INTEGRATED MASTER PLAN *for the* MAIN WASTEWATER TREATMENT PLANT

E100: Biogas Utilization Report

January 2022

E100: Biogas Utilization Study

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EBMUD

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TABLE OF CONTENTS

FIGURES

TABLES

ACRONYMS

A&G	Administrative and General
AB	Assembly Bill
BAAQMD	Bay Area Air Quality Management District
BEV	Battery Electric Vehicle
CAISO	California Independent System Operator
CalARP	California Accidental Release Prevention
CARB	California Air Resources Board
CASA	California Association of Sanitation Agencies
CCA	Community Choice Aggregator
CCCSWA	Central Contra Costa Solid Waste Authority
CCE	Community Choice Energy
CEC	California Energy Commission
CI	Carbon Intensity
CIP	Capital Improvement Program
CNG	Compressed Natural Gas
COD	Carbonaceous Oxygen Demand
CTE	Center for Transportation and the Environment
DAF	Dissolved Air Flotation
DAF	Dissolved Air Flotation
DCS	Distributed Control System
District	East Bay Municipal Utility District
EBCE	East Bay Community Energy
EBMUD	East Bay Municipal Utility District
EER	Energy Economy Ratio
EER	Energy Economy Ratio
eGRID	Emissions and Generation Resource Integrated Database
EPA	Environmental Protection Agency
eRIN	Electric Renewable Identification Numbers
ESA	Extended Service Agreement
EV	Electric Vehicle
FCEV	Fuel Cell Electric Vehicle
FEF	FirstElement Fuel
FOG	Fats, Oils, and Grease
FY	Fiscal Year
gal	Gallon
gCO2e/MJ	Grams of Carbon Dioxide Equivalent per Megajoule
GHG	Greenhouse Gas
gpm	Gallon per Minute

HRT	Hydraulic Residence Time
HSL	High-Strength Liquid
HSW	High-Strength Waste
k	Thousand
kg	Kilogram
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LCFS	Low Carbon Fuel Standard
LSE	Load-Serving Entity
M	Million
MMBtu	One Million British Thermal Units
MT	Metric Ton
MW	Megawatt
MWh	Megawatt-hour
MWWTP	Main Wastewater Treatment Plant
NQC	Net Qualifying Capacity
O&M	Operations and Maintenance
OSHA	Occupational Safety and Health Administration
PEV	Plug-In Electric Vehicle
PG&E	Pacific Gas & Electric
PGS	Power Generation Station
PGS1	Engines
PGS2	Turbine
Port	Port of Oakland
POTW	Publicly Owned Treatment Works
PPA	Power Purchase Agreement
PSM	Process Safety Management
Q	Quarter
R2	Resource Recovery
RA	Resource Adequacy
RCER	Routine Capital Equipment Replacement
REC	Renewable Energy Credit
RFEOI	Request for Expressions of Interest
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RMP	Risk Management Plan
RNG	Renewable Natural Gas
SB	Senate Bill
scfm	Standard Cubic Feet per Minute

SLW	Solid/Liquid Waste Receiving Station
TS	Total Solids
TWAS	Thickened Waste Activated Sludge
WAPA	Western Area Power Administration
WDT	Wholesale Distribution Tariff
ZEV	Zero Emission Vehicle

EXECUTIVE SUMMARY

The East Bay Municipal Utility District (District) produces biogas at its Main Wastewater Treatment Plant (MWWTP) from co-digestion of municipal sludge and high-strength trucked organic wastes, which are managed through the Resource Recovery (R2) Program. The District combusts the biogas on-site in engines and a turbine at the Power Generation Station (PGS) to generate renewable electricity. The renewable electricity is used to power the MWWTP and surplus electricity is exported to the Port of Oakland (Port) under a Power Purchase Agreement (PPA).

The renewable energy landscape in California is dynamic and has changed significantly over recent years. Over this time, the District has conducted a number of studies to evaluate biogas utilization opportunities. This report summarizes the studies with respect to the following goals:

- Characterize challenges and economics for PGS now and in the future
- Ensure that continued operation of PGS offers economic and non-economic value
- Identify opportunities to increase the value of on-site electricity generation
- Identify opportunities and challenges for new uses of biogas that are not based on electricity
- Recommend near-term steps that maintain program flexibility and maximize future biogas value

Existing Biogas Utilization:
Chapters 1 and 2 examine the economics of PGS. A cost-benefit financial analysis was performed and took into account a variety of factors, including operating expenses, tip fees, electricity sales, and offset electricity purchases. For offset electricity purchases, two options were considered: “brown power” from the Western Area Power Administration (WAPA) and “green power” from Pacific Gas and Electric (PG&E).

Three scenarios were developed: no change to current operations, retire turbine, and retire engines. The three scenarios were examined with respect to economic criteria as well as non-economic criteria such as greenhouse gases (GHSs) and local air emissions. The “no change to current operations” scenario remains the recommended option for the near-term future. This recommendation could be affected by the outcome of two significant over the next two years: the expiration of the current PPA and the renewal of the turbine extended service agreement (ESA).

The current PPA with the Port expires in November 2022. In advance of this event, District staff has performed a market assessment for surplus renewable power generated at PGS by engaging with parties that are potentially interested in the upcoming PPA, including the Port, East Bay Community Energy, Peninsula Clean Energy, and other regional community choice aggregators. The District issued a Request for Expressions of Interest (RFEOI) and received two responses. Based on the results of the RFEOI, the District expects to obtain more favorable terms in the future PPA; however, negotiations are still ongoing.

The turbine ESA with the manufacturer ends in November 2023. Currently, it is recommended that the ESA be renewed under the same terms and conditions; however, the financial analysis should be reviewed and updated prior to the renewal.

Chapter 3 discusses potential ways to increase the value of the District's renewable electricity, including:

- The implementation of Senate Bill (SB) 1383 procurement requirements may increase demand for renewable electricity derived from landfill diverted food waste.
- More favorable terms and conditions in the next PPA.
- Through the state's Low Carbon Fuel Standard (LCFS) program or the federal Electric Renewable Identification Numbers (eRINs) program, the value of renewable electricity may be increased when used as vehicle fuel through transportation-related credit trading.
- The District's renewable electricity could be used to charge electric vehicles (EVs) at the MWWTP, which is generally a higher value use.
- The District could install a direct connection to the Port or an on-site third party. A direct connection would avoid PG&E transmission fees, which could help the District negotiate favorable contract terms.

Biogas Utilization Alternatives:
Biogas utilization alternatives are discussed in Chapters 4 and 5.

Chapter 4 discusses challenges for alternative uses of biogas, including regulatory requirements, air permitting, and competing priorities in the Capital Improvement Program (CIP).

Chapter 5 examines new uses of biogas that are not based on electricity, including hydrogen vehicle fueling, renewable natural gas (RNG), bioplastic production, and future on-site uses. No alternative use for biogas has been identified that is currently feasible, primarily due to regulatory challenges and economics.

Conclusions:
The key conclusions of this report are:

- No alternative use for biogas has been identified that is currently feasible, primarily due to regulatory challenges and economics.
- While there are challenges to operating the turbine and the engines, the benefits outweigh the costs. No alternative arrangement to downsize PGS, i.e. by retiring the turbine or engines, has been identified that would improve the holistic outlook (economics, GHGs, and local air emissions).
- It is recommended that the PPA and turbine ESA be renewed. The District may be able to negotiate more favorable terms and conditions.
- Over the longer term, biogas utilization will be affected by several factors, including limits on nitrogen discharges to the Bay, dewatering capacity limitations, GHG reduction goals, and potential on-site uses of biogas (e.g., a post-digestion facility for biosolids).
- The renewable energy market is dynamic, so the analyses conducted in this report should be reviewed and updated on a regular interval (e.g., every 2 years) and at strategic decision-making milestones.

- Staff will continue to proactively monitor developments in the renewable energy market and engage with regulatory agencies and other stakeholders.

Next Steps:
In the near-term (1-2 years), the District will focus on the following next steps:
- Renew the PPA with the Port or a new party.
- Renew the turbine ESA.
- Consistently track PGS and R2 economics to ensure that costs don't exceed benefits.
- Strategically increase tip fees for high-strength wastes to ensure that the R2 program covers treatment costs and maximizes revenue.
- Clarify and/or establish green energy purchasing policy to meet the District's climate change goals.
- Continue to monitor LCFS and eRIN credit trading; EV charging of EBMUD fleet and/or employee vehicles; and a direct power supply connection with the Port or a third party.
- Continue to monitor and influence the guidance on the implementation of California Occupational Safety and Health Administration's (Cal/OSHA's) process safety management (PSM) on-site use exception.

In the mid-term (2-5 years), the District will focus on the following next steps:
- Analyze the resulting economics of PGS with the new PPA, new ESA, higher tip fees, feedstock changes, cost to treat, and the settlement between WAPA and PG&E regarding the pass-through wheeling wholesale distribution tariff (WDT).
- When required by regulations, implement the Right-Sizing of R2 to reduce and/or eliminate high-strength wastes that are high in nitrogen. Start first with protein wastes and evaluate the corresponding impact on nitrogen discharges to the Bay. If greater reductions are needed, target dairy wastes, as well. The impact this has on biogas generation and PGS economics will be carefully monitored.

1 BIOGAS PRODUCTION – CURRENT AND FUTURE

This chapter evaluates the following topics:

- Current biogas production and use
- Factors affecting future biogas production
- Impact of Right-Sizing R2
- Impact of Covid-19 pandemic
- Potential biogas utilization improvements

1.1 Current Biogas Production and Use

To understand how to better utilize and generate revenue from the District's biogas, it is important to understand the quantity and timing of biogas production.

Figure 1-1 and Figure 1-2 show a typical week's biogas production/use and excess biogas, respectively. The data have a frequency of 5 minutes and were averaged over a period of 6 months before the pandemic (April-October 2019).

Biogas production varies on a weekly cycle in part because trucked wastes are typically delivered during standard business hours on weekdays. Due to limitations in the biogas conditioning system, the maximum flow of biogas that can be utilized for renewable electricity generation is 2,300 standard cubic feet per minute (scfm). Biogas in excess of 2,300 scfm is flared.

From Tuesday morning through Saturday afternoon, biogas production exceeds utilization capacity and approximately 250 scfm on average is flared. In contrast, from Saturday afternoon through Tuesday morning, biogas production drops below the maximum utilization capacity and no biogas is flared.

To handle variations in biogas flow, the turbine is typically operated 95 percent of the time or greater (referred to as "base generation"), while engines are operated as needed when sufficient additional biogas is available.

Figure 1-1. Typical biogas production and use

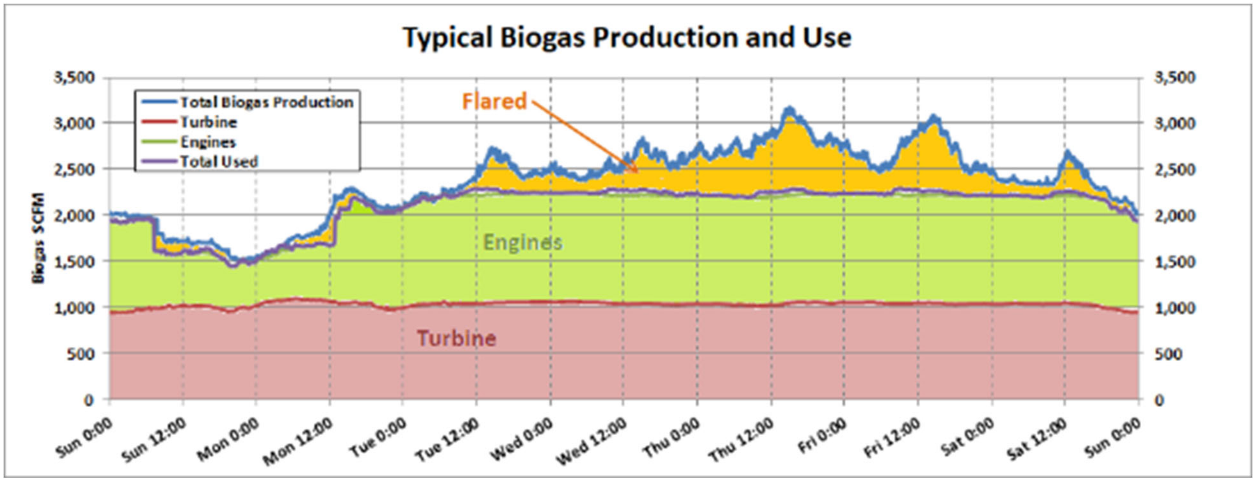
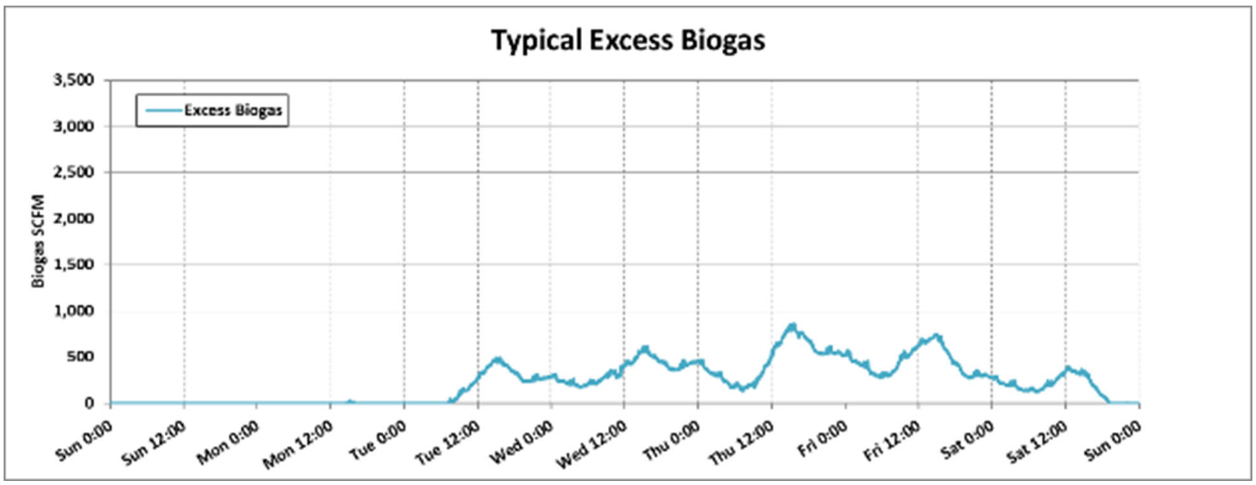


Figure 1-2. Typical excess biogas (over the 2,250 scfm that can be used)



This analysis indicates that, if new biogas utilization equipment were procured, it could only be operated for part of the week when excess biogas is available. Furthermore, when excess biogas is being produced, the quantity of excess biogas varies significantly, which creates challenges for the sizing of new equipment. If new equipment were sized for peak excess biogas, then the new equipment would be frequently underutilized. If the new equipment were sized for average excess biogas, then there would be periods of time when flaring would still be necessary.

Changing the pattern of biogas production such that production is more level over the course of a week would significantly improve the economics for both the existing generation and any new project.

1.2 Factors Affecting Future Biogas Production

The following four factors were evaluated regarding future biogas production:
- Receiving station capacity
- Digester capacity
- Dewatering capacity
- New regulations on nutrient discharges to the Bay

Receiving station capacity and digester capacity are not limiting to future biogas production. In contrast, dewatering capacity and new regulations on nutrient discharges to the Bay are limiting. More information is provided below.

1.2.1 Receiving Station Capacity

Receiving station capacity is likely not a constraining factor for future growth.

There are two stations where high-strength wastes (HSWs) are received at the MWWTP:
- **Solid Liquid Waste (SLW) Receiving Station:** SLW has two stations for liquid wastes, one station for blood wastes, and two stations for end dump trucks to dump higher solids (TS > 20%) loads. Historically, the limiting factor for accepting solid waste has been challenges associated with contamination in the delivered wastes. However, recently the District has worked with its food waste partners to reduce the amount of contamination in the solid waste loads. These efforts appear to have succeeded in reducing those challenges and the required processing time. With the improved solid waste quality, the receiving station likely has capacity for 3-4 solid waste deliveries per day and typically receives no more than one currently.
- **High-Strength Liquids (HSL) Receiving Station[1]:** The HSL Receiving Station typically receives 40-50 deliveries per day, corresponding to approximately 250,000 gallons per day. On the busiest of days, the station has received more than 70 trucks in a day, corresponding to 370,000 gallons delivered. The theoretical station capacity is over 1 million gallons per day, assuming one truck every 30 minutes for each of the five receiving bays.

1.2.2 Digester Capacity

The information provided below is from a previous study that the District performed to evaluate the MWWTP's capacity to accept raw sludge from Palo Alto for digestion.

The average flow to the digesters in 2017 and 2018 was approximately 460-490 gpm total, with 150 gpm from R2. The digesters have a total capacity of about 550-625 gpm depending on the assumptions used for the organic loading rate, minimum hydraulic residence time, and number of digesters in service.

[1] Also known as FOG Receiving station or Blend Tank Receiving Station.

The difference between current loading and the estimated total digester capacity indicates that digester capacity is not a limiting factor and there is room for significant growth in feed volumes to the digesters.

As feed volumes to the digesters increase, there may be increased potential for foaming. In July 2020, digester foam overflowed from the top of the digesters and caused challenges for operation. In response, the R2 feed was reduced to decrease loading to the digesters, which allowed the foaming to recede and provided more flexibility to operators for troubleshooting. However, no clear cause for the foaming was found and evidence to date does not seem to implicate trucked wastes.

1.2.3 Dewatering Capacity

The District completed a detailed dewatering capacity assessment in June 2019. This assessment analyzed available operating data from 2016-2018 and determined that dewatering capacity is often limited due to a variety of reliability issues that cause equipment to malfunction or be taken offline. Until the dewatering capacity limitations are addressed, the R2 program cannot bring in significant additional feedstock for digestion.

There are two projects in development that are intended to relieve the dewatering capacity constraints:

- **Second-Stage Digester Mixing:** The addition of pump mixing to the second-stage digesters should reduce the incidents of grit slugs going to dewatering. This project should be completed within 2 years; however, the extent to which it will reduce downtime isn't clear yet.
- **Grit Removal at Blend Tanks:** There is a capital project to add grit removal to the Blend Tanks to remove grit upstream of the digesters. This project also has the potential to reduce grit going to the dewatering process and increase dewatering capacity, but is not expected to be operational until late 2022.

Depending on the results of these improvements, the R2 strategy in the short term is to moderately reduce flow to the digesters by increasing tip fees. The Master Plan roadmap includes the planning, design, and construction of a new Dewatering Building that is expected to be completed in 2029. During the planning and design phases, the feasibility of increasing dewatering capacity to accommodate R2 will be evaluated. If sufficient capacity is provided at the new Dewatering Building, the bottleneck can be eliminated altogether.

1.2.4 New Regulations on Nutrient Discharges to the Bay

To comply with expected future nutrient regulations and meet the District's goals of reducing GHGs for the wastewater system, the Master Plan roadmap includes the implementation of "Right-Size R2." In this strategy, some trucked wastes that are high in nitrogen such as protein wastes and dairy dissolved air flotation (DAF) wastes (hereby referred to as "dairy wastes") will be reduced and/or eliminated. If more significant nutrient reductions are needed, a nutrient removal technology such as sidestream treatment or mainstream treatment can be implemented.

Once implemented, effluent nitrogen would be reduced to such a degree that high-nitrogen R2 waste streams could be brought back if desired.

Implementing Right-Size R2 will require a strategic and iterative approach involving further analysis and trial and error. Some questions to analyze prior to implementing Right-Size R2 are:

- Are estimates of nitrogen in protein and dairy wastes accurate?
- Should the District raise prices for protein and dairy wastes to discourage those customers, or explicitly prohibit the wastes altogether?
- How do prices impact the desire of R2 customers to deliver trucked wastes to the MWWTP? Will gradually increased prices gradually reduce deliveries? Or is there a threshold price at which deliveries will abruptly decrease or even stop?
- Are there other high-strength or low-strength waste streams that are high in nitrogen and should be reduced and/or eliminated?
- Will new or expanded trucked wastes (such as food waste) have high nitrogen loads? What is the best way to determine nitrogen load prior to accepting new wastes?

1.3 Impact of Right-Size R2

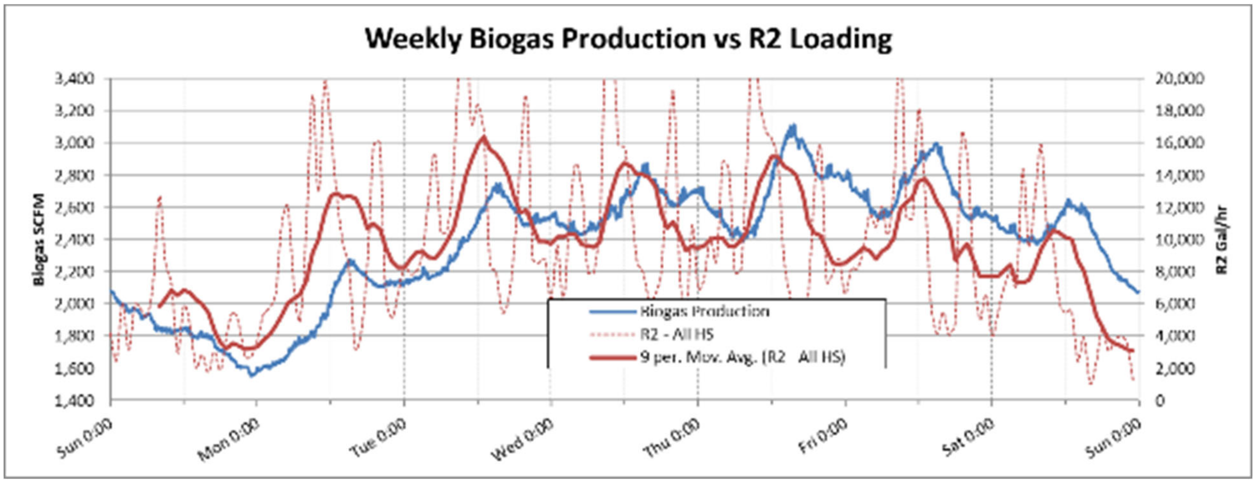
Implementing Right-Size R2 will reduce and/or eliminate high-nitrogen waste streams. In general, reducing HSW deliveries of any kind will in turn reduce biogas production. Whether the reduction in biogas production has an impact on power generation depends on the timing and magnitude of the reduction. This section provides an overview of various analyses that evaluated the impact that eliminating protein and dairy wastes would have on biogas production.

Analyses conducted by the District and the Lawrence Berkeley National Laboratory indicated that R2 feedstocks are generally broken down and converted into biogas within one day.[2]

Figure 1-3 juxtaposes the data shown in Figure 1-1 with the typical R2 carbonaceous oxygen demand (COD) loading to show the delay between when the R2 feedstocks are fed into the digester and the corresponding change in biogas production. On average, the delay is approximately 9 hours. This method is relatively accurate in predicting biogas production; however, it overestimates biogas production early in the week and underestimates biogas production later in the week.

[2] Wang, Yang; Huntington, Tyler; Scown, Scorinne (2021): Tree-based automated machine learning to predict biogas production for anaerobic co-digestion of organic waste. Preprint 06.28.2021

Figure 1-3. Biogas production vs R2 loading

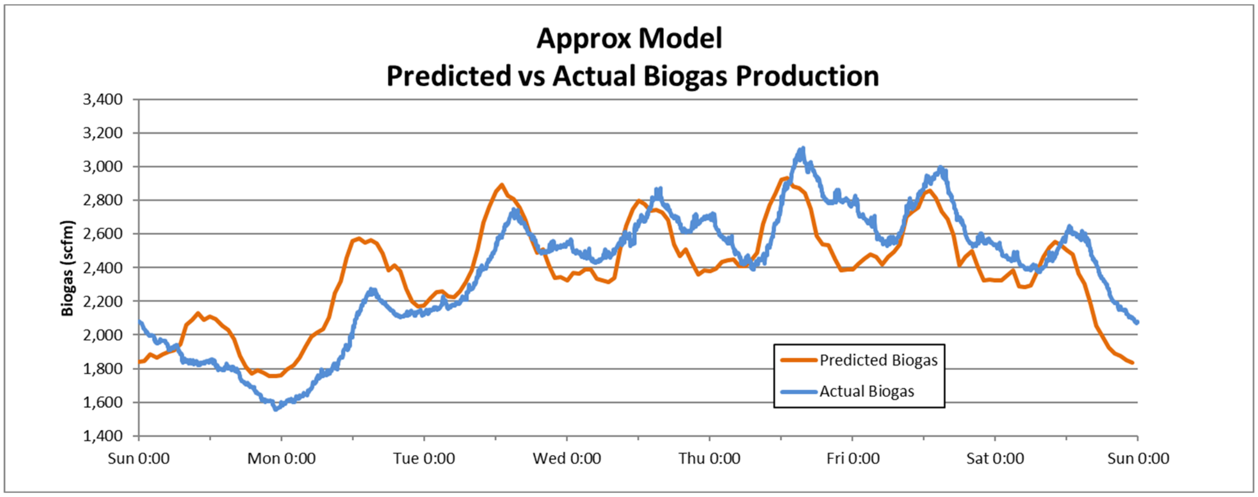


A preliminary model to simulate biogas production was developed based on the following assumptions:

- An average of 1,000 scfm of biogas from primary sludge and thickened waste activated sludge (TWAS), resulting in an average of 8.7 scfm of biogas/gal of R2 waste. This metric is in agreement with the cost-to-treat model.
- 60% of the R2 waste is broken down and converted to biogas evenly over 9 hours.
- 40% is broken down and converted into biogas evenly over 4 days.

The model output is shown in Figure 1-4, which juxtaposes predicted and actual biogas production for all R2 wastes. While imperfect, the predicted biogas curve is reasonably close enough to estimate the effect of removing certain trucked wastes.

Figure 1-4. Comparison of predicted and actual biogas



The model was used to simulate biogas production from protein and dairy wastes, as shown in Figure 1-5 and Figure 1-6, respectively. It was assumed that these feedstocks generate 9.2 scfm of biogas/gal of waste (slightly more biogas than the R2 average of 8.7). In both figures, the dashed line represents the deliveries of feedstock, while the solid line represents the corresponding predicted biogas.

For protein wastes, the deliveries are represented as large peaks and generally occur from Monday through Friday during business hours. With a one-day lag, most of the biogas that is produced from these feedstocks occurs from Tuesday through Saturday. If protein waste were completely eliminated, the total biogas lost would be 160 scfm on average.

For dairy wastes, the deliveries are more consistent throughout the entire week, so the biogas production is more even. If dairy wastes were completely eliminated, the total biogas lost would be 380 scfm on average.

Figure 1-5. Biogas derived from protein wastes

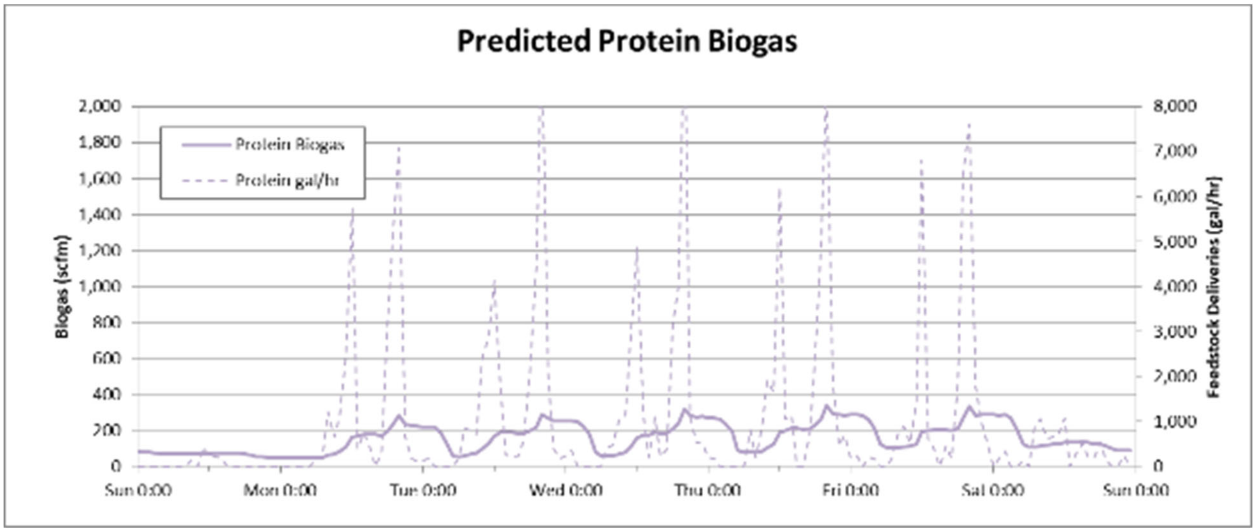
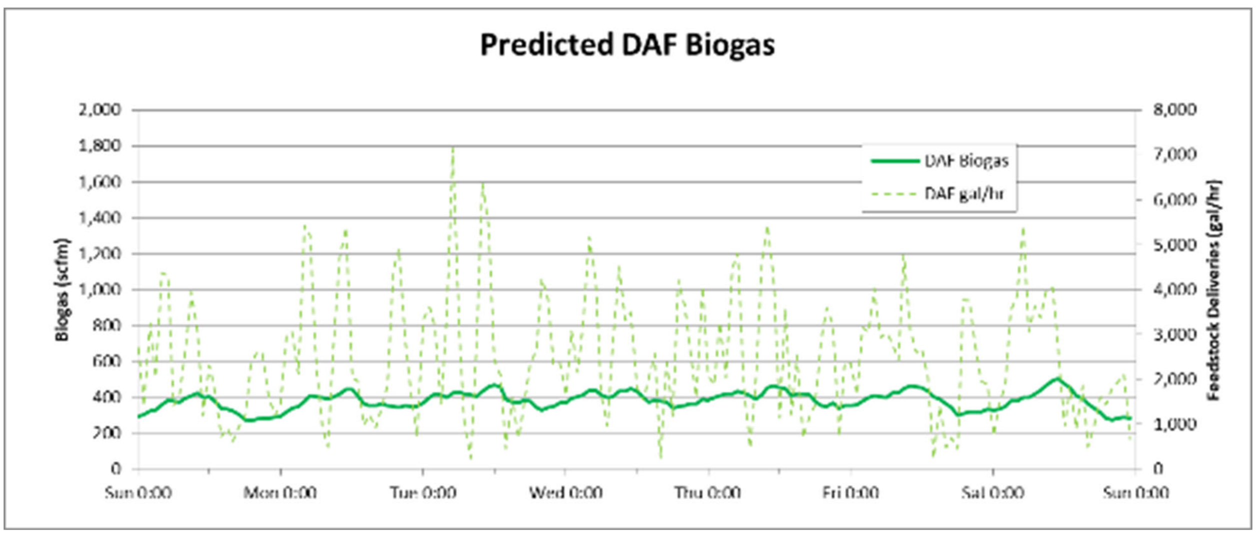


Figure 1-6. Biogas derived from dairy wastes



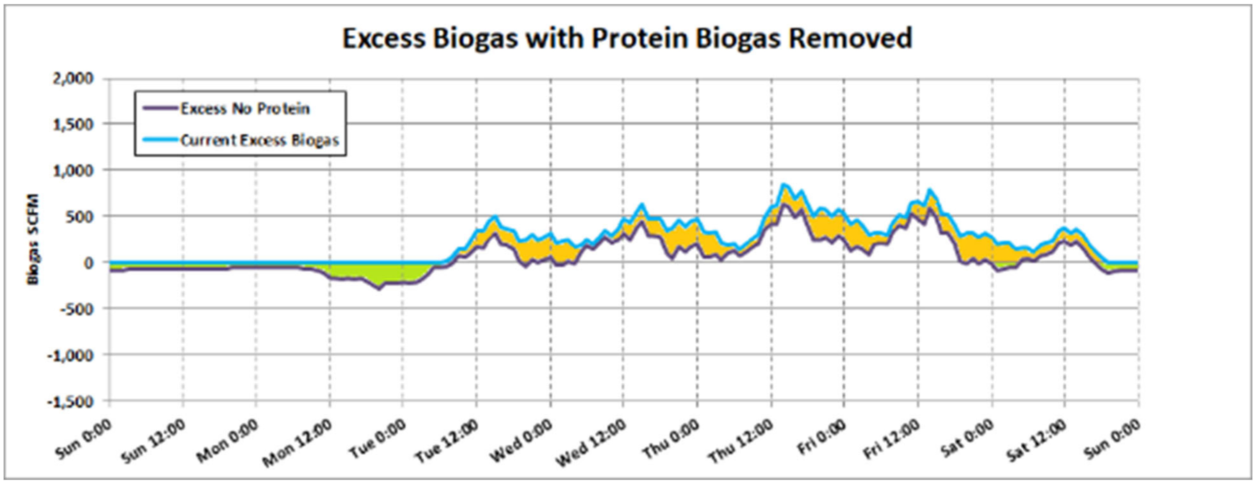
The typical excess biogas in Figure 1-2 and the predicted biogas in Figure 1-5 and Figure 1-6 were used to determine the impact of eliminating protein and dairy wastes. The results are shown in Figure 1-7 and Figure 1-8.

In Figure 1-7, the shaded area between the two lines shows the excess biogas that would be lost if protein wastes were eliminated. The upper blue line is the original excess biogas (Figure 1-2), and the lower purple line is the resulting excess biogas after elimination of protein wastes. When the lower purple line drops below zero, the excess biogas is shaded green and shows *useful lost biogas*. In other words, this biogas could have been used to generate power and would not have been flared. When the purple line is above zero, the biogas is shaded orange and shows lost biogas that would have been flared.

The orange area is significantly larger than the green area, indicating that most of the lost biogas would not be useful anyway due to the timing. The useful portion of the biogas lost is 26% of the total, equivalent to 40 scfm or 2% of the biogas currently being used (total biogas production due to protein wastes is nearly 200 scfm). As a result, eliminating protein waste would only reduce power production by 2%, equivalent to 1,000 MWh per year.

Operationally, the elimination of protein wastes would mean that the second engine would be turned on slightly later in the week, i.e. on Tuesday instead of Monday.

Figure 1-7. Excess biogas if protein wastes were eliminated



A similar analysis for dairy wastes is shown in Figure 1-8. The green area is much larger and occurs over a much larger fraction of the week. The useful portion of the biogas lost is 48% of the total, equivalent to 185 scfm or 9% of the biogas currently being used (the total biogas production due to dairy wastes is nearly 400 scfm). As a result, eliminating dairy wastes would reduce power production by 9%, equivalent to 4,500 MWh per year.

Operationally, the elimination of dairy wastes would have the following impacts:

- On the weekend, only the turbine would operate.
- On weekdays, the turbine and one or two engines would operate. The second engine would be turned on later in the week, and may need to cycle on and off more frequently.

Figure 1-8. Excess biogas if dairy wastes were eliminated

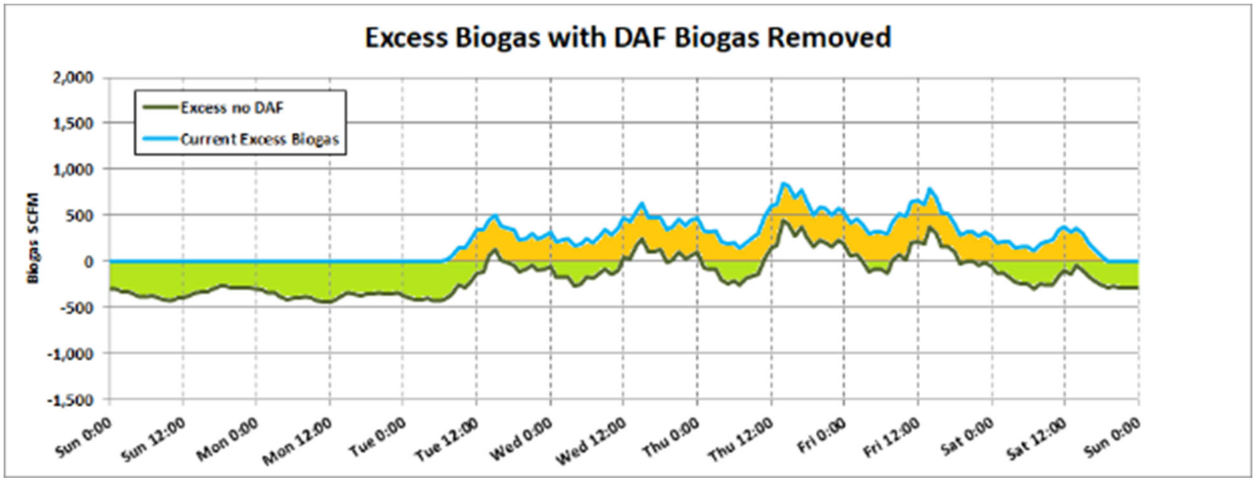
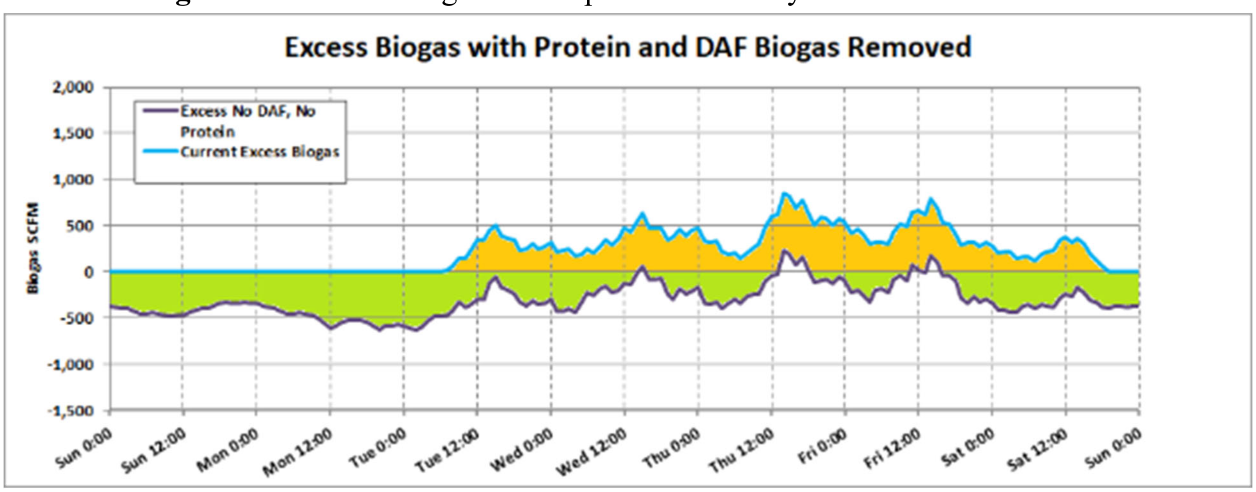


Figure 1-9 shows a similar analysis for the elimination of both protein and dairy wastes. The total biogas lost would be about 600 scfm on average with the useful portion of the biogas lost being about 60% of the total, equivalent to 310 scfm or 15% of the biogas currently being used. As a result, eliminating both protein and dairy wastes would reduce power production by 15%, equivalent to 7,500 MWh per year.

The results indicate that the impact is not additive. In other words, one might think that a 2% reduction for protein wastes plus 9% reduction for dairy wastes would result in a total reduction of 11%; however, the actual impact is larger at 15%.

Figure 1-9. Excess biogas if both protein and dairy wastes were eliminated



The financial impact of the scenarios in Figure 1-7, Figure 1-8, and Figure 1-9 is illustrated in Table 1-1. This table includes the profit margin from each stream, as well as the impact of reduced power production. The net revenue lost is $225,000 for protein wastes only, $460,000 for dairy wastes only, and $725,000 for both protein and dairy wastes.

Table 1-1. Financial impact of eliminating protein and dairy wastes

	FY20 Gallons	Gross Revenue	Profit Margin	Net Revenue	Total Biogas Production (scfm)	Power production/yr (% of total)	Biogas Operating Revenue/yr	Total Net Revenue/yr
Protein Wastes Only	10 MG	\$800,000	\$0.02	\$200,000	200	~ 1,000 MWh (~ 2%)	\$25,000	\$225,000
Dairy Wastes Only	18 MG	\$700,000	\$0.02	\$350,000	400	~ 4,500 MWh (~ 9%)	\$100,000	\$460,000
Protein and Dairy Wastes Combined	28 MG	\$1.5M	--	\$550,000	600	~ 7,500 MWh[1] (~ 15%)	~ \$175,000[1]	\$725,000

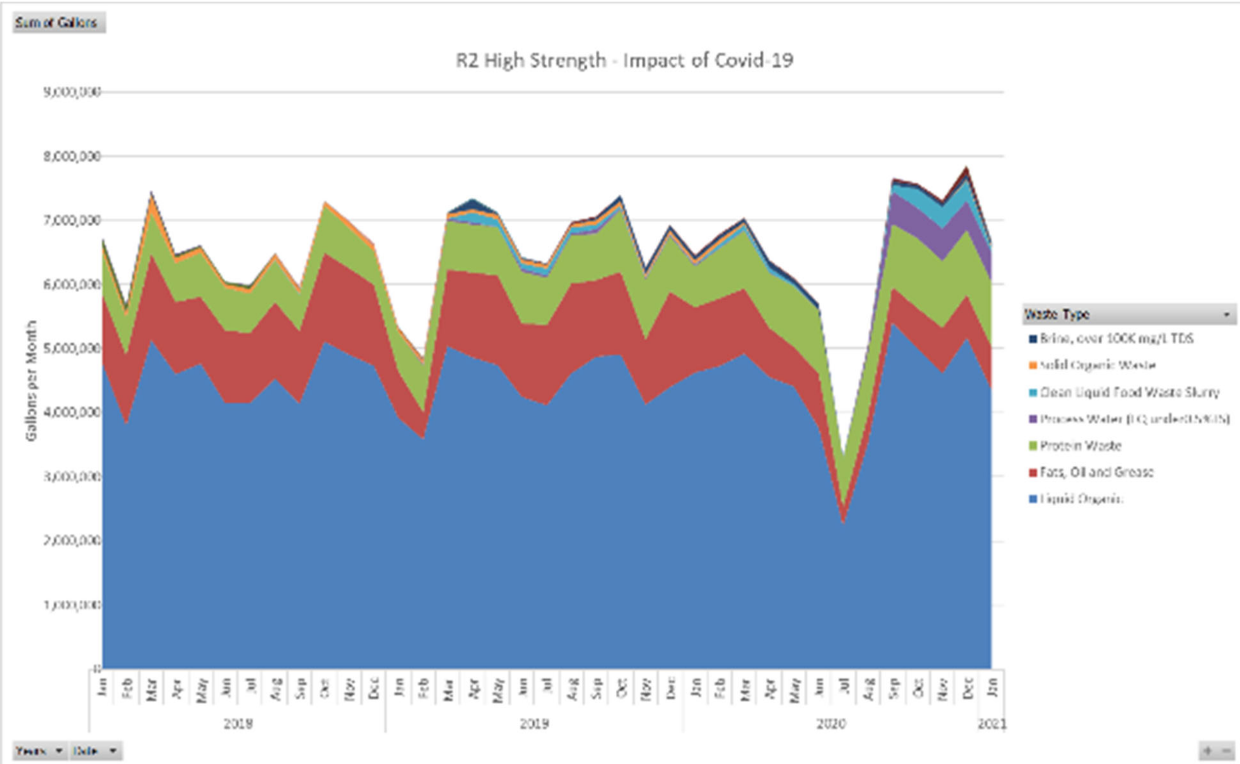
1. The combined losses are larger than the simple addition because there is less excess protein biogas that would otherwise be flared when dairy wastes are also removed.

1.4 Impact of Covid-19 Pandemic

Figure 1-10 shows the monthly volume of HSW from 2018 through 2021. Note that the major drop in July 2020 was due to delivery restrictions imposed due to a digester foaming incident, as discussed in Section 1.2.2.

From April-August 2020, there was a slight reduction in HSW deliveries due to the pandemic. However, since September 2020, HSWs have been as high or higher than historical levels. Currently, there is no reason to expect a long-term impact on HSW deliveries due to the pandemic.

Figure 1-10. Impact of Covid-19 on HSWs



1.5 Potential Biogas Utilization Improvements

As discussed in Section 1.1, biogas production varies on a weekly cycle due to the timing of R2 deliveries. The vast majority of R2 customers are not required to provide advance notice or schedule a planned delivery. Instead, the customer can deliver the load whenever it suits them best. While this flexibility makes the District a more attractive disposal option compared to competitors, it does lead to challenges with optimizing biogas utilization.

In recent years, one of the goals for the R2 program has been to even out the production of biogas throughout the week, which would reduce the amount of flaring, better utilize the engines, and increase annual energy production. There are several methods that could be used to achieve this goal, including:

- Incentivize weekend R2 deliveries through discounts
- Biogas storage
- Liquid high-strength waste storage
- Upgrade gas conditioning capacity

These methods are discussed in more detail below.

1.5.1 Incentivize Weekend R2 Deliveries Through Discounts

The District has evaluated two ways to incentivize weekend R2 deliveries through discounts.

In 2017, the District signed a five-year contract with Hilmar for dairy wastes. As a part of the contract, Hilmar was given a 0.5 cent/gallon discount on weekend deliveries. However, an increase in weekend deliveries has not been observed, as shown in Figure 1-11.

After the Hilmar pilot showed little-to-no impact with a single large customer, the District pilot tested a larger program for fats, oils, and grease (FOG) haulers with a 0.3 cent/gallon discount. FOG haulers were targeted because it was assumed that they do not have fixed production schedules. The pilot test lasted from February-April 2020 and had no discernable impact on the weekly pattern of deliveries, as shown in

Figure 1-12.

Figure 1-11. Impact of Hilmar pricing incentive

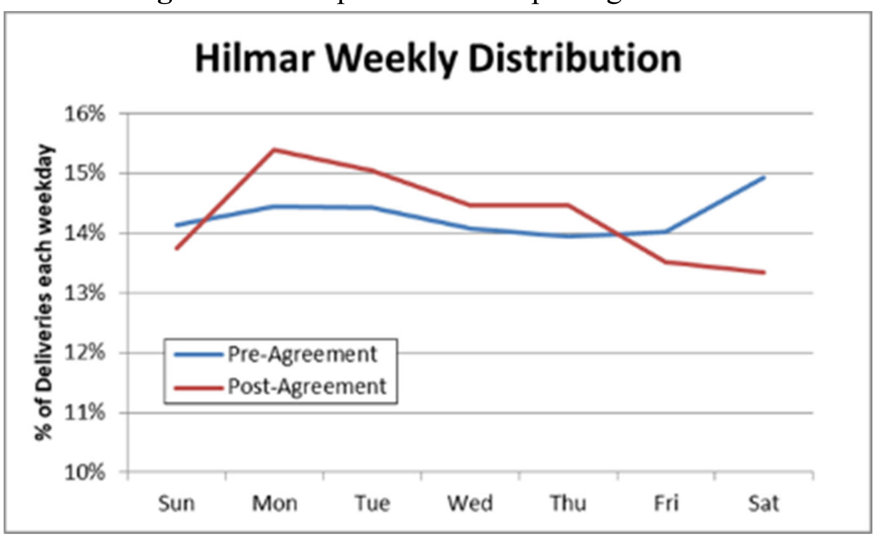
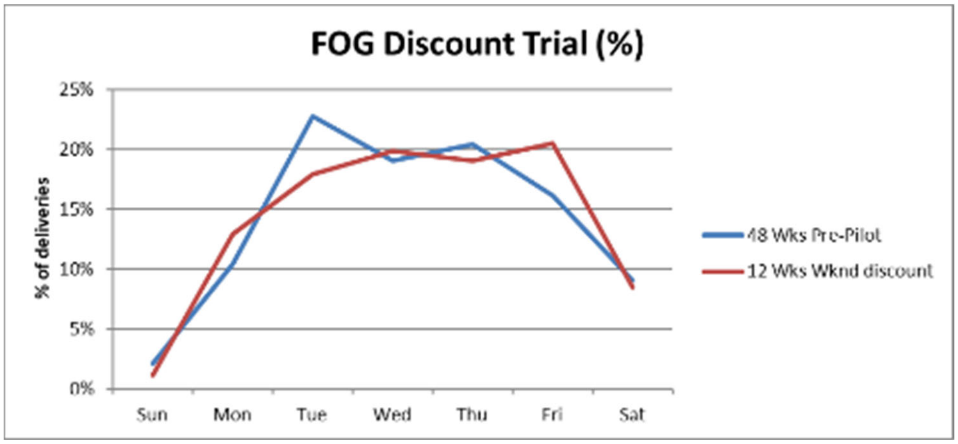


Figure 1-12. Impact of FOG pricing pilot



The results of these two efforts show that incentive pricing for weekend deliveries has limited potential to even out biogas production. The suspected reasons for why the efforts had limited success include:

- The tip fees charged by the District are only a fraction of the total disposal cost. For example, the cost to haul to the MWWTP can be as high or higher than the tip fee.
- Haulers may charge a higher price for weekend trips, thereby negating any discount provided by the District.
- In general, the tip fee is a very small fraction of R2 customers' operating costs. The R2 customers are unlikely to make major changes based on a pricing incentive.

The District will continue to explore opportunities to encourage weekend deliveries where and when it makes sense, e.g. with customers that operate 7 days a week. However, this is not expected to be able to meaningfully change the distribution of biogas production.

1.5.2 Biogas Storage

Biogas storage is one alternative to manage variable biogas production. Excess biogas that is produced on weekdays can be stored for several days and then used on the weekend.

Digester 2 already has a Dystor double membrane gas holder providing some gas storage and Dystor covers are being added to Digesters 3 and 4 adding an additional ~ 320,000 scf of biogas storage. When complete, there will be roughly 500,000 scf of low pressure biogas storage. If fully utilized, this storage could in theory supply an additional 600 scfm (1 engine) of biogas for about 14 hours of the weekend drop. In practice, this storage is likely to be mostly used for maintaining steady pressures and smooth operation and likely will have limited use for shifting biogas to the weekend for use.

The next best option for biogas storage would be high-pressure storage using a Horton sphere. This alternative would provide approximately 600,000 scf of biogas storage, which is enough to supply one engine at 600 scfm for 16 hours. However, a Horton sphere has several major drawbacks. The cost would be over $10M, so even if it were used every weekend, the payback period would be over 100 years. In addition, high-pressure gas storage would have potential safety hazards and would be challenging to operate due to corrosion from the moisture and hydrogen sulfide present in digester gas.

1.5.3 Liquid High-Strength Waste Storage

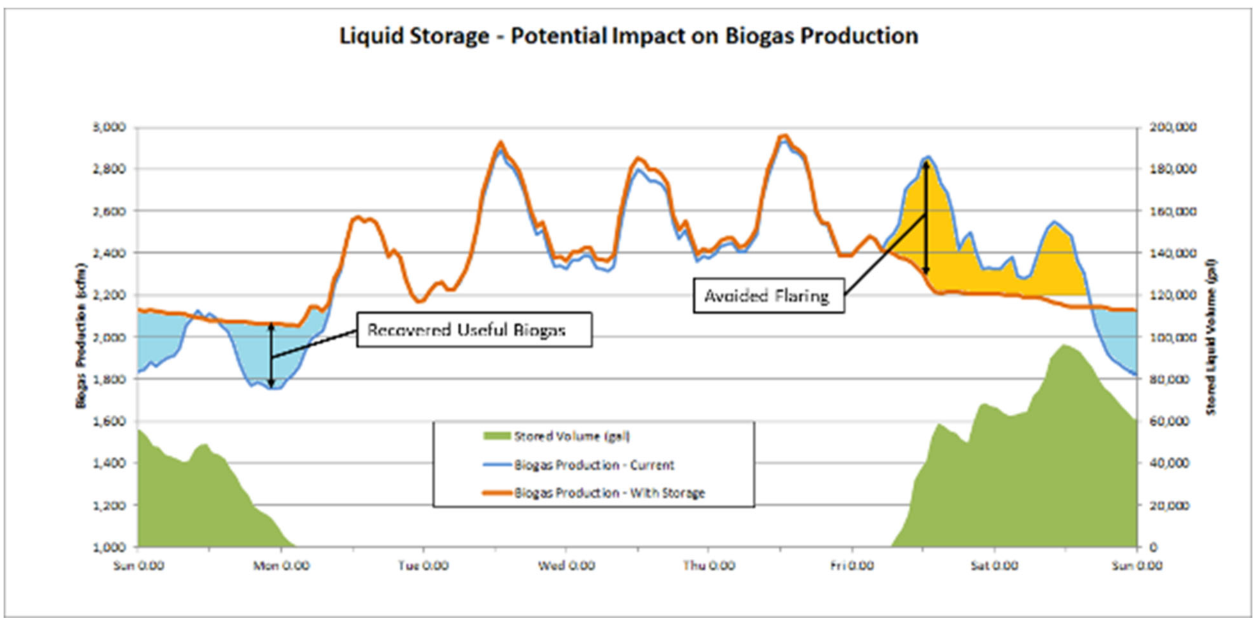
An alternative to storing biogas is to store liquid HSWs, i.e. prior to digestion.

The estimated amount of biogas from the average HSW is approximately 8.7 scf/gal. As a result, the volume needed to store liquid HSW is 65 times smaller than that of the resultant biogas.

In theory, one of the existing Blend Tanks with a volume of 200,000 gallons could store enough liquid HSW to produce 1.7 million scf of biogas. This amount is enough to supply 600 scfm for about 2 days, which would be more than enough to manage the weekend lull in biogas production.

Figure 1-13 illustrates how this alternative could operate in practice. The first Blend Tank would be used to equalize the liquid HSW feed rate from Friday morning through Sunday night. Over this period, 6,800 gal/hr of liquid HSW would be continuously fed from the first Blend Tank into the digesters. Any excess over this amount would be stored in the second Blend Tank for use over the weekend. In the figure, the volume that is stored in the second Blend Tank is shown in green and the predicted resultant biogas production is shown as the solid red line.

Figure 1-13. Simulation of storing liquid HSWs



The stored volume of liquid HSW would not exceed 100,000 gallons, which is well under the total capacity of 200,000 gallons. Biogas flaring (shaded in orange) would be reduced by 20-25% on Friday and Saturday. The biogas production rate would not drop below 2,100 scfm due to the recovered useful biogas (shaded in blue), allowing for 1,500 MWh of more power to be produced annually. With this operating scenario, it would not be necessary to shut off one of the engines due to the drop in biogas that normally occurs.

Since HSW is more "energy-rich" than primary sludge or TWAS, this scenario would be the most effective if only HSW were stored in the Blend Tank. However, another option would be to store a mixture of HSW, primary sludge, and TWAS.

There are a number of concerns and potential challenges to this alternative that would need to be evaluated through further analysis and a pilot study, including:

- Odor control
- Potential to produce methane in the Blend Tank used for storage
- Reduced operational redundancy
- Increased operational complexity

1.5.4 Upgrade Gas Conditioning Capacity

Currently, the gas conditioning system only has capacity to support the turbine and two engines. One alternative would be to increase the biogas conditioning system capacity to allow for the operation of a third engine.

Assuming that a third engine could be run any time that there is excess biogas over 300 scfm and that that engine could use up to 600 scfm, the benefits of running a third engine with high uptime could be up to:

- A 70% reduction in flaring
- 4,800 MWh more power produced each year with a marginal value of around $100k/year

Some of the potential challenges to this alternative include:

- How often is a third engine actually available? One engine is often out of service for maintenance or rehabilitation, so the actual uptime and benefits may be much lower than the maximum.
- The current amount of excess biogas is often only 300-400 scfm. Balancing the operation of a third engine on this reduced amount of biogas may be challenging, especially given the variable and rapidly changing amount of biogas being produced.
- The third engine may need to cycle on and off each day based on the diurnal swings in biogas production.

Given the operational challenges and limited potential upside, this alternative is unlikely to provide a meaningful return on investment.

2 EXISTING ENERGY SYSTEM REVENUES AND COSTS

This chapter evaluates the following topics:

- Existing energy system
- Value of electricity produced
- Cost to operate PGS
- PGS operational cost and value
- Additional biogas value
- Projected revenue and cost
- Optimizing PGS operations

2.1 Existing Energy System

2.1.1 Energy Generation

Three internal combustion engines were installed in 1985. Each engine is rated at 2.15 MW and uses biogas as the primary fuel. Heat is recovered from engine jacket, lube oil system, and engine exhaust for digester heating using hot water. Collectively, the three engines are referred to as Power Generation Station One (PGS1). The engines are classified as dual fuel, and use a de minimis amount of diesel fuel (<2% of total fuel input) for co-firing. At one time in the early 2000s, the engines also used fossil natural gas (gas blending), but that practice was discontinued after a few years when it became economically impractical. Since diesel use is de minimis, all of the electricity generated by the engines is classified as renewable energy by the state.

Diesel continues to be used in the engines for two reasons. First, the engines need to use diesel for start up until they are warm enough to switch over to using biogas as the primary fuel. Second, even after start up, a small amount of diesel (~30 gallons/day) is required for the engine to continue to operate under normal conditions. In a diesel engine, ignition is caused by the heat of compression and not a spark ignition like in a gasoline car engine. This is possible due to the nature of diesel fuel, which ignites under relatively low compression. However, natural gas and biogas are high-octane fuels that can withstand more compression before igniting. As a result, natural gas and biogas won't combust under compression in a diesel engine which lacks a sparks ignition. For the dual fuel engines to run on biogas, small amounts of diesel have to be continuously added to ignite under compression, which then ignites the biogas.

Due to growth in biogas production from the R2 Program, a Solar Mercury 50 gas-fired 4.6 MW turbine was installed in 2012 to increase generation capacity and reduce flaring. This turbine features a recuperated design with a heat exchanger to pre-heat the air entering the unit, increasing system efficiency. The turbine is referred to as Power Generation Station Two (PGS2) and currently operates as a base load unit, i.e. the primary means of on-site generation. The turbine also recovers heat via the exhaust stack and the resulting hot water heats the digesters. Unlike the engines, the turbine is fueled exclusively by biogas.

Table 2-1 provides an overview of key similarities and differences between the engines and turbine:

Table 2-1. Design criteria of engines and turbine

Characteristic	Engines	Turbine
Name	PGS1	PGS2
Year of Installation	1985	2012
No. of Operating Units	3	1
Gross Generation Capacity (MW)	6.45 total (2.15 each)	4.6
Fuel	Biogas w/de minimis diesel	Biogas only
Heat Recovery	Engine jacket, oil lube, exhaust	Exhaust
Fuel Compression (psi)	65	200
Nominal Fuel Use at Max. Generation (scfm)	Approx. 2,000 scfm for all three engines	Approx. 1,200
Electrical Efficiency	~30%	~39%

There are several key differences between the operation and maintenance of the engines and turbine. While engine overhauls can be performed by a number of qualified contractors, the turbine must be serviced exclusively by the manufacturer, Solar. As a result, the District entered into an Extended Service Agreement (ESA) with Solar in 2013 and 2018, each time with 5-year contracts. The ESA includes complete overhaul of the main body of the turbine nearing the end of each term.

Another difference is that the turbine requires conditioned biogas that is free of siloxanes. A gas conditioning system (dryer and activated carbon) was installed with the turbine in 2012. To reduce engine maintenance, conditioned biogas is also fed to the engines, although the engines are more tolerant of siloxanes.The biogas conditioning system has a capacity of roughly 2,300 scfm. This conditioning capacity limits the total biogas consumption to roughly the turbine and up to 2 engines and is not sufficient to support running the turbine and 3 engines simultaneously.

2.1.2 Air Emissions and Air Permit

The air permit for the MWWTP contains several clauses relevant to the use of PGS1, PGS2, the boiler and the flares. The relevant clauses include:

> ***Cond# 18860***[3]
> *Emissions from* [the digesters] *shall be abated at all times by combustion at any or all of the following sources:* [Engine 1, Engine 2, Engine 3, boiler and turbine], *except as specified in Part 2. ….*

[3] MWWTP Permit to Operate, Expiring May 1, 2021

> *Emissions from* [the digesters] *shall be abated by of the following:* [flares] *only when required as a result of gas production exceeding available combustion capacity, equipment testing, or emergency conditions…*

The air permit requires the engines or turbine to be used before the flares and normally only allows the flares to be used when gas production exceeds the available combustion capacity. The underlying assumption being that the flares are for non-routine use.

The MWWTP has four primary ways to combust biogas. The turbine is the cleanest, followed by the engines, the new flares, and lastly the old flares. The reason the new flares were permitted to be less clean than the engines is because the flares are an abatement device only to be used when the engines are not available. As a result, even under new standards for the new flares, the emission limits are less stringent than for a "prime" engine.

The emissions from the engines and flares are routinely monitored, and a comparison between their emissions is shown below in Table 2-2. The turbine is cleaner than the engines for all the parameters by varying orders of magnitude. For example, the turbine is four times cleaner for nitrous oxides, 50 times cleaner for carbon monoxide, and several thousand times lower for methane.

Table 2-2. Comparison of air emissions for the engines and turbine

Parameter	Engines		Turbine	
	Average	Typical Range	Average	Typical Range
Nitrous oxides	20	15-25	6.5	4-15
Carbon monoxide[1]	260	250-350	4.5	1-8
Sulfur dioxide (ppm)	8	5-10	5	1-10
Methane (ppm)	3,400	3,000-4,000	1	0.5-3

2.1.3 Energy Supply

The MWWTP is fed by two PG&E lines from separate PG&E substations for redundancy (Oakland C and Oakland L as shown in Figure 3-2 and Figure 3-3). The MWWTP operates under a split bus arrangement, i.e. most equipment can be powered by either line. The engines are normally aligned with the C Line and the turbine is normally aligned with the L Line. Under unusual operating conditions like a prolonged outage, a tie bus may close such that the entire plant is served by one PG&E circuit and the cogeneration unit(s) aligned with that circuit. EBMUD's interconnection agreement with PG&E prohibits aligning both generating systems to one or the other circuit simultaneously. The L Line has a capacity of approximately 5,700 kilowatts (kW) and the C Line has a capacity of approximately 4,800 kW.[4]

[4] EBMUD, *Main Wastewater Treatment Plant Energy System Master Plan,* 2012, p. 8

Figure 2-1. Map of PG&E transmission lines and substations (in red)

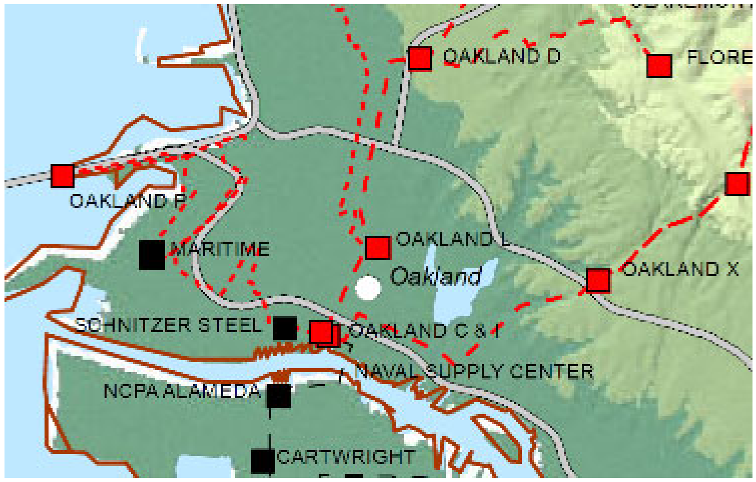
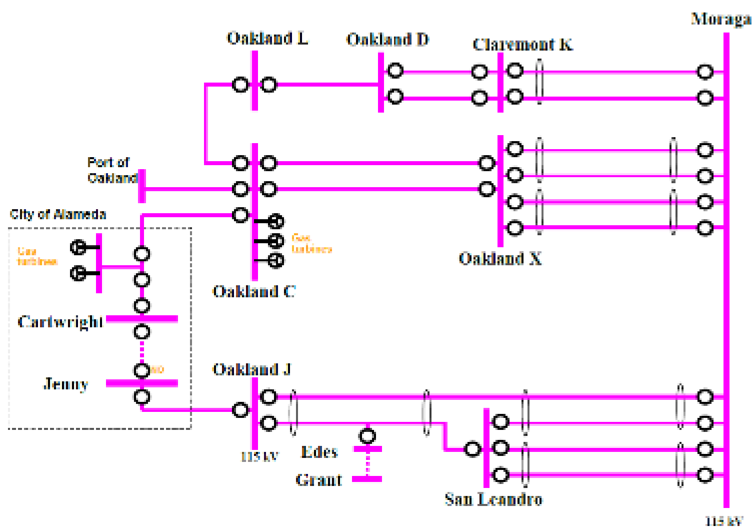


Figure 2-2. Existing Oakland 115 kV system (2017)



Historically, transmission capacity has not been a limiting factor for providing power to the MWWTP or exporting the District's on-site electricity. The capacity of the two PG&E lines matches the demand of 10.5 MW for the MWWTP in the contract with PG&E, prior to changes made in 2021. These changes are discussed in greater detail in Section 2.2.2 below, but include a reduction in the contract demand to 8 MW, as requested by the District. If PGS were downsized, the contract demand with PG&E would likely need to be revisited.

The contract demand is the maximum amount of capacity and energy that the Distribution Provider (PG&E) determines can safely and reliably be provided over its Distribution System to each of a Distribution Customer's (District's) Points of Delivery, based upon the Distribution Customer's request. The Distribution Customer shall request a Contract Demand based upon its expected non-coincident peak load at each Point of Delivery, and the Distribution Provider shall make all reasonable efforts to accommodate the request. Contract demand shall be expressed to the nearest tenth of a megawatt on a 30-minute interval (commencing on the clock hour and half-hour) basis.

2.2 Value of Electricity Produced

The electricity that is produced on-site is used to power the MWWTP, reducing the amount of off-site power that needs to be purchased. Surplus electricity that is produced on-site is exported to the PG&E grid and is currently sold to the Port under a PPA.

2.2.1 WAPA Power

While most of the electricity used at the MWWTP is generated on-site, there is still a significant amount of power that is purchased each year during periods of high power demand such as wet weather and maintenance outages.

Electricity is delivered to the MWWTP via PG&E distribution at the primary (12 kV) level. Electricity is purchased from the Western Area Power Administration (WAPA) with a pass through wheeling wholesale distribution tariff (WDT) charge from PG&E for distribution.

WAPA is one of four power marketing administrations within the US Department of Energy whose role is to market and transmit wholesale electricity from multi-use water projects like the Central Valley Project. Within the Wastewater Department, only the MWWTP is served by WAPA. The wet weather facilities and pump stations are served directly by PG&E or a local community choice aggregator such as the East Bay Community Energy (EBCE). Rates for WAPA are significantly lower than for PG&E or EBCE. For example, WAPA power has historically been approximately one third of the cost of PG&E or EBCE.

EBMUD electricity purchased from WAPA generally falls under two categories:

- **Base Resource Power:** Base resource power is generally sourced from hydroelectric projects and is cheaper than custom product power. Water Operations has priority over Wastewater for use of base resource power, although any surplus may be apportioned to Wastewater.
- **Custom Product Power:** Custom product power is supplemental power purchased by WAPA on the wholesale market for its customers and is the bulk of the power provided to Wastewater. Sources for custom product power vary, and WAPA has not provided the District with detailed information on these sources. For GHG emission accounting purposes, the District uses the EPA's Emissions and Generation Resource Integrated Database (eGRID) for the environmental characteristics of WAPA Custom Product power delivered in California. The most recent eGRID data (2018) show that California's resource mix includes 50% generation[5] from fossil-derived fuels, which is the assumed resource mix for WAPA custom product power used at the MWWTP.

[5] https://www.epa.gov/sites/production/files/2020-01/documents/egrid2018_summary_tables.pdf

Charges for WAPA electrical service are multiple and complicated, and some charges may adjust or correct over time, e.g. imbalance charges assessed by the California Independent System Operator (CAISO). This makes it challenging to accurately summarize and trend these charges for comparative purposes. Some of the more impactful charges and their characteristics include:

- The unit rate for base resource power varies each month depending on hydrologic conditions and outlook.
- The unit rate for custom product power varies according to wholesale power market and contract portfolio.
- The charges for scheduled power delivery vs unscheduled delivery are different and settled on different timeframes, e.g. for unscheduled power delivery (CAISO imbalances) charges can be adjusted months or sometimes years after the power was delivered.
- WAPA sends only one bill to the District, so charges are segregated between Water Operations and Wastewater. Some flat administrative fees are apportioned between Departments based on relative usage.

The analysis below considers these factors in assessing the cost of imported power at the MWWTP.

2.2.2 PG&E Pass Through Wheeling Charge

The WAPA bill includes a PG&E pass through wheeling WDT charge, which covers the transmission and distribution charges from PG&E for delivering WAPA power to the MWWTP.

Prior to 2021, the WDT charge for the MWWTP was based on the peak simultaneous ("coincident") power draw over 30 minutes for both grid connections combined each month. The WDT charge was $5,673/MW per month plus admin fees. This charge was based only on the peak monthly power draw and was not related to the total amount of power purchased or the contract demand.

In September 2020, PG&E filed proposed rate changes and revisions to certain non-rate terms and conditions of its WDT Service Agreement with WAPA. The proposed rate changes would modify the basis for, and increase the cost of, its WDT. WAPA filed an Intervention and Protest on October 6, 2020. WAPA's intervention and protest, along with all other filings, can be viewed on the Federal Energy Regulatory Commission's website under Docket ER20-2878. Since the matter is in active litigation, limited details are available.

PG&E's proposed changes include a 130% increase in the WDT rate from $5.567 to $12.950/kW per month. PG&E also proposed changing the basis for the WDT charge. Instead of charging based on the actual peak power draw each month, the charge would be based on the contract demand, regardless of the actual peak power draw. If the peak power draw exceeded the contract demand, PG&E would have the right to revisit the contract demand.

In June 2021, interim rates went into effect under an interim settlement between WAPA and PG&E. The interim terms include:

- An updated rate of $3.97/KW per month
- Contract demand based rate

- Opportunity to update or modify the contract demand. The District took this opportunity to change the contract demand for the MWWTP to 8 MW based on historical data.

It is unknown how long it will take for WAPA and PG&E to reach resolution. Details about the settlement are unavailable, but could include a retroactive modification to the interim settlement rate and basis.

As the proposed rate changes are still in flux, the historical WDT charges were used in this cost-benefit financial analysis. Once the rates have been finalized, the WDT portion of this analysis will need to be updated.

2.2.3 Value of Offset Electricity Purchases

By producing its own on-site power, the District avoids purchasing power from WAPA. The value of the avoided WAPA electricity purchases has two main components: the avoided total power purchased each month and the avoided contract demand charge. The value of each of these has been estimated separately and is discussed in more detail below.

Avoided Power Purchase: The cost per kWh for power purchased from WAPA has been estimated for each of the last five fiscal years, as shown in Table 2-3. The energy rate (which does not include the contract demand charge from PG&E) shows significant variation, with a low of $57.53 in FY17 and a high in FY19 of $76.37. It is difficult to determine if there is a trend; however, the recent years have had higher rates.

For the purposes of this analysis, the estimated rate for each fiscal year was used for that year. For years before FY16, the average of the FY16/FY17 rate was used. For years after FY20, the average of the FY19/FY20 rate was used.

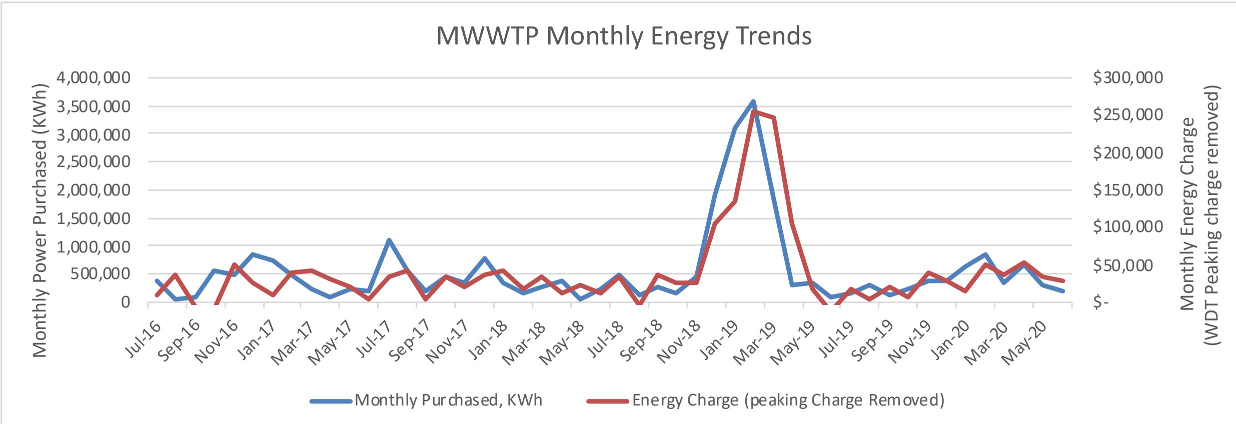
Table 2-3. Estimated WAPA energy rate ($/kWh) for the last five fiscal years

	FY16	FY17	FY18	FY19	FY20
Total Energy Invoice (peaking charge removed)	$308,709	$251,064	$314,303	$966,142	$332,130
Total Energy Purchased (kWh)	4,415,845	4,364,400	4,878,336	12,650,160	4,644,480
Average Unit Rate ($/kWh)	$69.91	$57.53[1]	$64.43	$76.37	$71.51

1. In previous version of this analysis, FY17 was the only year used to estimate the WAPA energy rate. This happened to have been an unusually low-cost year, likely due to an abundance of hydropower.

Figure 2-3 shows the monthly power purchased and energy charge (with the WDT peaking charge removed) over the past several years. In FY19, the MWWTP imported significantly more power than normal (nearly three times as much) due to an extended engine outage over three to four months. This figure shows a strong but imperfect correlation between the amount of energy purchased and the energy bill due to all the factors discussed above. Absent any extended on-site generation outages, more power tends to be purchased during the winter when wet weather can cause power demand to sometimes exceed generation capacity.

Figure 2-3. MWWTP monthly energy trends

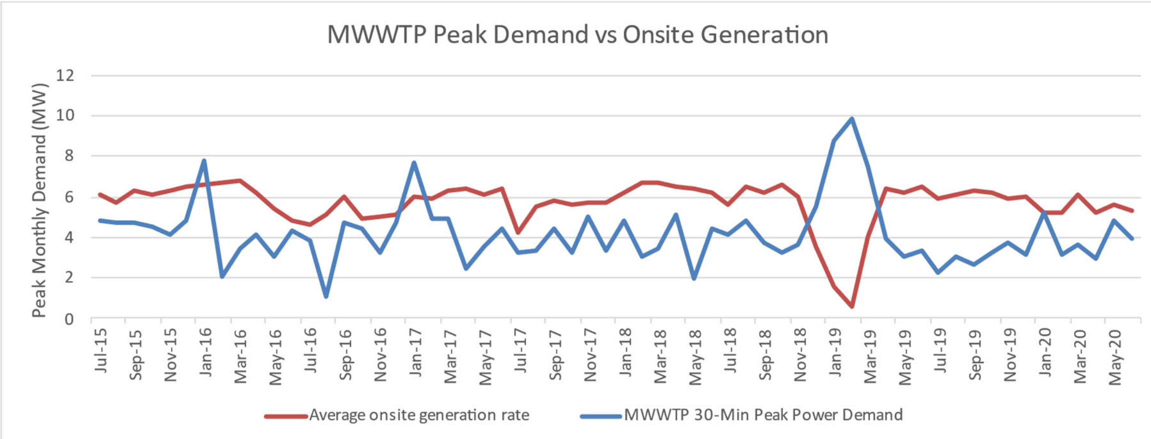


Avoided PG&E Pass Through Wheeling WDT Charge: As discussed above, historically the WDT charge was based on the peak 30 minutes of power drawn from the grid through both lines (coincident demand) in a given month.

The historical reduction in the monthly peak power draw was estimated as being equal to the average on-site generation rate for the year, which is typically 5-6 MW. This estimate is not precise, but provides a reasonable approximation.

This estimate can be checked by comparing the typical peak monthly demand with the two-month period in early 2019 when on-site generation was severely reduced, as shown in Figure 2-4. The average peak demand for the 12 months before and after this period is 3.6 MW. In early 2019, on-site generation was much lower than normal (averaging only 1.1 MW), while the peak demand was much higher than normal (averaging 9.2 MW during wet weather events). A peak demand of 9.2 MW is 5.6 MW higher than normal, even with some on-site generation still taking place, which gives some indication that the estimated 5-6 MW reduction in peaking charges due to on-site generation is a reasonable estimate. The current WDT charge is $5,673 per MW per month.

Figure 2-4. MWWTP peak monthly demand vs on-site generation



If the basis for the WDT charge changes from peak power draw to contract demand, the method above will not work. Instead, PGS would be assigned the benefit of any reduction in the contract demand due to having on-site generation. It is unlikely that the District would have reduced the contract demand for the MWWTP to 8 MW from 10.5 MW without having on-site generation.

2.2.4 Value of Electricity Sold to the Port of Oakland

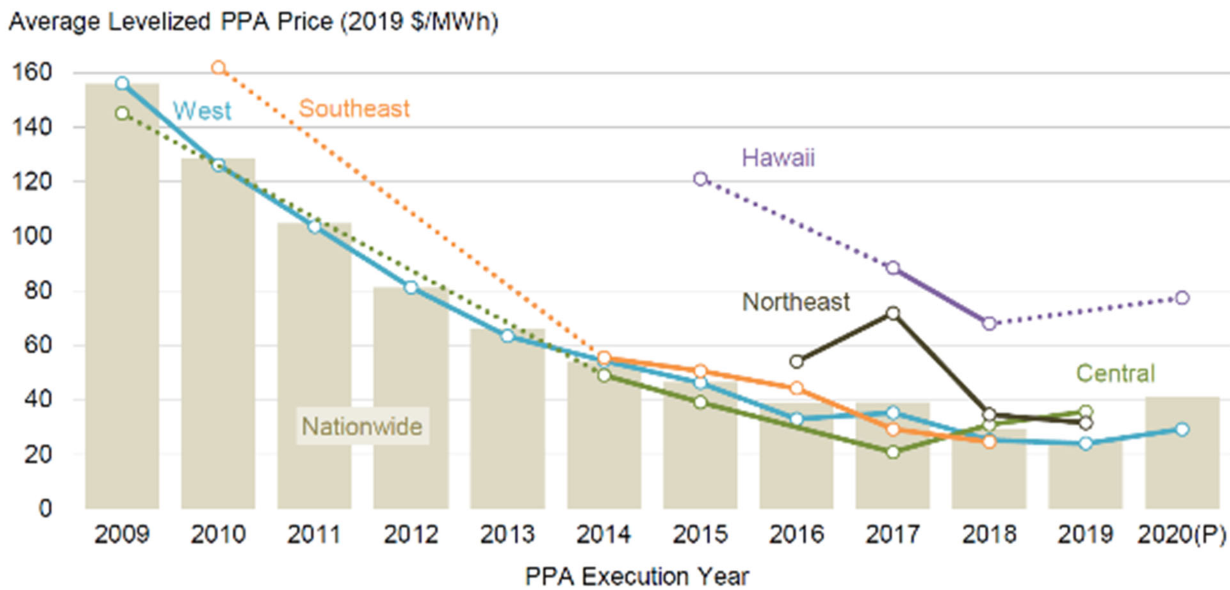
Prior to 2012, surplus electricity at the MWWTP was sold to PG&E under a longstanding Qualifying Facility or Standard Offer agreement dating back to 1986 when PGS began operation. This agreement did not provide any value for environmental attributes associated with renewable electricity such as renewable energy credits (RECs), and only covered surplus power sales from the engines and not from the turbine. Under that PPA, PG&E paid the District about $34/MWh for the power and no additional charges for the associated RECs.

To better capture the full value of the electricity being produced and exported, the District terminated the agreement with PG&E and signed a new PPA with the Port in 2012. This agreement was for a five-year term with a rate of $71/MWh for exported power, including $35/MWh for the REC. This agreement was renewed in 2017 again for a five-year term (expiring in 2022) with a rate of $58/MWh for exported power, including $12/MWh for the REC.

In early 2022, the District issued an RFEOI soliciting new offers for power purchase. The Port once again offered the most favorable rates and negotiations are currently ongoing. The PPA rate for 2022 – 2027 is expected to be over $60/MWh.

As shown in Figure 2-5, the drop in the value of the REC over the five years from 2012 to 2017 is a reflection of the major changes that occurred in the renewable energy markets over that period. In California, this was especially driven by the dramatic drop in prices for renewable solar energy. While this is a beneficial development for California ratepayers and for reducing GHG emissions, it is challenging for a renewable energy producer with higher fixed costs using renewable fuels like biogas. This decreasing trend in PPA prices was expected to continue in the future; however, there may be other ways to capture greater value from the District's electricity, as discussed in Chapter 4 and the negotiations for the next PPA are likely to yield a higher price.

Figure 2-5. Solar PPA price history



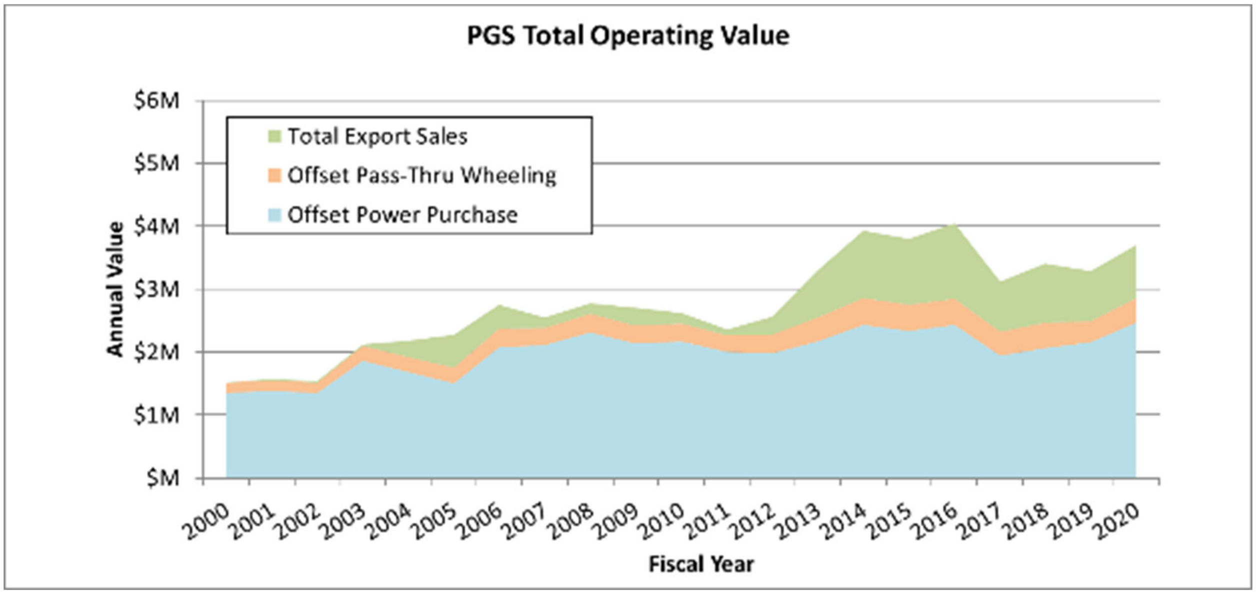
Source: Berkeley Lab, FERC – "Utility Scale Solar Data Update 2020 Edition" Mark Bolinger, Joachim Seel, Dana Robson, Cody Warner

2.2.5 Combined Value from PGS Operations

The annual value of producing on-site electricity (i.e. through operation of PGS1 and PGS2) is shown in Figure 2-6. The annual value is shown as the solid area with the avoided power purchases in light blue, the avoided WDT charge in orange, and the export sales in green. The majority of the value comes from avoided power purchases. Only about 25% of the value comes from export sales, which limits the impact of the exported power PPA price on the overall value proposition.

This figure shows a large increase in operating revenue around 2013 when the turbine began operating and increased power production significantly. Subsequently, the value peaked near $4 million for three years before dropping in 2017 due to a combination of lower energy generation and the lower export PPA price. Since 2017, the value has ranged from $3.1-$3.7 million.

Figure 2-6. Operating value of producing on-site electricity at PGS1 and PGS2



2.3 Cost to Operate PGS

A financial analysis was conducted to determine the combined operating costs for both PGS1 and PGS2. A combined approach was taken because current accounting categories make it difficult to tease out these costs separately. In addition, some of the equipment and costs are shared for both PGS1 and PGS2. Capital project costs and associated capital debts were excluded.

PGS operating costs can be categorized into five broad categories:

- Turbine Extended Service Agreement
- PGS Maintenance
- PGS Operation
- Routine capital equipment replacement
- Engine rehabilitation costs

These categories are discussed in more detail below.

2.3.1 Turbine Extended Service Agreement

In November 2013, the District entered into a five-year ESA with Solar Turbines, Incorporated, Division of Caterpillar Company (Solar) for turbine service and repairs. The ESA was not exceed $682,000 annually and included an initial “buy-in” fee of $700,000 to address turbine wear and tear to date since turbine startup in September 2011. The ESA terms included monthly fees starting at $48,537 with a 4% escalation each year.

In December 2018, the ESA was renewed starting at $725,000 in the first year with annual escalation at the beginning of each calendar year at 2.5% with a total amount not to exceed $3,820,000 over the five-year term of the agreement.

Half of this ESA is charged to the maintenance budget, while the other half is charged to the Routine Capital Equipment Replacement (RCER) budget. Any servicing or repairs costs paid to Solar that are not covered under the ESA are generally charged to the RCER budget.

The "Turbine ESA Total" costs shown in Figure 2-7 below include the ESA cost as well as any other costs paid to Solar.

2.3.2 PGS Maintenance

Costs to maintain PGS1 and PGS2 are taken directly from the end of year "Statement of Operating Expenses WWG (195)", program code 3657 "Maint Power Generation Facility." This is the code that all PGS maintenance expenses are charged to, including Department Overhead but excluding Administrative and General (A&G) overhead.

Half the of the turbine ESA fee is charged to this budget, but was included under the turbine ESA cost in the figure below.

2.3.3 PGS Operation

Costs to operate PGS1 and PGS2 are taken directly from the end of year "Statement of Operating Expenses WWG (195)", program code 3627 "Operate Power Generation Facility." This is the code that all PGS Operation expenses are charged to, including Department Overhead but excluding A&G overhead.

2.3.4 Routine Capital Equipment Replacement at PGS

RCER work at PGS1 and PGS2 typically includes the repair and replacement of equipment throughout entire facility, e.g. gas compressors, lube pumps, engines/generators, governors and control/monitoring equipment. Even through RCER work is considered a capital cost, it was included in the operating costs analysis since these are generally routine replacement items.

The other half of the turbine ESA fee is charged to this budget, but was included under the turbine ESA cost in the figure below.

2.3.5 Engine Rehabilitation Costs

The PGS1 engines are more or less in a state of continuously rehabilitation in order to stay in good working condition. These costs don't occur every year, but are effectively ongoing and needed to keep the engines operational.

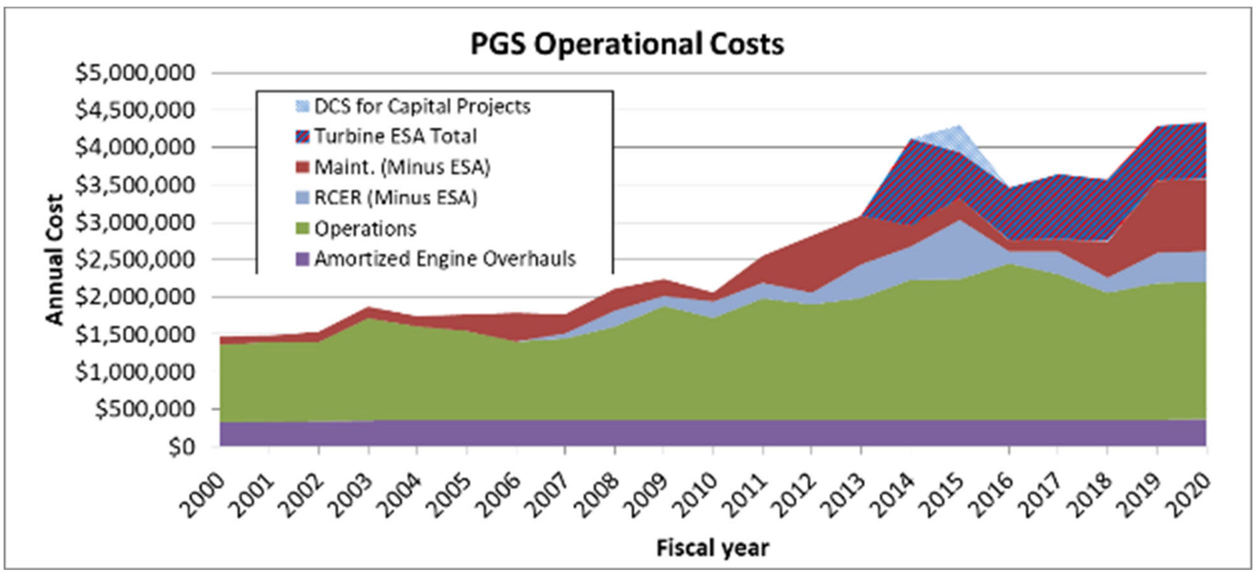
The total cost to rehabilitate the engines over two full cycles over fifteen years from FY04 to FY18 was amortized over that period then escalated by 2% per year going forward starting in FY19.

2.3.6 Operational Costs of PGS1 and PGS2

The combined operational costs for PGS1 and PGS2 are shown in Figure 2-7. The costs are broken down into the categories discussed above, as well as a one-off Distributed Control System (DCS) upgrade project.

From 2000 until 2011, the combined operational costs gradually increased. In 2012 and 2014, there were significant increases when the turbine was brought online and the ESA was initiated, respectively. Following, costs were relatively stable until 2019, when there was a significant increase in maintenance costs, the cause of which has yet to be determined. Improved cost accounting to distinguish between PGS1 and PGS2 maintenance costs can provide better data for future financial analyses.

Figure 2-7. Operational costs of producing electricity at PGS1 and PGS2

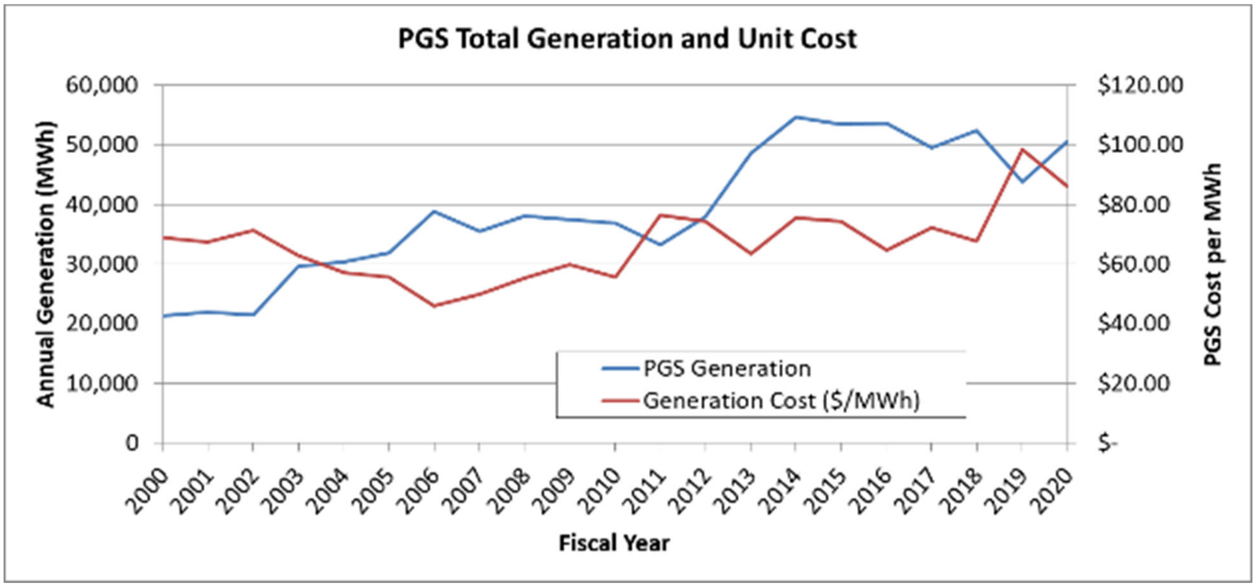


Another useful way to view the cost data is on a unit basis as cost per MWh produced, as shown in Figure 2-8. In this figure, the total annual generation is shown in blue and the unit cost is shown in red.

For the total annual generation, an increase is visible in 2002 when the R2 program was initiated, which increased biogas production as well as the utilization of the engines. Energy production reached a plateau in 2006 when the engine utilization reached capacity despite increased biogas production. Energy production then increased again significantly when the turbine was brought online in 2012.

For the unit costs, the initial cost was $70/MWh. As the utilization of the engines increased, unit costs dropped to $50-$60/MWh. Following commissioning of the turbine, the unit cost increased to around $70/MWh for six years, which would be lower than they were in 2000 when adjusted for inflation. In 2019 and 2020, the unit cost increased to $90/MWh.

Figure 2-8. PGS total generation and unit cost



To inform future decision making about PGS, it is necessary to consider the financial outlook holistically. How much of the cost is related to operating only the turbine, how much is related to operating only the engines, and how much is common for both? While the ESA is clearly only for the turbine, the other costs in Figure 4-8 are not tracked separately between the turbine and the engines.

The following future potential scenarios for PGS were evaluated:

- **Scenario 1 – No Turbine & High Cost:** Under this scenario, the turbine is retired and the ESA cost is eliminated. However, operations costs remain the same and maintenance/RCER costs are 80% of current costs. This scenario reflects that most of the turbine maintenance is covered under the ESA.
- **Scenario 2 – No Turbine & Low Cost:** Under this scenario, the turbine is retired and the ESA cost is eliminated. Operations costs are maintained due to limitations in how much staffing could realistically be reduced. Maintenance/RCER costs are reduced by 50%. This is somewhat of a best-case scenario.
- **Scenario 3 – No Engines:** Under this scenario, the engines are retired and the ESA cost remains the same as current. Operational costs remain the same and maintenance/RCER costs are reduced to 20% of the current costs. This scenario reflects that most of the turbine maintenance is covered under the ESA.

A financial analysis of each scenario is summarized in Table 2-4. It is unlikely that any of the three scenarios will improve the current financial outlook. No scenario shows reduced losses compared to current operations, largely because the operational costs are expected to remain the same. In other words, no scenario eliminates having to ensure 24/7 staffing.

In the table below, the "annual power value" is the combined value of the avoided power purchases and the exported power under each scenario.

Table 2-4. Downsized PGS cost scenarios

Parameter	Current	Scenario 1 No Turbine (% of current)	Scenario 2 No Turbine (% of current)	Scenario 3 No Engines (% of current)
ESA Cost	$ 800,000	0%	0%	100%
Maintenance	$ 950,000	80%	50%	20%
RCER	$ 415,000	80%	50%	20%
Operations	$ 1,800,000	100%	100%	100%
Engine Rebuild	$ 370,000	100%	100%	0%
Annual Production (MWh)	50,565	30,000[1]	30,000[1]	30,000[1]
Annual Cost	$4.3M	$3.3M	$2.9M	$2.9M
Annual Power Value	$3.7M	$2.2M	$2.2M	$2.2M
Annual Cost/Benefit	**-$0.6M**	**-$1.1M**	**-$0.7M**	**-$0.7M**

1. Based on assumption of 1,150 scfm of biogas used and 95% uptime. The same efficiency was used for both the turbine and the engines.

2.4 Operational Cost and Value of PGS1 and PGS2

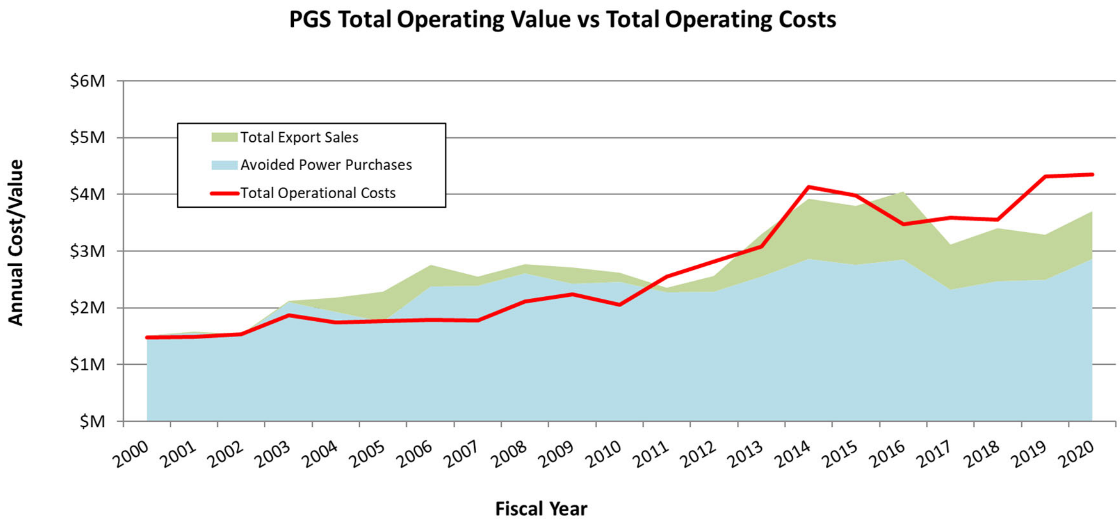
The combined operational cost of PGS1 and PGS2 is juxtaposed with the value of the power in Figure 2-9. The red line represents the operational cost and the shaded area represents the power value. There are two sources of value: avoided power purchases and export sales. Tip fees are not included in this analysis and are discussed later in this chapter.

In 2000 before the R2 program, the cost and value were approximately the same. In other words, the red line overlaps with the top of the shaded area. After the R2 program was initiated and engine utilization increased, the value was significantly higher than costs for about 10 years. After the commissioning of the turbine, the value and cost were approximately even for about four or five years. Since 2017, as the value of the electricity exported has dropped and operational costs have increased, the value has been consistently below the cost by an average of around $0.6M per year.

It is important to note that, as discussed above, this financial analysis does not include any repayment of the capital costs associated with the construction of the equipment or any other non-routine capital investment. However, an earlier and separate financial analysis of the R2

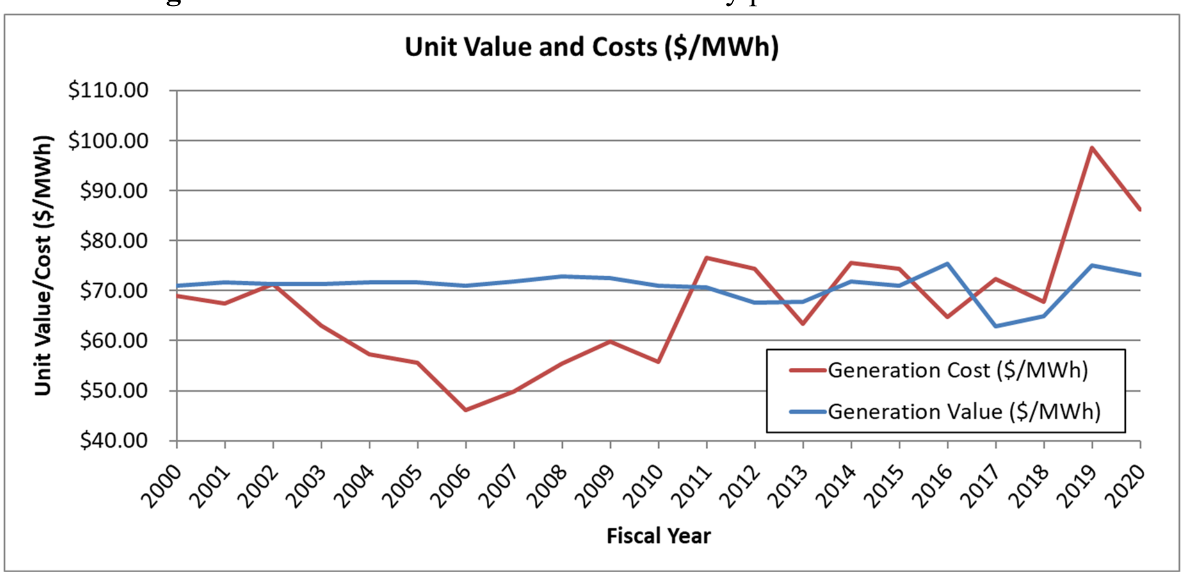
Program, which included tip fee revenues and capital costs for PGS1 and PGS2, indicated that financial benefits exceeded costs, including amortized capital. It was assumed that the turbine would be paid for out of all R2 Program revenues.

Figure 2-9. Total value and total operating costs of electricity produced at PGS1 and PGS2



The data in Figure 2-9 are shown on a per unit basis in Figure 2-10. The red line shows the unit cost and the blue line shows the unit value. The unit value has been relatively steady around $70/MWh. However, this may not be fully accurate for data prior to 2016. As explained earlier, for all years before 2016, the avoided power purchase unit value, which makes up the vast majority of the benefit, is assumed to be the average unit rate for FY16 and FY17. In contrast, the unit cost is not steady and fluctuated significantly over time from $45-100/MWh.

Figure 2-10. Unit value and costs of electricity produced at PGS1 and PGS2



2.5 Additional Biogas Value

In addition to the direct value of the electricity produced from the biogas, there are other aspects of the biogas that have real value, including biogas green energy attributes and tip fees. These items are discussed in more detail below.

2.5.1 Biogas Green Energy Attributes

The District places value on powering the MWWTP with renewable energy, even though it is not a regulatory requirement. The renewable electricity produced on-site generates RECs ("Bucket 3") that could be "unbundled" from the underlying energy and sold to a third party; however, the District retains these RECs as part of its GHG emission reduction goals. For electricity exported to the Port, the RECs are sold bundled with the power ("Bucket 1"), and are not retained by the District.

The value of the green energy attributes can estimated via the cost of two possible alternatives:

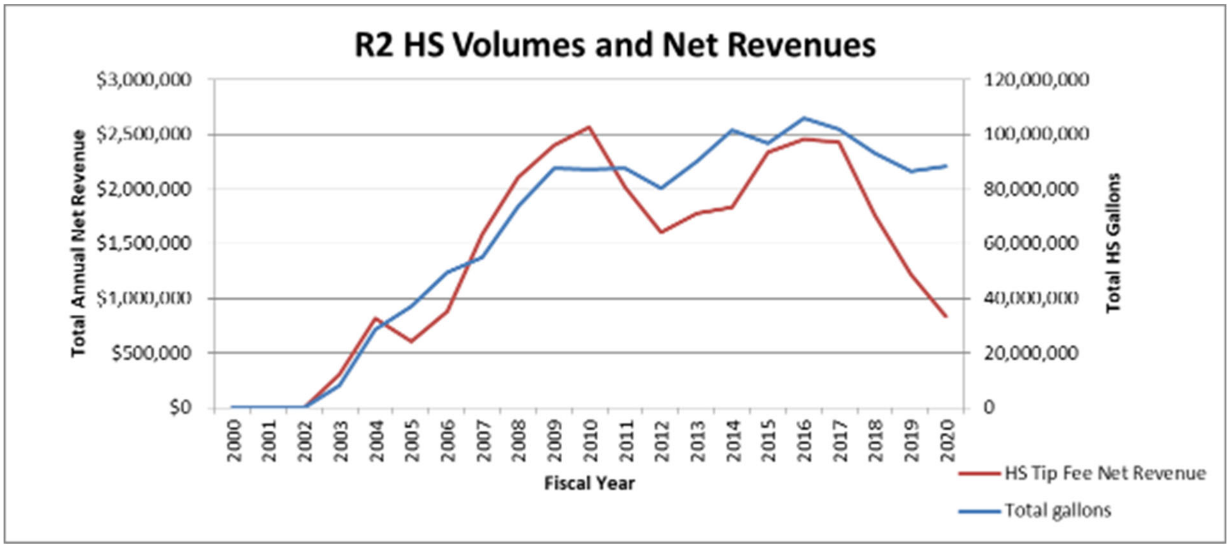
- **Buying Unbundled RECs:** The easiest and lowest value method is to consider the market value of buying unbundled RECs. In the last two years, this has varied between \$0.70-\$1.50/MWh. Compared to the total value of the energy (\$70/MWh), the unbundled REC value has minimal impact on the overall economics.
- **Sourcing Renewable Energy:** The alternative method is to consider the cost of sourcing renewable energy for use at the MWWTP. Sourcing renewable energy has not historically been the District's policy, so this is mainly discussed under future scenarios in Section 2.6. However, the cost for this alternative would likely be well in excess of \$200/MWh.

2.5.2 Tip Fees

The analyses discussed earlier in this chapter did not consider HSW tip fees. The analyses presented below take into account the net revenue, which is calculated as the tip fee minus all of the costs associated with treating these wastes such as biosolids disposal, ferric chloride use, polymer use, increased O&M at the digesters and centrifuges, etc. The net revenue does not include any credit or costs associated with PGS. A "R2 Net Revenue Analysis" memo was developed in 2018 and updated in 2020 to reflect increased costs for chemicals and biosolids disposal.

The historical net revenues and volume for high-strength wastes are shown below in Figure 2-11. For years prior to FY17, the FY17 cost-to-treat was used, which is likely a conservative overestimate. High-strength net revenues and volume grew in tandem from 2002 to 2009 until reaching a quasi-plateau from 2009 to 2018. During this plateau, high-strength net revenues and volume both relatively steady at around \$2M/yr and 90 million gallons/yr, respectively, which corresponds to approximately \$0.02/gallon. Since 2019, the high-strength volume has remained steady, while net revenues have dropped by more than half due to recent cost increases, especially for chemicals and biosolids disposal.

Figure 2-11. High-strength net revenues and volumes

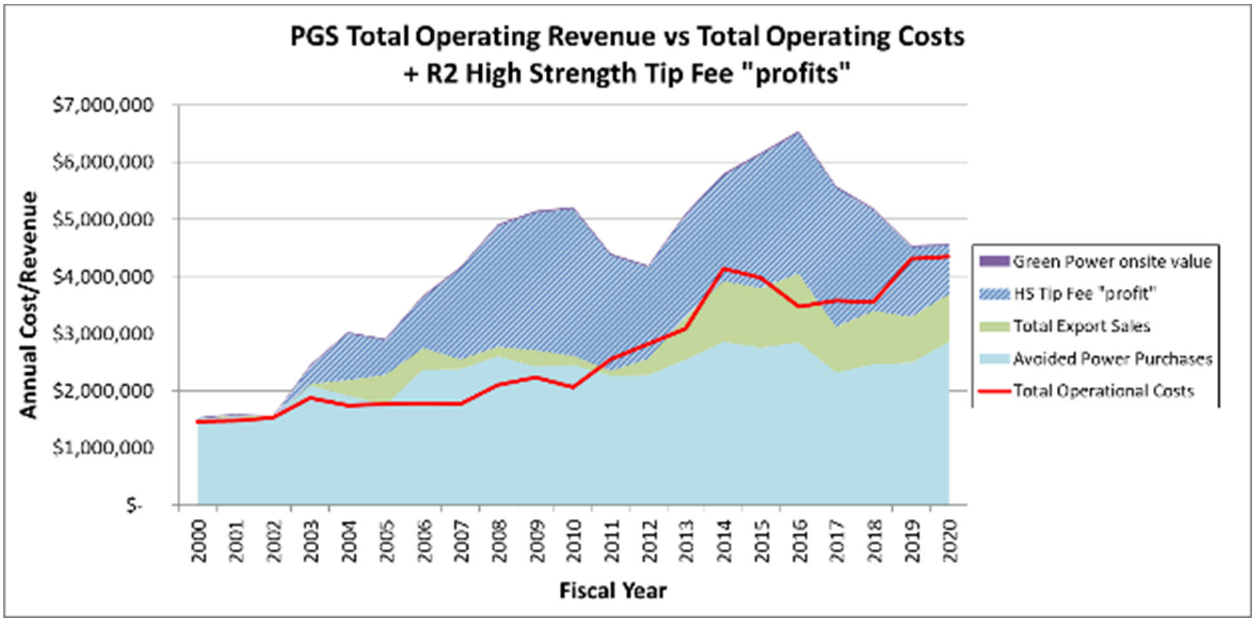


The PGS financial analysis discussed above (in Figure 4-10) was modified to include both high-strength net revenues and an unbundled REC value of $1/MWh, as shown in Figure 2-12. The inclusion of high-strength net revenues makes a significant difference; however, an unbundled REC value at this price makes almost no difference, as the purple shaded area at the top is barely visible.

In this method of financial analysis, benefits have outweighed costs for most of the R2 program's history. Only in the last several years has the margin shrunk dramatically due to lower export PPA values and higher costs for operating PGS and treating wastes.

The financial goal for the R2 program is to increase net revenue back to $0.02/gal. The higher cost for treating wastes is being addressed via higher tip fees. Rates for some high-strength wastes, including liquid organics, FOG, and protein, were increased effective January 1, 2021. Addressing the lower export PPA values and higher costs for operating PGS may be harder to address.

Figure 2-12. PGS financial analysis including high-strength net revenues (tip fees and unbundled REC)



2.6 Projected Revenue and Cost

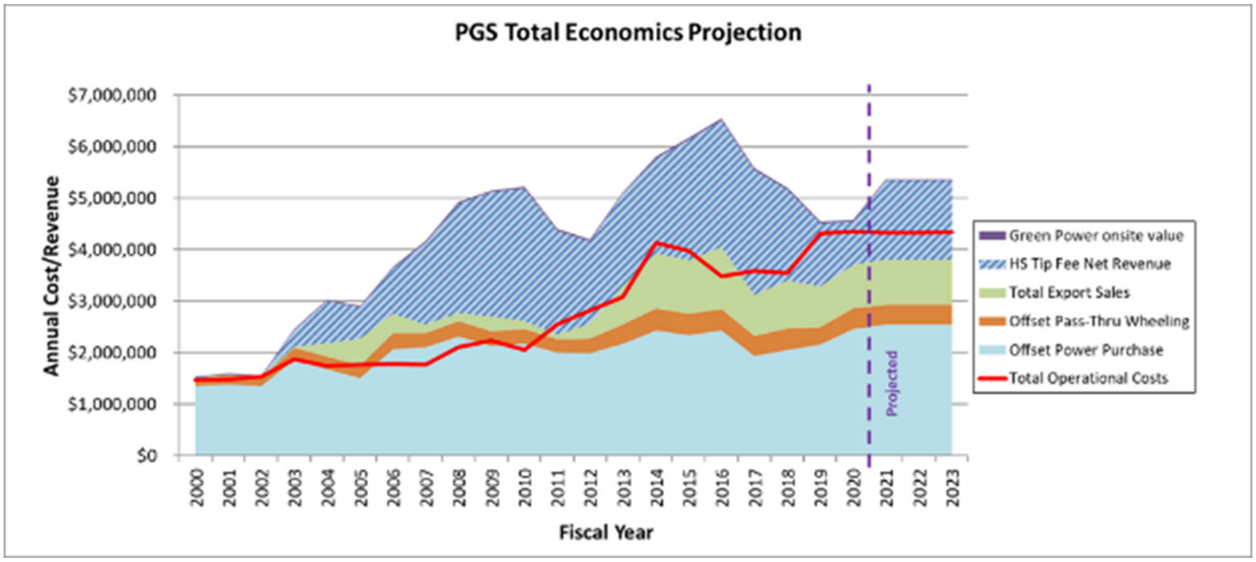
2.6.1 Impact of Pricing Adjustment and Reducing Protein Acceptance

Financial projections were developed assuming the following:

- **Target net revenue of $0.02/gal for all high-strength wastes:** As discussed in the previous section, the financial goal for the R2 program is to increase net revenue back to $0.02/gal through higher tip fees.
- **Elimination of protein waste:** As introduced in Section 1.3, the Master Plan roadmap includes Right-Sized R2, which will reduce and/or eliminate high-nitrogen waste streams such as protein and dairy wastes. For this analysis, it was assumed that protein waste was completely eliminated at the end of FY20; however, in practice, protein waste could be gradually phased out over time. This analysis does not assume that dairy wastes are eliminated because dairy wastes produce more useful biogas than protein wastes.
- **Power values:** The average WAPA cost for FY19 and FY20 ($73.94/MWh) was used to compute the value of avoided power purchases. The exported surplus power value was maintained at $58/MWh.
- **Cost to operate:** The O&M costs were assumed to be the same as they were in FY20, minus a small amount ($35 in marginal cost avoided for each MWh not produced) to account for reduced materials consumption, which is consistent with the cost-to-treat model.
- **Green Power onsite:** The unbundled REC value of $1/MWh was used for the value of the green attributes.

Based on these assumptions, the projected economics for the next three years are shown in Figure 2-13. The financial outlook is favorable. Even if costs remain high, increasing tip fees adequately compensates for the other factors that had reduced the profit margin.

Figure 2-13. Projection for PGS economics including high-strength net revenues (tip fees and unbundled REC)



2.6.2 Impact of Future PPA Values

Since most of the renewable electricity that is generated is used on-site, the value received for the exported power via a PPA has a relatively small impact. Further, if protein wastes are eliminated, there will be less exported power.

Table 2-5 shows the impact of different prices for the PPA that will be initiated in 2023. If the PPA dropped to $40/MWh, the loss would be $275,00/year. In contrast, if the PPA increased to $100/MWh, the gain would be $625,000/yr. While not insignificant, these amounts do not change the holistic economic outlook of PGS shown in Figure 2-13.

Table 2-5. Impact of PPA price

2023 PPA Price ($/MWh)	Annual Export Revenue	Change from current ($58/MWh)
$40	$600,000	-$275,000
$58	$875,000	No Change
$70	$1,050,000	$175,000
$100	$1,500,000	$625,000

2.6.3 Impact of Green Energy Purchasing Policy

As discussed previously, the District places value on using renewable energy at the MWWTP. The renewable electricity produced on-site generates RECs that could be sold to a third party; however, the District retains these RECs as part of its GHG emission reduction goals. The value of on-site renewable power generation is very dependent on how these reduction goals would otherwise be met.

When an organization is trying to reduce GHG emissions, there are generally two ways to do it. The most effective approach is to directly reduce emissions under the control of the emissions source. If direct reductions are difficult to achieve, GHG emission offsets can be purchased. While offsets may lead to real emission reductions, they are generally considered inferior to direct reductions in large part due to local impacts from non-GHG emissions, e.g. other priority pollutants. It is generally considered best practice to reduce emissions as much as possible before buying offsets for remaining emissions. In some ways, purchasing GHG offsets is similar to buying unbundled RECs to green up power used. However, one key difference is that carbon offsets are generally required to meet the requirements of an "additionality test." That is, each offset must demonstrate that it is beyond business-as-usual and would not have otherwise occurred. There is no such requirement for RECs.

Approximately half of the custom product power delivered by WAPA to the MWWTP is considered as derived from fossil sources. If the District continues to buy WAPA power, it could consider purchasing unbundled RECs to "green up" that power. However, this faces some of the same drawbacks as buying offsets to reduce carbon emissions. In addition, unbundled RECs can be generated when at a time and place where there is an excess of renewable energy and don't need to match the location or timing of the energy demand. The purchase of unbundled RECs would not address the challenges of producing renewable energy when the MWWTP is using it and having it delivered to West Oakland. The REC could have been generated almost anywhere at any time. This makes them significantly less impactful than producing green power onsite.

The alternative to buying unbundled RECs is to purchase renewable energy directly from a greener source such as the East Bay Community Energy (EBCE), which is the local Community Choice Energy (CCE) program in the East Bay. If the District bought renewable energy from EBCE, it would pay PG&E for transmission and delivery of power and EBCE for the power generation.

Under the EBCE 100% Renewable Plan, the generation rates for 2021 are $10/MWh higher than the standard PG&E rate. The PG&E rates are time-of-use rates where both the generation and demand charge vary with season and time of day, so the cost of PG&E power ranges from $220-$270/MWh plus the additional $10/MWh to purchase 100% renewable power from EBCE. These rates would increase annual electricity costs at the MWWTP by approximately $5 million more than doubling the current costs.

Figure 2-14 juxtaposes the actual total cost for electricity at the MWWTP with the estimated theoretical cost for purchasing all power from either WAPA or EBCE. Note that prior to 2018, green power was available from PG&E instead of EBCE. The actual cost is reasonably close to the theoretical WAPA cost, while EBCE is more than twice as expensive.

Figure 2-15 shows the same data as Figure 2-14 but with the inclusion of high-strength tip fees, which makes on-site generation even more financially favorable, i.e. the blue line representing cost moves down.

Figure 2-14. Projected cost of electricity at the MWWTP not including high-strength net revenues (tip fees and unbundled REC)

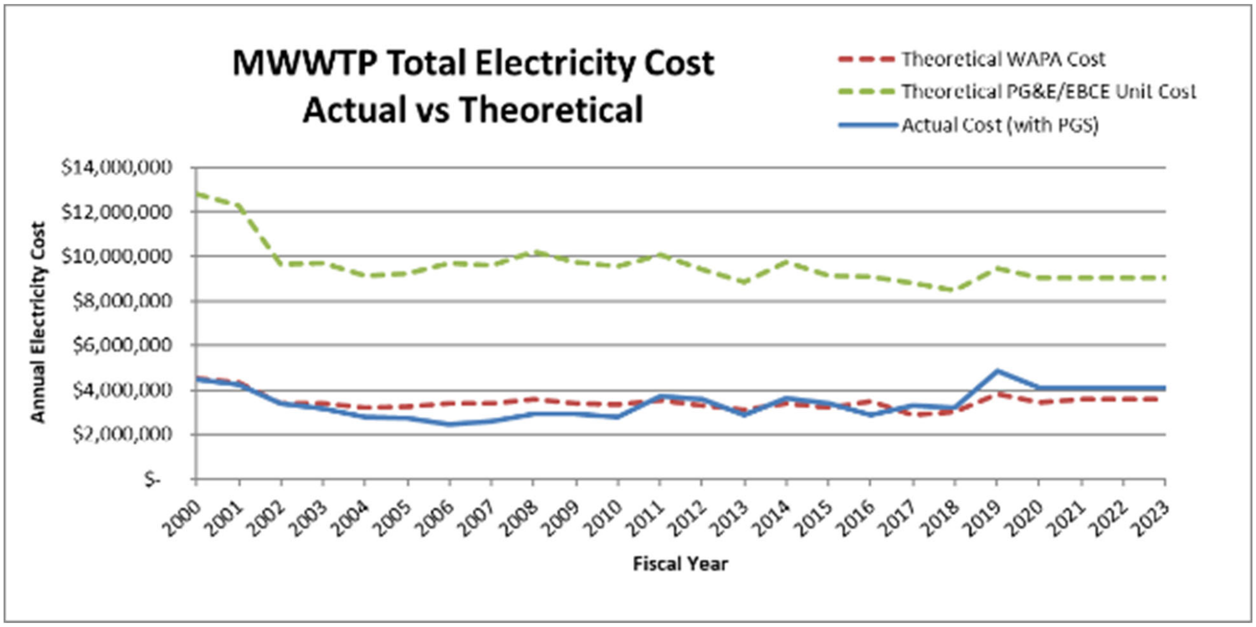


Figure 2-15. Projected cost of electricity at the MWWTP including high-strength net revenues (tip fees and unbundled REC)

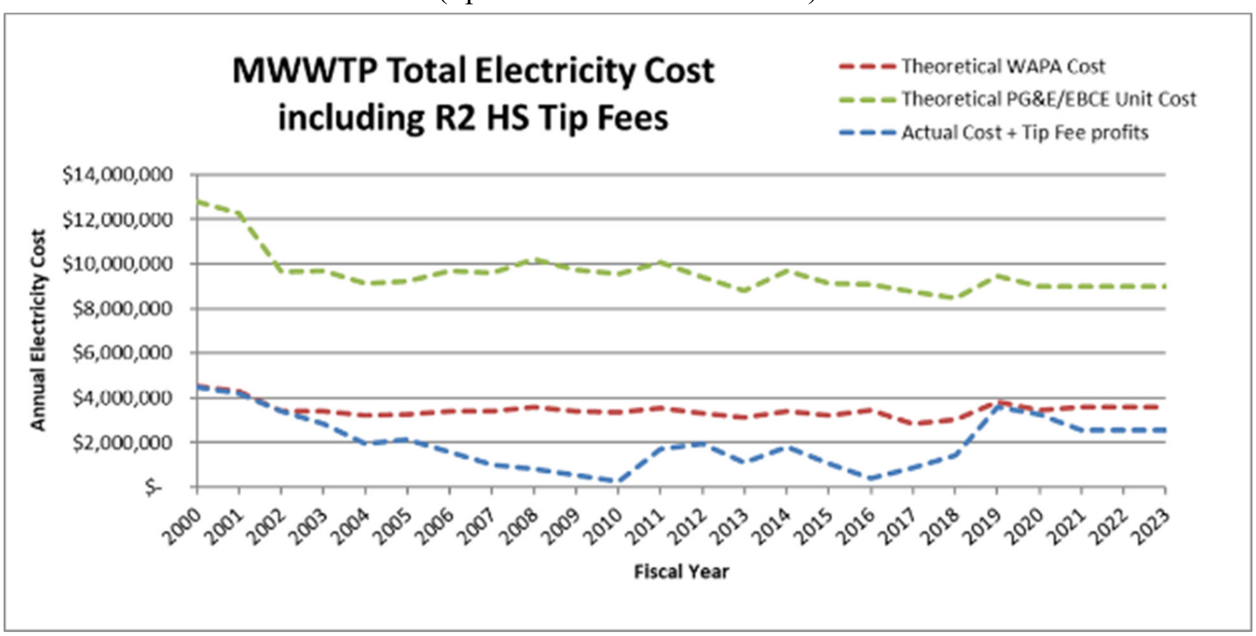
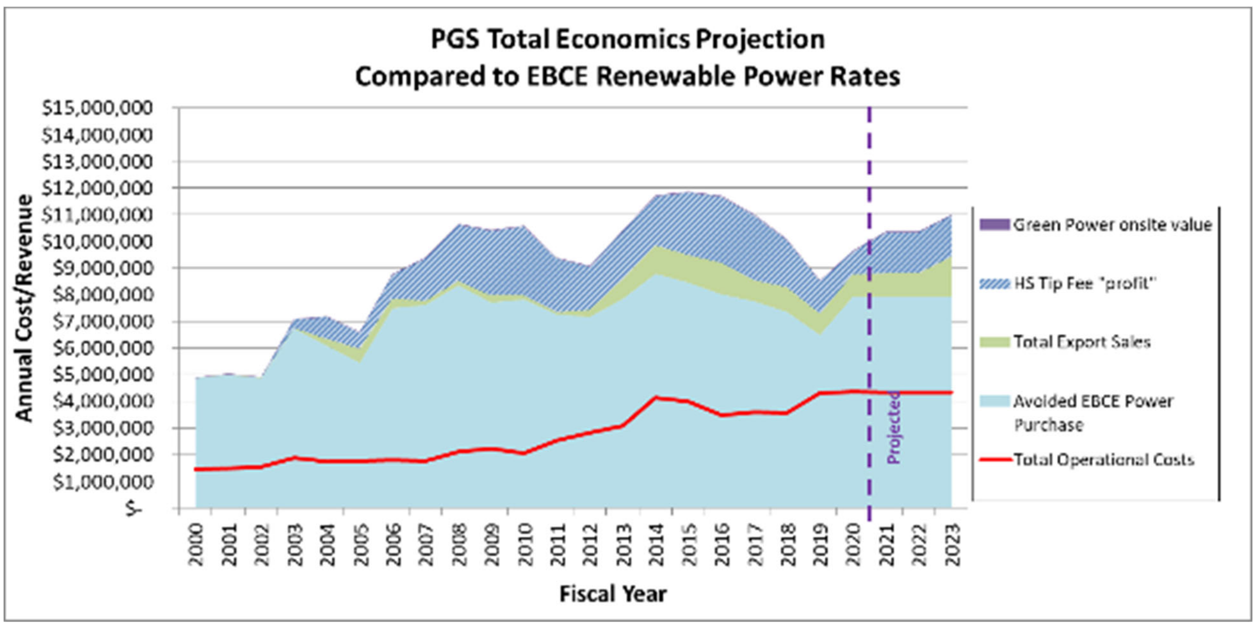


Figure 2-16 shows the PGS economics if the District purchased renewable power from EBCE instead of WAPA. This analysis includes tip fees and assumes $230/MWh for the offset power purchase, which is at the lower end of the expected range for EBCE power.

Since EBCE power is more expensive than WAPA power, the light blue shaded area is significantly larger in Figure 4-17 than in Figure 4-15. As a result, in this scenario, there is added benefit to operating PGS because it avoids a much larger cost. In other words, it is cheaper for the District to generate its own renewable power than to purchase renewable power from EBCE. The projected net revenue is $5-7M/yr, depending on whether high-strength tip fee net revenue is included. If the higher end of the range for EBCE power were used for this analysis ($280/MWh), then it would be even more favorable to generate electricity on-site.

This scenario highlights how avoided power purchase greatly affects financial decision making. For wastewater facilities that do not have access to cheap power, investing in on-site generation is easier to justify financially. Since the District has access to cheap brown power, the financial analysis and decision making is more complicated.

Figure 2-16. Projected PGS economics including high-strength net revenues (tip fees and unbundled REC), as well as EBCE rates for avoided power purchases



2.7 Optimizing PGS Operations

To optimize PGS operations, a cost-benefit analysis was performed and evaluated the following alternatives:

- No change to PGS
- Downsize PGS - keep the engines and retire the turbine
- Downsize PGS - keep the turbine and retire the engines
- Eliminate on-site generation at PGS completely

These alternatives are discussed in the text and Table 2-6 below.

No Change to PGS: This scenario represents the current mode of operation using both PGS1 and PGS2 to generate 50,500 MWh per year on average. Annual operating costs exceed the benefits by $0.6M per year and high-strength profits remain at $1.5M per year. The green energy benefits are better than any of the other options.

Downsize PGS - Keep the Engines and Retire the Turbine: Under this scenario, the engines would continue to be operated, while the turbine would be retired. As described in Table 2-4, the annual cost/benefit would likely be worse than under the current mode of operation, with annual costs exceeding benefits by $0.7-1.1M per year. High-strength flows and corresponding profits would need to be reduced to avoid excessive flaring. There would still be significant on-site energy production (30,000 MWh per year), but the green energy benefits would be reduced and local air emissions would likely be worse for most pollutants.

In summary, this alternative would likely be worse financially than the current operation by $1-1.5M per year and would not improve any of the other metrics for green energy production or local air emissions.

Downsize PGS - Keep the Turbine and Retire the Engines: Under this scenario, the turbine would continue to be operated, while the engines would be retired. As described in Table 2-4, the annual cost/benefit would likely be similar to the current mode of operation, with annual costs exceeding benefits by around $0.7M per year. High-strength flows and corresponding profits would need to be reduced to avoid excessive flaring. There would still be significant on-site energy production (30,000 MWh per year), but the green energy benefits would be reduced and local air emissions would likely be cleaner for most pollutants. Unlike the engines, the turbine requires specialized skills for maintenance, so the District would likely continue to rely on Solar for maintenance through an ESA.

In summary, this alternative would likely be worse financially than the current operation by $1M per year, worse in terms of green energy production, and better in terms of local air emissions.

Eliminate On-Site Generation at PGS Completely: This alternative has not been seriously considered, but is still included here as a point of comparison. Even if on-site generation were eliminated, there would still be an annual cost associated with managing some things that are currently accounted for under the umbrella of PGS. The flares and digester membrane covers would still need to be monitored and maintained, which is currently managed by PGS staff. It would also be necessary to consider how the regulatory requirement for full backup power would be met without PGS. The costs for these items have not been estimated, but are not trivial. This alternative would require all high-strength wastes to be essentially eliminated along with all the associated profits. Local air emission impacts would be mixed. The biogas would be combusted in the flares, but the volume of biogas combusted would likely be reduced significantly, offsetting some of that impact.

In summary, this alternative would likely be worse financially than the current operation by at least $1M per year, worse in terms of green energy production, and mixed in terms of local air emissions.

Table 2-6. PGS optimization alternatives

Parameter	Current	Downsize PGS – Keep Engines	Downsize PGS – Keep Turbine	Eliminate PGS
PGS Annual Cost/Benefit[5]	-$0.6M	-$0.7M to -$1.1M	-$0.7M	Unknown[4]
Change in R2 High-Strength Profits	--	-$1.0M[2]	-$1.0M[2]	-$1.5M
Net Operating Cost	**-$0.6M**	**-$2.0M[2]**	**-$1.7M[2]**	**-$1.5M+**
On-Site Energy Production (MWh)	50,500	30,000	30,000	0
Impact to R2 High Strength Wastes[1]	--	Reduce 80%	Reduce 80%	Eliminate
Green Energy Benefits	Best	Lower	Lower	Worst
Change to Local Air Emissions	--	Mostly Worse	Better	Likely Mixed[3]

1. Assuming flaring biogas as the primary abatement method is not an option.
2. Assumes the District could charge more for the 20% of R2 that continues to be delivered.
3. Would still need to flare ~900 scfm of sludge biogas. Depending on how dirty the flares are compared to the turbine/engine combination, some emissions would likely be worse (CO and CH4), while others might be improved (SO2)
4. There would still be costs associated with managing the biogas (flares, dystors) that would need to be taken into account. It would also be necessary to consider the requirement for backup power.
5. As shown in Table 2-4.

This cost-benefit analysis indicates that there are costs associated with the handling of biogas regardless of whether on-site electricity is produced. The current set-up with PGS and high-strength waste is better than the other alternatives in terms of economics and green energy benefits. Unless there is a significant change in the economics, continuing with the current mode of operation is the recommended alternative. However, as discussed in the next section, capital investments should be considered carefully.

2.7.1 Capital Investment Strategy

There are a number of upcoming capital projects associated with either PGS or high-strength receiving, including the PGS Reliability Improvements project and Blend Tank odor control improvements.

Since all the alternatives have annual costs that are at least $1M higher than the current arrangement, a simple 10 to 15-year payback indicates that a capital investment of $10-15M would likely be relatively easy to justify on economic terms alone. If the required investment is in the $15-25M range, it could likely still be justified, but would require a longer payback period and/or justification based on non-economic factors, e.g. valuing the impact on local air quality. If the required investment exceeds $25M, it may require more careful consideration.

This economic analysis should be revisited regularly (every two or three years), as well as at key decision points such as major capital investments at PGS or for R2, renewal of the ESA contract with Solar, and other biogas project opportunities.

To make informed decisions about capital investment, the following questions need to be answered:

- If the District were to “green up” WAPA power purchases, would unbundled REC purchases be acceptable? Or would District policy require direct purchase of green power, such as from East Bay Community Energy?
- What is the split in O&M costs between the turbine and the engines?
- Are the increased maintenance costs sustained going forward in time?
- Has the R2 program been able to increase net revenues on high-strength wastes?
- What is the new value of exported electricity after the current PPA expires in 2022? Have any of the options discussed in Chapter 3 for increasing the value of electricity developed in significant ways?
- What is the actual cost for extending the turbine ESA?
- What are the terms of the final WDT settlement between WAPA and PG&E (~2023)?

3 POTENTIAL TO INCREASE VALUE OF ELECTRICITY

The District will continue to evaluate ways to increase the value of renewable electricity that is generated on-site. This chapter examines exported electricity, vehicle fuel, and direct supply.

3.1 Exported Electricity

As discussed previously, electricity exported to the PG&E grid competes with the broader wholesale renewable energy market, especially low-cost renewables. Given the way that the wholesale renewable energy market operates, there are likely very limited options for increasing the value of the core energy and/or RECs that are sold on this market.

The following options for increasing the value of exported electricity are discussed below:

- Senate Bill (SB) 1383 procurement requirements for renewable gas and electricity
- Location value
- Net qualifying capacity for resource adequacy

3.1.1 SB 1383 Procurement Requirements

Background:
In September 2016, Governor Brown signed into law SB 1383, which established targets for reductions in short-lived climate pollutants such as methane emissions from organic wastes at landfills. SB 1383 requires a 50% reduction in organic waste disposal to landfills by 2020 and a 75% reduction by 2025. If a jurisdiction fails to meet its procurement targets, it may be liable for fines of up to $10,000 per day.

SB 1383 supports the market for products derived from diverted organics through procurement requirements. Procurement requirements mandate that cities and counties must procure a certain quantity of recovered organic waste products such as compost, mulch, biofuel, renewable gas, or electricity. The quantity is determined on an annual basis based on population.

It should be noted that the law defines renewable gas as derived from solid waste, so only a fraction of the District's biogas and thus electricity is eligible. In other words, only the portion of biogas and electricity that is derived from qualifying high-strength wastes is eligible. Biogas and electricity that are derived from non-qualifying R2 wastes (both high-strength and low-strength) or human wastes (primary sludge and TWAS) are not eligible. Currently it appears that only food waste coming from a transfer station will qualify as procurement eligible.

The procurement requirement takes effect beginning on January 1st, 2022. The District has recently seen increased interest in its procurement eligible products, but it is anticipated that it will take 1-2 years for the market value to be established.

Value of Procured Biogas and Electricity:
A jurisdiction is required to procure the equivalent of 0.08 tons of organic waste per California resident per year. Table 3-1 illustrates how much organic waste would need to be procured by

the five East Bay cities that make up Central Contra Costa Solid Waste Authority (CCCSWA) which is the District's primary food waste partner. In total, the CCCSWA food waste that is diverted to the District represents about 20% of CCCSWA's procurement requirement and is likely the only food waste received by the District that is eligible to generate a credit.

Table 3-1. CCCSWA procurement by member agency

Member Agency	2020 Population	Estimated Tons to Purchase (x 0.08%)
Danville	43,876	3,510
Lafayette	25,604	2,048
Moraga	16,946	1,355
Orinda	19,009	1,520
Walnut Creek	70,860	5,668
Total	176,295	14,104

Source: Silver J. (2021). *SB1383 Compliance Update* (Agenda Item No. 4a, 02/25/2021 BOD Meeting). Recycle Smart, CCCSWA.

Under the regulations, one ton of organic waste in a recovered organic waste product is equivalent to 242 kWh of electricity derived from renewable gas, regardless of the actual on-site production efficiency. An estimate of the total amount of electricity produced by the District that is derived from renewable gas that could be eligible for procurement is shown below in Table 3-2. Since the market for procurement products is new, the value of procurement products has not yet been determined. Accordingly, a back-of-the envelope calculation was performed to estimate the value of this procurement credit[6].

Table 3-2. SB1383 Procurement Products

Diverted Organics Type	Tons Received per year	Approximate Value of Procurement Credit	Approximate Value	Equivalent Electricity (@ 242 kWh/ton)
CCCSWA Food Waste	3,000	$6/ton	$18,000/yr	726 MWh/yr

Allocating this credit is at the discretion of the District and does not need to be tied to any physical transaction. The District could allocate this procurement credit to any agency in the State of California and would only need to provide documentation of this allocation to do so.

[6] District staff has heard anecdotally that the price of procurement for eligible compost has gone up by around $10/ton. Due to how the regulation is administered, the increase in the compost price can be directly compared to the District's electricity that is eligible for procurement credit:

- One ton of procurement credit = 0.58 tons of compost or 1.72 tons of credit per ton of compost (per the regulation)
- If the price of compost has increased by $10/ton, then the customer is paying $10 for 1.72 tons of procurement credit, so **a ton of procurement credit is worth about $6** ($10/1.72)
- For each ton of diverted organics received by the District, one ton of procurement credit in electricity is generated. If the District received $6 for each ton of procurement credit, the food waste tip fee could be reduced by $6/ton. Current tip fees are around $55-65/ton, so a reduction in $6/ton is approximately a 10% reduction.
- The District receives around 3,000 tons of organic waste from CCCSWA per year, so the total value would be around **$18,000/year** (3,000 x $6). 1 ton of procurement credit is equal to 242 KWh, which is equivalent to **$24/MWh**, which is a significant premium. However, the credit is really associated with the food waste receipt and not really the electricity.
- Our current agreement with CCCSWA may require us to share some of the proceeds of any procurement credit sales.

This procurement credit is also stackable with any other value generated by the renewable electricity and does not preclude the selling of RECs.

Next Steps:
For the 2022 calendar year, the District has chosen to allocate the procurement credit to CCCSWA at no cost until the market becomes more established. In coming years, the District may choose to sell this procurement credit and/or the credit allocation may be assigned to CCCSWA as part of the next food waste agreement between CCCSWA and the District.

3.1.2 PPA Renewal

The current PPA with the Port expires in November 2022. In advance of this event, District staff have performed a market assessment for surplus renewable power generated at PGS by talking with parties that are potentially interested in the upcoming PPA, including the Port, East Bay Community Energy, and other regional community choice aggregators. Two parties ultimately submitted offers for power from the MWWTP, the Port and Peninsula Clean Energy, with the Port making the better offer. Negotiations with the Port are currently ongoing as of March 2022 for a new PPA.

Based on the responses recieved, the next PPA will likely have a higher price for the surplus renewable power.

Location Value:
The District's location does not currently appear to confer any monetary advantage in the broader renewable energy market when the District exports electricity onto the PG&E grid and is selling to a third party via a PPA. However, the node at which the surplus power from the MWWTP is delivered is within a congested area which can result in a higher market price for power sold on the open market without a PPA. The Locational Marginal Price (LMP) is the market mechanism for wholesale electric energy prices that reflects the value of electric energy at different locations. It is a dynamic price and it accounts for the patterns of load, generation, and the physical limits of the transmission system. This price is for the electricity only and does not include the value of any RECs which could potentially be sold separately.

The average LMP price at the nodes the surplus power from the MWWTP is delivered too for 2021 was $54.65/MWh. However, as the price is a dynamic market price, it is difficult to predict whether the LMP price would be higher or lower on average in future years.

Resource Adequacy:
Resource adequacy (RA) is a power product that is separate from the underlying electricity or any environmental attributes like RECs. RA is a measure of generation capacity, and utilities like the Port are required to purchase amounts specified by the California Independent System Operator (CAISO) to demonstrate reliability.

The CAISO assigns electricity generators a net qualifying capacity (NQC) based on historical generator output. In 2021, the monthly NQC values for the District's PGS are:

- Turbine: 0
- Engines: 0.56 (January 2021)-1.65 (August 2021)

Under the existing PPA, the Port has first rights to purchase the District's NQC to meet its RA requirement; however, the Port has not yet exercised this right. The District's NQC is relatively small, however, the value of RA has increased in recent years and the District is actively exploring the current market value for this NQC.

3.2 Vehicle Fuel

Electricity that is used in a vehicle can generate revenue that is separate from the value of the energy or any other environmental attributes. This value derives from government programs that specifically target green fuels to reduce GHG emissions from transportation.

The following are discussed in more detail below:

- Low Carbon Fuel Standard (LCFS) Program
- Electric Renewable Identification Numbers (eRINs)
- Charging an EBMUD Electric Vehicle Fleet
- Charging Electric Vehicles (EVs) at the Port of Oakland

3.2.1 Low Carbon Fuel Standard Program

The State of California's plan for reducing GHG emissions is known as the Scoping Plan. A major component of the Scoping Plan addresses the transportation sector through the LCFS. The goal of the LCFS is to gradually reduce the overall carbon intensity (CI) of transportation over time by increasing vehicle efficiency and increasing the use of low-CI fuels like renewable natural gas (RNG) or renewable electricity. Each year the mandated CI target is reduced, driving the market towards lower and lower CI fuels.

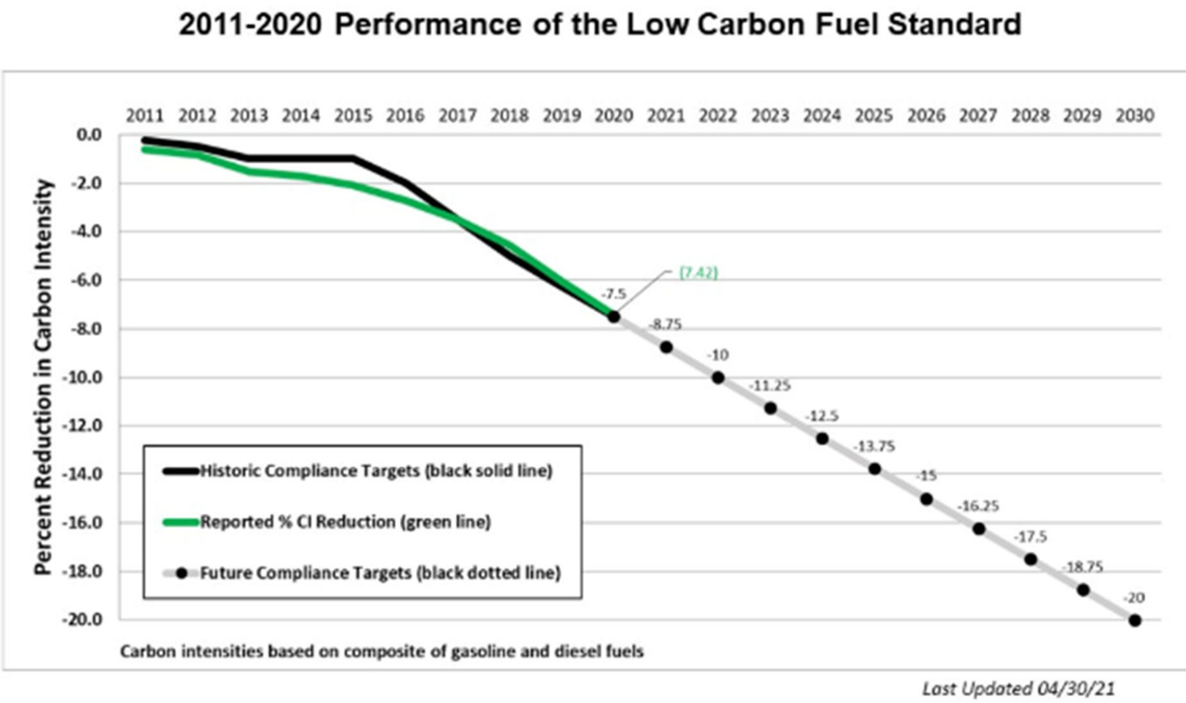
Owners of high-efficiency vehicles and producers of low-CI fuels can earn credits (referred to as LCFS credits), which can then be sold to obligated parties who may use them to comply with the LCFS requirements. The obligated parties that have to buy these LCFS credits are those parties that sell fuel in California with a higher CI than the target.

When a vehicle is fueled in California, there are two aspects that govern how many LCFS credits can be generated by a fuel pathway: the CI of the fuel used and fuel/vehicle combination efficiency. These two topics are discussed in more detail below. Credits can also be generated by projects and fueling capacity for zero emission vehicle (ZEV) infrastructure, but those are limited and not relevant to this discussion.

Carbon Intensity of the Fuel Used:
The goal of the LCFS program is to gradually reduce the CI of California's transportation fuel pool, with a current target of a 20% reduction by 2030. This reduction is achieved by setting a declining annual target or compliance standard CI for each fuel type. Fuels used in California with a CI *higher* than the compliance standard generate a carbon emissions deficit that needs to

be filled. In contrast, fuels used in California with a CI *lower* than the compliance standard generate an LCFS credit with each LCFS credit representing 1 metric ton of CO2e emissions avoided. Entities with an emissions deficit are required to buy LCFS credits to cover their deficit. The CI targets over time and the LCFS program's performance against them are shown below in Figure 3-1.

Figure 3-1. LCFS performance[7]



The compliance standard CI for gasoline fuel was 91.08 and 88.62 gCO2e/MJ in 2019 and 2020, respectively. For comparison, the CI for electricity generated at the MWWTP is expected to be less than 10 gCO2e/MJ. For electricity derived from food waste, the CI is expected to be around -35 gCO2e/MJ, which represents the landfill-associated methane emissions that are avoided. The difference between the compliance standard CI and the CI of the electricity generated at the MWWTP is what generates the LCFS credit that can be sold to entities with a deficit.

Fuel/Vehicle Combination Efficiency:

LCFS credits are also generated by vehicles that are more efficient than the standard. The vehicle efficiency is described by its Energy Economy Ratio (EER), which is a dimensionless number that describes how much more efficient an alternative fuel vehicle is compared to the reference vehicle, i.e. how much farther it will travel using the same amount of energy. A short list of select fuel/vehicle combinations is shown below in Table 3-3.

Table 3-3. EER values for select applications

[7] https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm

Fuel/Vehicle Combination	EER Values Relative to Displacement Fuel	Displacement Fuel
Gasoline in Gasoline Vehicles	1	Gasoline
CNG used in light duty Vehicles	1	Gasoline
Electricity used in a Battery Electric or plug in hybrid EV	3.4	Gasoline
Hydrogen Used in a Fuel Cell Vehicle	2.5	Gasoline
Diesel fuel used in a diesel	1	Diesel
CNG used compression ignition engine	1	Diesel
Electricity used in a Heavy Duty Truck	2.7	Diesel
Electricity used in a Heavy Duty Bus	4.2	Diesel
Hydrogen used in a Heavy Duty Fuel Cell Vehicle	1.9	Diesel

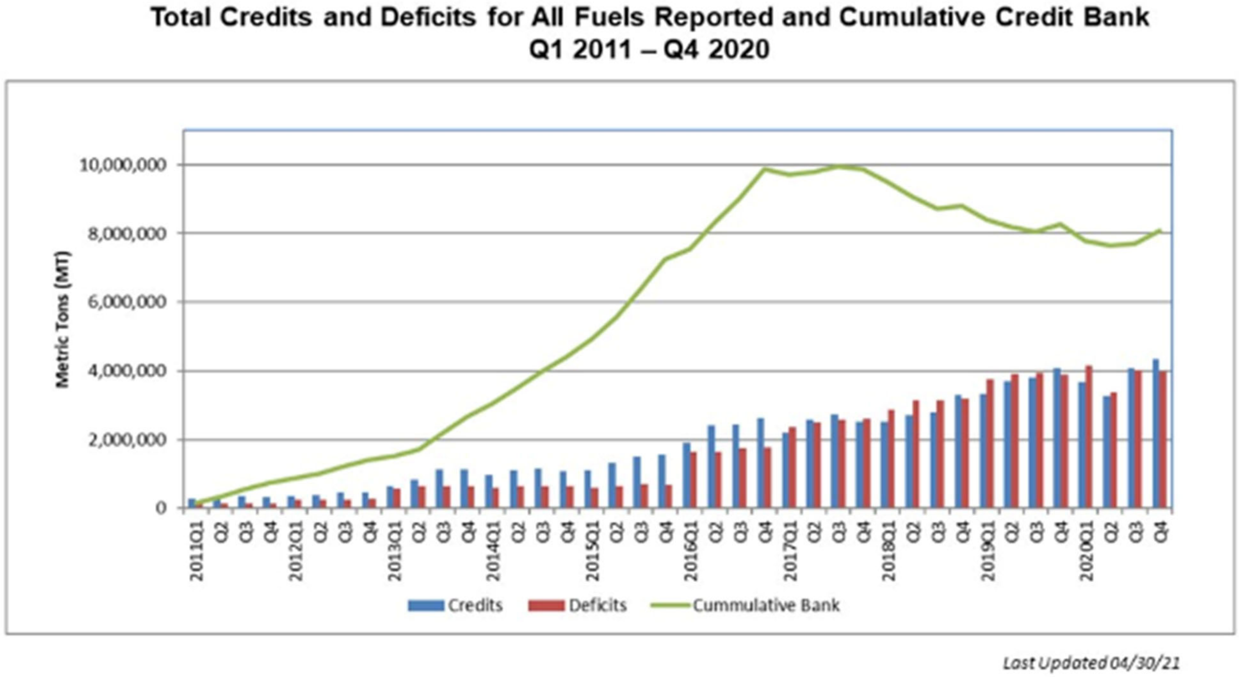
A fuel/vehicle combination with a high EER can generate a significant number of LCFS credits, even if the fuel is not much cleaner than the reference fuel standard for a given compliance year. For example, the 2020 compliance year standard CI for gasoline was 88.62 gCO2e/MJ and the default CI for the California grid was 82.92 gCO2e/MJ, which are relatively close in value. However, an alternative fuels CI is divided by its EER to get the EER-adjusted CI value, representing the emissions that occur from the use of alternative fuel per MJ of conventional fuel displaced. In the 2020 compliance year, the EER adjusted CI value for an EV using grid electricity was 24.39 gCO2e/MJ, which is much lower than the compliance standard. LCFS credits are generated using this EER-adjusted CI value.

One note, the LCFS credits generated by the EER are additive with those generated by the vehicle's CI. There is no advantage to putting a low-CI fuel into a high-EER vehicle as opposed to a low-EER vehicle.

LCFS Credit Market

The value of LCFS credits is market driven and subject to fluctuation with supply and demand, as shown in Figure 3-2. Under the LCFS program, demand is driven by the declining compliance standard, while supply is created when alternative fuels are used. From 2011 to 2016, there was generally an excess supply of credits, with the cumulative bank of credits increasing. However, since 2017, there has generally been more demand than supply, with the gap between the two being filled by the previously banked credits. There is also a notable drop in the generation of both credits and deficits in Q2 2020, which likely reflects the drop in travel associated with the Covid-19 pandemic.

Figure 3-2. LCFS credit bank[8]

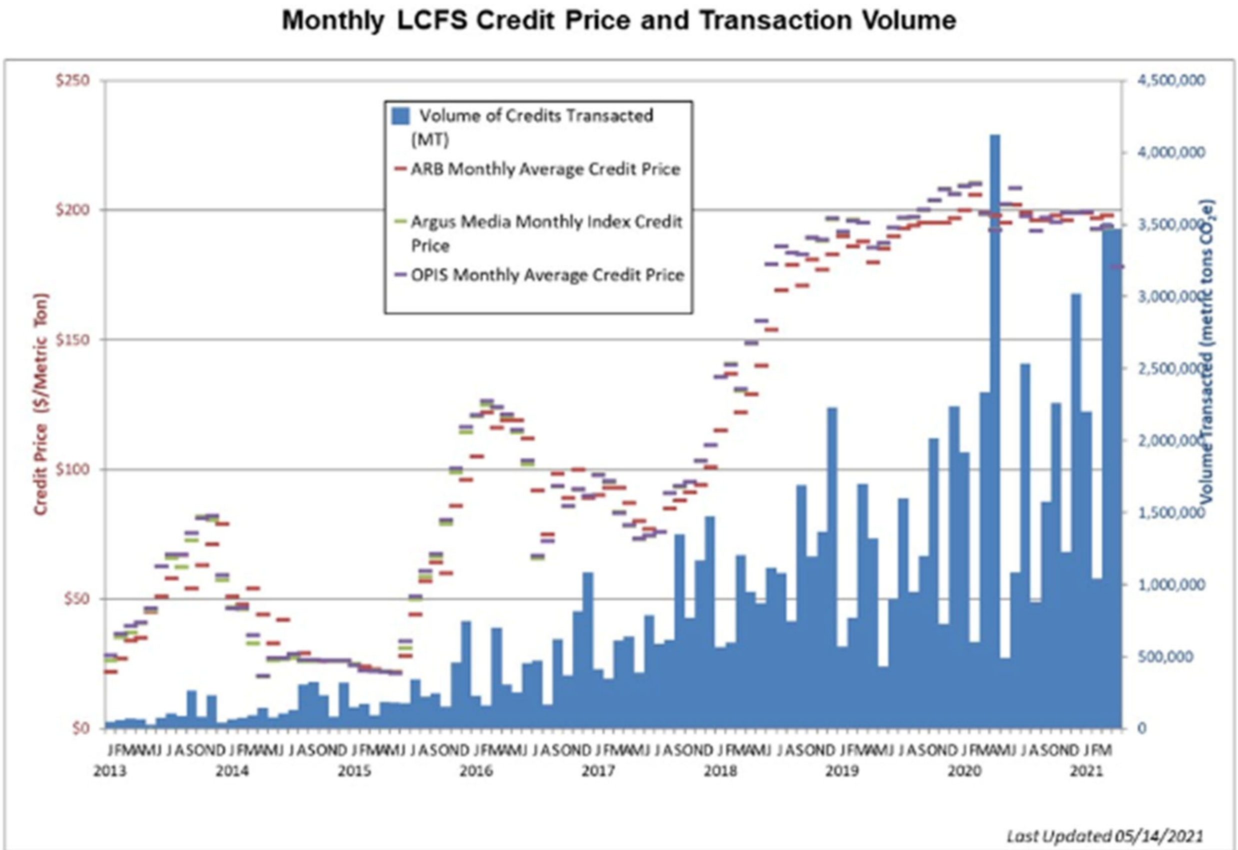


The trends described in Figure 3-2 are reflected in the historic trading values for LCFS credits, as shown in

Figure 3-3. Prior to 2017, credit prices were generally $50-100/MT. However, starting in mid-to-late 2017 when there was more demand than supply, prices began increasing until they reached $200/MT in 2019 and have remained around that level since. There is an inflation-adjusted cap on LCFS credit values that started at $200 in 2016 and is currently at $221.67/MT. For most of the financial analysis discussed below, a slightly conservative value of $180/credit was used.

[8] https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm

Figure 3-3. LCFS credit prices[9]



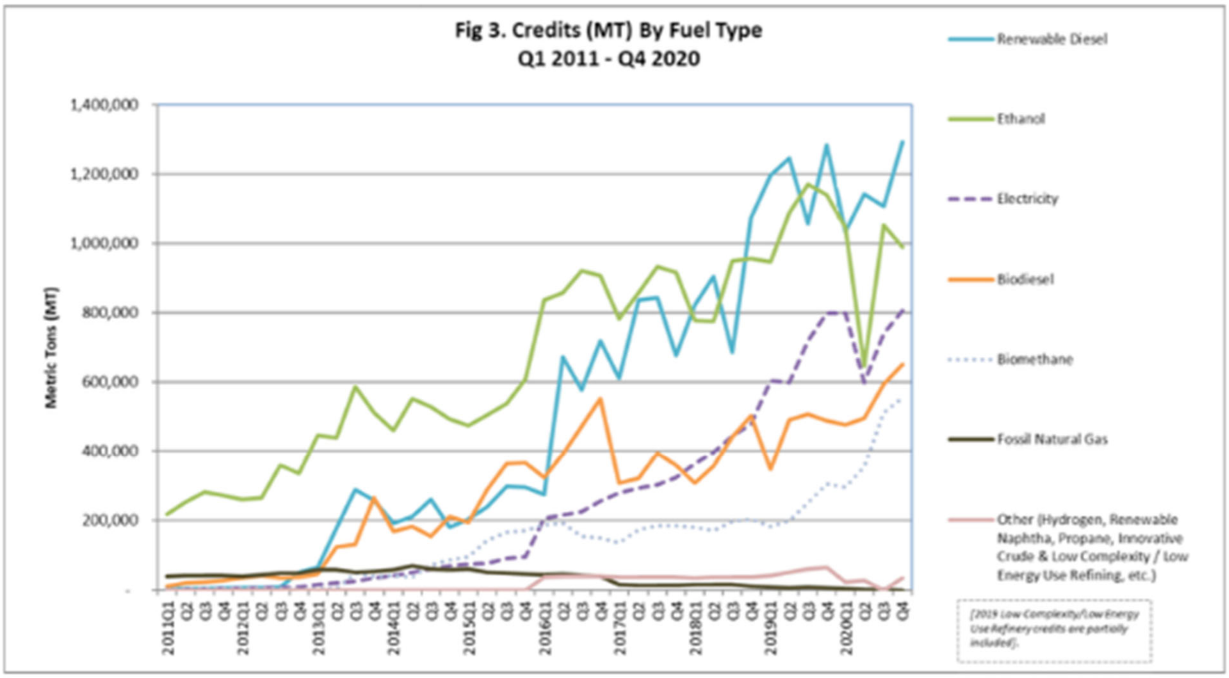
The LCFS credit supply is driven by the evolution of the alternative fuel technologies as shown in Figure 3-4. Several observations include:

- Prior to 2016, the fuel type creating the largest number of credits by a wide margin was ethanol, which is typically blended in with gasoline. However, around 2018, renewable diesel became the largest generator of LCFS credits.
- Credits generated by electricity were rising rapidly before 2020.
- Credits generated by biomethane increased dramatically in 2020, possibly due to dairy digesters coming online.
- There was significant drop in credits generated by ethanol and electricity in Q2 2020 that doesn't seem to be reflected in the other alternative fuels. This may reflect the drop in small vehicle personal travel associated with the Covid-19 Pandemic.

[9] https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm

One of the risks to the LCFS credit pricing is that, if an alternative fuel type achieved runaway success and flooded the market with LCFS credits, the value of the credits would decrease. This scenario would be favorable for California to reach its climate goals, but would be challenging for alternative fuel producers. This scenario is somewhat analogous to what occurred in the Renewable Electricity REC market with the dramatic drop in price of solar and wind generation.

Figure 3-4. LCFS credits by fuel type[10]



One other aspect of the LCFS market is that for vehicles that are fueled by either electricity or compressed natural gas, the market is currently constrained by the number of vehicles to be fueled, not by the supply of the fuel. As a result of this market dynamic, the owner of the vehicle/fueling station has significant market leverage and typically retains a percentage of any LCFS credits generated by a low-CI fuel (in addition to retaining 100% the credits generated by the high EER). This market dynamic also means that fuels with a very low CI will have an easier time competing for a vehicle for their fuel. As the California electricity market is expected to have an abundant supply of solar generated electricity with a CI of 0, any fuel with a CI at this level or higher may have a harder time competing to fuel a limited number of electric vehicles

Carbon Intensity of PGS Electricity:
In order to generate LCFS credits for electricity produced on-site at PGS and EV vehicle efficiency, the District needs to establish a CI value for PGS electricity, which involves an application and approval from the California Air Resources Board (CARB). District staff is

[10] 2020 LCFS Reporting Tool (LRT) Quarterly Data Summary Report No. 4, https://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm

currently in the process of obtaining this approval; however, the number and variability of high-strength wastes greatly complicates the CI calculation, which has prolonged the process.

For most of the electricity generated, the District hopes to get less than 10 gCO2e/MJ. In addition, District staff hopes to establish a separate pathway for electricity derived from food waste, which would be expected to get a much lower CI around -35 gCO2e/MJ due to avoided methane emissions in landfill. As discussed above, electricity with a negative CI is expected to have a much easier time competing in the market given current dynamics.

Potential Value of LCFS credits:

Restrictions: One major caveat to the value of electricity-based LCFS credits is that the regulation stipulates that proceeds from LCFS credits generated using electricity pathways can only be used to benefit EV drivers or be invested in projects that promote transportation electrification in California. CARB has issued guidance on how Electricity Credit Proceeds can be used[11]. For Non Load-Serving Entities (non-LSEs) which includes the District, examples for suitable investment include:

1. Providing incentive support for purchasing/leasing of EVs or other electric transportation equipment, e.g. example, electric forklifts, electric cargo handling equipment, electric transportation refrigeration units, electric buses, electric trucks, etc.
2. Providing incentive or direct investment for installing EV charging infrastructure.
3. Providing rebates or other incentives for using electricity as a transportation fuel, e.g. providing discounted or no-cost electricity for transportation applications, providing discounted or no-cost rides on electric public transit, etc.
4. Marketing, education, and outreach programs to inform the public on the benefits of electric transportation. This could include information regarding the environmental, health, and economic benefits of electric transportation, including a comparison of the total cost of electric transportation mode versus other alternatives (including the cost of refueling, servicing and maintenance, etc.).

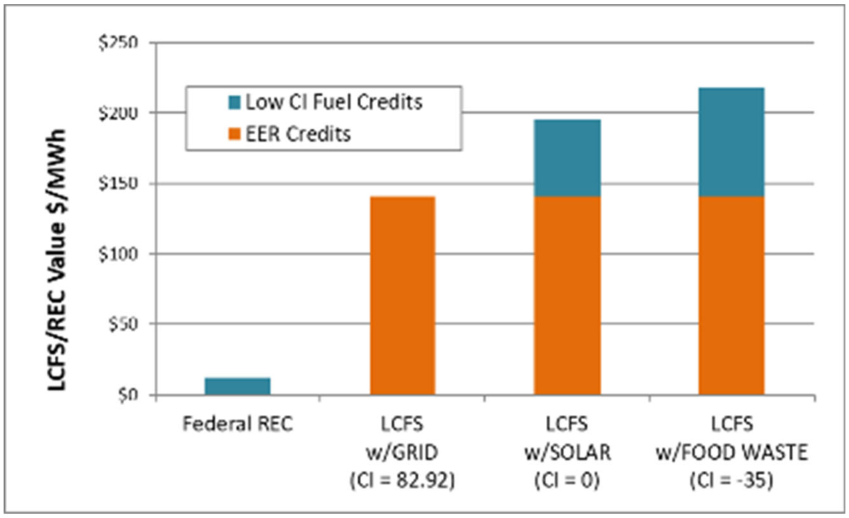
Potential Value: Using 2020 values and an LCFS credit price of $180, the potential full value of a PGS-to-EV pathway is shown in Figure 3-5. The value of the RECs being generated under the current PPA (on the left) is juxtaposed with the three options for LCFS credits, assuming different CI values. For each option, the portion in orange (worth $140/MWH) is primarily generated by an EV's EER and would likely be retained by the fueling station owner. The additional value of a low-CI fuel could range from around $55/MWh for a fuel with a CI of 0 gCO2e/MJ to $75 for a fuel with a CI of -35 gCO2e/MJ. This portion of the credit would likely be split between the fuel creator and the owner of the charging station.

If EBMUD were to create a -35 gCO2e/MJ fuel and split the low-CI credit value 50/50 with the charging station owner, it would be worth around $38/MWh to the District. Combined with an

[11] California Air Resources Board; Low Carbon Fuel Standard (LCFS) Guidance 20-03, Electricity Credit Proceeds Spending Requirements, Updated April 2021.

energy value of $45/MWh, the total potential value is $85/MWh. If the District also owned the chargers, the potential value would be much higher.

Figure 3-5. Potential LCFS credit value



3.2.2 Electric Renewable Identification Numbers

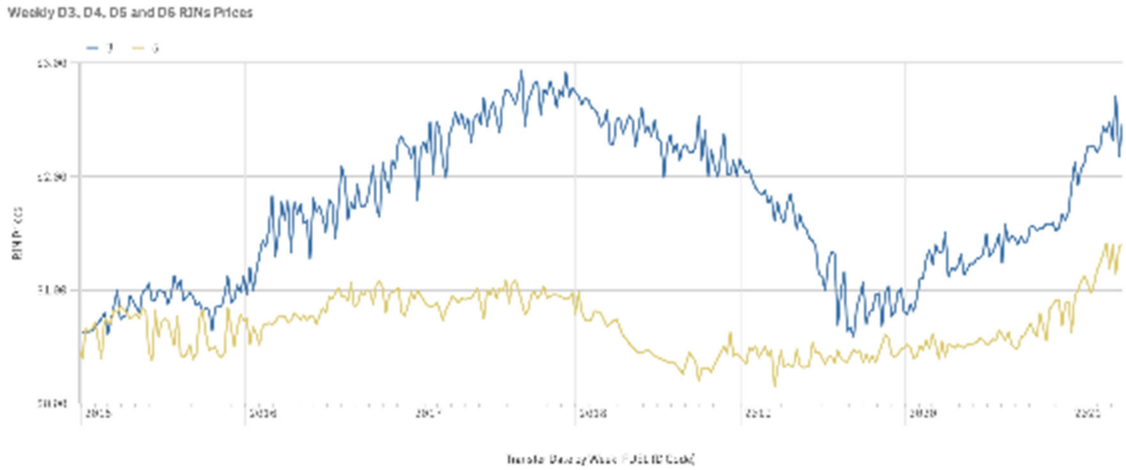
At the federal level, the Renewable Fuel Standard (RFS) Program is similar to the LCSF program. Renewable fuel producers generate Renewable Identification Numbers (RINs), which are the credits used for compliance by obligated parties.
While the LCFS program is dependent on a fuel production pathway and calculated CI, the RFS simply places fuels in different categories with a "D" value:

- D3 (More Valuable) – RNG generated from POTW sludge (primary sludge and TWAS)
- D5 (Less Valuable) – RNG generated from food waste

If D3 and D5 feedstocks are blended together and co-digested, as is done by the District, the blended feedstock is assigned the lower value D5 designation.

The market history for D3 and D5 RINs is shown in Figure 3-6. There are periods when D3 and D5 values diverge and D3 values are significantly higher. Since the District blends D3 and D5 feedstocks, the District would not be able to take advantage of periods when D3 values are significantly higher, making it more challenging to economically justify a RNG project for a codigestion facility. CASA and other wastewater agencies continue to petition the EPA to allow flexibility for blended feedstock RINs.

Figure 3-6. D3 and D5 RIN prices[12]



While compatible with the Renewable Fuel Standard Program, it is currently not possible to generate RINs using electricity (referred to as eRINS) as the renewable fuel. The EPA has not processed the necessary RFS applications and pathway petitions for electricity as a renewable fuel.

There is some indication that the EPA's policy on eRINs may change in the near future. If this happens, the potential value for an electricity project should be evaluated. If eligible, generating eRINs would likely require a fairly extensive process similar to that for the LCFS standard.

3.2.3 Conversion of EBMUD Fleet to EVs and Charging at the MWWTP

When renewable electricity that is generated by the District is used to fuel an EV, it has the potential to generate LCFS and RIN credits as discussed above. These credits are typically split in some way between the fuel generator (District) and the fuel dispenser (charging equipment owner). The generation and vehicle charging do not need to occur at the same location. The credits can be generated using "book-and-claim" accounting as long as renewable portfolio standard (RPS) RECs are not also claimed. If RECs are generated, then the appropriate number of RECs must be retired in WREGIS, an independent web-based tracking system for RECs in the Western region, to account for the electricity claimed under LCFS[13] to avoid double counting.

When an EV is charged with equipment (at any location) that is owned by the District, the District has the potential to generate and retain the full value of the LCFS credit discussed below. The full value is expected to be significantly higher than the portion of the credit theoretically retained by the District when the vehicle fueling is done by another party (like the Port).

The District has a total fleet size of around 1,300 vehicles consisting of:

- 400 light-duty vehicles

[12] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information
[13] California Air Resources Board, *LCFS Guidance 19-01, Book-and-Claim accounting for Low-CI Electricity,* April 2019

- 800 medium- and heavy-duty vehicles
- 6 plug-in hybrid and 4 fully electric vehicles

The potential for converting the District's light-duty vehicles to EVs was evaluated in Table 3-4. Currently, there are no medium- or heavy-duty EVs available on the market, so this was excluded from analysis, but should be re-evaluated in the future.

Even if all light-duty vehicles were converted to EVs, the total annual energy demand would only be a small fraction (4%) of the current power sold to the Port. However, because the LCFS credits have the potential to be more lucrative, the revenue could be around 15% of the current power sales to the Port.

Table 3-4. EBMUD fleet electricity use potential

Parameter	Current	Potential
Light-Duty EVs	10	400
Estimated Mileage	100 miles/week	
Vehicle Fuel Economy	0.3 kWh/mile	
Annual Energy use/vehicle	1.5 MWh/yr	
Fleet Annual Energy Use	15 MWh/yr	600 MWh/yr
% of Current Excess Power[1]	0.1%	4%
Potential Annual LCFS Value[2]	$3,000	$120,000
% of Current Power Sales[3]	0.4%	15%

Notes:
1. Current excess power sold to the port is roughly 14,000 MWh/year
2. Based on $180/LCFS credit and a CI of -35, the credit is worth ~$200/MWh
3. Current Power sales are roughly $800,000 per year @ $58/MWh

The District could also evaluate EV charging for employees or the public to increase energy use and LCFS credit revenues. There is currently a pilot at the MWWTP to explore the potential of EV charging for employees only. Providing EV charging for the public is challenging because charging takes several hours and the MWWTP is not a typical location for a charging station, e.g. near locations where the public would likely spend several hours such as a restaurant or an overnight rest stop.

Next steps for the District with regard to EV conversion and EV charging are:
- Develop LCFS pathway to establich a CI for MWWTP electricity
- Continue to evaluate potential for converting fleet vehicles to EVs and selling LCFS credits
- Determine the results of the pilot for employees to charge EVs at the MWWTP

3.2.4 Charging Electric Vehicles at the Port of Oakland

The LCFS program is intended to reduce the CI of transportation fuel in California, beyond just the traditional light duty and heavy-duty vehicles. The Port of Oakland has several other types of fuel use can also qualify to generate credits under the program, including

- Electric cargo handling equipment
- Electric power for ocean-going vessels
- Electric transportation refrigeration units
- Electric forklifts

In addition, the Port has made significant infrastructure investments to allow ocean going vessels to use shore power when docked. Each ship can draw anywhere from 0.75-8 MW. Currently the Port estimates that ships at dock use around 30,000 MWh/yr of electricity[14], compared to the District's current export of around 14,000 MWh/yr. The Port has already registered these shore power substations in the LCFS program.[15]

The Port is planning for significant electrification of its on-site trucks, especially drayage[16] trucks. There are 4 electric trucks manufactured by BYD operating at the Port currently and there was expected to be 17 by the end of 2020. The number of electric trucks is expected to grow from there.

The Port can already generate LCFS credits for these vehicles using the standard CI for grid electricity or for its electricity mix; however, there is potential to generate additional credits if paired with a low or negative CI source like the District's electricity. The amount of additional value would depend on the CI established by the District, as discussed in previously. Once the District establishes a CI for a significant fraction of its exported electricity, an amendment to the PPA with the Port could allow the District to sell the Port a low-CI electricity under LCFS instead of generating renewable RECs.

One other item to note is that the different equipment at the Port has different EERs under LCFS. The LCFS program evaluates the amount of energy put into the vehicle, and the EER is intended to correct for the difference in efficiency between the different engine types. For example, for every unit of energy put into an EV, a much higher fraction of that energy goes into moving the vehicle as opposed to a traditional combustion engine where a lot of that energy is lost as waste heat. However, there is no additional benefit to putting a low-CI fuel into a vehicle with a high (more efficient) EER vs a vehicle with a low EER. The benefits are additive and not duplicative.

Next steps for the District with regard to EV charging at the Port include:

- Develop LCFS pathway for a significant fraction of low-CI feedstocks
- Begin conversations with the Port on amending the PPA to obtain a greater value for the RECs associated with the LCFS program

[14] Discussions with Port Staff, 2019-12-05
[15] Port of Oakland, *Seaport Air Quality 2020 and Beyond Plan,* May 2019
[16] "Drayage" refers to moving of goods over short distances, it comes from the low side less wagon called a "dray" that was historically used for this purpose

3.3 Direct Supply

One alternative to increasing the value of electricity supplied to the market via the PG&E grid would be to directly supply electricity to another party.

3.3.1 Direct Connection to the Port of Oakland

This alternative would be to construct a direct connection to supply electricity to the Port and avoid PG&E distribution charges, i.e., the wholesale distribution tariff or WDT. This is sometimes referred to as an "over-the-fence" transaction.

The Port is a publicly owned Load Serving Entity (LSE). Under the RPS, LSEs in California are required to procure eligible renewable electricity resources to meet the following goals:

- 33% by the end of 2020
- 44% by the end of 2024
- 52% by the end of 2027
- 60% by the end of 2030

Historically, the Port has purchased the District's renewable electricity via PG&E to meet this requirement. Port staff estimates that the Port pays PG&E approximately $20/MWh to bring the power over[17].

[17] Port of Oakland. (2016, July 14). *Board of Port Commissioners.* Agenda Report, File #: 200-16

Source: Port of Oakland 2019

Figure 3-7. Port utility service area

The Port has approached the District several times with interest in pursuing a direct electrical connection from the MWWTP to the Port's electrical grid. As shown in Figure 3-7, the Port utility service area extends to the southern corner of the MWWTP site. A direct connection would potentially provide several benefits to the Port and could create additional value that would help fund a direct connection project. Potential benefits include:

- **Avoided transmission costs**: A direct connection would avoid PG&E's $20/MWh transmission cost entirely. For the current exports of ~ 14,000 MWh/year, this would be roughly equivalent to saving $2.8M over ten years.
- **Avoided transmission upgrades for the Port:** A report prepared for the Port projected that the total future Port load is expected to grow from 22 MW in 2018 to 100 MW by 2038.[18] This projection includes the addition of:
    - 16 MW of shore power growth by 2023
    - Up to 50 MW of demand due to mobile cargo handling equipment electrification, starting in 2023
    - 10 MW from other developments including increased cold storage facilities, larger electric cranes, and new warehouses

[18] Burns & McDonnell, *Port of Oakland, Maritime Power Capacity Study for Terminal Electrification,*2019,

Based on this anticipated load growth, the report projected a total transmission and distribution upgrade cost of $46.8M by 2023.

- **Additional opportunities for EV charging at the Port:** The Port has identified several areas at the northern end of the Port service area that have expressed an interest in EV charging infrastructure. However, the Port would need to upgrade an internal 12 kV circuit to serve this load. A direct connection from the MWWTP could potentially serve these loads and avoid or delay the need to upgrade the 12 kV circuit.
- **Reliable power for the Port**: The Port is interested in procuring consistent power from the District, as opposed to the current arrangement where the District sells surplus, as-available power, without a guarantee to sell a specified amount. The District would need to commit to selling a certain fraction of its generation on a scheduled or firm basis.

The District performed a brief regulatory and legal review to identify if there were any threshold issues that would prevent an "over-the-fence" direct connection to the Port. At a high level, no issues were identified and it did not appear that a direct connection would alter the current regulatory status for the MWWTP. However, there were several considerations identified that would need to be explored further, including:

- Impact to any current agreements with PG&E
- Ensuring that the energy transmitted maintains its status as an RPS product, despite the change to wholesale delivery
- Allocation of responsibilities for operation and maintenance of the interconnection

The Port is reviewing the feasibility of a direct connection project. Pending the outcome of that analysis, additional review and investigation will be necessary.

3.3.2 Direct Connection to an On-Site Third Party

This alternative would be to provide electricity to an on-site thirty party. In this scenario, the rate would likely be somewhere between the WAPA rate and the PG&E rate.

This alternative has recently been explored in some detail with First Element Fuels (FEF) for a hydrogen production facility on the West End asphalt cap site. Using electricity to produce hydrogen rather than the raw biogas avoids the potential challenges associated with PSM and RMP discussed below. However, the cost of delivering power to the West End property ultimately made this project infeasible and was not pursued.

Periodically, the California Energy Commission (CEC) makes grant money available for a hydrogen production facility (most recently Grant Funding Opportunity GFO-20-609 Transportation Fuel Renewable Hydrogen Production) with a capacity of at least 1,000 kg/day. FEF fuels has estimated that they would need around 2.5 MW to produce that amount of hydrogen. Providing 2.5 MW would slightly increase the amount of imported power required for the MWWTP, as the current excess power averages around 1.7MW.

The potential terms discussed with FEF included:

- **Demand charge for 2.5MW:** $10,000/month (based on the interim PG&E WDT rate)
    - There may be options to reduce the cost if FEF demand can be reliably turned down when the District's overall site demand nears the contract demand. This is likely rare, for example, during large storms only a few times a year.
- **Energy Pricing:** ~$90/MWh. The District briefly discussed a two-tier pricing approach; however, upon further reflection, the District would prefer an all-inclusive price for simplicity.
- **Availability:** The District anticipates supplying power 24/7 under most normal conditions. If there were a grid or on-site generation outage, the District would potentially need to curtail the amount of power supplied temporarily to ensure its own continuous operations.

Under these terms, the annual value to the District was expected to be around $500k higher than under the status quo with a PPA price of $58/MWh. However, the cost estimate for providing 12 kV power to the entire West End property was $9.5M, which effectively rendered the project economically non-viable unless a significant amount of grant funding was obtained.

Next steps for the District include:

- Explore the potential for grant money to cover project costs

4 CHALLENGES FOR ALTERNATIVE USES OF BIOGAS

As an alternative to finding a higher-value use for the electricity already being produced on-site, the biogas could instead be used for a different purpose as described below. However, there are several significant challenges to any alternative use of biogas.

4.1 Loss of Process Safety Management and Risk Management Plan Rule Exemption

There are two national regulations that act in parallel to prevent major industrial accidents. In the Clean Air Act Amendments of 1990, Congress required OSHA to adopt the Process Safety Management (PSM) standard to protect workers and required the EPA to protect the community and environment by issuing the Risk Management Plan (RMP) Rule. These two regulations are similar but have several key differences. These regulations apply to a site if there is more than a threshold amount of a hazardous chemical on-site. The chemical categorization and threshold amounts are similar but not identical for both programs.

For the MWWTP, the relevant hazardous chemical is flammable gas (biogas), which has a threshold of 10,000 lbs. If there is more than 10,000 lbs of flammable gas on-site, these regulations apply with some exceptions. The full weight of the biogas used for this calculation, not just the methane fraction of the biogas. The MWWTP site typically has over 40,000 lbs of biogas on-site in the digesters and biogas system (660,000 ft^3 biogas @ 0.0679 lb/ft^3), and thus exceeds the threshold. However, the PSM and RMP regulations do not currently apply to the MWWTP due to the on-site fuel use exception described below.

PSM Applicability to Public Employees:
While Federal OSHA does not have direct jurisdiction over employees of state and local governments, twenty-five states, including California, administer their own occupational safety and health programs under plans approved by OSHA. These states are required to adopt and enforce occupational safety and health standards that are at least as effective as those promulgated by OSHA and must extend their coverage to public sector employees. Therefore, both public sector employees of POTWs and any contract employees who perform operations, maintenance, or other PSM-covered activities, would be covered by the state's PSM standard.

PSM and RMP Exceptions:
There are two relevant exceptions from these regulations that affect potential biogas projects. The relevant language for the California Accidental Release Prevention (CalARP) Program is below. This is the state level version of the RMP program:

- **CalARP exclusion (Section 2770.4.1): (<u>highlights added</u>)**
  A flammable substance listed in Section 2770.5, Table 2, is nevertheless excluded from all provisions of this chapter when the substance is <u>used as a fuel</u> or <u>held for sale as a fuel at a retail facility</u>.

- **OSHA PSM Exceptions (Title 8 CCR §5189(b)(1)): (<u>highlights added</u>)**

> *(2) Hydrocarbon fuels used solely for workplace consumption (e.g. comfort heating propane, gasoline for motor vehicle refueling) …*
> *3) These regulations do not apply to retail facilities …*

Guidance from both OSHA[19] and the EPA[20] indicated that normal POTW operations that used all biogas on-site as a fuel did fall under these exceptions and excluded them from the program. The MWWTP currently operates with this exception.

Potential Loss of Exception:
The District's initial interpretation of this language is that any project that moves biogas off-site has the potential to remove the exception for the entire biogas system under both PSM and RMP. This includes moving the biogas to a third-party site on land leased from the District. While there is no clear guidance on the subject, this does match the experience and interpretation of the rule as applied at several other POTWs, including King County in Washington State and Sac Regional in California.

However, in May 2020, Clyde J. Trombettas, Statewide Manager & Policy Adviser for Cal/OSHA Statewide PSM Unit, issued an email in response to a project by LA County Sanitation Districts with a different interpretation of the language that would allow the MWWTP to maintain its exception. Since May 2020, the District has sought a regulatory clarification specific to the MWWTP site and met with Cal/OSHA staff in June 2021 to review hypothetical scenarios for some proposed projects. Discussion at this meeting indicated that the MWWTP could pursue these types of projects without risking the loss the exception from PSM in the near term. However, at least two challenges remain:

- The interpretation could potentially be reevaluated with a change in personnel at Cal/OSHA. This has happened in the past with other regulatory bodies and the R2 Program.
- This interpretation would not apply to the RMP program.

If the District were to get the desired clarification for a specific project, there would need to be an assessment as to whether this would lower the risk enough to pursue that project.

Consequences of Loss of Exception:
As a part of evaluating a possible RNG project in early 2019, the District extensively reviewed the implications of losing the exception at the MWWTP. This review included multiple interviews with other POTWs and a site visit to Sac Regional, which was working towards complying with the requirements of PSM. The District ultimately concluded that the implications would be different for RMP than for PSM given the different rules involved.

[19] https://www.osha.gov/laws-regs/standardinterpretations/2000-09-21
[20] EPA, *General RMP Guidance - Appendix F: Supplemental Risk Management Program Guidance for Wastewater Treatment Plants* (July 2004)

Under PSM, there are no different levels, just a single set of requirements to be met. The District determined that while there were some beneficial aspects of these requirements, the benefits would not ultimately be worth the extensive costs in capital and manpower required to comply.

Under RMP, the first step would be to perform a worst-case release analysis. Depending on the results of that analysis, the MWWTP would be assigned to a risk level: Program 1 (lowest risk), Program 2 (medium risk), or Program 3 (highest risk). The requirements of each risk level are shown in Table 4-1. The requirements of Program 1 are relatively easy to meet, whereas the requirements of Program 3 are as strict as those under PSM. The District believes that the MWWTP would qualify as a Program 1, but this would need to be confirmed.

Table 4-1. CalARP comparison of program requirements[21]

COMPARISON OF PROGRAM REQUIREMENTS		
Program 1	**Program 2**	**Program 3**
Executive Summary	Executive Summary	Executive Summary
Worst-case release analysis	Worst-case release analysis	Worst-case release analysis
	Alternative release analysis	Alternative release analysis
5-year accident history	5-year accident history	5-year accident history
	Document management system	Document management system
Prevention Program		
Certify no additional prevention steps needed	Safety Information	Process Safety Information
	Hazard Review	Process Hazard Analysis
	Operating Procedures	Operating Procedures
	Training	Training
	Maintenance	Mechanical Integrity
	Incident Investigation	Incident Investigation
	Compliance Audit	Compliance Audit
		Management of Change
		Pre-Startup Review
		Contractors
		Employee Participation
		Hot Work Permits
Emergency Response Program		
Coordinate with local emergency responders	Develop a plan and program (if applicable) and coordinate with local emergency responders	Develop a plan and program (if applicable) and coordinate with local emergency responders
Submit One Risk Management Plan for All Covered Processes		

[21] USEPA's General Guidance for Risk Management Programs, May 2000, Exhibit 2-4

4.2 Air Permit

Any project at the MWWTP that increases local air emissions is likely to face a challenging process with the community and the Bay Area Air Quality Management District (BAAQMD). Assembly Bill (AB) 617 directs air regulators to work with communities facing air pollution and poor health to develop solutions and reduce air pollution in those areas. West Oakland was identified under AB617 as one of these communities. Introducing a new source of emissions would potentially run counter to those goals and could be difficult to implement.

4.3 Competing Priorities

A challenge for an alternative biogas use project is that the District has competing priorities to rehabilitate aging infrastructure, prepare for new regulations, build climate change resiliency, and alleviate capacity constraints. Projects to address these issues are identified in the Master Plan roadmap and 10-year CIP. An alternative biogas use project would thus compete for staffing resources and funding.

To manage staffing, the District could work with a third-party consultant on the project design and execution. If the PSM and RMP challenges are addressed, this could be worth exploring.

5 ENERGY PRODUCT ALTERNATIVES TO ELECTRICITY

If the challenges discussed in Chapter 4 can be addressed, there are a number of alternatives that could be explored, several of which are described below.

One critical question for any project will be biogas availability. If an alternative project is limited to just the excess biogas that is currently flared, then the scale and uptime for a project will be challenging, as discussed previously. However, if the value is high enough, it may be worth reducing generation from PGS and giving priority to an alternative use project. These factors would need to be weighed in the evaluation of any project.

5.1 Supply Biogas for Hydrogen Vehicle Charging

One option would be to upgrade and supply biogas for the production of hydrogen via steam reformation. The hydrogen could then be used in fueling zero emission vehicles (ZEVs).

5.1.1 Hydrogen Vehicles Background

Hydrogen fuel cell electric vehicles (FCEVs) and Battery Electric Vehicles (BEVs) are the two primary options for ZEVs. A FCEV is refueled with compressed hydrogen, which is used in the vehicle's fuel cell to produce electricity for operation. The only emissions from the vehicle are water vapor and warm air. FCEVs are often seen as having several advantages over BEVs, especially for the developing heavy-duty truck market, including fast refill times (comparable to traditional gas or diesel), longer ranges, and higher payload capacity. One of the main challenges for FCEVs has been the high vehicle and fuel costs, especially when compared with the cost of fueling a BEV.

California has made significant investments in developing FCEV transportation including (as of Dec 2018):

- $110.9 million for 64 retail hydrogen refueling stations
- $10.7 million for ongoing operations and maintenance of 34 hydrogen refueling stations
- $10.0 million to support hydrogen refueling for public infrastructure
- $8.0 million for hydrogen infrastructure to support 10 fuel cell electric trucks at the Port of Long Beach
- $3.97 million for a 5,000 kg/day electrolysis plant[22]

As of September 2018, there were 35 open-retail hydrogen refueling stations in California capable of supporting up to 9,550 FCEVs and roughly 5,000 light duty FCEVs on the road. The total hydrogen demand for all FCEVs on the road was approximately 3,500 kg hydrogen/day. As a point of comparison, as of October 2019, there were estimated to be more than 650,000 Plug in Electric Vehicles (PEVs) on the road in California.

[22] California Energy Commission, *Tracking Progress, Zero-Emission Vehicles and Infrastructure,* Dec 2018

5.1.2 FirstElement Fuel Hydrogen Fueling Station at the MWWTP

In November 2020, the CEC and CARB jointly released solicitations for a zero-emission drayage truck and infrastructure project with grant funds. A single applicant would assemble a team to manufacture and operate zero-emission drayage trucks, install and operate fueling infrastructure, and demonstrate the feasibility of this approach at a California port. The District announced that it was interested in leasing property to support such projects serving the Port. Two teams indicated interest in utilizing the MWWTP property and staff submitted letters of support to CEC for both proposals.

On April 5, 2021, one of the District-supported applicants, the Center for Transportation and the Environment (CTE) was selected as one of two proposed award recipients. The other District-supported team was not awarded funds. CTE proposed using heavy-duty FCEVs operating on renewable hydrogen fuel. The proposed project will fuel up to 30 heavy-duty fuel cell Class 8 tractor trailers manufactured by Hyundai and leased to Glovis America. Trucks will be fueled by a FEF fueling station located on the West End property. FEF currently has 24 operational hydrogen fueling stations in California and expects to have a total of 80 stations in service throughout California by 2025. A summary of the CTE team members is shown below in Table 5-1. The proposed grant award to CTE is $17.1 million in combined funds from CEC and CARB.

Table 5-1. Drayage truck pilot team

Team Member	Role
CTE	Lead grant applicant and project manager
Hyundai	Vehicle manufacturer
FirstElement	Hydrogen fueling infrastructure
Glovis America	Drayage fleet operator
Transportation Sustainability Research Center, University of California, Berkeley	Data analysis, project evaluation, and reporting
West Oakland Environmental Indicators Project	Disadvantaged community liaison

On May 25th 2021, the Board approved a 10-year lease with FEF at the building 1086 site.

The District will see a number of benefits in addition to the project being a significant step toward reducing greenhouse gas emissions and improving local air quality. The District will earn lease revenue of about $3.3 million over the ten-year term and $5.4 million if the lease is extended to 15 years. FEF will demolish Building 1086 at its own expense and the site will be available for District use following future termination of the lease. The lease features an option for the District to provide biogas as a feedstock to produce hydrogen fuel should a production project become feasible. Also, the lease features an option for the District to purchase hydrogen for its fleet vehicles in case the District purchases fuel-cell electric vehicles in the future. This project is a significant demonstration of zero-emission heavy-duty vehicle operation that, if successful, may expand and dramatically reduce diesel emissions in West Oakland.

5.1.3 Potential Third-Party FCEV projects

It is unlikely that the District would produce hydrogen on its own and would instead likely partner with a third party. Since FEF is building a fueling station at the MWWTP, FEF could be a partner for any hydrogen production project. However, other possible partners include Shell, Switch Maritime, Air Liquide, and Air Products.

In addition to the challenges discussed in Chapter 4, a challenge would be delivering biogas to the hydrogen production site. The most likely location for hydrogen production would be the asphalt cap site. The initial cost estimate for delivering biogas to this site was roughly $8M.

5.2 Renewable Natural Gas

Converting biogas into renewable natural gas (RNG) could unlock a number of potential markets and increase the value of biogas. RNG can replace fossil natural gas wherever natural gas is used; however, currently most RNG ends up as a vehicle fuel due to the LCFS and RIN incentives discussed in Chapter 4.

To convert biogas into RNG, the methane concentration needs to be increased, while carbon dioxide and other impurities need to be removed. There are several well-developed technologies to do this upgrading. The scale and required purity of the RNG generally drive the choice between different technologies for upgrading. The RNG purity requirements are determined by the intended use. The highest standard is for RNG that will be injected into the natural gas network. RNG used to fuel vehicles directly does not require as stringent or expensive of upgrading.

One challenge for RNG is that, while emissions are much lower than for traditional diesel or gasoline vehicles, it is still not a zero-emission technology. Today, much of the grant funding and state support is focused on creating a true zero-emission transportation network, including BEVs and FCEVs.

5.2.1 Renewable Natural Gas Market

Once the biogas has been upgraded, there are a number of potential markets for the RNG. The highest value market for RNG is in the transportation fuel market due to LCFS and RIN incentives. Credits under both these programs could be generated for RNG used to fuel vehicles; however, there are some challenges to the vehicle fueling market for RNG including:

- Revenue volatility for LCFS and RIN credits
- Highly competitive market for supplying fuel in CA (necessary to generate LCFS credits). RNG generated from dairy farms often has very negative CI values that the District’s biogas would be unable to compete with.
- A shrinking RNG vehicle market as alternative zero-emission technologies are rolled out

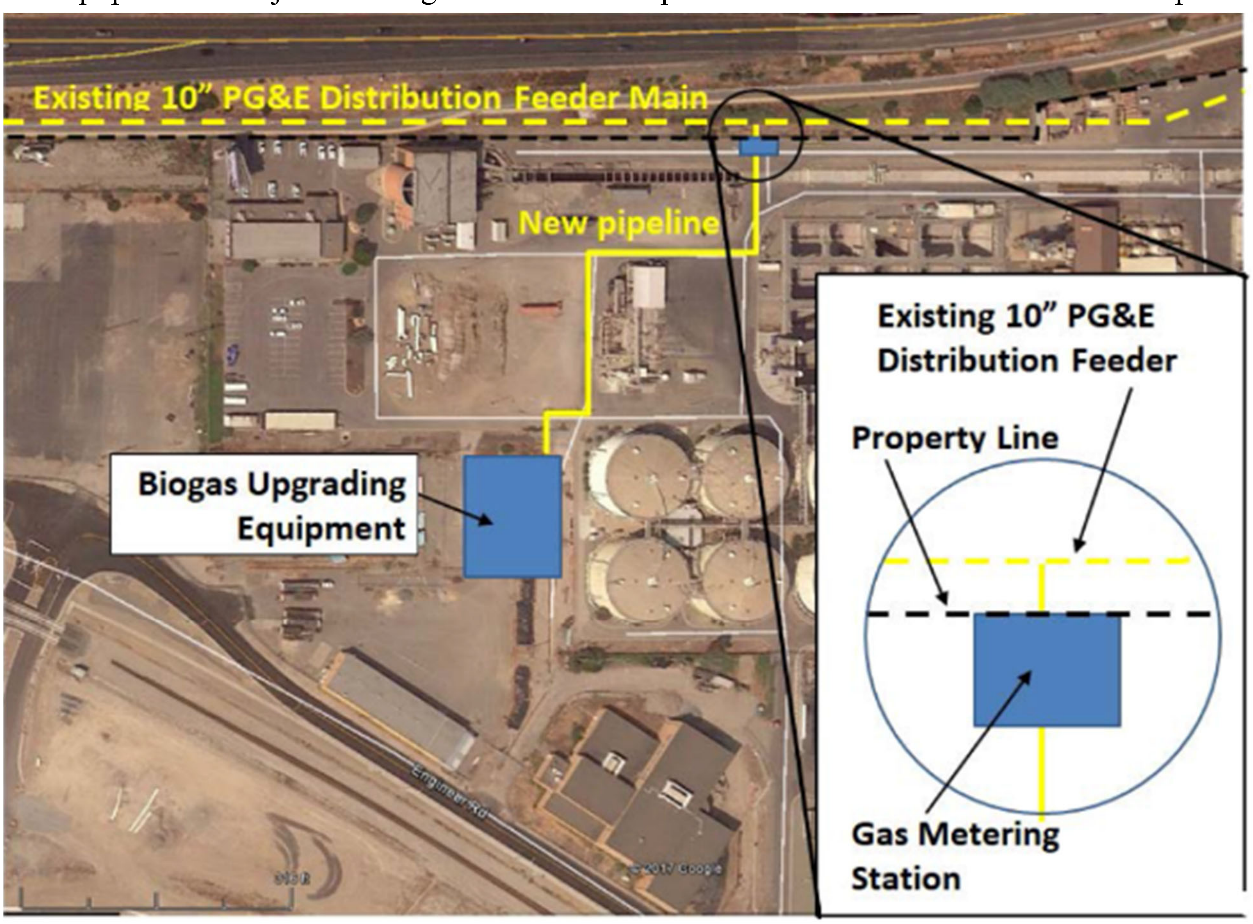
On-Site Vehicle Fueling: This option would have some advantages, as the upgrading would be less expensive than for pipeline injection. However, there would be a number of significant challenges that would need to be addressed including:

- Construction and operation of the fueling station
- Identification of a local fleet of sufficient size to use the RNG
- RNG storage and/or transportation to match production pattern to use pattern
- Backup natural gas connection for reliability.

Pipeline Injection: Injecting RNG into the PG&E natural gas network would likely be the most feasible option for an RNG project. As shown in Figure 5-1, there is a 10” PG&E Distribution Feeder Main that runs along the northern edge of the MWWTP property. Interconnecting to the PG&E network would likely be expensive, on the order of $3M - $4M for the injection point alone; however, there would be a number of major advantages including:

- Ability to market to any customer connected to the natural gas grid
- Ability to use the pipeline as essentially unlimited storage. Operationally, there would be no need to balance supply with demand in the short term.
- No additional truck traffic

Figure 5-1. Conceptual pipeline injection layout. Note that the location of the biogas upgrading equipment is subject to change based on the implementation of the Master Plan roadmap.



Once the RNG has been injected into the natural gas network, it can be sold for vehicle fueling to any compressed natural gas user on the network. In addition, pipeline injection would also allow access to the green gas market for users trying to reduce the environmental impact of their natural gas use. One of the major, local buyers of green gas is the University of California System. Initial talks with them indicated that the green gas value of RNG could be in the $10-12/MMBtu range with the potential for 10-20 year contracts.

5.2.2 CEC Grant GFO-18-601

In 2018, the District applied for a $3 million grant from the California Energy Commission (CEC) to develop an RNG Pipeline Injection project under the Alternative and Renewable Fuel and Vehicle Technology Program Grant GFO-18-601. In January 2019, the District was notified that it was selected for a "proposed" award. The total capital cost for the proposed project size was $16.4 million. In addition to the CEC grant, the project would have also been eligible for California Public Utility Commission incentive funding for 50% of the interconnection costs, estimated at $1.7 million. Taking into account the grant and incentive funding, the estimated remaining project cost to the District would have been $11.7 million.

However, on March 14, 2019, District staff sent a memo to the Board notifying the Board that staff had decided to not proceed with the biogas upgrading project, and notifying the CEC that the District would not accept the grant award. The CEC was notified of this decision on March 18, 2019.

The determination not to accept the grant award was based on two primary risks. The first risk to the project was an ongoing PG&E bankruptcy proceeding. PG&E sought bankruptcy protection in January 2019 after accumulating liability for wildfires started by its equipment. The bankruptcy could have presented unforeseen complications with the potential to delay the interconnection and/or jeopardize the District's ability to receive the expected incentive funding to offset a portion of the interconnection costs. Since District staff estimated that there is a limited window to obtain maximum value for biogas as transportation fuel, any project delay due to the PG&E bankruptcy would reduce the expected overall revenue and cost-effectiveness of the project.

The second risk was the PSM and RMP challenge described in Chapter 5. In evaluating this project, District staff estimated that complying with PSM would require up to seven additional staff and $500,000 in consulting costs over the first several years, with unknown capital costs to replace current equipment to meet documentation requirements.

5.2.3 Next Steps for Renewable Natural Gas

If the PSM and RMP challenge can be addressed and/or mitigated, then an RNG project supplying green gas via the pipeline would likely still be economically favorable even without the CEC grant, especially at the 1,000+ scfm scale. However, if these challenges remain, an RNG project is likely not prudent for the District.

5.3 Bio-Plastic Production

One developing opportunity for using biogas is to produce plastic or other materials via fermentation of methanotrophs. By manipulating the growing conditions, these methanotrophs can be induced to convert the methane in biogas into biopolymer that can be used for a wide variety of applications, including biodegradable plastics production.

Next steps for bio-plastic production include:

- Explore whether using biogas for biopolymer production would have the same PSM and RMP challenges as other biogas uses
- Evaluate the cost of delivering the biogas to a suitable site on the West End property for biopolymer production

5.4 Future On-Site Uses

In addition to the options discussed above, there are other potential high-value on-site uses that would maintain the PSM/RMP exemption and are thus more feasible. In addition, these uses would generally be offsetting the purchase of retail natural gas from PG&E. In 2020, the PG&E natural gas rate used for the Master Plan was $1/therm or ~ $10/MMBtu. If this offset is compared to buying green gas as opposed to fossil natural gas, the value would be even higher, likely more on the order of $20/MMBtu.

There are two primary ways biogas could be used on-site: replacing natural gas in on-site buildings and biosolids thermal drying. More information is described below.

Replace Natural Gas in On-Site Buildings: This option was identified in the Master Plan roadmap to reduce the GHG emissions. This option would require some capital investment in:

- Biogas upgrading equipment to produce RNG
- RNG piping to the Administration & Lab Building
- Some RNG storage to balance supply and demand

Natural gas is used at both the Field Services Building and the Administration & Lab Building. However, Field Services only accounts for about 1% of the total demand, while the Administration & Lab Building typically uses 99% of the total, or around 150,000 therms per year or 15,000 MMBtu, which equates to a range of 30-80 scfm and an average of 50 scfm of raw biogas demand. This demand is relatively small relative the available supply and is likely financially unattractive. However, this option might be worth pursuit given the District's GHG reduction goals.

Biosolids Thermal Drying: One alternative for reducing biosolids hauling and disposal costs is to thermally dry the biosolids to a higher solids content, reducing their volume by nearly five times. This alternative was identified in the Master Plan roadmap for the 2030s. If a thermal dryer were installed at the MWWTP, biogas could be used for heating (around 29 MMBtu/h, which translates to 800 scfm).

Next steps for future on-site uses include:

- Evaluate the cost of using biogas in building heating
- Continue to monitor the biosolids market and the potential need for thermal drying