Total Annual Costs (Revenues)		$ 1,796,526	$ 2,095,979	$ 2,206,864	$ 2,323,528	$ 2,446,271	$ 2,575,406	$ 2,657,457
Present Worth of Annual Costs (Revenues)		$ 1,073,242	$ 1,076,020	$ 1,089,370	$ 1,102,845	$ 1,116,446	$ 1,130,174	$ 1,121,328
TOTAL PRESENT VALUE	**$ 23,401,831**							
Annualized Total Project Capital Cost		$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481	$ 147,481
Annualized Total Project Benefit		$ 1,944,007	$ 2,243,460	$ 2,354,345	$ 2,471,009	$ 2,593,751	$ 2,722,886	$ 2,804,938

FCE Fuel Cell	1,400 kW per unit	2034	2035	2036	2037	2038	2039
Number of Units		1	1	1	1	1	1
Number of Units Operating		1	1	1	1	1	1
Fuel rate, Btu/kW-hr		9,342	9,482	9,625	9,769	9,915	10,064
Cogeneration heat recovery/fuel input		0%	0%	0%	0%	0%	0%
Cogeneration electricity recovery/fuel input		37%	36%	35%	35%	34%	34%
Power output, kW		1,400	1,400	1,400	1,400	1,400	1,400
Operating hours per year		8,322	8,322	8,322	8,322	8,322	8,322
Capital cost estimate	$1,937,000						
Grant	$0						
Net Capital Costs	$1,937,000						

San Bernardino WRP
Biogas Gas Use Applications
Alternative 4
Pipeline Injection

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2020**	**2021**	**2022**	**2023**	**2024**
Operation Data						
Average Digester Gas Available (million Btus)	73,015	83,287	83,287	83,287	60,572	61,783
Digester Gas after treatment (million Btus)	69,364	79,122	79,122	79,122	57,543	58,694
Pipeline Injection Gasoline Gallon Equivalents (GGE's)	603,169	688,020	688,020	688,020	500,378	510,385
Tail Gas (million Btus)	3,651	4,164	4,164	4,164	3,029	3,089
Boiler Heating Input (million Btus)	5,704	6,506	6,506	6,506	4,732	4,826
Tail Gas Flared (million Btus)	3,651	4,164	4,164	4,164	3,029	3,089
Natural Gas Consumed (million Btus)	5,704	6,506	6,506	6,506	4,732	4,826
Cleaned Digester Gas Consumed (million Btus)	69,364	79,122	79,122	79,122	57,543	58,694
Flared Digester Gas (million Btus)	6,571	7,496	7,496	7,496	5,451	5,561
Utilization Percentage	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Peak Electricity Required by Plant (kW)	2,893	3,300	3,300	3,300	2,400	2,448
Average Electricity Required by Plant (kW)	1,459	1,665	1,665	1,665	1,211	1,235
Parasitic Electrical Usage (kW)	-	-	-	-	-	-
Electricity Purchased (MW-hrs)	12,784	14,583	14,583	14,583	10,606	10,818
Required plant heating - (million Btus)	4,563	5,205	5,205	5,205	3,785	3,861
Excess boiler heat req'd (million Btus)	4,563	5,205	5,205	5,205	3,785	3,861
Daily peak heat demand, million Btu/hr	0.92	0.78	0.79	0.81	0.82	0.84
Cogen heating capacity, million Btu/hr	-	-	-	-	-	-
Excess (Required boiler make up) peak day, million Btu/hr	(0.92)	(0.78)	(0.79)	(0.81)	(0.82)	(0.84)
BioCNG Low Carbon Fuel Standard CO2e (MT CO2e)	5,022	5,729	5,729	5,729	4,167	4,250
Costs/(Revenues) for project: Baseline. No financing.						
Cost for electricity purchased	$ 2,126,932	$ 1,838,264	$ 1,893,412	$ 1,950,214	$ 1,460,888	$ 1,534,809
Revenue for NG sale to pipeline	$ (174,057)	$ (146,896)	$ (151,303)	$ (155,842)	$ (116,740)	$ (122,647)
Revenue for RIN/LCFS Credits less tracking cost	$ (369,907)	$ (991,315)	$ (1,021,054)	$ (1,051,686)	$ (124,376)	$ (130,669)
O&M costs for CNG/fuel treatment facilities	$ 736,078	$ 639,045	$ 639,045	$ 658,216	$ 493,064	$ 518,013
Cost of NG for heating digesters	$ 45,987	$ 38,811	$ 39,976	$ 41,175	$ 30,844	$ 32,404
Total Cost/(Revenue)	**$ 2,564,215**	**$ 1,377,909**	**$ 1,400,075**	**$ 1,442,077**	**$ 1,743,680**	**$ 1,831,910**
Initial Capital Cost Investment $10,556,000						
Total Annual Costs / (Revenues)		$ 1,377,909	$ 1,400,075	$ 1,442,077	$ 1,743,680	$ 1,831,910
Present Value of Annual Costs / (Revenues)		$ 1,224,956	$ 1,196,790	$ 1,185,282	$ 1,378,055	$ 1,392,101
TOTAL PRESENT VALUE $ 29,901,865						
Total Annual cash flow - Expenditure / (Revenue)	$ -	$ 1,377,909	$ 2,777,984	$ 4,220,061	$ 5,963,741	$ 7,795,650
Cummulative Present Value (Cash Flow)		1,224,956	2,374,632	3,468,583	4,713,231	5,924,054

Simple payback period: >20 years

San Bernardino WRP
Biogas Gas Use Applications
Alternative 4
Pipeline Injection

Year		**Average**		**2025**		**2026**		**2027**		**2028**		**2029**
Operation Data												
Average Digester Gas Available (million Btus)		73,015		63,019		64,280		65,565		66,876		68,214
Digester Gas after treatment (million Btus)		69,364		59,868		61,066		62,287		63,533		64,803
Pipeline Injection Gasoline Gallon Equivalents (GGE's)		603,169		520,593		531,005		541,625		552,458		563,507
Tail Gas (million Btus)		3,651		3,151		3,214		3,278		3,344		3,411
Boiler Heating Input (million Btus)		5,704		4,923		5,021		5,122		5,224		5,329
Tail Gas Flared (million Btus)		3,651		3,151		3,214		3,278		3,344		3,411
Natural Gas Consumed (million Btus)		5,704		4,923		5,021		5,122		5,224		5,329
Cleaned Digester Gas Consumed (million Btus)		69,364		59,868		61,066		62,287		63,533		64,803
Flared Digester Gas (million Btus)		6,571		5,672		5,785		5,901		6,019		6,139
Utilization Percentage		95.0%		95.0%		95.0%		95.0%		95.0%		95.0%
Peak Electricity Required by Plant (kW)		2,893		2,497		2,547		2,598		2,650		2,703
Average Electricity Required by Plant (kW)		1,459		1,260		1,285		1,310		1,337		1,363
Parasitic Electrical Usage (kW)		-		-		-		-		-		-
Electricity Purchased (MW-hrs)		12,784		11,034		11,255		11,480		11,710		11,944
Required plant heating - (million Btus)		4,563		3,938		4,017		4,098		4,179		4,263
Excess boiler heat req'd (million Btus)		4,563		3,938		4,017		4,098		4,179		4,263
Daily peak heat demand, million Btu/hr		0.92		0.85		0.87		0.88		0.90		0.91
Cogen heating capacity, million Btu/hr		-		-		-		-		-		-
Excess (Required boiler make up) peak day, million Btu/hr		(0.92)		(0.85)		(0.87)		(0.88)		(0.90)		(0.91)
BioCNG Low Carbon Fuel Standard CO2e (MT CO2e)		5,022		4,335		4,422		4,510		4,600		4,692
Costs/(Revenues) for project: Baseline. No financing.												
Cost for electricity purchased	$	2,126,932	$	1,612,470	$	1,694,061	$	1,779,781	$	1,869,838	$	1,964,451
Revenue for NG sale to pipeline	$	(174,057)	$	(128,853)	$	(135,373)	$	(142,223)	$	(149,419)	$	(156,980)
Revenue for RIN/LCFS Credits less tracking cost	$	(369,907)	$	(137,281)	$	(144,228)	$	(151,526)	$	(159,193)	$	(167,248)
O&M costs for CNG/fuel treatment facilities	$	736,078	$	544,224	$	571,762	$	600,693	$	631,088	$	663,021
Cost of NG for heating digesters	$	45,987	$	34,044	$	35,767	$	37,577	$	39,478	$	41,475
Total Cost/(Revenue)	**$**	**2,564,215**	**$**	**1,924,604**	**$**	**2,021,989**	**$**	**2,124,302**	**$**	**2,231,792**	**$**	**2,344,720**
Initial Capital Cost Investment $10,556,000												
Total Annual Costs / (Revenues)			$	1,924,604	$	2,021,989	$	2,124,302	$	2,231,792	$	2,344,720
Present Value of Annual Costs / (Revenues)			$	1,406,290	$	1,420,623	$	1,435,102	$	1,449,729	$	1,464,505
TOTAL PRESENT VALUE $ 29,901,865												
Total Annual cash flow - Expenditure / (Revenue)	$	-	$	9,720,255	$	11,742,244	$	13,866,546	$	16,098,337	$	18,443,058
Cummulative Present Value (Cash Flow)				7,102,495		8,249,945		9,367,742		10,457,173		11,519,479

Simple payback period: >20 years

San Bernardino WRP
Biogas Gas Use Applications
Alternative 4
Pipeline Injection

Year	**Average**	**2030**	**2031**	**2032**	**2033**	**2034**
Operation Data						
Average Digester Gas Available (million Btus)	73,015	69,578	70,970	72,389	73,837	75,314
Digester Gas after treatment (million Btus)	69,364	66,099	67,421	68,770	70,145	71,548
Pipeline Injection Gasoline Gallon Equivalents (GGE's)	603,169	574,777	586,272	597,998	609,958	622,157
Tail Gas (million Btus)	3,651	3,479	3,548	3,619	3,692	3,766
Boiler Heating Input (million Btus)	5,704	5,435	5,544	5,655	5,768	5,883
Tail Gas Flared (million Btus)	3,651	3,479	3,548	3,619	3,692	3,766
Natural Gas Consumed (million Btus)	5,704	5,435	5,544	5,655	5,768	5,883
Cleaned Digester Gas Consumed (million Btus)	69,364	66,099	67,421	68,770	70,145	71,548
Flared Digester Gas (million Btus)	6,571	6,262	6,387	6,515	6,645	6,778
Utilization Percentage	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Peak Electricity Required by Plant (kW)	2,893	2,757	2,812	2,868	2,926	2,984
Average Electricity Required by Plant (kW)	1,459	1,391	1,419	1,447	1,476	1,505
Parasitic Electrical Usage (kW)	-	-	-	-	-	-
Electricity Purchased (MW-hrs)	12,784	12,183	12,426	12,675	12,928	13,187
Required plant heating - (million Btus)	4,563	4,348	4,435	4,524	4,614	4,707
Excess boiler heat req'd (million Btus)	4,563	4,348	4,435	4,524	4,614	4,707
Daily peak heat demand, million Btu/hr	0.92	0.93	0.94	0.96	0.97	0.99
Cogen heating capacity, million Btu/hr	-	-	-	-	-	-
Excess (Required boiler make up) peak day, million Btu/hr	(0.92)	(0.93)	(0.94)	(0.96)	(0.97)	(0.99)
BioCNG Low Carbon Fuel Standard CO2e (MT CO2e)	5,022	4,786	4,882	4,979	5,079	5,181
Costs/(Revenues) for project: Baseline. No financing.						
Cost for electricity purchased	$ 2,126,932	$ 2,063,853	$ 2,168,284	$ 2,277,999	$ 2,393,265	$ 2,514,365
Revenue for NG sale to pipeline	$ (174,057)	$ (164,923)	$ (173,268)	$ (182,036)	$ (191,247)	$ (200,924)
Revenue for RIN/LCFS Credits less tracking cost	$ (369,907)	$ (175,711)	$ (184,602)			
O&M costs for CNG/fuel treatment facilities	$ 736,078	$ 696,570	$ 731,817	$ 768,847	$ 807,750	$ 848,622
Cost of NG for heating digesters	$ 45,987	$ 43,574	$ 45,779	$ 48,095	$ 50,529	$ 53,086
Total Cost/(Revenue)	**$ 2,564,215**	**$ 2,463,363**	**$ 2,588,009**	**$ 2,912,905**	**$ 3,060,298**	**$ 3,215,149**

Initial Capital Cost Investment	$10,556,000						
Total Annual Costs / (Revenues)			$ 2,463,363	$ 2,588,009	$ 2,912,905	$ 3,060,298	$ 3,215,149
Present Value of Annual Costs / (Revenues)			$ 1,479,432	$ 1,494,511	$ 1,617,433	$ 1,633,918	$ 1,650,572
TOTAL PRESENT VALUE	**$ 29,901,865**						
Total Annual cash flow - Expenditure / (Revenue)		$ -	$ 20,906,421	$ 23,494,430	$ 26,407,335	$ 29,467,633	$ 32,682,782
Cummulative Present Value (Cash Flow)			12,555,855	13,567,448	14,663,056	15,733,010	16,778,466

Simple payback period: >20 years

San Bernardino WRP
Biogas Gas Use Applications
Alternative 4
Pipeline Injection

Year		**Average**		**2035**		**2036**		**2037**		**2038**		**2039**
Operation Data												
Average Digester Gas Available (million Btus)		73,015		76,820		78,356		79,924		81,522		81,424
Digester Gas after treatment (million Btus)		69,364		72,979		74,439		75,927		77,446		77,353
Pipeline Injection Gasoline Gallon Equivalents (GGE's)		603,169		634,600		647,292		660,238		673,443		672,633
Tail Gas (million Btus)		3,651		3,841		3,918		3,996		4,076		4,071
Boiler Heating Input (million Btus)		5,704		6,001		6,121		6,244		6,368		6,361
Tail Gas Flared (million Btus)		3,651		3,841		3,918		3,996		4,076		4,071
Natural Gas Consumed (million Btus)		5,704		6,001		6,121		6,244		6,368		6,361
Cleaned Digester Gas Consumed (million Btus)		69,364		72,979		74,439		75,927		77,446		77,353
Flared Digester Gas (million Btus)		6,571		6,914		7,052		7,193		7,337		7,328
Utilization Percentage		95.0%		95.0%		95.0%		95.0%		95.0%		95.0%
Peak Electricity Required by Plant (kW)		2,893		3,044		3,105		3,167		3,230		3,226
Average Electricity Required by Plant (kW)		1,459		1,535		1,566		1,597		1,629		1,627
Parasitic Electrical Usage (kW)		-		-		-		-		-		-
Electricity Purchased (MW-hrs)		12,784		13,451		13,720		13,994		14,274		14,257
Required plant heating - (million Btus)		4,563		4,801		4,897		4,995		5,095		5,089
Excess boiler heat req'd (million Btus)		4,563		4,801		4,897		4,995		5,095		5,089
Daily peak heat demand, million Btu/hr		0.92		1.00		1.02		1.03		1.05		1.06
Cogen heating capacity, million Btu/hr		-		-		-		-		-		-
Excess (Required boiler make up) peak day, million Btu/hr		(0.92)		(1.00)		(1.02)		(1.03)		(1.05)		(1.06)
BioCNG Low Carbon Fuel Standard CO2e (MT CO2e)		5,022		5,284		5,390		5,498		5,608		5,601
Costs/(Revenues) for project: Baseline. No financing.												
Cost for electricity purchased	$	2,126,932	$	2,641,592	$	2,775,256	$	2,915,684	$	3,063,218	$	3,151,320
Revenue for NG sale to pipeline	$	(174,057)	$	(211,091)	$	(221,772)	$	(232,993)	$	(244,783)	$	(251,823)
Revenue for RIN/LCFS Credits less tracking cost	$	(369,907)										
O&M costs for CNG/fuel treatment facilities	$	736,078	$	891,563	$	936,676	$	984,072	$	1,033,866	$	1,063,601
Cost of NG for heating digesters	$	45,987	$	55,772	$	58,594	$	61,559	$	64,674	$	66,534
Total Cost/(Revenue)	**$**	**2,564,215**	**$**	**3,377,836**	**$**	**3,548,754**	**$**	**3,728,321**	**$**	**3,916,974**	**$**	**4,029,632**

Initial Capital Cost Investment	$10,556,000											
Total Annual Costs / (Revenues)			$	3,377,836	$	3,548,754	$	3,728,321	$	3,916,974	$	4,029,632
Present Value of Annual Costs / (Revenues)			$	1,667,395	$	1,684,389	$	1,701,557	$	1,718,900	$	1,700,325
TOTAL PRESENT VALUE	**$ 29,901,865**											
Total Annual cash flow - Expenditure / (Revenue)	$	-	$	36,060,618	$	39,609,372	$	43,337,693	$	47,254,667	$	51,284,299
Cummulative Present Value (Cash Flow)				17,800,535		18,800,288		19,778,757		20,736,936		21,639,686

Simple payback period: >20 years

San Bernardino WRP
Biogas Gas Use Applications
Alternative 5
CNG for Vehicle Fuel

Year	**Average**	**2020**	**2021**	**2022**	**2023**	**2024**
	Life Cycle Present Worth of Annual Costs					
Operation Data						
Average Digester Gas Available (million Btus)	73,015	83,287	83,287	83,287	60,572	61,783
Digester Gas after treatment (million Btus)	69,364	79,122	79,122	79,122	57,543	58,694
Digester Gas Sold as CNG (million Btus)	20,809	23,736.67	23,737	23,737	17,263	17,608
Digester Gas Remaining (MMBTUs)	48,555	55,386	55,386	55,386	40,280	41,086
Treated Gas GGEs	180,951	206,406	206,406	206,406	150,113	153,116
Tail Gas (million Btus)	3,651	4,164	4,164	4,164	3,029	3,089
Boiler Heating Input (million Btus)	5,704	6,506	6,506	6,506	4,732	4,826
Boiler Digester Gas Consumed	42,851	48,879	48,879	48,879	35,549	36,260
Tail Gas Consumed (million Btus)	-	-	-	-	-	-
Natural Gas Consumed (million Btus)	(37,147)	(42,373)	(42,373)	(42,373)	(30,817)	(31,433)
Digester Gas Consumed (million Btus)	63,661	72,616	72,616	72,616	52,812	53,868
Flared Digester Gas (million Btus)	12,275	14,002	14,002	14,002	10,183	10,387
Utilization Percentage	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%
Electricity Purchased (MW-hrs)	12,784	14,583	14,583	14,583	10,606	10,818
Required heat for plant - (million Btus)	4,563	5,205	5,205	5,205	3,785	3,861
Excess boiler heat req'd (million Btus)	4,563	5,205	5,205	5,205	3,785	3,861
Daily peak heat demand, million Btu/hr	0.92	0.78	0.79	0.81	0.82	0.84
BioCNG Low Carbon Fuel Standard CO2e (MT CO2e)	1,507	1,719	1,719	1,719	1,250	1,275
Costs/(Revenues) for project						
Cost for electricity purchased	$ 2,126,932	$ 1,838,264	$ 1,893,412	$ 1,950,214	$ 1,460,888	$ 1,534,809
Revenue of DG sold as CNG	$ (167,774)	$ (141,594)	$ (145,842)	$ (150,217)	$ (112,526)	$ (118,220)
Revenue for RIN/LCFS Credits less tracking cost	$ (104,289)	$ (297,395)	$ (306,316)	$ (315,506)	$ (236,343)	$ (39,201)
Cost of NG for heating digesters	$ (297,466)	$ (252,763)	$ (252,763)	$ (260,346)	$ (195,023)	$ (204,891)
O&M costs for fuel treatment facilities	$ 298,057	$ 257,460	$ 272,346	$ 277,573	$ 232,544	$ 239,347
Total Annual Cost / (Revenue)	**$ 1,855,460**	**$ 1,403,972**	**$ 1,460,837**	**$ 1,501,718**	**$ 1,149,541**	**$ 1,411,844**

Initial Capital Cost Investment $7,247,000						
Total Annual Costs		$ 1,403,972	$ 1,460,837	$ 1,501,718	$ 1,149,541	$ 1,411,844
Present Value of Annual Costs		$ 1,248,126	$ 1,248,729	$ 1,234,303	$ 908,499	$ 1,072,885
TOTAL PRESENT VALUE $ 29,953,877						
Total Annual cash flow - Expenditure / (Revenue)	$ 7,247,000	$ 8,650,972	$ 10,111,809	$ 11,613,527	$ 12,763,068	$ 14,174,911
Cummulative Present Value (Cash Flow)		7,690,683	8,643,617	9,545,473	10,086,838	10,771,768

Simple payback period: >20 years

San Bernardino WRP
Biogas Gas Use Applications
Alternative 5
CNG for Vehicle Fuel

Spreadsheet calculates the net present value of the CNG for Vehicle Fuel Option. Note: 'Cos

Year		**Average**		**2025**		**2026**		**2027**		**2028**		**2029**
Operation Data												
Average Digester Gas Available (million Btus)		73,015		63,019		64,280		65,565		66,876		68,214
Digester Gas after treatment (million Btus)		69,364		59,868		61,066		62,287		63,533		64,803
Digester Gas Sold as CNG (million Btus)		20,809		17,960		18,320		18,686		19,060		19,441
Digester Gas Remaining (MMBTUs)		48,555		41,908		42,746		43,601		44,473		45,362
Treated Gas GGEs		180,951		156,178		159,301		162,488		165,737		169,052
Tail Gas (million Btus)		3,651		3,151		3,214		3,278		3,344		3,411
Boiler Heating Input (million Btus)		5,704		4,923		5,021		5,122		5,224		5,329
Boiler Digester Gas Consumed		42,851		36,985		37,724		38,479		39,248		40,033
Tail Gas Consumed (million Btus)		-		-		-		-		-		-
Natural Gas Consumed (million Btus)		(37,147)		(32,062)		(32,703)		(33,357)		(34,024)		(34,705)
Digester Gas Consumed (million Btus)		63,661		54,945		56,044		57,165		58,308		59,474
Flared Digester Gas (million Btus)		12,275		10,595		10,807		11,023		11,243		11,468
Utilization Percentage		87.2%		87.2%		87.2%		87.2%		87.2%		87.2%
Electricity Purchased (MW-hrs)		12,784		11,034		11,255		11,480		11,710		11,944
Required heat for plant - (million Btus)		4,563		3,938		4,017		4,098		4,179		4,263
Excess boiler heat req'd (million Btus)		4,563		3,938		4,017		4,098		4,179		4,263
Daily peak heat demand, million Btu/hr		0.92		0.85		0.87		0.88		0.90		0.91
BioCNG Low Carbon Fuel Standard CO2e (MT CO2e)		1,507		1,300		1,326		1,353		1,380		1,408
Costs/(Revenues) for project												
Cost for electricity purchased	$	2,126,932	$	1,612,470	$	1,694,061	$	1,779,781	$	1,869,838	$	1,964,451
Revenue of DG sold as CNG	$	(167,774)	$	(124,202)	$	(130,487)	$	(137,089)	$	(144,026)	$	(151,314)
Revenue for RIN/LCFS Credits less tracking cost	$	(104,289)	$	(41,184)	$	(43,268)	$	(45,458)	$	(47,758)	$	(50,174)
Cost of NG for heating digesters	$	(297,466)	$	(215,259)	$	(226,151)	$	(244,722)	$	(257,105)	$	(270,114)
O&M costs for fuel treatment facilities	$	298,057	$	246,493	$	254,001	$	261,889	$	270,176	$	278,883
Total Annual Cost / (Revenue)	**$**	**1,855,460**	**$**	**1,478,318**	**$**	**1,548,157**	**$**	**1,614,401**	**$**	**1,691,126**	**$**	**1,771,732**

Initial Capital Cost Investment		$7,247,000										
Total Annual Costs			$	1,478,318	$	1,548,157	$	1,614,401	$	1,691,126	$	1,771,732
Present Value of Annual Costs			$	1,080,193	$	1,087,715	$	1,090,632	$	1,098,523	$	1,106,619
TOTAL PRESENT VALUE	**$**	**29,953,877**										
Total Annual cash flow - Expenditure / (Revenue)	$	7,247,000	$	15,653,230	$	17,201,387	$	18,815,788	$	20,506,914	$	22,278,646
Cummulative Present Value (Cash Flow)				11,437,662		12,085,466		12,711,272		13,320,900		13,915,177

Simple payback period: >20 years

San Bernardino WRP
Biogas Gas Use Applications
Alternative 5
CNG for Vehicle Fuel

ts' shown are in positive values and 'Revenues' are negative values.

Life Cycle Present Worth of Annual Costs

Year	**Average**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Operation Data										
Average Digester Gas Available (million Btus)	73,015	69,578	70,970	72,389	73,837	75,314	76,820	78,356	79,924	81,522
Digester Gas after treatment (million Btus)	69,364	66,099	67,421	68,770	70,145	71,548	72,979	74,439	75,927	77,446
Digester Gas Sold as CNG (million Btus)	20,809	19,830	20,226	20,631	21,044	21,464	21,894	22,332	22,778	23,234
Digester Gas Remaining (MMBTUs)	48,555	46,270	47,195	48,139	49,102	50,084	51,085	52,107	53,149	54,212
Treated Gas GGEs	180,951	172,433	175,882	179,399	182,987	186,647	190,380	194,188	198,071	202,033
Tail Gas (million Btus)	3,651	3,479	3,548	3,619	3,692	3,766	3,841	3,918	3,996	4,076
Boiler Heating Input (million Btus)	5,704	5,435	5,544	5,655	5,768	5,883	6,001	6,121	6,244	6,368
Boiler Digester Gas Consumed	42,851	40,834	41,651	42,484	43,334	44,200	45,084	45,986	46,906	47,844
Tail Gas Consumed (million Btus)	-	-	-	-	-	-	-	-	-	-
Natural Gas Consumed (million Btus)	(37,147)	(35,399)	(36,107)	(36,829)	(37,565)	(38,317)	(39,083)	(39,865)	(40,662)	(41,475)
Digester Gas Consumed (million Btus)	63,661	60,664	61,877	63,115	64,377	65,665	66,978	68,317	69,684	71,077
Flared Digester Gas (million Btus)	12,275	11,697	11,931	12,170	12,413	12,662	12,915	13,173	13,437	13,705
Utilization Percentage	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%
Electricity Purchased (MW-hrs)	12,784	12,183	12,426	12,675	12,928	13,187	13,451	13,720	13,994	14,274
Required heat for plant - (million Btus)	4,563	4,348	4,435	4,524	4,614	4,707	4,801	4,897	4,995	5,095
Excess boiler heat req'd (million Btus)	4,563	4,348	4,435	4,524	4,614	4,707	4,801	4,897	4,995	5,095
Daily peak heat demand, million Btu/hr	0.92	0.93	0.94	0.96	0.97	0.99	1.00	1.02	1.03	1.05
BioCNG Low Carbon Fuel Standard CO2e (MT CO2e)	1,507	1,436	1,465	1,494	1,524	1,554	1,585	1,617	1,649	1,682
Costs/(Revenues) for project										
Cost for electricity purchased	$ 2,126,932	$ 2,063,853	$ 2,168,284	$ 2,277,999	$ 2,393,265	$ 2,514,365	$ 2,641,592	$ 2,775,256	$ 2,915,684	$ 3,063,218
Revenue of DG sold as CNG	$ (167,774)	$ (158,970)	$ (167,014)	$ (175,465)	$ (184,343)	$ (193,671)	$ (203,471)	$ (213,767)	$ (224,583)	$ (235,947)
Revenue for RIN/LCFS Credits less tracking cost	$ (104,289)	$ (52,713)	$ (55,380)	$ (58,183)	$ (61,127)	$ (64,220)	$ (67,469)	$ (70,883)	$ (74,470)	$ (78,238)
Cost of NG for heating digesters	$ (297,466)	$ (283,782)	$ (298,141)	$ (313,227)	$ (329,076)	$ (345,728)	$ (363,222)	$ (381,601)	$ (400,910)	$ (421,196)
O&M costs for fuel treatment facilities	$ 298,057	$ 288,030	$ 297,640	$ 307,736	$ 318,343	$ 329,486	$ 341,194	$ 353,494	$ 366,416	$ 379,992
Total Annual Cost / (Revenue)	**$ 1,855,460**	**$ 1,856,417**	**$ 1,945,388**	**$ 2,038,860**	**$ 2,137,062**	**$ 2,240,232**	**$ 2,348,624**	**$ 2,462,500**	**$ 2,582,138**	**$ 2,707,829**

			2030	2031	2032	2033	2034	2035	2036	2037	2038
Initial Capital Cost Investment	$7,247,000										
Total Annual Costs			$ 1,856,417	$ 1,945,388	$ 2,038,860	$ 2,137,062	$ 2,240,232	$ 2,348,624	$ 2,462,500	$ 2,582,138	$ 2,707,829
Present Value of Annual Costs			$ 1,114,916	$ 1,123,413	$ 1,132,106	$ 1,140,995	$ 1,150,075	$ 1,159,347	$ 1,168,807	$ 1,178,454	$ 1,188,286
TOTAL PRESENT VALUE	**$ 29,953,877**										
Total Annual cash flow - Expenditure / (Revenue)		$ 7,247,000	$ 24,135,063	$ 26,080,451	$ 28,119,311	$ 30,256,372	$ 32,496,605	$ 34,845,228	$ 37,307,728	$ 39,889,865	$ 42,597,695
Cummulative Present Value (Cash Flow)			14,494,894	15,060,811	15,613,655	16,154,124	16,682,887	17,200,585	17,707,830	18,205,214	18,693,300

Simple payback period: >20 years

San Bernardino WRP
Biogas Gas Use Applications
Alternative 5
CNG for Vehicle Fuel

Year		**Average**		**2039**
Operation Data				
Average Digester Gas Available (million Btus)		73,015		81,424
Digester Gas after treatment (million Btus)		69,364		77,353
Digester Gas Sold as CNG (million Btus)		20,809		23,206
Digester Gas Remaining (MMBTUs)		48,555		54,147
Treated Gas GGEs		180,951		201,790
Tail Gas (million Btus)		3,651		4,071
Boiler Heating Input (million Btus)		5,704		6,361
Boiler Digester Gas Consumed		42,851		47,786
Tail Gas Consumed (million Btus)		-		-
Natural Gas Consumed (million Btus)		(37,147)		(41,425)
Digester Gas Consumed (million Btus)		63,661		70,992
Flared Digester Gas (million Btus)		12,275		13,689
Utilization Percentage		87.2%		87.2%
Electricity Purchased (MW-hrs)		12,784		14,257
Required heat for plant - (million Btus)		4,563		5,089
Excess boiler heat req'd (million Btus)		4,563		5,089
Daily peak heat demand, million Btu/hr		0.92		1.06
BioCNG Low Carbon Fuel Standard CO2e (MT CO2e)		1,507		1,680
Costs/(Revenues) for project				
Cost for electricity purchased	$	2,126,932	$	3,151,320
Revenue of DG sold as CNG	$	(167,774)	$	(242,733)
Revenue for RIN/LCFS Credits less tracking cost	$	(104,289)	$	(80,488)
Cost of NG for heating digesters	$	(297,466)	$	(433,310)
O&M costs for fuel treatment facilities	$	298,057	$	388,100
Total Annual Cost / (Revenue)	**$**	**1,855,460**	**$**	**2,782,888**

Initial Capital Cost Investment	$7,247,000				
Total Annual Costs				$	2,782,888
Present Value of Annual Costs				$	1,174,255
TOTAL PRESENT VALUE	**$ 29,953,877**				
Total Annual cash flow - Expenditure / (Revenue)		$	7,247,000	$	45,380,583
Cummulative Present Value (Cash Flow)					19,148,581

Simple payback period: >20 years

San Bernardino WRP
Biogas Gas Use Applications
Alternative 0
Flaring

Life Cycle Present Worth of Annual Costs

Year		**Average**		**2020**		**2021**		**2022**		**2023**		**2024**		**2025**		**2026**		**2027**
Operation Data																		
Average Digester Gas Available (million Btus)		72,255		82,419		82,419		82,419		59,941		61,140		62,363		63,610		64,882
Boiler Fuel Consumed (million Btus)		-		-		-		-		-		-		-		-		-
New Cogen Fuel Consumed (million Btus)		72,255		82,419		82,419		82,419		59,941		61,140		62,363		63,610		64,882
Total Fuel Consumed (million Btus)		72,255		82,419		82,419		82,419		59,941		61,140		62,363		63,610		64,882
Natural Gas Consumed (million Btus)		-		-		-		-		-		-		-		-		-
Digester Gas Consumed (million Btus)		72,255		82,419		82,419		82,419		59,941		61,140		62,363		63,610		64,882
Flared Digester Gas (million Btus)		-		-		-		-		-		-		-		-		-
Electricity Generated (MW-hrs)																		
Electricity Purchased (MW-hrs)		12,373		14,583		14,583		14,583		10,606		10,818		11,034		11,255		11,480
Required plant heat - (million Btus)		6,155		5,205		5,305		5,405		5,505		5,605		5,705		5,805		5,905
Excess boiler heat req'd (million Btus)		-		-		-		-		-		-		-		-		-
Daily peak heat demand, million Btu/hr		0.92		0.78		0.79		0.81		0.82		0.84		0.85		0.87		0.88
Cogen heating capacity, million Btu/hr		3.71		4.23		4.23		4.23		3.08		3.14		3.20		3.27		3.33
Excess (Boiler make up) peak day, million Btu/hr		2.79		3.46		3.44		3.43		2.26		2.30		2.35		2.40		2.45
Costs/(Revenues) for project																		
Cost for electricity purchased from SCE	$	2,114,710	$	1,784,723	$	1,838,264	$	1,893,412	$	1,418,338	$	1,490,106	$	1,565,505	$	1,644,720	$	1,727,942
O&M costs	$	26,084	$	20,770	$	21,393	$	22,035	$	22,696	$	23,377	$	24,078	$	24,800	$	25,544
Total Cost / (Revenue)	**$**	**2,140,794**	**$**	**1,805,493**	**$**	**1,859,657**	**$**	**1,915,447**	**$**	**1,441,034**	**$**	**1,513,483**	**$**	**1,589,583**	**$**	**1,669,520**	**$**	**1,753,487**
Intial Capital Cost Investment = $2,077,000																		
Total Annual Costs (Revenues)	$	2,140,794	$	1,805,493	$	1,859,657	$	1,915,447	$	1,441,034	$	1,513,483	$	1,589,583	$	1,669,520	$	1,753,487
Present Worth of Annual Costs (Revenues)	$	1,285,030	$	1,605,076	$	1,589,643	$	1,574,358	$	1,138,870	$	1,150,122	$	1,161,493	$	1,172,983	$	1,184,593
TOTAL PRESENT VALUE $ 27,777,597																		
Annualized Total Project Capital Cost	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140
Annualized Total Project Benefit	$	2,298,934	$	1,963,632	$	2,017,797	$	2,073,587	$	1,599,174	$	1,671,622	$	1,747,723	$	1,827,660	$	1,911,627
TOTAL COST OF OPTION	**$**	**29,854,597**																

Capital cost estimate	$2,077,000
Grant	$0
Net Capital Costs	$2,077,000

San Bernardino WRP
Biogas Gas Use Applications
Alternative 0
Flaring

Year		**Average**		**2028**		**2029**
Operation Data						
Average Digester Gas Available (million Btus)		72,255		66,180		67,503
Boiler Fuel Consumed (million Btus)		-		-		-
New Cogen Fuel Consumed (million Btus)		72,255		66,180		67,503
Total Fuel Consumed (million Btus)		72,255		66,180		67,503
Natural Gas Consumed (million Btus)		-		-		-
Digester Gas Consumed (million Btus)		72,255		66,180		67,503
Flared Digester Gas (million Btus)		-		-		-
Electricity Generated (MW-hrs)						
Electricity Purchased (MW-hrs)		12,373		11,710		11,944
Required plant heat - (million Btus)		6,155		6,005		6,105
Excess boiler heat req'd (million Btus)		-		-		-
Daily peak heat demand, million Btu/hr		0.92		0.90		0.91
Cogen heating capacity, million Btu/hr		3.71		3.40		3.47
Excess (Boiler make up) peak day, million Btu/hr		2.79		2.50		2.56
Costs/(Revenues) for project						
Cost for electricity purchased from SCE	$	2,114,710	$	1,815,376	$	1,907,234
O&M costs	$	26,084	$	26,311	$	27,100
Total Cost / (Revenue)	**$**	**2,140,794**	**$**	**1,841,687**	**$**	**1,934,334**
Intial Capital Cost Investment = $2,077,000						
Total Annual Costs (Revenues)	$	2,140,794	$	1,841,687	$	1,934,334
Present Worth of Annual Costs (Revenues)	$	1,285,030	$	1,196,325	$	1,208,180
TOTAL PRESENT VALUE $ 27,777,597						
Annualized Total Project Capital Cost	$	158,140	$	158,140	$	158,140
Annualized Total Project Benefit	$	2,298,934	$	1,999,827	$	2,092,474
TOTAL COST OF OPTION	**$**	**29,854,597**				

Capital cost estimate	$2,077,000
Grant	$0
Net Capital Costs	$2,077,000

San Bernardino WRP
Biogas Gas Use Applications
Alternative 0
Flaring

Year		**Average**		**2030**		**2031**		**2032**		**2033**		**2034**		**2035**		**2036**		**2037**
Operation Data																		
Average Digester Gas Available (million Btus)		72,255		68,853		70,231		71,635		73,068		74,529		76,020		77,540		79,091
Boiler Fuel Consumed (million Btus)		-		-		-		-		-		-		-		-		-
New Cogen Fuel Consumed (million Btus)		72,255		68,853		70,231		71,635		73,068		74,529		76,020		77,540		79,091
Total Fuel Consumed (million Btus)		72,255		68,853		70,231		71,635		73,068		74,529		76,020		77,540		79,091
Natural Gas Consumed (million Btus)		-		-		-		-		-		-		-		-		-
Digester Gas Consumed (million Btus)		72,255		68,853		70,231		71,635		73,068		74,529		76,020		77,540		79,091
Flared Digester Gas (million Btus)		-		-		-		-		-		-		-		-		-
Electricity Generated (MW-hrs)																		
Electricity Purchased (MW-hrs)		12,373		12,183		12,426		12,675		12,928		13,187		13,451		13,720		13,994
Required plant heat - (million Btus)		6,155		6,205		6,305		6,405		6,505		6,605		6,705		6,805		6,905
Excess boiler heat req'd (million Btus)		-		-		-		-		-		-		-		-		-
Daily peak heat demand, million Btu/hr		0.92		0.93		0.94		0.96		0.97		0.99		1.00		1.02		1.03
Cogen heating capacity, million Btu/hr		3.71		3.54		3.61		3.68		3.75		3.83		3.91		3.98		4.06
Excess (Boiler make up) peak day, million Btu/hr		2.79		2.61		2.67		2.72		2.78		2.84		2.90		2.97		3.03
Costs/(Revenues) for project																		
Cost for electricity purchased from SCE	$	2,114,710	$	2,003,740	$	2,105,130	$	2,211,649	$	2,323,559	$	2,441,131	$	2,564,652	$	2,694,423	$	2,830,761
O&M costs	$	26,084	$	27,913	$	28,751	$	29,613	$	30,501	$	31,416	$	32,359	$	33,330	$	34,330
Total Cost / (Revenue)	**$**	**2,140,794**	**$**	**2,031,654**	**$**	**2,133,880**	**$**	**2,241,262**	**$**	**2,354,060**	**$**	**2,472,547**	**$**	**2,597,011**	**$**	**2,727,753**	**$**	**2,865,091**
Intial Capital Cost Investment = $2,077,000																		
Total Annual Costs (Revenues)	$	2,140,794	$	2,031,654	$	2,133,880	$	2,241,262	$	2,354,060	$	2,472,547	$	2,597,011	$	2,727,753	$	2,865,091
Present Worth of Annual Costs (Revenues)	$	1,285,030	$	1,220,158	$	1,232,263	$	1,244,493	$	1,256,852	$	1,269,340	$	1,281,958	$	1,294,707	$	1,307,590
TOTAL PRESENT VALUE $ 27,777,597																		
Annualized Total Project Capital Cost	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140	$	158,140
Annualized Total Project Benefit	$	2,298,934	$	2,189,793	$	2,292,020	$	2,399,402	$	2,512,200	$	2,630,687	$	2,755,151	$	2,885,893	$	3,023,231
TOTAL COST OF OPTION	**$**	**29,854,597**																

Capital cost estimate	$2,077,000
Grant	$0
Net Capital Costs	$2,077,000

San Bernardino WRP
Biogas Gas Use Applications
Alternative 0
Flaring

Year		**Average**		**2038**		**2039**
Operation Data						
Average Digester Gas Available (million Btus)		72,255		80,673		80,576
Boiler Fuel Consumed (million Btus)		-		-		-
New Cogen Fuel Consumed (million Btus)		72,255		80,673		80,576
Total Fuel Consumed (million Btus)		72,255		80,673		80,576
Natural Gas Consumed (million Btus)		-		-		-
Digester Gas Consumed (million Btus)		72,255		80,673		80,576
Flared Digester Gas (million Btus)		-		-		-
Electricity Generated (MW-hrs)						8,230
Electricity Purchased (MW-hrs)		12,373		14,274		6,027
Required plant heat - (million Btus)		6,155		7,005		7,105
Excess boiler heat req'd (million Btus)		-		-		-
Daily peak heat demand, million Btu/hr		0.92		1.05		1.06
Cogen heating capacity, million Btu/hr		3.71		4.14		4.14
Excess (Boiler make up) peak day, million Btu/hr		2.79		3.10		3.08
Costs/(Revenues) for project						
Cost for electricity purchased from SCE	$	2,114,710	$	2,973,998	$	3,059,534
O&M costs	$	26,084	$	35,360	$	-
Total Cost / (Revenue)	**$**	**2,140,794**	**$**	**3,009,357**	**$**	**3,059,534**
Intial Capital Cost Investment = $2,077,000						
Total Annual Costs (Revenues)	$	2,140,794	$	3,009,357	$	3,059,534
Present Worth of Annual Costs (Revenues)	$	1,285,030	$	1,320,607	$	1,290,987
TOTAL PRESENT VALUE $ 27,777,597						
Annualized Total Project Capital Cost	$	158,140	$	158,140	$	158,140
Annualized Total Project Benefit	$	2,298,934	$	3,167,497	$	3,217,674
TOTAL COST OF OPTION	**$**	**29,854,597**				

Capital cost estimate	$2,077,000
Grant	$0
Net Capital Costs	$2,077,000

Appendix C

OPERATIONAL EXPERIENCE AND SITE TOURS

Alternative 1: Internal Combustion Engines with SCR - Orange County Sanitation District

A tour of the Plant No. 1 Cogeneration Facility at OCSD was provided by Mr. Aaron Suarez to SBWMD staff and Carollo Engineers, Inc. on March 5th, 2018.

Description of the Plant No. I Cogeneration Facility

The facility operates three 2.5 MW electric (MWe) engines by Cooper Bessemer installed in 1990. The facility consists of a 3-story building with the ICEs located on the ground level, auxiliary equipment for cooling loop, oil loop, jacket hot water recovery are located in the basement. The top level houses the exhaust treatment with SCR and CO catalysts and a heat recovery system with steam boilers.

Emissions and Compliance

The NOx concentration in the exhaust prior to the SCR treatment unit was around 30 ppm. As regulated by Rule 1110.2 the emission limits for NOx are 11 ppm and the actual operating level is consistently below 8 ppm NOx. Lower levels near 0 ppm NOx are achievable, but the secondary goal is to reduce urea consumption and to minimize the ammonia slip, required to be below 5 ppm (Rule 1110.2).

Heat recovered from the engines is used for digester heating and two adsorption chillers to generate chilled water at 45 Deg F for cooling of all administration buildings.

Digester Gas Pre-Treatment and Operational Experience with SCR

The digester gas is chilled to remove condensate prior to gas treatment in carbon vessels. The raw digester gas contains 20 - 28 ppm H_2S.

The gas treatment consisted of two steel vessels holding approximately 5,000 pounds (lbs) of carbon and other layers of media designed to remove H_2S and siloxane. The two vessels are operated in series as primary and polishing vessels. The cost to replace the media is $10,000 per vessel and it is replaced every 4 months. The media is good for 200 Million cubic feet of DG, before a breakthrough is detected. In addition, OCSD is also monitoring the treated DG for Toluene, which tends to break through before H_2S and siloxanes.

The fouling of the SCR is a slower process; if the NOx concentration increases above 11 ppm with the addition of urea, that is a sign that the catalysts are fouled. The catalyst replacement costs range from $50,000 - $100,000.

Cleaning of the catalyst off-site is possible, however it is important not to add any water to the SCR catalyst, because the metals used are water soluble. Johnson Matthew is the provider of the SCR equipment.

The only operational problem OCSD staff has encountered were air bubbles entrapped in the peristaltic pump tubing used for urea injection, which interrupts the flow.

For the continuous emission monitoring system the supplier CEMTEK provides service and equipment maintenance (e.g., filter replacement for air sampling lines) and CEMS calibration.

Operator Requirements

OCSD employs O&M staff dedicated to the operation and maintenance of the Plant 1 and Plant 2 power generation facilities. The O&M staff are trained as power plant operators and is separate from treatment plant O&M staff.

AQMD Permit

The system has been in compliance and the permit NOx compliance limit was subsequently modified from a 15-min moving average to a permit with 120-day moving average for NOx. Also, the 10 percent maximum for addition of NG was removed.

Costs:

The urea is replaced every 6 weeks (1,200 gallon), which equates to 28.57 GPD (urea feed pumps are sized for max 2.1 gpm) and 14.3 GPD per engines.

Urea usage: 30 GPD usage for 7.5 MW, 3.5 GPD per MW.

Carbon replacement costs:

The carbon costs at Plant No. 1 are $30,000 per year for 1,500 cfm (500 cfm per engine at 2.5 MW).

Economic Benefits:

- Power savings for the total plant is $9 million per year
- Steam production is around 5,000 lbs per hour
- DG at 75 psig feed pressure requires compressors
- Electrical Efficiency for the Cooper Bessemer is 39 percent (per operations staff) compared with a new Jenbacher engine which is at 40 percent.
- Every 15 minutes in downtime would cost OCSD $50,000 in electrical stand-by charges.

The electrical power demand for Plant No. 1 is 9 MW, while the generation is 7.5 MW. In addition, 5 engines are installed at Plant No. 2, which are generating excess power which can exported or used at Plant No. 1 to cover the total power demand. Plant No. 2 has a steam turbine rated at 1 MWe which results in a total of up to 15 MW for the OCSD complex.

The total DG flow rate is 3,000 cfm in a shared gas piping system.

Alternative 2: MTs - Santa Margarita Water District (SMWD)

A tour of the MT cogeneration facility was provided by Ron Johnson, Operations Manager at SMWD on March 5th, 2018. The Water District is operating five small MTs rated at 30 kW each fueled by digester gas. The untreated digester gas H_2S levels are around 100 ppm and testing is completed on a weekly basis. The DG is chilled for condensate removal, then treated for siloxane and H_2S using a specialty media called SAG B DM provided by AFT/Clean Methane Systems. The MTs are used units handed down from other Water Districts and one unit was received from University of California Irvine through a demonstration project.

At the time of the visit four of the five MTs operated continuously generating 120 kW of power. The required DG flow rate was 45 cfm (or 0.375 cfm/kW). The heat is recovered in heat exchangers to produce hot water for digester heating. The fuel input needed for MT is higher compared to ICE because the electrical efficiency at 27 percent – 33 percent is lower. An ICE can reach electrical efficiencies up to 42 percent. Emission source testing or continuous emission monitoring are not required for MTs. For the purpose of the annual emission inventory reporting to AQMD a source test was completed at SMWD. Also, no AQMD permit was required for these

MT rated < 50 HP since a MT is classified as a minor emitters. All maintenance and installation is being completed in-house.

Clean Methane Systems is providing the media vessels and replaces the media as part of a service contract. With a H_2S level of 100 ppm and the chiller removing some of the siloxane the media life is around one year.

Alternative 3: Fuel Cells with PPA - City of Riverside

A tour of the Fuel Cell cogeneration plant operated on DG at the City of Riverside was provided by Gilbert Perez, Operations Supervisor on March 5th, 2018. Based on the experience gained at the City of Riverside and other WWTP in California the maintenance and operation of a fuel cell operating on DG and the media replacement are commonly handled by the Fuel Cell Manufacturer (FCE) as part of a maintenance contract or PPA to protect the investment in the fuel cell stack.

The start-up of the fuel cell cogeneration plant under the current Power Purchase Agreement with the vendor FCE was on July 24, 2016. FCE has an easement and a business address at the WRP. The rate for the power purchased under the 20-year PPA started at 7.5 cents per kWh and will increase by 1.75 percent per year. In comparison the average power charges by the power provider Riverside Public Utilities are 11 cents per kWh (including the peak and standby charges).

With the outsourced operation and maintenance contract for the fuel cell and gas cleaning skids a certified and experienced maintenance service can be provided. The contract includes all gas scrubbing equipment, maintenance on all gas cleaning and fuel cell equipment, AQMD related permits source testing as applicable. The fuel cell gas handling includes a low pressure gas holder operating at 4 in W.C.

Under this PPA the City is required to reduce the H_2S levels from 140 ppm to below 50 ppm. Ferric chloride is added in the digester for this purpose. This ferric addition is also helpful in the case of a flaring event to achieve the SO_2 limits in the flare exhaust.

Experience with the service provided by FCE at Riverside was positive. Recently one VFD was damaged and was replaced within a week.

FCE can monitor the system operations, digester gas feed pressure and power output remotely (52U utility breaker). A load bank is included in the system to make up for power glitches. The City of Riverside has a very reliable power grid with only 2 power glitches per year, which helps with the stable operation of the FC.

No power export is currently possible, in case of excess power production. Since the WWTP is not connected to Edison grid the BioMAT program would not be available here. The feed flow rate is 296 to 300 cfm of DG to the fuel cell. The fuel cell has a nameplate efficiency of 48 percent and electrical output of 1.4 MW.

The WWTP facility digester production is enhanced through the addition of FOG and ADM (anaerobic digestible material), which is achieving a total of 411 cfm of digester gas.

The City of Riverside has a 75 percent diversion goal for organics by 2020. The City is working with the waste hauler Burrtec Waste Industries to process food waste at the Material Recovery Facility Aqua Mansa. Riverside WRP would receive a bioslurry for digestion in a dedicated digester or co-digestion with biosolids.

Figure D.1 Fuel Cell Installation at the Riverside RWQCP

Alternative 4: Gas Sale RNG Pipeline Injection

A list of related project references for the conversion of DG to RNG for pipeline injection at wastewater treatment plants is presented in Table below, which includes projects that have been completed or are underway.

Table D.1 Pipeline Injection Project Status

Project Location	Average Dry Weather Flow	Production Since	Biogas Utilization
Point Loma, CA	240 mgd	2012	Pipeline injection
Clean Water Services, OR	65 mgd	2017	Pipeline injection
CR&R	Dry Fermenter for Food and Green Waste	March, 2018	Pipeline injection
Des Moines, IA		Construction to begin in 2017	Pipeline injection
South Bend, IN	48 mgd	Completion expected September 2017	Pipeline injection

Alternative 5: Gas Sales as CNG at a Vehicle Fueling Station

Use of DG for the production of CNG for vehicle fuel has gained increasing interest over the past decade due to the economic benefit of offsetting vehicle fuel rather than electricity. With municipal fleet and private sector vehicles across the country converting to CNG, there is a great opportunity for collaboration by locating vehicle fueling stations near existing wastewater treatment plants and making use of an already available fuel source. While implementation of these types of projects at wastewater treatment plants is relatively new, the technology for conditioning and compressing the gas into CNG is well-established, and is currently in use at landfills across the country. Newly developed regulations and goals geared toward GHG emission reductions are providing newfound incentives for implementing these types of projects.

The Table below summarizes projects that have been completed or are underway to convert DG to CNG for vehicle fueling at wastewater treatment plants in the United States. The majority of the projects with CNG fueling stations are located in Northern California and out of State.

Table D.2 CNG Vehicle Fuel Project Status

Project Location	Average Dry Weather Flow	Production Since	Biogas Utilization
City of Janesville, WI	13 mgd	2012	CNG for vehicle fuel
City of Grand Junction, CO	8 mgd	2015	CNG for vehicle fuel
St. Petersburg, FL	35 mgd	2015	CNG for vehicle fuel
Napa Sanitation District, CA	9 mgd	In Progress	CNG for vehicle fuel
Columbia Boulevard Water Treatment Plant, OR	100 mgd	City Council approved; design not yet begun	CNG for vehicle fuel
City of San Mateo, CA	12 mgd	2016	CNG for vehicle fuel
City of Porterville, CA	5 mgd	Evaluation complete; design not yet begun	CNG for vehicle fuel
Petaluma, CA	5 mgd	In Design; Construction to begin in 2017	CNG for vehicle fuel

Figure D.2 Digester Gas Conditioning System in Grand Junction