Dublin San Ramon Services District
Water, wastewater, recycled water

Dublin San Ramon Services District
Energy Facilities Master Plan

Volume 1
TECHNICAL MEMORANDA 1-12
ENERGY FACILITIES MASTER PLAN

FINAL | June 2024

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FINAL | June 2024

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Energy Facilities Master Plan

Technical Memorandum 1
STATE OF THE DISTRICT ENERGY MANAGEMENT AND GREENHOUSE GAS EMISSIONS

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Abbreviations

ACH	aluminum chlorohydrate
ADAF	average daily annual flow
Al_2O_3	aluminum oxide
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
BOD_5	biological oxygen demand
BTU/hr	British thermals unit per hour
CARB	California Air Resources Board
cBOD	carbonaceous biochemical oxygen demand
CCA	community choice aggregation
CCT	chlorine contact tank
cf	cubic feet
cfm	cubic feet per minute
CH_4	methane
CIP	capital improvement program
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
DAFT	dissolved air flotation thickener
DERWA	Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority
DLD	dedicated land disposal
DOE	Department of Energy
DSRSD/District	Dublin San Ramon Services District
EBDA	East Bay Dischargers Authority
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
F	Fahrenheit
FeCl2	ferrous chloride
FOG	fat, oil, and grease
FSL	facultative sludge lagoon
GHG	greenhouse gas
gpd	gallons per day
gpm	gallons per minute
GWh	giga watt-hours
H_2S	hydrogen sulfide
HFC	hydrofluorocarbon
hp	horsepower

HRS	heat recovery system
HVAC	heating, ventilation, and air conditioning
JPA	Joint Powers Authority
kg/day	kilograms per day
kV	kilovolts
kVAR	kilovolt-amperes reactive
kW	kilowatts
kWh	kilowatt-hour
LAVWMA	Livermore-Amador Valley Water Management Agency
lb VSS/day	pounds of volatile suspended solids per day
MCC	motor control center
MF	microfiltration
MG	million gallons
mgd	million gallons per day
mg/L	milligrams per liter
MMBtu/hr	million British thermal units per hour
MW	megawatt
MWh	megawatt-hour
N_2O	nitrous oxide
N/A	not applicable
NaOCl	sodium hypochlorite
NH_4OH	ammonium hydroxide
NPDES	National Pollutant Discharge Elimination System
NZEV	near-zero-emission vehicle
O&M	operations and maintenance
ORT	odor reduction tower
PFAS	per- and polyfluoroalkyl substances
PFC	perfluorocarbon
PG&E	Pacific Gas & Electric Company
POTW	publicly owned treatment works
ppd	pounds per day
PSR1	Recycled Water Pump Station R1
PTO	permit to operate
PUC	Public Utilities Commission
RAS	return activated sludge
SB	Senate Bill
SCADA	supervisory control and data acquisition
scf	standard cubic feet
scf/day	standard cubic feet per day

scfm	standard cubic feet per minute
SF	sand filtration
SF_6	sulfur hexafluoride
SFEI	San Francisco Estuary Institute
SSM	solid state meter
State Water Board	State Water Resources Control Board
SVI	sludge volume index
TDH	total dynamic head
TIN	total inorganic nitrogen
TIPS	Tertiary Influent Pump Station
TKN	total Kjeldahl nitrogen
TM	technical memorandum
TS	total solids
TSS	total suspended solids
UV	ultraviolet
UVT	ultraviolet transmittance
V	volt
VFD	variable frequency drive
WAS	waste activated sludge
WWTP	wastewater treatment plant
ZEV	zero-emission vehicle
Zone 7	Zone 7 Water Agency

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Technical Memorandum 1

STATE OF THE DISTRICT ENERGY MANAGEMENT AND GREENHOUSE GAS EMISSIONS

1.1 Introduction

The Dublin San Ramon Services District's (DSRSD/District) 2024 to 2028 Strategic Plan serves as a framework for decision-making over a five-year period. The Strategic Plan outlines 10 goals and action items for fiscal years ending 2024 through 2028, including a specific goal of improving energy efficiency and reliability for the District. The energy efficiency and reliability goals include the following two specific action items:

- Develop a District energy policy and District energy master plan that evaluates sustainable energy sources and opportunities for cost-effective energy conservation and efficiency.
- Initiate cost-effective energy projects consistent with the District's energy policy, business needs, and future regulations.

To achieve this goal, DSRSD has commissioned this master plan to prepare a roadmap to reduce energy usage, increase energy generation, and minimize its environmental footprint in a financially sustainable manner, while achieving regulatory compliance. Over the past years, DSRSD has successfully implemented various energy efficiency and recovery projects. Decisions for further improvements to support the 2024 to 2028 strategic energy goals will require a careful evaluation of environmental opportunities, capital and operation and maintenance (O&M) costs and return on investments, future regulatory requirements, energy reliability and resilience, workforce resource impacts, and trade-offs between these and other factors.

The following facilities are included in this Phase 1 evaluation:

- Wastewater treatment plant (WWTP).
- Recycled water treatment and distribution.
- Potable water distribution.
- Administrative and field operations office facilities.
- Fleet assets.

Facilities owned by the Livermore-Amador Valley Water Management Authority (LAVWMA) Joint Powers Authority (JPA) and the Dublin San Ramon Services District– East Bay Municipal Utilities District Recycled Water Authority (DERWA), which are operated under contract by DSRSD but are under joint ownership and/or capacity rights, are not the focus of this Energy Facilities Master Plan. JPAs make separate business and policy decisions about their respective facilities. However, for context, a general introduction to those facilities is included as part of this Technical Memorandum (TM) 1. The facilities covered in this TM 1 include DERWA's Recycled

Water Treatment Facility, DERWA's Recycled Water Distribution System (including Recycled Water Pump Station R1 [PSR1]) and LAVWMA's effluent pump station.

The project is organized into two phases: Phase 1 will conduct an analysis of the energy status of all these district-wide facilities, while Phase 2 will specifically focus on the alternative and cost evaluation of energy efficiency and production opportunities for the facilities that DSRSD owns and operates. The two main objectives of this project are to:

1. Support DSRSD in establishing a board-approved energy policy that is achievable and implementable, and that provides DSRSD with the direction for overall capital improvement plans, staffing resources, O&M costs, rate impacts, and integration with its current and future technology infrastructure.
2. Develop a feasible Energy Capital Improvement Program (CIP) that has the support of the Board, management, and organization for implementation and helps prioritize energy related upgrades with other necessary improvements.

1.2 Objectives

This TM is the first TM in this project under Phase 1 and documents the "State of the District – Energy Management and Greenhouse Gas (GHG) Emissions". This evaluation has the following specific objectives:

1. Describe the necessary background on current facilities and planning context for this project.
2. Summarize the energy demand and production across all facilities, including electricity, primary energy sources (gasoline, diesel, natural gas), and renewable energy.
3. Prepare a baseline GHG inventory for all facilities.
4. Analyze the energy demand in more detail for the wastewater treatment and biosolids handling facilities in preparation for the alternative's evaluation in Phase 2.
5. Summarize the energy efficiency efforts undertaken by DSRSD in previous years.

1.3 Facilities Overview

Of the facilities covered in this Energy Facilities Master Plan, the DSRSD owns and operates the regional WWTP, water distribution system, and certain recycled water distribution system facilities, including Reservoirs R20 and R300, and Pump Stations R20, R300A and R300B. Other facilities owned and operated by DSRSD included in this project evaluation are the office administrative building, field operations facility building, and vehicle fleet.

LAVWMA owns the WWTP effluent pump station that DSRSD operates and maintains under contract. Variable costs related to the operation and maintenance of the export pump station are allocated to the member agencies of LAVWMA in proportion to the actual flows discharged to the pump station. Based on the flow data from 2021, DSRSD's proportionate share of the variable costs for the operation of LAVWMA export pump station is approximately 60 percent.

DSRSD also owns the recycled water treatment plant and PSR1, and operates and maintains these facilities under contract, on behalf of DERWA. The costs for operating these facilities, however, are allocated to the member agencies of DERWA in proportion to the actual delivery of recycled water in any contract year. Costs for operating the DERWA owned portions of the recycled water distribution system (Reservoirs R100 and R200; Pump Stations R200A and R200B) are also allocated to the member agencies in the same manner. Based on the actual

quantities of recycled water delivered in calendar year 2021, DSRSD's share of the variable costs for the operation of the DERWA facilities are approximately 70 percent.

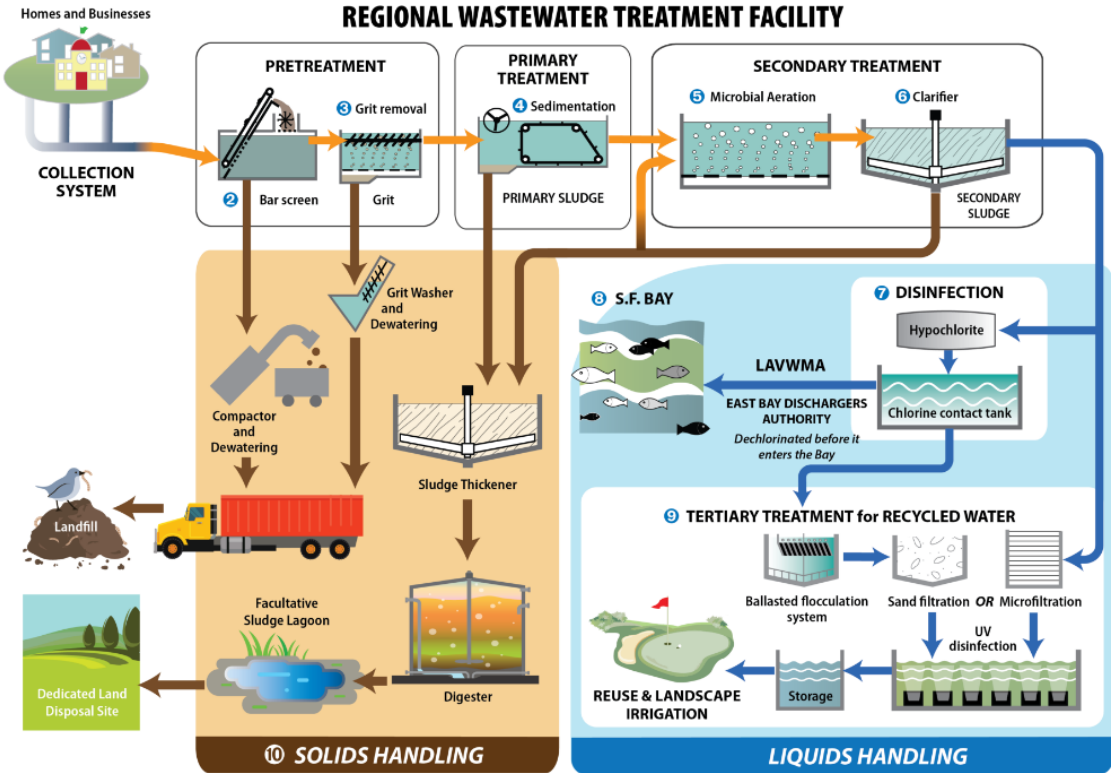
The WWTP located at 7399 Johnson Drive, Pleasanton, California, provides primary and secondary treatment and disinfection. The facility also has four concrete-lined holding basins with a total capacity of 22 million gallons (MG) that can be used for flow equalization during extreme wet weather events. One of the basins, Holding Basin 4, is dedicated to the recycled water treatment facility. Primary and secondary sludges are thickened, anaerobically digested, conditioned in on-site facultative sludge lagoons (FSL) for approximately four to five years, and then injected into the soil at an on-site DSRSD-owned dedicated land disposal (DLD) site. Note that the District's wastewater collection system is not included in the energy evaluation under this project, as its electricity consumption is relatively small and there are comparatively fewer opportunities for energy efficiency, recovery or GHG reduction measures in the wastewater collection system.

Digester gas from the WWTP's anaerobic digesters is recovered and converted to electricity for on-site demand. A portion of the thermal energy from the digesters is recovered for digester and building heating and cooling needs.

Approximately 40 to 45 percent (on an annual basis) of the secondary effluent receives further treatment through the Recycled Water Treatment facilities, and then is supplied to irrigation customers of DERWA and the City of Pleasanton.

Treated effluent not used for the DERWA recycling program is transported to the LAVWMA export pump station and pumped to the East Bay Dischargers Authority (EBDA) common outfall in the lower San Francisco Bay. Note that the effluent pumping from the export pump station, recycled water treatment and recycled water distribution (exclusive to DERWA) are excluded in the energy evaluation under this project (Phase 2); these facilities are owned separately by LAVWMA and DERWA, respectively, which are responsible for energy policy decisions for those facilities.

A schematic of the wastewater and recycled water treatment system is shown in Figure 1.1.



(Source: DSRSD)

Figure 1.1 Overview of DSRSD's Wastewater Treatment and Recycle Water Systems

The DSRSD's office administrative building is located at 7051 Dublin Boulevard, Dublin, California. It houses billing, planning, permitting, engineering, and other administrative services.

The field operations facility, located at 7035 Commerce Circle in Pleasanton, California, has primarily offices and warehouse storage space for field operators who operate and maintain the wastewater collection, potable water distribution, and recycled water distribution systems.

Figure 1.2 shows the site locations of the wastewater and recycled water treatment facilities included in Phase 1 of this energy facility master plan evaluation. Note that the LAVWMA storage reservoirs shown in this Figure are not part of this evaluation.

Pacific Gas & Electric Company (PG&E) supplies electricity and natural gas to the WWTP. Power supplies are also supplemented by the three cogeneration units fueled by a combination of digester gas recovered from the anaerobic digesters and natural gas by PG&E.

DSRSD provides potable water distribution to the City of Dublin and the Dougherty Valley area of the City of San Ramon. The distribution system is comprised of 4 turnouts, 9 pressure zones, 14 water storage reservoirs, and 17 pump stations. DSRSD purchases potable water from Zone 7 Water Agency (Zone 7), DSRSD's sole potable water supplier.

Relevant features for each of the facilities are described in more detail in Sections 1.3.1 through 1.3.6.

Figure 1.2 Location of Wastewater and Recycled Water Treatment Facilities Operated by DSRSD Included in the Phase 1 Evaluation

1.3.1 DSRSD Service Area

The District's wastewater treatment service area encompasses the entire boundaries of Dublin and Pleasanton as well as a small, southern portion of San Ramon in the East Bay of California (see Figure 1.3).

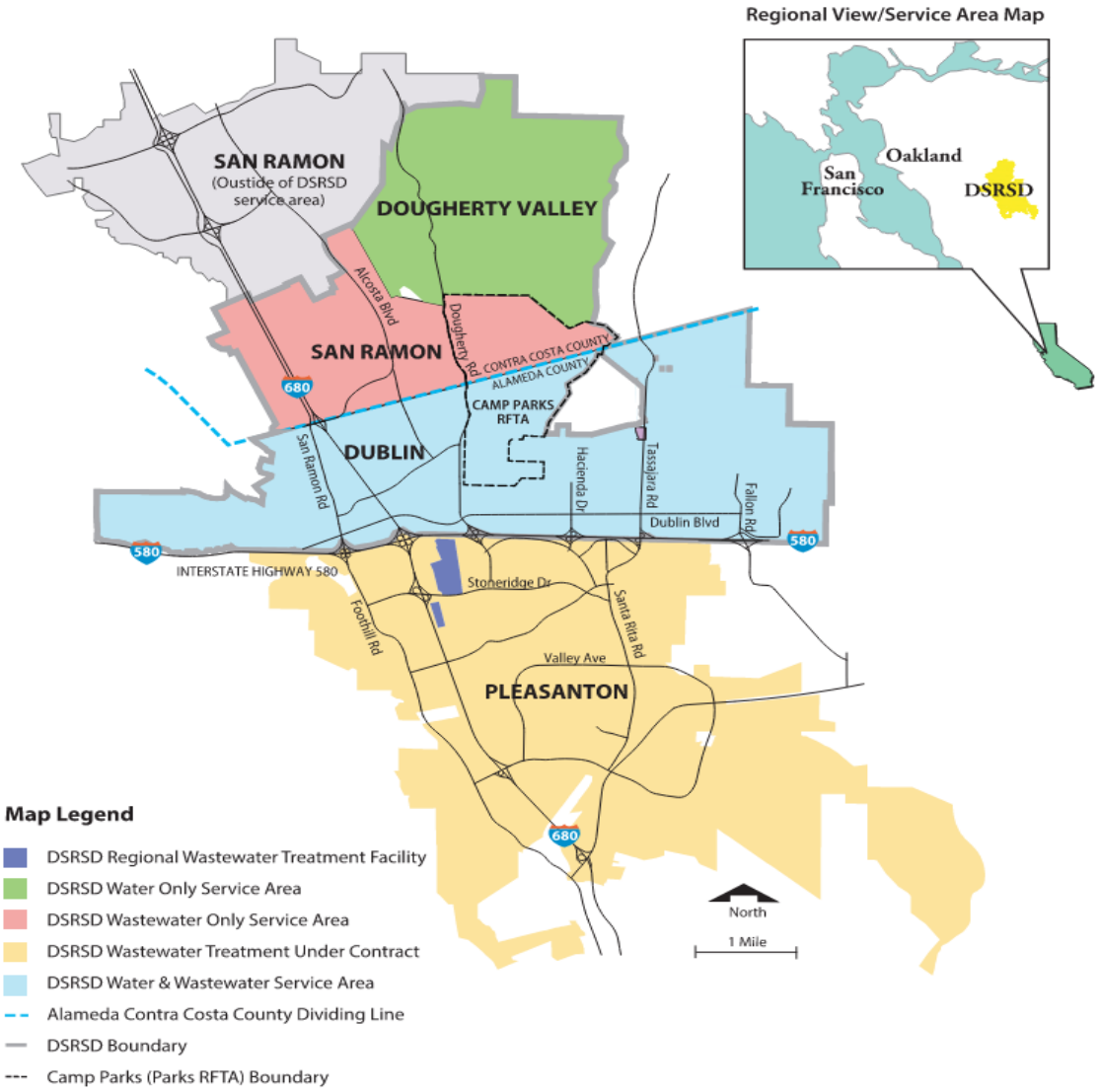


Figure 1.3 DSRSD Service Area Map (adopted from DSRSD)

The last service area population analysis was conducted for Dublin and Pleasanton in the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan*. Table 1.1 summarizes the current and anticipated population for both cities based on this report.

Table 1.1 DSRSD Wastewater Service Area Population Projections

Year	Combined Population (Dublin + Pleasanton)
2015	126,668
2020	135,099
2022 (estimated)	**140,000**
2025	143,330
2030	151,861
2035	160,892

Notes:
(1) Adopted from 2017 *Wastewater Treatment and Biosolids Facilities Master Plan*.

According to the United States Census Bureau, the populations of Dublin and Pleasanton in 2020 were 72,589 and 79,871, respectively, which equates to a combined population of 152,460.[1,2] This is approximately the projected 2030 population according to the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan*.

DSRSD also maintains internal population records, which are summarized in Table 1.2. The District's population estimates are substantially higher than the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan*, in part because the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan* did not include South San Ramon in its calculations. The higher estimate of 160,371 wastewater customers, as shown in Table 1.2, was used as the population baseline for this project.

Table 1.2 DSRSD Water and Wastewater Service Area Population Estimates

Year	Water Customers(1)	Wastewater Customers(2)	Total Population Served
2015	78,430	148,356	170,942
2020	80,030	150,109	172,790
2017	83,650	154,002	177,966
2018	88,538	160,411	185,708
2019	89,177	163,392	188,011
2020	91,130	162,485	187,899
2021	91,872	160,371	187,548

Notes:
(1) Includes customers from Dublin and Dougherty Valley.
(2) Includes customers from Dublin, Pleasanton, and South San Ramon.

[1] United States Census Bureau. n.d. "Dublin city, California." Accessed March 27, 2025. https://data.census.gov/profile/Dublin_city,_California?g=160XX00US0620018.
[2] United States Census Bureau. n.d. "Pleasanton city, California." Accessed March 27, 2025. https://data.census.gov/profile/Pleasanton_city,_California?g=160XX00US0657792.

DSRSD is planning to update its water demand projections through 2045 based on a) new United States census data and b) the impact of future water conservation efforts. The new water demand projections will be evaluated as part of the Water System Master Plan and Operations Plan Update (CIP No. 20-W017), which is expected to commence in 2024.

1.3.2 Wastewater Treatment Facility

The DSRSD WWTP provides for liquid and solids stream treatment and digested solids are pumped to a separate FSL/DSD site for conditioning and final land disposal (see Figure 1.2). The WWTP includes influent storage and flow equalization basins, primary and secondary treatment, solids thickening, anaerobic digestion, cogeneration, and final disinfection. The FSL/DLD site is approximately 100 acres in size and includes six FSLs and the biosolids disposal site.

Figure 1.4 shows a detailed process flow diagram of the liquid stream process at the WWTP. Figure 1.5 shows the process flow diagram of the WWTP storage facilities, and Figure 1.6 of the solids handling facilities.

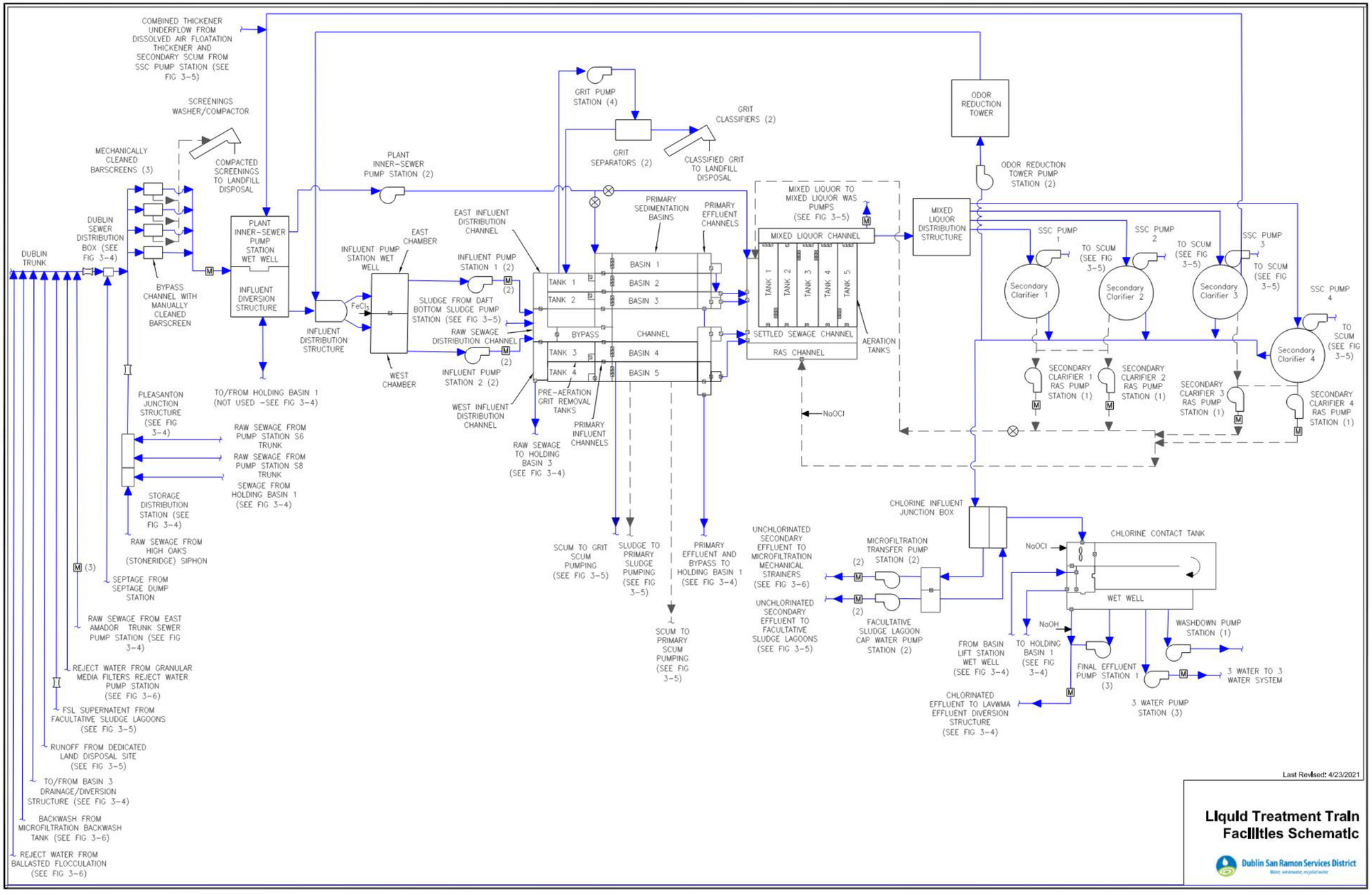


Figure 1.4 DSRSD WWTP Process Flow Diagram

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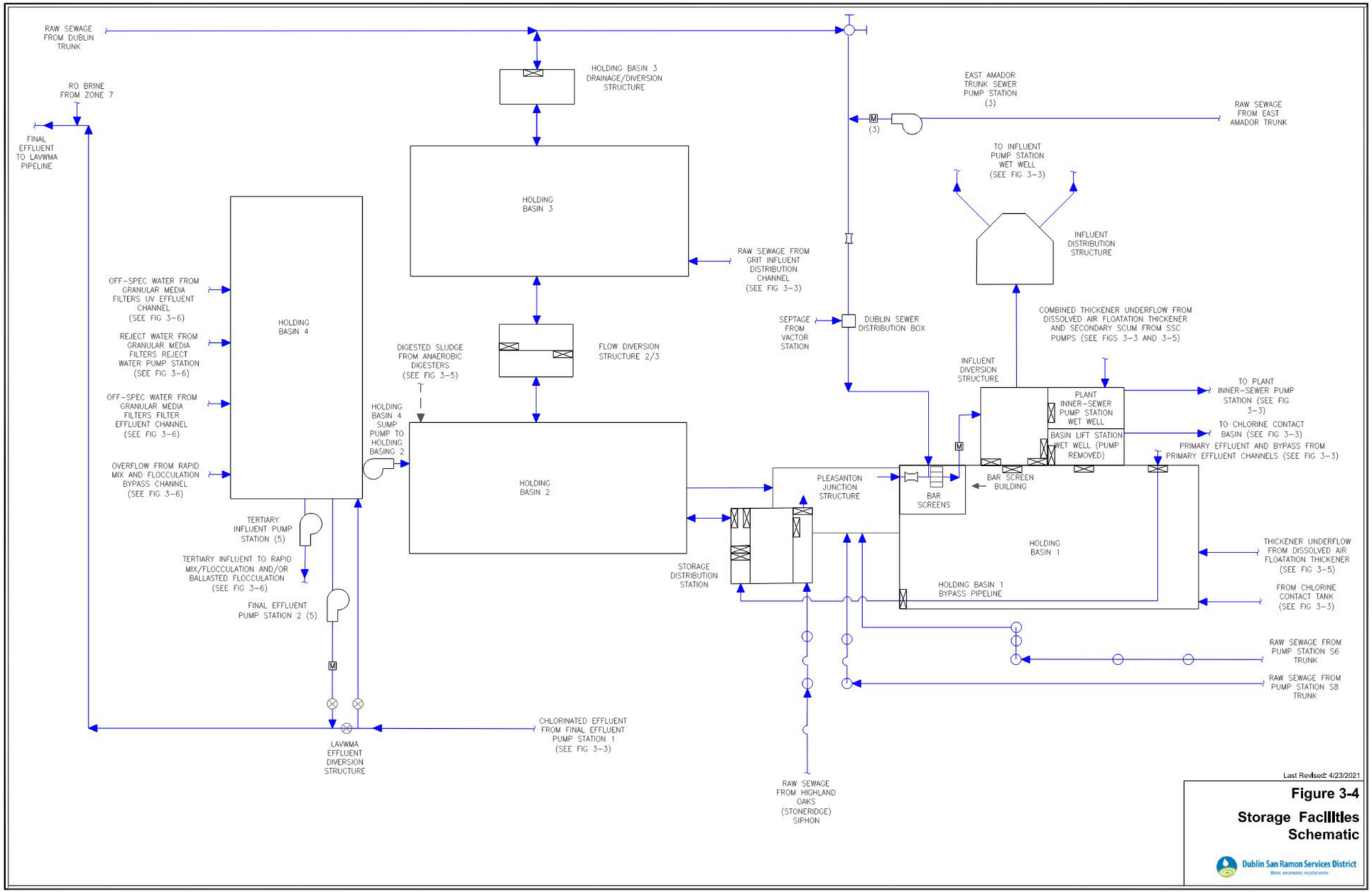

Figure 1.5 DSRSD WWTP Storage Facilities

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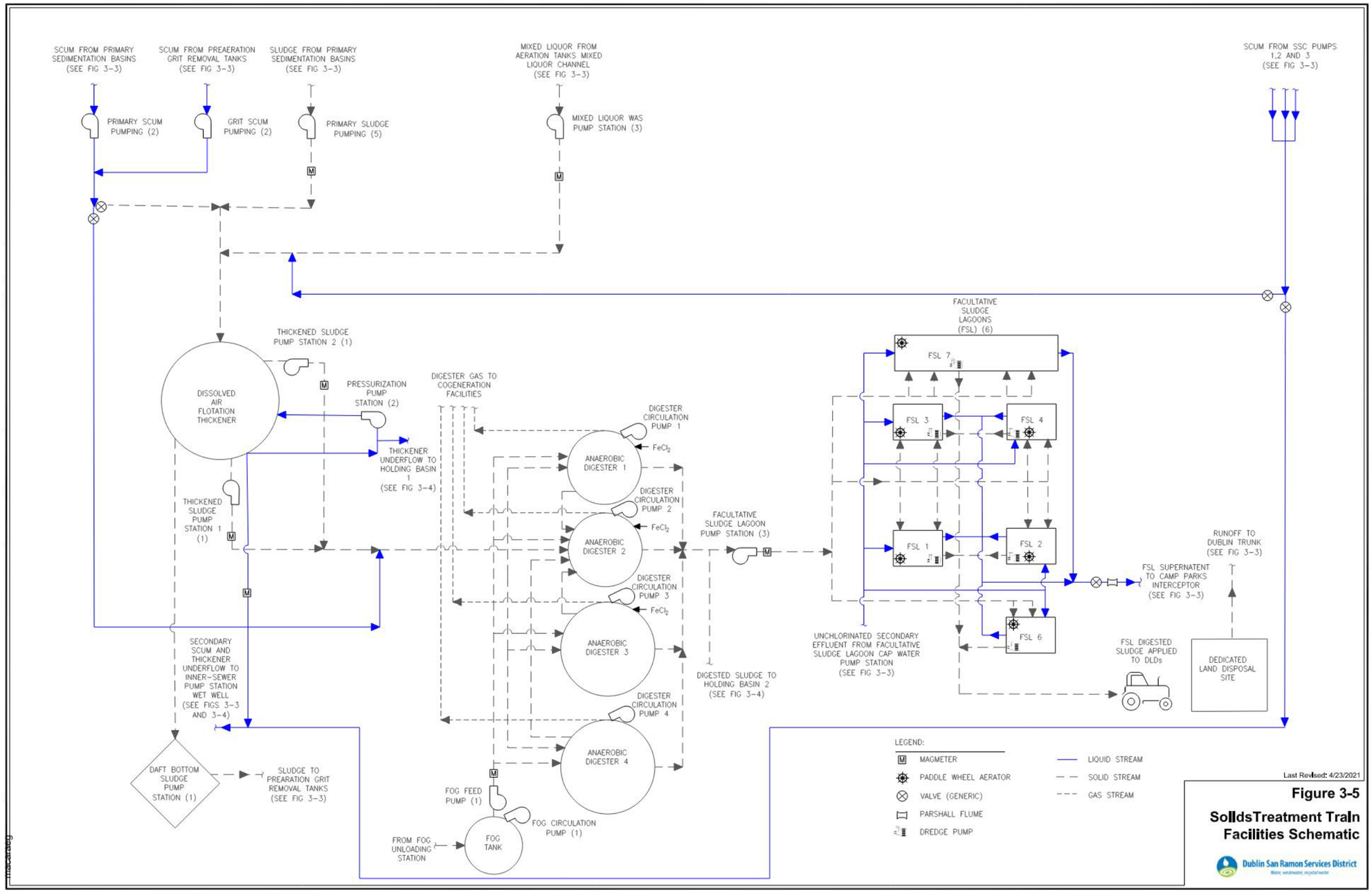

Figure 1.6 DSRSD WWTP Solids Treatment Facilities

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1.3.2.1 Flow Equalization

Holding basins 1, 2, and 3 can be used for the equalization of raw wastewater, screened wastewater, primary effluent, or wet weather equalization of secondary effluent. Flow equalization is not part of normal WWTP operations but can be used if a) the treatment or conveyance capacity of the facilities downstream of the primary sedimentation basins is exceeded or impaired or b) secondary effluent flows exceed the allowable discharge capacity to the LAVWMA system.

The three basins provide a high degree of flexibility in how they can be used. A detailed description of the holding basin operation strategy can be found in the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan* (see Figure 1.4). Influent flow equalization could allow for baseline loading of the downstream liquid stream process, reduce peak energy demands, and improve the balance of onsite energy production and demands. However, using the basins in this function also results in odor production impacting neighboring residents. Therefore, DSRSD does not, nor does it intend to, use the holding basins for flow equalization.

1.3.2.2 Influent Screening, Pumping, and Grit Removal

Influent flows include raw wastewater and internal recycle flows from the WWTP. Flows pass through bar screens and the screenings are washed and compacted for off-site disposal. The screened wastewater then flows through the influent diversion structure and the influent distribution structure, which splits flows into the two chambers of the influent pump station wet well. The four centrifugal influent pumps are summarized in Table 1.3.

Table 1.3 Influent Pump Station Pumps Summary

Wet Well Chamber	Number	Type	hp	Capacity, each (mgd)
East chamber	2	Centrifugal	200	25
West chamber	1	Centrifugal	200	15
	1	Centrifugal	200	25

Notes:
hp - horsepower; mgd - million gallons per day.

The four pumps discharge into the raw sewage distribution channel, which then splits into the east and west influent distribution channels. The west influent distribution channel conveys the screened wastewater into grit tanks 1 and 2, and the east influent distribution channel conveys wastewater to grit tanks 3 and 4. Effluent from the grit removal tanks is discharged into four separate channels and conveyed to the primary sedimentation basins. Grit tank 4 was installed in 2021. Note that the addition of the new grit tank 4, as well as supporting equipment (new grit pump, grit scum pump), was installed during the energy baseline year; the energy demand from this equipment, therefore, may not be fully captured in the baseline data.

The four grit removal tanks are aerated with three, 25 hp pre-aeration blowers that feed into a common air header; each blower has a design capacity of 450 cubic feet (cf) per minute.

Each grit tank is equipped with a dedicated, recessed impeller centrifugal pump for conveying the separated grit to the grit classifiers. The four grit pumps (20 hp each) have a capacity of 250 gallons per minute (gpm) at 65 feet total dynamic head (TDH) each. Two grit scum pumps (10 hp each) have a capacity of 50 gpm at 35 feet TDH each. There are two grit separators and two grit classifiers. The grit classifiers are rated at 30 cf per hour and 50 hp each.

1.3.2.3 Plant Inner-Sewer Pump Station

The plant inner-sewer pump station is adjacent to the influent diversion structure. This pump station receives plant internal recycle flows, including the underflow from the dissolved air flotation thickener (DAFT), and the WWTP's sanitary and storm sewer flows. The pump station is also capable of pumping secondary scum from the secondary clarifiers. This pump station is equipped with two, 20 hp submersible pumps with capacities of 1.0 mgd each. These pumps discharge the combined flows to the grit tank effluent channels. As of the writing of this TM, the plant inner-sewer pump station is out of service.

1.3.2.4 Primary Treatment

Wastewater flows from the grit effluent channel via gravity to five rectangular primary sedimentation basins. Primary treatment was expanded from four to five primary tanks. The fifth tank came online in 2021. Each sedimentation basin is 100 feet long and 19 feet wide. Primary sedimentation tanks 1 to 3 have a 9-foot side water depth, which equates to a surface area of 1,900 square feet and an approximate volume of 17,100 cf for each of the three basins. Primary sedimentation tanks 4 and 5 have a 13.5-foot side water depth.

Primary effluent from the sedimentation basins flows via gravity to the secondary treatment process. Primary sludge and scum are pumped to the DAFT or the anaerobic digesters using five sludge pumps and two scum pumps. The design information for the primary treatment pumps is summarized in Table 1.4.

Table 1.4 Primary Treatment Pumps Summary

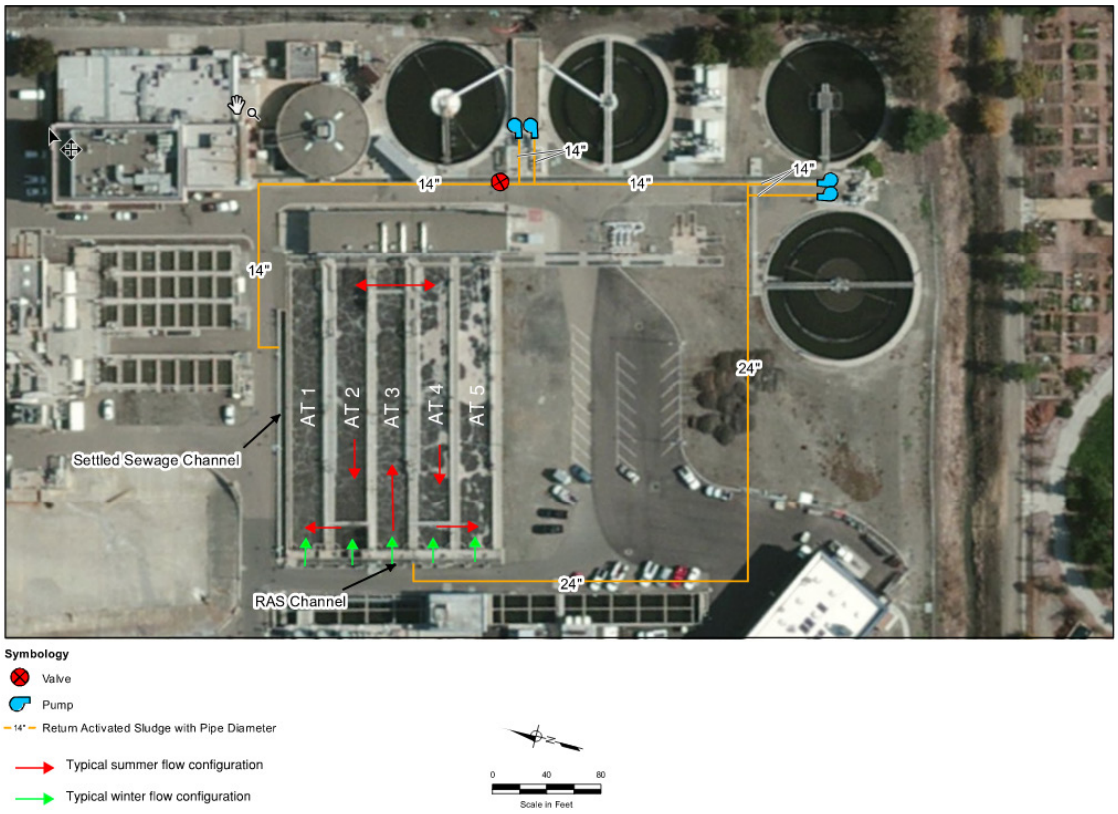
Service	Number	Type	hp	Capacity (gpm)	Design TDH (feet)
Primary sedimentation sludge	5	Positive displacement	15 hp	90	35
Primary sedimentation scum	2	Positive displacement	15 hp	150	45

1.3.2.5 Secondary Treatment

Activated Sludge Reactors

The primary effluent enters the activated sludge reactors, while return activated sludge (RAS) enters the reactors from a separate RAS channel. All five aeration tanks are 210 feet long and 30 feet wide with a 15.3-foot side water depth, which equates to an approximate volume of 94,600 cf for each tank.

The activated sludge reactors can either be operated in series or in parallel depending on wastewater characteristics and seasonal treatment needs. Typically, the aeration tanks are operated in series in an anaerobic/aerobic process configuration during the summer months. In this mode, all wastewater flows into tank 3 (operated as an anaerobic selector) before being split into an aerated northern and southern flow path. The northern flow path enters tank 2 and exits out of tank 1 while the southern flow path enters tank 4 and exits out of tank 5 (see Figure 1.7). This operational strategy is used to improve the secondary sludge settleability by favoring biological phosphorus accumulation in the sludge solids.



Modified from 2017 Wastewater Treatment and Biosolids Facilities Master Plan

Figure 1.7 Typical Aeration Tank Flow Configuration

During the winter, when phosphorus-rich cap water (surface water decant) from the FSLs is returned to the main WWTP process, the secondary treatment configuration is switched to parallel operations where flow is divided equally between all five fully aerobic tanks. This conventional activated sludge operation prevents biological phosphorus removal. Biological phosphorus removal is generally not desired since it results in phosphorus spikes in the secondary sludge during anaerobic digestion and FSL treatment, which can cause struvite precipitation problems in the solids handling process. For this reason, DSRSD is in the process of adding the ability to add metal coagulants to the FSL cap water recycle flows. An alum addition station will be constructed near the FSLs and is expected to be in operation by 2023.

The aeration tanks, settled sewage channel, and RAS channel are aerated by three, 400 hp blowers with capacities of 8,500 cubic feet per minute (cfm) each. The age of the blowers is 22 years. Aeration tank 3 is also equipped with four 9 hp mechanical mixers. According to operations staff, the blowers are adequately sized and operating as designed. Typically, one unit is in operation, and twice a day a second blower kicks on during diurnal peak loads. DSRSD has operated with all aeration basins in service as a standard in past years.

Effluent from the aeration tanks flows through the mixed liquor channel to the mixed liquor distribution structure where the flow is split to feed four secondary clarifiers. Solids are wasted from the mixed liquor channel to the DAFT using three 20 hp submersible waste activated sludge (WAS) pumps with capacities of 835 gpm each.

Secondary Clarifier Process

Mixed liquor enters the four, circular secondary clarifiers from the mixed liquor distribution structure. Clarifiers 1, 2, and 3 are 90 feet in diameter, while clarifier 4 is 110 feet in diameter. Clarified effluent is sent to the secondary effluent disinfection system and the FSL Cap Water Pump Station.

Each secondary clarifier has a dedicated centrifugal, variable-drive RAS pump that can pump the adjacent clarifier if one becomes offline. The capacities of the four RAS pumps are summarized in Table 1.5. RAS is recycled to the aeration tanks via a 24-inch pipeline (see Figure 1.7). A 14-inch RAS return line has been abandoned in place.

Table 1.5 RAS Pumps Design Criteria Summary

RAS Pump Service	hp	Capacity (mgd)
Clarifier 1	60	6.1
Clarifier 2	60	6.1
Clarifier 3	60	6.1
Clarifier 4	125	8.5

Each secondary clarifier is serviced by one centrifugal scum pump that pumps to the Inner-Sewer Pump Station wet well or to the DAFT. Each 5 hp clarifier scum pump is rated for 200 gpm at 25 ft TDH.

The mixed liquor can exhibit very poor settling during parts of the year with very high sludge volume index (SVI) values. Settling specifically becomes poor when the anoxic selector is aerated in winter time and the basins are operated in parallel. Poor secondary effluent quality can increase the chemical and ultraviolet (UV) doses required for treatment at DERWA. DSRSD is currently implementing modifications to its treatment process to facilitate the addition of alum to the FSL return stream to precipitate ortho-phosphorus chemically and prevent nuisance struvite formation downstream in the treatment process. Once the alum addition station goes into operation (expected by the end of 2023), DSRSD expects to operate the anoxic selector year-round.

1.3.2.6 Final Disinfection

Secondary effluent that is not diverted to the FSL Cap Water Pump Station flows to the chlorine contact tank (CCT) for final disinfection. Effluent from the CCT is discharged to either holding basin 4 or can be valved to discharge directly to the LAVWMA export facilities. In case effluent flows do not meet permit requirements for surface water discharge, DSRSD has the option to divert effluent flows directly to holding basin 1. Effluent can also be routed from holding basin 4 to DSRSD headworks for retreatment by pumping it to holding basin 2, from where it can flow by gravity back to the facility influent.

The sodium hypochlorite storage facility consists of a covered open-air structure with four hypochlorite storage tanks with a capacity of 6,600 gallons each. Three post-chlorination metering pumps with a capacity of 69.7 gallons per hour and rated at 0.33 hp are used to supply hypochlorite solution to the CCT. Two RAS chlorination pumps with a capacity of 200 gallons per day (gpd) and rated at 1 hp each are used for optional RAS chlorination to help improve settling. A sixth metering pump with a maximum capacity of 240 gpd and rated at 0.5 hp was used to

pump hypochlorite solution to the discharge of the microfiltration (MF) transfer pump station. DSRSD is currently in the process of replacing the hypochlorite facilities. The new hypochlorite building is expected to be constructed in 2025.

1.3.2.7 Final Effluent Pumping

There are two final effluent pump stations: Final Effluent Pump Station No. 1 and Final Effluent Pump Station No. 2. Final Effluent Pump Station No. 1 consists of three 250 hp vertical turbine pumps equipped with variable frequency drives (VFD). The pumps are rated for 25 mgd at 40 feet of head. The pump station is located downstream of the CCT and can pump either to holding basin 4, or when valved appropriately, directly to the LAVWMA export facility. When pumping to holding basin 4, the pump station has a firm capacity of 50 mgd and an estimated total capacity of 75 mgd. When pumping to LAVWMA, the pump station has a rated capacity of 35 mgd and an estimated total capacity of 53 mgd.

Final Effluent Pump Station No. 2 consists of five vertical mixed flow pumps that transfer treated effluent from holding basin 4 to the LAVWMA system. Two of the pumps are 75 hp and have a maximum capacity of 10 mgd, while the remaining three pumps are 250 hp and have a maximum capacity of 19 mgd. In total, the pump station has a firm capacity of 58 mgd and a total capacity of 77 mgd. Final Effluent Pump Stations No. 1 and No. 2 cannot be operated at the same time; DSRSD operates one, or the other, based on the operating scheme in place at the time.

LAVWMA also owns an off-site secondary effluent pump station which pumps secondary effluent to the permitted discharge outfall. This pump station has 10 discharge pumps, 6 rated at 500 hp (pumps 1,3,5,6, 8, and 10) and 4 rated at 600 hp (pumps 2,4,7, and 9). In addition to the effluent from the WWTP, the LAVWMA export facility also pumps treated effluent from the City of Livermore's WWTP and brine received from Zone 7's groundwater demineralization plant.

1.3.2.8 Holding Basin 4

The WWTP has four holding basins that are available for storage of raw, primary, secondary, and/or tertiary treated effluent. Holding basins 1, 2, and 3 can receive raw wastewater, primary effluent, and secondary treated flows (see Section 1.3.2.1). Holding basin 4 can only receive secondary treated effluent or off-spec water from DERWA. Holding basin 4 can feed the Tertiary Influent Pump Station (TIPS) or discharge to the LAVWMA system via the Final Effluent Pump Station No. 2. Holding basin 4 also provides storage for the recycled water facilities to ensure adequate flows are available during recycled water peak demands.

1.3.2.9 Solids Thickening

Solids from both the primary and secondary processes are combined and thickened in the DAFT unit. Co-thickening of primary and secondary sludge in the DAFT is operationally easier than sending primary sludge directly to the digester. Also, operations staff reports that co-thickening has made the total solids (TS) loading to the digesters more stable and controlled.

The DAFT has a diameter of 65 feet, with a tank water surface diameter of 60 feet and a side water depth of 8 feet. The DAFT is supplied by three, 40 hp air compressors, and two DAFT pressurization pumps to deliver air-enriched flow to the tanks. The pumps are 125 hp and 150 hp centrifugal pumps with a capacity of 1,600 gpm each. The DAFT contains one 3 hp 100 gpm double disc bottom sludge pump (i.e., DAFT thickened sludge pump 2) that is used to pump settled DAFT sludge to the aerated grit tanks. After thickening, thickened sludge is pumped to

the anaerobic digesters using two, 25 hp progressive cavity thickened sludge pumps (i.e., DAFT thickened sludge pumps 1 and 3) with a capacity of 200 gpm each.

DSRSD also maintains a trailer-mounted gravity belt thickener that can be used if the DAFT is offline. The gravity belt thickener has a capacity of 300 gpm but is very rarely used. Its operation over the past few years is inconsequential for the historical electricity consumption of the WWTP.

The current DAFT system is oversized and no chemical addition is needed. Therefore, it is easy to operate but requires significant energy for pumping.

1.3.2.10 Anaerobic Digestion

The WWTP has four mesophilic, high-rate anaerobic digesters with a firm capacity of 43,900 pounds of volatile suspended solids per day (lb VSS/day). The two smaller digesters (digesters 1 and 2) have a capacity of 11,600 lb VSS/day each, and digesters 3 and 4 have a capacity of 20,700 lb VSS/day. The average solids feed concentration was 4.6 percent and the average digester effluent solids concentration was 2 percent in 2021.The design solids retention time in the digesters is 22 days with all digesters in service. In 2021, the average operating solids retention time was 25 days.

Digesters 1 and 2 are each equipped with a 12,500 gpm draft tube mixer with mechanical mixers rated at 10 hp each. Digester 3 is equipped with three 7,200 gpm draft tube mixers for a total capacity of 21,600 gpm, with a mechanical mixer rated at 10 hp. Digester 4 is equipped with three 10,400 gpm draft tube mixers for a total capacity of 31,200 gpm with a mechanical mixer rated at 10 hp. Three 25 hp, 200 gpm facultative sludge pumps equipped with VFDs convey the final digested sludge to the FSLs.

All four digesters have dedicated heat exchangers that can provide a total of 4.0 million British thermal units per hour (MMBTU/hr). Digesters 1 and 2 have a thermal energy recovery capacity of 0.77 MMBTU/hr each; and digesters 3 and 4 have a thermal energy recovery capacity of 1.24 MMBTU/hr each. The digester 1 and 2 heat recovery system (HRS) heat exchanger pumps (hot water) are 3 hp each and have capacities of 220 gpm at 26 feet TDH. The digester 3 HRS pump (hot water) is 3 hp with a capacity of 210 gpm at 21 feet TDH, and the digester 4 HRS pump (hot water) is 5 hp with a capacity of 150 gpm at 32 feet TDH. Each digester also has a 15 hp centrifugal circulating sludge pump with a capacity of 600 gpm each; these pumps circulate sludge through the hot water/sludge heat exchanger to ensure a temperature of approximately 95 degrees Fahrenheit (F) in each anaerobic digester.

Digester gas is collected in the headspace of each of the digesters. Pressure and vacuum relief assemblies are located on each digester roof to protect the digesters in case of a clog in the piping. The digester gas is cooled to remove condensate and pressurized using two, 40 hp fuel skid gas compressors for use in the on-site engine generators to produce power. Excess gas that cannot be send to the engines because of hydraulic limitations is flared in the existing waste gas flare. Per the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan*, the maximum capacity of the gas flare is 2,700,000 British thermal units per hour (BTU/hr).

Each digester is equipped with a gas meter. An additional flow meter is located on the combined gas line to each of the three cogeneration engines. The flare also has a dedicated gas meter. According to the 2020 *Digester Gas Treatment System Improvements Evaluation and Engineering Report*, the digesters produced 205,067 standard cubic feet per day (scf/day) of digester gas, and

the digesters are projected to produce approximately 460,800 scf/day on average by 2035 (with the addition of the fat, oil, and grease [FOG] facility discussed below). A new waste gas burner, with a capacity of up to 520 scfm, will replace the existing waste gas burner; it is expected to be in operation by 2024.

1.3.2.11 Fat, Oil, and Grease Receiving Facility

DSRSD added a FOG receiving facility in 2020 with a tank capacity of 15,000 gallons. The facility has not started operating yet because of delays to its air permit approval. Once in operation, the facility will operate with a mixer pump of 300 gpm and a heat reservoir supply pump of 210 gpm. The FOG facility has a heat exchange capacity of 1.24 MMBTU/hr. Per analysis conducted by HDR in 2021, DSRSD anticipates an average delivery of about 12,000 gallons of FOG resulting in an additional average biogas production of 87 scfm.

1.3.2.12 Facultative Sludge Lagoons

Digested sludge is distributed among six FSLs. Lagoons 1,2,4, and 6 each have surface areas of approximately 3.3 acres; and lagoons 2, 3, and 7 have surface areas of approximately 2.9 acres, 3.8 acres, and 4.2 acres, respectively. The Facultative Lagoon Cap Water Pump Station conveys unchlorinated secondary effluent to cover (cap) the solids for odor control while digested sludge is further stabilized. This pump station is equipped with two centrifugal pumps: one 75 hp pump with a capacity of 1,000 gpm and one 10 hp pump with a capacity of 500 gpm. Each FSL has a 5 hp brush aerator designed to maintain aerobic conditions throughout the water cap.

The FSLs are sized to allow the biosolids to stabilize for four to five years before harvesting. One FSL is dredged every summer using dredge / boat and a centrifugal pump. This equipment runs on diesel fuel. The stabilized biosolids are discharged to the harvested sludge pipeline and conveyed to the DLD site for disposal via injection.

1.3.2.13 Dedicated Land Disposal

The DLD site includes 55 acres used for biosolids injection. The original design capacity of the site was established to be 100 dry tons per acre per year, with the assumption that the biosolids are between 4 and 6 percent solids by weight. However, operational data indicates that the average solids concentration of the sludge applied in 2021 was approximately 2.5 percent, and that the site's capacity is limited by the water content of the applied biosolids.

1.3.2.14 Cogeneration

The cogeneration system consists of three reciprocating engine generators located in the cogeneration room in the southern portion of the administration building. Engines 1 and 3 are both rich-burn engines with less than 3 percent oxygen in the exhaust, while engine 2 is a lean-burn engine with more than 9 percent oxygen in the exhaust; each engine produces both electrical power and heat energy.

Digester gas produced in the digesters flows through a gas conditioning system before reaching the cogeneration engines. Digester gas is primarily utilized in engine 2 (the lean-burn engine), but digester gas can also be blended with natural gas and burned in engine 1. Due to the fuel skid limitation, operations staff sets a limit of up to 44 percent digester gas blend for engine 1; otherwise, the fuel skid will crash if both engines (1 and 2) are on digester gas.

Engine 3 generates electricity utilizing only natural gas as a fuel source; it is not currently configured to burn digester gas. DSRSD purchases pooled natural gas for the cogeneration system inexpensively from the State of California, Department of General Services; the low cost of this aggregated natural gas is a major driver for continued generation of electricity from natural gas to date.

The current installed cogeneration capacity is approximately 1,400 kilowatts (kW). According to the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan*, the typical output of the system is 1,200 kW.

The cogeneration system also collects thermal heat off the three engines to generate hot water. The hot water is used to preheat primary and secondary sludge up to the digesters' operating temperature and to heat the digesters directly. Additionally, cogenerated heat energy is an energy source for the heating, ventilation, and cooling system in the Administration Building and Maintenance Building. The hot water loop is continuously used directly for building heating and domestic hot water and also drives absorption chillers for air conditioning in the summer months. According to the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan*, the total hot water demand at the plant is 3.52 MMBtu/hr in the summer and 3.68 MMBtu/hr in the winter. The three cogeneration engines can recover a maximum of approximately 7.5 MMBtu/hr thermal heat total.

Cogeneration engines 1 and 2 were installed in 1983. The third cogeneration engine is an early 1990s model and was installed in 2008. The engines have been kept in operation by operations and maintenance staff despite recent unexpected downtimes. Every 20,000 hours staff conducts minor maintenance services; every 40,000 hours a major service is conducted. This requires taking an engine out for about 40 hours of maintenance (a week of downtime). During this time, DSRSD incurs higher peak demand charges for electricity.

1.3.2.15 Odor Control

The odor control consists of three processes: one odor reduction tower (ORT) and two soil bed biofilters. The newly constructed FOG facility is equipped with an activated carbon absorber. The ORT treats odors generated in the influent pumping station and preliminary treatment facilities (the old bar screen channels, the grit building, the influent diversion structure, and the aerated grit tanks). The operating air flow rate is approximately 13,000 cfm. The system is powered by several fans that push air from the individual buildings to the biotower. Two 10 hp ORT effluent supply pumps deliver unchlorinated secondary effluent to the top of the media to keep the biofilm wet. Each pump has a capacity of 380 gpm.

One of the two soil bed biofilters is used to treat odors generated in the headworks screenings conveyors and screening compaction and storage room. This biofilter has three beds and is fed by two exhaust fans rated at 15,000 cfm and 75 hp each, drawing air from the screenings conveyors and screening storage room. Under normal operating conditions, only one exhaust fan is in operation; the second exhaust fan is in standby.

The other biofilter is used to reduce odors generated in the DAFT and three of the four secondary clarifiers. This biofilter consists of a single bed which is fed by fans drawing air from the DAFT and the center well of the secondary clarifiers 1 and 2 at a design air flow of 1,000 cfm.

1.3.2.16 Other Appurtenances

Heating, Ventilation, and Air Conditioning (HVAC) Systems

The various WWTP buildings are equipped with HVAC systems that include air handling units, exhaust fans, odor control system feed fans, condensing units, and chiller pumps.

Plant Water System

The WWTP has a 1W, 2W, 3W, and 4W system. The 1W system uses potable water from the City of Pleasanton and becomes 2W at a booster pump station located inside the Operations and Cogeneration Building. The 2W booster pump station consists of three 7.5 hp centrifugal pumps with a capacity of 10 gpm each. DSRSD does not currently use the 2W system, but has the ability to tie the 2W (without booster pump) system to the main 1,250 kW backup generator as cooling water.

The 3W system uses disinfected secondary effluent supplied by a pumping facility located adjacent to the CCT and next to the Final Effluent Pump Station No.1. The three 3W pumps are rated at 75 hp and 1,200 gpm each. Another 75 hp vertical turbine, high-pressure 3W washdown pump has a capacity of 685 gpm, but it is not operational as the high pressure 3W washdown has been retired; there is no intention to replace the 3W pumps. The 4W system replaced the 3W system and uses disinfected tertiary effluent pressurized by PSR1 and static pressure from recycle reservoir R100.

1.3.2.17 Chemical Addition

Various chemicals and consumables are used in the WWTP in support of treatment processes and ancillary systems. Table 1.6 summarizes the chemicals used at the WWTP and the estimated total amounts for each per year.

Table 1.6 Chemical and Consumable Consumption at the Wastewater Treatment Facilities

Process Area	Chemical Name	Type of Chemical	Chemical Strength	Estimated Consumption in 2021(1)
WWTP, Gravity Belt Thickener	Clarifloc C-6288	Polymer	41 percent	(not typically used, only if DAFT down) 3,450 pounds
WWTP	FeCl2	Coagulant	28 percent	883,580 pounds
WWTP	Sulfatreat	H_2S removal	N/A	16,000 pounds
WWTP	NaOCl	Disinfectant	12.5 percent	301,900 gallons

Notes:
FeCl2 - ferrous chloride; H_2S - hydrogen sulfide; N/A - not applicable; NaOCl - sodium hypochlorite.
(1) The consumption volume for most chemicals is provided based on the 2020 calendar year provided by DSRSD.

1.3.2.18 Power Supply

PG&E supplies power to the WWTP via two, 21 kilovolts (kV) underground service feed vaults. This redundant loop supply system was built to provide redundancy on the 480 volt (V) level in case of a transformer failure.

Power supplies are also supplemented by the three cogeneration units fueled by a combination of digester gas recovered from the anaerobic digesters and natural gas, which is also supplied by PG&E. Power is distributed at 21 kV to seven distribution transformers. Four of these supply power to the WWTP, and the other three supply power to DERWA's recycled water treatment facility.

Each three-phase step down transformer converts 21 kV power to 480 V power for further distribution within specific areas of the plant.

1.3.2.19 Backup Power Systems

Standby power is provided by a 1250 kW and a 750 kW diesel driven generator. The 1250 kW generator (G4) powers switchgear DPA/DPB in the Operations Building, which in turn can power switchgear DPD in Building D and DPE in the Blower Building through emergency tie breakers. If DSRSD loses utility power, the standby generators will automatically come online.

The 750 kW generator (G5) powers switchgear DPG in Effluent Pump Station No. 1. Portable generator connections are provided throughout the facility at each switchgear that does not have a permanently-installed standby generator.

The WWTP needs approximately 1.2 megawatts (MW) to continue operation based on staff estimates. The WWTP has sufficient back up power for two days before additional fuel needs to be brought in.

In times of a power outage, the main breakers for the three cogeneration engines will trip automatically to remove the engines from the plant's power distribution system and the transfer switch sends a start signal to the 1250 kW standby diesel generator. This sequence takes about eight seconds. After the cogeneration breakers trip, the cogeneration engines will shut down on engine overspeed protection. Once PG&E power is back and proves to be stable for approximately 15 minutes, plant power switches back to PG&E and the standby diesel engine starts its cooldown period. After power is switched to PG&E, the cogeneration engines need to be manually reset, restarted, and connected back to the plant's power distribution system.

Over the past years, staff estimates that power outages have occurred approximately three times per year and could last up to two days. The future of the frequency and duration of PG&E Power outages in California is uncertain. Statistically, power outages in California have increased in the past five years per data by the United States Department of Energy (DOE), both weather and non-weather related.[3] At the same time, PG&E is working on improving its system to make system shutoffs of shorter duration and magnitude.

1.3.2.20 Power Monitoring Systems

Electrical parameters, including power, energy, voltage, and current, are monitored by solid state meters (SSM), and from communications with protective relays, circuit breaker trip units, and communications to control devices such as reduced-voltage solid state starters. These devices are connected to an Ethernet network which allows data to be obtained by a power management system on Eaton's Foreseer platform and by plant supervisory control and data acquisition (SCADA). The Foreseer system is designed to easily show power and energy data throughout the facility. Meter data is not combined easily in this software with process data. SCADA requires more work to set up individual parameters to monitor, but can show real time and historical power and energy data on the same screens and historical graphs as process data.

Figure 1.8 shows a simplified view of the power distribution system with key metering points. This only shows the top level of the power distribution system in each location. In many cases, circuit breaker trip units and protective relays provide redundant data to the solid-state meters

[3] DOE. March 2021. State of California Energy Sector Risk Profile.

shown. There are additional points with power metering within each location, including SSMs, communicating circuit breakers, and solid-state starters.

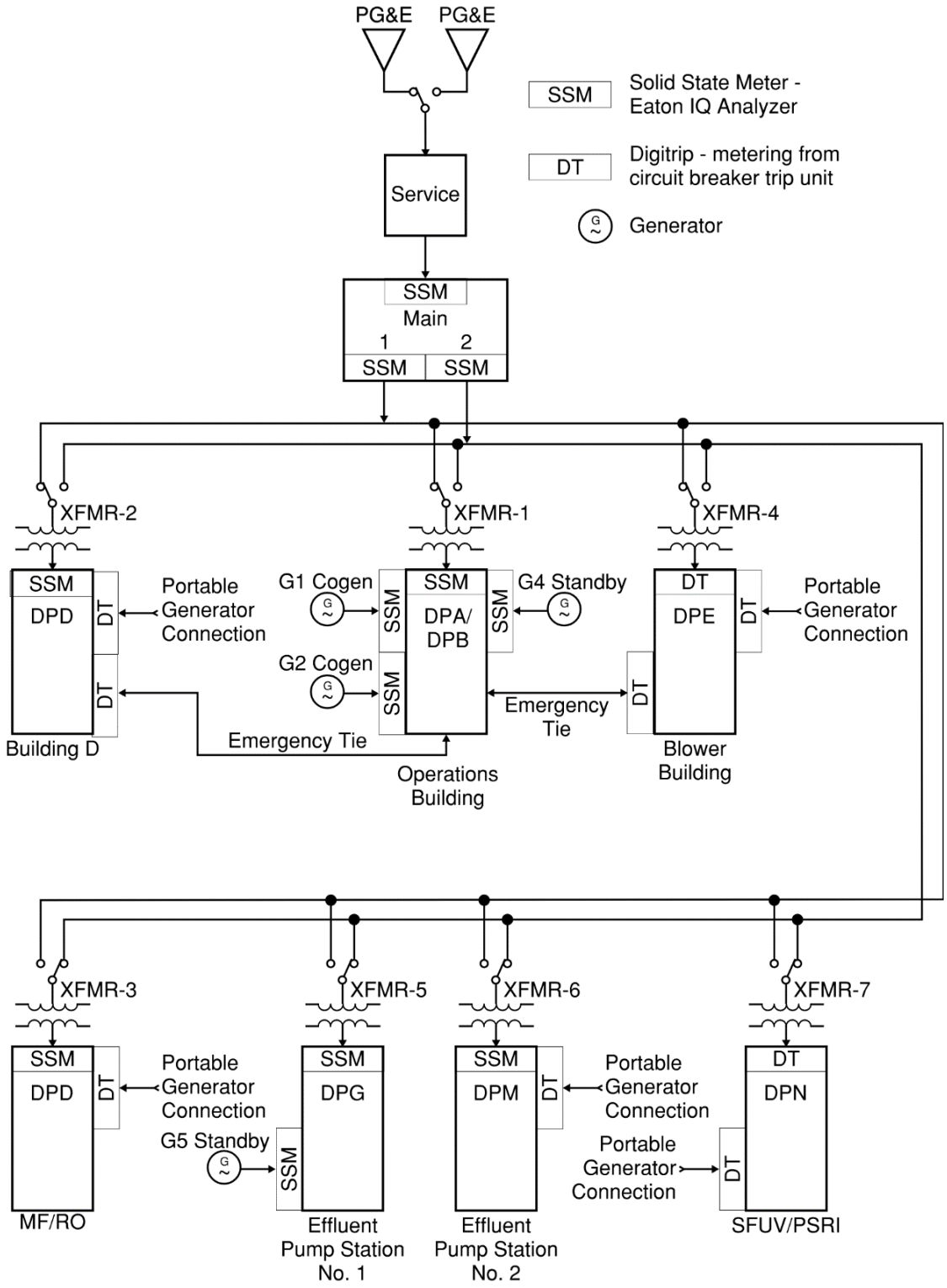


Figure 1.8 Overview of DSRSD's Power Distribution and Metering System

1.3.3 Recycled Water Treatment Facility

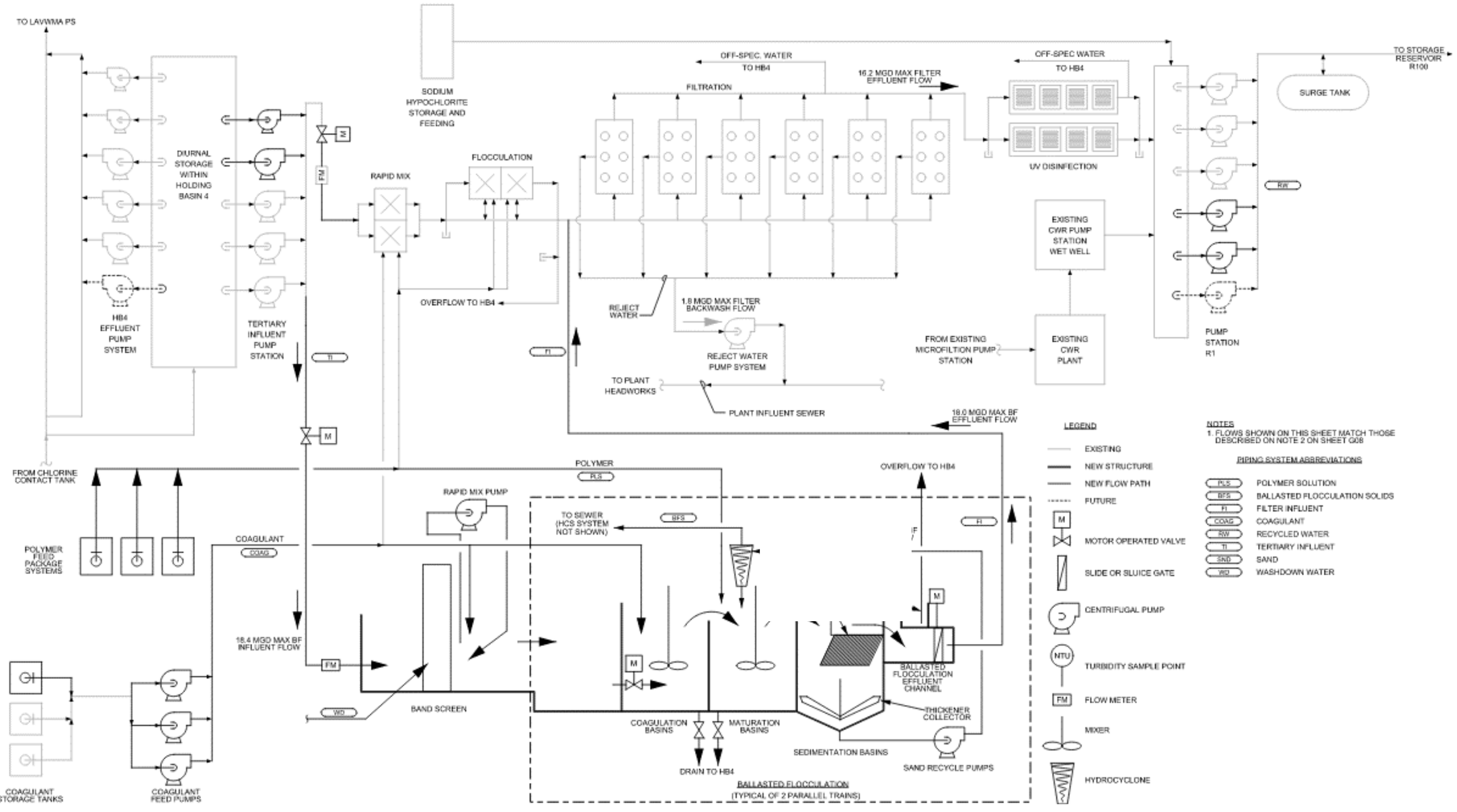
1.3.3.1 Facility Overview

The recycled water treatment facilities are located adjacent to and to the north of the main WWTP (see Figure 1.2). The MF system was constructed in 1998 and the sand filtration (SF) system was constructed in 2005 with improvements added in 2018. The two filtration systems are two separate treatment trains. The process flow diagram for the recycled water treatment system is shown in Figure 1.9. The MF/UV treatment train was decommissioned in 2021 and is no longer in use. The historical annual total DERWA recycled water production and demand are summarized in Table 1.7. The recycled water demand includes the demand by DERWA customers as well as recycled water used at the WWTP for various recycled water end uses.

Table 1.7 Recycled Water Production and Demand

Year	DERWA Demand (MG)	Total Demand (MG)	Total Production (MG)
2017	1,067	1,385	1,533
2018	1,178	1,469	1,385
2019	1,190	1,505	1,403
2020	1,304	1,693	1,575
2021	1,389	1,766	1,880

The total production of recycled water listed in Table 1.7 is the sum of recycled water produced in both DERWA treatment trains (the SF and MF systems), and potable water makeup (a smaller negligible contribution). The monthly seasonal recycled water demand is shown in Figure 1.10 for the year 2021. Figure 1.11 shows the rising trend of recycled water demand over the past 15 years.



Source: Carollo. November 2018. DERWA Recycled Water Treatment Facilities - Phase 2, Volume 4 of 4 - Drawings. Prepared for DSRSD.

Figure 1.9 Recycled Water Treatment Facility – SF/UV Process Train Flow Diagram

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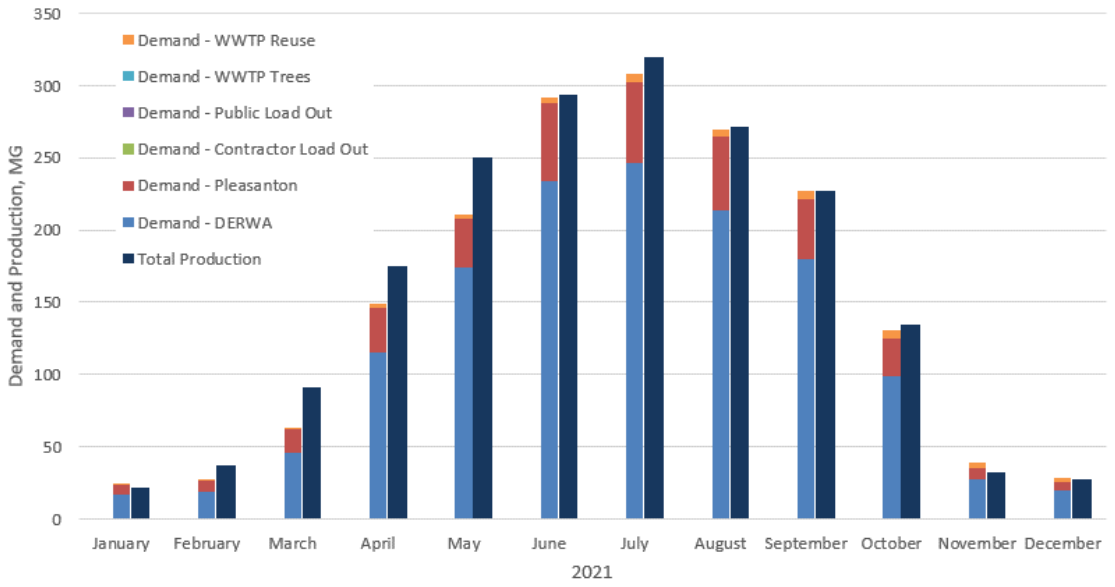


Figure 1.10 Monthly Recycled Water Production and Demand in 2021

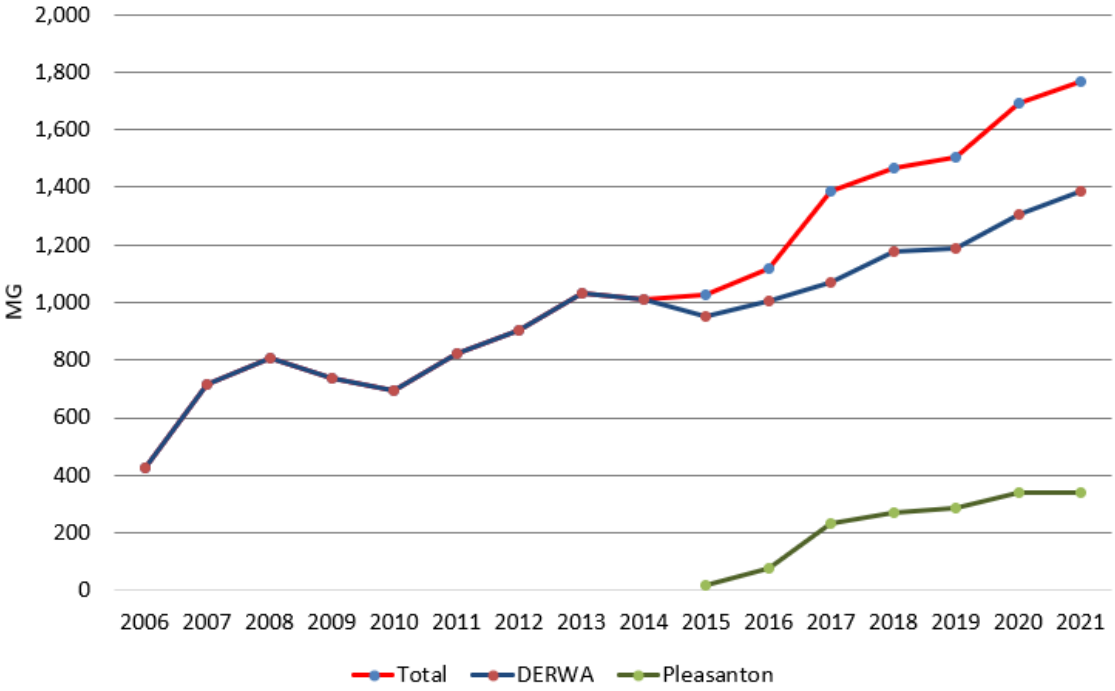


Figure 1.11 Annual Recycled Water Demand (Total, DERWA, and Pleasanton) (2006-2021)

1.3.3.2 Treatment Process

Tertiary Influent Pump Station

The TIPS pumps secondary effluent from holding basin 4 to the recycled water treatment facilities. The pump station is equipped with four, 50 hp vertical turbine pumps with capacities of 7 mgd each. There is an additional 20 hp pump with a capacity of 2.0 mgd.

Sand Filtration/Ultraviolet Plant

The SF/UV system was installed in 2005 and includes a pretreatment system consisting of a band screen, coagulation, and flocculation. In 2017 and 2018, DSRSD, on DERWA's and Pleasanton's behalf, constructed the Recycled Water Treatment Facilities - Phase 2, which includes a new band screen and a ballasted flocculation process to provide pretreatment upstream of the tertiary filters. The 2005 pretreatment system is only still in use when the ballasted flocculation process is not in operation.

After pretreatment, effluent flows to six continuous backwash, upflow deep bed filters with a capacity of 16.2 mgd. Filter reject water is pumped to the WWTP influent sewer line using two 10 hp, 350 gpm submersible pumps.

The filtered water flows from the sand filters to the dedicated UV disinfection system. There are two channels containing five banks of lamps each. The UV system is designed to provide a dose of 100 milli Joules per square centimeter at 60 percent ultraviolet transmittance (UVT). Disinfected finished recycled water is collected in a wetwell of PSR1, chlorinated, and then pumped to Storage Reservoir R100 for distribution. The pump station consists of five 450 hp, variable drive vertical turbine pumps with capacities of 4.9 mgd each.

The recycled water plant operation depends on the secondary effluent quality, which can impact chemical addition and UV disinfection. Higher UVT in the secondary effluent may be a result of lower secondary effluent solids and turbidity resulting in lower UV power output to meet disinfection UV dosages and lower chemical demand at the DERWA facilities.

1.3.3.3 Recycled Water System Chemical Addition

The Recycled Water Treatment Facilities uses various chemicals and consumables that are summarized in Table 1.8. In normal operational mode, aluminum sulfate is used with ballasted flocculation upstream of filtration. In rare situations, such as when the influent to the recycled plant has extremely high turbidity or if the ballasted flocculation system is offline for some reason, aluminum chlorohydrate (ACH) may be used and purchased in 250-gallon totes.[4]

Table 1.8 Chemical and Consumable Consumption at the Recycled Water Treatment Facilities

Process Area	Chemical Name	Application	Chemical Strength	Estimated Consumption in 2020(1)
Ballasted flocculation	Aluminum Sulfate	Coagulant	8 percent as Al_2O_3 by weight	197,130 gallons
Ballasted flocculation and direct filtration	CalChem 2120 (ACH with polymer)	Cationic coagulant polymer hybrid	N/A	Not used, but planned to be used in 2022.
Ballasted flocculation	Clarifloc A210P(2)	Anionic polymer	41 percent	25,300
Ballasted flocculation	Clarifloc WE-363	Cationic polymer	N/A	41,400 pounds
Ballasted flocculation and direct filtration	JenChem 1679 (ACH with polymer)	Cationic coagulant polymer hybrid	N/A	Not typically used

[4] DSRSD. 2019. *DERWA Report of Operations*.

Process Area	Chemical Name	Application	Chemical Strength	Estimated Consumption in 2020(1)
Ballasted flocculation	Sand (hydrex)	Ballast	NA	31,000 pounds
Post-disinfection	NaOCl	Disinfectant for residual	12.5 percent	32,630 gallons

Notes:
Al_2O_3 - aluminum oxide.
(1) The consumption volume for most chemicals is provided based on the 2020 calendar year provided by DSRSD.
(2) Note that DSRSD replaced this anionic polymer since 2020 with a cationic polymer.

1.3.4 Recycled Water Distribution System

The finished recycled water leaves the PSR1 and is pumped directly into the recycled water distribution system. The distribution system encompasses four pressure zones, four recycled water storage tanks (for a total storage capacity of approximately 11 MG), and five pump stations. Recycled water is distributed to customers through approximately 72 miles of pipelines. The diameters of the recycled water distribution pipes range from 4-inches to 36 inches. A schematic of the recycled water distribution system is shown in Figure 1.12, and a map of the system is shown in Figure 1.13.

Ownership of the recycled water distribution system infrastructure is owned by either DERWA or DSRSD. For the purposes of the Energy Facilities Master Plan, DSRSD's recycled water distribution system includes reservoirs R20 and R300 and pump stations R20, R300A and R300B. DERWA's recycled water distribution system includes reservoirs R100 and R200, and pump stations R200A, and R200B. PSR1 is considered a DERWA facility, and is generally referred to separately from the DERWA system in this memo because its electricity use is billed through a WWTP account number.

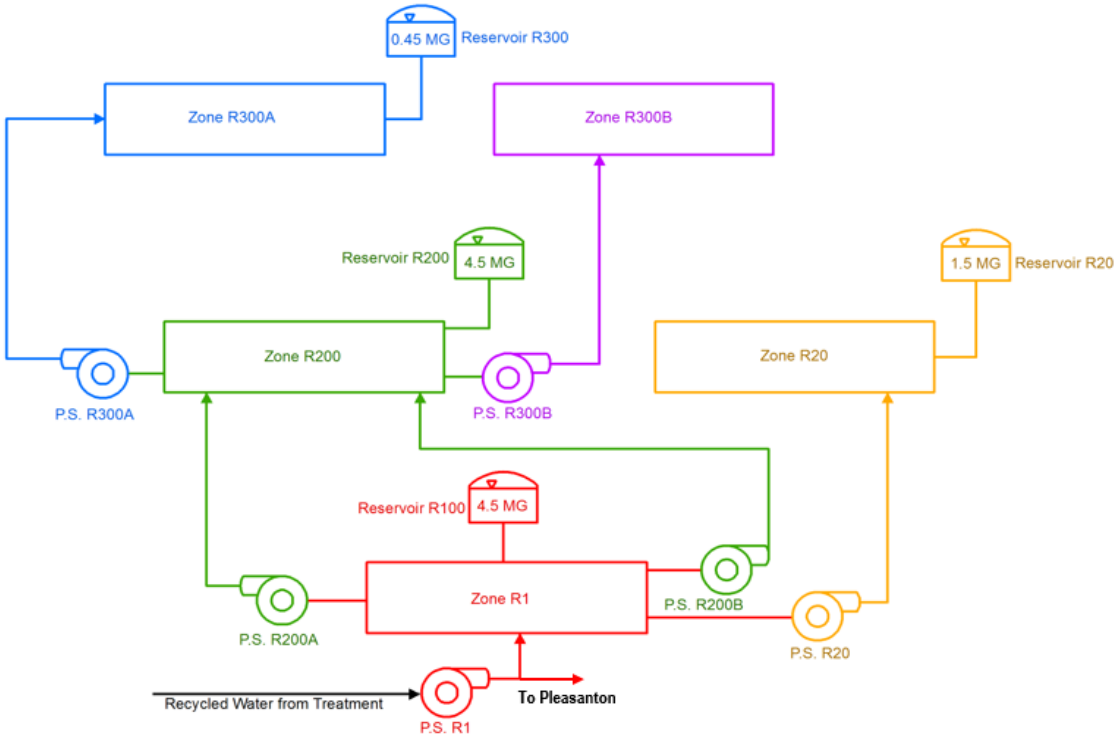
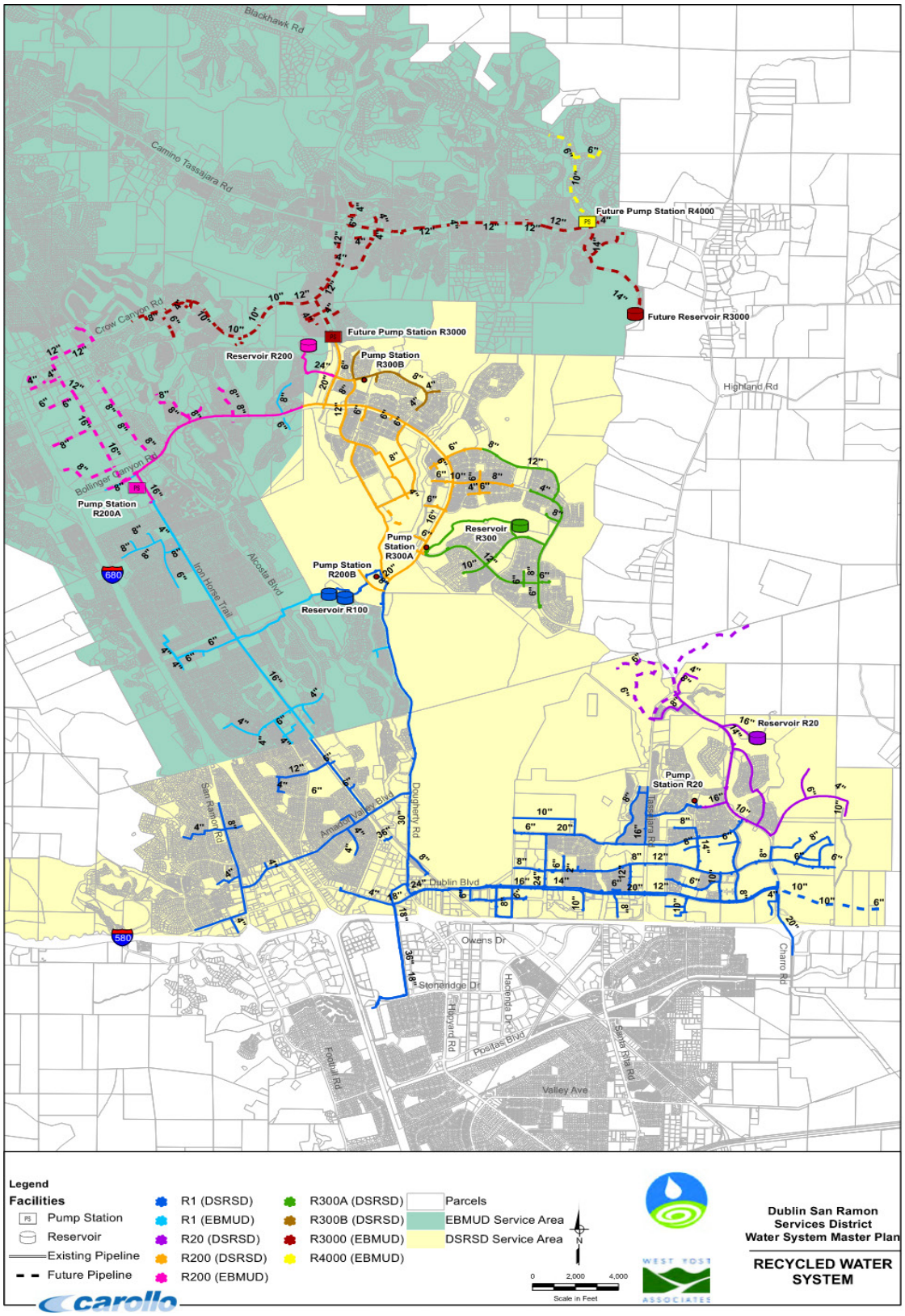


Figure 1.12 Recycled Water Distribution System Schematic



Source: West Yost Associates 2016.

Figure 1.13 Recycled Water Distribution System Map

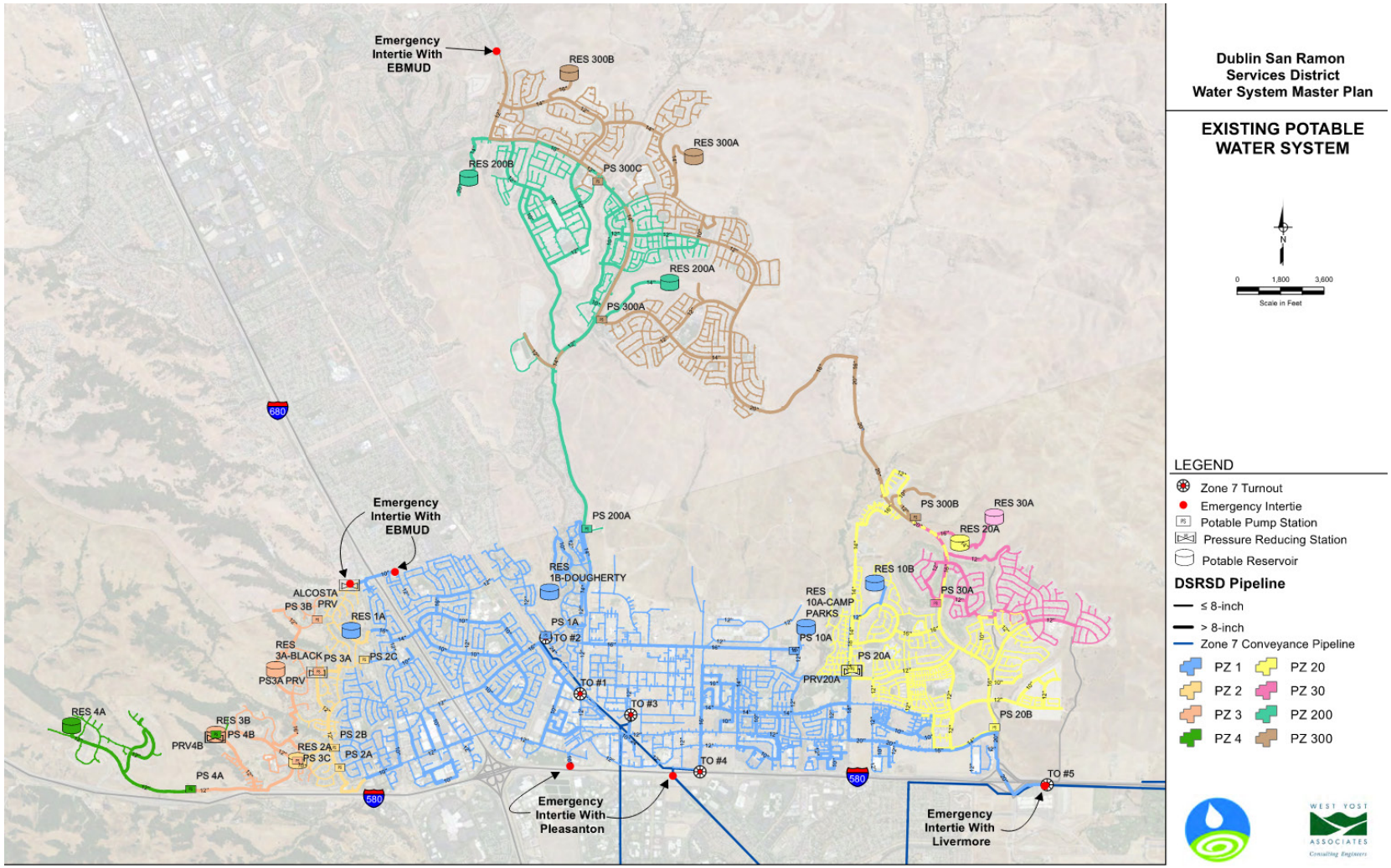
1.3.5 Potable Water Distribution System

1.3.5.1 System Overview

DSRSD provides potable water service to central, eastern, and western Dublin as well as the Dougherty Valley area of the City of San Ramon. DSRSD also distributes potable water to the United States Army Reserve's Parks Reserve Forces Training Area, the Federal Bureau of Prison's Federal Correctional Institution at Dublin, and the Alameda County's Santa Rita Jail. Figure 1.14 provides an overview of the DSRSD's potable water distribution service area.

DSRSD purchases its potable water supply from the Zone 7, which acquires and treats the water supply and conveys it to the DSRSD service area. The potable water is delivered to customers via five water supply turnout facilities, numbered turnouts 1 through 5. Turnouts 1, 2, and 5 are operated regularly; turnout 4 is operated seasonally (approximately June through October), and turnout 3 is physically disconnected from the water distribution system. Figure 1.13 shows the eight pressure zones within DSRSD potable water distribution service area.

There are also 14 potable water storage reservoirs for a total storage capacity of approximately 25 MG. This includes Reservoir 10A, a 3 MG reservoir that is permanently out of service and is scheduled to be replaced when growth of the service area necessitates additional water storage. DSRSD's 17 potable water pump stations convey potable water to the storage reservoirs based on the water levels in the tanks. Potable water is distributed to customers through 337 miles of pipelines. The diameters of the distribution pipes range from 4 inches to 20 inches.



(Source: DSRSD Water System Master Plan 2016)

Figure 1.14 Water Distribution System Map

1.3.5.2 Chemical Consumption

DSRSD fluorinates water supplies received from Zone 7 prior to distribution. In addition, at two of its water storage reservoirs, DSRSD adds ammonia and sodium hypochlorite for chloramination. Table 1.9 summarizes the annual consumption of chemicals in 2021.

Table 1.9 Chemical and Consumable Consumption at the Wastewater Treatment Facilities

Process Area	Chemical Name	Type of Chemical	Chemical Strength	Estimated Consumption in 2021(1)
Water Distribution System	Aqueous Ammonia (NH_4OH)	Chloramination	19 percent	3,100 pounds
Water Distribution System	NaOCl	Disinfectant	12.5 percent	9,710 gallons
Water Distribution System	Fluoride	Water additive	41 percent	68,600 pounds

Notes:
NH_4OH - ammonium hydroxide.
(1) The consumption volume for most chemicals is provided based on the 2020 calendar year provided by DSRSD.

1.3.6 Administrative and Other Buildings

There are two buildings outside of the WWTP site included in the energy evaluation in this project: 1) the DSRSD Office Administration Building and 2) the Field Operations Department (see Figure 1.2).

The WWTP and DERWA facilities consist of 16 buildings (Buildings A through U) as listed in Table 1.10. All buildings with motor control centers (MCC) are equipped with HVAC systems. The District's metal buildings are not insulated and staff reports that, in these buildings, HVAC systems run constantly (specifically, Buildings S and T are reportedly not very energy efficient). Building T is equipped with a floor heating system supplied from recovered heat supplied from the heat pump from the cogeneration system.

Except for DSRSD's Office Administration Building, the Fleet Building, and the Field Operations Facility, other buildings listed in Table 1.10 do not have dedicated gas or electricity meters and their energy consumption is metered under the WWTP's PG&E account. This Energy Facilities Master Plan will assess the energy consumption specifically of DSRSD's Office Administration Building and the Field Operations Facility, which are served by dedicated PG&E gas and electricity accounts.

Table 1.10 Buildings and Energy Features

Name of Building	Function	Occupancy	Energy systems (HVAC, heating, cooling, etc.)
DSRSD Office Administration Building		Yes	Electricity and natural gas for office activities, HVAC
Field Operations Facility		Yes	Electricity and natural gas for office activities, HVAC
BLDG A	OPERATIONS BUILDING	Yes	Electricity and natural gas, laboratory services, space heating and hot water production with recovered heat from cogen system
BLDG B	BLOWER BUILDING / MCC B	No	HVAC, Electricity
BLDG C	BAR SCREEN BUILDING	No	Electricity
BLDG D	MCC D BUILDING	No	HVAC, Electricity
BLDG E	EALS / MCC E BUILDING	No	HVAC, Electricity
BLDG F	HYPO STORAGE / MCC F BUILDING	No	HVAC, Electricity
BLDG G	SAMPLE STATION / MCC G BUILDING	No	HVAC, Electricity
BLDG H	GRIT / MCC H BUILDING	No	HVAC, Electricity
BLDG I	ODOR REDUCTION TOWER BUILDING	No	Electricity
BLDG J	750 GENSET BUILDING	No	Electricity
BLDG K	COMPRESSOR / MCC K BUILDING	No	HVAC, Electricity
BLDG L	MCC L WHITE HOUSE BUILDING	No	Electricity
BLDG M	MCC M BUILDING	No	HVAC, Electricity
BLDG N	MCC N BUILDING (DERWA)	No	HVAC, Electricity
BLDG O	COMPRESSOR / CHEMICAL BUILDING (DERWA)	No	HVAC, Electricity
BLDG P	UV CONTROL BUILDING (DERWA)	No	HVAC, Electricity
BLDG Q	FLEET BUILDING	Yes	Natural Gas (PG&E Acc. No. 4772588550-4)
BLDG R	MF / UV BUILDING	No	Electricity
BLDG S	MAINTENANCE BUILDING	Yes	Space heating and hot water production with recovered heat from cogen system
BLDG T	MAINTENANCE SHOP	Yes	Space heating and hot water production with recovered heat from cogen system
BLDG U	BF SAND STORAGE	-	Electricity

1.4 Relevant Previous Planning and Project Documents

The following section provides a brief summary of previous DSRSD studies relevant for this Energy Facility Master Plan, including assessments, reports, and other planning documents. These reports have been reviewed and highlights are briefly summarized to provide planning continuity and consistency of this planning project with previous energy or capital improvement plan definition efforts.

- ***Dublin San Ramon Services District Cogeneration Master Plan*, June 2006, Whitley Burchett and Associates.**
  Five alternatives for adding more cogeneration capacity to the WWTP were evaluated for life cycle costs and payback periods. The study ultimately recommended a) adding a third reciprocating engine as a standby unit and b) pursuing installing a fuel cell. DSRSD subsequently installed a fuel cell system and operated it for five years. The system was decommissioned in 2012 in part due to high O&M costs.
- **Center *Energy Conservation & Waste Management Assessment*, May 2010, San Francisco State University Industrial Assessment.**
  This energy assessment of the WWTP was funded by the DOE as part of the "Save Energy Now Initiative." The report quantified the electrical and natural gas energy used onsite between March 2009 and February 2010. The assessment then recommended eleven equipment-related improvements intended to reduce electricity use at the plant. Of these, DSRSD implemented a subset (i.e., LED light replacements).
- ***Water System Master Plan*, March 2016, West Yost Associates.**
  The 2016 Water System Master Plan evaluated the existing potable and recycled water system facilities, including their distribution systems, and recommended capital improvements to meet the DSRSD's existing, intermediate, and future needs. No direct energy-related improvements were recommended as part of this plan.
- ***Wastewater Treatment and Biosolids Facilities Master Plan*, September 2017, West Yost Associates.**
  The 2017 *Wastewater Treatment and Biosolids Facilities Master Plan* summarized the WWTP's energy sources and demands. It calculated an energy balance for the 2013-2015 conditions and projected an energy balance for 2035 conditions. The plan proposed energy-saving improvements throughout the WWTP and presented strategies for producing energy at the plant to achieve a net zero energy demand. Several energy management-related projects were recommended for inclusion in the Master Plan Capital Improvement Plan. Two energy management-related projects, anaerobic digester no. 4 and FOG Receiving Facility, were under construction at the time of the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan* and have since been completed. Since completion of the Master Plan, DSRSD implemented the primary sedimentation expansion.
- ***Primary Sedimentation Expansion and Improvements Project Preliminary Design Report*, January 2019, West Yost Associates and HDR.**
  This Preliminary Design Report presented the basis of design and initial plans for the expansion and improvements of the WWTP's primary sedimentation facilities and improvements to the grit removal system. The project included electrical and instrumentation improvements throughout the primary treatment system.

- ***Biogas System Improvements Evaluation and Engineering Report*, November 2019, Black & Veatch.**
  The WWTP's biogas management and transport system were evaluated for potential improvements. The report recommended upgrades across several aspects of the biogas system, including updating the air quality permit and adding biogas storage capacity. Additional follow-up work is currently in progress.
- ***Digester Gas Treatment System Improvements Evaluation and Engineering Report*, April 2020, Black & Veatch.**
  This evaluation compared the projected digester gas production to the existing digester gas treatment system to determine when and which component upgrades will be required to meet future capacity demands for a 2035 design year and 2055 "future design year." At the time of the report, some components of the digester gas system were already at or over capacity. The evaluation recommended media modifications of the hydrogen sulfide removal system and replacement of the following system components: compressors and inlet heat exchangers, the moisture removal heat exchangers, and the siloxane/volatile organic compound removal vessels. Design of these components is currently under development.
- ***Alum Addition TO1 Predesign Report*, November 2021, HDR.**
  HDR designed alum addition facilities for the supernatant return flow from the FSLs. This process would "bind up" phosphorus in the FSL return flow that currently requires the WWTP to operate its aeration basins in parallel during the winters. The goal is to operate the aeration basins in series year-round. The predesign report includes the design basis, a preliminary layout and equipment options, and estimated capital and O&M costs. This project is expected to be in operation in 2023.

1.5 Basis of Planning Assumptions for this Energy Facilities Master Plan

This section summarizes important planning assumptions used for this Energy Facilities Master Plan and references the sources on which these assumptions are based. These assumptions will be used for various evaluations throughout this project through completion. It is important to note that the project team anticipates that several of the stated assumptions might change over the duration of this project. Such uncertainties can be considered in future analyses by defining for key parameters value ranges or specific scenario alternatives to conduct sensitivity analyses. Where relevant to DSRSD, these value ranges and scenarios are defined in Sections 1.5.1 through 1.5.3.

1.5.1 Baseline Year and Planning Period

This Energy Facilities Master Plan is developed for the baseline year 2021 and a planning horizon of 25 years (planning period 2021 to 2046). The baseline year 2021 was selected as the most recent calendar year for which data is fully available. This year is most representative for the current operation at all facilities and includes some recent process upgrades (such as primary clarifier and digester expansion projects). In addition, the calendar year 2021 did not show abnormalities in plant influent flows and loads or energy consumption patterns as a result of possible pandemic related dynamics.

The planning horizon of 25 years is sufficient in length to consider long-term regulatory developments relevant to this energy and GHG planning process. The longer the planning period the larger the uncertainties related to regulatory and treatment requirements or technology developments. For this reason, certain scope elements of this project will be developed for shorter planning periods where it makes sense, i.e., improvement projects for the next 10 years, which corresponds to DSRSD's CIP planning horizon.

1.5.2 Current and Future Wastewater Treatment Plant Influent Flow and Loads Projections

The current WWTP influent and secondary influent flows and loads will be used to calculate specific energy performance metrics for the 2021 baseline year. Since secondary treatment typically contributes the largest percentage to the energy consumption of wastewater treatment, current primary effluent loadings are discussed to develop meaningful energy demand performance metrics.

The future WWTP influent flow and loads projected through planning period 2021 to 2046 will be used in the projection of the future energy demand and production for DSRSDs WWTP.

1.5.2.1 Current Influent Flows

The historical annual average influent wastewater flows over the past five years (2017 to 2021) are summarized in Table 1.11. The reported influent flow rates are calculated as the sum of the four influent pump flow rates less the FSL supernatant return rate and the inner sewer flow rate. Reject flows from the recycled water treatment are included in this calculation.

Table 1.11 Historical Influent Flow Rates 2017 to 2021

Year	ADAF (mgd)
2017	11.1
2018	10.9
2019	11.0
2020	10.7
2021	11.7

Notes:
ADAF - average daily annual flow.
(1) Average flow across the lowest three consecutive dry season months between May 1 and October 31.
(2) Source: DSRSD's Discharge Monitoring Reports.

The annual average influent flow rates are summarized in Table 1.11 and daily influent flows are shown in Figure 1.15.

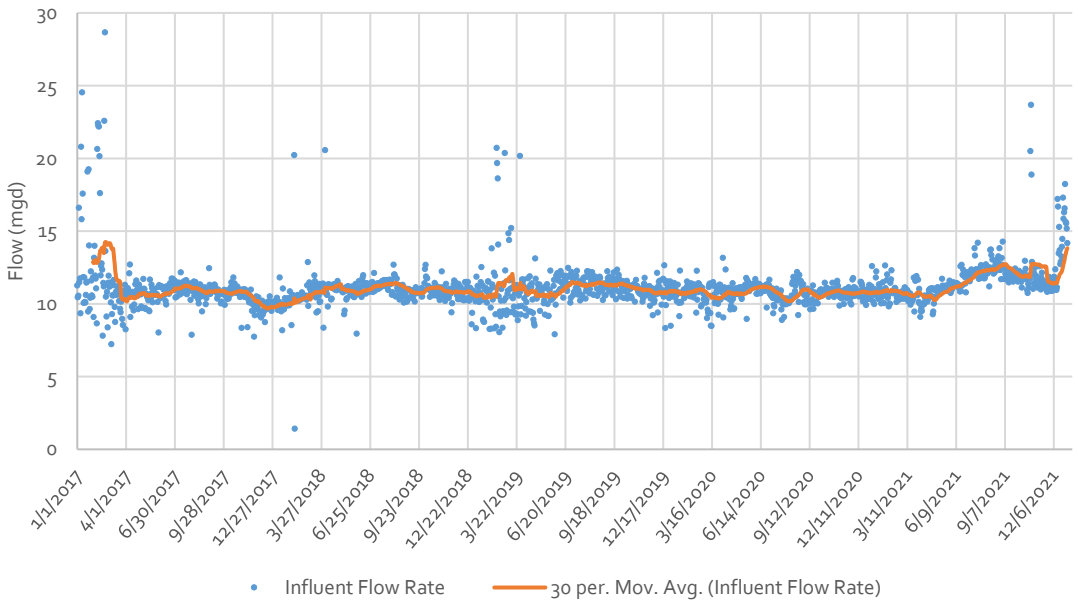


Figure 1.15 Daily Average Plant Influent Flows (2017 to 2021)

The data shows that the plant influent flows have been seasonally very steady around 11 mgd. DSRSD does not experience frequent significant wet weather influent flow conditions (Figure 1.15). For this reason, projections for energy demand and production will be developed in this study on the basis of annual average influent flow conditions and not separated out based on wet and dry weather flow events.

1.5.2.2 Current Plant Influent and Primary Effluent Loading Rates

Figure 1.16 shows the annual average plant influent loads for carbonaceous biological oxygen demand (BOD_5), total suspended solids (TSS), and total Kjeldahl nitrogen (TKN) between 2017 and 2021. The reported concentrations were combined with the corresponding daily flow rates to calculate the daily average influent loading rates. While influent flows have remained constant over past years (Figure 1.15), TSS and, to a lesser extent, BOD_5 influent loads have increased over the same time period. This is typically attributable to water conservation measures among customers in the service area that compensate for the additional growth. Because of this influent flow and load pattern, it will be more appropriate to compare the energy consumption and production over time for DSRSD on an influent load basis (kilowatt-hour [kWh]/pounds per day [ppd] TSS or BOD_5) rather than a flow basis (e.g., kWh/mgd).

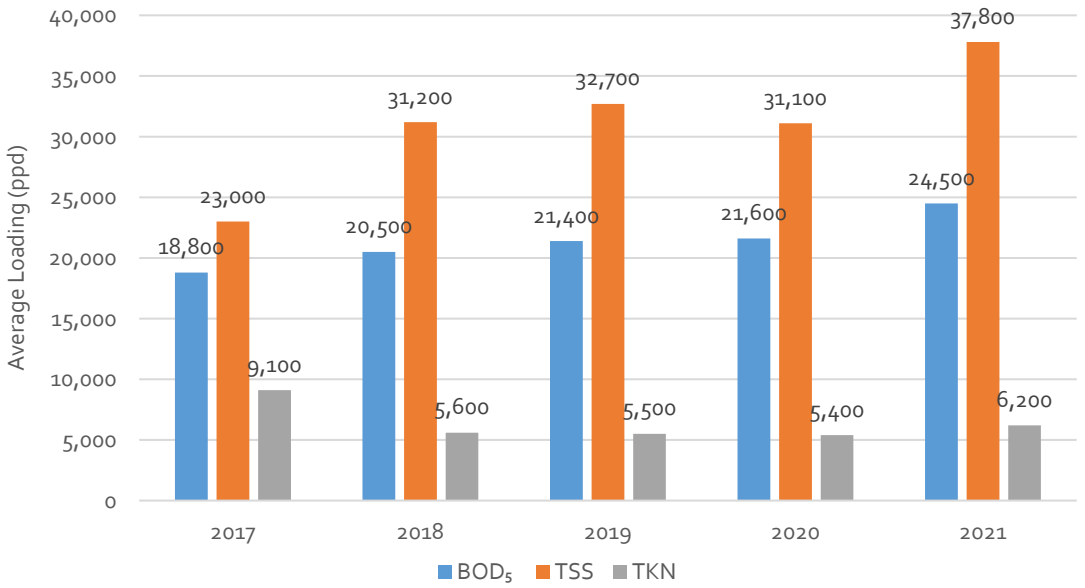


Figure 1.16 Historical Plant Influent Annual Average Loading Rates (2017 to 2021)

Figure 1.17 shows the plant influent loads over time for the same time period for carbonaceous biochemical oxygen demand (cBOD), TSS, and TKN (which is rarely measured). This data series indicates localized high loading rates in July 2018 and again the summer and winter of 2021. TKN loading does not seem to follow an increasing trend, although this parameter was only measured 14 times over the same period. Figure 1.18 shows the cBOD and TSS removal efficiencies in the primary clarifiers. The efficiency was noticeably increased in 2019 and the plant was able to maintain relatively stable secondary influent cBOD and TSS loads (Figure 1.19), despite the fact that influent cBOD and TSS loadings increased over the past years. (Note that several outlier values have been removed from Figure 1.18 and Figure 1.19.)

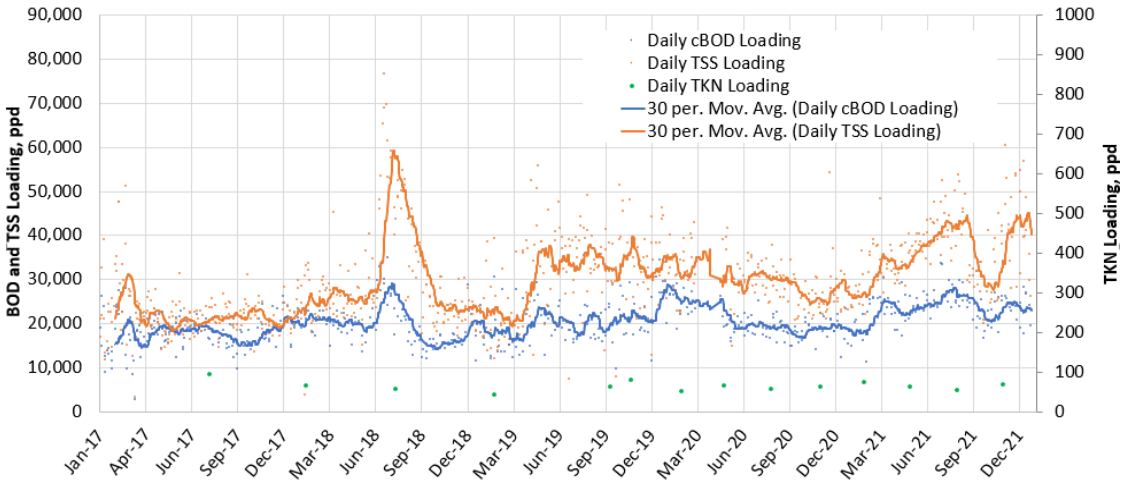


Figure 1.17 WWTP Influent BOD_5, TSS, and TKN Loading Rates (2017 to 2021)

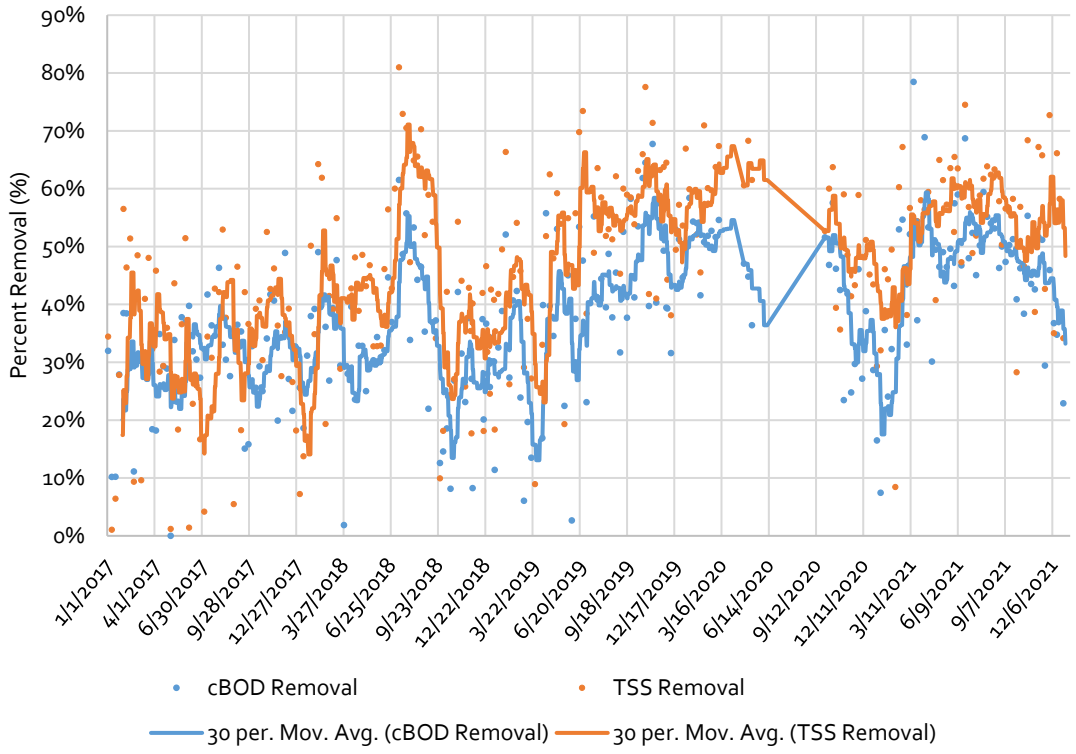


Figure 1.18 Historical Primary Clarifier cBOD and TSS Removal Rates (2017 to 2021)

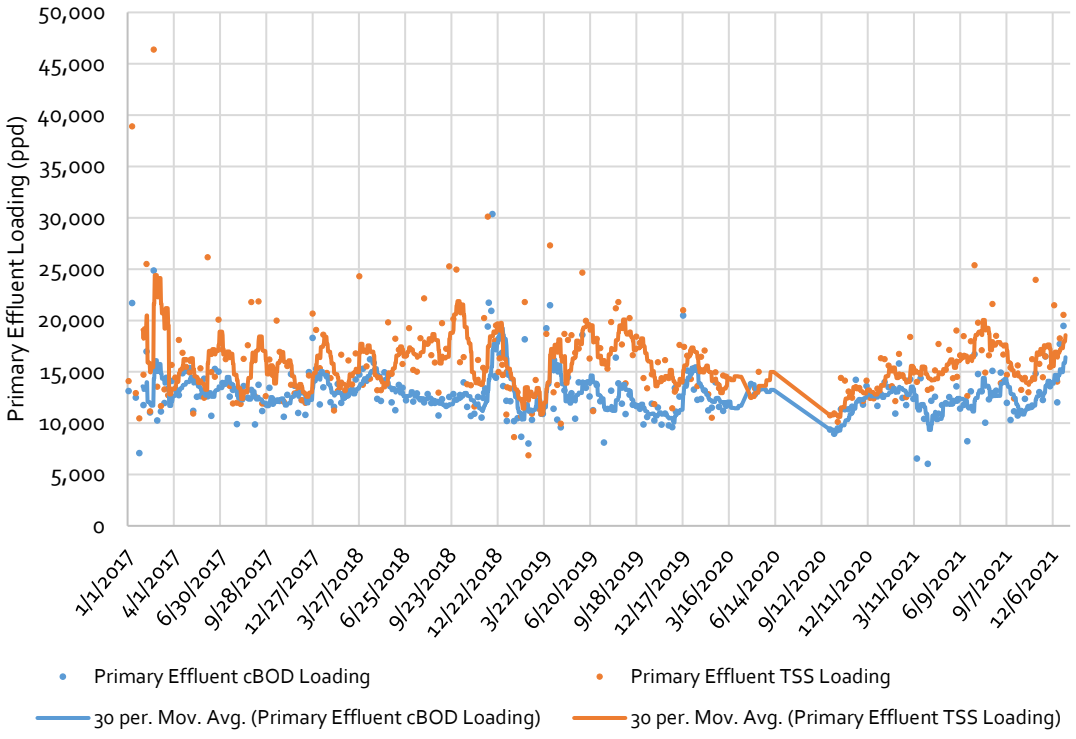


Figure 1.19 WWTP Primary Effluent BOD_5 and TSS Loading Rates (2017 to 2021)

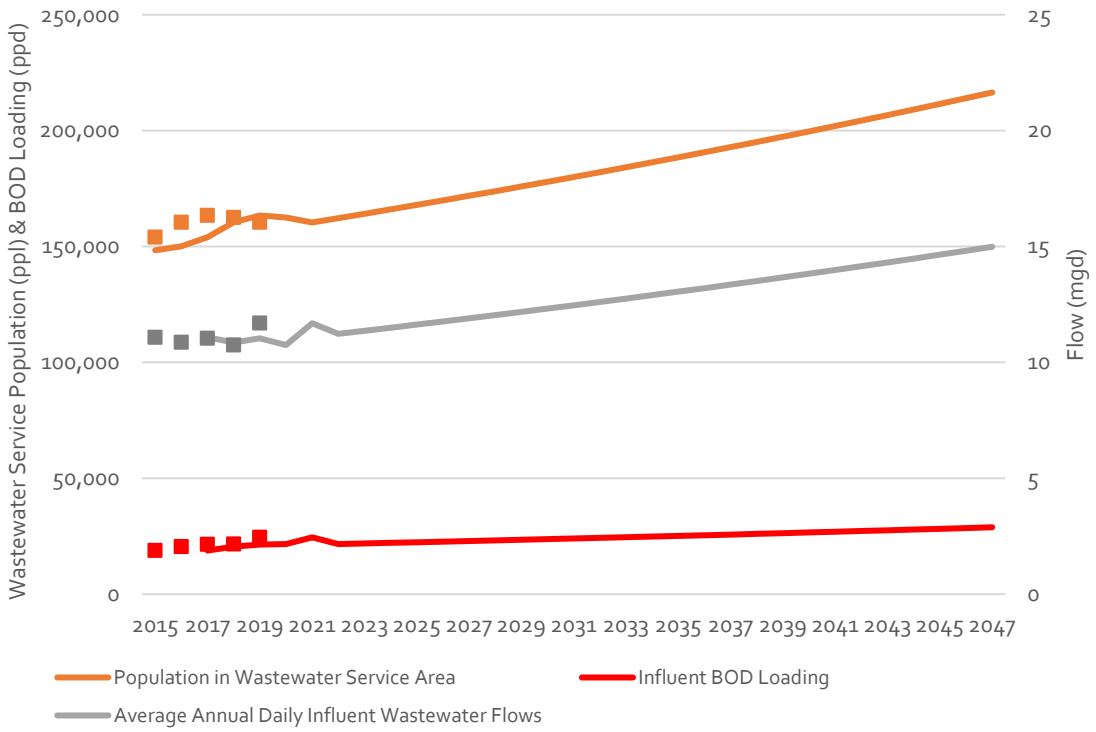
1.5.2.3 Projected Influent Flow and Loadings

The projections for this Energy Facilities Master Plan were adopted from the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan* and under consideration of the *2021 Alternative Water Supply Study: A Framework for a Resilient and Sustainable Water Future*. The projected influent flows and loads for the years 2022 through 2047 based on the projected population growth in the wastewater service area observed during the recent years (see Table 1.2). The average per capita flow and loading rates between 2017 and 2021 were applied to the projected wastewater service population assuming a 1.16 percent growth rate. This linear growth rate might be conservative as the future recycle and potable water demand could taper off starting in 2030 per DSRSD's projections. The projected flows and loads and are summarized in Table 1.12 and shown in Figure 1.20 along with the population projection in the wastewater service area.

Table 1.12 Projected Plant Influent Flows and Loads for Planning Period

Year	ADAF (mgd)	Average Annual BOD Loading (ppd)	Average Annual TSS Loading (ppd)	Average Annual TKN Loading (ppd)
2021(1)	11.7	24,500	37,800	6,200
2035(2)	13.1	25,125	36,605	7,522
2047(2)	15.0	28,855	42,038	8,639

Notes:
(1) Baseline year for this Energy Facilities Master Plan.
(2) Developed based on a linear projection of the 2021 influent flows and loads using a 1.16 percent annual population growth rate.



(The data points shown are actual calendar year averages. The lines are calculated projections.)

Figure 1.20 Projected Plant Influent Flows and Loads for Planning Period 2022 to 2047

1.5.3 Regulatory Review

This section summarizes current and future regulations that may impact this Energy Facilities Master Plan. Any future strategy to create a sustainable, resilient, reliable, and cost-efficient energy infrastructure must be flexible to accommodate and prepare for anticipated future regulatory changes affecting DSRSD's facilities operation.

1.5.3.1 Current Permits

Discharge Permit

DSRSD, LAVWMA, and EBDA currently operate under Order R2-2022-0024, National Pollutant Discharge Elimination System (NPDES) permit no. CA0037613 issued by the San Francisco Bay Regional Water Quality Control Board and effective since September 1, 2022, for the discharge of secondary treated wastewater to discharge point 001 into the Lower San Francisco Bay. The permit will expire on August 31, 2027.

The current permit specifies discharge limits as summarized in Table 1.13. The discharger shall comply with these effluent limitations at the treatment plant and at discharge point no. 001 (EBDA Common Outfall), with compliance measured at monitoring locations EFF-001, EFF-002F1, EFF-002F2 and EFF-002F3, as defined in Table E-1 under Order R2-2022-0024, NPDES Permit CA0037613.

Table 1.13 Current Effluent Discharge Limits

Parameter	Current Limit	Comment
Design Flow, mgd(2)	20.2 (average dry weather flow) 17 (average dry weather influent flow from DSRSD WWTP) 3.2 (Zone 7 reverse osmosis reject water)	Upon satisfying Provision 6.3.5.4, the average dry weather influent flow from the treatment units may be increased from 17.0 mgd to 20.7 mgd, and the total average dry weather flow may be increased from 20.2 mgd to 23.9 mgd.
BOD_5, mg/L	25 (average monthly) 40 (average weekly) 85 percent removal (average month)	Monitoring Location: EFF-002F1 (A point in the treatment plant at which adequate disinfection has taken place and prior to the addition of Zone 7 reject water.)
TSS, mg/L	30 (average monthly) 45 (average weekly) 85 percent removal (average month)	Monitoring Location: EFF-002F1 (A point in the treatment plant at which adequate disinfection has taken place and prior to the addition of Zone 7 reject water.)
Total Ammonia-N, mg/L	86 (average monthly) 110 (maximum daily)	Monitoring Location: EFF-001 (EBDA Common Outfall)

Notes:
mg/L - milligrams per liter.
(1) Various other parameters regulated in the discharge permit are not listed here for brevity as not directly relevant to this Energy Facilities Master Plan.
(2) Average dry weather influent flow from the treatment units shall be determined from three consecutive dry weather months (May 1 to October 31) each year, with compliance measured at Monitoring Location INF-002F as described in the Monitoring and Reporting Program.

Air Permit

The California Air Resources Board (CARB) regulates mobile source air emissions in compliance with the federal Clean Air Act as well as state programs. DSRSD must comply with CARB's current and developing fleet emissions standards.

Additionally, the Bay Area Air Quality Management District (BAAQMD) regulates the DSRSD's stationary emission sources. Various permits to operate (PTO) have been issued to DSRSD for onsite stationary combustion (e.g., standby diesel generators, mobile generators, etc.) and gasoline dispensing operations. In November 2021, the District submitted an application to revise its PTO for permit no. 1371. The revision seeks to include additional equipment and infrastructure recently constructed at the WWTP, including a new anaerobic digester (i.e., digester no. 4), expansion of the primary clarifiers, FOG receiving station, and a new waste gas burner.

Title 22 Recycled Water Quality Permit

The Recycled Water Facility operates to meet the requirements of the Title 22 California Code of Regulations for Recycled Water. Briefly, this permit requires DSRSD to meet final product water requirements after tertiary treatment and disinfection that meets final requirements for plaque forming units of F-specific bacteriophage MS2, polio virus, and total coliform bacteria.

1.5.3.2 Existing, Developing, and Anticipated Future Regulations

Figure 1.21 provides an overview of the recently adopted and developing regulations that may play a role in DSRSD's Energy Facilities Master Plan and in the Bay Area at large. The regulatory developments may impact the liquids and solids treatment, air quality, and other planning drivers (funding and aging infrastructure both above and below-ground) that directly influence energy related planning and decision-making. These regulatory developments span the 25-year planning horizon for this planning effort targets.

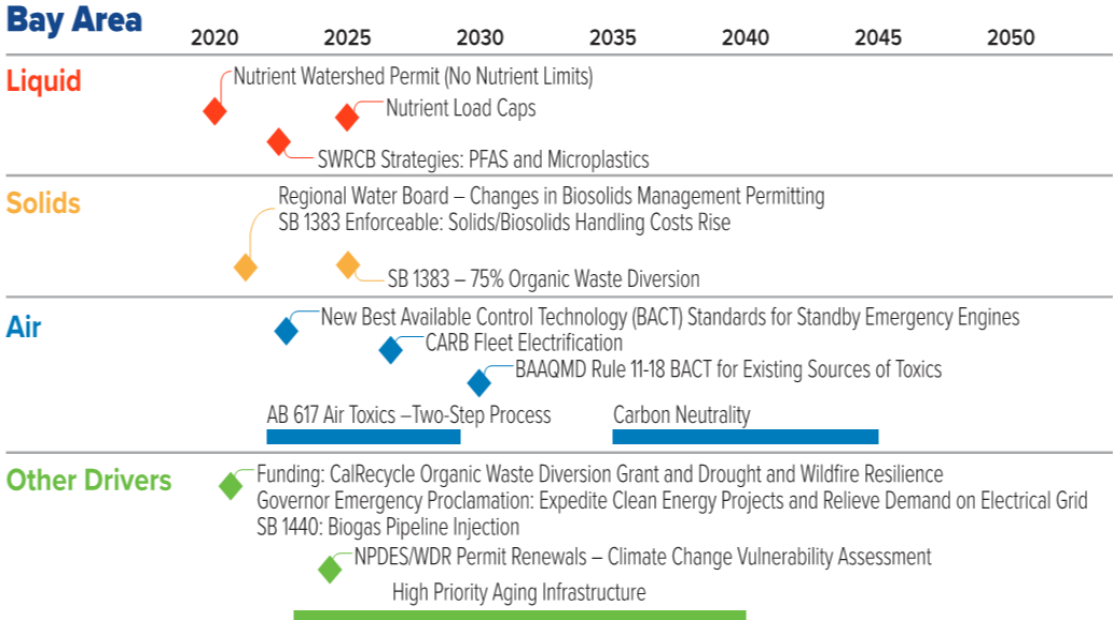


Figure 1.21 Future Bay Area Regulations and Drivers Affecting Publicly Owned Treatment Works

The regulatory developments in Figure 1.21 are briefly summarized in the following sections.

Watershed Permit Nutrient Load Limits

In 2024, the Regional Water Board intends to establish nutrient effluent limitations as part of the watershed-wide NPDES permit CA0038873. Order no. R2-2019-0017 includes current total inorganic nitrogen (TIN) discharge loads and estimated future TIN load targets. DSRSD discharges to the Bay through a common outfall via EBDA. The order suggests that EBDA should prepare for a dry season load target of 9,600 kilograms per day (kg/day) TIN in 2024 (see Table 1.14), which in the near-term does not impose an actual load reduction compared to current discharge loads. Furthermore, because the potential load targets will apply in the dry season only, this regulation will likely not apply to DSRSD given its current recycled water operation.

Table 1.14 Current and Estimated 2024 TIN Load Targets per Regional Water Board Order

Parameter	Total Annual Average TIN Load (kg/day)	2024 Dry Season Average Load Targets (Current Performance +15 percent growth buffer)
TIN	8,400	9,600

Notes:
(1) Loads apply to EBDA, which includes the following members: City of Hayward, City of San Leandro, Oro Loma and Castro Valley Sanitary Districts, Union Sanitary District, East Bay Regional Parks District, LAVWMA, DSRSD, and City of Livermore. These combined dischargers have a design flow of 107.8 mgd of which DSRSD has currently a design flow capacity of 20.2 mgd.

Nitrification limits could be implemented in DSRSD's permit but this is anticipated to be more than 10 years into the future.

Per- and Poly-fluoroalkyl Substances (PFAS)

At this time, the State of California has not implemented regulatory limits for PFAS in permitted effluents or biosolids. The July 2020 State Water Resources Control Board (State Water Board) Investigative Order for Publicly Owned Treatment Works (POTW) is not applicable to San Francisco Bay Regional Water Board POTWs. Instead, the Bay Area Clean Water Agencies worked with the State and Regional Water Boards staff and obtained approval to fund and conduct a regional study through the Regional Monitoring Program in collaboration with the San Francisco Estuary Institute (SFEI). Selected POTWs within the San Francisco Bay Region are participating in the study to establish a database on the occurrence of PFAS in the influent, treated effluents and biosolids to better understand the sources in case elevated concentrations are detected. In March 2022, SFEI published the *Study of Per- and Polyfluoroalkyl Substances in Bay Area POTWs: Phase 2 Sampling and Analysis Plan*, building upon the efforts of Phase 1 that included monitoring for PFAS at a broader set of Bay POTWs. It is anticipated that PFAS may become regulated in the foreseeable future at the source (via source control or pretreatment programs), for effluent discharge, or biosolids. This could result in additional treatment requirements at POTWs experiencing exceedances. Carollo recommends tracking the regulatory developments and monitoring results. At this time, it is speculative to estimate when or what PFAS limits may be implemented for DSRSD's effluent discharge or biosolids.

Microplastics

The State Water Board adopted a standard definition for microplastics in June 2020 and is anticipated to adopt a standardized methodology for sampling for microplastics in drinking water in 2022. It is uncertain whether this monitoring program may lead to drinking water regulations for microplastics in the future, whether such limits may also impact wastewater

effluent dischargers, and what treatment upgrades such regulations may trigger. The Ocean Protection Council initiated a study in 2020 to assess the efficacy of microplastic removal in California wastewater treatment plants, with anticipated completion in early 2023.

Biosolids Management Considerations – Senate Bill (SB) 1383

California adopted SB 1383 in September 2016 as part of a statewide effort to reduce emissions of short-lived climate pollutants, including methane. Specifically, this law requires a 40 percent reduction in methane emissions in California by 2030 relative to levels emitted in 2013 via two pathways – diverting organic waste from landfills and management of dairy cow manure. This regulation has various implications and opportunities for the wastewater sector:

- Biosolids, sludges, and digestate are included in the organic waste definition, requiring them to be diverted from landfills for the reduction of methane production and release. Landfills statewide must divert 75 percent of the organic waste (and recycle it) by January 1, 2025.
- Diverted organic waste that is anaerobically digested and land applied constitutes a reduction in landfill disposal (18983.1(b)(6)(B)). All other treatment options, including aerobic digestion, incineration, pyrolysis, or surface disposal, are considered landfill disposal (18983.1(a)(3)).
- The wastewater sector is recognized to play an important role in the co-digestion of divertible and digestible food waste to meet statewide diversion mandates by January 1, 2025. Existing anaerobic digesters and biogas handling systems at POTWs that have available capacity and accept diverted food waste for co-digestion may qualify for funding to support infrastructure upgrades and low carbon fuel standard credits if the biogas is used as a transportation fuel. The biogas is also eligible for mandatory procurement under SB 1440 to be injected into a utility pipeline.

Air Quality Requirements – Air Toxics

BAAQMD's "Best Available Control Technology" (BACT) regulations require permit applicants to use the most stringent level of emissions control that is achieved by other, similar facilities or that is proven to be technologically and economically feasible. The BACT for large (≥1000 brake horsepower) diesel backup generators were revised in March 2021, and new or modified emergency diesel engines must now meet Environmental Protection Agency (EPA) Tier 4 emission standards. This new requirement will apply to DSRSD's 1250 kW and possibly 750 kW backup diesel generator.

BAAQMD Regulation 11, Rule 18, was adopted in November 2017 to reduce health risks from existing sources of toxic air emissions. It sets risk action thresholds for cancer risk and non-cancer chronic and acute hazards and requires facilities that exceed those thresholds to either reduce their associated emissions or implement Best Available Retrofit Control Technology.

BAAQMD will perform emissions estimates to determine if DSRSD exceeds the risk action thresholds and will notify DSRSD by fall of 2024, which will begin a health risk assessment process to confirm the estimates.

CARB adopted amendments to the Air Toxics "Hot Spots" Program Emission Inventory Criteria and Guidelines and the Reporting of Criteria Air Pollutants and Toxic Air Contaminants Regulation in 2020 in effort to further improve air toxic emissions reporting (statewide), the public's access to the data, and reduction strategies for priority communities. CARB approved a

phased compliance approach that allows permitted POTWs to report air toxics business as usual through 2028 while the sector executes the two-step process to:

1. Perform a scan of air samples across various treatment plant unit processes to determine detectable compounds (of the 1,000+ compounds).
2. Quantify the emissions of detectable toxic compounds based on an approved sampling and analysis approach (working with air districts and CARB).

In the meantime, DSRSD will not need to quantify any new air toxic compounds until the completion of the statewide two-step process (estimated to be complete by 2026), but it is expected that BAAQMD will require a selection of POTWs to participate in the two-step process managed by the California Association of Sanitation Agencies. Once the two-step process is complete, air districts will re-assess the relative risk POTWs pose to surrounding receptors to determine whether a risk reduction plan must be developed and implemented.

Statewide Carbon Neutrality Requirements

In 2021, at the Governor's request and in time for the next climate change scoping plan update, CARB began evaluating pathways for the state to achieve carbon neutrality by 2035 – in advance of the 2045 target. This included strategies to reduce fossil fuel demand and supply and transition to 100 percent clean and renewable resources for all electricity retail. Additionally, the Governor has ordered an end to the sale of new fossil fuel vehicles by 2035 and required heavy-duty truck manufacturers transition to zero-emission vehicles (ZEV) by 2045 (see "Advanced Clean Fleets – Public Fleet Requirements Draft Regulation" section).

As essential public service providers, the water sector is currently weighing in on these developing regulations to ensure that there are options to be energy and fuel independent at any time in order to maintain operations and avoid loss of service during emergencies.

Advanced Clean Fleets – Public Fleet Requirements Draft Regulation

CARB is currently in the process of developing an "Advanced Clean Fleets" regulation with the objective of electrifying vehicles, beginning with public fleets. The draft regulatory language was released in September 2021 for public review. Specifically, the draft regulation proposes for a public agency as DSRSD:

- Starting January 1, 2024, 50 percent of the total number of new medium-duty and heavy-duty vehicle purchases in each calendar year must be a ZEV.
- Starting January 1, 2027, 100 percent of the total number of new medium-duty and heavy-duty vehicle purchases in each calendar year must be ZEVs.
- Alternative vehicle purchases are allowed until 2035 if ZEVs are not available.

ZEVs includes vehicle types with drivetrains that produce zero exhaust emissions of any criteria pollutant for GHGs, specifically full battery-electric or hydrogen fuel cell vehicles. This currently does not allow for near-zero-emission vehicles (NZEV) fueled by compressed renewable natural gas.

Until January 1, 2035, NZEV, i.e., plug-in hybrid-electric vehicle) purchases will be counted the same as a ZEV purchase if a public bid is issued to purchase ZEVs and NZEVs, but no responsive bids for ZEVs are received for that bid.

The draft regulation includes a few exemptions based on vehicle type, one of which applies to vehicles used in DSRSD's current fleet. Specifically, emergency response vehicles used in wastewater services for which NZEVs are not available. However, there is a limitation on the number of miles traveled per year.

In addition, the following exemptions are proposed that are of relevance to DSRSD:

- A vehicle still complies as a non-ZEV as long as it was owned by the fleet prior to January 1, 2024, and is still within its minimum useful life. Non-ZEV vehicles that are beyond their useful life would be required to be replaced with ZEV alternatives.
- Backup vehicles are exempt from milestone requirements as long as these vehicles do not exceed 1,000 miles per year.
- A daily mileage exemption applies for ZEVs that cannot meet the daily mileage needs of the specific combustion powered vehicle in the fleet of that type, meaning that DSRSD's combustion vehicles would be exempt for which there is no equal ZEV alternative based on daily milage requirements and vehicle type Note that this current definition does not currently include the idle time (time when vehicle is not moving but has a significant power draw for lighting and other uses during service) into the mileage calculation.

Table 1.15 summarizes the proposed ZEV phase-in schedule.

Table 1.15 Proposed ZEV Phase-In Schedule per CARB's September 2021 Draft Advanced Clean Fleet – Public Fleet Requirements Regulation

Parameter	Proposed Phase-in Schedule for ZEV				
	10%	25%	50%	75%	100%
Box trucks, vans, two-axle buses, yard trucks	2025	2028	2031	2033	2035
Work trucks, day cab tractors, three-axle buses	2027	2030	2033	2036	2039
Sleeper cab tractors and specialty vehicles	2030	2033	2036	2039	2042

Notes:
(1) Source: CARB. September 9, 2021. Advanced Clean Fleets Regulation Workshop. https://ww2.arb.ca.gov/sites/default/files/2021-09/210909acfpres_ADA.pdf. A new version was released May 4, but there were no significant changes relative to Public Fleets.

Other Drivers – Energy Resilience and Funding

Senate Bill 1440 – Mandatory Procurement of Biomethane from Publicly Owned Treatment Works

In 2018, the California legislature passed SB 1440, with the objective to explore how California's gas delivery system can support the delivery of biomethane and require the Public Utilities Commission (PUC) to consider adopting biomethane procurement targets for electricity providers in order to reduce the state's reliance on fossil natural gas.

The PUC issued a decision extending and implementing the procurement program in February 2022.The proposal requires the Joint Utilities to procure biomethane produced from organic waste for their core customers to support California's statutory obligation to divert 75 percent of 2014 organic waste levels away from state landfills by January 1, 2025. To be eligible to contract with an investor-owned utility, biomethane producers would have to meet several eligibility conditions and provide biomethane at cost-effective rates.

This program creates a reliable market and security for producers of biogas.

Climate Change Vulnerability Assessment and Resilience Planning

In March of 2017, the State Water Board adopted its Comprehensive Resolution on Climate Change, outlining approximately 30 actions to mitigate and adapt to a changing climate. Two of these actions relate to assessing the vulnerability of wastewater treatment systems to climate change impacts via NPDES/waste discharge requirement permit renewals and developing resilience plans to mitigate those impacts. As DSRSD is preparing its permit renewal package, a special study will likely be included requiring a climate change vulnerability assessment (considering each weather-related natural hazard as identified in the *Tri-Valley Local Hazard Mitigation Plan*) and development of a resilience plan within 12 months of the permit renewal being approved.

1.6 Current Electricity Consumption

This section summarizes the current electricity use at DSRSD's facilities along with a more detailed breakdown of the current consumption for different end uses at DSRSD's WWTP.

The facilities included in the energy evaluation in this Energy Facilities Master Plan include the following:

1. WWTP, including the Lab HVAC, fleet maintenance building, and service aerators for the sludge lagoons.
2. Recycled Water Treatment system (DERWA).
3. Recycled water pumping station PSR1 (DERWA).
4. DERWA recycled water distribution system.
5. DSRSD recycled water distribution system.
6. Potable water distribution system.
7. LAVWMA export pump station.
8. Field Operation Facility.
9. District Administrative Building.

Note that the energy consumption for DERWA and LAVWMA are proportioned based on flow from each partner agency. For example, the energy costs for the LAVWMA effluent pump station are shared amongst the City of Livermore, DSRSD and City of Pleasanton, in proportion to each partner agency's flows that are exported by LAVWMA. Based on the flow data from 2021, DSRSD's share of the variable costs for the operation of LAVWMA and DERWA (including energy) is approximately 60 percent and 70 percent, respectively.

1.6.1 Baseline Electricity Demand Results

DSRSD's electricity demand is supplied through purchases from PG&E and onsite production from its cogeneration system which is fed with digester biogas and natural gas purchased from PG&E.

The following sections describe the baseline electricity demand for the following nine facilities:

1. WWTP.
2. DERWA Recycled Water Treatment Plant.
3. DERWA PSR1.
4. DERWA Recycled Water Distribution System (R100, R200, PS R200A, PS R200B).
5. DSRSD Recycled Water Distribution System (R20, R300, PS R20, PS R300A, PS R300B).
6. LAVWMA Export Pump Station.

7. Potable Water Distribution.
8. District Administrative Building.
9. Field Operations Facility.

1.6.1.1 Wastewater Treatment Plant

Figure 1.22 shows the monthly electricity consumption at the WWTP (excluding PSR1, the Recycled Water Treatment Plant, and the LAVWMA pump station) provided by PG&E and/or cogeneration. The electricity demand has remained fairly stable over time, though there are some outlier months.

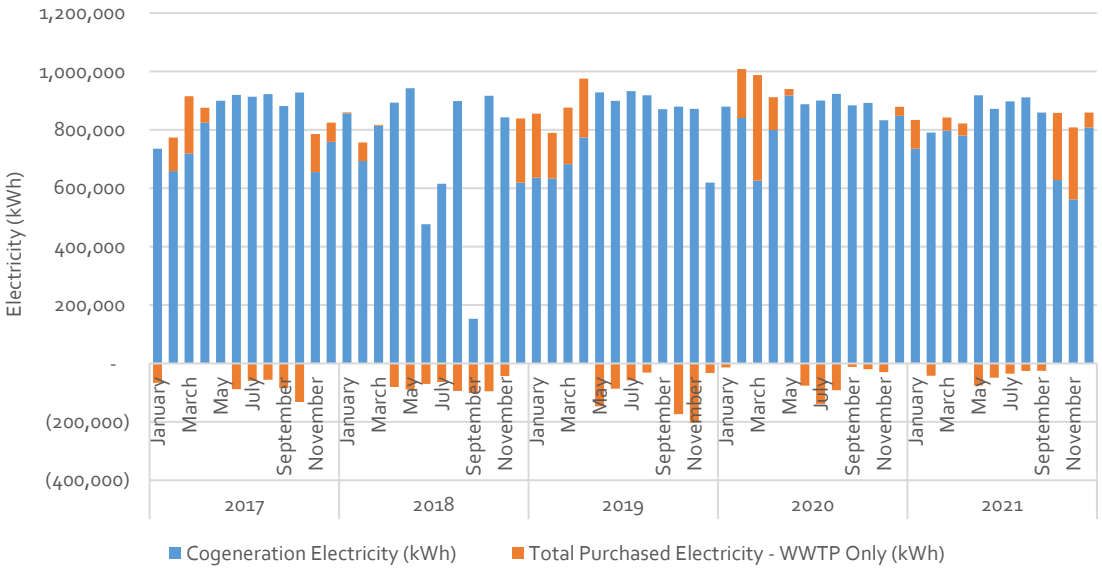


Figure 1.22 Monthly Electricity Consumption at the WWTP (2017 to 2021)

In 2021, DSRSD's total electrical demand (purchased electricity from PG&E plus electricity generated through cogeneration) for the WWTP was approximately 10,020 megawatt-hours (MWh); of this total electrical demand, 9,561 MWh, or approximately 95 percent of the WWTP total electrical demand was produced through cogeneration.

By analyzing the mechanical equipment within the WWTP, an alternative method for determining the electricity consumption at the WWTP was also performed. Figure 1.23 and Figure 1.24 present the inventory of all mechanical equipment at the WWTP with a power rating of more than 5 hp. Motors less than 5 hp were excluded from this analysis because it was assumed their electrical loads had minimal impacts on the WWTP's overall electrical demands. Based on the estimated average annual runtimes of each equipment in 2021, the estimated electricity consumption of each equipment was calculated and then compared to the aggregated electricity consumption, by process area, to the total billed electricity for the WWTP in year 2021 by PG&E. For the equipment that is metered and for which data is available in DSRSD's electrical monitoring software, Foreseer, actual power consumption data was used.

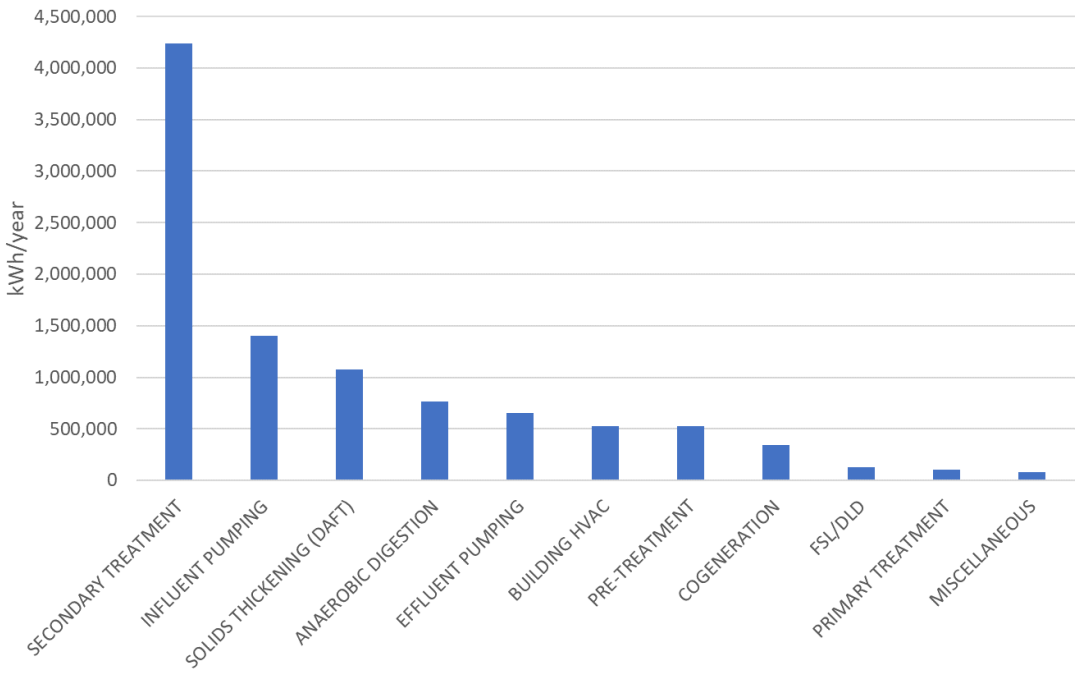


Figure 1.23 Estimated Electricity Consumption by Process Area at the WWTP (2021)

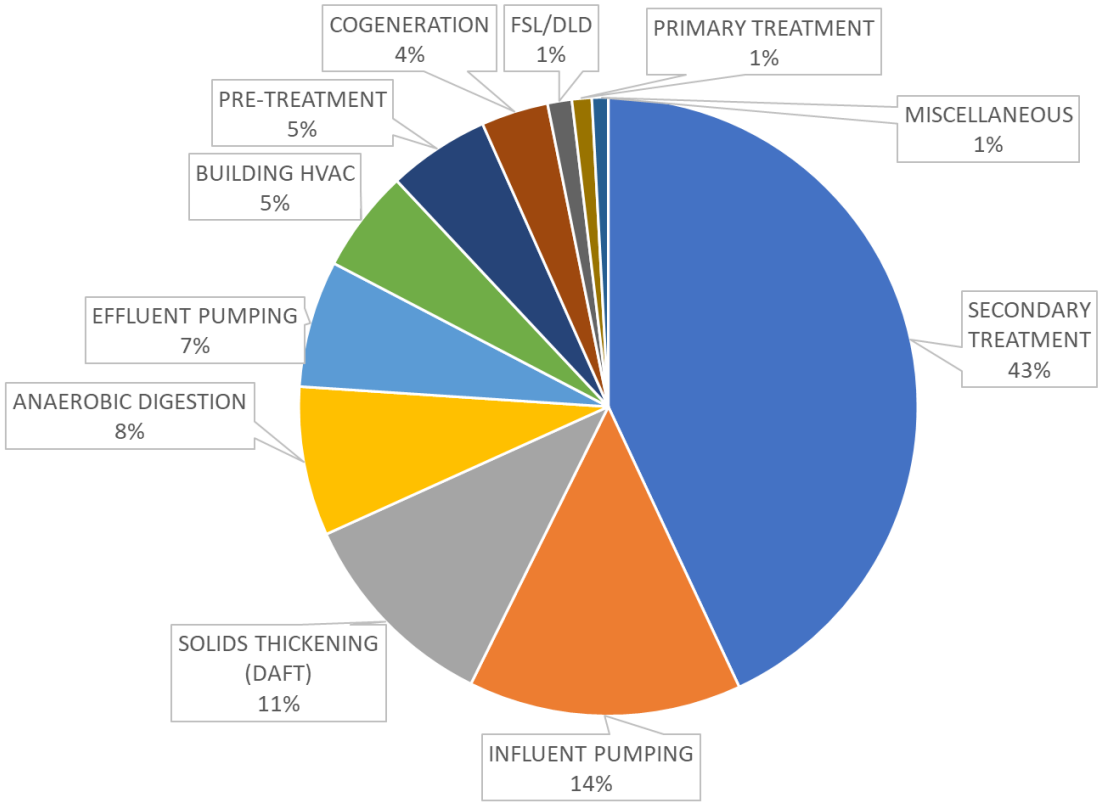


Figure 1.24 Relative Electricity Consumption by Process Area at the WWTP in (2021)

The total aggregated power consumption based on all WWTP equipment runtime in 2021 amounts to approximately 9,840 MWh/year. In comparison, the power consumption for the WWTP in 2021 based on billings from PG&E and 100 percent of the power produced by cogeneration totaled 10,020 MWh/year.

Based on the annual average data for 2021, several energy metrics were calculated for the WWTP (Table 1.16).

Table 1.16 Energy Metrics for the DSRSD WWTP (2021 Average)

Energy Metric	Units	2021 Average	Industry Range for Comparison	Reference
Electricity consumption per flow treated (excluding effluent pumping)	kWh/ 1,000 gallons	2.3(1)	2.0(5)	EPRI 2013
Electricity consumption per organic carbon load treated (WWTP)	kWh/pounds $cBOD_5$	1.12(2)	0.2-2.2(6)	Pennsylvania Department of Environmental Protection 2011
Electricity consumption per organic carbon load treated (secondary treatment)	kWh/pounds $cBOD_5$	0.9(3)	Not available	
Electricity consumption by solids handling processes per solids handled	kWh/pounds solids processed	0.1(4)	Not available	

Notes:
EPRI - Electric Power Research Institute.
(1) Based on 11.5 mgd ADAF in 2021 and 10.02 million kWh/year does not include LAVWMA pumping.
(2) Based on 24,100 ppd average influent $cBOD_5$ in 2021 and 10.02 million kWh/year.
(3) Based on 12,500 primary effluent cBOD load in 2021 and a total electricity consumption of 4,263 MWh in 2021 for the secondary treatment (mixers, blowers, WAS pumps, RAS pumps, secondary clarifiers, and scum pumps.
(4) Assumes an average of 53,415 ppd TSs in DAFT overflow in 2021 and an electricity consumption of 1,938 MWh for solids treatment (including DAFT, digestion, and FSL/DLDs).
(5) Weighted average electricity use for facilities with an average daily flow range of 7-16 mgd or which 59 percent were nitrifying. Source: EPRI and Water Research Foundation. November 2013. *Electricity Use and Management in the Municipal Water Supply and Wastewater Industries*.
(6) Electricity consumption per BOD loading for conventional activated sludge facilities with a design flow of more than 5 mgd. Source: Pennsylvania Department of Environmental Protection. March 2011. *Electric Use at Pennsylvania Sewage Treatment Plants*.

1.6.1.2 Recycled Water Treatment Plant, DERWA Recycled Water Distribution System, Pump Station R1, and DSRSD Recycled Water Distribution System

Figure 1.25, Figure 1.26, Figure 1.27, and Figure 1.28 show the monthly electricity demand at the recycled water treatment plant, PSR1, the DERWA recycled water distribution system, and the DSRSD recycled water distribution system, respectively. The monthly electricity demand generally follows the seasonal pattern of recycled water demand, production, and distribution. The recycled water treatment plant and PSR1 are DERWA facilities. The recycled water distribution system infrastructure is owned by either DERWA or DSRSD. DSRSD's recycled water distribution system includes reservoirs R20 and R300 and pump stations R20, R300A and R300B. DERWA's recycled water distribution system includes reservoirs R100 and R200, and pump stations R200A, and R200B. DSRSD's share of the electrical demand of the DERWA facilities

(recycled water treatment plant, PSR1, and DERWA's portion of the recycled water distribution system) is approximately 70 percent.

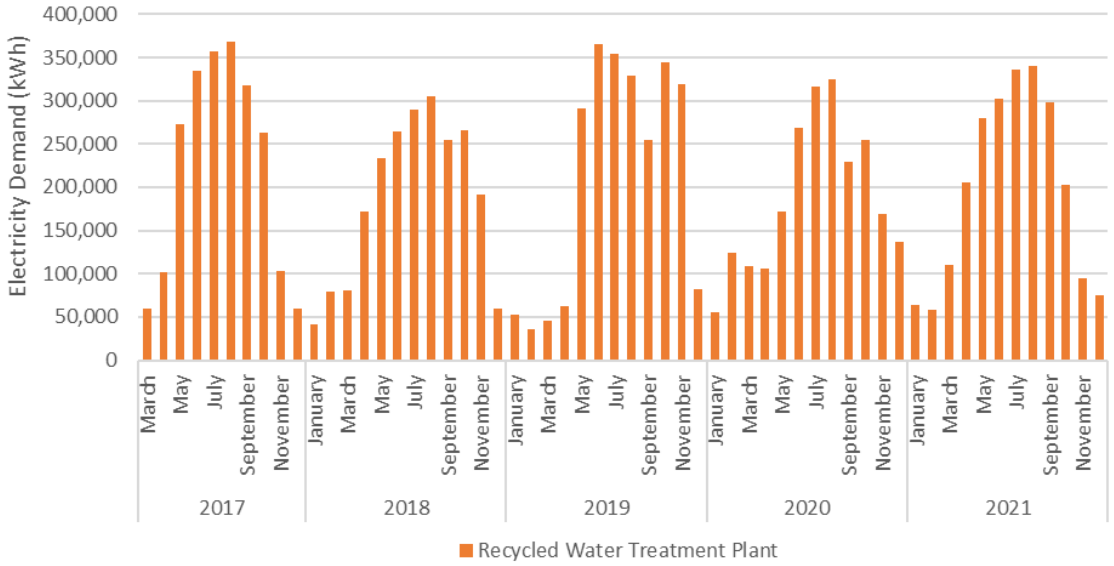


Figure 1.25 Monthly Electricity Consumption for the Recycled Water Treatment Plant (2017 to 2021)

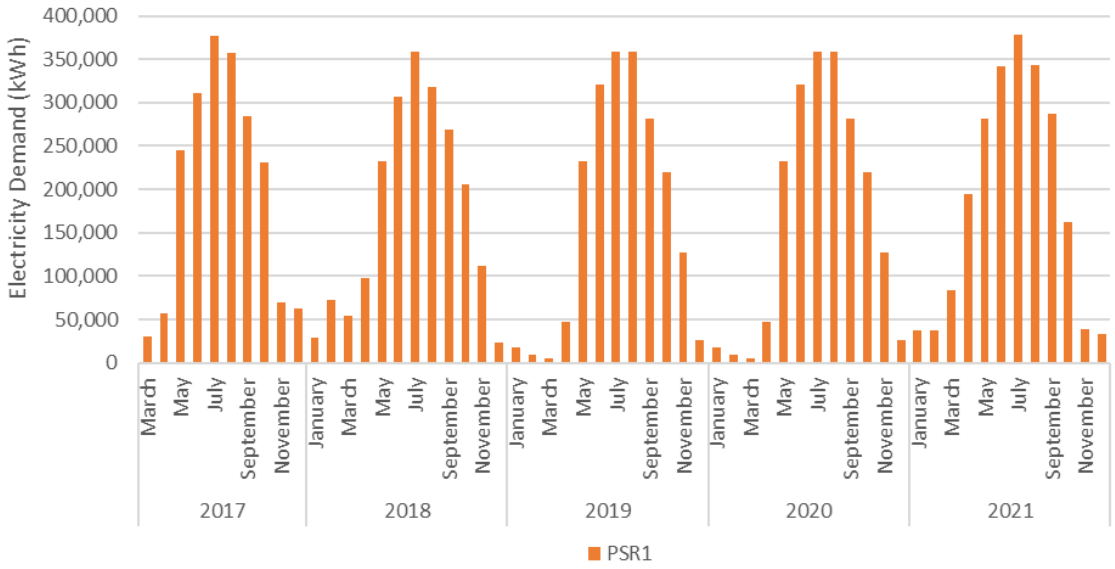


Figure 1.26 Monthly Electricity Consumption for PSR1 (2017 to 2021)

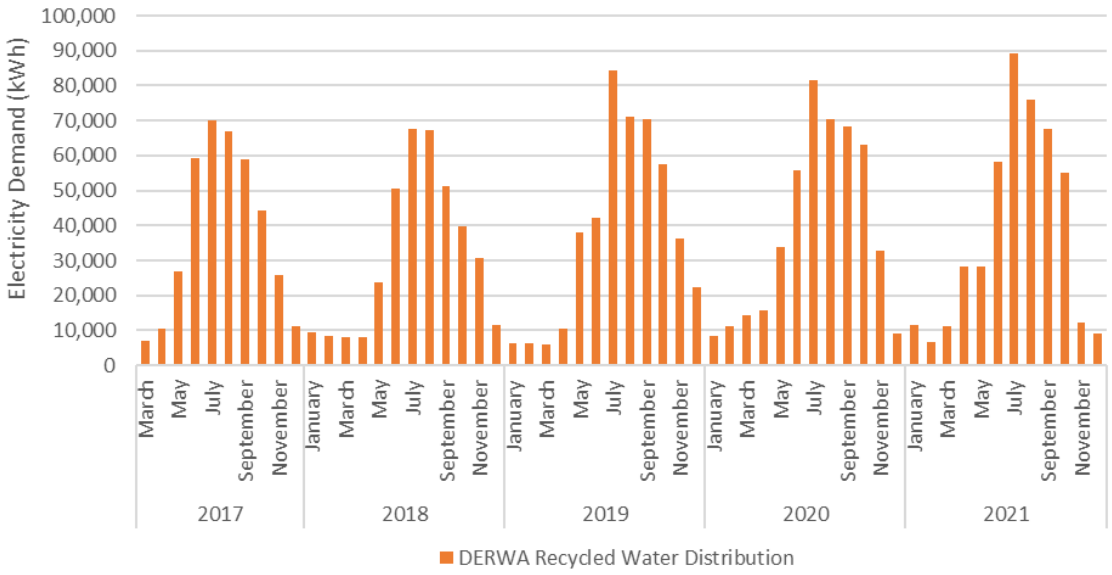


Figure 1.27 Monthly Electricity Consumption for the DERWA Recycled Water Distribution System (2017 to 2021)

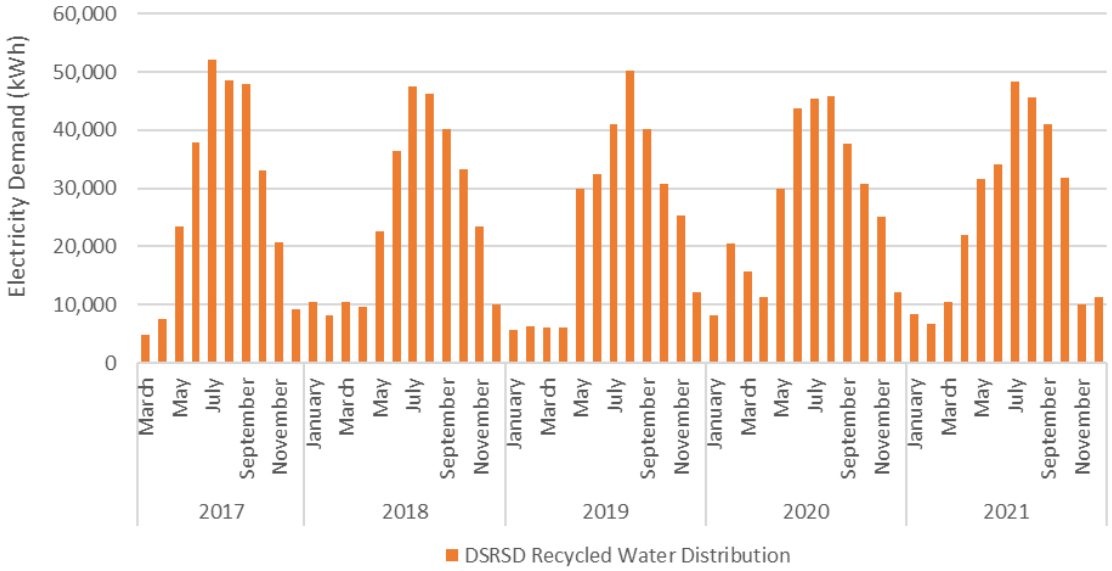


Figure 1.28 Monthly Electricity Consumption for the DERWA Recycled Water Distribution System (2017 to 2021)

In 2021, DSRSD's total electrical demand for the DSRSD recycled water distribution system was approximately 301 MWh.

Table 1.17 summarizes the 2021 electrical demands for the DERWA recycled water facilities, as well as DRSRD's proportionate share, calculated as 70 percent of the total based on its proportion of recycled water deliveries. In 2021, the total electrical demand for the operation of the DERWA recycled water facilities (recycled water treatment system, PSR1 and the DERWA recycled water distribution system) was approximately 5,040 MWh. Based on actual deliveries of

recycled water received in 2021, DSRSD's proportionate share of the DERWA recycled water facilities electrical demand was approximately 3,528 MWh.

Table 1.17 2021 Electrical Demands for DERWA Recycled Water Facilities

Facility	2021 Electrical Demand (MWh)	DSRSD's portion of Electrical Demand (MWh)
Recycled water treatment plant	2,367	1,657
PSR1	2,219	1,554
DERWA recycled water distribution system	454	317
Total	5,040	3,528

Notes:
(1) DSRSD's proportionate share of the DERWA facilities electrical demand was calculated as 70 percent of the total based on its proportion of recycled water deliveries.

Annual energy use for 2017 to 2021 for the recycled water treatment plant and the recycled water distribution systems (inclusive of PSR1 and the DSRSD and DERWA recycled water distribution systems) per million gallons of recycled water demand (kWh/MG) is summarized in Figure 1.29. Recycled water demand is used rather than recycled water supplied because DSRSD has more accurate tracking of demand, and to facilitate the comparison of kWh/MG use for recycled water treatment and distribution using the same volume benchmark. Demand includes recycled water used by DSRSD, East Bay Municipal Utility District, and Pleasanton customers. Annual water demand and energy use are based on DSRSD annual reporting to DERWA.

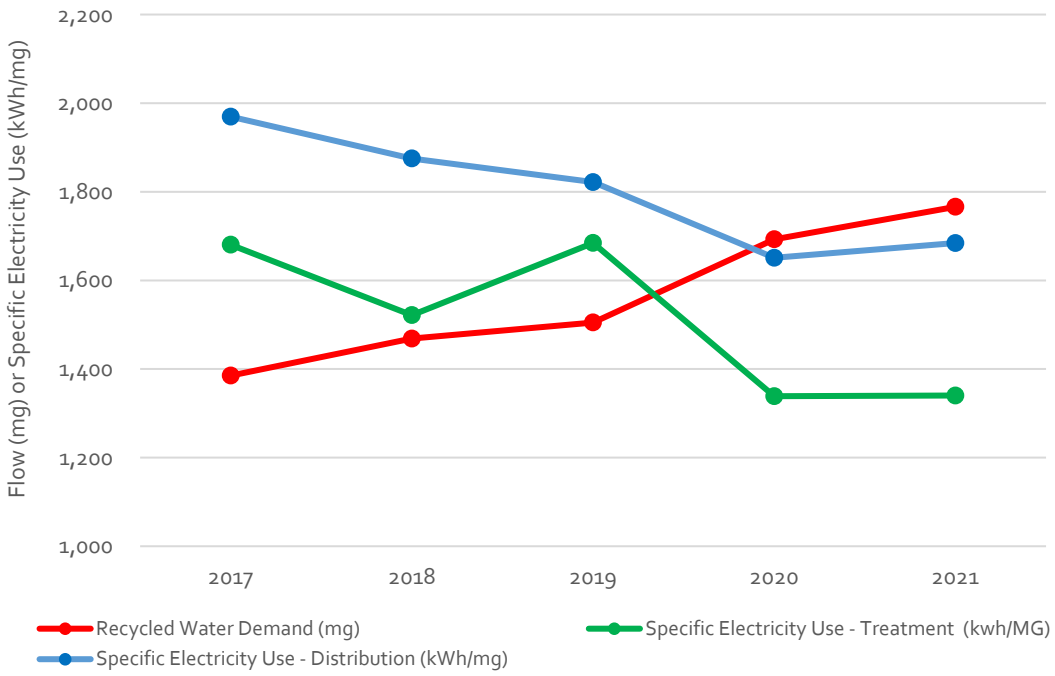


Figure 1.29 Recycled Water Treatment and Distribution Annual Energy Use per MG (2017 to 2021)

As shown in Figure 1.29, recycled water demand has increased over 25 percent in the past five years. The energy use for treatment per mg has decreased over 20 percent over the same period as a result of several energy efficiency measures (see Sections 1.11.3 and 1.11.4). Recycled

water distribution system energy use per gallon treated has also decreased by almost 15 percent over the past five years. The decrease in specific energy use appears to be due to increased demand in pressure zone 1 compared to the higher-pressure zones. Pumping to pressure zone 1 requires less pumping and therefore less energy than pumping to the higher-pressure zones.

Figure 1.30 summarizes the shift in annual demand by pressure zone over the past five years.

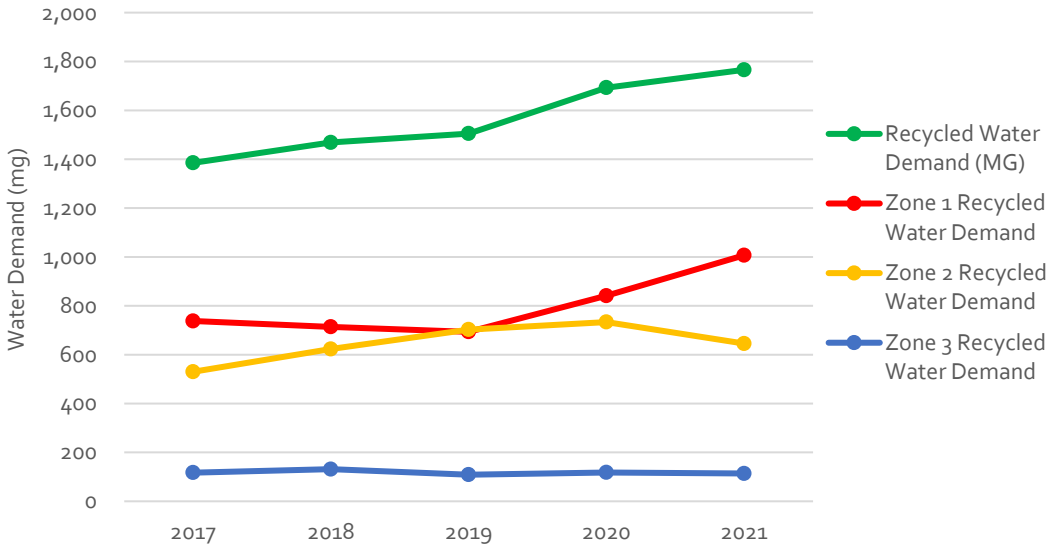


Figure 1.30 Recycled Water Distribution Annual Demand by Zone (2017 to 2021)

1.6.1.3 Potable Water Distribution System

Figure 1.31 shows the seasonal electricity demand for the potable water distribution system. In 2021, DSRSD's total electrical demand for the water distribution system was approximately 3,918 MWh.

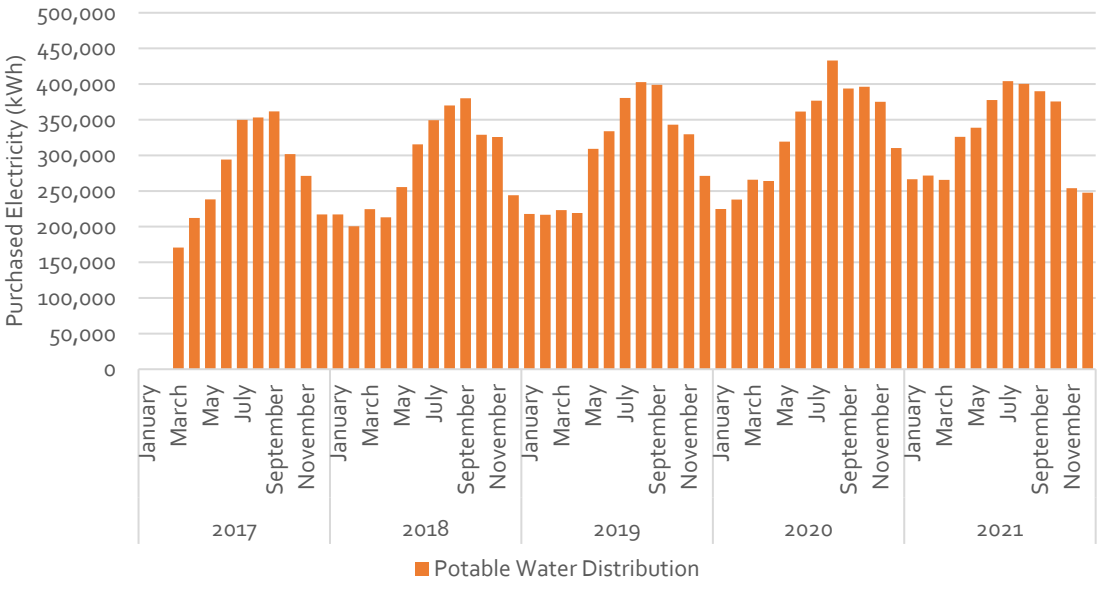


Figure 1.31 Monthly Electricity Consumption for the Potable Water Distribution System (2017 to 2021)

Annual energy use for 2017 to 2021 for the potable water distribution system per million gallons of water supplied (kWh/MG) is summarized in Figure 1.32. Annual water demand is based on Zone 7 water billing. Annual energy use is based on the sum of all PG&E bills for DSRSD potable water facilities with a bill end date in a given calendar year.

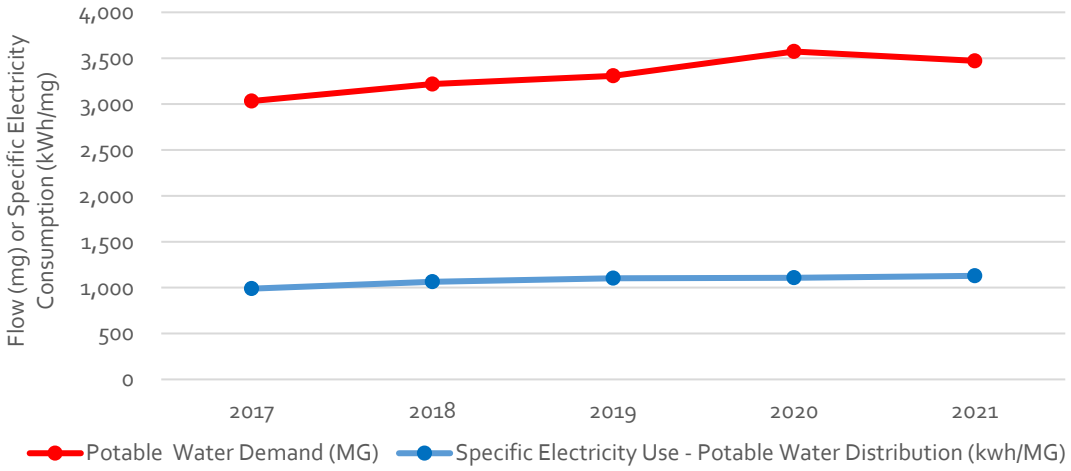


Figure 1.32 Potable Water Distribution Annual Energy Use per MG (2017 to 2021)

As shown in the figure, the amount of potable water supplied by the District has increased over 10 percent in the past five years, from approximately 3,000 MG in 2017 to approximately 3,500 MG in 2021. The specific electricity consumption (energy use per MG supplied), however, has remained fairly constant at approximately 1,000 kWh/MG.

1.6.1.4 LAVWMA Export Pump Station

Figure 1.33 shows the seasonal electricity demand for the LAVWMA Export Pump Station. In 2021, the total electrical demand for the operation of the LAVWMA Export Pump Station was approximately 7,230 MWh.

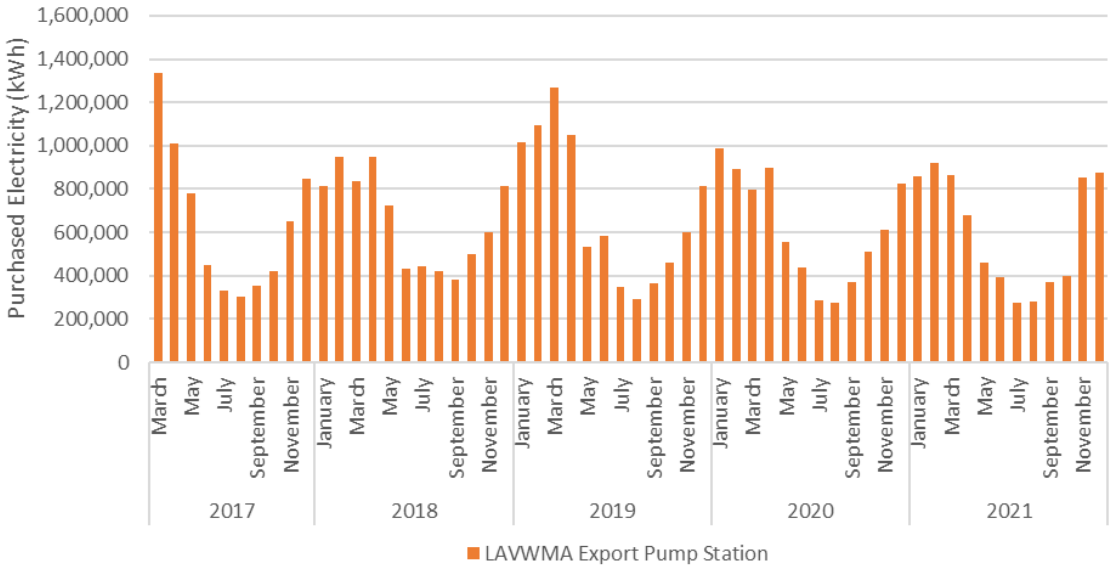


Figure 1.33 Monthly Electricity Consumption for the LAVWMA Export Pump Station (DSRSD and LAVWMA) (2017 to 2021)

Based on the quantities of secondary effluent received at the export pump station from each member agency in 2021, DSRSD's proportionate share of the total electrical demand for operating the LAVWMA export pump station was approximately 60 percent of the total annual electrical demand, or approximately 4,338 MWh.

1.6.1.5 District Administrative Building and Field Operations Facility

Figure 1.34 and Figure 1.35 show the monthly electricity consumption for the District's Administrative Building and the Field Operations Facility, respectively. In 2021, DSRSD's District Administrative Building used approximately 291,400 MWh and the Field Operations Facility used approximately 272,400 MWh for a total electrical demand for both administrative buildings of approximately 564,000 MWh. The District's Administrative Building was unoccupied from approximately December 2018 to April 2020.

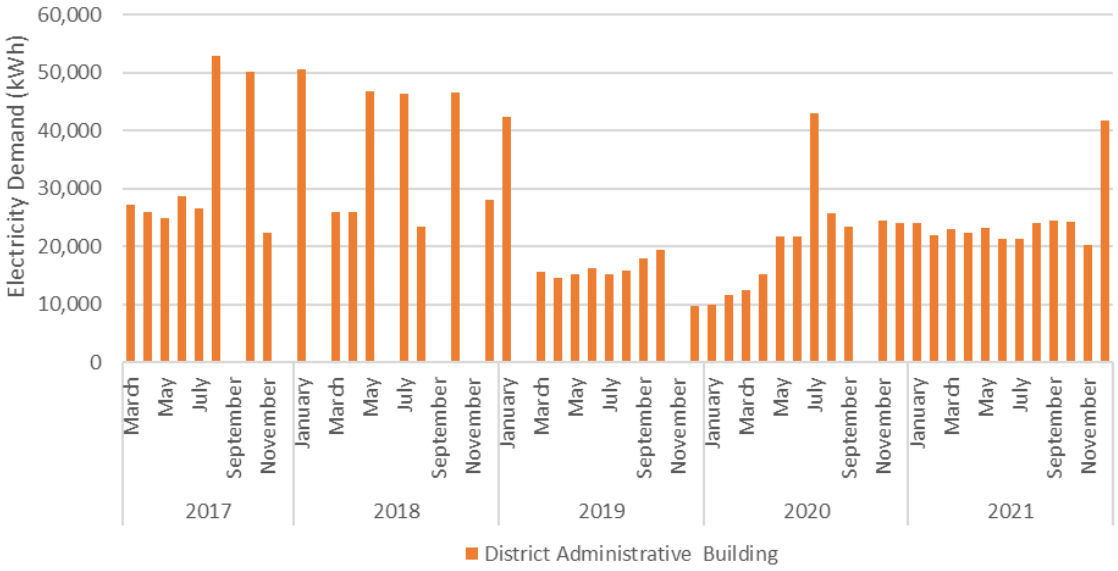


Figure 1.34 Monthly Electricity Consumption for the District's Administrative Office (2020 to 2021)

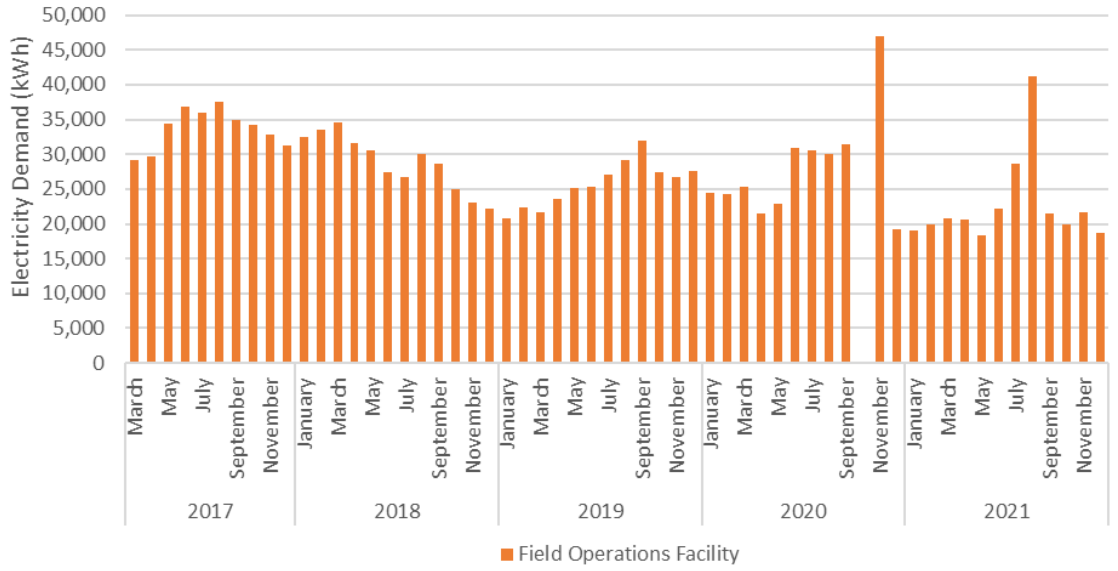


Figure 1.35 Monthly Electricity Consumption for the Field Operations Facility (2020 to 2021)

1.6.1.6 Summary of the 2021 Baseline Electricity Demand Results

Figure 1.36 shows the total annual electricity consumption across all nine facilities – WWTP, Recycled Water Treatment Plant, PSR1, DERWA Recycled Water Distribution System, DSRSD Recycled Water Distribution System, Potable Water Distribution System, LAVWMA export pump station, District Administrative Building and the Field Operations Facility – over the past five years. This data includes all purchased electricity *plus* total electricity production generated by cogeneration.

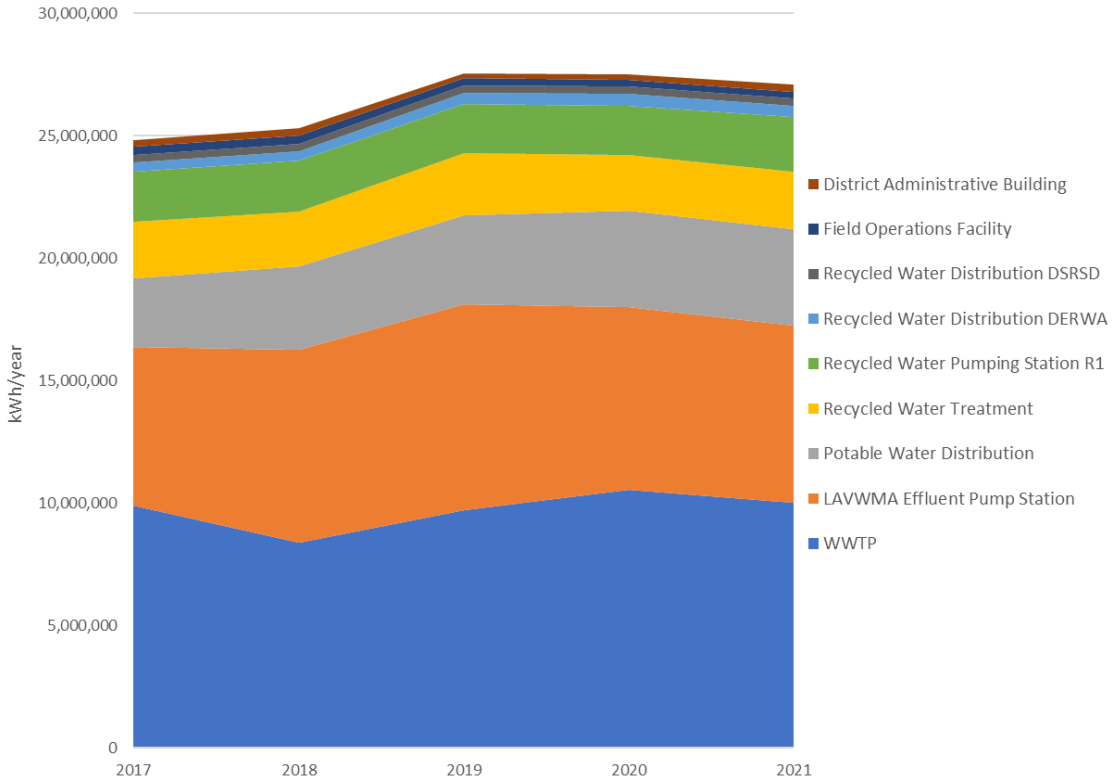


Figure 1.36 Total Annual Electricity Consumption

For simplicity, the cogeneration-produced electricity consumption was attributed entirely to the WWTP. In reality, a small portion of this produced electricity is provided to DERWA's recycled water treatment facilities when needed. Calculating this fraction is not straightforward because of the current data collection and meter installations.

As shown in Figure 1.36, starting in 2019, electricity consumption for all the facilities has increased to approximately 27 gigawatt-hours (GWh) and has remained relatively constant through 2021. When accounting for only DSRSD's share of the total electrical demand for the JPA facilities (e.g., 60 percent for LAVWMA, 70 percent for DERWA), in 2021, DSRSD's total electrical demand was approximately 22 GWh.

Figure 1.37 compares the same data shown in Figure 1.36 as a bar chart to better illustrate the relative electricity consumption across the facilities. About 65 percent of the total electricity is used by the WWTP and LAVWMA effluent pump station. Refer to Appendix 1A for a complete list of all PG&E electricity account numbers associated with each of the nine facilities.

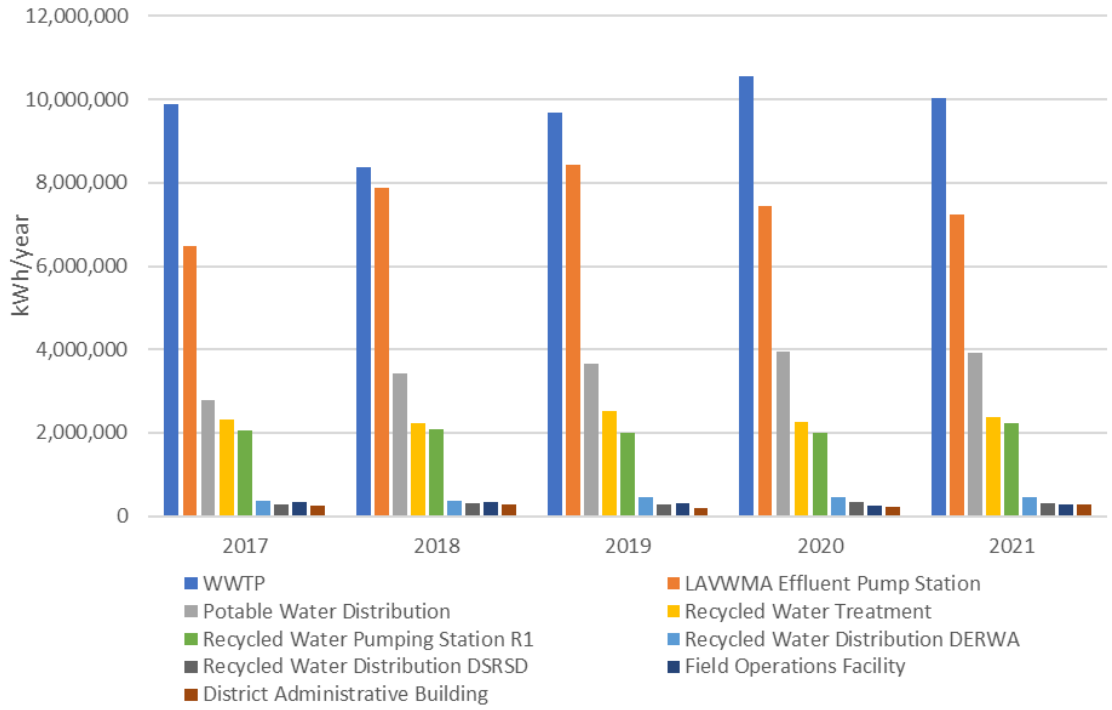


Figure 1.37 All Facilities Annual Electricity Consumption

1.6.2 Electricity Purchases Through Pacific Gas & Electric Company

1.6.2.1 Electrical Rate Structure and Cost Impacts

DSRSD's accounts fall under various rate categories under PG&E's programs. The electrical rates under each rate category vary by the time of the day and seasonally. They are also periodically updated.

DSRSD is also enrolled in the Community Choice Aggregation (CCA) program and receives for two account numbers (9824217199 – Sewer Collection System, and 713296436 – Potable Water System Reservoir 3A) CCA electricity purchased within DSRSD's community.

The electricity billing categories for DSRSD's account includes the following components that can be separated into fixed costs and demand dependent costs:

- *Fixed cost categories:*
  - Service and reservation charges: These are fixed costs based on the number of billing days in a specific billing period.
  - Generation credit: The amount PG&E would have charged for electric generation that becomes a credit for CCA customers.
  - Energy commission tax.
  - Reactive power charge: These charges are based on peak reactive demand in kilovolt-amperes reactive (kVAR) and applied by the distribution network operator to DSRSD and are charged for reactive power, which is the difference between the electricity supplied and the electricity converted into useful power at a given site due to lower power factor (losses).

- *Demand dependent cost categories:*
  - Energy charges (peak, part, off): These charges are billed based on the kWh used and capture the costs of electricity consumption. The peak energy charge is calculated based on the single highest 15-minute demand period during each billing cycle measured in kWh. Actual electricity consumption (in kWh) is tracked monthly but billed annually in July.
  - Demand charges (max, peak, part): These charges are based on the peak electrical real power demand (in kW). The peak demand charge is calculated based on the single highest 15-minute demand period during each billing cycle measured in kW. These charges capture the fixed costs of power plants to provide the needed power capacity.

Figure 1.38 shows exemplary each cost components as a fraction of the total monthly electricity bills between January 2021 and February 2022 for the largest consumptive use at the WWTP (account number 4053823994). Note that the energy usage charges (i.e., the energy commission tax and the peak, part, and off energy charges) are shown as monthly charges but are billed annually, as discussed above. The illustration shows that, on average, more than 90 percent of the electrical costs are tied to demand dependent cost categories. In August 2021, for example, total fixed costs were approximately $5,000 and total demand dependent charges (i.e., energy and demand charges) were approximately $162,000. In this example, demand dependent cost categories accounted for approximately 97 percent of the total electrical bill. The monthly electrical costs vary between about $40-60k in winter months to $140-160k in summer months, even though wastewater flows and loads are quite consistent throughout the year.

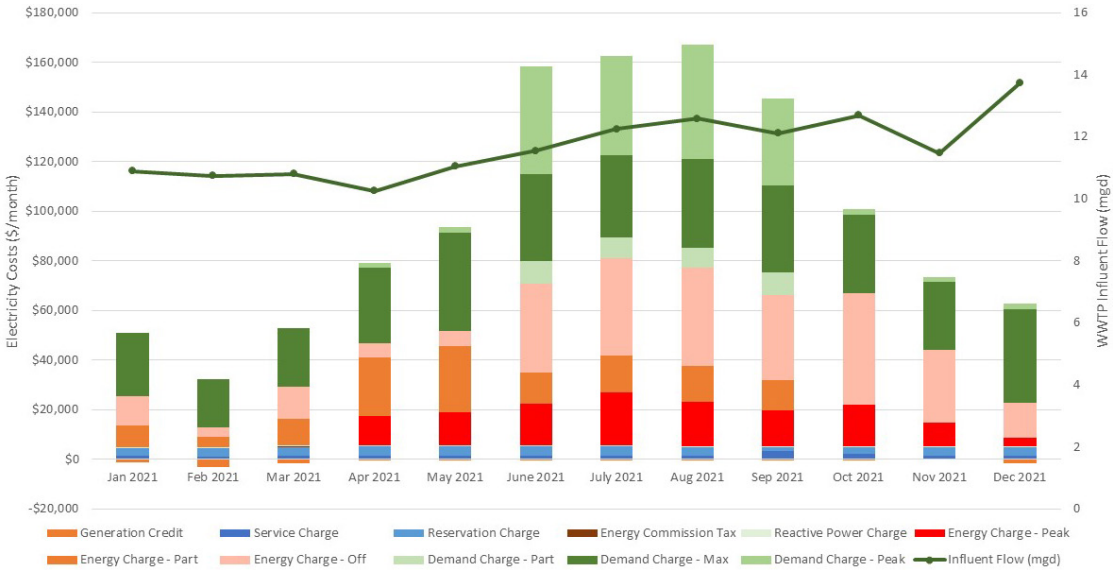


Figure 1.38 Monthly Electricity Bill Cost Components (January 2021 to February 2022)

1.6.2.2 Baseline Pacific Gas & Electric Company Costs

Figure 1.39 shows DSRSD's total annual electrical costs, by facility. Figure 1.40 shows DSRSD's share of the electrical costs, by facility. In 2021, DSRSD spent approximately $3.72 million for purchased through PG&E. Of this total, approximately $1.24 million and $1.30 million were electricity purchases to operate DERWA and LAVWMA facilities, respectively. The District's proportion share for these variable costs were approximately $830,000 and $780,000, respectively, for an approximate total of $1.61 million. DSRSD's electricity costs, including its proportionate share for the operation of the JPA facilities, was approximately $2.85 million. Excluding its proportionate share for the operation of the JPA facilities, DSRSD's total electrical cost was approximately $1.24 million.

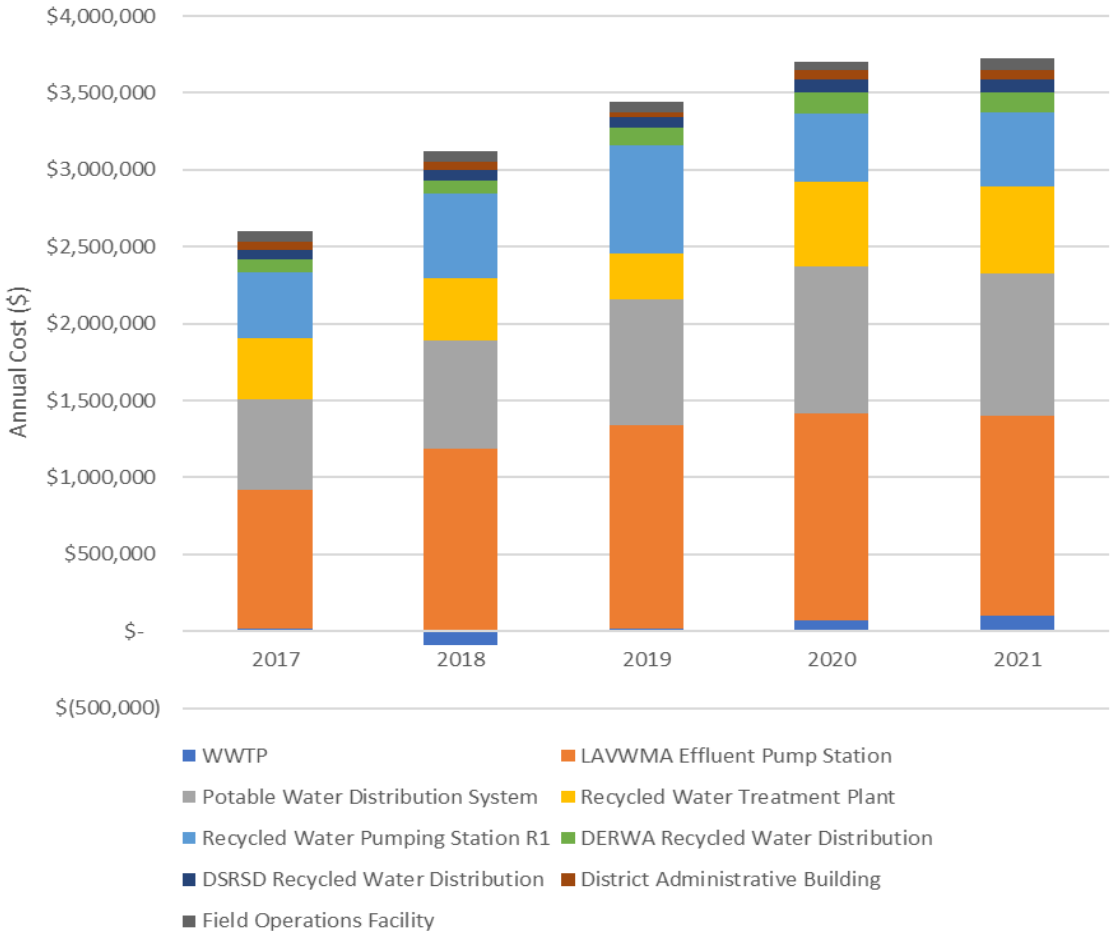


Figure 1.39 Total Annual Electricity Costs Purchased From PG&E by Facility (2017 to 2021)

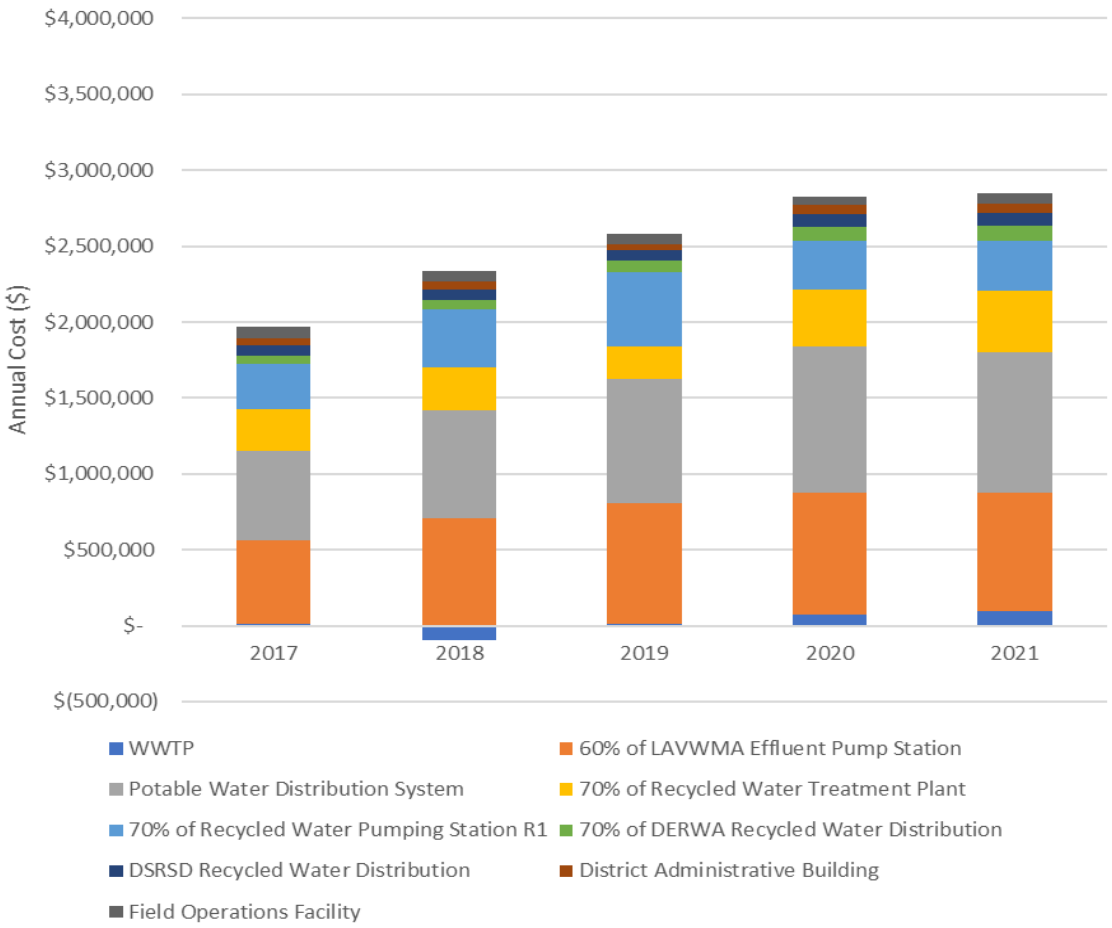


Figure 1.40 DSRSD's Share of Annual Electricity Costs Purchased From PG&E by Facility (2017 to 2021)

Figure 1.41 shows the breakdown between total purchased electricity for all nine facilities (in orange) and electricity produced by cogeneration (in blue), by month, over the past five years for all facilities. On average, DSRSD's cogeneration system, produces approximately 814 MWh per month, or approximately 9.8 GWh per year. (Note that the low data record for September 2018 cogeneration is incorrect and was therefore not included.). In 2021, approximately 65 percent of DSRSD's total electrical demand (excluding DSRSD's proportionate share for the operation of the JPA facilities) was met through electricity generated through cogeneration.

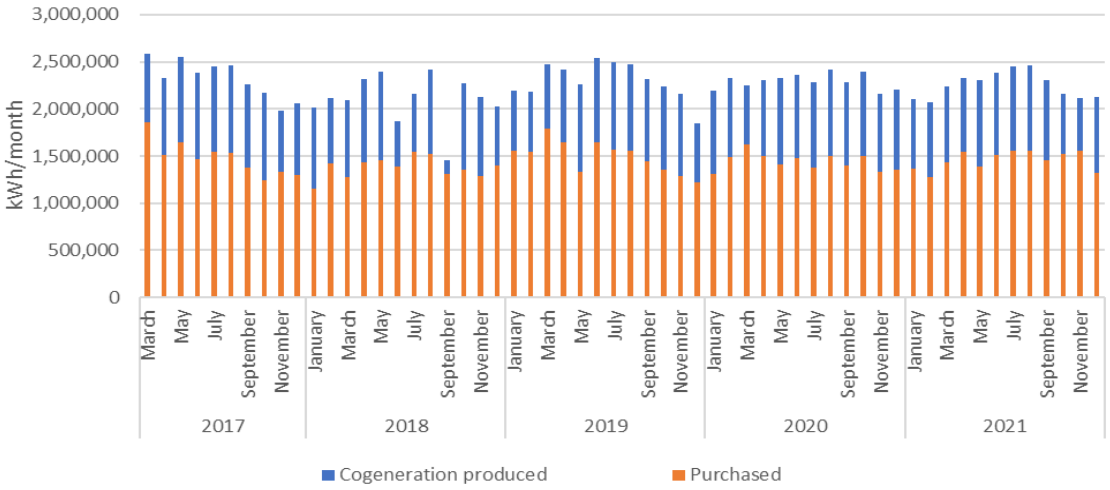


Figure 1.41 Electricity Purchased and Produced by Month (2017 to 2021)

1.6.2.3 Summary of the 2021 Pacific Gas & Electric Company Electricity Purchases

Table 1.18 summarizes the total billed electricity usage and charges across all facilities in 2021. Note that this table summarizes purchased electricity from PG&E only, and therefore excludes the electricity generated through cogeneration.

Table 1.18 District-Wide Electricity Billed Charges and Consumption

Facility	Account Numbers	2021 Total Charges	Total Usage (kWh)	2021 Total Charges/ Usage ($/kWh)
WWTP	221861436, 4053823994, 4772588550, 9710579242	$98,900	460,000	$0.22
Recycled Water Treatment Plant(1)	4053823994	$571,700	2,366,500	$0.24
PSR1(1)	4053823994	$477,300	2,219,500	$0.22
DERWA Recycled Water Distribution(1)	9527215162, 4336062954, 7149544256, 8671211128, 3048001111	$134,800	$134,800	$0.30
DSRSD Recycled Water Distribution	6741341553	$82,900	301,200	$0.28
Potable Water Distribution System	713296436, 6741341553, 6772573820, 9553855890	$925,400	3,917,500	$0.24
LAVWMA Pump Station(2)	8440395259, 8482061923	$1,298,800	7,230,400	$0.18
District Administrative Building	2472675499, 2514342163, 2753993276	$62,600	291,400	$0.21
Field Operations Facility	6772573820 (meter: 1010759964)	$70,500	272,400	$0.26
Total		**$3,722,800**	**17,512,400**	**$0.21**

Notes:
(1) DERWA Facility. DSRSD's proportionate share of the electrical demand and electrical cost are approximately 70 percent of the values shown in this table.
(2) LAVWMA Facility. DSRSD's proportionate share of the electrical demand and electrical cost are approximately 60 percent of the values shown in this table.

1.7 Current Primary Energy Consumption

This section summarizes and analyzes the consumption of primary energy sources at DSRSD. Primary energy is defined as energy found in nature that has not been converted by human processes to a different form of energy. Primary energy sources at DSRSD include diesel and gasoline used for the vehicle fleet, diesel used for FSL/DLD operations, and natural gas used for heating and cooling of buildings, heating of water, and as fuel in the cogeneration equipment.

1.7.1 Diesel and Gasoline

DSRSD's vehicle fleet's inventory, mileage, and primary fuel consumption for 2021 are presented in Table 1.19 and Figure 1.42. In 2021, DSRSD's vehicle fleet included a total of 63 vehicles; 38 of these vehicles were actively used on a regular basis. In total, these vehicles traveled approximately 80,000 miles and consumed 9,350 gallons and 630 gallons of gas and diesel, respectively.

Table 1.19 Vehicle Fleet Fuel Usage

Vehicle Class	Number in Fleet (2021)	Fuel Type	2021 Annual Vehicle Miles Traveled	2021 Total Fuel Consumption (gallons)
Heavy-Duty Truck	17	Gasoline	49,530	6,780
Light-Duty Truck	11	Gasoline	20,500	1,760
Passenger Car	4	Gasoline	4,820	380
Heavy-Duty Truck	3	Diesel	1,800	630
Heavy-Duty Van	2	Gasoline	1,590	340
Passenger Van	1	Gasoline	1,970	100
Total	**38**	**-**	**80,204**	**9,976**

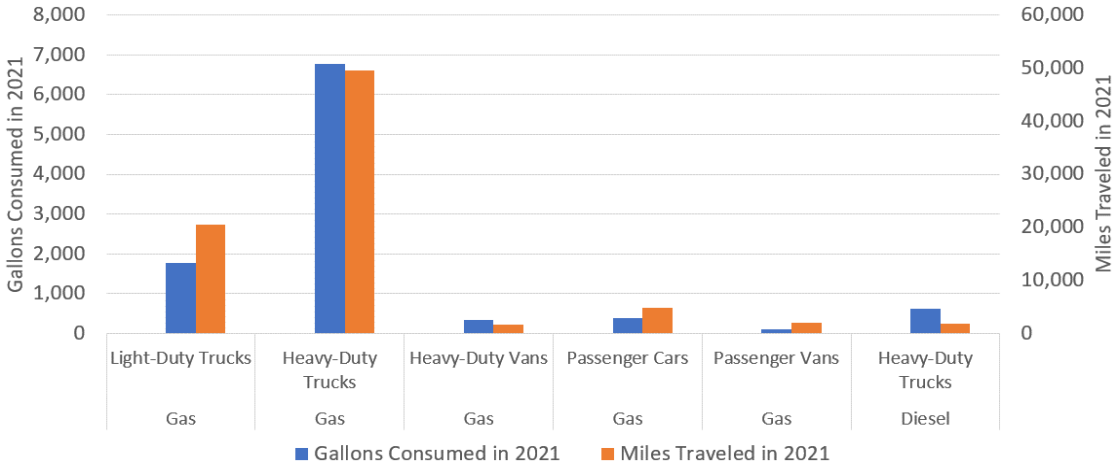


Figure 1.42 Vehicle Fleet Gasoline and Diesel Fuel Consumption (2021)

In addition, DSRSD has approximately 25 additional vehicles that are not typically used and for which mileage and fuel consumption data was not provided.

As shown in Figure 1.42, the diesel, heavy-duty trucks consumed the most fuel relative to their mileage (2.9 miles per gallon). The gas passenger van consumed the least with an overall

efficiency of 19.7 miles per gallon in 2021. The GHG emissions associated with this fuel use are discussed in Section 1.10. Fuel consumption for fleet use has only been tracked by DSRSD for one year, therefore historical trends cannot be shown.

DSRSD also uses diesel in the equipment used to dredge the FSLs. One FSL is dredged every summer using a dredge boat and a centrifugal pump, both of which use diesel. In 2021, 3,306 gallons of diesel were used to dredge one FSL.

DSRSD also uses diesel in several on-site backup power generators. Neither fuel consumption nor generator run times have been tracked in past years. DSRSD has started this year to monitor this information, but consumption data is not yet available. Therefore, fuel consumption for generators was not included in this energy baseline analysis.

1.7.2 Natural Gas

Natural gas is used by DSRSD as a supplemental energy source for co-generation at the WWTP, supply for a natural gas-fueled boiler used as a backup for heating the digesters, heating and cooling of buildings, and water heating. Table 1.20 summarizes all PG&E end use account numbers and buildings to which natural gas is provided. The large majority (98 percent) of the purchased natural gas is used year-round for supplemental fuel to the cogeneration system.

Table 1.20 DSRSD Natural Gas End Uses and Account Numbers

Building / Address	Account Number	Type of Energy End Use	Annual Natural Gas Consumption (2021), Therms
WWTP Cogeneration	9876775750	Heat and Electricity generation, digester heating	706,080(1)
District Administrative Building, 7051 DUBLIN BLVD, DUBLIN	2514342163	Space heating and cooling, hot water	7,100
District Utility Building Gas, 7049 DUBLIN BLVD, DUBLIN	4170882011	Space heating, hot water (no air conditioning)	88
WWTP Fleet Office Maintenance Building, 7399 JOHNSON DR, PLEASANTON	4772588550	Space heating and cooling, hot water	2,170
Field Operations Facility, 7035 COMMERCE CIR, PLEASANTON	6772573820	Space heating and cooling, hot water	3,300
Total			718,770

Notes:
(1) The gas consumption for the cogeneration calculated for this account number is about 6 percent higher compared to the natural gas consumption tracked by DSRSD for the three individual cogeneration engines (documented as standard cubic feet [scf] and equivalent to 667,920 therms in 2021). DSRSD states that the gas meters are not providing reliable measurements.

Figure 1.43 shows the monthly natural gas consumption for the three cogeneration engines Typically, the natural gas consumption remains fairly stable year-round at about 70,000 therms monthly. The natural gas feed drops noticeably off in winter months (November to April). DSRSD prioritizes burning all biogas first before external gas is purchased.

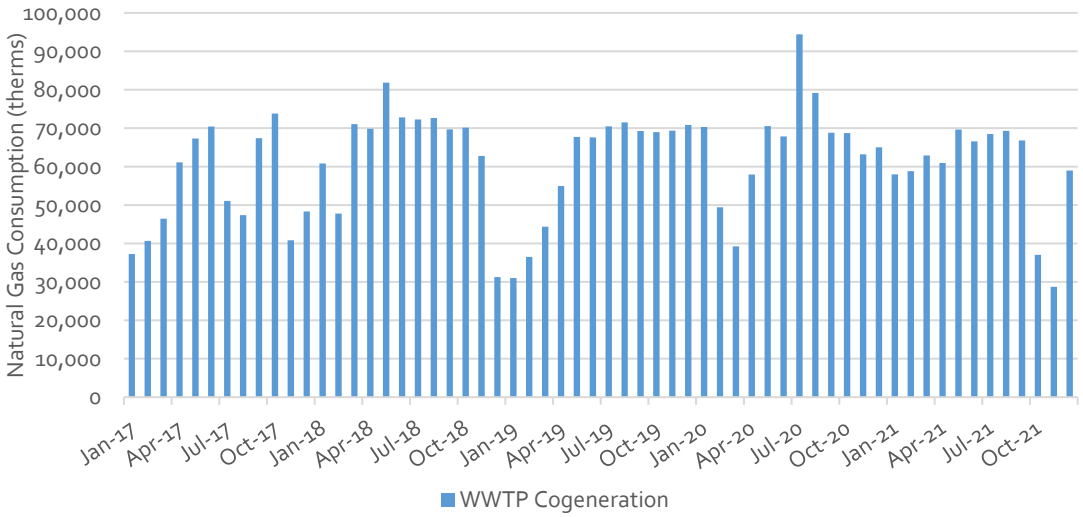


Figure 1.43 Monthly Natural Gas Consumption for Cogeneration (2017 to 2021)

The historical consumption of natural gas to each of the cogeneration engines is summarized in Table 1.21 and Figure 1.44. The quantity of natural gas burned in engine 2 is much lower than in the other two engines because engine 2 is primarily used to burn biogas.

Table 1.21 Historical Natural Gas Consumption by Cogeneration Engine (2017 to 2021)

Year	Engine 1 (scf)	Engine 2 (scf) (Lean Burn)	Engine 3 (scf)	Total Natural Gas Consumption (scf)
2017	26,615,900	2,050	36,618,410	63,236,380
2018	28,949,510	2,666,050	38,832,820	70,448,380
2019	26,080,440	0	35,289,490	61,369,930
2020	25,163,780	3,153,290	46,806,250	75,123,320
2021	25,085,810	493,210	38,830,200	64,409,220

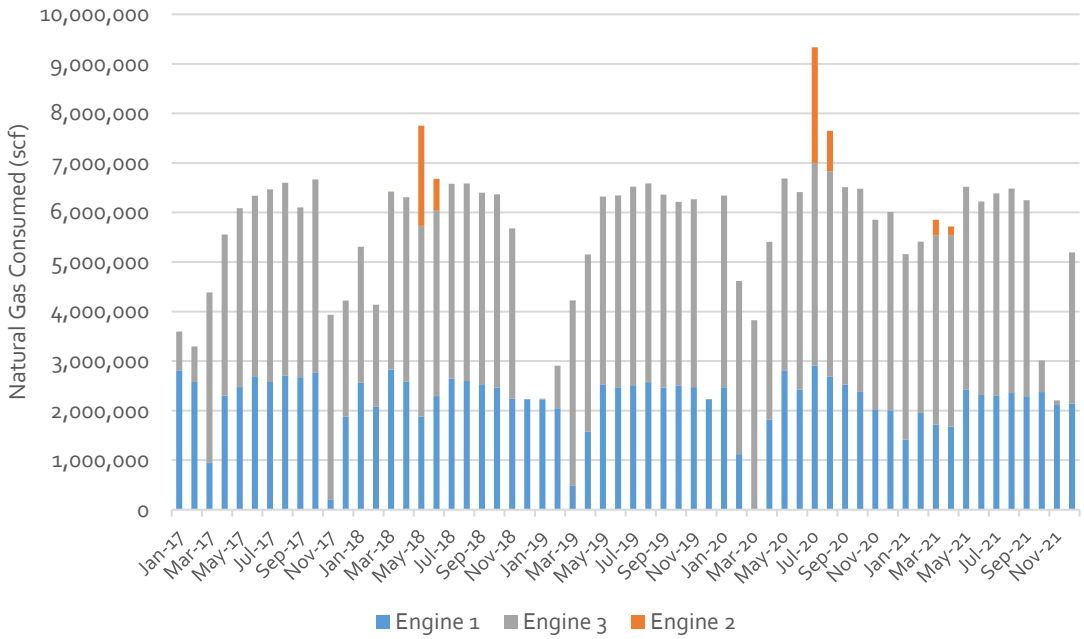


Figure 1.44 Monthly Natural Gas Consumption by Cogeneration Engine (2017 to 2021)

The District also uses natural gas for heating at the district office, the district office utility building, the WWTP fleet maintenance office, and the Field Operations Facility. Combined, these uses of natural gas constitute about 2 percent of the total natural gas consumption in 2021. These monthly uses are shown in Figure 1.45 reflecting the general seasonality of higher demand in winter months and smaller demand in summer months. The comparison of different years shows clearly that certain months have been characterized by an uncommonly high natural gas consumption that is driving primarily by the District's Administrative Building and the Field Operations Facility. (Note that in fall of 2018 the District Administrative Building was flooded and not occupied between approximately November 2018 through April 2020.)

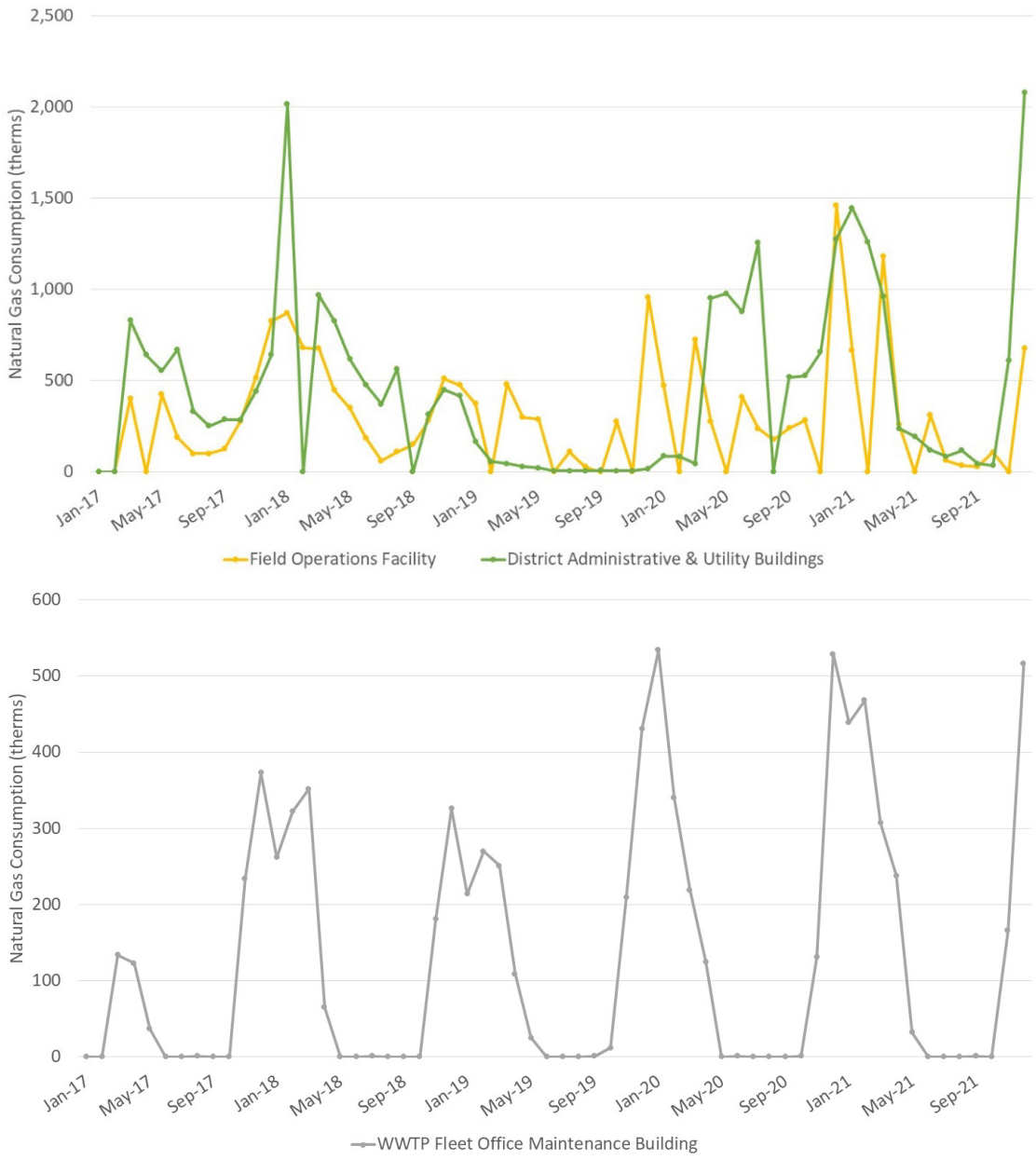


Figure 1.45 Monthly Natural Gas Consumption for District Facilities (2017 to 2021): a) Field Operations Facility (Top), and District Administrative and Utilities Buildings (Bottom)

The costs for the five natural gas-related account numbers are summarized in Figure 1.46, and the 2021 overall consumption and costs are summarized in Table 1.22. DSRSD typically pays between $6,000 to $14,000 each month for natural gas. The long-term trend shows an increasing natural gas cost for the District Administrative Building, and overall, natural gas costs have increased over the past five years. The average billed cost per therm used in the cogeneration engines was $0.2 per therm, whereas the average cost across the four other facilities was higher at $1.8 per therm. The cogeneration engines receive natural gas at a lower rate because the WWTP is a gas aggregator facility, meaning natural gas usages are combined for different consumers to form a buying group that can negotiate a lower natural gas price.

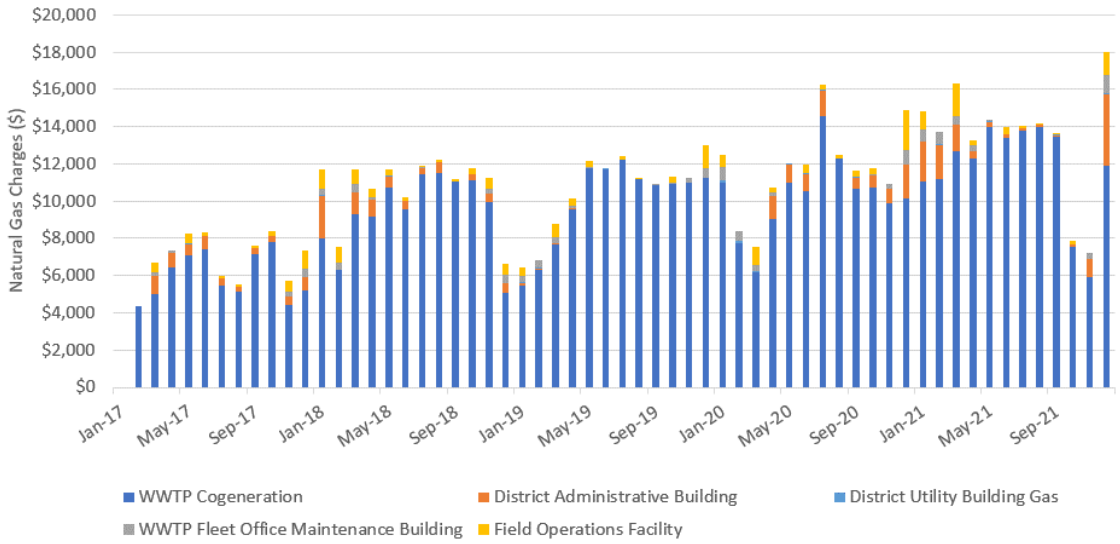


Figure 1.46 Monthly Natural Gas Costs by Facility (2017 to 2021)

Table 1.22 2021 District-Wide Natural Gas Consumption and Costs

Facility	2021 Consumption (therms)	2021 Costs	Cost/Therm
WWTP Cogeneration	706,080	$141,230	$0.2
District Administrative Building	7,100	$11,460	$1.6
District Utility Building Gas	88	$230	$2.6
WWTP Fleet Office Maintenance Building	2,170	$3,500	$1.6
Field Operations Facility	3,300	$5,140	$1.5
Total	**718,770**	**$161,550**	**$0.2**

1.8 Current Energy Production

DSRSD recovers energy from its operation in form of electricity from the cogeneration engines and thermal energy from digester heat recovery and wastewater heat recovery for building heating. DSRSD currently does not produce any other forms of renewable energy, e.g., in form of solar, geothermal, or wind.

1.8.1 Electricity Production From Biogas

DSRSD produces biogas in its anaerobic digesters that is used in its majority for cogeneration in three engines to produce electricity. The remainder of excess biogas that cannot be processed in the engines is flared. Figure 1.47 shows the monthly biogas quantities sent to cogeneration or flare. The fraction of biogas that is flared is typically small; on average 13 percent of the biogas was flared in 2021.

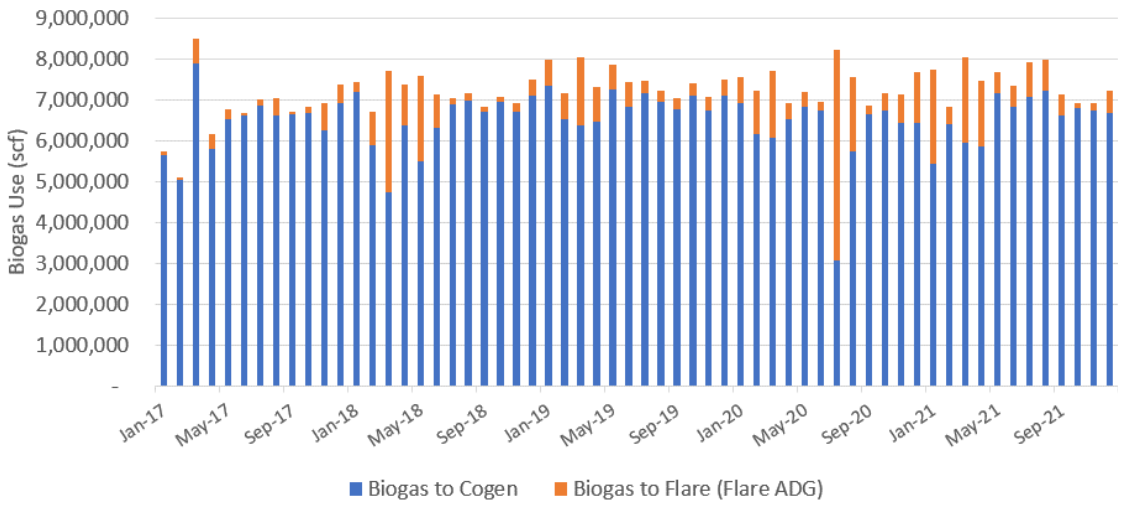


Figure 1.47 Monthly Biogas Amounts Sent to Cogeneration or Flare (2017 to 2021)

The combined cogeneration system electricity production per year is about 8,750 to 10,500 MWh with an almost equal contribution from each of the three engines (Figure 1.48). The system ran in 2021 at a capacity of about 1,100 kW, which is about 92 percent of its typical annual output (1,200 kW).

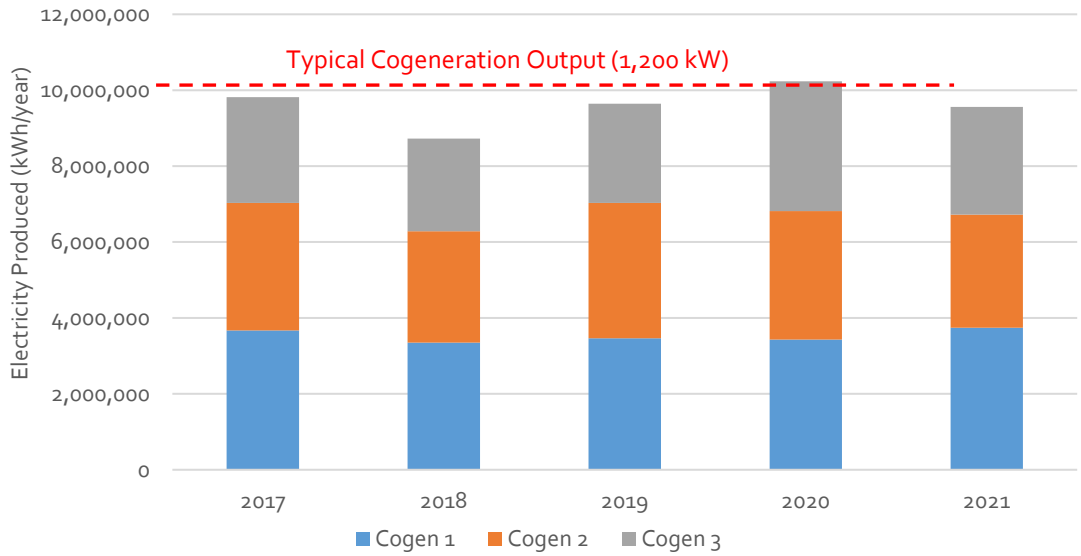


Figure 1.48 Total DSRSD Cogeneration Annual Electricity Production (2017 to 2021)

Figure 1.49 shows the monthly electricity generation at the WWTP from cogeneration since 2017, which ranges from about 560,000 to 920,000 kWh per month. Cogeneration engine 1 was not operating for the month of March 2020 and cogeneration engine 3 was not operating for the month of November 2021, therefore these months show lower electricity production.

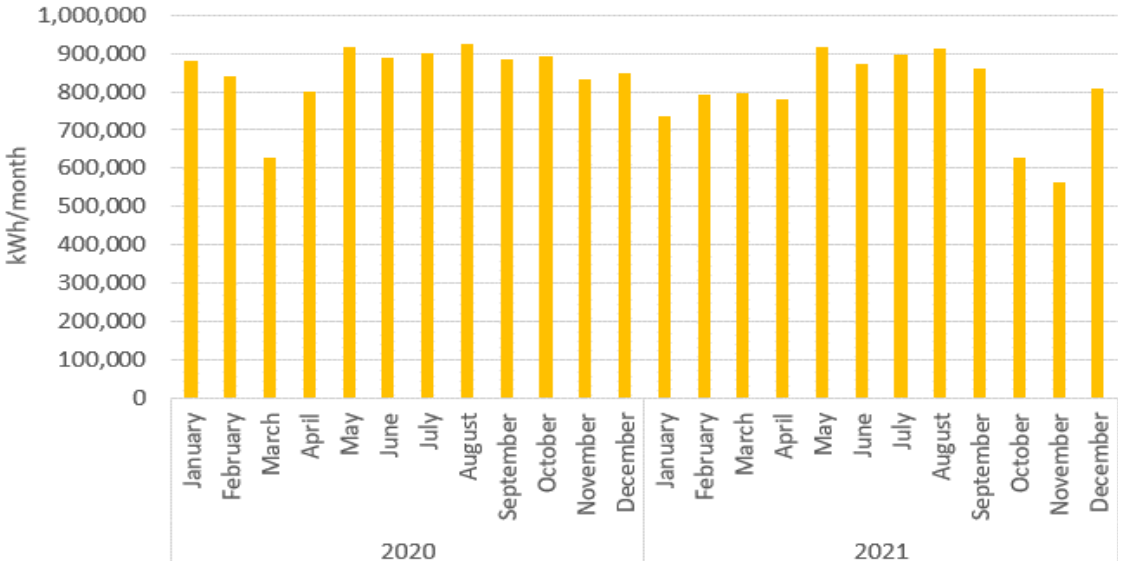


Figure 1.49 DSRSD Monthly Cogeneration Electricity Production (2020 to 2021)

The electricity generated from biogas (excluding natural gas) with cogeneration averaged about 62 percent of the total electricity demand of the WWTP over the past five years. Figure 1.50 compares the annual electricity demand at the WWTP with the cogeneration electricity production from biogas and purchased natural gas since 2017. Electricity self-sufficiency is defined as the ratio of annual average electricity produced onsite from biogas compared to the total energy consumption (i.e. excludes energy production through natural gas). The highest degree of electricity self-sufficiency was achieved in 2019 (71 percent).

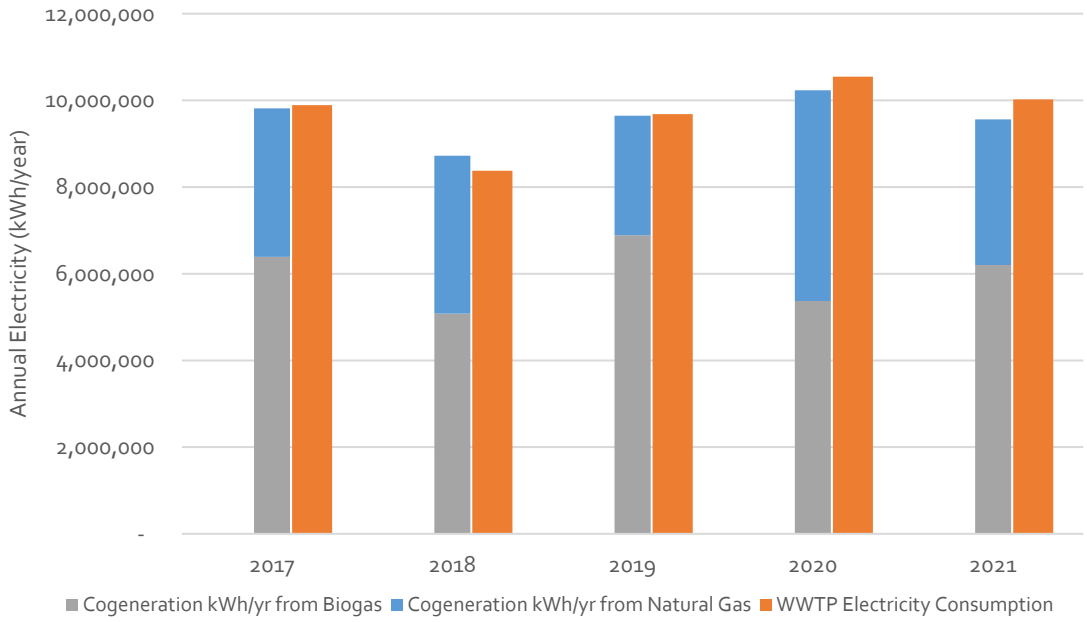


Figure 1.50 Total Annual WWTP Electricity Demand and Cogeneration Production from Biogas (2017 to 2021)

1.8.2 Thermal Energy

Wastewater contains a substantial amount of thermal energy that is largely unused. Typical heat pump systems make it feasible to recover up to nine degrees F from wastewater. At an average annual daily wastewater flow of 11.7 mgd in 2021, the maximum practical thermal energy capacity that can be recovered is approximately 10 MW for DSRSD. For comparison, the largest wastewater heat recovery systems currently in operation in North America are the False Creek Neighborhood in the City of Vancouver with a capacity of 3.2 MW (planned for expansion in 2022 to 8 MW), and the National Western Center Complex in Denver, Colorado with a capacity of 4 MW (planned for expansion in the future to 12 MW).

DSRSD operates several heat recovery systems at this time:

1. Heat recovery from digesters:
   a. All four heat exchangers dedicated to each digesters provide a total of 4.0 MMBtu/hr of recovered heat to the digester feed sludges.
2. Heat recovery from cogeneration system:
   a. The cogeneration system recovers thermal heat off the three engines to generate hot water used to preheat primary and secondary sludge up to the digesters' operating temperature and to heat the digesters directly.
   b. Additionally, cogenerated heat energy is used as an energy source for the heating, ventilation, and cooling system in the Administration Building and Maintenance Building. The hot water loop is used directly for building heating and domestic hot water and also drives absorption chillers for air conditioning in the summer months. According to the 2017 *Wastewater Treatment and Biosolids Facilities Master Plan*, the total hot water demand at the plant is 3.52 MMBtu/hr (1,030 kWh) in the summer and 3.68 million MMBtu/hr (1,080 kWh) in the winter. The three cogeneration engines can recover a maximum of approximately 7.5 MMBtu/hr thermal heat total (2,200kWh).

1.8.3 Other Renewable Energy

DSRSD has a 5 kW solar array pilot project installed on the roof of Building T.

1.9 Vehicle Fleet

1.9.1 Current Fleet Description

In 2021 (baseline year for the energy evaluation) DSRSD recorded vehicle mileage and information for 38 vehicles in their fleet (see Section 1.7.1); DSRSD's overall fleet, however, is larger and is anticipated to include 62 vehicles by the end of 2023.

Table 1.23 shows the expected 2023 fleet breakdown of DSRSD by number, type, and service functions.

Table 1.23 2023 Vehicle Fleet Inventory Summary

Make of Vehicle	Class	Model	Service Function	Number
Ford	Passenger Car or Van	Escape	Inspections, significant on-duty driving and idle times	6
		Explorer	Passenger transport	1
		Fusion	Passenger transport	2
	Light – Duty Truck or Van	F-150	Inspection trucks, High daily mileage, tow vehicles	11
		Ranger	Inspection trucks, High daily mileage, tow vehicles	3
		Transit Connect	On-call services, Transport of electrical equipment with exposure protection to weather elements	3
	Medium – Duty Truck or Van	F-250	Equipment transport (tools, compressors, lighting, hauling)	17
		F-350		7
		Econoline E250		1
		Transit T-150		1
	Heavy – Duty Truck	F-450		4
		F-550	Valve Truck	1
		F-600	Closed-caption Television Truck	1
GMC	Light-Duty Truck	Sonoma		1
Freightliner	Heavy-Duty Truck	Camel: 108 SD		1
		Camel: 114 SD	Specialty vehicle for emergency response (sewer overflows). 3 axle with vactor system on the chassis with power take-off device for accessories.	1
Sterling	Heavy-Duty Truck	Condor	This vehicle has less than 1000 miles per year and serves as a standby vactor truck.	1
Total				**62**

DSRSD operates a total of 19 electric golf carts and two flatbed electric carts, which are summarized in Table 1.24. Since 2015, DSRSD has systematically acquired electric carts each year to renew its fleet.

Table 1.24 2023 Summary of Golf and Flat Bed Carts

Type	Type	Year of Acquisition	Number
Golf Cart	Electric	1997	1
		1998	1
		2004	2
		2015	3
		2016	3
		2017	1
		2018	3
		2019	5
Flat Bed Cart	Electric	2008	2
Total			**21**

DSRSD's Fleet Management Program and Replacement Schedule sets clear criteria for the timing of the replacement of vehicles. Replacement decisions are made based on age, mileage, maintenance costs, reliability, and overall vehicle conditions. Vehicles are replaced in accordance with the following guidance:

- Light-duty and medium-duty vehicles: Replace every 10 years, or 100,000 miles.
- Heavy-duty and specialty vehicles: Replace every 15 years, or 150,000 miles.

Purchases of vehicles and equipment follows the Districts Purchasing Policy.

DSRSD has a large fraction of vehicles in its fleet that are approaching or have exceeded the 10- year life threshold. Only two of its vehicles are in high enough use to reach the mileage threshold in under 10 years. Therefore, fleet management is in the process of replacing several of its vehicles in 2023.Future vehicle replacements will need to comply with CARB's Advanced Clean Fleets regulations which are discussed further in TM 07 of this Energy Facilities Master Plan.

To date, DSRSD does not have electric charging stations for ZEVs on site.

1.10 Current Greenhouse Gas Inventory

The purpose of the GHG baseline inventory is to provide DSRSD a means to quantify the current baseline emissions associated with their operations. In future stages of this Energy Facilities Master Plan, this baseline inventory will be used to compare to energy-saving alternatives to evaluate their impact on reducing GHG emissions. Developing the inventory requires several steps that are summarized in Figure 1.51.

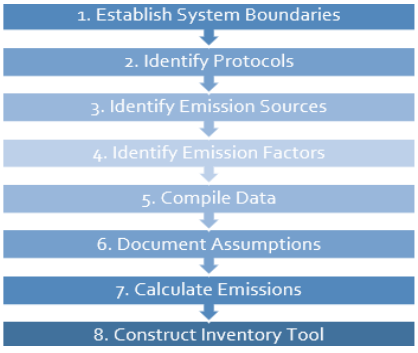


Figure 1.51 Steps for Developing the GHG Inventory

The process of estimating GHG emissions is important to produce results that are trusted and verifiable. The process requires use of estimating protocols and global warming potentials, identifying and categorizing emission sources, and selecting the appropriate emission factors. Carollo has developed a GHG emissions estimating and reporting tool based on

methods aligned with the GHG Protocol Initiative, an accounting protocol developed by the World Resources Institute and the World Business Council for Sustainable Development. This protocol serves as an accounting framework for almost all GHG standards and programs in the world - from the Organization of International Standards to The Climate Registry General Reporting Protocol to EPA's mandatory GHG reporting program.

1.10.1 Establishing the System Boundary for the Greenhouse Gas Inventory

Establishing the system boundary is a necessary first step to define relevant GHGs, life cycle stages (e.g., construction, operations, etc.), facilities or unit processes, and time frame (e.g., present or future year) for building a GHG inventory.

Six GHGs have been prioritized for GHG inventory purposes, based on each gas' capacity to absorb and reradiate heat, and thus contribute to climate change. These GHGs include: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6). Of these, CO_2, CH_4, and N_2O are considered relevant for wastewater treatment emissions and are the focus of this inventory.

For the purposes of this Energy Facilities Master Plan, only emissions associated with operations are included in the system boundary; emissions associated with construction activities are not included.

The calendar year selected for the baseline GHG inventory was 2021. The baseline was selected based on an analysis of flows and loads and electricity usage and production for the years 2017 to 2021. This assures that improvements performed at the WWTP and Recycled Water Plant in years prior to 2021 are reflected in the baseline GHG inventory results. Over the past five years, influent flows and loads, electricity usage, or energy production did not change significantly, therefore the latest year for which a full set of data was available was selected.

Facilities included in the GHG inventory include:

1. WWTP, including the lab HVAC, fleet maintenance building, and service aerators for the sludge lagoons.
2. DERWA Recycled Water Treatment and Distribution (Recycled Water Treatment Plant, PSR1, and DERWA recycled water distribution system).
3. DSRSD recycled water distribution system.
4. LAVWMA export pump station.
5. Potable water distribution system.
6. Field Operation Facility and District Administrative Building.
7. Vehicle Fleet.

A separate GHG baseline inventory was developed for each of these facilities to facilitate comparison to alternatives that will be developed in later stages of this project.

1.10.2 Protocols Used for the GHG Inventory

In order to estimate GHG emissions from wastewater treatment facility sources, there are a number of estimating protocols that (in combination) serve as the basis for a complete inventory of the WWTP. These protocols include:

1. 2006 Intergovernmental Panel on Climate Change Guidelines for National GHG Inventories.
2. EPA's Mandatory GHG Reporting Rule (40 Code of Federal Regulations Part 98).

1.10.3 Emission Sources by Scope

Determining the sources of emissions and offsets within the system boundary is a fundamental step in the development of the inventory. Emissions are typically categorized as Scope 1, Scope 2, or Scope 3, as a standard and for comparison across other inventories. Below are summaries of each Scope category as they relate to DSRSD operations.

1.10.3.1 Scope 1

Scope 1 includes direct anthropogenic (fossil fuel based) and biogenic GHG emissions related to on-site combustion and treatment processes within the system boundary, as well as mobile combustion of fleet vehicles owned and operated by DSRSD. Scope 1 emission sources within the system boundary include:

- Emissions due to natural gas combustion.
- Emissions due to biogas combustion, including biogenic CO_2, CH_4, and N_2O.
- Process emissions due to nutrient removal processes (not currently applicable at DSRSD).
- Process emissions due to remaining nitrogen concentrations in the effluent discharge.
- Process emissions due to use of facultative sludge lagoons.
- Emissions associated with mobile or idle combustion from the vehicle fleet.

At this time, mandatory GHG emissions reporting required by the California Global Warming Solutions Act of 2006 (Assembly Bill 32) by CARB is limited to Scope 1 emissions above 10,000 metric tons of carbon dioxide equivalents (CO_2e) per year - specifically, natural gas and biogas combustion (CH_4 and N_2O only). Scope 1 emissions above 25,000 metric tons of CO_2e per year would trigger cap-and-trade requirements. As described in section 1.10.4.8, the District's 2021 baseline Scope 1 emissions are 4,890 metric tons of CO_2e per year, well below both the reporting and cap-and-trade thresholds.

1.10.3.2 Scope 2

Scope 2 encompasses indirect anthropogenic emissions related to the consumption of purchased electricity, steam, heating, or cooling. These emissions are a result of DSRSD operations, but occur at a source that is not owned or operated by the District. Scope 2 emissions for this inventory include purchased electricity, for example used for buildings and electric car power.

1.10.3.3 Scope 3

All other (non-Scope 2) indirect anthropogenic GHG emissions that result from treatment plant operations are considered Scope 3 emissions. Examples include the production and the transport of chemicals. Scope 3 emissions within the system boundary identified at DSRSD include:

- Off-site natural gas production.
- Chemical production.
- Chemical transport; including truck and freight.

Avoided emissions were also identified within Scope 3. Avoided emissions at DSRSD include avoided purchased electricity through biogas conversion using the combined heat and power system. If biosolids alternatives evaluated in later stages of this Energy Facilities Master Plan include land application of biosolids, then avoided emissions will also include those associated

with land application of biosolids, specifically, carbon sequestration and avoided use of inorganic fertilizer.

1.10.4 Baseline Greenhouse Gas Emission Inventory Results

The 2021 baseline GHG emission estimates for each of DSRSD's facilities are summarized in the following sections. Refer to Appendix 1D for a detailed summary of emissions factors and sources used as a basis for these estimates.

1.10.4.1 Wastewater Treatment Plant

The baseline GHG inventory for the WWTP (excluding PSR1, the Recycled Water Treatment Plant, and the LAVWMA pump station) is presented in Figure 1.52. The net GHG emissions generated by the WWTP are estimated to be approximately 3,926 metric tons CO_2e annually. The net emissions are calculated by subtracting 702 metric tons CO_2e of avoided or negative emissions associated with electricity generated from cogeneration from the 4,628 metric tons CO_2e of positive emissions.

The largest source of emissions is from natural gas used as a supplemental energy source for cogeneration, which accounts for 78 percent of the WWTP's positive emissions. Other major sources of emissions include emissions from purchased electricity, followed by N_2O emissions from secondary treatment. The other sources of emissions account for only a small portion of the total WWTP emissions. Additional details on the GHG emissions by source and emission factors used is provided in Appendix 1D.

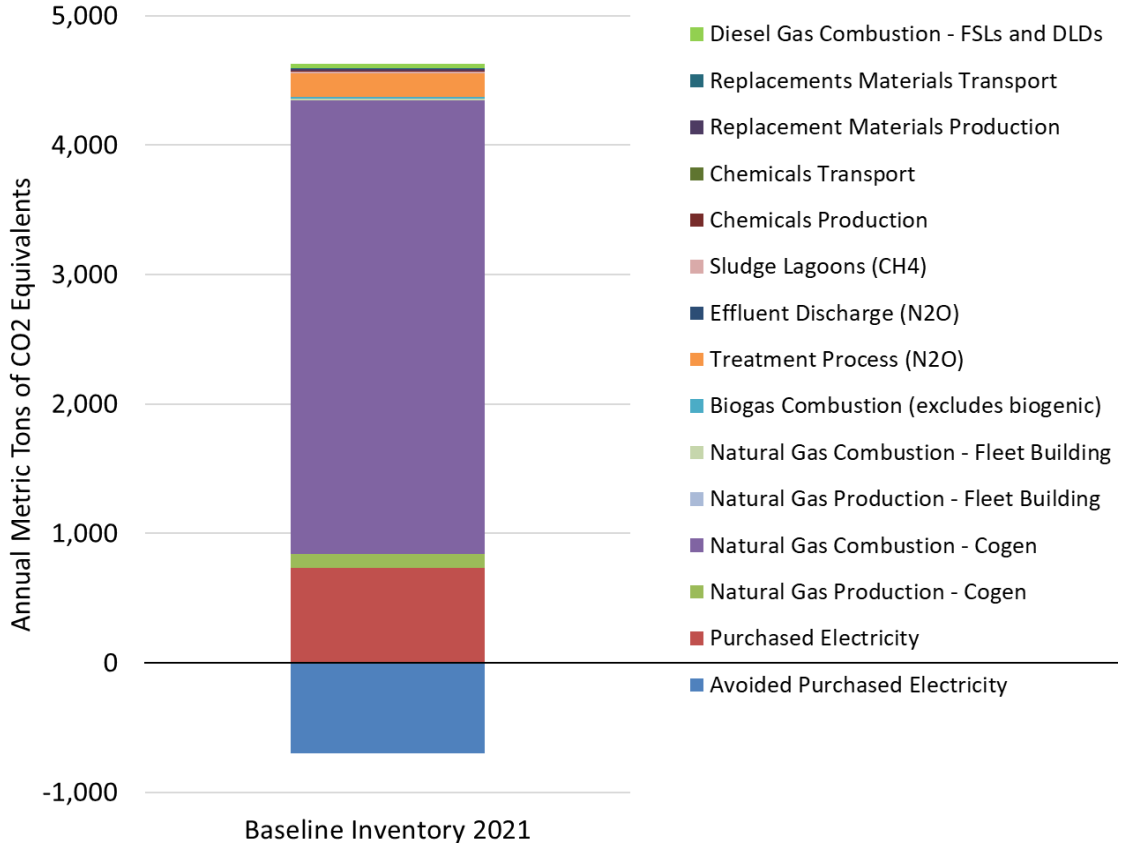


Figure 1.52 Baseline GHG Emissions Inventory Results for the WWTP

1.10.4.2 DERWA Recycled Water Treatment and Distribution

The baseline GHG inventory for the DERWA Recycled Water Treatment and Distribution – Recycled Water Treatment Plant, PS R1, DERWA Recycled Water Distribution System is presented in Figure 1.53.

The total GHG emissions generated are estimated to be approximately 414 metric tons CO_2e annually, of which 218 metric tons CO_2e, 163 metric tons CO_2e, and 33 metric tons CO_2e metric tons CO_2e can be attributed to the operation of the recycled treatment plant, PSR1, the DERWA recycled water distribution system, respectively. Based on actual deliveries of recycled water received in 2021, DSRSD's proportionate share (estimated as 70 percent) of these GHG emissions are approximately 290 metric tons CO_2e (e.g. recycled water treatment plant – 152 metric tons CO_2e; recycled water distribution – 23 metric tons CO_2e; and PSR1 – 114 metric tons CO_2e).

All of the emissions are due to indirect sources, included in Scopes 2 and 3, since there are no direct emissions associated with the Recycled Water Plant, PSR1, and/or DERWA Recycled Water Distribution System. The largest source of emissions is from purchased electricity (accounting for 89 percent of the total emissions), followed by chemicals production (with polymer being the major source). Emissions from replacement materials production and chemicals and materials transport account for only a small portion of the total Recycled Water Plant and distribution system emissions.

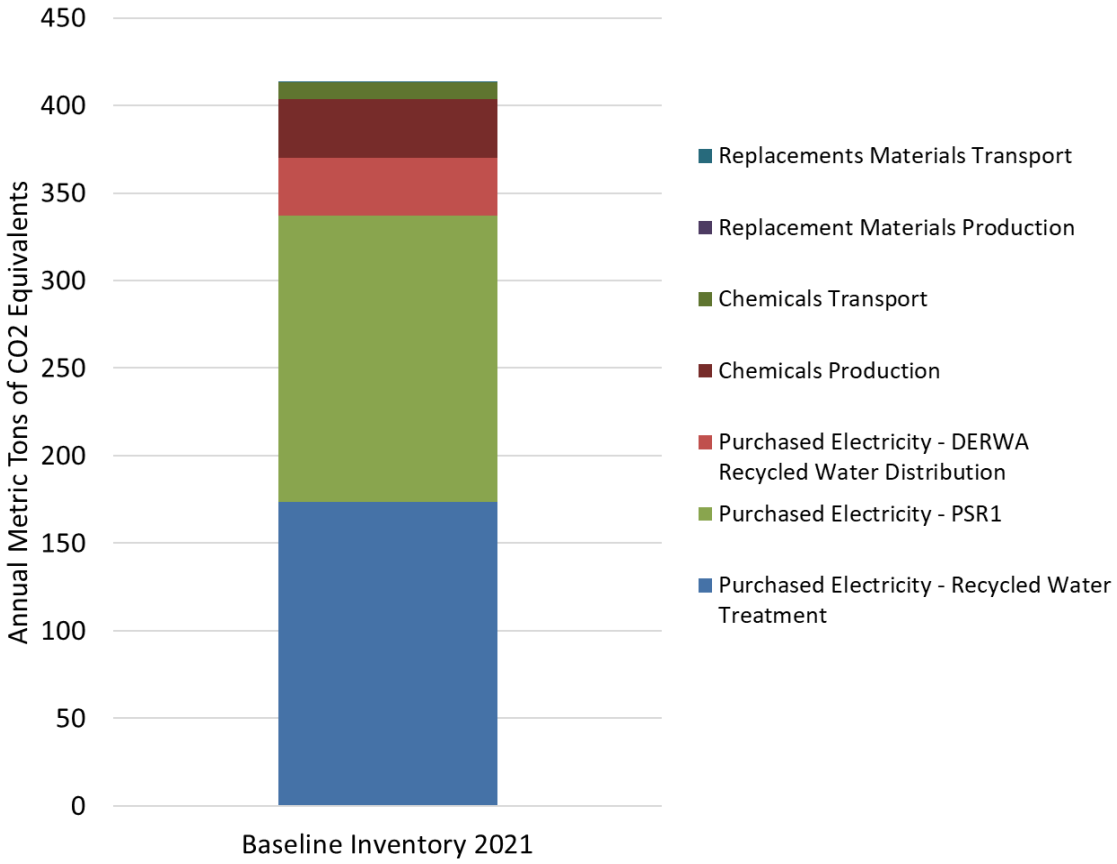


Figure 1.53 Baseline GHG Emissions Inventory Results for DERWA Recycled Water Treatment and Distribution

1.10.4.3 DSRSD Recycled Water Distribution

The baseline GHG inventory for the DSRSD Recycled Water Distribution System is presented in Figure 1.54. The total GHG emissions generated are estimated to be approximately 22 metric tons CO_2e annually.

All of the emissions are due to purchased electricity, an indirect source included in Scope 2.

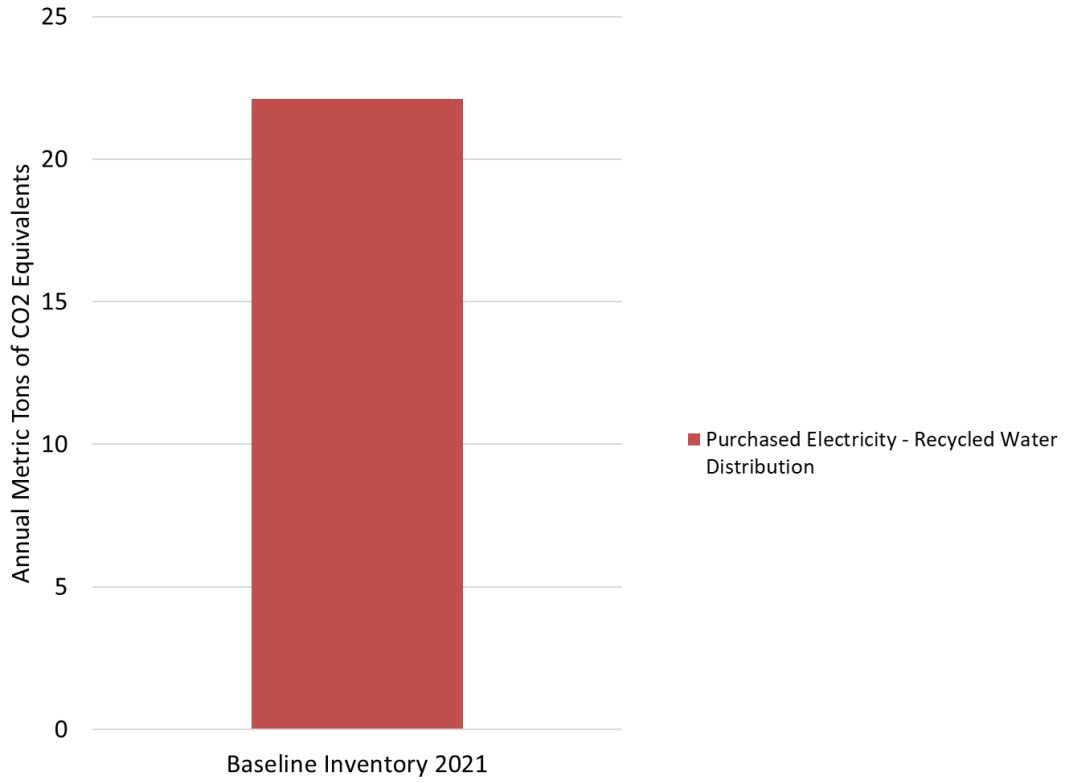


Figure 1.54 Baseline GHG Emissions Inventory Results for DSRSD Recycled Water Distribution

1.10.4.4 Potable Water Distribution

The baseline GHG inventory for the potable water distribution system is presented in Figure 1.55. The total GHG emissions generated are estimated to be approximately 295 metric tons CO_2e annually. All of the emissions are due to indirect sources, included in Scopes 2 and 3, since there are no direct emissions associated with the Potable Water Distribution System.

The largest source of emissions is from purchased electricity, which accounts for 98 percent of the total emission. Emissions from chemicals production and transport account for a small portion of the potable water distribution system emissions.

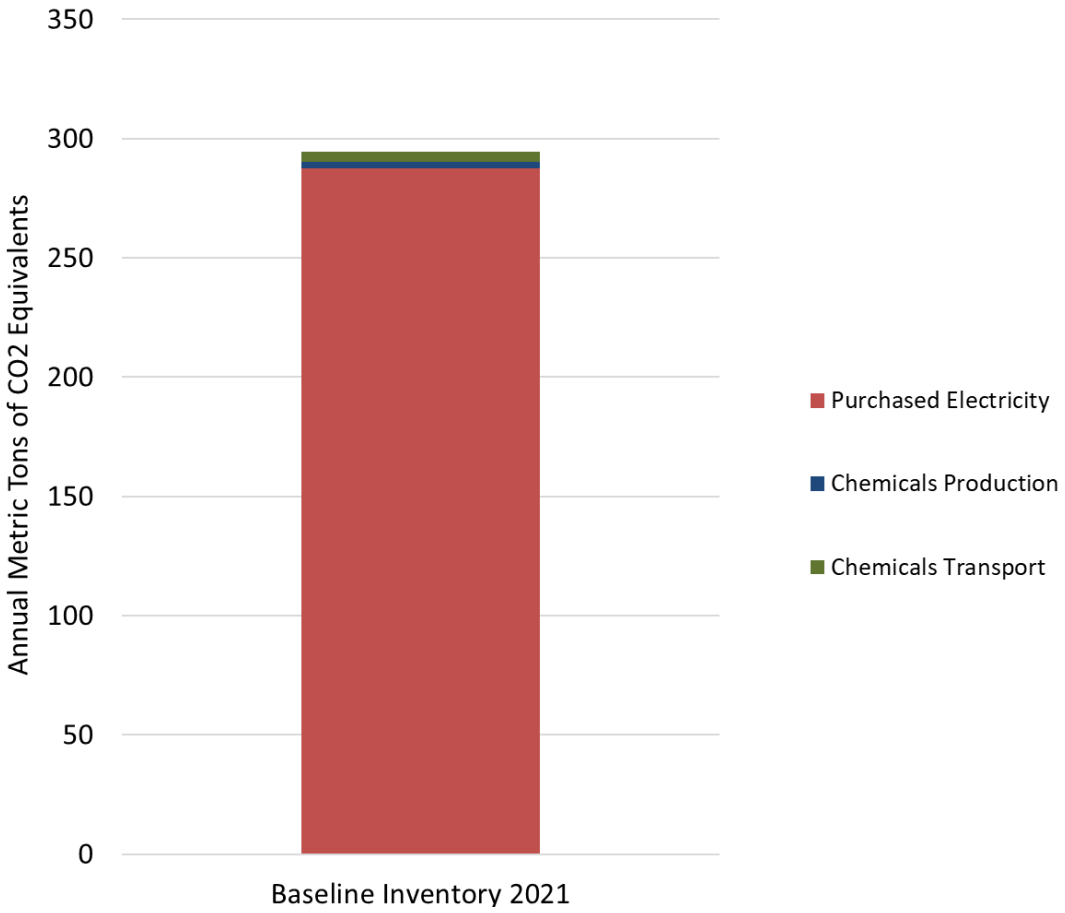


Figure 1.55 Baseline GHG Emissions Inventory Results for Potable Water Distribution

1.10.4.5 LAVWMA Effluent Pump Station

The baseline GHG inventory for the LAVWMA Pump Station is presented in Figure 1.56. The total GHG emissions generated are estimated to be approximately 531 metric tons CO_2e annually. Based on actual flows discharged by the member agencies through the LAVWMA Pump Station in 2021, DSRSD's proportionate share (estimated as 70 percent) of these GHG emissions is approximately 319 metric tons CO_2e.

All of the emissions are due to purchased electricity, which is an indirect source included in Scope 2.

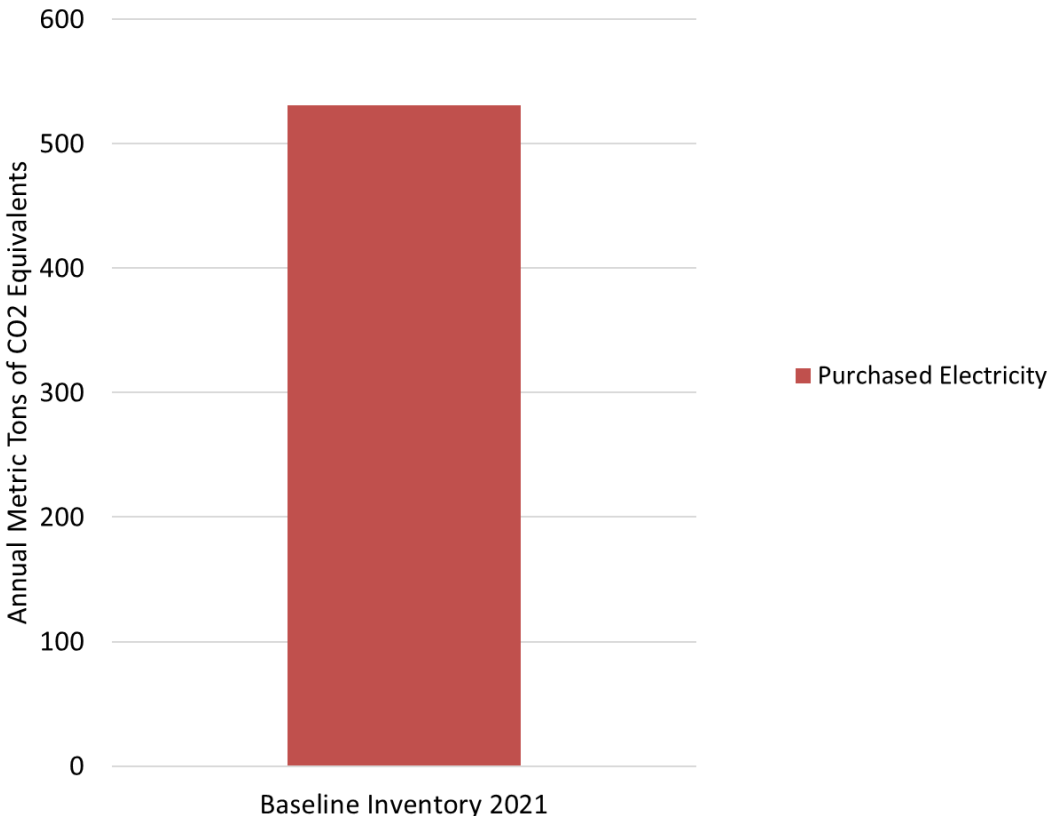


Figure 1.56 Baseline GHG Emissions Inventory for the LAVWMA Pump Station

1.10.4.6 District Administrative Buildings and Field Operations Facility

The baseline GHG inventory for the District Office Buildings and Field Operations Facility is presented in Figure 1.57. The total GHG emissions generated are estimated to be approximately 100 metric tons CO_2e annually. The largest source of emissions is from onsite combustion of natural gas for building heating, a direct emission included in Scope 1. The second largest source of emissions is from purchased electricity, which is an indirect source included in Scope 2. The indirect emissions from natural gas production are minimal.

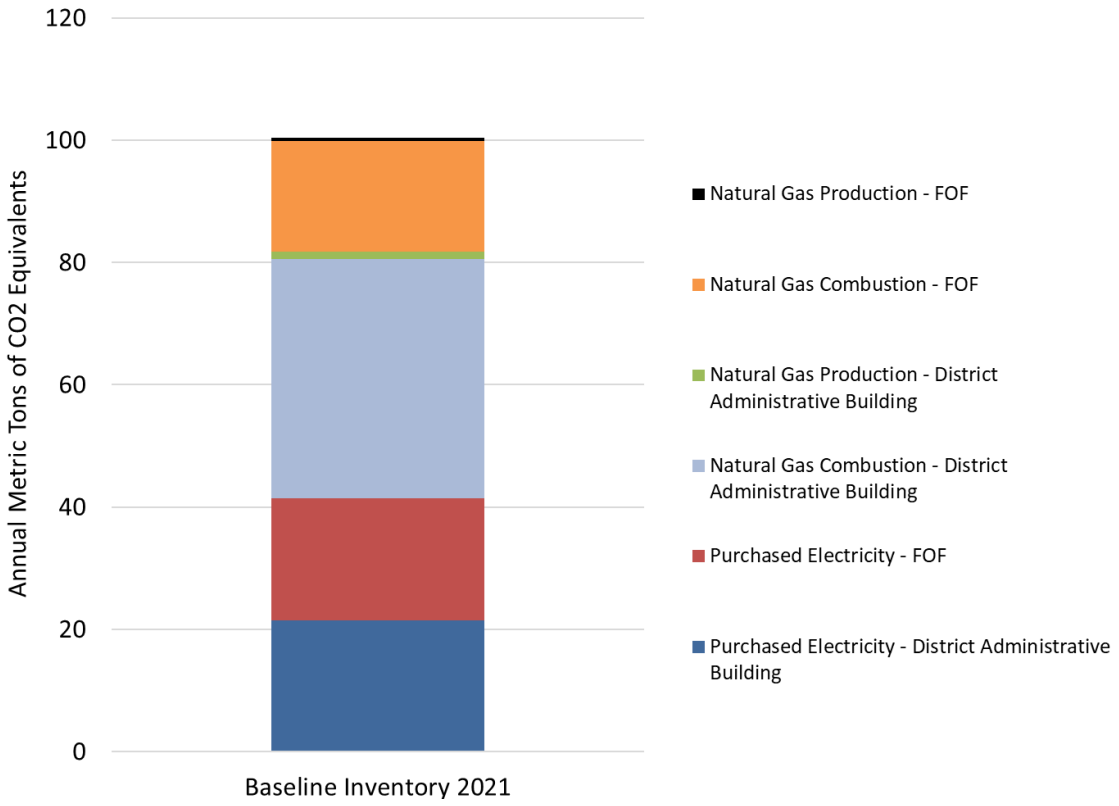


Figure 1.57 Baseline GHG Emissions Inventory Results for the District Administrative Building and Field Operations Facility

1.10.4.7 Vehicle Fleet

The baseline GHG inventory for the Vehicle Fleet is presented in Figure 1.58. The total GHG emissions generated are estimated to be approximately 89 metric tons CO_2e annually.

All of the emissions are due to direct sources from combustion of diesel and gasoline, included in Scopes 1. The largest source of emissions is from gasoline combustion, given that the majority of DSRSD's fleet vehicles use gasoline, followed by diesel combustion. In comparison to the other facilities, the vehicle fleet emissions are a minor source of GHG emissions.

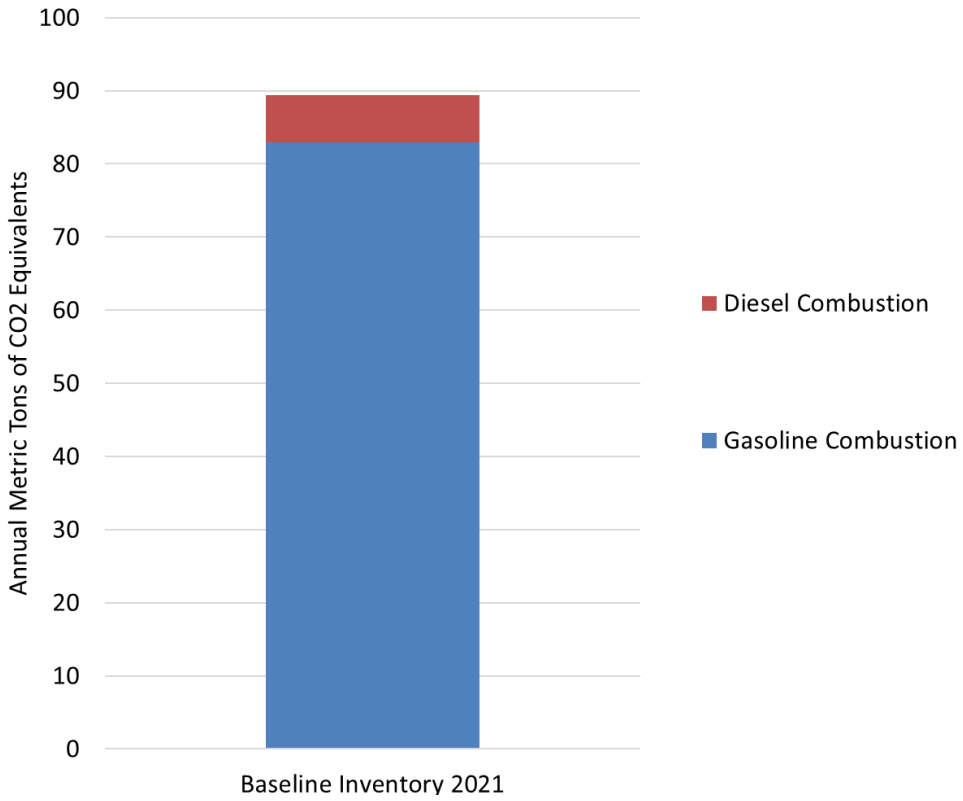


Figure 1.58 Baseline GHG Emissions Inventory Results for the Vehicle Fleet

1.10.4.8 Summary of the 2021 Baseline Greenhouse Gas Inventory Results

Figure 1.59 and Figure 1.60 compare the Baseline 2021 GHG inventory results for all facilities in terms of relative and absolute contributions. The majority of the emissions are contributed by the WWTP, which accounts for approximately 73 percent of the total GHG emissions.

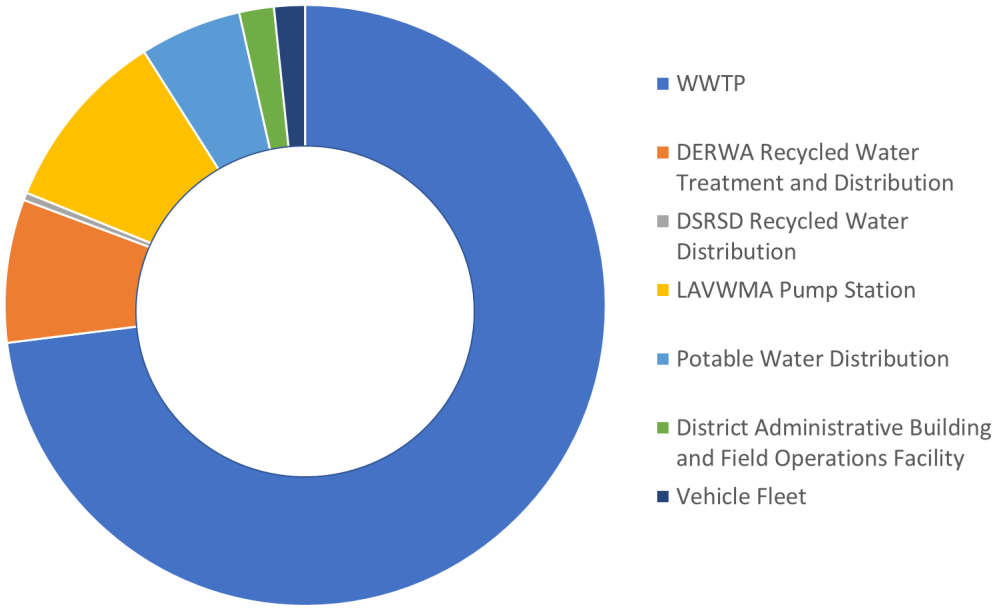


Figure 1.59 Relative Contribution of GHG Emissions by Facility (Baseline Inventory 2021)

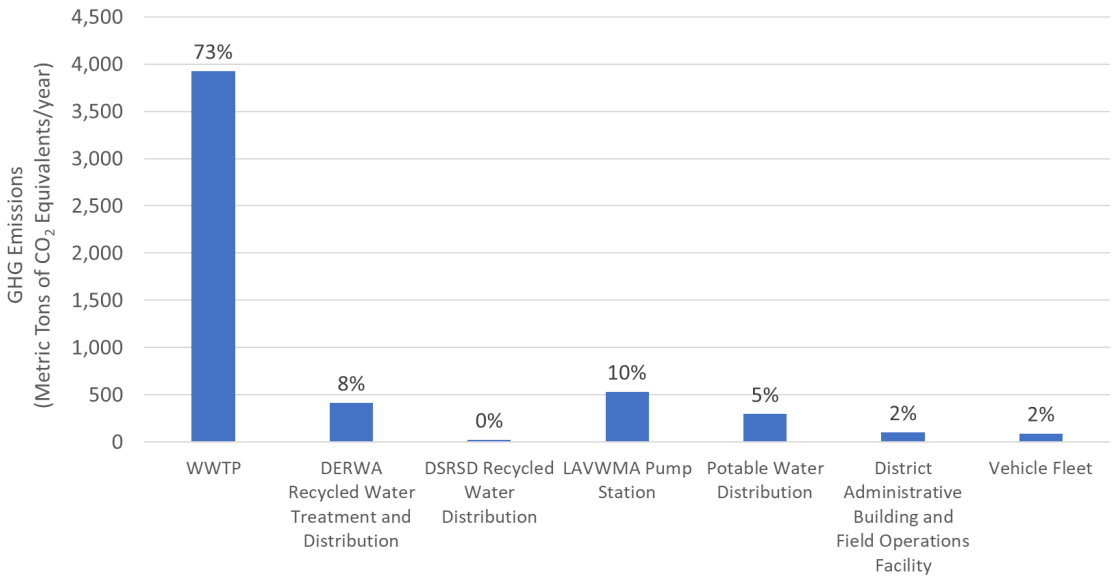


Figure 1.60 Comparison of GHG Emissions by Facility (Baseline Inventory 2021)

Figure 1.61 and Figure 1.62 break down the Baseline 2021 GHG inventory results for all facilities into Scope 1, 2, and 3 emissions. The majority of the emissions are from Scope 1, accounting for 73 percent of the total District emissions. Scope 1 emissions amount are estimated at 3,910 metric tons CO_2e per year, well below the CARB reporting and cap-and-trade threshold of 25,000 metric tons CO_2e per year described in Section 1.10.3.1.

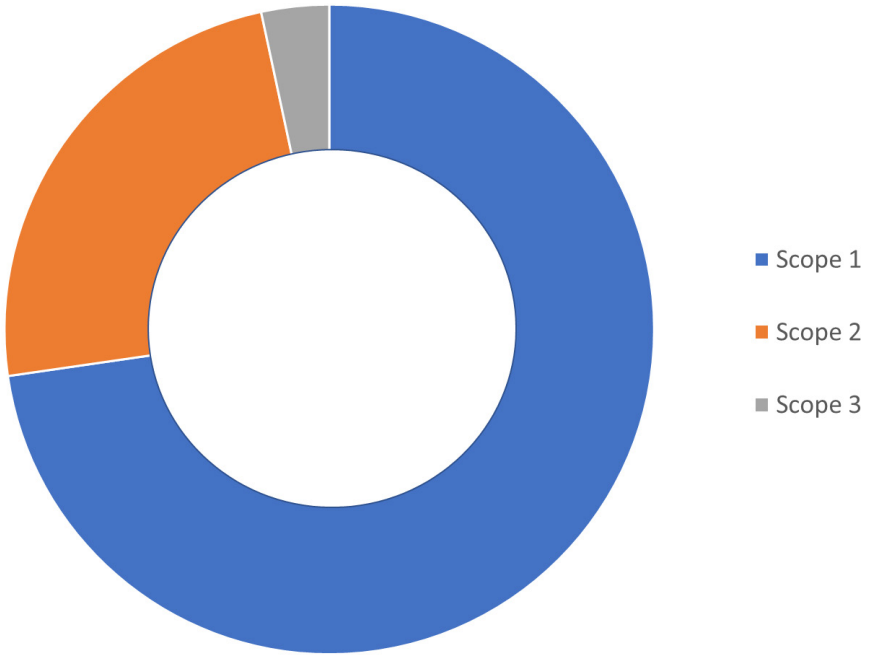


Figure 1.61 Relative Contribution of GHG Emissions by Scope (Baseline Inventory 2021)

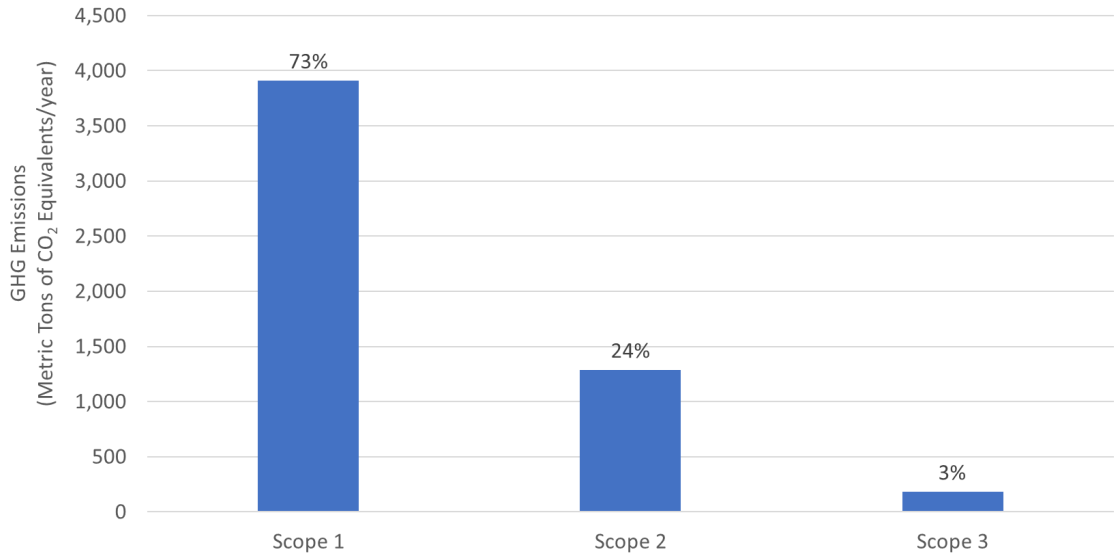


Figure 1.62 Comparison of GHG Emissions by Scope (Baseline Inventory 2021)

1.11 Past Energy Efficiency Efforts and Results

Over the past years DSRSD has made consistent progress towards energy efficient operation in all areas of their facilities. As illustrated in the following sections these achievements have been impressive, particularly given that DSRSD has operated for several years with about 15 to 20 percent vacancy positions.

1.11.1 Wastewater Treatment Facility

1.11.1.1 Aeration

DSRSD undertook various efforts in the past to reduce the energy consumption of the secondary treatment process, including the following:

- Changed to new airflow meters and REXA air control valves thus improving aeration accuracy and reducing aeration demand. The valves were installed in two phases in April 2018 and May 2021.
- Optimization of dissolved oxygen setpoint control programming and tuning.
- Expanded primary clarification to divert carbon from secondary treatment system. This saves each day aeration energy and increases biogas production.
- Are working on management of struvite to allow year-round operation of the anoxic selectors (currently the selector is aerated in winter months to prevent struvite formation).
- Peak demand reduction through optimizing the timing and duration of phasing additional blower in to meet secondary influent peak loads.

1.11.1.2 Cogeneration/Flare

- DSRSD has expanded digester capacity in 2019 providing the capacity for additional digester gas production in the future.
- This expansion also expanded the heat recovery capacity for digester and building heating.

- DSRSD uses more than 85 percent of its biogas beneficially and minimizes gas flaring to the extends current infrastructure limitations allow.
- A FOG facility was constructed to allow for receiving of energy-rich co-substrates for cogeneration in the future. Staff estimates that with FOG DSRSD could generate 1 MW continuously with biogas alone in the future phasing out natural gas.
- Even though the cogeneration engines are past their useful life and have had some failures and shutdowns in past years, staff has managed to maintain the units in operation and maintain a very high degree of self-sufficiency through cogeneration. The cogeneration units are currently planned for replacement or major rehabilitation in the next 10-year CIP. DSRSD is still evaluating the best timing for this project. DSRSD staff estimates that even with exceptional maintenance, the current units will need to be replaced in the next 5 to 10 years; replacement parts will become more challenging to procure in the future.

1.11.1.3 Solids handling

The current sludge disposal method at the FSLs and DLDs is highly energy efficient compared to common alternatives. The FSL operation does not require sludge dewatering saving the DSRSD significant energy.

1.11.2 Instrumentation and Controls

- DSRSD has invested in past years into sensors and instrumentation for predictive maintenance of pumps and efficient operation of equipment.
- The aeration system was upgraded with motorized control valves for better air flow control and feedback.
- Nutrient analyzers have been installed for nitrogen, ammonia, and phosphorus for better process control and preventing nitrification which results in increased aeration demand.
- A platform for a plant-wide networking system is already in place that has redundancy and can serve as foundation for green-energy solutions.
- With the current SCADA project DSRSD will upgrade to fiber communication throughout the plant and increase the network communications speed.
- DSRSD is collecting a lot of data throughout the facility and is ready to engage OSI PI and other infrastructure to better utilize and visualize the data.
- Power monitoring and EATON Foreseer data tracking has allowed DSRSD to accurately define the electricity costs by DERWA and receive adequate reimbursement.

1.11.3 Recycled Water Treatment Facility

Two major recycled water treatment energy efficiency improvements have contributed to reducing the energy input for recycled water treatment by over 20 percent over the past five years:

- Energy efficiency upgrade to the Wedeco UV disinfection system controls that was implemented as part of the DERWA Recycled Water Treatment Facilities Phase 2 in 2018.
- Decommissioning the more energy-intensive MF/UV treatment plant in 2021.

1.11.4 Recycled Water Distribution System (DERWA)

District staff have set up programming to be able to use time of use pumping to recycled water Reservoir R200 from Pump Stations R200A and R200B. However, staff have not yet experimented with shifting some of the pumping to these tanks from peak to off-peak electrical demand periods to reduce energy cost and reduce dependence on utility power during peak periods.

1.11.5 Water Distribution System

District staff have set up programming to be able to use time of use pumping to two of the potable water storage tanks (Reservoirs 30A and 4A) to assist in maintaining better water quality in the water distributions system. Recently, DSRSD has also experimented with shifting some of the pumping to these tanks from peak to off peak electrical demand periods to reduce energy cost and reduce dependence on utility power during peak periods. DSRSD is planning to expand this operation in the future to other tanks.

DSRSD has also experimented with mixer addition, water quality monitoring, and modifying the fill cycle duration in some reservoirs to help improve water quality and reduce the need for frequent fill / draw pumping to maintain fresh water.

1.11.6 Fleet Management

Fleet management has made a concerted effort over the past years to phase out larger vehicles and trucks and replace those with smaller vehicles, hybrid cars, and electric golf carts.

During Covid DSRSD implemented the policy of one employee per car but is currently in the process of relaxing this requirement and reducing vehicle miles traveled further.

1.11.7 Building Energy Efficiency

DSRSD has already undertaken several steps to make buildings energy efficient:

- Switched halogen lights to LED lights.
- Climate controls with mobile climate controls in pump stations.
- Installed heat loop system to recovery heat from cogeneration and digestion process for space heating in the maintenance shop (Building T).

1.12 Current Capital Improvement Plan Review

This section summarizes the CIP projects that are currently ongoing and planned over the next 10 years. As one important outcome of this Energy Facilities Master Plan, DSRSD targets a CIP that integrates Master Plan related CIP projects and projects recommended under the Energy CIP that will be developed in this Energy Facilities Master Plan. In addition, DSRSD would like to revisit currently scheduled CIP projects and define recommendations for projects that should be a) postponed, b) accelerated, or c) modified or omitted in light of possible outcomes of investigations conducted as part of this project.

1.12.1 Current Relevant CIP Projects

Table 1.25 summarizes CIP projects that are currently on DSRSD's CIP 2-year budget and 10-year plan with relevance to this Energy Facilities Master Plan project and the years for when they are scheduled.

Table 1.25 Summary of DSRSD's Currently Scheduled CIP Projects

Project	Year Scheduled	Comment
General		
Fleet Assets Program	2024-Ongoing	Continuous annual replacement funds for fleet replacement. Replacement with ZEVs will be evaluated as part of this Energy Facilities Master Plan.
Wastewater Treatment		
Heat Exchanger Replacements for Anaerobic Digesters No. 1 and 2	2024	New heat exchangers may improve digester heating efficiency.
Alum Addition	2024	Addition of alum to the facultative sludge lagoon return water may improve overall treatment efficiency, while increasing Scope 3 emissions associated with chemical use.
WWTP SCADA Improvements	2024-2025	Includes replacement of SCADA system and replacement of VFDs on nine pumps, both of which may increase energy efficiency.
Biogas Treatment System Improvements	2024-2025	Includes improvements to the biogas treatment system and the FOG receiving station. Clean biogas improves engine efficiency and FOG receiving will substantially increase biogas flows.
Cogeneration System Improvements and Upgrades	2024-2026	Replacement of cogeneration system components may improve cogeneration efficiency and reliability.
WWTP Replacement and Rehabilitation Program	2024-Ongoing	Replacement of pumps and mixers may increase energy efficiency.
DAFT System Improvements and Upgrades	2025	Replacement of DAFT TWAS pump and two pressurization pumps may increase energy efficiency.
Biosolids Dewatering Facility	2025-2029	New dewatering facility will increase energy use and chemical use. Decommissioning of the FSLs will eliminate direct methane emissions from the FSLs.
WWTP HVAC Replacements	2026	May improve HVAC energy efficiency.
WWTP/Biosolids Master Plan Update	2026	Recommendations from master plan may include expanding or building new facilities, changing treatment processes, and changing biosolids handling, all of which may impact power and chemicals usage.
Odor Reduction Tower Replacement	2026-2027	Replacement of odor control system may increase or reduce power usage. It may also impact chemicals and consumables usage, which impact Scope 3 GHG emissions.
WWTP Administration Building (Building A) Remodel/Renovation	2027	Renovation may impact lighting and HVAC energy usage.

Project	Year Scheduled	Comment
WWTP Motor Control Center and Distribution Panel "A" Improvements	2027-2028	Some equipment is old and replacement parts are not any longer available in case of failure. Some have short circuit rating limitations. Consider this for earlier replacement.
Cogeneration Engine Replacement	2028-2030	Replacing the engines will improve cogeneration efficiency and reliability. The need and timing of this project will be evaluated as part of this Energy Facilities Master Plan.
Cogeneration Engine# 4	2031	Project will increase cogeneration capacity. The need and timing of this project will be evaluated as part of this Energy Facilities Master Plan.
Nutrient Removal	Beyond 2033	Future treatment upgrades may be needed, which would impact power and chemical usage.
Emergency Power for Distribution Panel-D	Beyond 2033	Will increase back-up power reliability. The need and timing of this project will be evaluated as part of this Energy Facilities Master Plan.
Water System		
2023 Water Conservation Plan	2024	Will provide a framework for water conservation programs. Water conservation reduces treatment and pumping energy usage.
Leak Detection Technology Study	2024	May reduce water losses, in turn, reducing treatment and pumping energy usage.
Water System Master Plan and Operations Plan Update	2024-2025	Recommendations from master plan may include reliability or efficiency improvements.
Pump Station 1A Rehabilitation	2024-2025	Pump system replacement may improve energy efficiency.
Reservoir 1B Mixing System Replacement	2024-2025	New mixing system may have higher power use than existing.
2021 Alternative Water Supply Study – Phase 2	2024-2026	Recommendations from study may include increasing groundwater sources of recycled water and implementing potable reuse.
Water System Replacement and Rehabilitation Program	2024-Ongoing	Replacement of various pumps and other infrastructure may increase energy efficiency.
Pump Station 3A MCC Improvements	2025	Will replace electrical equipment, improving reliability.
Pump Station 20A Improvements	2027	Addition of new pump and modifications to MCC
Long-Term Water Resiliency Program	2028-Ongoing	May include a potable reuse project, desalination, or supplemental groundwater projects. New facilities will impact energy use.

1.12.2 Priorities for Potential Future Capital Improvement Program Additions

The following is a list of priority areas raised by DSRSD staff that should be evaluated as part of this project for possible inclusion and prioritization in the next DSRSD CIP update. The next updates will be defined starting in fall 2022.

1.12.2.1 Electrical

- Review electrical equipment rating and consider upgrades to equipment with high priority safety concerns.
- Identify single points of failure for electrical power supplies in the condition assessment as possible priorities for the next CIP cycle.
- Evaluate backup power supply for the laboratory, which is currently fed by only one breaker. This breaker cannot be maintained without interrupting the power supply for the full lab. Consider this as a design project beyond addition of power supplies for instruments. Suggested to provide a conceptual design in this Energy Facilities Master Plan to define where backup power is needed. The MCCs cannot be upgraded because the electrical room has space limitations. Would need to identify location of additional MCCs.
- Evaluate switchgear preventative maintenance (e.g., for breaker replacements), which is challenging because processes powered cannot be taken out of service.
- Optimize the backup power for the cogeneration system. Currently the diesel backup engines are started in a power supply failure situation and the cogeneration system is phased in as needed. This needs to occur in hand operation as both system programs fight each other. Consider changing the control description such that the cogeneration system provides a steady load, and the diesel engines are phased in as needed.

1.12.2.2 Process/Mechanical

- Consider energy and equipment changes in case facility would need to add nitrification in coming years. Would additional basins be needed? Timing of nutrient removal may be out by more than 10 years.
- Evaluate timing of diffuser replacement and consider changing to different manufacturer. Currently fine bubble diffusers are changed every 5 years (one basin per year).
- Evaluate reliability of air head manifolds. Recent failure in segment raises concerns about future failures.
- Consider blower replacement. The blowers are 20 years old and are approaching the end of their useful life.

1.12.2.3 Data Management

- Provide a recommendation on whether Foreseer software should continue to be maintained based on value for DSRSD.

Appendix 1A

PG&E ACCOUNT NUMBER CATEGORIZATION

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Category	PG&E Account #	PG&E Meter #	Descriptor
WWTP	221861436	1005725442	7176 Johnson Drive Streetscape Irrigation Controller
	4053823994	17P314	Sewer Plant
	4772588550	61520424	WWTP Lab HVAC
		50584952	WWTP Fleet Mtce Building
		1006763924	SERVICE AERATORS-FLS
	9876775750	2R9040	
	9710579242	1009654755	Alamo Trunk Sewer
Potable Water System	713296436	1009001722	Reservoir 3A?
	6741341553	1005726923	Reservoir 10B
		1006485295	Altitude Valve (Reservoir 10B)
		1006711215	Pump Station 4A
		1008833299	Pump Station 30A
		1009484123	PUMP STATION 300A
		1009503959	Pump Station 300B
		1009511424	Pump Station 200A
		1009511448	Pump Station 20B
		1009540556	Pump Station 300C
		1009847275	Pump Station 2B
		1010027828	Pump Station 4B?
		1010086007	Pump Station 10A
		1010332068	Turnout No. 4
		5000078738	RESERVOIR #208
	6772573820	1006485544	Reservoir 4A
		1006955700	Pump Station 2A
		1009454985	Pump Station 3B
		1009454986	Fire Pump Station 3C
		1009482822	Pump Station 3A
		1009486018	PUMP STATION 2C
		1009656975	Reservoir 300B
		1009847260	Pump Station 1A
		1009984042	Reservoir 2A w Pump Station 3C
		1010270795	Pump Station 3C
		1010384071	Turnout No. 1
		1010410391	Pump Station 20A
	9553855890	1010573565	
LAVWMA don't include	1289380223	1004473681	RECTIFIER STA P 3
		1004475291	SERVICE TO RECTIFIER
		1005373381	SERVICE TO RECTIFIER
		1005725723	
		1005726172	RECTIFIER
		1005726570	CATHOLIC PROTECTION SY
		1006494170	PUMP
		1008906063	RECTIFIER L-5
		1008990622	RECTIFIER STA P 4
		1010732167	RECTIFIER STA P 6
		1010579803	RECTIFIER STA L 3
		1010214998	RECTIFIER STA L 4
		(No meter)	LAUMA RECTF STA

Category	PG&E Account #	PG&E Meter #	Descriptor
District Office Building	2472675499	1009542707	District Office - Office
	2514342163	62394287	District Office - Administration Bldg
	2753993276	1009654860	District Office - Utility Building Shed
	4170882011	45971266	District Office - Utility Building OFC
Recycled Water Distribution	3048001111	1010140965	Pleasanton Recycled Water Turnout (needs confirmation)
	4336062954	1006751863	Reservoir R200 DERWA Tank 2
	6741341553	1009482825	Pump Station R300A
		1009513774	Pump Station R20 - Water Pump
		1009847221	Pump Station R300B - Water Pump Station
	7149544256	1009503954	Pump Station R200A
	8671211128	1006731690	Pump Station R200B
	9527215162	1009075775	Reservoir R100 - DERWA Tank 1
Field Operations Facilities	6772573820	47854290	VAC COMM/BTWN TENANTS
		1010084925	
		1006955370	Dublin Lift Station
Sewer Collection System	9824217199	1010270801	
LAVWMA	8440395259	1009970579	
	8482061923	1010422558	PUMP STATION MT

Appendix 1B

WWTP ELECTRICITY CONSUMPTION

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Facility	GE_BLDG	Asset Name	VFD?	HP	Estimated Average Runtime in 2021 (hrs/day)	Power Factor	kWh per Year
INFLUENT PUMP STATION	01 - PRE-TREATMENT	INFLUENT PUMP 1	yes	200	24	0.7	914,500
INFLUENT PUMP STATION	01 - PRE-TREATMENT	INFLUENT SUMP PUMP 1	no	5	0	1	-
INFLUENT PUMP STATION	01 - PRE-TREATMENT	INFLUENT PUMP 2	yes	200	24	0.7	914,500
INFLUENT PUMP STATION	01 - PRE-TREATMENT	INFLUENT SUMP PUMP 2	no	5	0	1	-
INFLUENT PUMP STATION	01 - PRE-TREATMENT	INFLUENT PUMP 3	yes	200	3	0.7	114,300
INFLUENT PUMP STATION	01 - PRE-TREATMENT	INFLUENT PUMP 4	yes	200	0	0.7	-
PRE-TREATMENT	01 - PRE-TREATMENT	EALS PUMP 1	yes	20	24	0.7	91,500
PRE-TREATMENT	01 - PRE-TREATMENT	EALS PUMP 2	yes	20	24	0.7	91,500
PRE-TREATMENT	01 - PRE-TREATMENT	EALS PUMP 3	yes	20	12	0.7	45,700
PRE-TREATMENT	01 - PRE-TREATMENT	BAR SCREEN 1	no	5	6	1	8,200
PRE-TREATMENT	01 - PRE-TREATMENT	BAR SCREEN 2	yes	5	6	0.7	5,700
PRE-TREATMENT	01 - PRE-TREATMENT	BAR SCREEN 3	yes	5	6	0.7	5,700
PRE-TREATMENT	01 - PRE-TREATMENT	BAR SCREEN BLDG EXHAUST FAN 1	no	7.5	24	1	49,000
PRE-TREATMENT	01 - PRE-TREATMENT	BAR SCREEN BLDG EXHAUST FAN 2	no	7.5	0	1	-
PRE-TREATMENT	01 - PRE-TREATMENT	BAR SCREEN WASHER COMPACTOR 1 (WEST)	no	5	short duty cycle	1	
PRE-TREATMENT	01 - PRE-TREATMENT	BAR SCREEN WASHER COMPACTOR 2 (EAST)	no	5	short duty cycle	1	
PRE-TREATMENT	GROUND LEVEL	PREAERATION BLOWER 1	no	3	24	1	19,600
PRE-TREATMENT	GROUND LEVEL	PREAERATION BLOWER 2	no	3	0	1	-
PRE-TREATMENT	01 - PRE-TREATMENT	PREAERATION BLOWER 3	no	3	0	1	-
PRE-TREATMENT	01 - PRE-TREATMENT	SCREEN ROOM (TO ORT) EXHAUST FAN 2	no	7.5	24	1	49,000
PRE-TREATMENT	01 - PRE-TREATMENT	GRIT PUMP 1	no	10	6	1	16,300
PRE-TREATMENT	01 - PRE-TREATMENT	GRIT CLASSIFIER 1 Conveyor	no	5	24	1	32,700
PRE-TREATMENT	01 - PRE-TREATMENT	GRIT CLASSIFIER 2 Conveyor	no	5	24	1	32,700
PRE-TREATMENT	01 - PRE-TREATMENT	GRIT SCUM PUMP 2	no	5	6	1	8,200
PRE-TREATMENT	01 - PRE-TREATMENT	GRIT SCUM PUMP 3	no	5	6	1	8,200
PRE-TREATMENT	2 - PRE-TREATMENT	GRIT PUMP 4	no	10	6	1	16,300
PRE-TREATMENT	01 - PRE-TREATMENT	GRIT STORAGE ROOM EXHAUST FAN	no	15	24	1	98,000
PRE-TREATMENT	01 - PRE-TREATMENT	SECONDARY CLARIFIER TANK 1 EXHAUST FAN TO BIO-BED	no	10	24	1	65,300
PRE-TREATMENT	01 - PRE-TREATMENT	SECONDARY CLARIFIER TANK 2 EXHAUST FAN TO BIO-BED	no	10	0	1	-
PRE-TREATMENT	01 - PRE-TREATMENT	ORT EFFLUENT SUPPLY PUMP 1	no	10	24	1	65,300
PRE-TREATMENT	01 - PRE-TREATMENT	ORT EFFLUENT SUPPLY PUMP 2	no	10	0	1	-
PRIMARY TREATMENT	Headworks and Prim. Sediment	PRIMARY SCUM PUMP 1	no	10	12	1	32,700
PRIMARY TREATMENT	03 - PRIMARY TREATMENT	PRIMARY SCUM PUMP 2	no	7.5	12	1	24,500
PRIMARY TREATMENT	03 - PRIMARY TREATMENT	PRIMARY 1 SLUDGE COLLECTOR	yes	0.5	24	0.7	2,300
PRIMARY TREATMENT	03 - PRIMARY TREATMENT	PRIMARY 2 SLUDGE COLLECTOR	yes	0.5	24	0.7	2,300
PRIMARY TREATMENT	03 - PRIMARY TREATMENT	PRIMARY 3 SLUDGE COLLECTOR	yes	0.5	24	0.7	2,300
PRIMARY TREATMENT	03 - PRIMARY TREATMENT	PRIMARY 4 SLUDGE COLLECTOR	yes	0.5	24	0.7	2,300
PRIMARY TREATMENT	Headworks and Prim. Sediment	PRIMARY 5 SLUDGE COLLECTOR	yes	0.5	24	0.7	2,300
PRIMARY TREATMENT	03 - PRIMARY TREATMENT	PRIMARY SLUDGE GRINDER	no	7.5	24	1	49,000
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	MIXER 1	no	9	24	1	58,800
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	MIXER 2	no	9	24	1	58,800
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	MIXER 3	no	9	24	1	58,800
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	MIXER 4	no	9	24	1	58,800
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	BLOWER 1	yes	400	24	0.7	1,829,100
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	BLOWER 2	yes	400	12	0.7	914,500
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	BLOWER 3	yes	400	0	0.7	-
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	MIXED LIQUOR WAS PUMP 1	yes	20	24	0.7	91,500
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	MIXED LIQUOR WAS PUMP 2	yes	20	12	0.7	45,700
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	MIXED LIQUOR WAS PUMP 3	yes	20	0	0.7	-
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	RAS PUMP 1	yes	60	24	0.5	196,000
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	RAS PUMP 2	yes	60	24	0.5	196,000
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	RAS PUMP 3	yes	60	24	0.5	196,000
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	RAS PUMP 4	yes	125	24	0.5	408,300
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK 1 COLLECTOR	no	5	24	1	32,700
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK 2 COLLECTOR	no	5	24	1	32,700
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK 3 COLLECTOR	no	5	24	1	32,700
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK 4 COLLECTOR	no	5	24	1	32,700
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK DRAINAGE PUMP 1	no	20	0	1	-
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK 1 SCUM PUMP	no	5	12	1	16,300
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK 2 SCUM PUMP	no	5	12	1	16,300
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK 3 SCUM PUMP	no	5	12	1	16,300
SECONDARY TREATMENT	04 - SECONDARY TREATMENT	SEC CL TANK 4 SCUM PUMP	no	5	12	1	16,300
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 1	no	500	1	1	136,100
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 2	no	600	2	1	326,600
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 3	no	500	9	1	1,224,800
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 4	no	600	7	1	1,143,200
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 5	no	500	2	1	272,200
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 6	no	500	2	1	272,200
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 7	no	600	9	1	1,469,800
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 8	no	500	5	1	680,500
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 9	no	600	6	1	979,800
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	SEC EFF DISCHARGE PUMP 10	no	500	3	1	408,300
LAVWMA SEC EFF PUMP STATION	04 - PUMP STATION	WASH DOWN SYSTEM PUMP	no	100	0	1	-
EFFLUENT PUMP STATION 1	06 - EFFLUENT PUMPING	FINAL EFFLUENT PUMP 1	yes	250	4	0.7	190,500
EFFLUENT PUMP STATION 1	06 - EFFLUENT PUMPING	FINAL EFFLUENT PUMP 3	yes	250	0	0.7	-
EFFLUENT PUMP STATION 1	06 - EFFLUENT PUMPING	FINAL EFFLUENT PUMP 5	yes	250	0	0.7	-
EFFLUENT PUMP STATION	Effluent Pump Station	MF FEED TRANSFER PUMP 1	no	40	4	1	43,500
EFFLUENT PUMP STATION	Effluent Pump Station	MF FEED TRANSFER PUMP 2	no	40	0	1	-
EFFLUENT PUMP STATION	OUTSIDE	3 WATER PUMP 1	yes	75	24	0.7	342,900
EFFLUENT PUMP STATION	OUTSIDE	3 WATER PUMP 2	yes	75	0	0.7	-
EFFLUENT PUMP STATION	OUTSIDE	3 WATER PUMP 3	yes	75	0	0.7	-
EFFLUENT PUMP STATION 2	EFFLUENT PUMP STATION 2	BASIN 4 EFFLUENT PUMP 2	yes	250	13	0.7	619,200
EFFLUENT PUMP STATION 2	EFFLUENT PUMP STATION 2	BASIN 4 EFFLUENT PUMP 3	yes	250	0	0.7	-
EFFLUENT PUMP STATION 2	EFFLUENT PUMP STATION 2	BASIN 4 EFFLUENT PUMP 4	yes	250	0	0.7	-
EFFLUENT PUMP STATION 2	EFFLUENT PUMP STATION 2	BASIN 4 EFFLUENT PUMP 5	yes	75	0	0.7	-
EFFLUENT PUMP STATION 2	EFFLUENT PUMP STATION 2	BASIN 4 EFFLUENT PUMP 6	yes	75	0	0.7	-
DAFT	07 - DAFT	TANK DRAIN PUMP	no	20	1	1	5,400
DAFT	07 - DAFT	DAFT SOUTH PIT SUMP PUMP 1	no	5	12	1	16,300
DAFT	07 - DAFT	DAFT SOUTH PIT SUMP PUMP 2	no	5	0	1	-

DAFT	07 - DAFT	DAFT AIR COMPRESSOR 1	no	40	24	1	261,300
DAFT	07 - DAFT	DAFT AIR COMPRESSOR 2	no	40	12	1	130,600
DAFT	07 - DAFT	DAFT AIR COMPRESSOR 3	no	40	0	1	-
DAFT	07 - DAFT	DAFT PRESSURIZATION PUMP 1	no	125	24	1	816,500
DAFT	07 - DAFT	DAFT PRESSURIZATION PUMP 2	no	150	0	1	-
DAFT	07 - DAFT	DAFT THICK SLUDGE PUMP 1 (TWAS)	yes	25	20	0.7	95,300
DAFT	07 - DAFT	DAFT THICK SLUDGE PUMP 2 (TWAS)	yes	25	24	0.7	114,300
DAFT	07 - DAFT	DAFT THICK SLUDGE PUMP 3 (TWAS)	yes	25	20	0.7	95,300
DAFT	07 - DAFT	DAFT BUILDING EXHAUST FAN 1	no	5	24	1	32,700
DAFT	07 - DAFT	DAFT BUILDING EXHAUST FAN 2	no	15	24	1	98,000
DIGESTERS	08 - DIGESTERS	DIGESTER 1 MECHANICAL MIXER	no	10	24	1	65,300
DIGESTERS	08 - DIGESTERS	DIGESTER 1 CIRCULATION PUMP	no	15	24	1	98,000
DIGESTERS	08 - DIGESTERS	DIGESTER 2 MECHANICAL MIXER	no	10	24	1	65,300
DIGESTERS	08 - DIGESTERS	DIGESTER 2 CIRCULATION PUMP	no	15	24	1	98,000
DIGESTERS	08 - DIGESTERS	DIGESTER 3 MECHANICAL MIXER 1	no	7.5	24	1	49,000
DIGESTERS	08 - DIGESTERS	DIGESTER 3 MECHANICAL MIXER 2	no	7.5	24	1	49,000
DIGESTERS	08 - DIGESTERS	DIGESTER 3 MECHANICAL MIXER 3	no	7.5	24	1	49,000
DIGESTERS	08 - DIGESTERS	DIGESTER 3 CIRCULATION PUMP 1	no	15	24	1	98,000
DIGESTERS	08 - DIGESTERS	DIGESTER 4 MECHANICAL MIXER 1	no	7.5	24	1	49,000
DIGESTERS	08 - DIGESTERS	DIGESTER 4 MECHANICAL MIXER 2	no	7.5	24	1	49,000
DIGESTERS	08 - DIGESTERS	DIGESTER 4 MECHANICAL MIXER 3	no	7.5	24	1	49,000
DIGESTERS	08 - DIGESTERS	DIGESTER 4 HEAT EXCHANGER HRS PUMP	no	7.5	24	1	49,000
DIGESTERS	08 - DIGESTERS	DIGESTED SLUDGE PUMP 1	yes	25	24	0.7	114,300
DIGESTERS	08 - DIGESTERS	DIGESTED SLUDGE PUMP 2	yes	25	12	0.7	57,200
DIGESTERS	08 - DIGESTERS	DIGESTED SLUDGE PUMP 3	yes	25	0	0.7	-
FSL/DLD	09 - FSL/DLD	RECLAIMED WATER PUMP 1	no	75	2	1	40,800
FSL/DLD		FSL Pump	no	10	0	1	-
FSL/DLD	09 - FSL/DLD	FSL HORIZONTAL SURFACE MIXER 2	no	5	12	1	16,300
FSL/DLD	09 - FSL/DLD	FSL HORIZONTAL SURFACE MIXER 5	no	5	12	1	16,300
FSL/DLD	09 - FSL/DLD	FSL HORIZONTAL SURFACE MIXER 8	no	5	12	1	16,300
FSL/DLD	09 - FSL/DLD	FSL HORIZONTAL SURFACE MIXER 9	no	5	12	1	16,300
FSL/DLD	09 - FSL/DLD	FSL HORIZONTAL SURFACE MIXER 10	no	5	12	1	16,300
FSL/DLD	09 - FSL/DLD	FSL HORIZONTAL SURFACE MIXER 11	no	5	12	1	16,300
FSL/DLD	09 - FSL/DLD	FSL HORIZONTAL SURFACE MIXER 12	no	5	12	1	16,300
FSL/DLD	09 - FSL/DLD	FSL CONTROL BLDG VENTILATION FAN	no	5	24	1	32,700
CO-GENERATION	10 - CO-GENERATION	JACKET WATER CIRCULATING PUMP	no	5	24	1	32,700
CO-GENERATION	10 - CO-GENERATION	STARTING AIR COMPRESSOR 1	no	15	6	1	24,500
CO-GENERATION		STARTING AIR COMPRESSOR 2	no	15	6	1	24,500
CO-GENERATION	10 - CO-GENERATION	HRS PRIMARY LOOP PUMP 1	no	10	24	1	65,300
CO-GENERATION	10 - CO-GENERATION	HRS PRIMARY LOOP PUMP 2	no	10	24	1	65,300
CO-GENERATION	10 - CO-GENERATION	HRS PRIMARY LOOP PUMP 3	no	10	24	1	65,300
CO-GENERATION	10 - CO-GENERATION	COGEN ENGINE ROOM EXHAUST FAN 1	no	7.5	24	1	49,000
CO-GENERATION	10 - CO-GENERATION	COGEN ENGINE ROOM SUPPLY FAN 1	no	7.5	24	1	49,000
CO-GENERATION	10 - CO-GENERATION	ENGINE 1 COOLING PUMP	no	5	24	1	32,700
CO-GENERATION	10 - CO-GENERATION	ENGINE 2 COOLING PUMP	no	5	24	1	32,700
CO-GENERATION	10 - CO-GENERATION	ENGINE 3 COOLING PUMP	no	5	24	1	32,700
CO-GENERATION	12 - MISCELLANEOUS	PUMP FOR CHILLER/COGEN COOLING WATER	no	15	unknown	1	-
CO-GENERATION	10 - CO-GENERATION	FUEL SKID GAS COMPRESSOR 331	no	40	12	1	130,600
CO-GENERATION	10 - CO-GENERATION	FUEL SKID GAS COMPRESSOR 371	no	40	12	1	130,600
WWTP/HVAC	12 - MISCELLANEOUS	BLDG A- AIR HANDLING UNIT 1	no	15	24	1	98,000
WWTP/HVAC	12 - MISCELLANEOUS	BLDG A- AIR HANDLING UNIT 2	no	7.5	24	1	49,000
WWTP/HVAC	WWTP	BLDG A-AIR HANDLING UNIT 3	no	7.5	24	1	49,000
WWTP/HVAC	WWTP	BLDG A- AIR HANDLING UNIT 4	no	7.5	24	1	49,000
WWTP/HVAC	WWTP	BLDG A-AIR HANDLER UNIT 5	no	7.5	24	1	49,000
WWTP/HVAC	WWTP	BLDG A-AIR HANDLING UNIT 6	no	7.5	24	1	49,000
WWTP/HVAC	04 - SECONDARY TREATMENT	BLDG B- AIR HANDLING UNIT 1	no	5	24	1	32,700
WWTP/HVAC	04 - SECONDARY TREATMENT	BLDG B- AIR HANDLING UNIT 2	no	5	24	1	32,700
WWTP/HVAC	01 - PRE-TREATMENT	BULDG C- AIR HANDLING UNIT 1	no	5	24	1	32,700
WWTP/HVAC	01 - PRE-TREATMENT	BAR SCREEN BUILDING AIR HANDLING UNIT 1	no	5	24	1	32,700
WWTP/HVAC	Effluent Pump Station	BLDG G-AIR HANDLING UNIT 1	no	7.5	24	1	49,000
WWTP/HVAC	07 - DAFT	BLDG K- AIR HANDLING UNIT 1	no	7.5	24	1	49,000
WWTP/HVAC	10 - CO-GENERATION	COGEN SWITCHGEAR ROOM AIR HANDLING UNIT	no	7.5	24	1	49,000
WWTP/HVAC	04 - PUMP STATION	ROOF TOP EXHAUST FAN EF-1 (SOUTH)	no	12	24	1	78,400
WWTP/HVAC	04 - PUMP STATION	ROOF TOP EXHAUST FAN EF-4 (NORTH)	no	12	24	1	78,400
WWTP/HVAC	11 - BUILDINGS	FUME HOOD 2 SUPPLY FAN EF-1	no	5	unknown	1	-
WWTP/HVAC	04 - PUMP STATION	LAB EXHAUST FAN EF-6	no	5	unknown	1	-
WWTP/HVAC	04 - PUMP STATION	MEN'S ROOM EXHAUST FAN EF-7	no	5	unknown	1	-
WWTP/HVAC	04 - PUMP STATION	WATER HEATER ROOM EXHAUST FAN EF-8	no	5	unknown	1	-
WWTP/HVAC	11 - BUILDINGS	BUILDING D AIR HANDLING UNIT HW COIL PUMP	no	5	unknown	1	-
MISCELLANEOUS	12 - MISCELLANEOUS	ABSORPTION CHILLER HRS PUMP	no	7.5	24	1	49,000
MISCELLANEOUS	12 - MISCELLANEOUS	BLDG A- CHILLER 1	no	7.5	12	1	24,500
MISCELLANEOUS	12 - MISCELLANEOUS	BLDG A-CHILLER 2	no	7.5	12	1	24,500
MISCELLANEOUS	12 - MISCELLANEOUS	CHILLED WATER BOOSTER PUMP	no	5	24	1	32,700

Appendix 1C

VEHICLE FLEET INVENTORY DATA

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DSRSD Category / Group	Year/Make/Model	Replacement Cost	DSRSD Label	License Plate	VIN	2021 Annual Vehicle Miles Traveled (VMT)	2021 Fuel Consumption	Fuel Economy (mpg)	Fuel Type	Age of Vehicle	Remaining Useful Life	Anticipated DSRSD Target Replacement Year
| 15. MANAGEMENT SERIVCES	2014 FORD FUSION	$ 20,000.00	106	1429250	3FA6P0G78ER244162	1894.00	185.70	16.5	Gasoline	8	3	2025
| 42. PLANNING & PERMITTING	2000 FORD RANGER	$ 25,000.00	61	999525	1FTZR15VXYPB05980	903.00	86.80	11	Gasoline	22	0	2022
| 42. PLANNING & PERMITTING	2003 GMC SONOMA		72	1166888	1GTCS19X638282003	518.00	40.00	11.4	Gasoline	19	0	2022
| 42. PLANNING & PERMITTING	2008 FORD EXPLORER	$ 28,000.00	95	1303736	1FMEU73EX8UA94754	467.00	38.60	11	Gasoline	14	2	2024
| 42. PLANNING & PERMITTING	2008 FORD F-150	$ 30,000.00	96	1300993	1FTPW12508KD44553	749.00	61.90	11.9	Gasoline	14	2	2024
| 50. OPERATIONS ADMIN	2015 FORD FUSION	$ 20,000.00	107	1458150	3FA6P0G70FR208144	1589.00	92.50	20.5	Gasoline	7	3	2025
| 51. FIELD OPERATIONS	2002 FORD F-150		4	1103003	1FTRX18L02NB19101	565.00	64.70	11.4	Gasoline	20	0	2022
| 51. FIELD OPERATIONS	2008 FORD F350	$ 59,000.00	88	1206105	1FDSF30548EA28947	4746.00	589.80	8.3	Gasoline	14	2	2024
| 51. FIELD OPERATIONS	2008 FORD F350	$ 57,000.00	93	1305700	1FDWF37Y98EC99942	4554.00	814.70	5.2	Gasoline	14	2	2024
| 51. FIELD OPERATIONS	2008 FORD F350	$ 37,000.00	86	1269859	1FTWF33Y48EA15353	4817.00	764.10	5.2	Gasoline	14	2	2024
| 51. FIELD OPERATIONS	2014 FREIGHTLINER CAMEL	$ 500,000.00	109	1461112	1FVHG3CY9EHFZ2516	1136.00	521.20	1.5	Diesel	8	3	2025
| 52. PLANT OPERATIONS	2002 FORD F-250 SUPER DUTY	$ 25,000.00	63	1102995	1FTNX20LX2EC28567	630.00	110.50	8.8	Gasoline	20	0	2022
| 52. PLANT OPERATIONS	2014 FORD F150	$ 25,000.00	111	1460245	1FTFX1CF9EKG51537	10777.00	750.10	14.7	Gasoline	8	3	2025
| 53. MECHANICAL MAINTENANCE	2002 FORD RANGER		68	1103001	1FTZR15E12PA95007	629.00	69.70	12.4	Gasoline	20	0	2022
| 53. MECHANICAL MAINTENANCE	2004 FORD F250	$ 32,000.00	75	1184843	1FTNF20L14EB78681	1322.00	239.70	9	Gasoline	18	1	2023
| 53. MECHANICAL MAINTENANCE	2004 FORD F-250 SUPER DUTY	$ 32,000.00	74	1184844	1FTNF20L54EB78585	1046.00	118.20	10.4	Gasoline	18	1	2023
| 53. MECHANICAL MAINTENANCE	2004 FORD F-250 SUPER DUTY	$ 30,000.00	55	1201453	1FTNF20LX4ED78894	2684.00	385.70	5.9	Gasoline	18	1	2023
| 53. MECHANICAL MAINTENANCE	2004 FORD F-250 SUPER DUTY	$ 59,000.00	76	1194242	1FTNX20L04ED86144	2226.00	307.00	7.4	Gasoline	18	1	2023
| 53. MECHANICAL MAINTENANCE	2005 STERLING CONDOR	$ 380,000.00	77	1201527	49HHBVDC26RV87206	658.00	102.60	4.4	Diesel	17	1	2023
| 54. ELECTRICAL MAINTENANCE	2003 FORD F250	$ 40,000.00	71	1166880	3FTNX20L73MB18054	479.00	64.60	6.1	Gasoline	19	0	2022
| 54. ELECTRICAL MAINTENANCE	2006 FORD F-250 SUPER DUTY	$ 18,000.00	21	1218098	1FTNF20566EC61351	1694.00	187.00	8.5	Gasoline	16	1	2023
| 54. ELECTRICAL MAINTENANCE	2015 FORD ESCAPE	$ 25,000.00	108	1458045	1FMCU0F79FUA68350	869.00	61.70	14.1	Gasoline	7	3	2025
| 54. ELECTRICAL MAINTENANCE	2016 FORD TRANSIT CONNECT CARGO	$ 29,000.00	114	1493421	NM0LS7E79G1261344	1970.00	99.10	20.7	Gasoline	6	4	2026
| 55. ANALYTICAL LAB	2002 FORD RANGER	$ 25,000.00	64	1102997	1FTYR14UX2PA95009	1030.00	88.00	12.7	Gasoline	20	0	2022
| 55. ANALYTICAL LAB	2008 FORD F350	$ 59,000.00	94	1301017	1FDWF30568ED28412	2386.00	262.20	9.4	Gasoline	14	2	2024

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Appendix 1D

GHG EMISSIONS FACTORS AND RESULTS

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EMISSION FACTORS

	Description	Factor	Unit	Source
100-YEAR GLOBAL WARMING POTENTIALS (GWP)				
	Methane GWP	25		Intergovernmental Panel on Climate Change, Fourth Assessment Report (AR4) (IPCC, 2007)
	Nitrous oxide GWP	298		Intergovernmental Panel on Climate Change, Fourth Assessment Report (AR4) (IPCC, 2007)
CHEMICALS PRODUCTION				
	Ferric Chloride (FeCl2)	0.05	kWh/lb	Owen, William F. 1982. pg. 43. Energy in Wastewater Treatment. Prentice-Hall, Inc., Englewood Cliffs, NJ.
	Ferrous Chloride (FeCl3)	0.05	kWh/lb	Assume same as ferric chloride.
	Polymers	17,000	Petroleum Btu/lb	Owen, William F. 1982. pg. 43. Energy in Wastewater Treatment. Prentice-Hall, Inc., Englewood Cliffs, NJ.
	Sodium hypochlorite (NaOCl)	2.5	kWh/lb	"General Electrochemistry", by Dr. R. C. Rhees, Vice President Research, Pepcon Systems Inc. P.O. Box 629, Cedar City, Utah 84720 12/14/07 (MLH) - Have not checked this reference; obtained this info from: Energy Benchmarking Secondary Wastewater Treatment and Ultraviolet Processes at Various Municipal Wastewater Treatment Facilities. February 2002. Attachment D. SBW Consulting. Pacific Gas & Electric Company.
	Aluminum sulfate	1,000	Natural gas Btu/lb	Owen, William F. 1982. pg. 43. Energy in Wastewater Treatment. Prentice-Hall, Inc., Englewood Cliffs, NJ.
	Ammonium hydroxide (Aqua ammonia)	4.2	kWh/lb	Hu, Emmalynne. 2007. "An Evaluation of the Environmental Sustainability of Ultraviolet Versus Chlorine Disinfection. WEF.
	Fluoride (Hydrofluosilic acid)	0.97	kg CO2e/kg	Winniped WSRP South End Plant Process Selection Report, Appendix H - Emission factors in kg CO2-equivalent per unit, 2012
REPLACEMENT MATERIALS PRODUCTION				
	SulfaTreat (Unison H2S removal media)	0.75	kg CO2e/kg	From manufacturer. Contact info: Brian Kay at mailto:bkay@miswaco.slb.com
	SAG media (Unison siloxane removal media)	34,500	Natural gas Btu/lb	Owen, William F. 1982. pg. 43. Energy in Wastewater Treatment. Prentice-Hall, Inc., Englewood Cliffs, NJ.
	Microsand	16	kWh/short ton	http://www.metso.com/miningandconstruction/MaTobox7.nsf/DocsByID/EAE6CA3B8E216295C2257E4B003FBBA6/$File/Basics-in-minerals-processing.pdf
	Microsand	0.008	kWh/lb	Calculated
ELECTRICITY RELATED EMISSIONS - updates at:				
Carbon Dioxide				
	Specific Electricity Factor - PG&E	160	lbs CO_2/MWh	PG&E Greenhouse Gas Emissions Factors Fact Sheet
Methane				
	Electricity - California	0.033	lbs CH_4/MWh	eGRID 2019 Table 1. Subregion Output Emission Rates
Nitrous Oxide				
	Electricity - California	0.0037	lbs N_2O/MWh	eGRID 2019 Table 1. Subregion Output Emission Rates
NATURAL GAS, BIOGAS, AND TRANSPORTATION FUEL RELATED EMISSIONS				
Carbon Dioxide				
	Natural Gas Production	0.0365	kg CO_2/1000 cu ft	Table 4.2.4 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)
	Natural Gas Combustion	53.06	kg CO_2/MMBtu	40 CFR Part 98, Subpart C: Table C–1 Default CO2 Emission Factors and High Heat Values for Various Types of Fuel (last amended 3/31/2022)
	Natural Gas Combustion	54.39	kg CO_2/1000 cu ft	Calculated
	Biogas Combustion	52.07	kg CO_2/MMBtu	40 CFR Part 98, Subpart C: Table C–1 Default CO2 Emission Factors and High Heat Values for Various Types of Fuel (last amended 3/31/2022)
	Biogas Combustion	31.21	kg CO_2/1000 cu ft	Calculated
	Diesel fuel	73.96	kg CO_2/mmBtu	EPA Climate Leaders Greenhouse Gas Inventory Guidance - Direct Emissions from Mobile Combustion Source, Table A-3: Emission Factors for Equation 2 (EF2) - Emissions per Energy Unit for Fossil Fuel Combustion (December 2020)
	Diesel fuel	10.21	kg CO_2/gal	Calculated
	Petroleum - Distillate Fuel Oil No. 4	75.04	kg CO_2/mmBtu	Calculated
Methane				
	Natural Gas Production	0.0625	kg CH_4/1000 cu ft	Table 4.2.4 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)
	Natural Gas Combustion	0.001	kg CH_4/MMBtu	40 CFR Part 98, Subpart C: Table C–2 Default CH4 and N2O Emission Factors for Various Types of Fuel (last amended 3/31/2022)
	Natural Gas Combustion	0.00103	kg CH_4/1000 cu ft	Calculated

	Biogas Combustion	0.0032	kg CH_4/MMBtu	40 CFR Part 98, Subpart C: Table C–2 Default CH4 and N2O Emission Factors for Various Types of Fuel (last amended 3/31/2022)
	Biogas Combustion	0.0019	kg CH_4/1000 cu ft	Calculated
	Diesel medium- and heavy-duty trucks and buses	0.0051	g CH_4/mile	EPA Climate Leaders Greenhouse Gas Inventory Guidance - Direct Emissions from Mobile Combustion Source, Table B-1: CH4 and N2O Emission Factors for Onroad Vehicles (December 2020)
	Petroleum Products	0.003	kg CH_4/MMBtu	40 CFR Part 98, Subpart C: Table C–2 Default CH4 and N2O Emission Factors for Various Types of Fuel (last amended 3/31/2022)
Nitrous Oxide				
	Natural Gas Production	0.000000595	kg N_2O/1000 cu ft	Table 4.2.4 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)
	Natural Gas Combustion	0.0001	kg N_2O/MMBtu	40 CFR Part 98, Subpart C: Table C–2 Default CH4 and N2O Emission Factors for Various Types of Fuel (last amended 3/31/2022)
	Natural Gas Combustion	0.000103	kg N_2O/1000 cu ft	Calculated
	Biogas Combustion	0.00063	kg N_2O/MMBtu	40 CFR Part 98, Subpart C: Table C–2 Default CH4 and N2O Emission Factors for Various Types of Fuel (last amended 3/31/2022)
	Biogas Combustion	0.0004	kg N_2O/1000 cu ft	Calculated
	Diesel medium- and heavy-duty trucks and buses	0.0048	g N_2O/mile	EPA Climate Leaders Greenhouse Gas Inventory Guidance - Direct Emissions from Mobile Combustion Source, Table B-1: CH4 and N2O Emission Factors for Onroad Vehicles (December 2020)
	Petroleum Products	0.0006	kg N_2O/MMBtu	40 CFR Part 98, Subpart C: Table C–2 Default CH4 and N2O Emission Factors for Various Types of Fuel (last amended 3/31/2022)
DIRECT EMISSIONS				
Methane				
	Direct Emission: BOD_5 - Facultative Lagoon	0.6	kg CH_4/kg BOD_5	2019 Refinement to IPCC, V5, Ch6, Table 6.2
	Shallow lagoon MCF	0.2	correction factor	2020 Refinement to IPCC, V5, Ch6, Table 6.3
	Deep lagoon MCF	0.8	correction factor	2020 Refinement to IPCC, V5, Ch6, Table 6.3
Nitrous Oxide				
	Process emissions with NdN	7	g N_2O/ person-year	Equation 10.7, Page 105. Local Government Operations Protocol. August 2008.
	Process emissions without NdN	3.2	g N_2O/ person-year	Equation 10.8, Page 105. Local Government Operations Protocol. August 2008.
	Process emissions with NdN	0.01	kg N_2O/kg N removed	"Greenhouse Gas Emission Inventory and Management Strategy Guidelines for Water Utilities", Water Research Foundation and California Urban Water Agencies, 2009
	Process emissions without NdN	0.3	kg N_2O/kg N removed	"Greenhouse Gas Emission Inventory and Management Strategy Guidelines for Water Utilities", Water Research Foundation and California Urban Water Agencies, 2010
	Effluent Discharge	0.005	kg N_2O-N/kg sewage-N produced	Equation 10.9, Page 106. Local Government Operations Protocol. August 2008.
MISCELLANEOUS				
	Natural Gas HHV	1025	Btu/cubic foot	40 CFR Part 98, Subpart C: Table C–1 Default CO2 Emission Factors and High Heat Values for Various Types of Fuel (last amended 3/31/2022)
	Biogas HHV	599	Btu/scf	From DSRSD data in Table 3-8, Biogas System Improvements Evaluation and Engineering Report, Black & Veatch (2019)
	Diesel fuel	0.138	mmBtu/gal	EPA Climate Leaders Greenhouse Gas Inventory Guidance - Direct Emissions from Mobile Combustion Source, Table A:1 Emission Factors for Equation 1 (EF1) - Emissions per Mass or Volume Unit for Fossil Fuel Combustion (December 2020)
	Heavy duty truck fuel efficiency	6.7	mile/gal	U.S. EIA Motor Vehicle Mileage, Fuel Consumption, and Fuel Economy - Heavy-Duty Trucks (2020)
	Cake land application net emissions	-0.06605	metric ton CO2e/dry metric ton biosolids	BEAM*2022 net emissions including avoided emissions from carbon sequestration and fertilizer offset and direct N2O emissions from land applied biosolids.
	Food waste diversion from landfill	0.388	metric ton CO2e/wet short ton FW	Table 7 of the METHOD FOR ESTIMATING GREENHOUSE GAS EMISSION REDUCTIONS FROM DIVERSION OF ORGANIC WASTE FROM LANDFILLS TO COMPOST FACILITIES DRAFT (ca.gov)

Baseline Inventory 2021 - Breakdown by Emission Type

Wastewater Treatment Plant (Figure 1.52)

Emission Type	Metric Tons CO2e
Avoided Purchased Electricity	-702
Purchased Electricity	736
Natural Gas Production - Cogen	103
Natural Gas Combustion - Cogen	3,507
Natural Gas Production - Fleet Building	0.35
Natural Gas Combustion - Fleet Building	12
Biogas Combustion (excludes biogenic)	14
Diesel Gas Combustion - FSLs and DLDs	34
Treatment Process (N_2O)	179
Effluent Discharge (N_2O)	1.9
Sludge Lagoons (CH_4)	16
Chemicals Production	2.6
Chemicals Transport	4.3
Replacement Materials Production	14
Replacements Materials Transport	4.2
Total	**3,926**

DERWA Recycled Water Treatment and Distribution (Figure 1.53)

Emission Type	Metric Tons CO2e
Purchased Electricity - Recycled Water Treatment	174
Purchased Electricity - DERWA Recycled Water Distribution	33
Purchased Electricity - PSR1	163
Chemicals Production	34
Chemicals Transport	10
Replacement Materials Production	0.02
Replacements Materials Transport	0.53
Total	**414**

DSRSD Recycled Water Distribution (Figure 1.54)

Emission Type	Metric Tons CO2e
Purchased Electricity	22
Total	**22**

Potable Water Distribution (Figure 1.55)

Emission Type	Metric Tons CO2e
Purchased Electricity	288
Chemicals Production	2.6
Chemicals Transport	4.2
Total	**295**

LAVWMA Efffluent Pump Station (Figure 1.56)

Emission Type	Metric Tons CO2e
Purchased Electricity	531
Total	**531**

District Administrative Buildings and Field Operations Facility (Figure 1.57)

Emission Type	Metric Tons CO2e
Purchased Electricity - District Administrative Building	21
Purchased Electricity - Field Operations Facility	20
Natural Gas Production - District Administrative Building	1.1
Natural Gas Production - Field Operations Facility	0.53
Natural Gas Combustion - District Administrative Building	39
Natural Gas Combustion - Field Operations Facility	18
Total	**100**

Vehicle Fleet (Figure 1.58)

Emission Type	Metric Tons CO2e
Gasoline Combustion	83
Diesel Combustion	6
Total	**89**

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Appendix 1E

PRESENTATION FOR THE DSRSD BOARD ON RESULTS OF THE PHASE 1 ENERGY EVALUATION

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Energy Facilities Master Plan

Board Update No. 1

September 27, 2022

carollo®

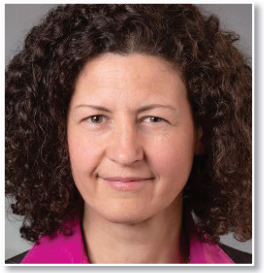
Dublin San Ramon Services District
Water, wastewater, recycled water

// Agenda

- Project overview
- Review Energy and GHG baseline for all DSRSD facilities
- Review preliminary energy opportunities assessment
- Solicit preferences on the Guiding Principles

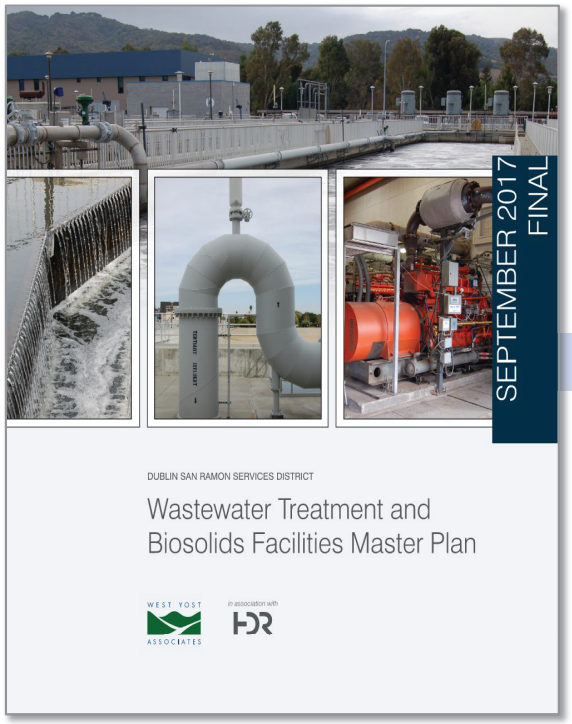
Speakers today:

Jason Ching
Project Manager



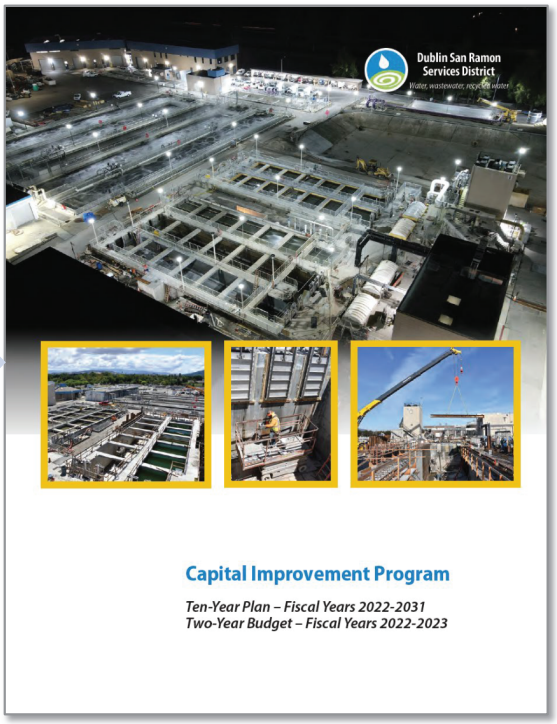
Tanja Rauch-Williams
Project Manager

// Project Background



Wastewater Treatment and Biosolids Facilities Master Plan

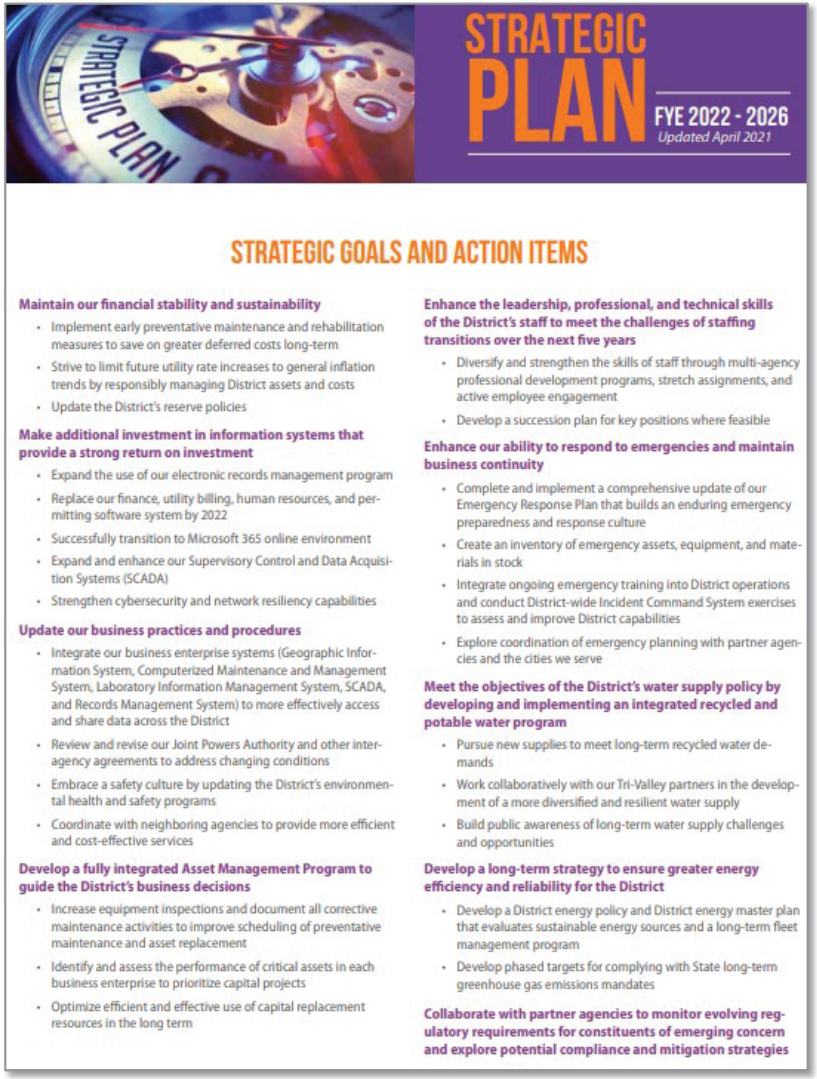
Strategic Plan



Capital Improvement Program

// Strategic Plan Goal

- **Develop a long-term strategy to ensure greater energy efficiency and reliability for the District**
  - Develop a District energy policy and District energy master plan that evaluates sustainable energy sources and a long-term fleet management program
  - Develop phased targets for complying with State long-term greenhouse gas emission mandates



STRATEGIC PLAN

FYE 2022 - 2026

Updated April 2021

STRATEGIC GOALS AND ACTION ITEMS

Maintain our financial stability and sustainability

- Implement early preventative maintenance and rehabilitation measures to save on greater deferred costs long-term
- Strive to limit future utility rate increases to general inflation trends by responsibly managing District assets and costs
- Update the District's reserve policies

Make additional investment in information systems that provide a strong return on investment

- Expand the use of our electronic records management program
- Replace our finance, utility billing, human resources, and permitting software system by 2022
- Successfully transition to Microsoft 365 online environment
- Expand and enhance our Supervisory Control and Data Acquisition Systems (SCADA)
- Strengthen cybersecurity and network resiliency capabilities

Update our business practices and procedures

- Integrate our business enterprise systems (Geographic Information System, Computerized Maintenance and Management System, Laboratory Information Management System, SCADA, and Records Management System) to more effectively access and share data across the District
- Review and revise our Joint Powers Authority and other interagency agreements to address changing conditions
- Embrace a safety culture by updating the District's environmental health and safety programs
- Coordinate with neighboring agencies to provide more efficient and cost-effective services

Develop a fully integrated Asset Management Program to guide the District's business decisions

- Increase equipment inspections and document all corrective maintenance activities to improve scheduling of preventative maintenance and asset replacement
- Identify and assess the performance of critical assets in each business enterprise to prioritize capital projects
- Optimize efficient and effective use of capital replacement resources in the long term

Enhance the leadership, professional, and technical skills of the District's staff to meet the challenges of staffing transitions over the next five years

- Diversify and strengthen the skills of staff through multi-agency professional development programs, stretch assignments, and active employee engagement
- Develop a succession plan for key positions where feasible

Enhance our ability to respond to emergencies and maintain business continuity

- Complete and implement a comprehensive update of our Emergency Response Plan that builds an enduring emergency preparedness and response culture
- Create an inventory of emergency assets, equipment, and materials in stock
- Integrate ongoing emergency training into District operations and conduct District-wide Incident Command System exercises to assess and improve District capabilities
- Explore coordination of emergency planning with partner agencies and the cities we serve

Meet the objectives of the District's water supply policy by developing and implementing an integrated recycled and potable water program

- Pursue new supplies to meet long-term recycled water demands
- Work collaboratively with our Tri-Valley partners in the development of a more diversified and resilient water supply
- Build public awareness of long-term water supply challenges and opportunities

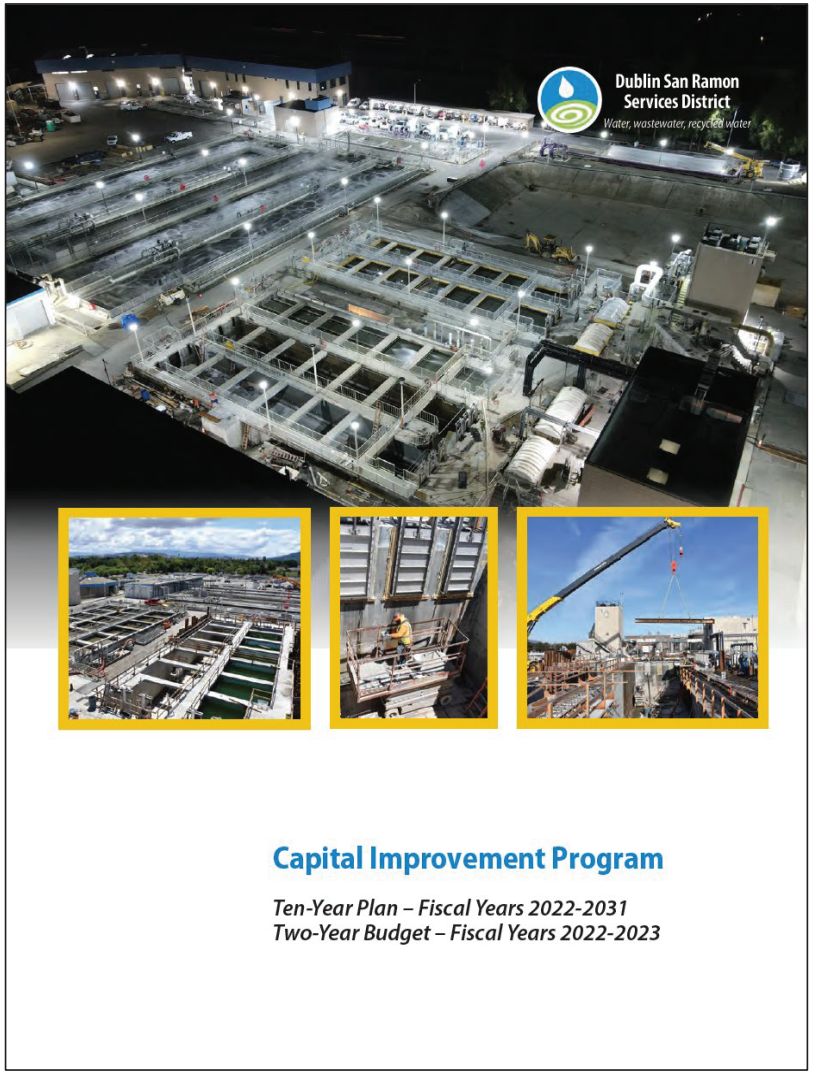
Develop a long-term strategy to ensure greater energy efficiency and reliability for the District

- Develop a District energy policy and District energy master plan that evaluates sustainable energy sources and a long-term fleet management program
- Develop phased targets for complying with State long-term greenhouse gas emissions mandates

Collaborate with partner agencies to monitor evolving regulatory requirements for constituents of emerging concern and explore potential compliance and mitigation strategies

// Project Overview

- All-Encompassing Review of All District Facilities
  - Wastewater Collections System
  - Wastewater Treatment Plant
  - Potable Water Distribution System
  - Recycled Water Distribution System
  - Administration & Field Office Buildings
  - Fleet
- Energy Policy
- Energy Master Plan
- Capital Improvement Program



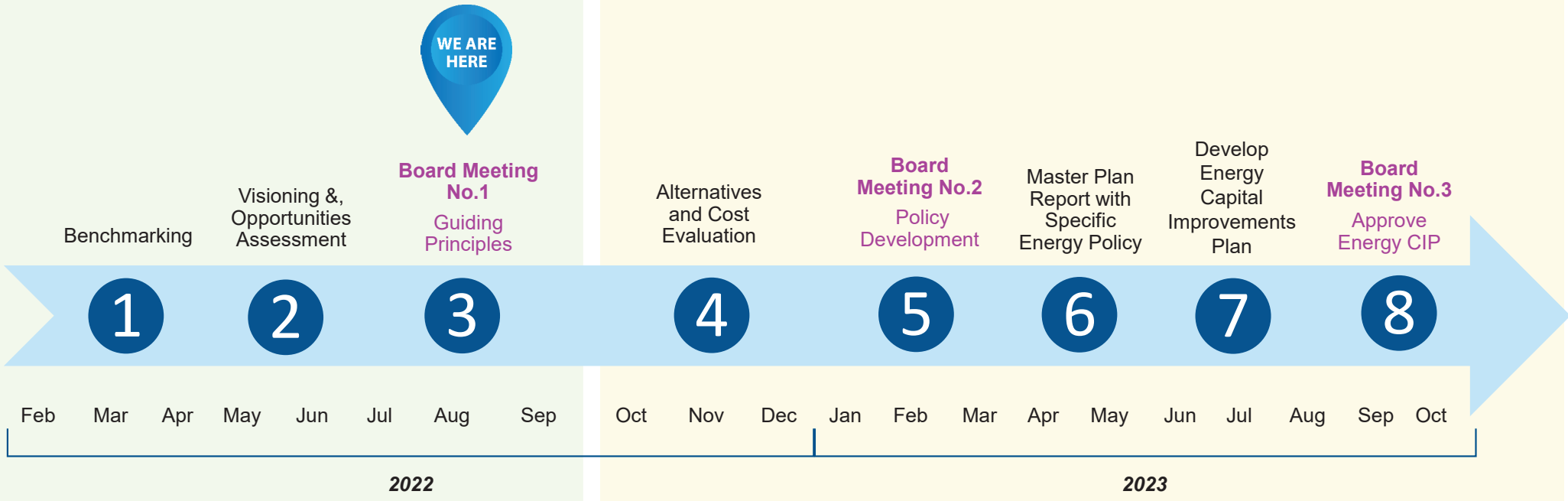
// Scope of Phase 1 and 2 of this planning project

Phase 1

State of the District Energy Baseline

Phase 2

Alternatives Evaluation and Prioritization



Baseline Energy and GHG Emissions

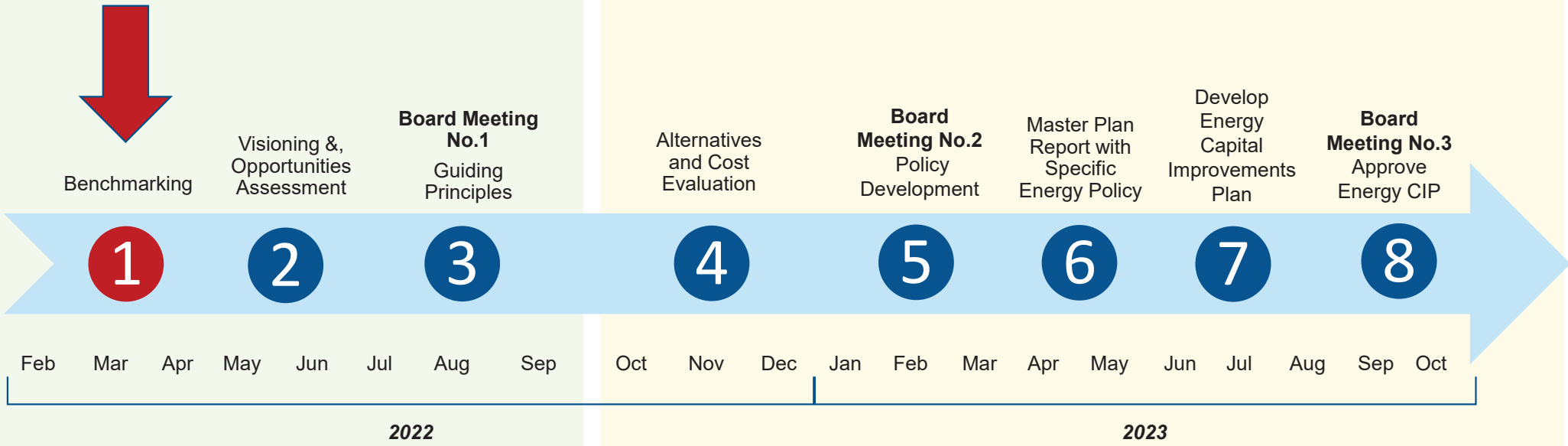
// Scope of Phase 1 and 2 of this planning project

Phase 1

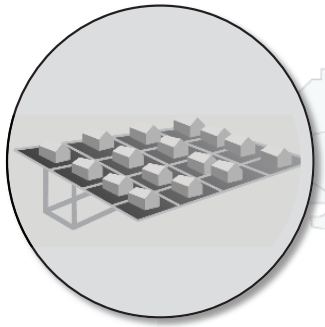
State of the District Energy Baseline

Phase 2

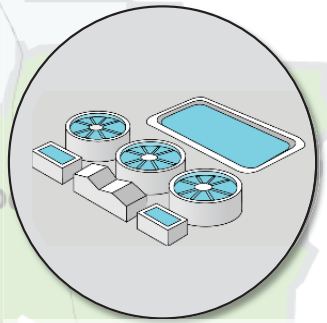
Alternatives Evaluation and Prioritization



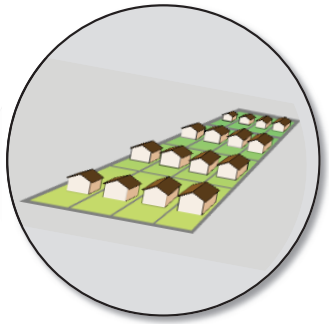
// Facilities included in the planning effort



Wastewater Collection System



Wastewater Treatment Plant



Water Distribution System

Recycled Water Treatment & Distribution (DERWA)

Wastewater Effluent Discharge (LAVWMA)

Recycled Water Distribution

Offices & Buildings

Fleet

// Types of “energy”

Energy Demands

Fuel

Thermal (Natural Gas)

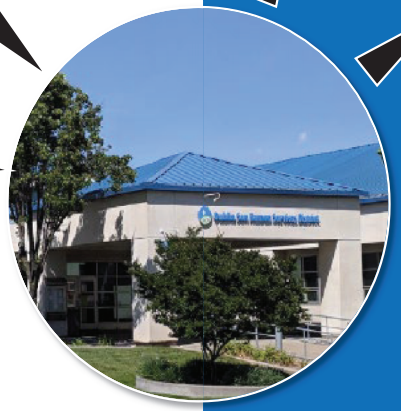
Electricity

Energy Production

Heat Recovery

Renewables

Biogas



Dublin San Ramon Services District

Water, wastewater, recycled water

Electrical Energy Demand

// Electrical Energy Demand

Total Electrical Demand:

~15 M kWh/year

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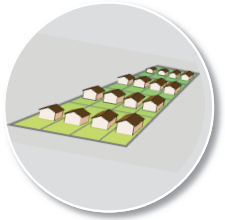
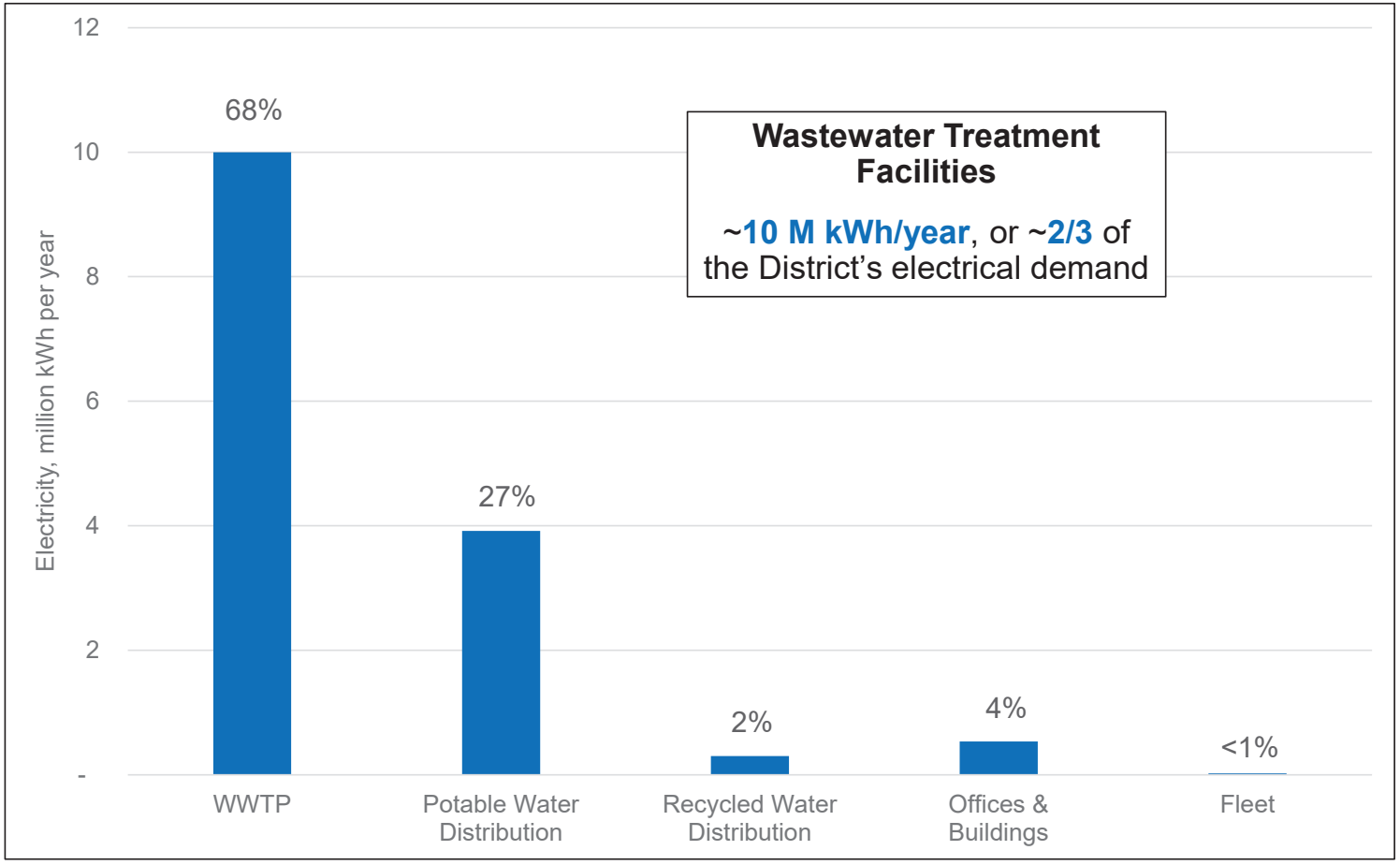


~2,500 Homes



// Electrical Energy Demand (including LAVWMA & DERWA)

Total Electrical Demand:

~23 M kWh/year

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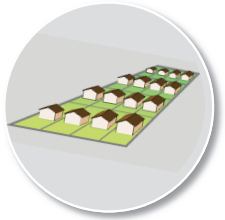
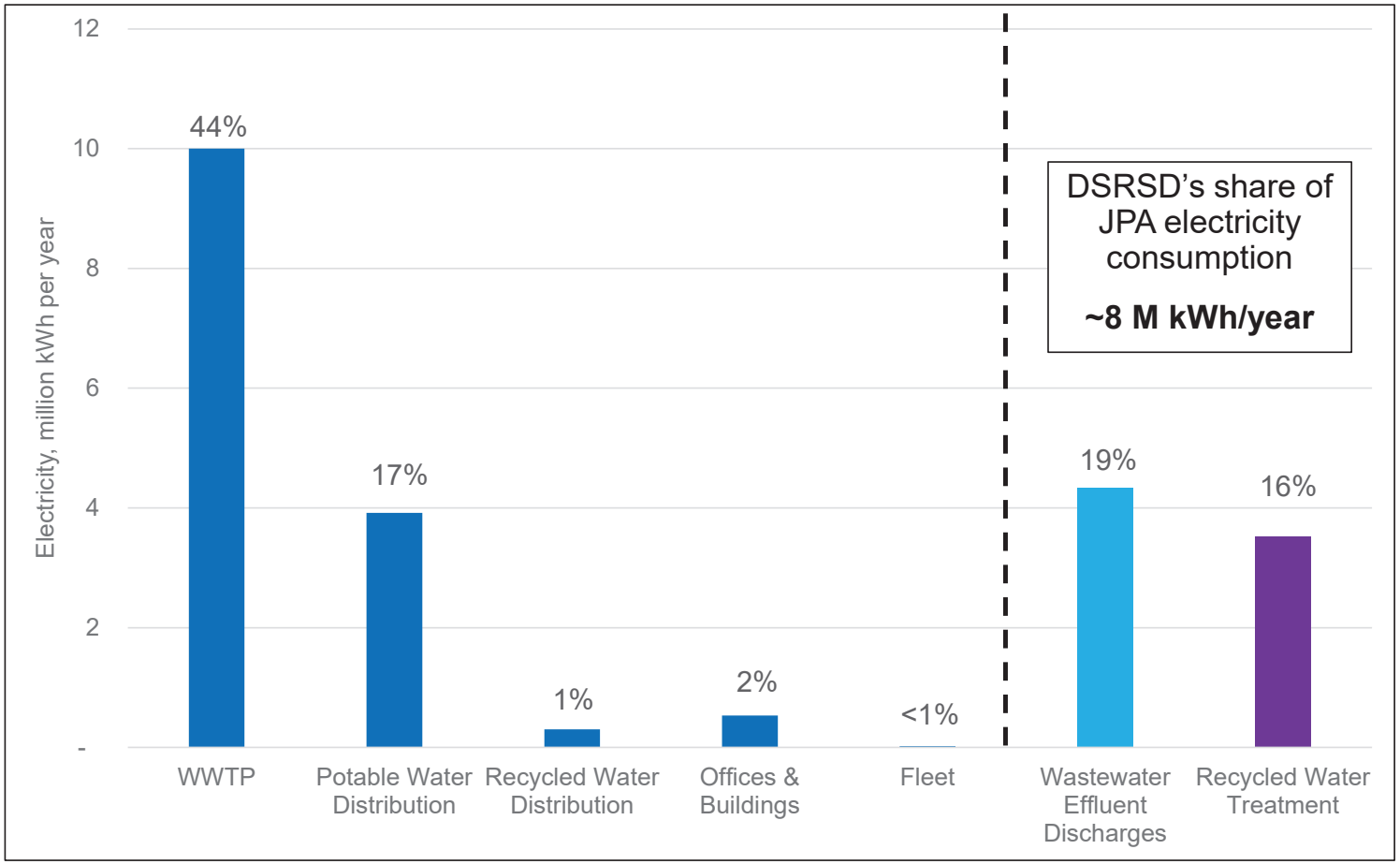


~3,500 Homes

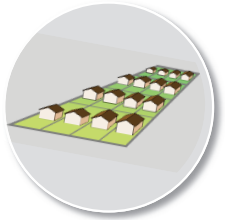


// Electrical Energy Demand (including LAVWMA & DERWA)

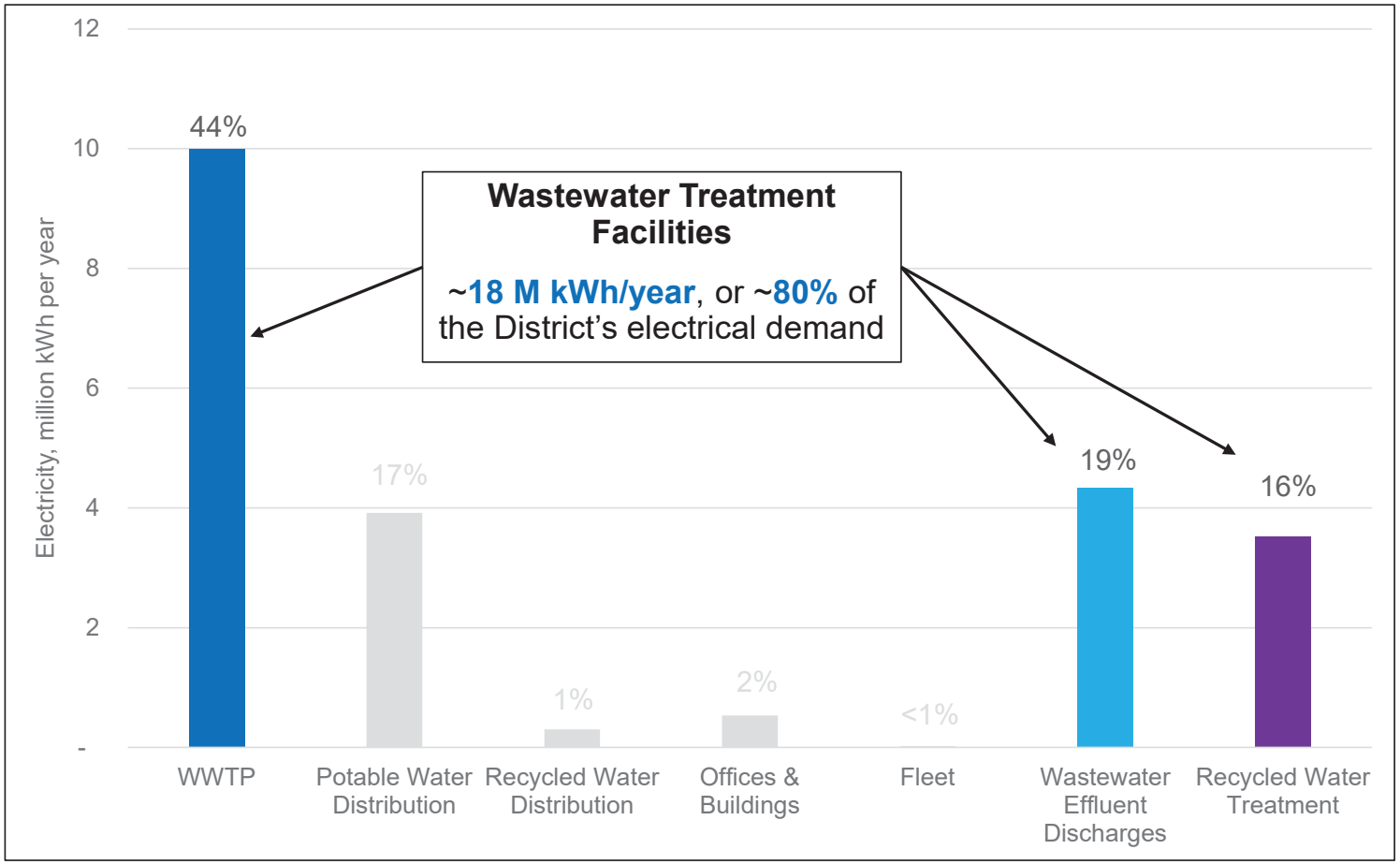
Total Electrical Demand:

~23 M kWh/year

=



~3,500 Homes



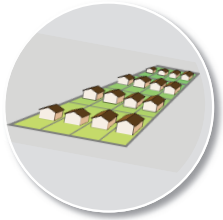
Thermal Energy Demand

// Thermal Energy Demand

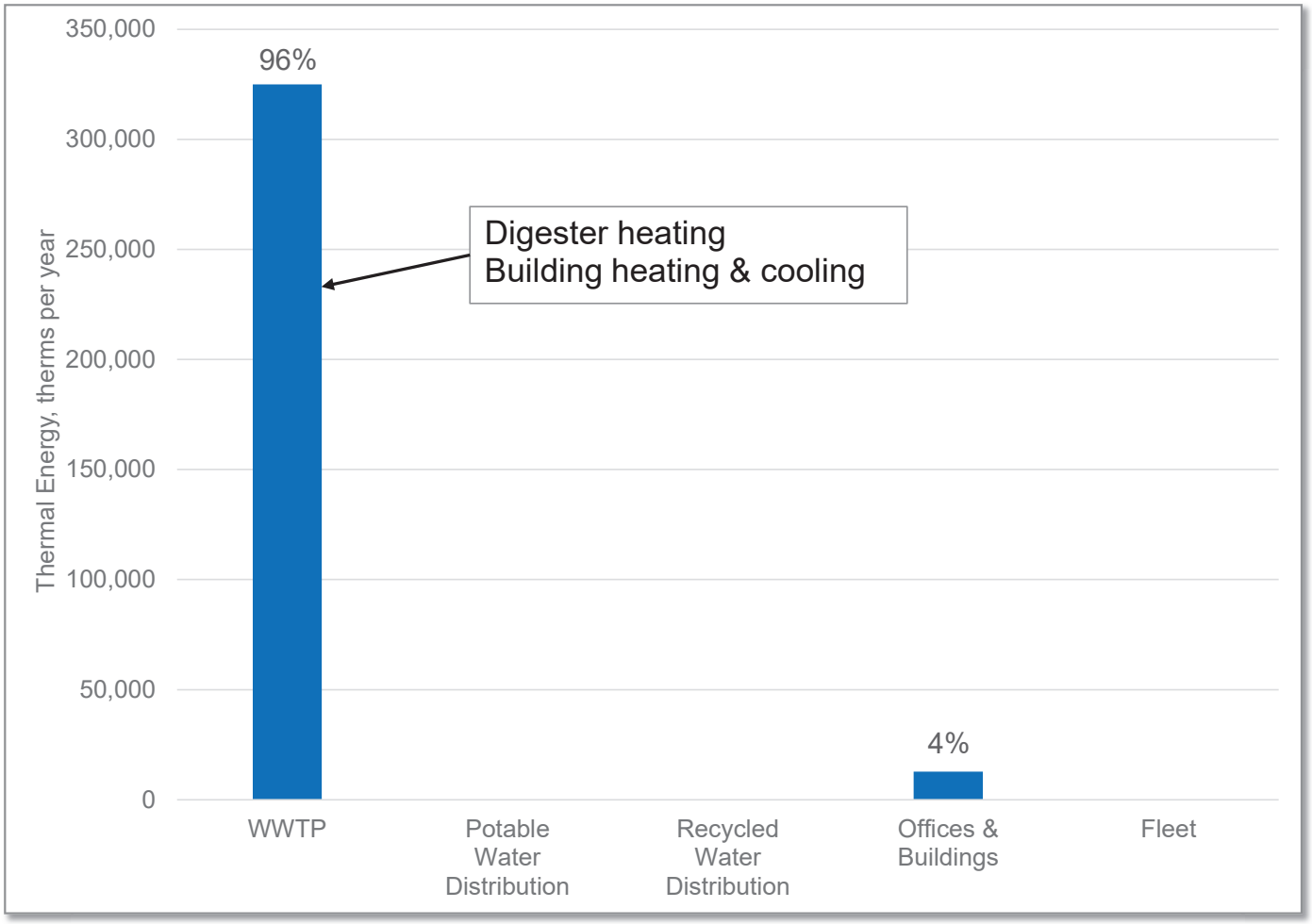
Total Thermal Demand:

~340,000 therms/year

=



~1,000 Homes

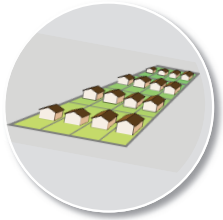


// Thermal Energy Demand (including LAVWMA & DERWA)

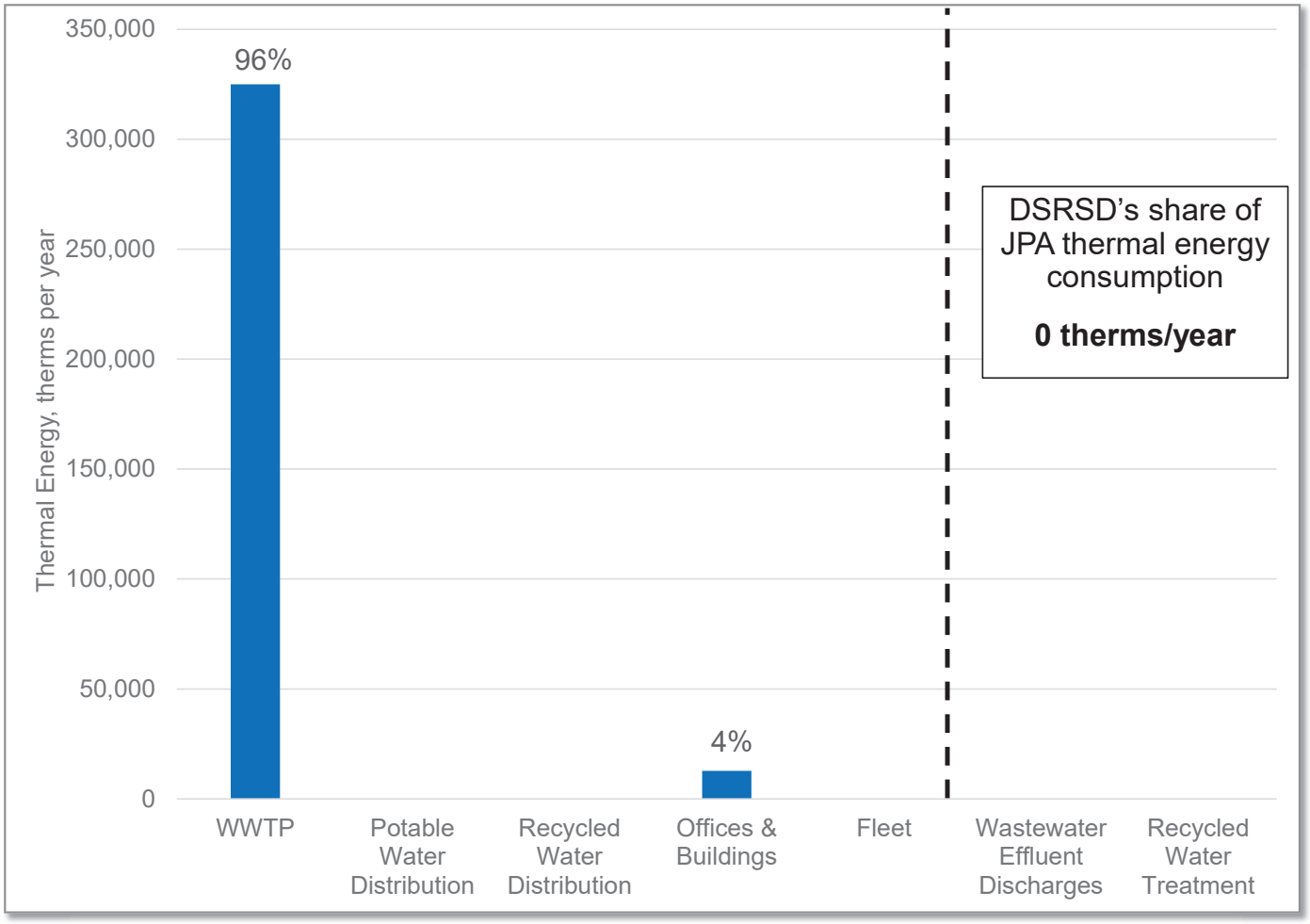
Total Thermal Demand:

~340,000 therms/year

=



~1,000 Homes



Fuel Consumption

// Fuel Consumption

District Fleet Summary:

- Vehicles: 59
- Electric-Powered Golf Carts: 22
- Backup Power Equipment: 9
- Cargo Equipment: 8
- Heavy Equipment: 24

Total Fuel Consumption:

~28,000
Gasoline gallon equivalents/year

=

~60
Vehicles

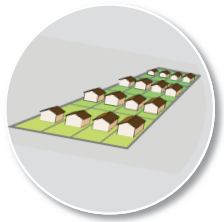
Total Energy (Electrical + Thermal + Fuel) Demand

// Total Energy Demand (Electricity + Thermal + Fuel)

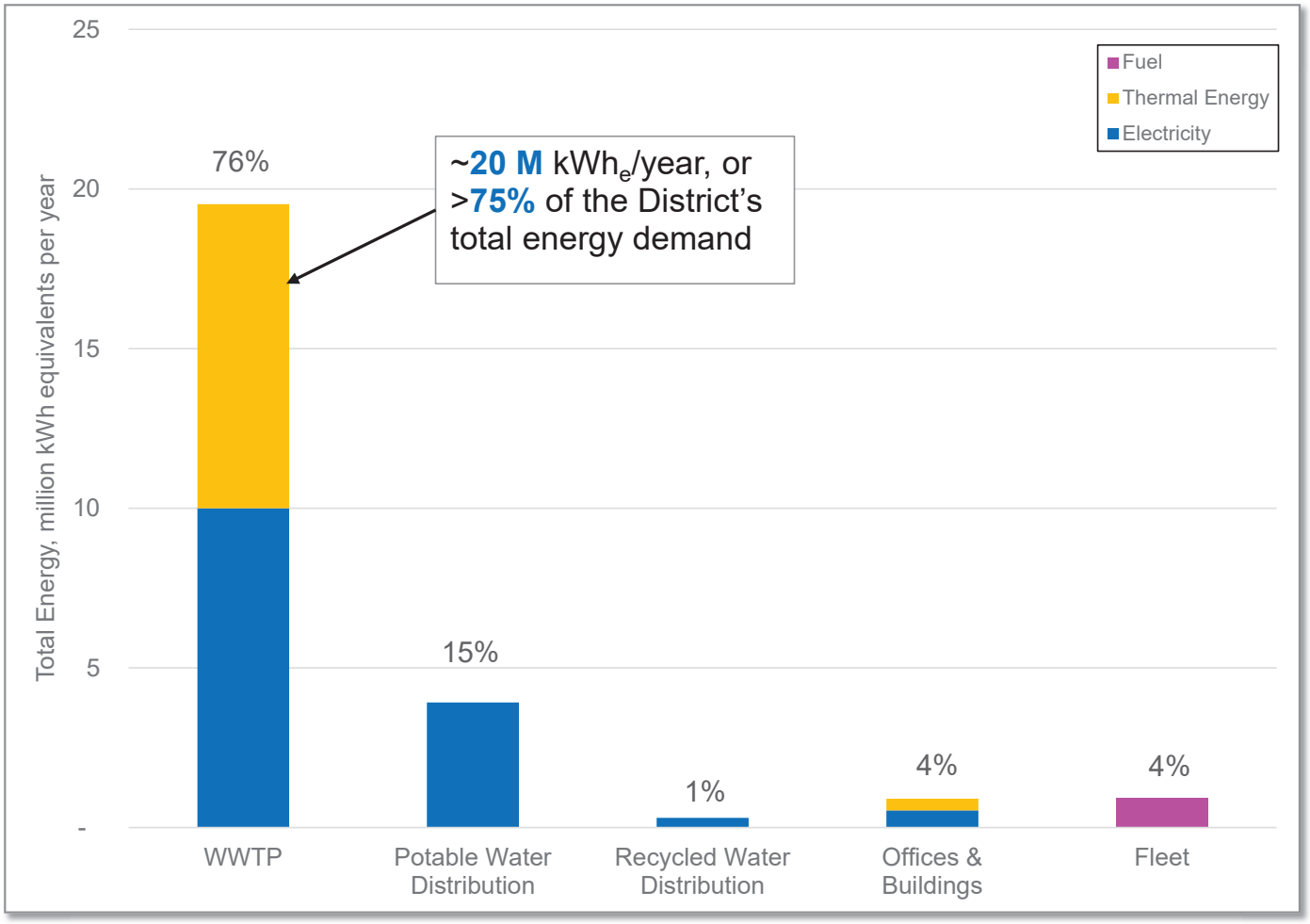
Total Energy Demand:

~25 M kWh$_e$/year

=



~4,000 Homes

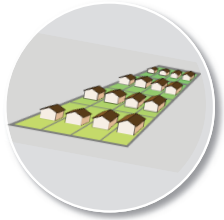


// Total Energy Demand (Electricity + Thermal + Fuel) including LAVWMA + DERWA

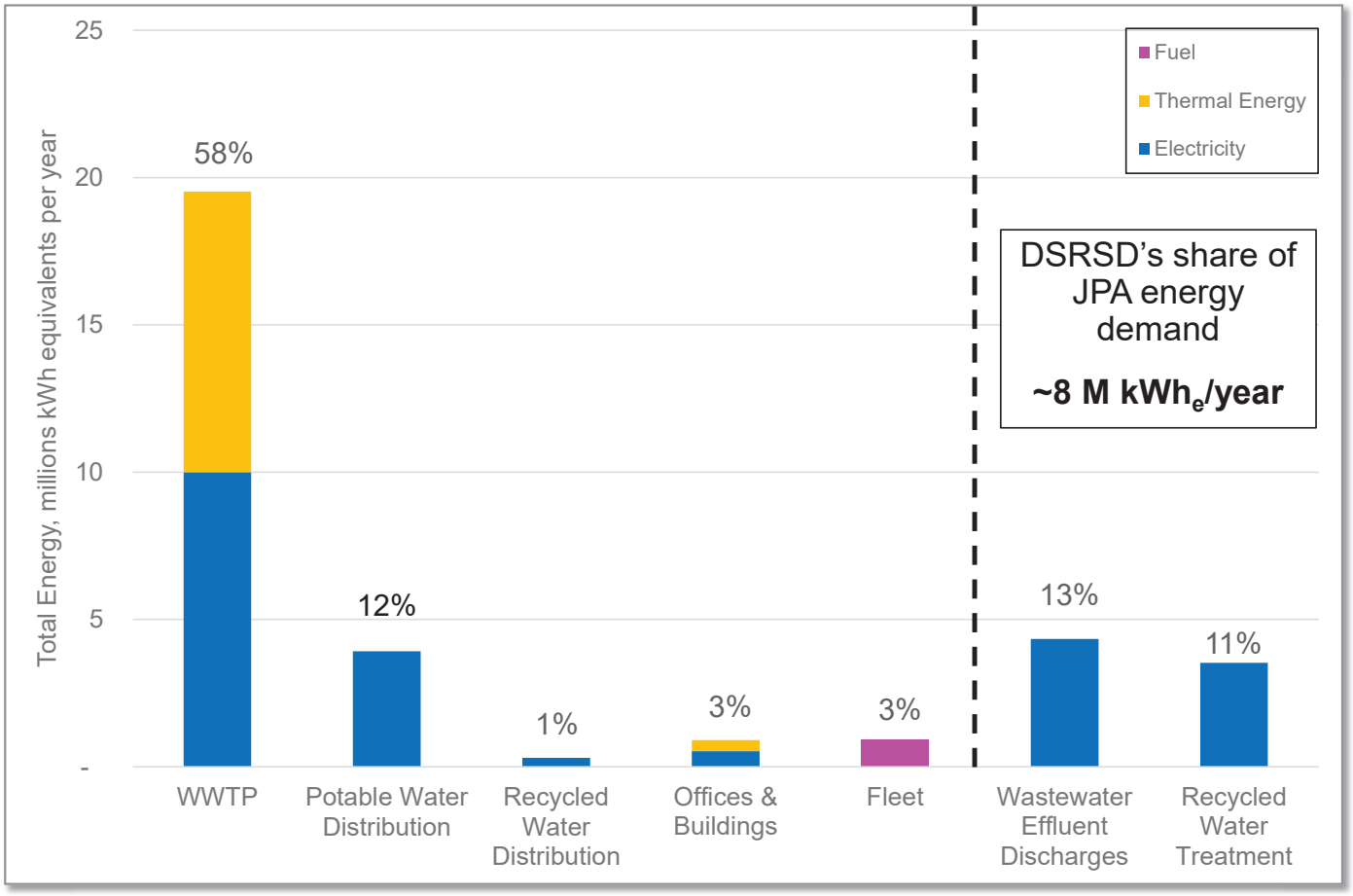
Total Energy Demand:

~33 M kWh$_e$/year

=



~5,000 Homes

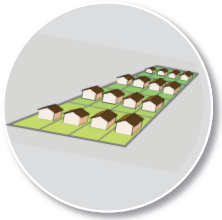


// Total Energy Demand (Electricity + Thermal + Fuel) including LAVWMA + DERWA

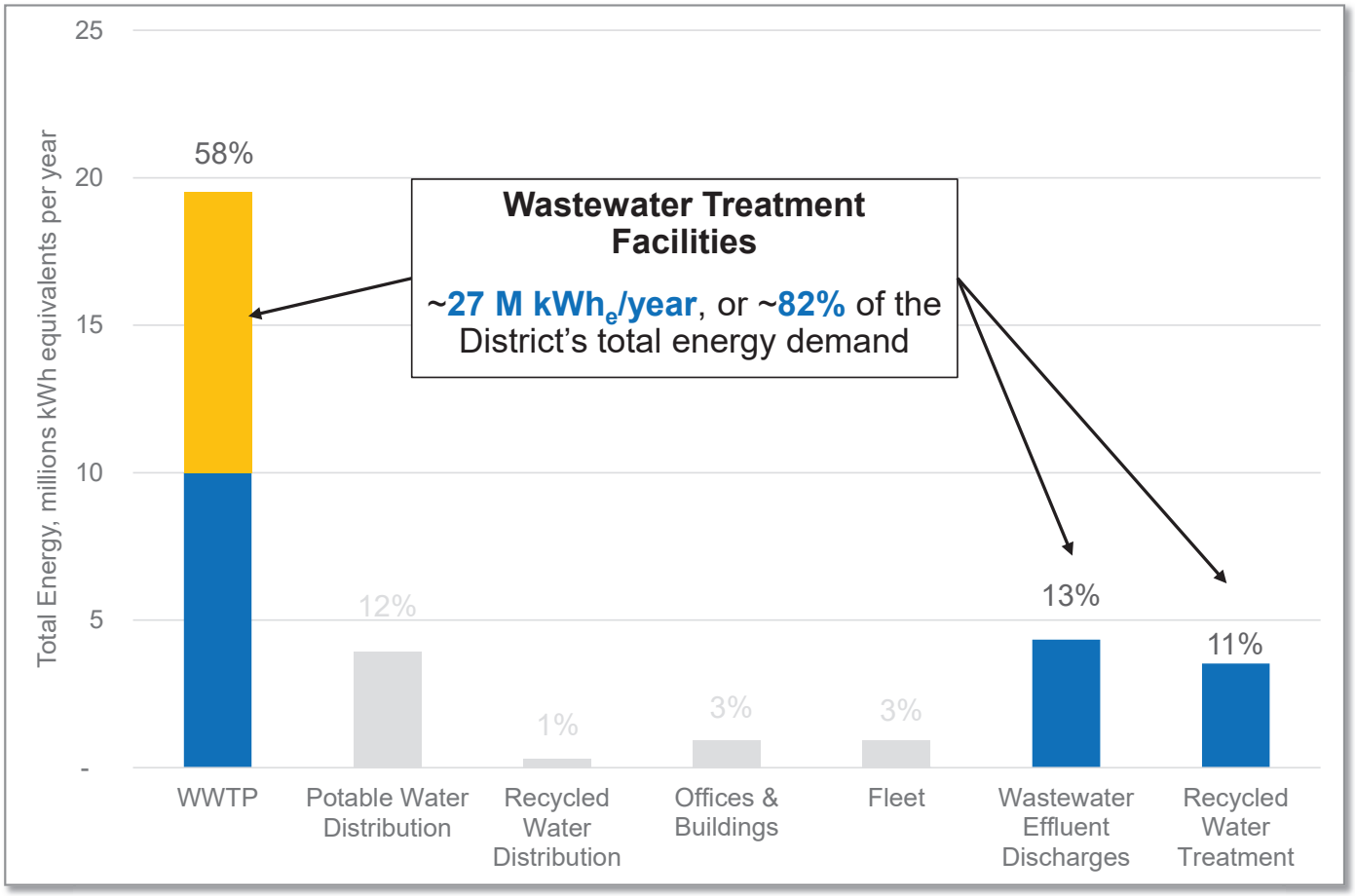
Total Energy Demand:

~33 M kWh_e/year

=



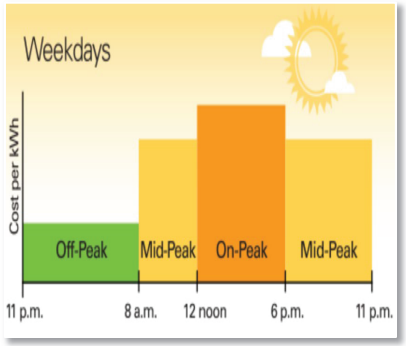
~5,000 Homes



// District's Historical Commitment to Energy Demand Management

Biosolids disposal at the FSLs and DLDs is highly energy efficient

Operational improvements and **optimization**

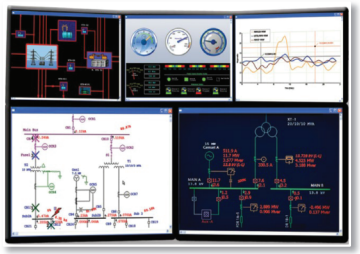


Point-of-Use pumping in the **water distribution system** has reduced electricity costs

Invested into more **energy-efficient buildings**

Alternative energy

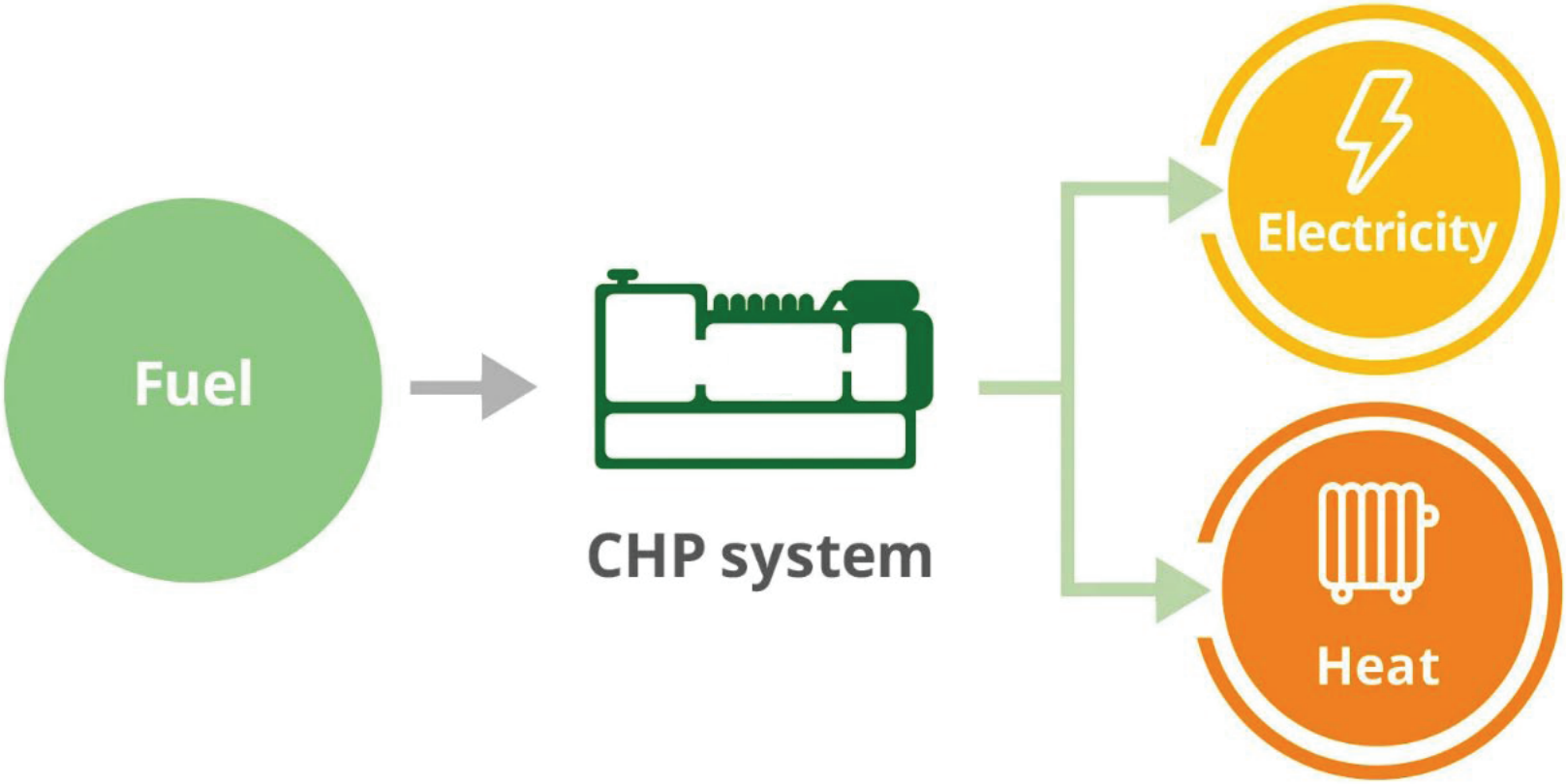
Fleet Management



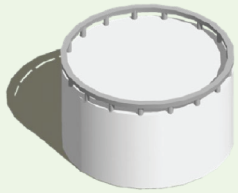
Technology Power monitoring

Energy Generation

// Cogeneration (Combined Heat and Power)



// Energy Generation and Heat Recovery thru Cogeneration



Anaerobic Digester

Biogas

Natural Gas

Pacific Gas and Electric

Cogeneration

Electricity

~9.5 M kWh/yr

Energy recovery for WWTP Operation

Heat Energy

~325,000 therms/yr

Energy Production: **9,500,000** kWh/year

Heat Recovery: Provides nearly all the thermal energy requirements for the WWTP

// Energy Generation and Heat Recovery thru Cogeneration

- **Fuels**: Biogas (**40%**) and Natural Gas (**60%**)
- **Energy Production**: ~**9,500,000** kWh/year
- **Heat Recovery**: ~**325,000** therms/year
- **Energy Savings**

PG&E Electricity	Cogeneration Biogas	Cogeneration PG&E Natural Gas
$0.22 per kWh	$0.04 per kWh	$0.10 per kWh

// Energy Generation and Heat Recovery thru Cogeneration

- **Fuels**: Biogas (**40%**) and Natural Gas (**60%**)
- **Energy Production**: **~9,500,000** kWh/year
- **Heat Recovery**: **~325,000** therms/year
- **Energy Savings**
  - Biogas: **>80% cost savings** vs. PG&E

PG&E Electricity	Cogeneration: Fueled w/ Biogas	Cogeneration: Fueled w/ PG&E NG
$0.22 per kWh	**$0.04** per kWh	$0.10 per kWh

Electricity Generated Using Biogas

Estimated Savings of ~$700,000 per year (>80% savings)

// Energy Generation and Heat Recovery thru Cogeneration

- **Fuels**: Biogas (**40%**) and Natural Gas (**60%**)
- **Energy Production**: **~9,500,000** kWh/year
- **Heat Recovery**: **~325,000** therms/year
- **Energy Savings**
  - Biogas: >80% cost savings vs. PG&E
  - Natural Gas: **>50% cost savings** vs. PG&E

PG&E Electricity	Cogeneration: Fueled w/ Biogas	Cogeneration: Fueled w/ PG&E NG
$0.22 per kWh	$0.04 per kWh	**$0.10** per kWh

Electricity Generated Using Natural Gas

Estimated Savings of ~$700,000 per year (>50% savings)

// Energy Generation and Heat Recovery thru Cogeneration

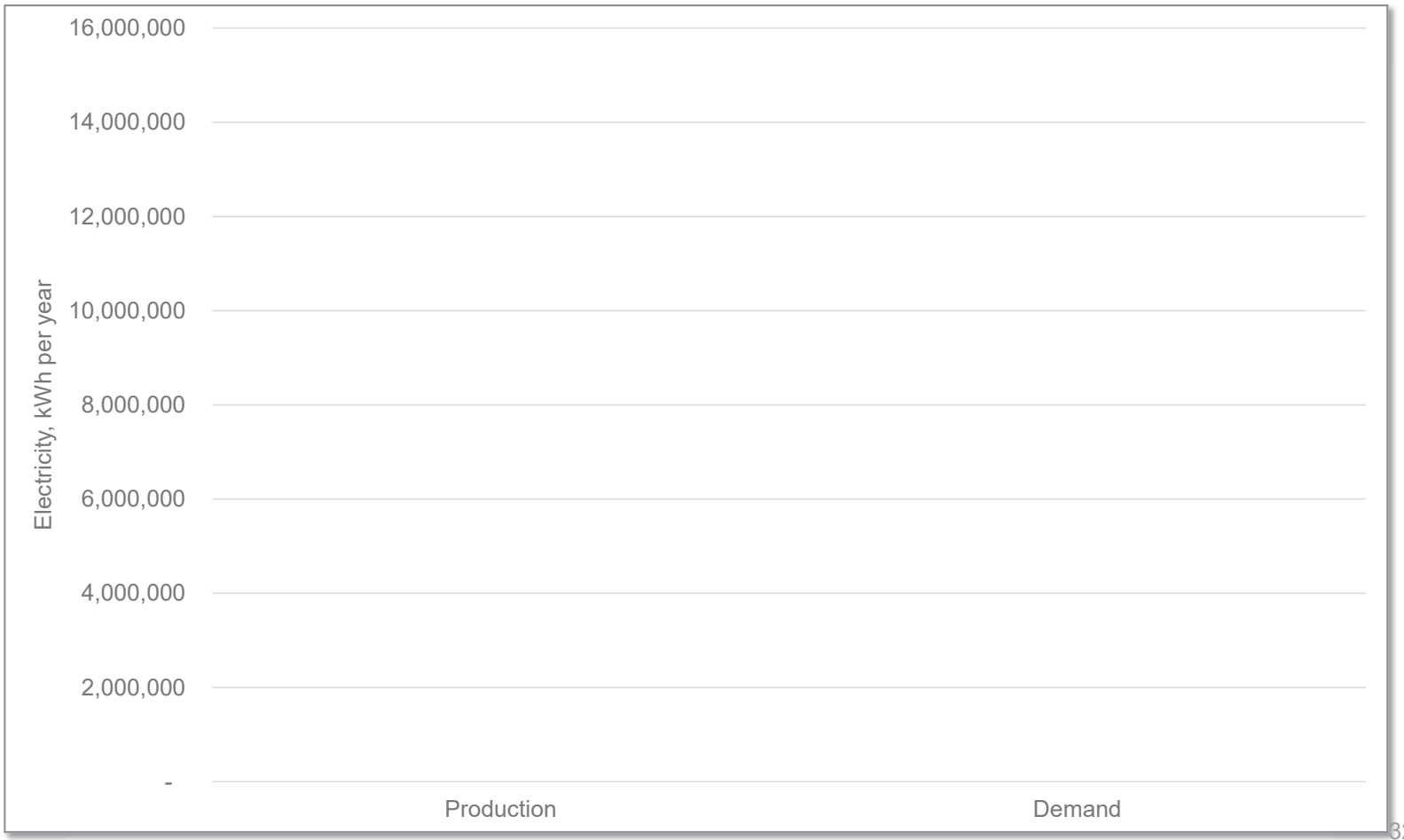
- **Fuels**: Biogas (**40%**) and Natural Gas (**60%**)
- **Energy Production**: **~9,500,000** kWh/year
- **Heat Recovery**: **~325,000** therms/year
- **Energy Savings**
  - Biogas: >80% cost savings vs. PG&E
  - Natural Gas: >50% cost savings vs. PG&E
  - Combined: **>65% cost savings** vs. PG&E

PG&E Electricity	Cogeneration: Fueled w/ Biogas + PG&E Natural Gas
$0.22 per kWh	**$0.08** per kWh

Cogeneration System - Total

Estimated Savings of ~$1,400,00 per year (~65% savings)

// Electrical Generation vs. Electrical Demand

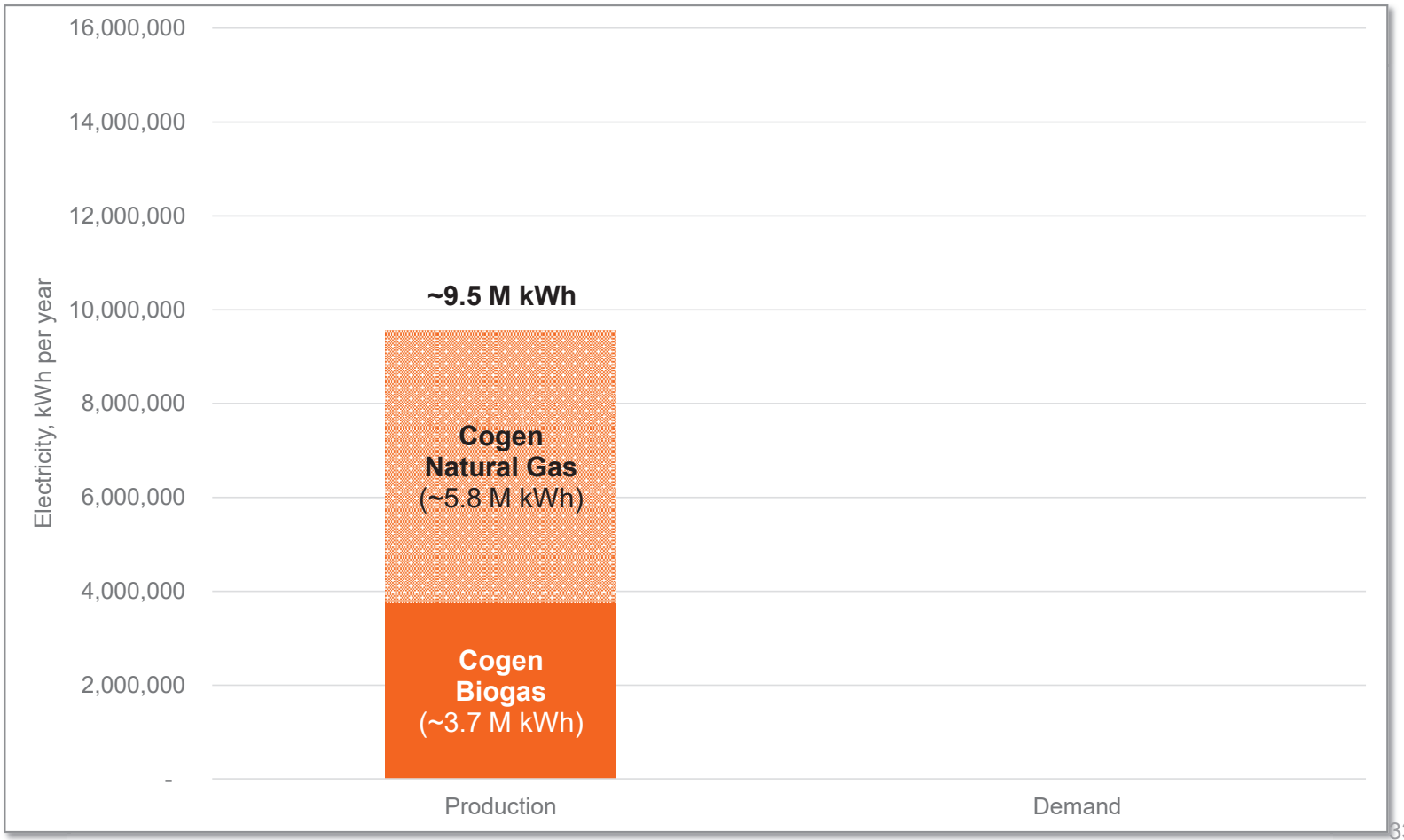


// Electrical Generation vs. Electrical Demand

In 2021, approximately **9.5 M kWh** of electrical energy was generated through the WWTP cogeneration system.

Biogas generates approximately **3.7 M kWh**.

Natural gas generates approximately **5.8 M kWh**.



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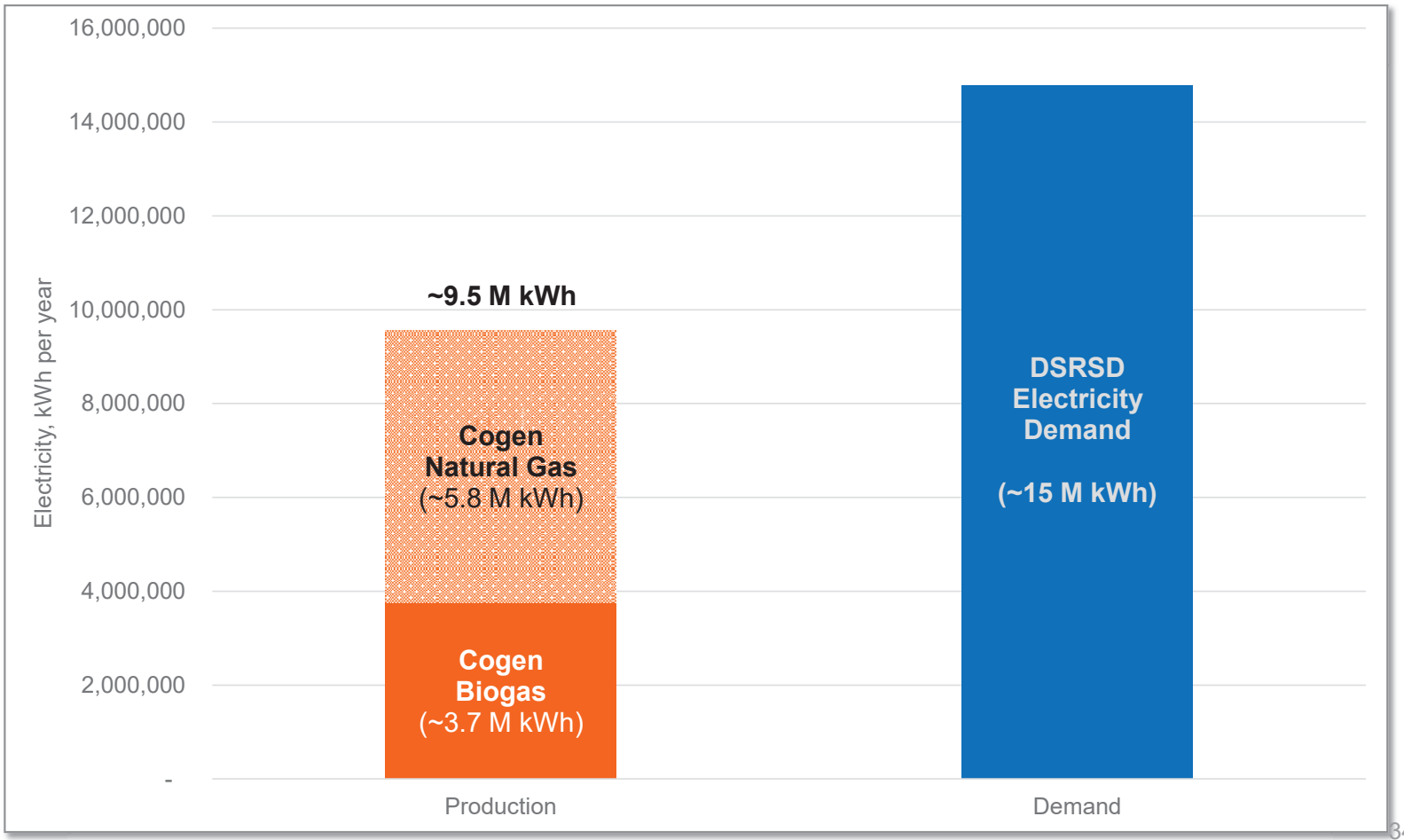

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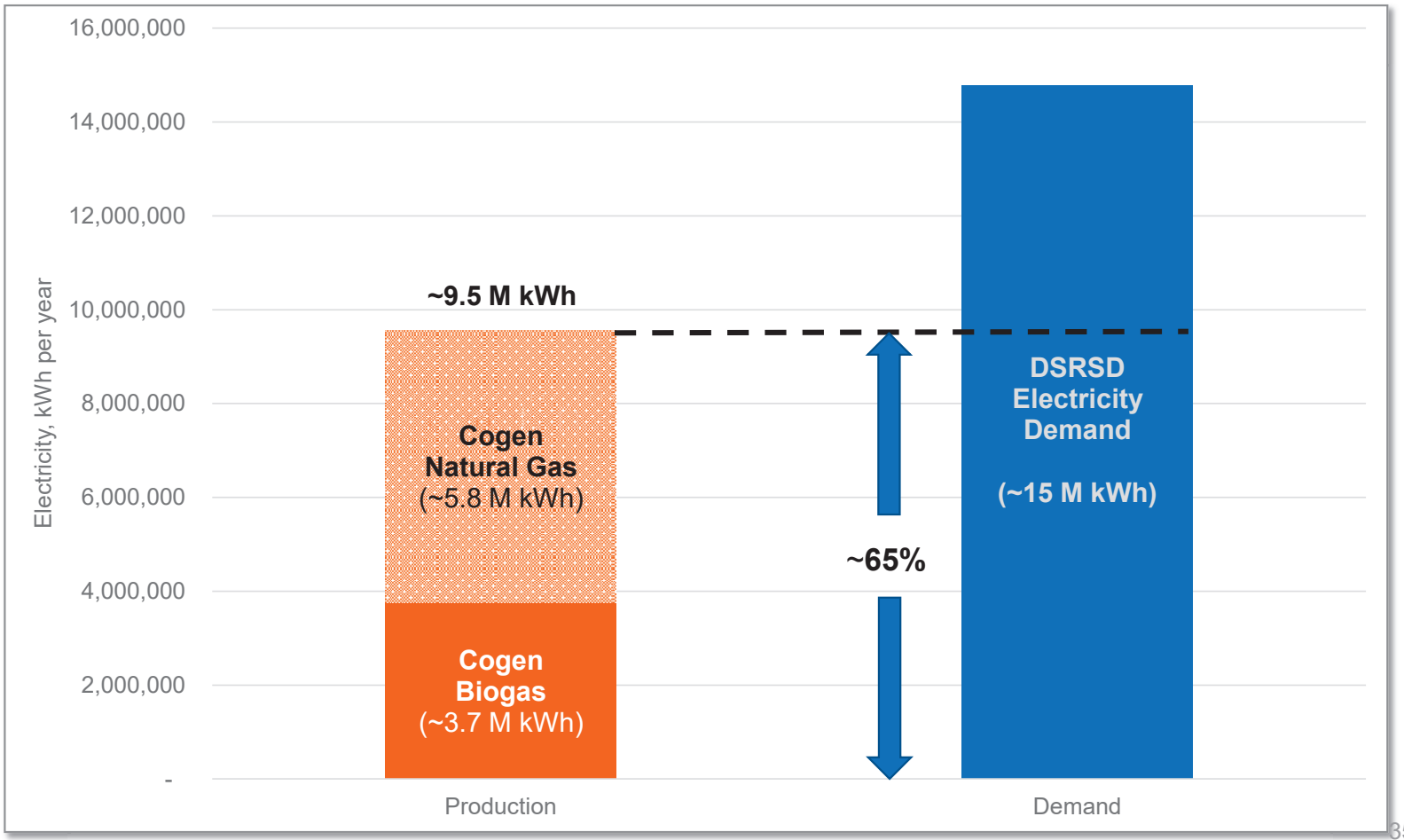
In total, cogeneration generates approximately **65%** of the District's electrical demands



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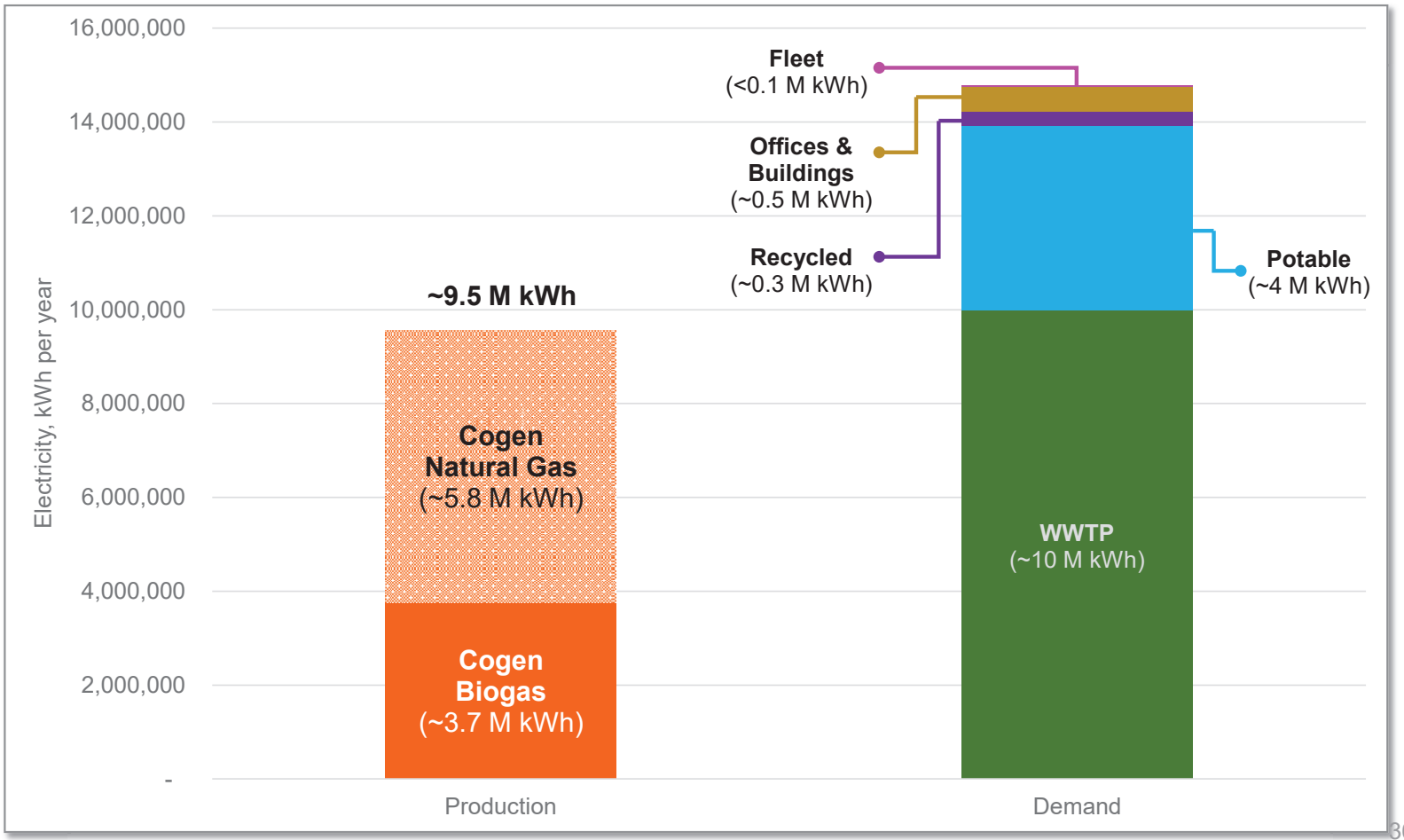
In total, cogeneration generates approximately 65% of the District's electrical demands



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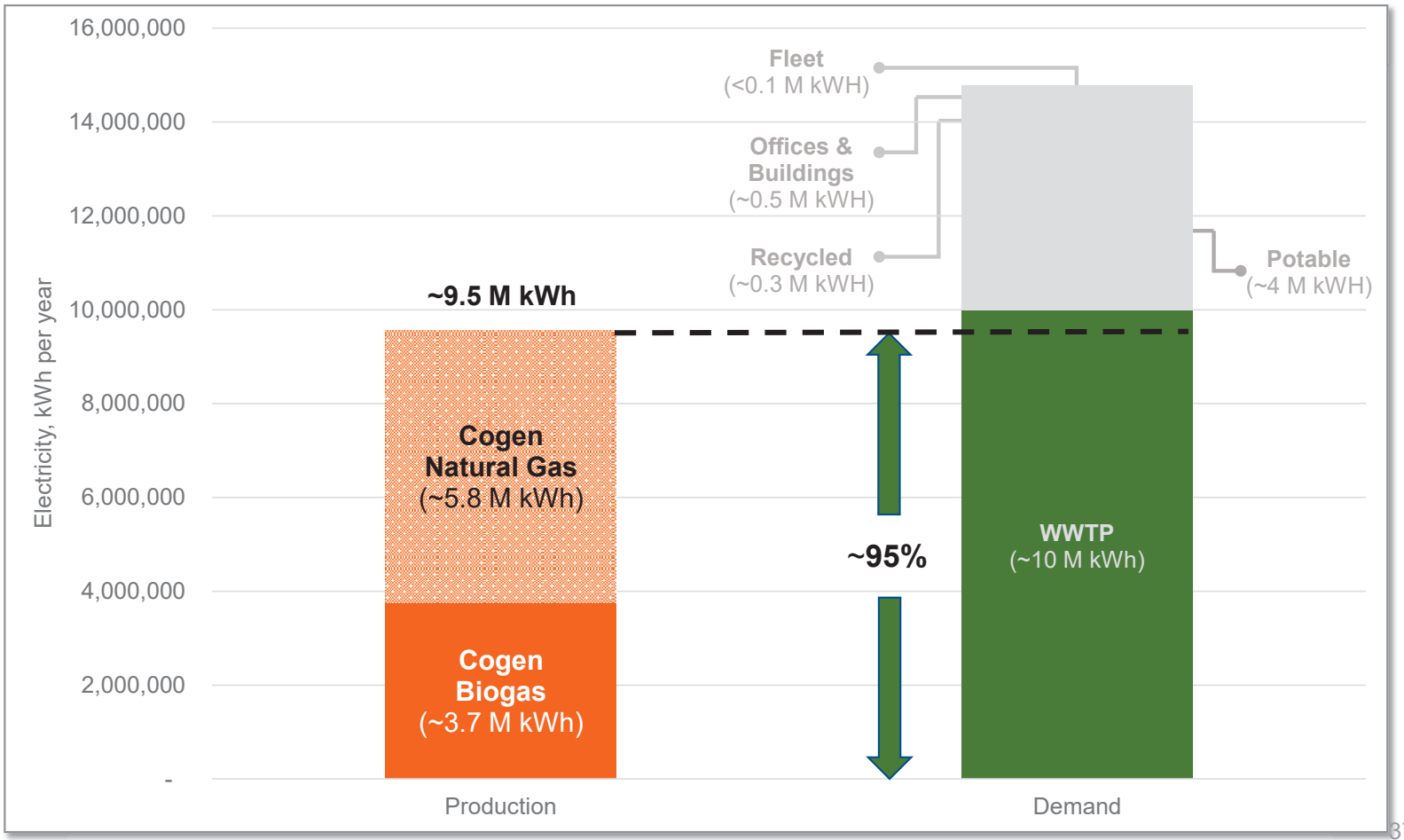
In 2021, approximately **9.5 M kWh** of electrical energy was generated through the WWTP cogeneration system.

Biogas generates approximately **3.7 M kWh**.

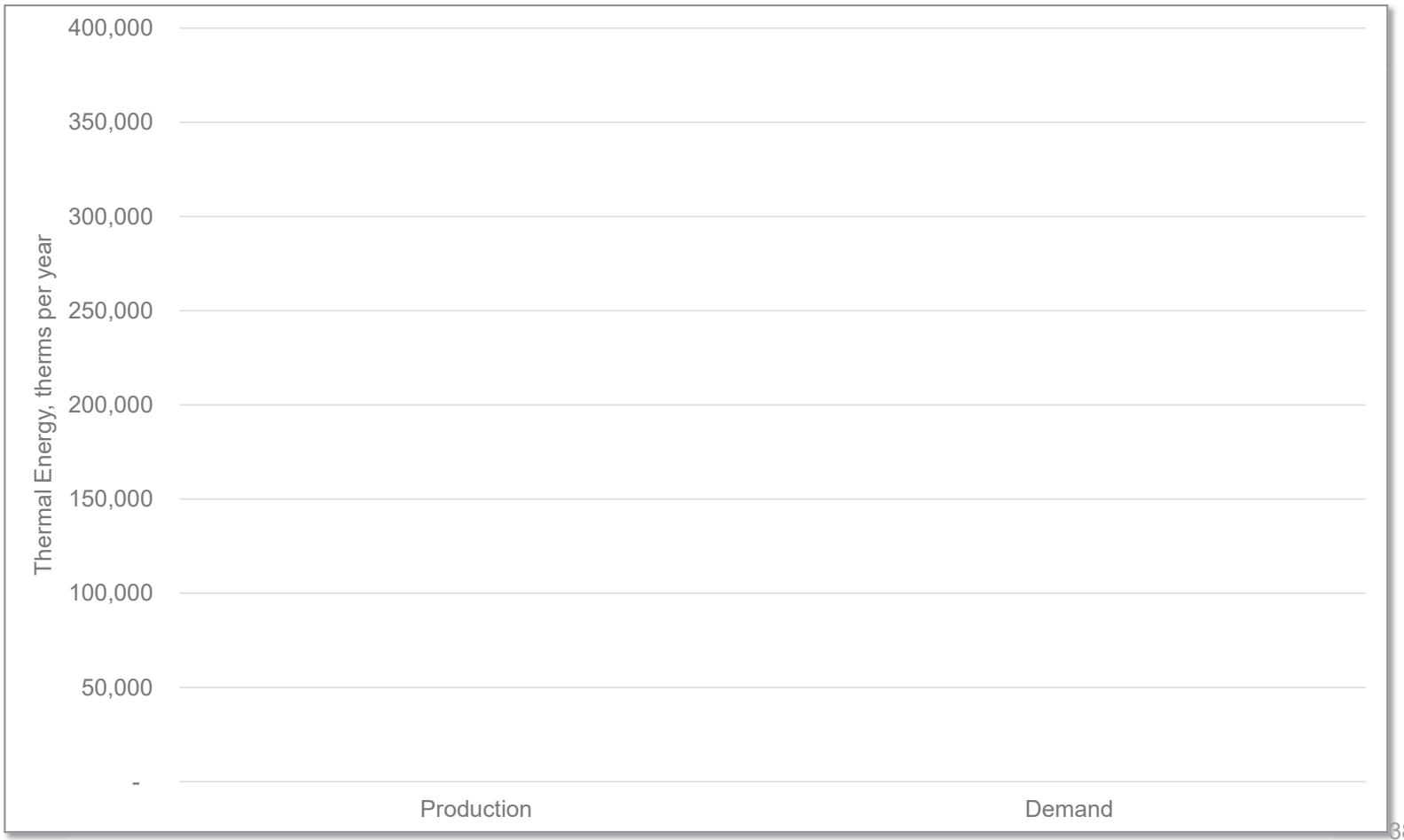
Natural gas generates approximately **5.8 M kWh**.

In total, cogeneration generates approximately 65% of the District's electrical demands

Cogeneration generates approximately **95%** of the electrical demands of the WWTP

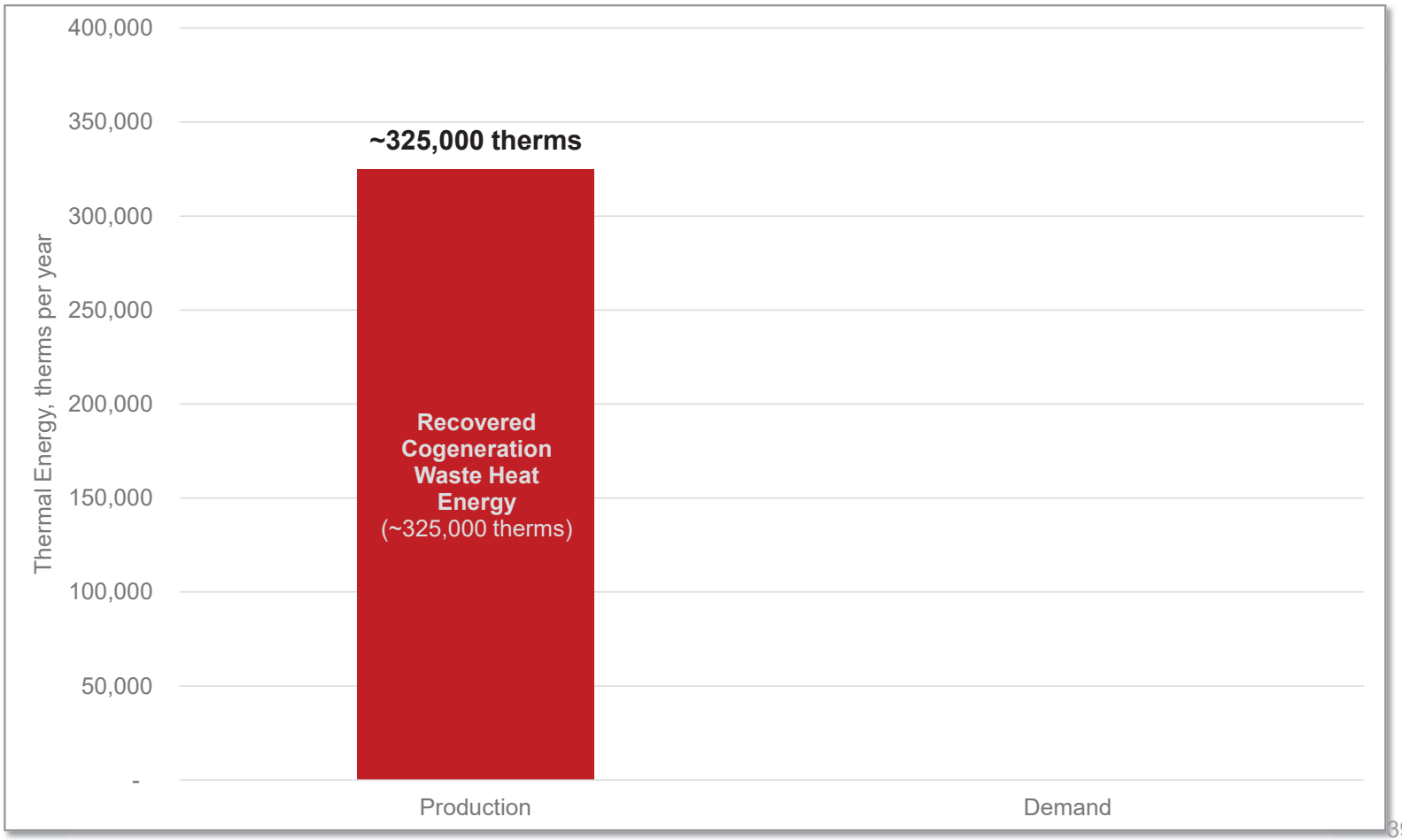


// Heat Recovery vs. Thermal Demand



// Heat Recovery vs. Thermal Demand

325,000 therms is recovered from the cogeneration system and is used to meet the thermal demands for the **anaerobic digesters** and **heating/cooling for WWTP buildings**



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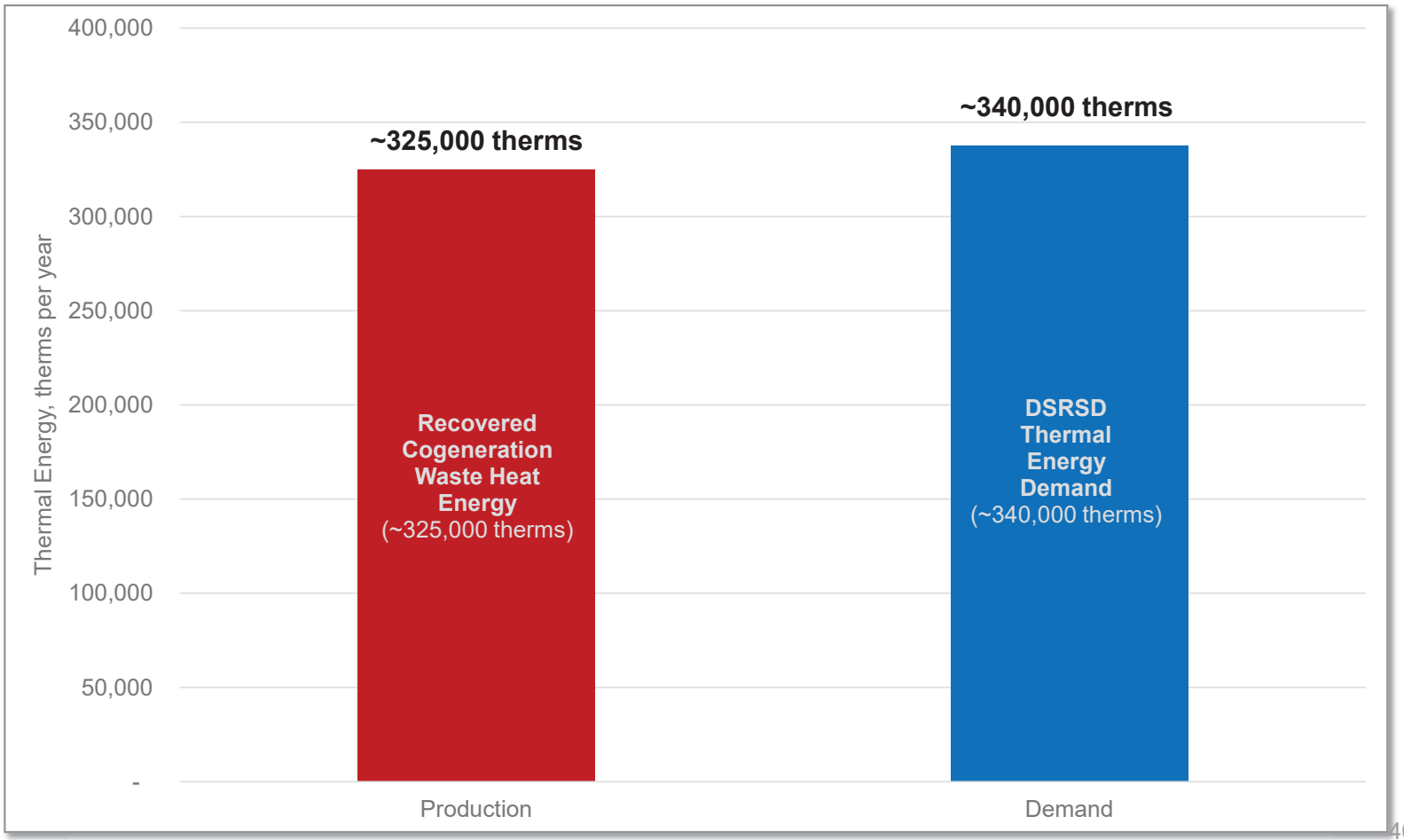

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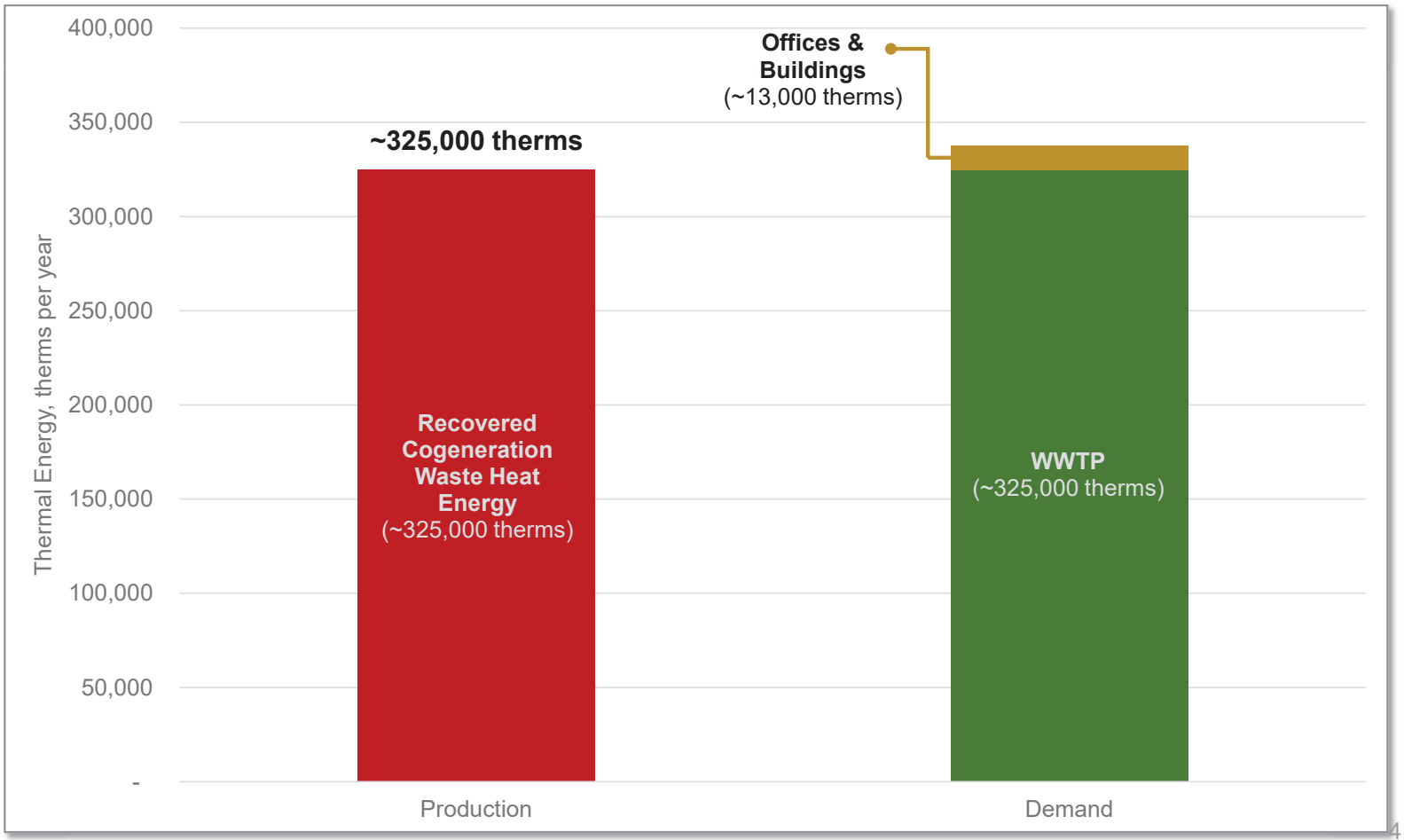
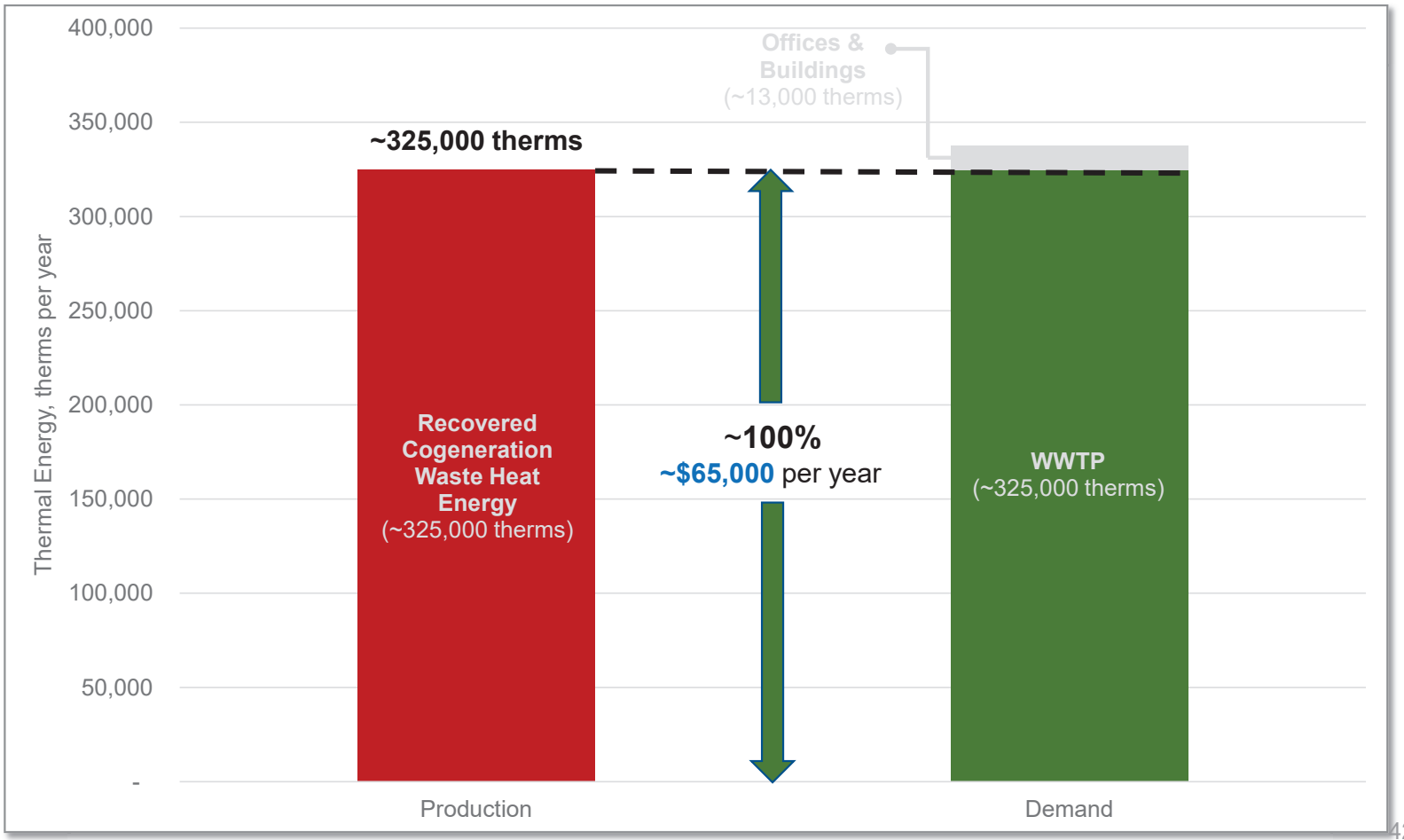


// Heat Recovery vs. Thermal Demand

325,000 therms is recovered from the cogeneration system and is used to meet the thermal demands for the **anaerobic digesters** and **heating/cooling for WWTP buildings**

Cogeneration meets nearly **100%** of the thermal energy demands of the WWTP

Estimated energy savings: **$65,000** per year



// Recent WWTP improvements will increase biogas production

Fourth Anaerobic Digester

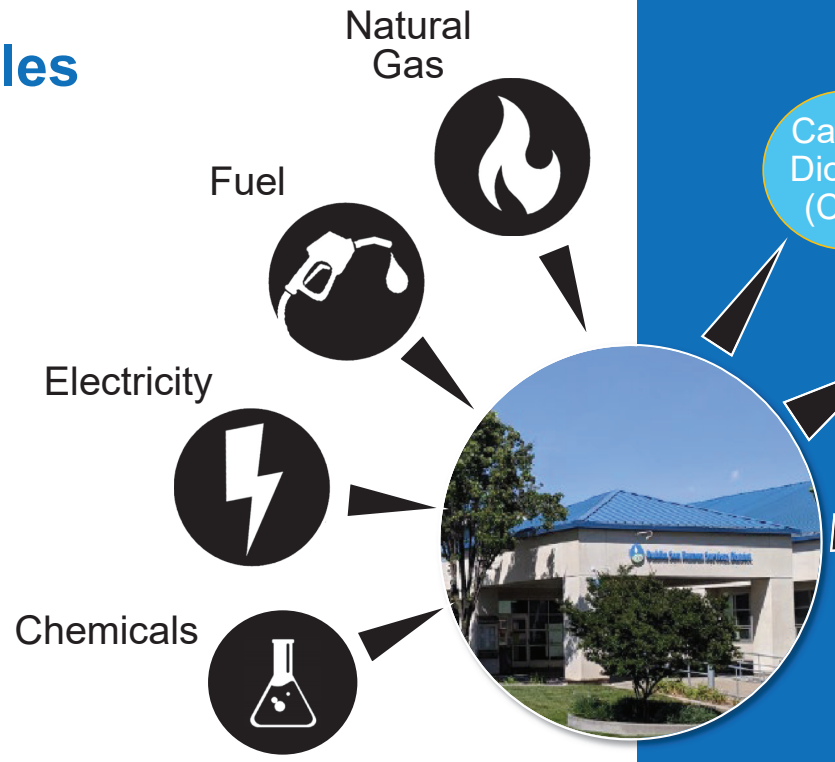
FOG Receiving Station

Primary Clarifier Addition

Greenhouse Gas (GHG) Emissions

// Defining "Greenhouse Gas Emissions"

Consumables



Dublin San Ramon Services District
Water, wastewater, recycled water

Greenhouse Gas Emissions

Carbon Dioxide (CO_2)

Methane (CH_4) 25

Nitrous Oxide (N_2O) 298

=

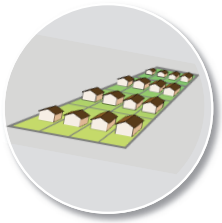
Carbon Dioxide Equivalent (CO_{2e})

// GHG Emissions

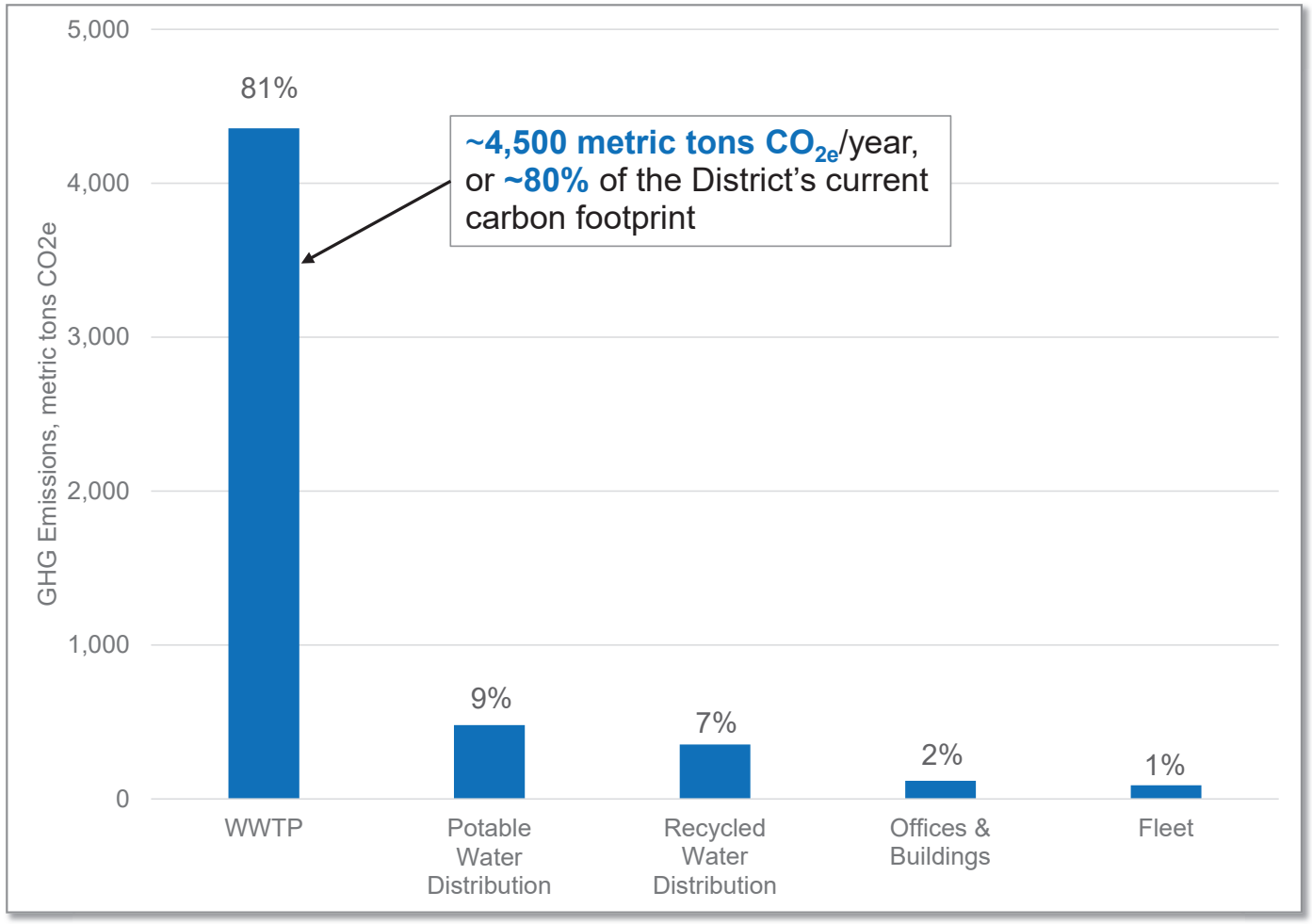
Total GHG Emissions:

~5,500 metric tons CO_{2e}/year

=



~175 homes

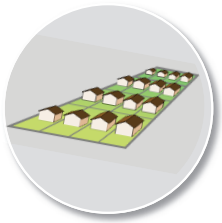


// GHG Emissions (including LAVWMA & DERWA)

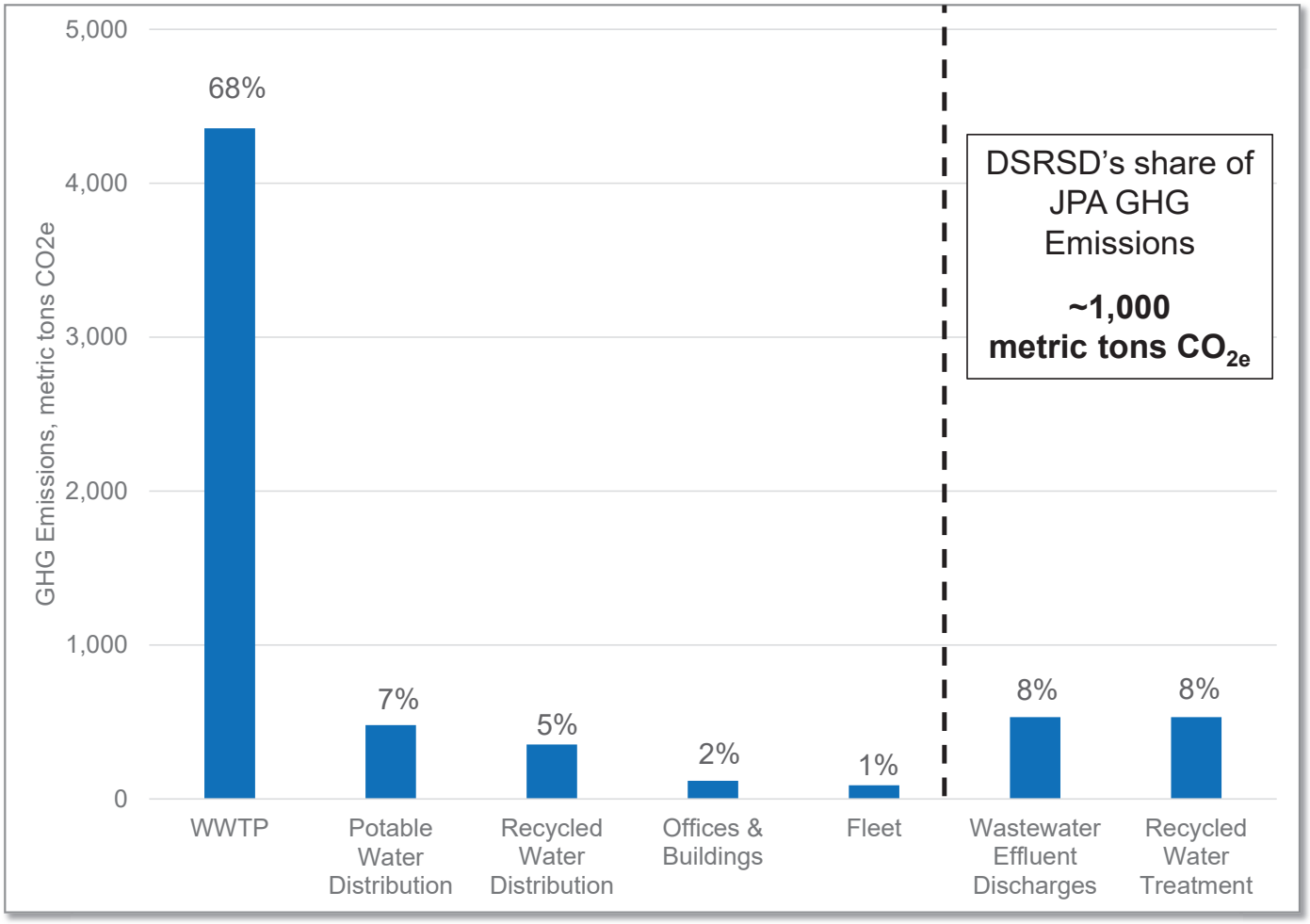
Total GHG Emissions:

~6,500 metric tons CO_{2e}/year

=



~200 homes

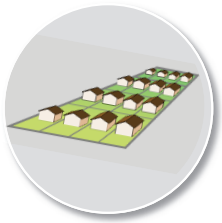


// GHG Emissions (including LAVWMA & DERWA)

Total GHG Emissions:

~6,500 metric tons CO_{2e}/year

=



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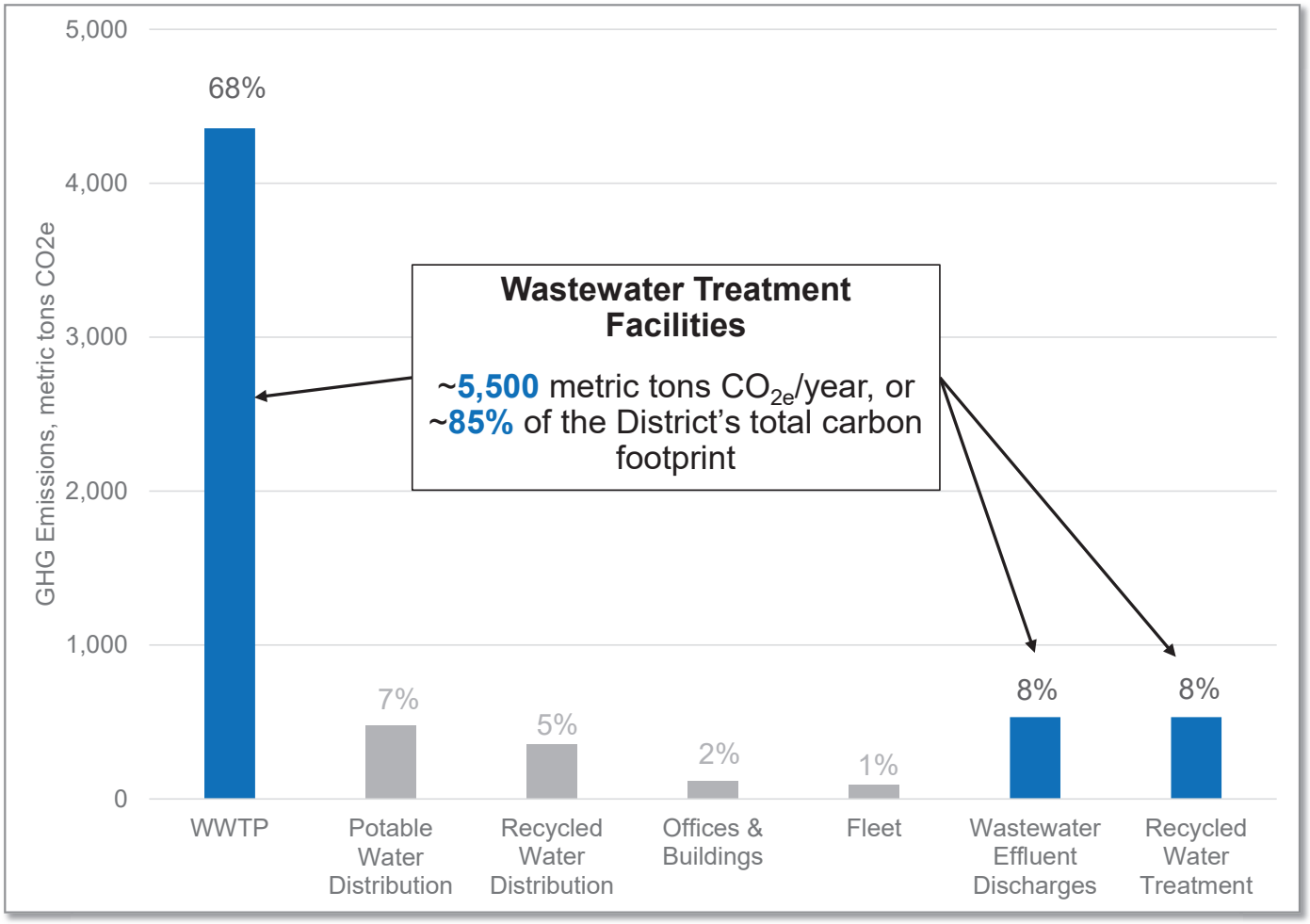
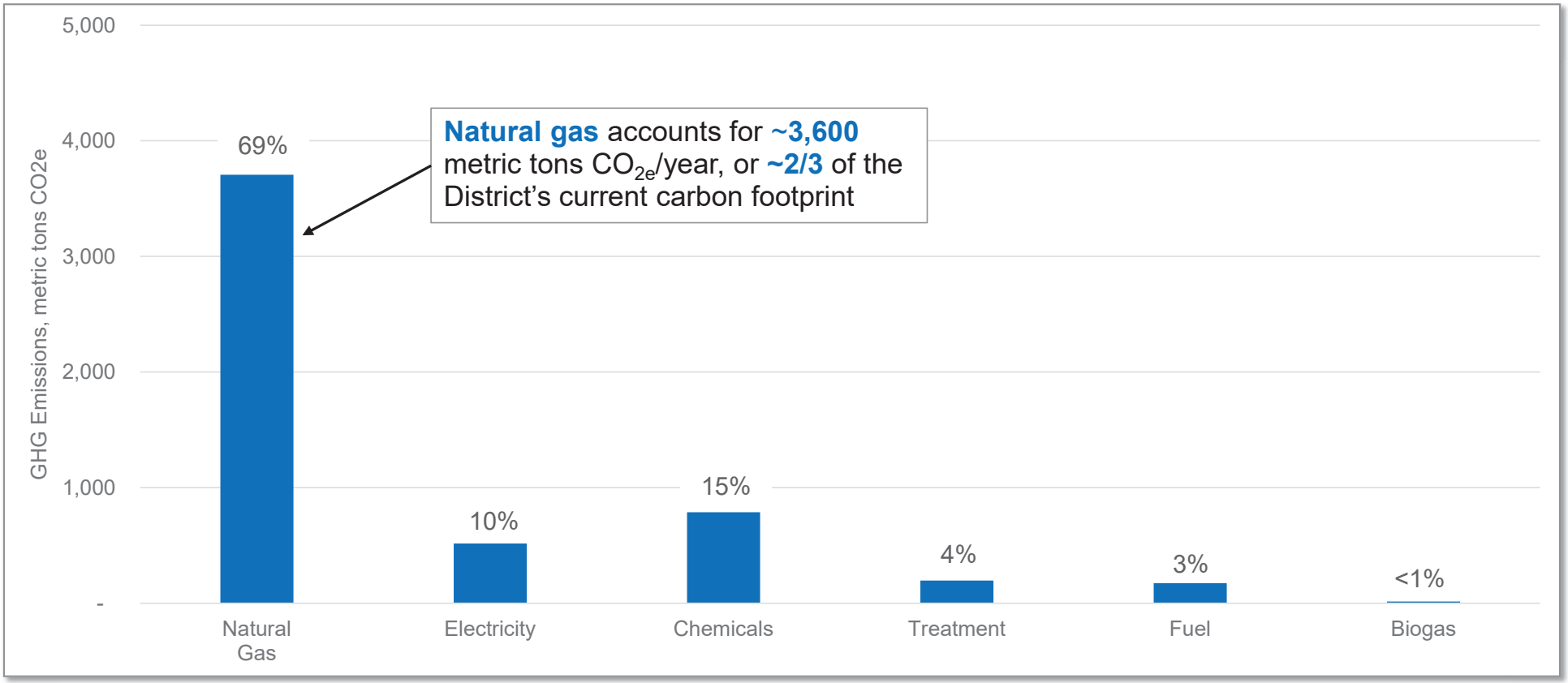


// GHG Emissions, by consumable



Cogen using Biogas	Cogen using PG&E NG	PG&E
2 g CO_2/kWh	542 g CO_2/kWh	73 g CO_2/kWh

Baseline Energy and GHG Emissions
Summary of Findings

// Summary of Baseline Findings

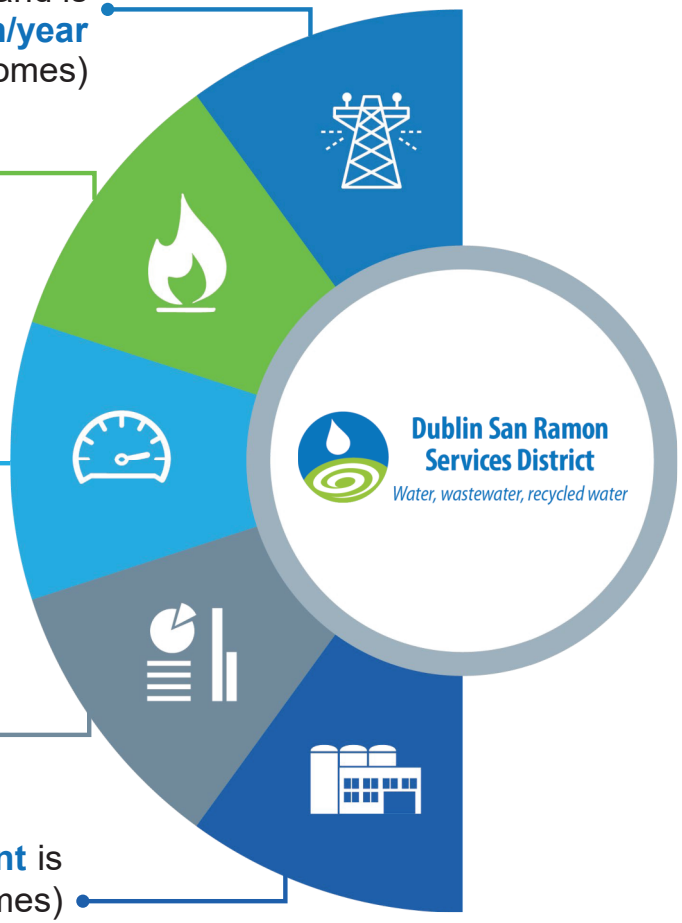
Electricity demand is **~15 M kWh/year** (~2,500 homes)

Thermal energy demand is **~340,000 therms/year** (~1,000 homes)

Fuel consumption is comparable to ~**60 vehicles** driven in the United States

~75% of the District's energy demands are associated with the operation of its **wastewater treatment facilities**

The District's GHG footprint is **~5,500** metric tons CO_{2e} (~175 homes)



95% of the power required for the WWTP is generated on-premise via the cogeneration system

Nearly **100%** of the thermal energy demands for the WWTP are met through thermal energy recovered from the on-premise cogeneration system

Questions and Break

Opportunities Assessment

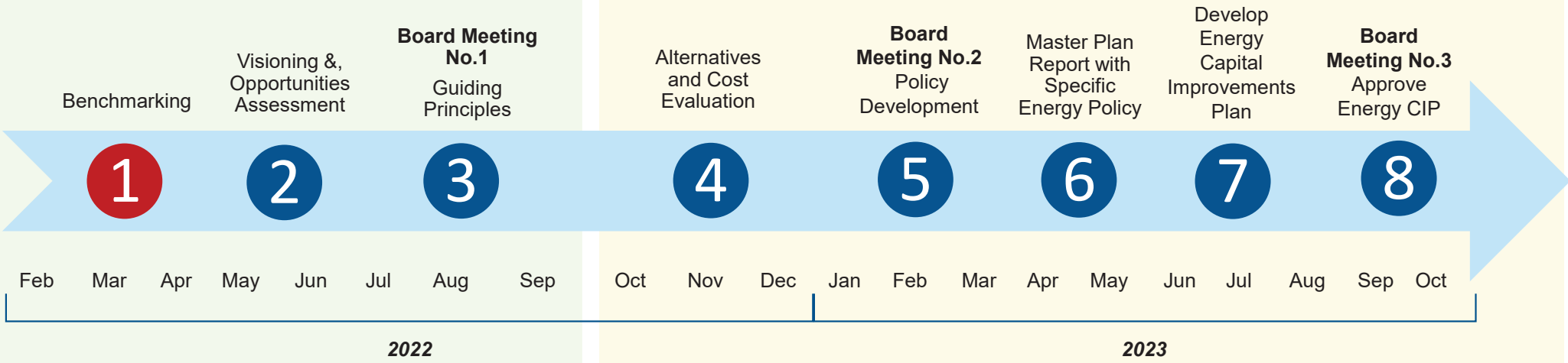
// Scope of Phase 1 and 2 of this planning project

Phase 1

State of the District Energy Baseline

Phase 2

Alternatives Evaluation and Prioritization



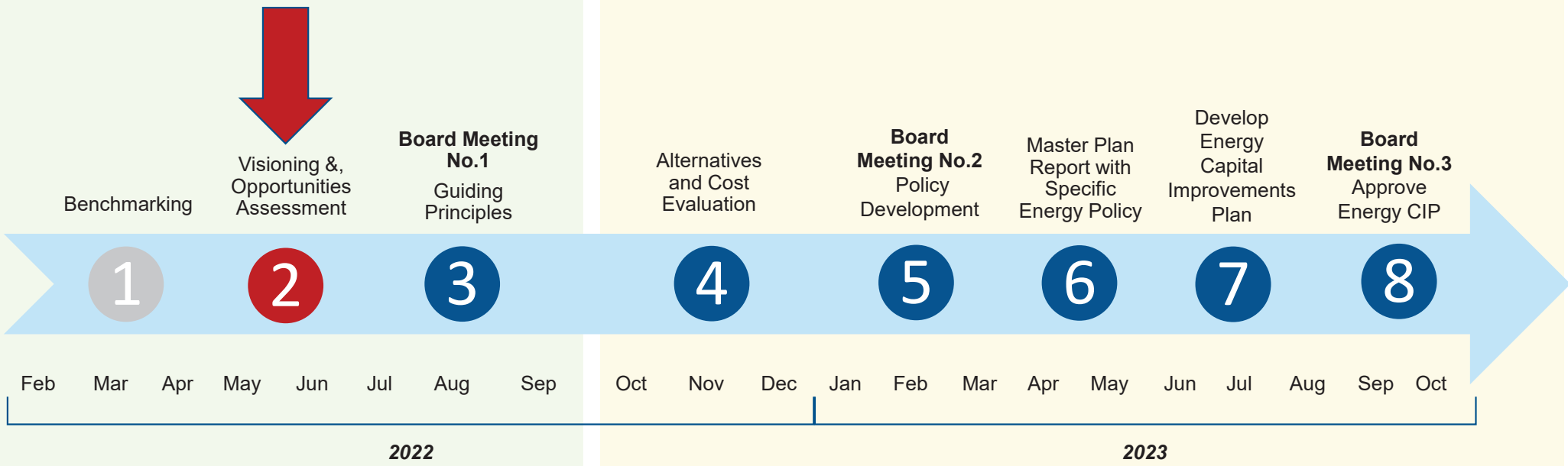
// Scope of Phase 1 and 2 of this planning project

Phase 1

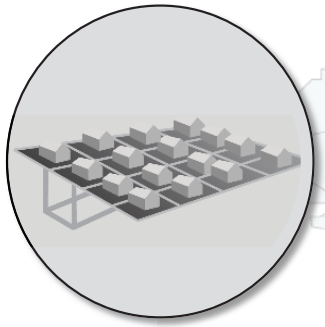
State of the District Energy Baseline

Phase 2

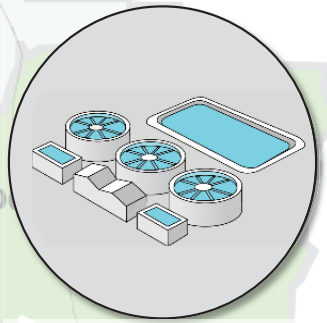
Alternatives Evaluation and Prioritization



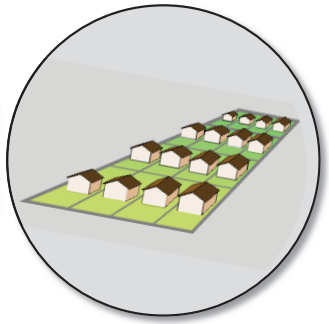
// Facilities included in the opportunities assessment



Wastewater Collection System



Wastewater Treatment Plant



Water Distribution System

Recycled Water Treatment & Distribution (DERWA)

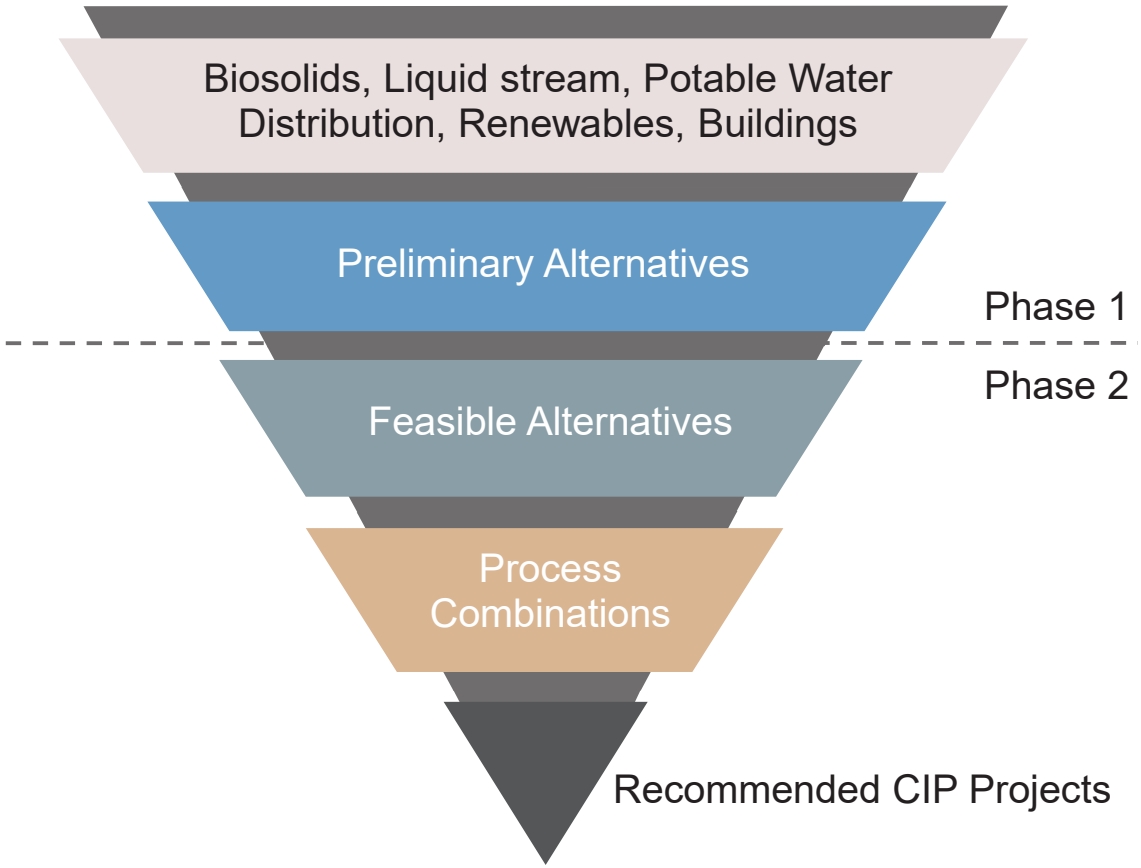
Wastewater Effluent Discharge (LAVWMA)

Recycled Water Distribution

Offices & Buildings

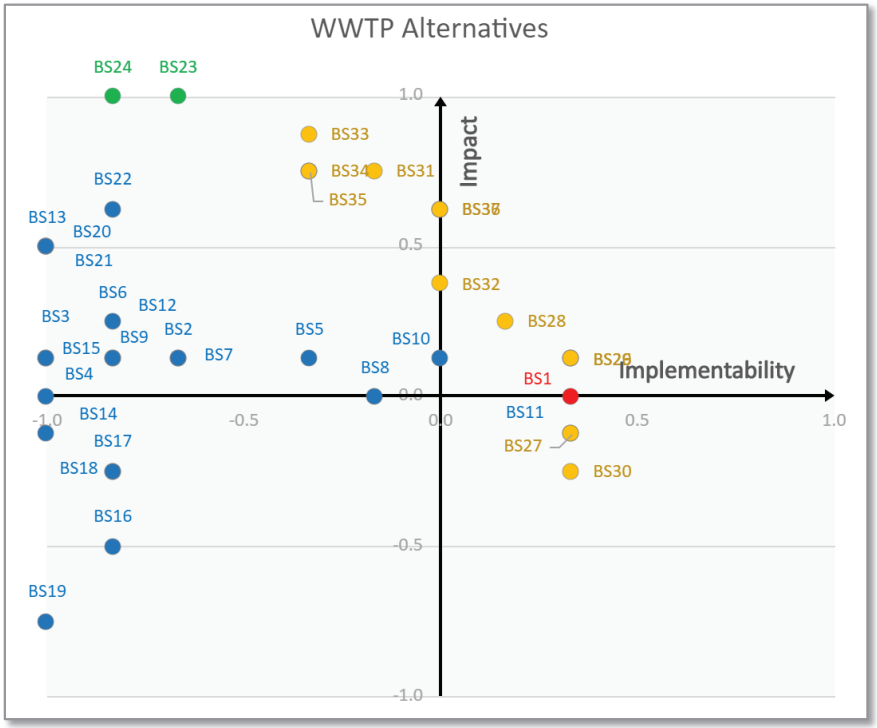
Fleet

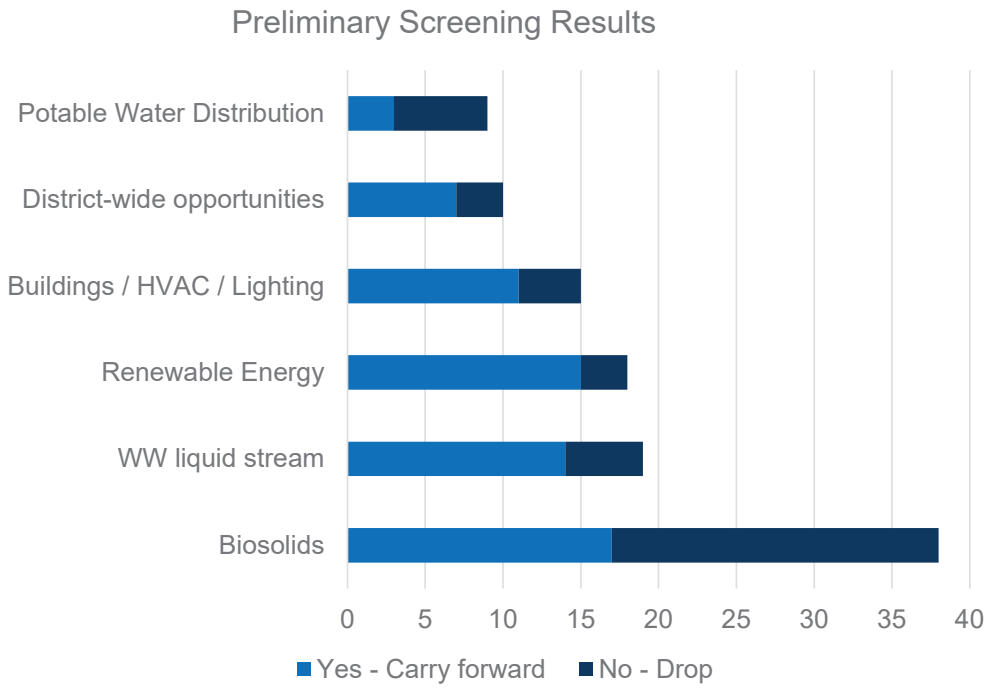
// Preliminary evaluation of options



// High level opportunities initial screening process

109 Alternatives Evaluated → **67** Alternatives Met Minimum Requirements

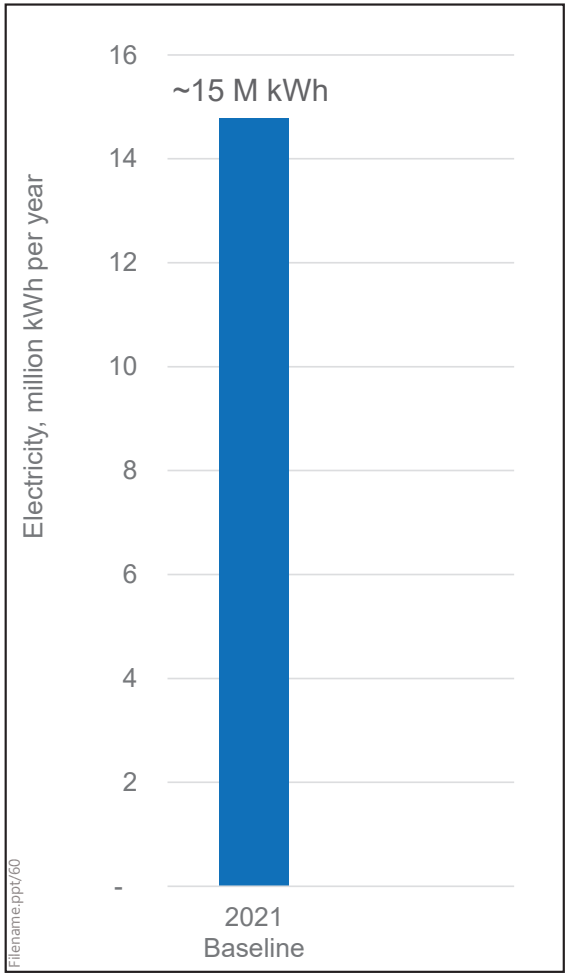




Opportunities Assessment

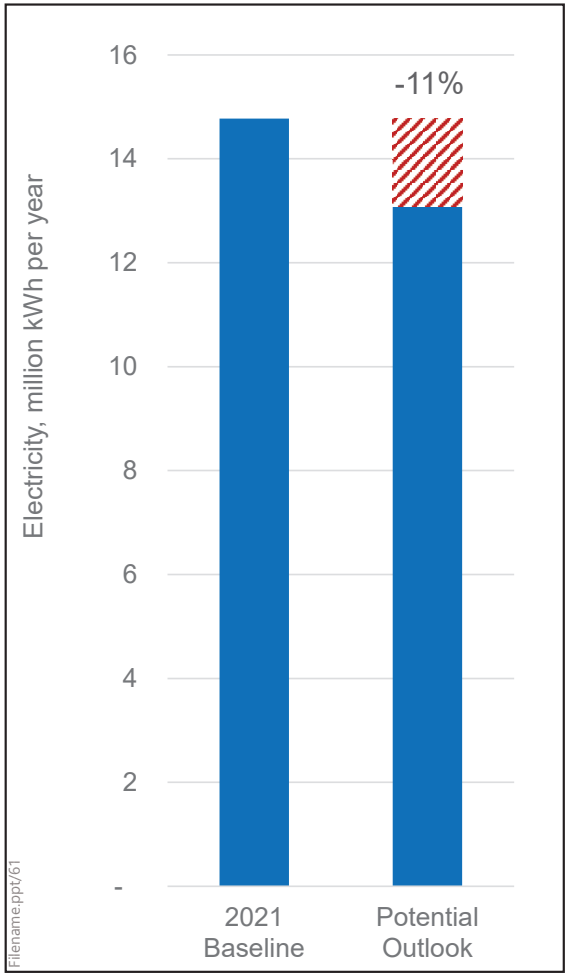
What is possible?
Energy Savings

// Opportunities Outlook – Potential Energy Savings



Current Electrical Demand:
~15 M kWh / yr

// Opportunities Outlook – Potential Energy Savings

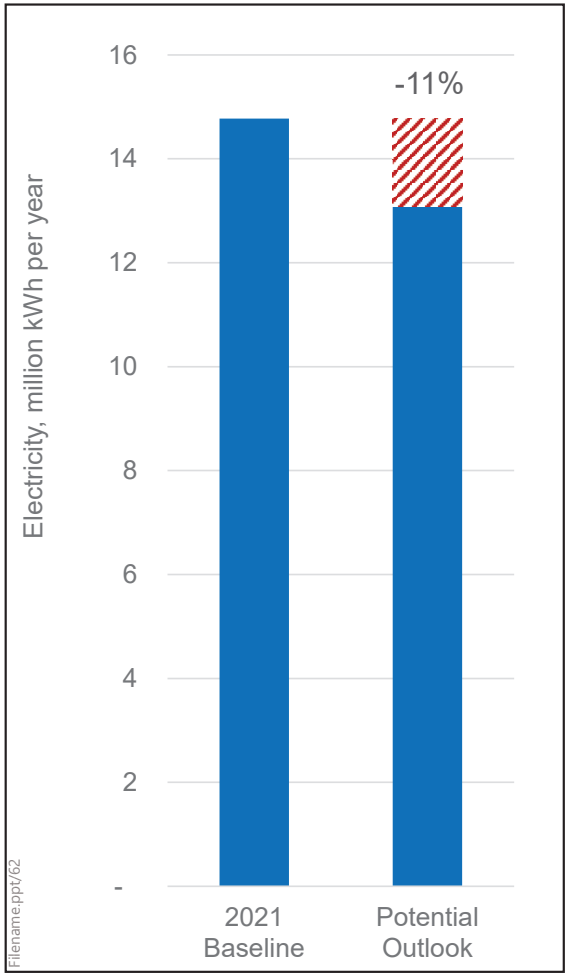


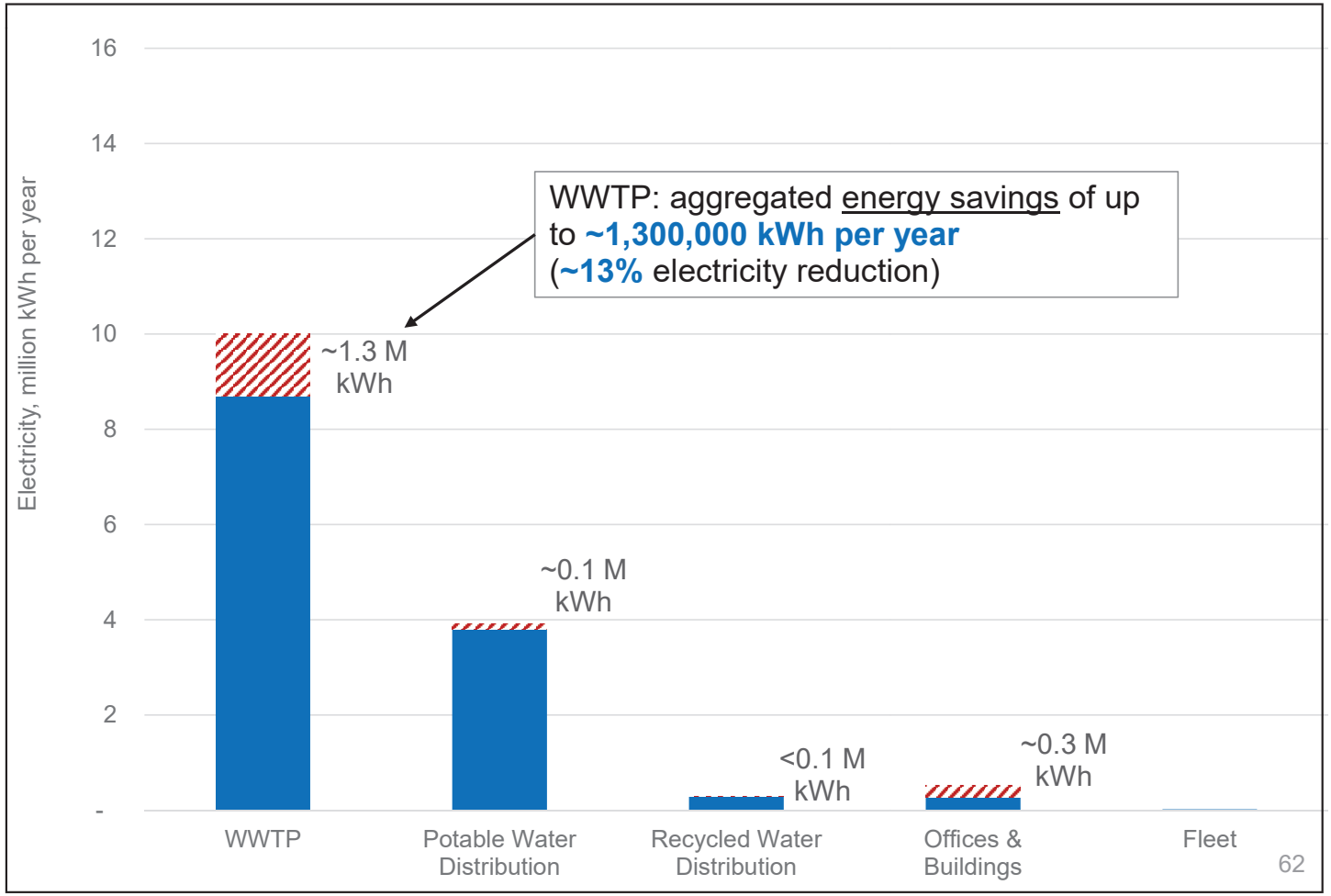
Current Electrical Demand:
~15 M kWh / yr

~13 M kWh / yr

Potential Reduction of **~1.7 M kilowatt-hours**, or approximately **11%** of District's current electricity demand

// Opportunities Outlook – Potential Energy Savings



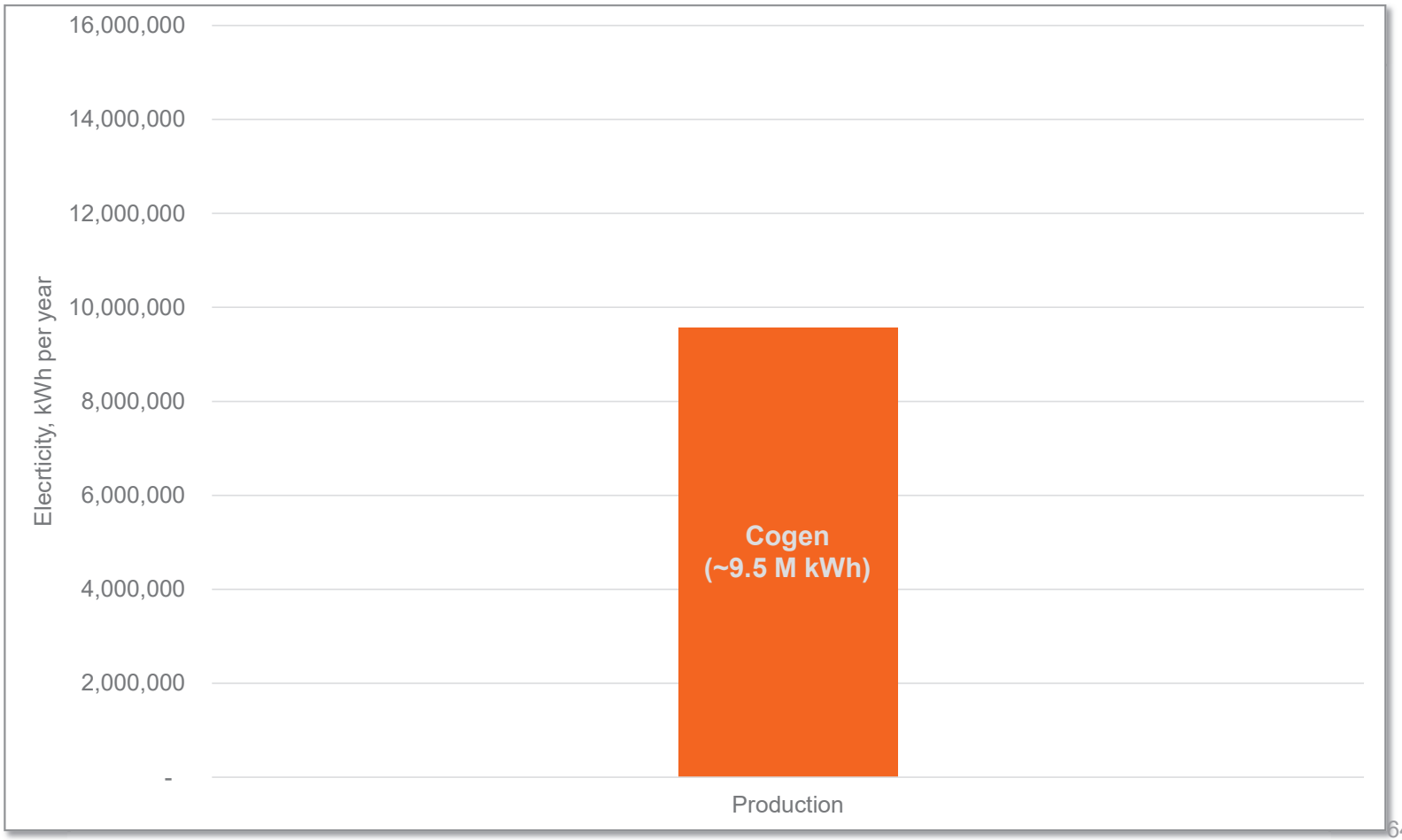


Opportunities Assessment

What is possible?
Energy Generation

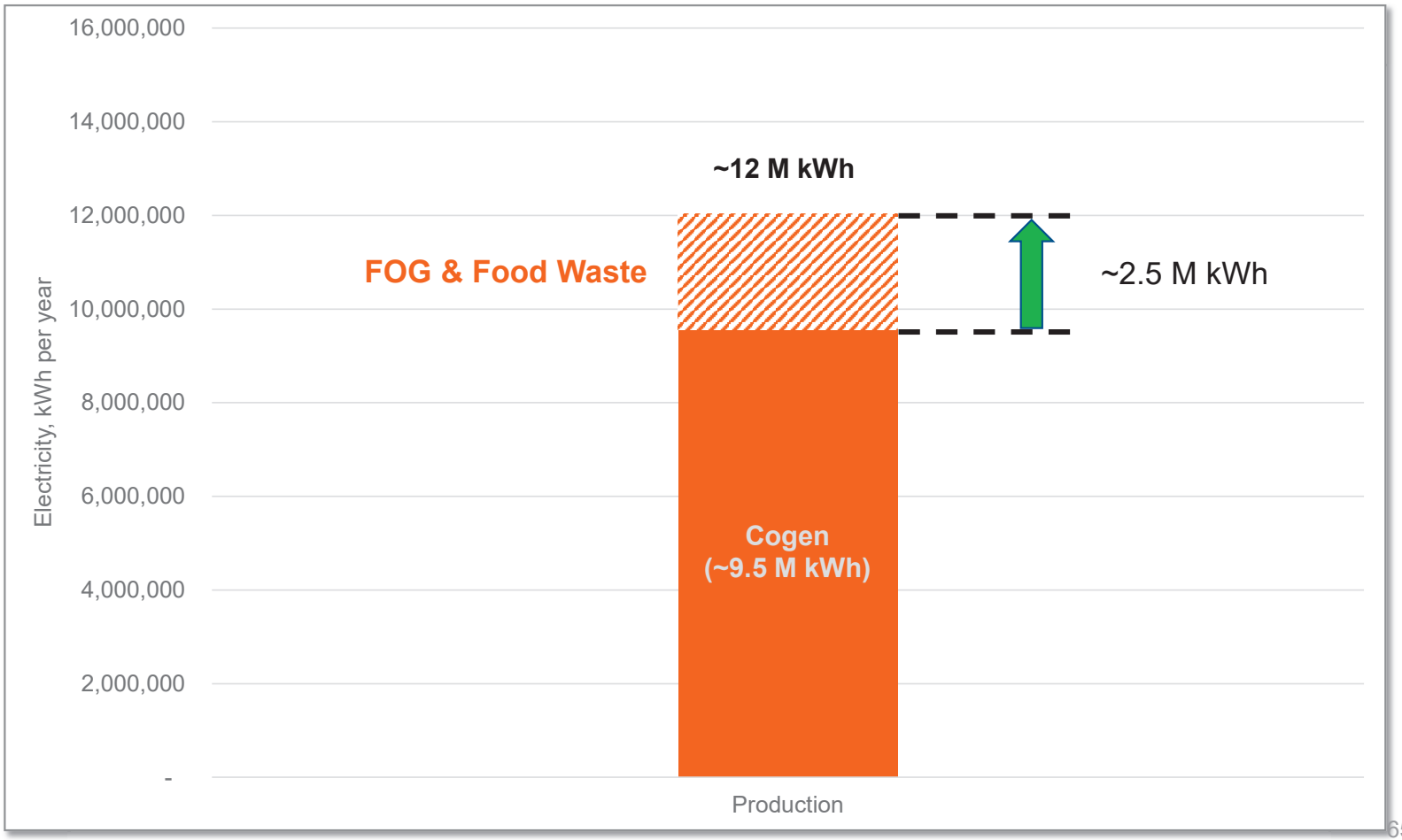
// Opportunities Outlook – Potential Energy Generation

The WWTP **Cogeneration System** currently produces **~9.5 M kWh**



// Opportunities Outlook – Potential Energy Generation

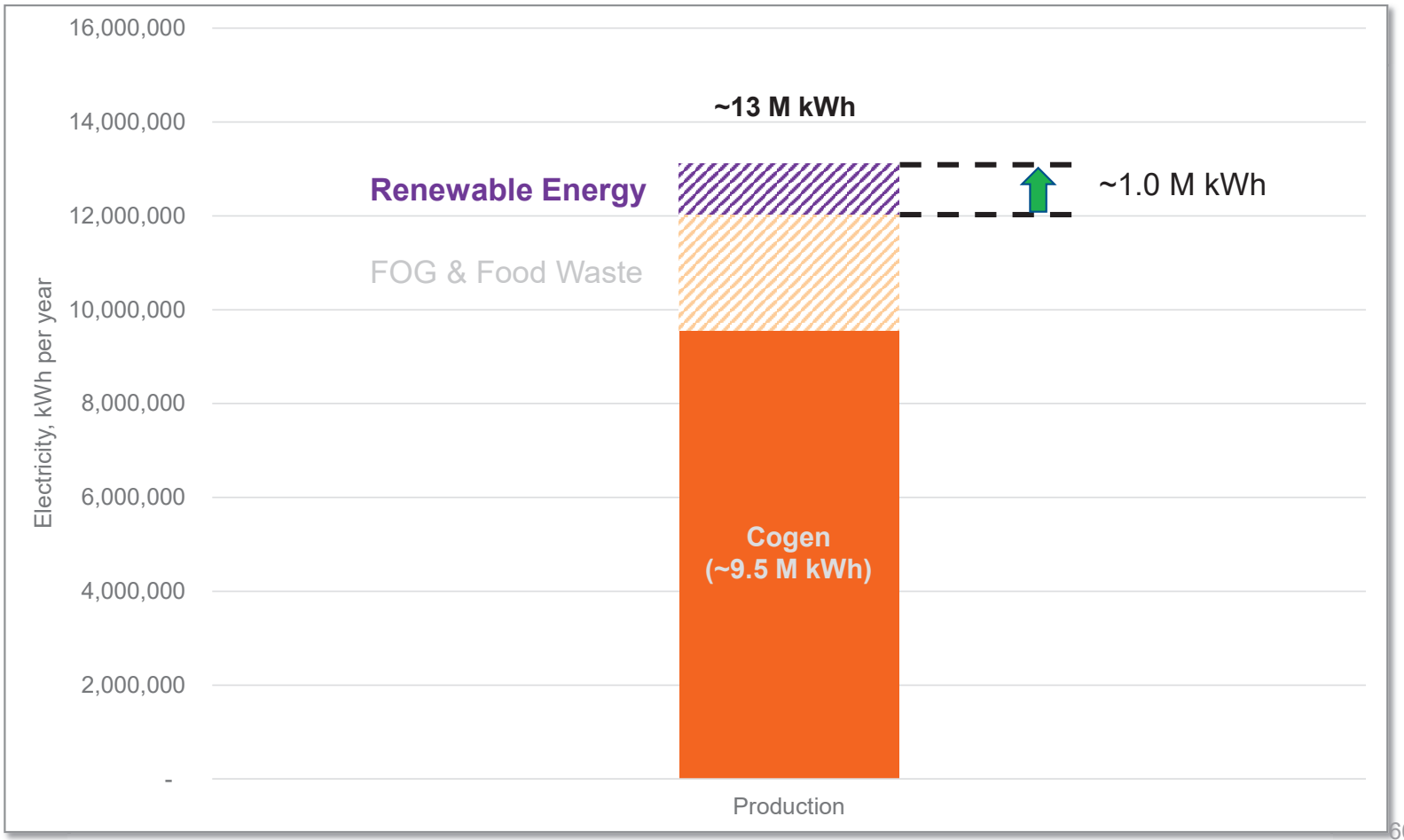
Additional Biogas through **Fats, Oils and Grease (FOG)** and **Food Waste programs**



// Opportunities Outlook – Potential Energy Generation

Additional Biogas through **Fats, Oils and Grease (FOG)** and **Food Waste programs**

Renewable Energy (i.e., Solar Power, Wind Power)



// Opportunities Outlook – Potential Energy Generation

Additional Biogas through **Fats, Oils and Grease (FOG)** and **Food Waste programs**

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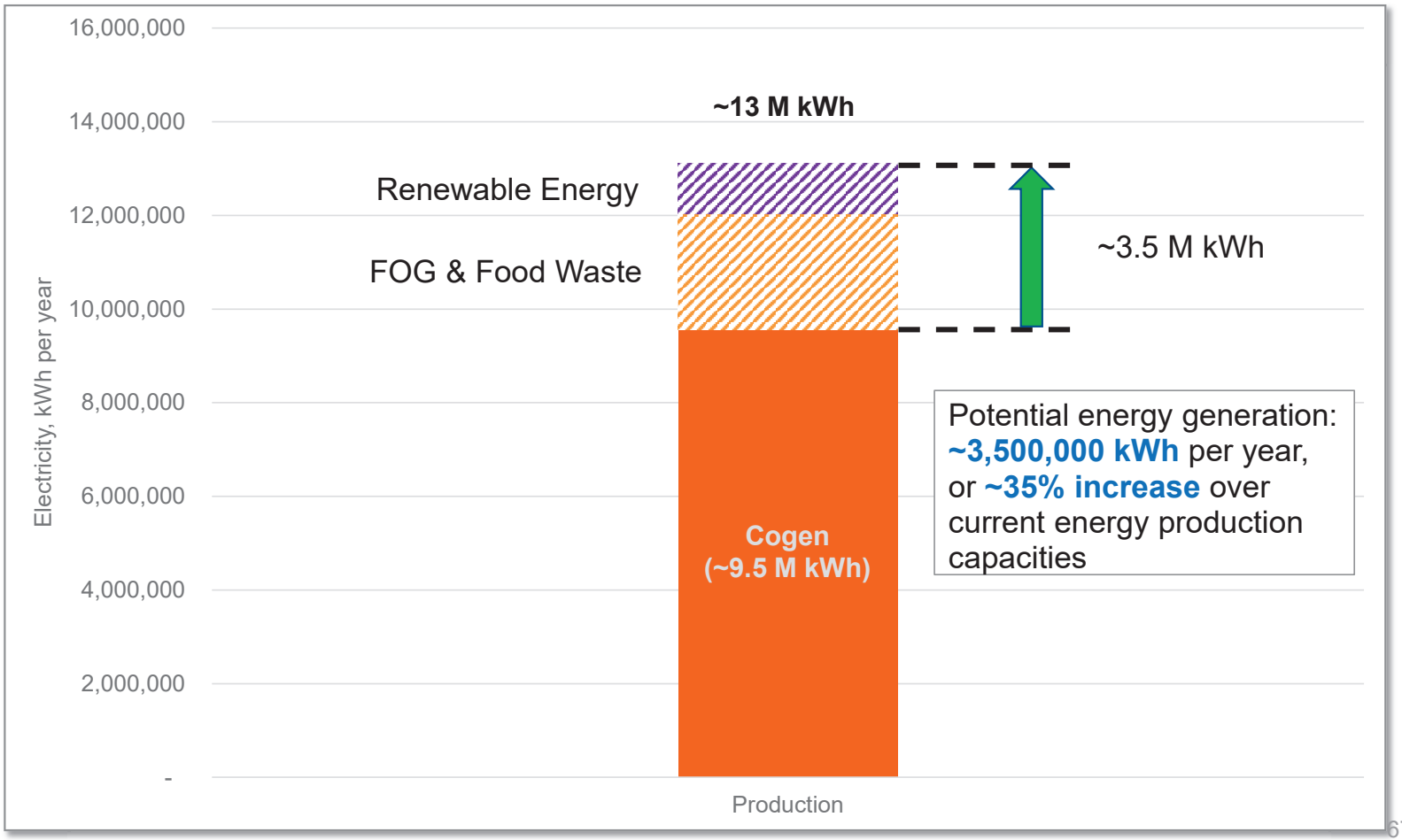
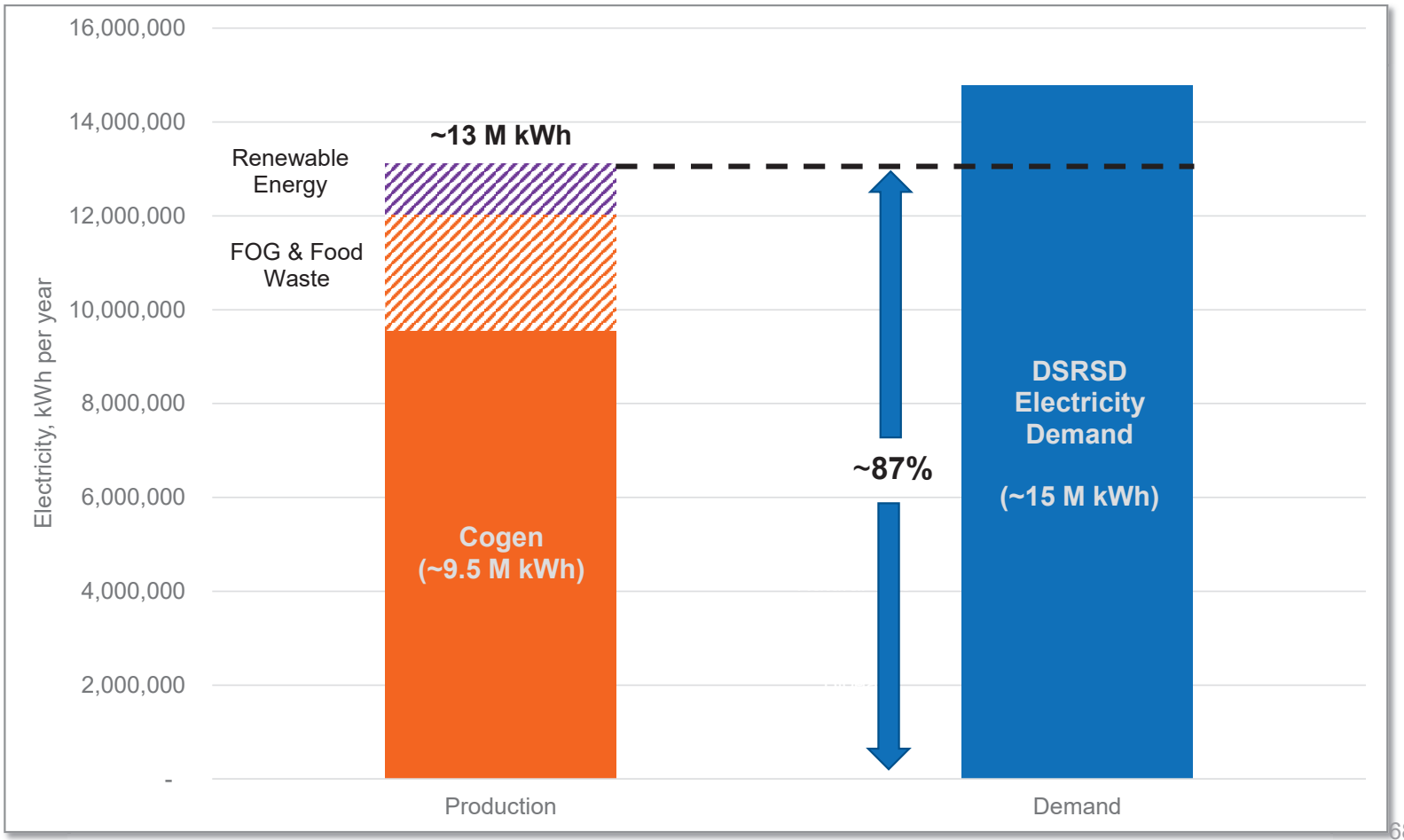


// Opportunities Outlook – Potential Energy Generation

Additional Biogas through **Fats, Oils and Grease (FOG)** and **Food Waste programs**

Renewable Energy (i.e., Solar Power, Wind Power)

Potential to generate up to **~87%** of the District's current electricity demand



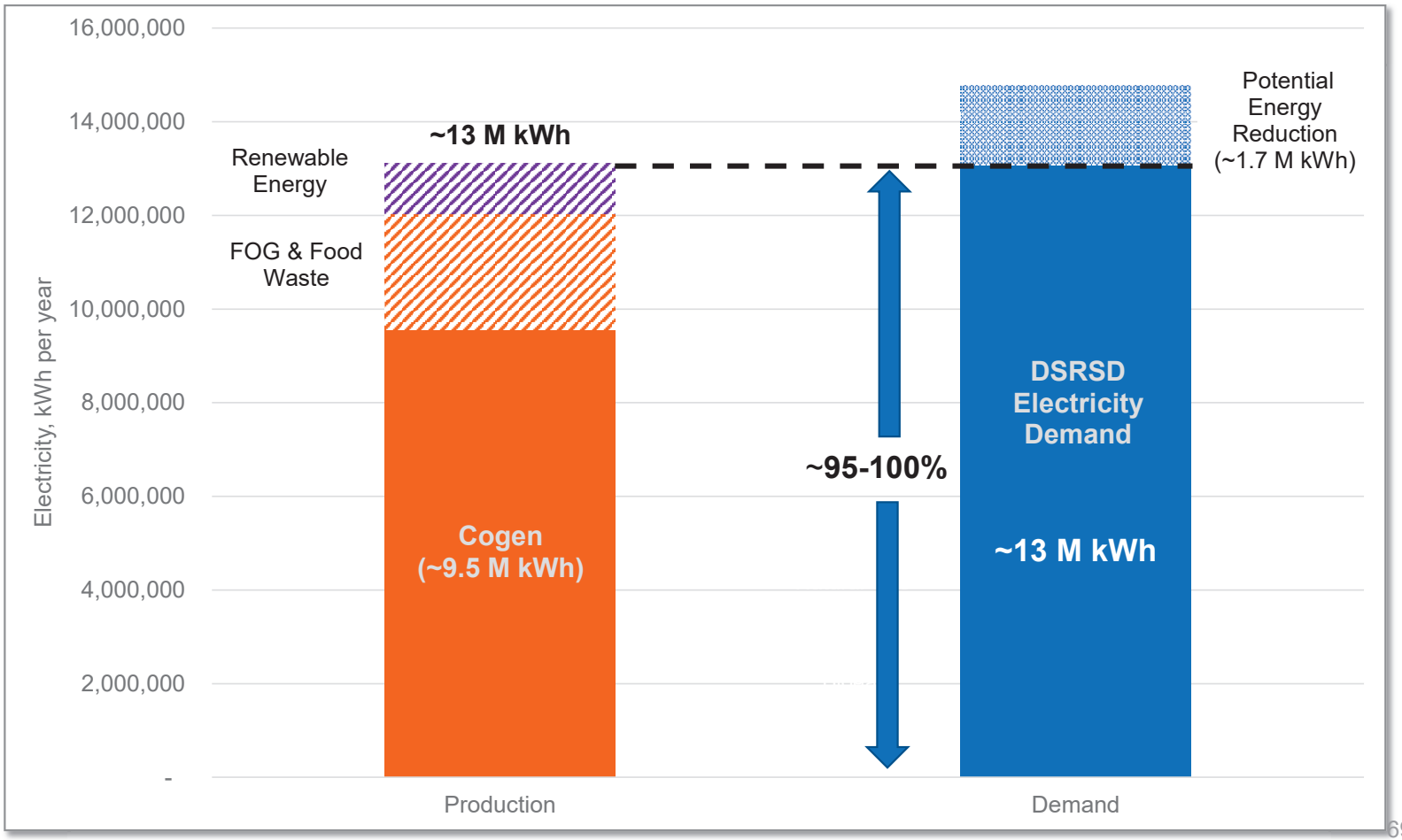
// Opportunities Outlook – Potential Energy Generation

Additional Biogas through **Fats, Oils and Grease (FOG)** and **Food Waste programs**

Renewable Energy (i.e., Solar Power, Wind Power)

Potential to generate up to ~87% of the District's current electricity demand

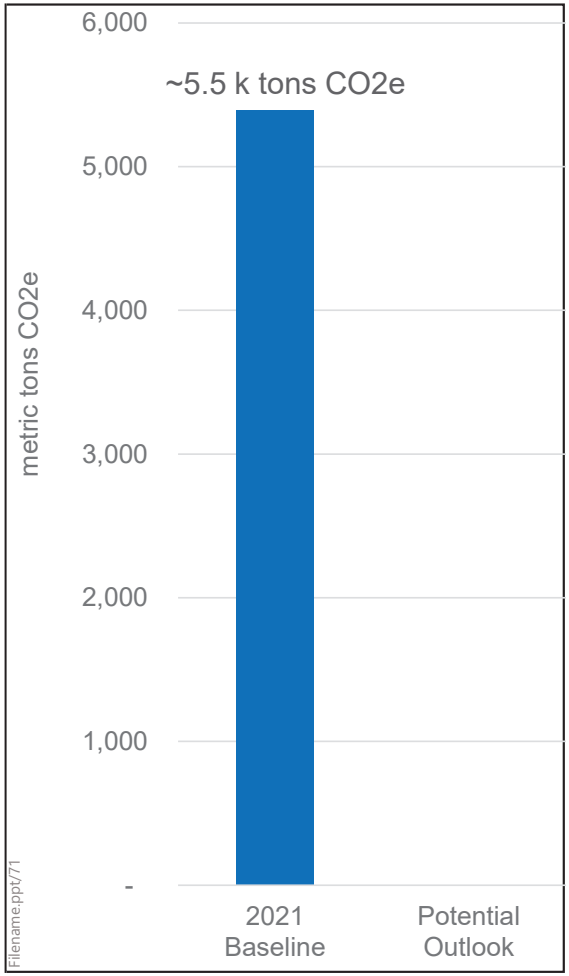
With potential energy reductions, potential to generate **~95% to 100%** of the District's current electricity demand



Opportunities Assessment

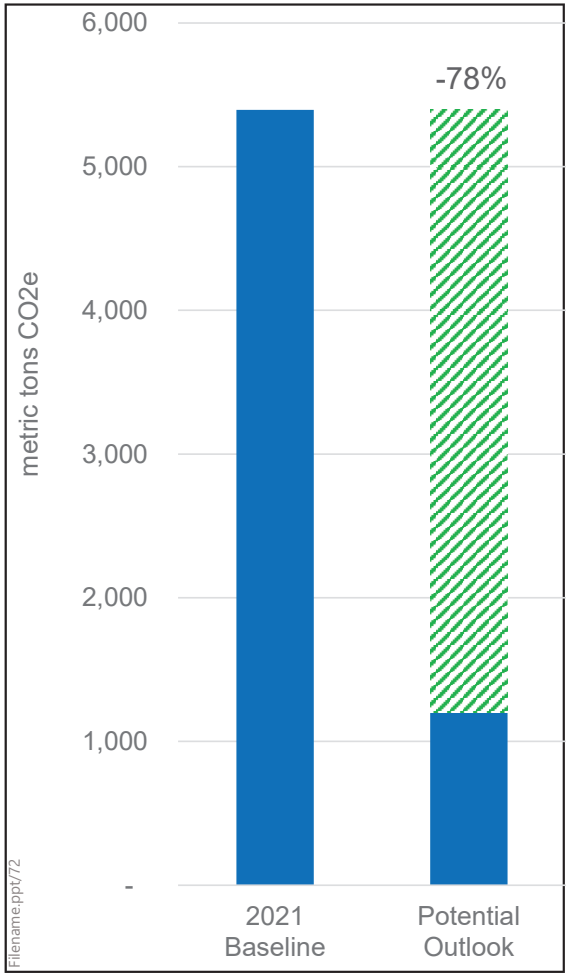
What is possible?
GHG Reduction

// Opportunities Outlook – Potential GHG Reduction



Current GHG Emissions:
~5,500 Total metric tons/year

// Opportunities Outlook – Potential GHG Reduction



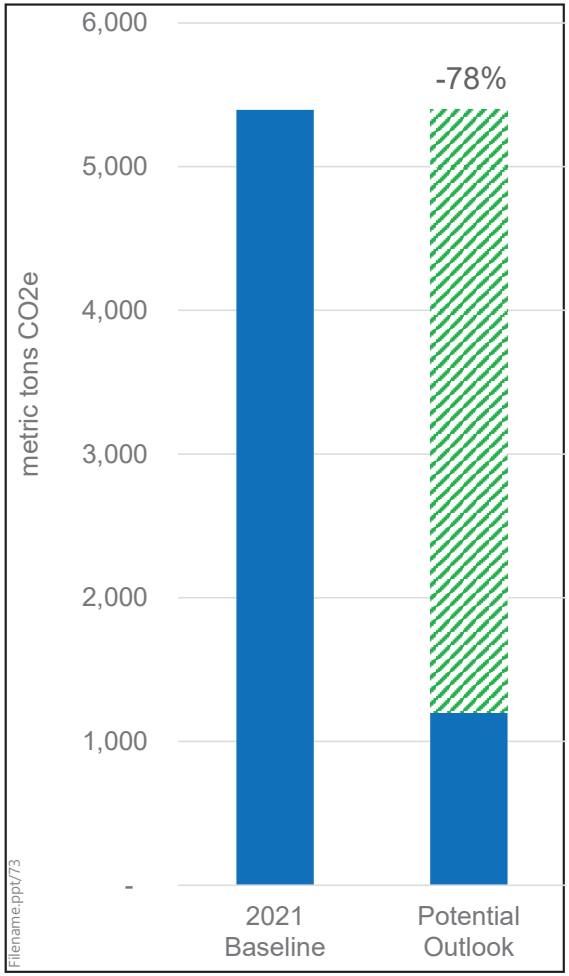
CO_{2e}

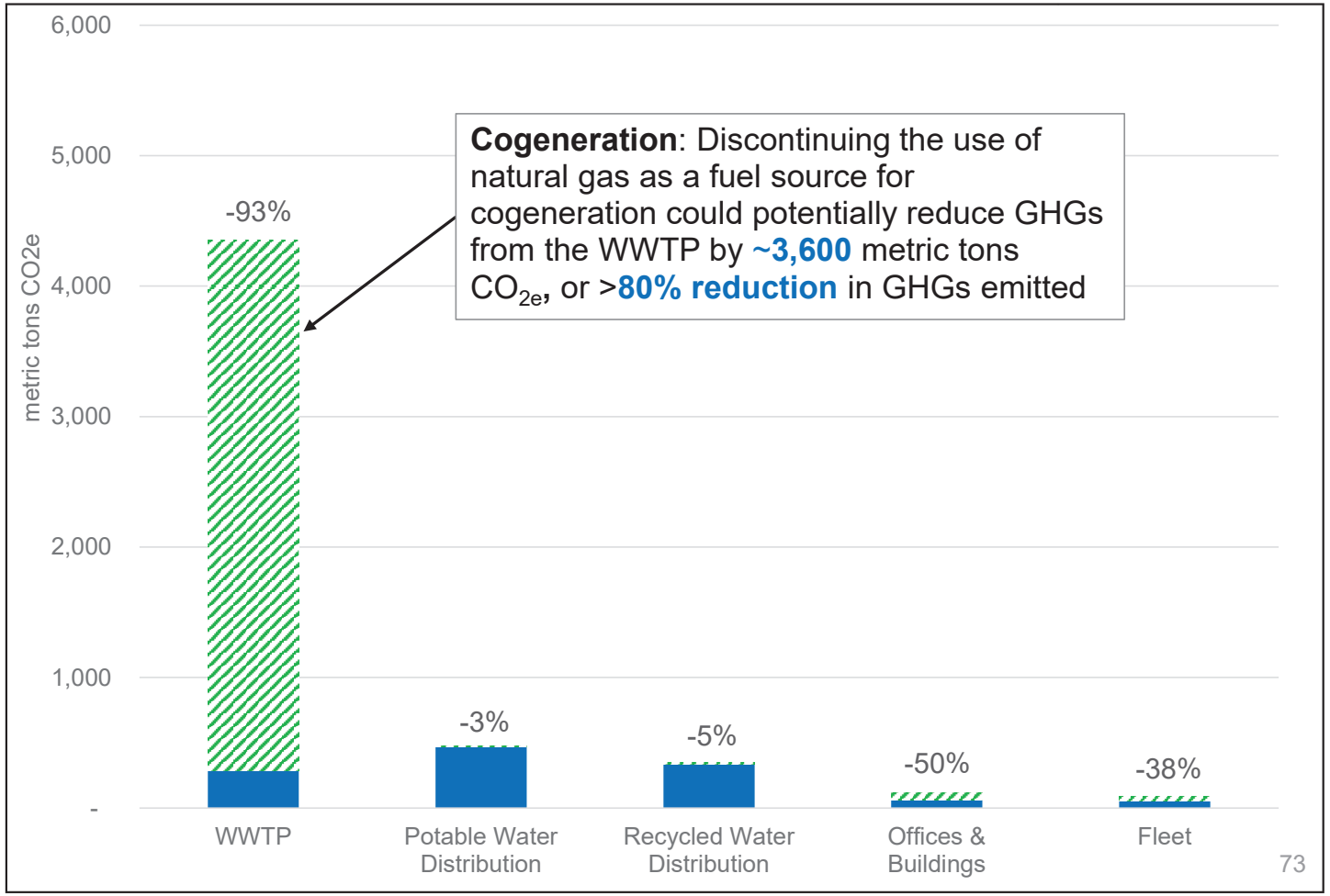
Current GHG Emissions:
~5,500 Total metric tons/year

~1,200 Total metric tons/year

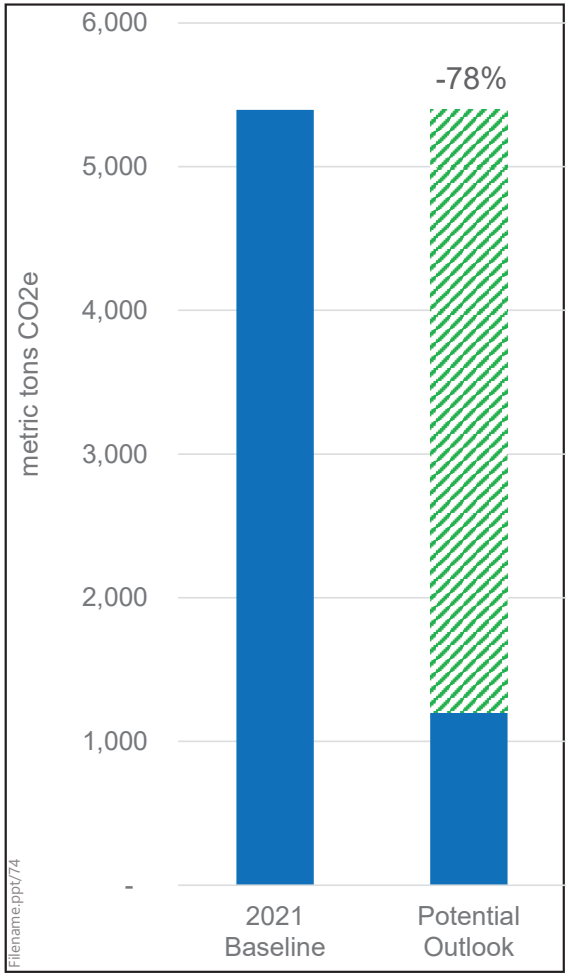
Potential Reduction of
~4,000 metric tons CO_{2e}, or
~80% of District's current carbon footprint

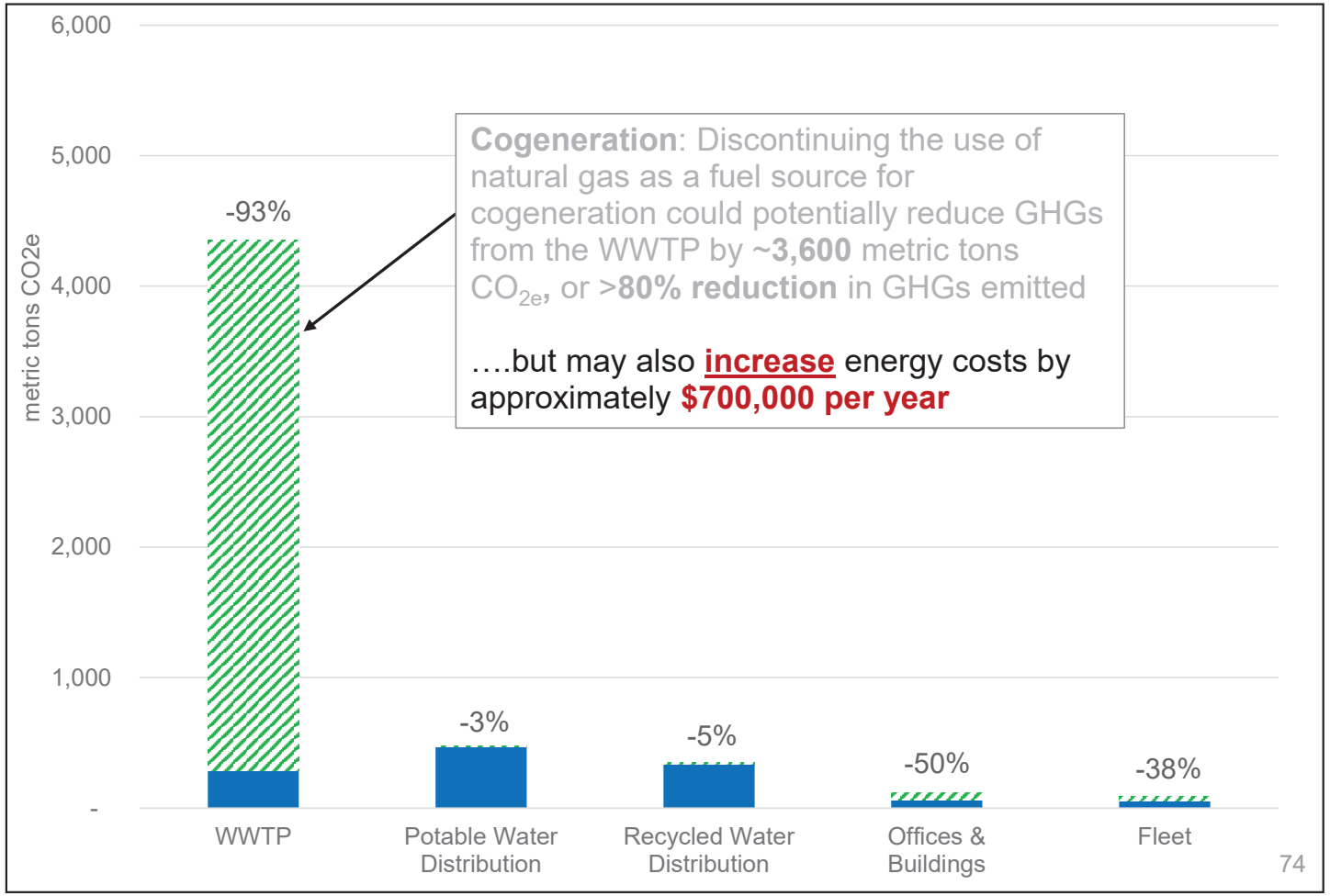
// Opportunities Outlook – Potential GHG Reduction





// Opportunities Outlook – Potential GHG Reduction





Opportunities Assessment

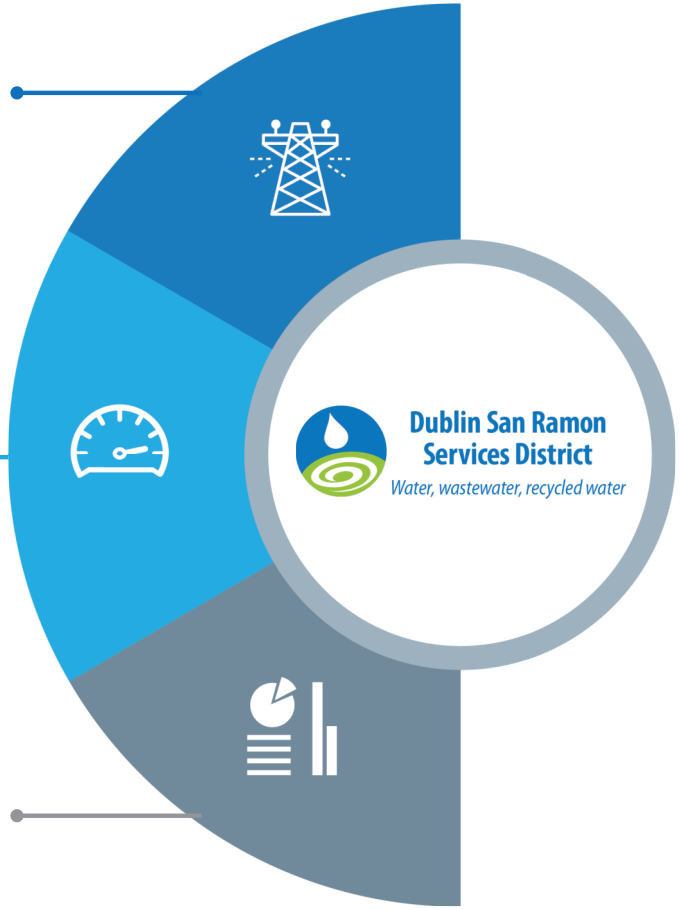
Summary

// Summary of opportunities estimates

Electricity savings opportunities of up to **11 percent** for DSRSD facilities

Electricity generation opportunities of up to **3.5 M kilowatt-hours**

Carbon footprint could be potentially reduced by as much as **2/3** if natural gas was discontinued as a fuel source for the cogeneration system



67 preliminary alternatives are carried forward into Phase 2 for further analysis.

// Summary of opportunities estimates

Electricity savings opportunities of up to **11 percent** for DSRSD facilities

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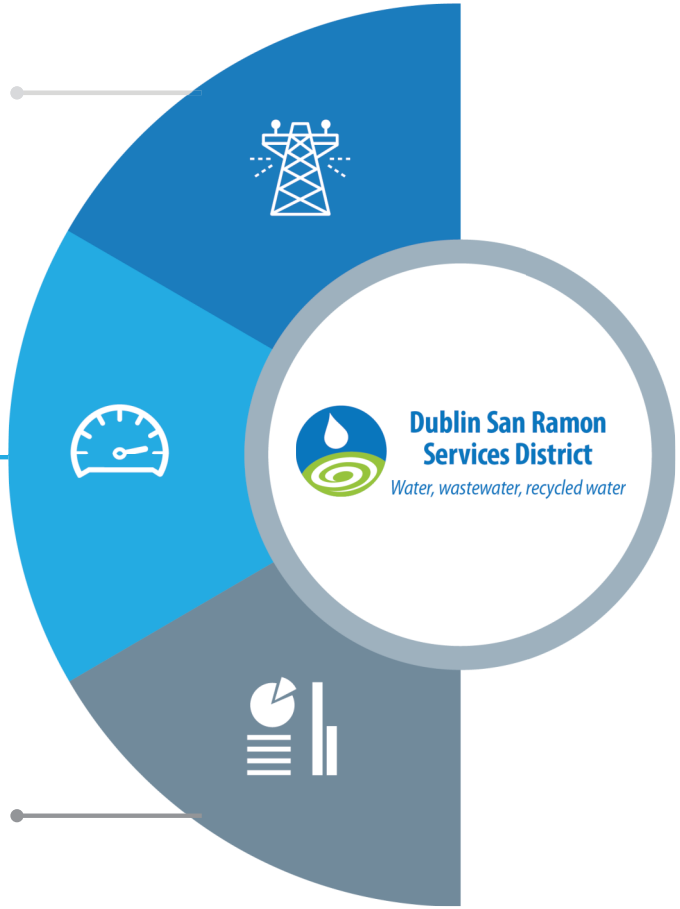


67 preliminary alternatives are carried forward into Phase 2 for further analysis.

Questions

Energy Guiding Principles

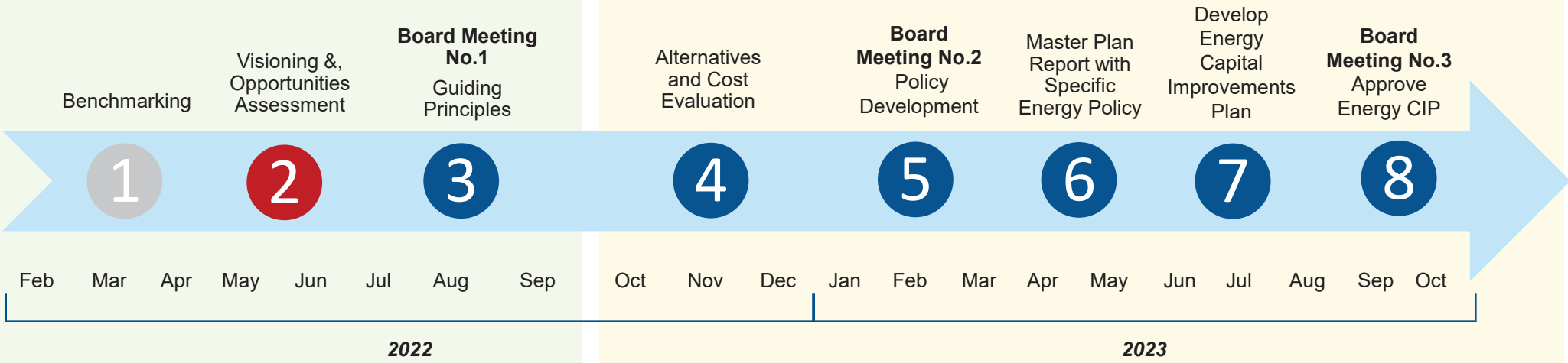
// Scope of Phase 1 and 2 of this planning project

Phase 1

State of the District Energy Baseline

Phase 2

Alternatives Evaluation and Prioritization



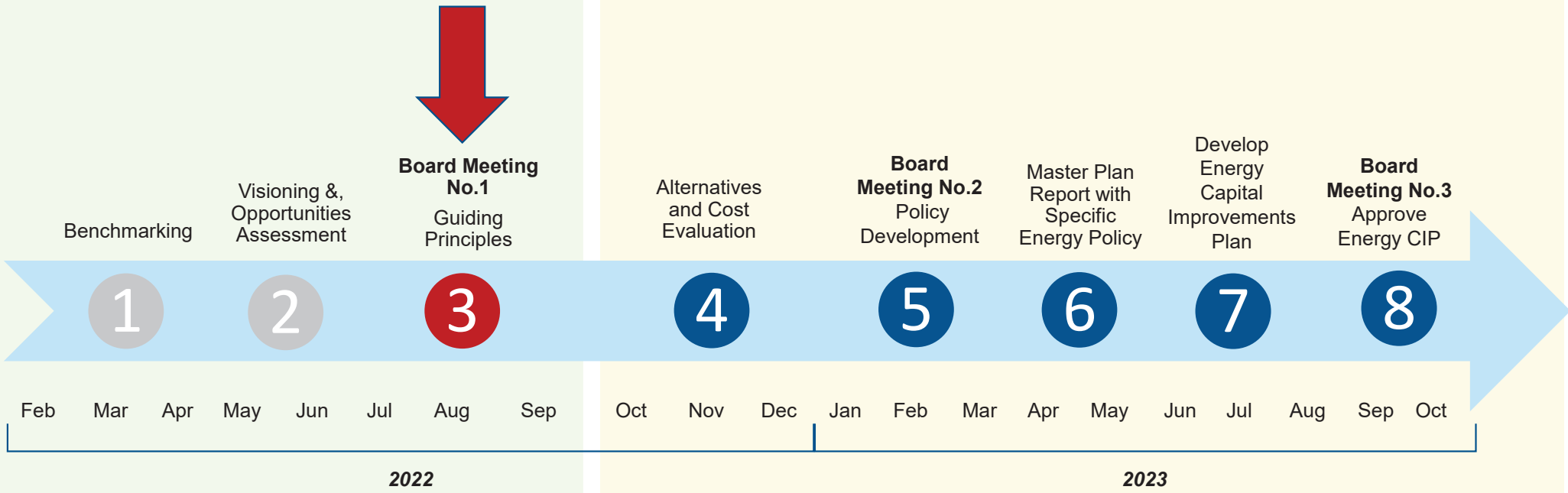
// Scope of Phase 1 and 2 of this planning project

Phase 1

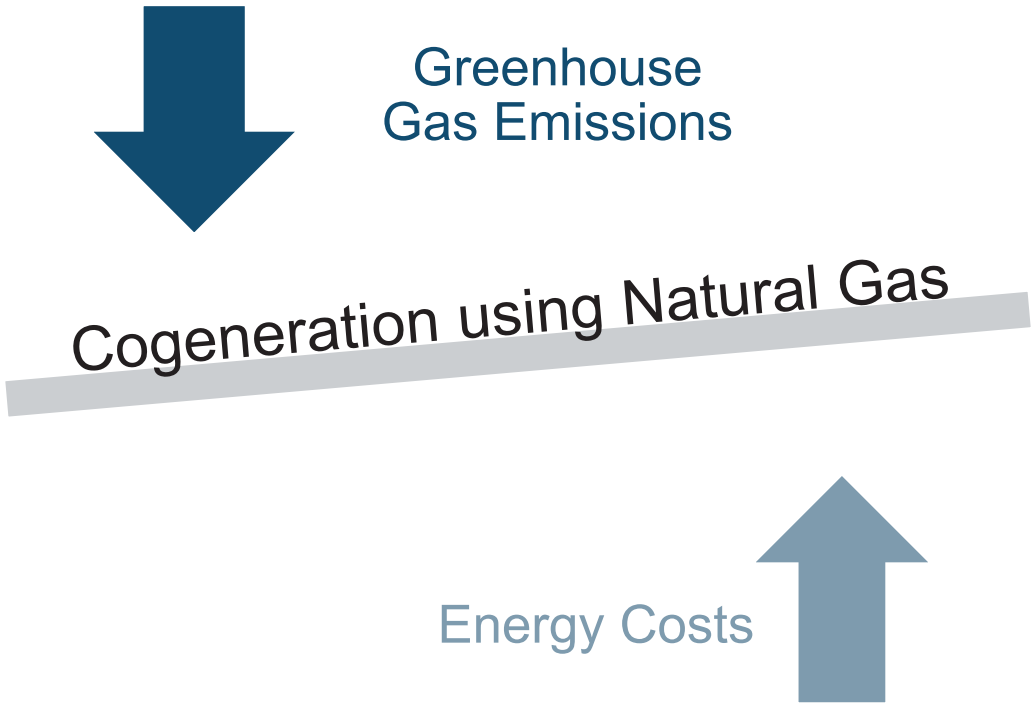
State of the District Energy Baseline

Phase 2

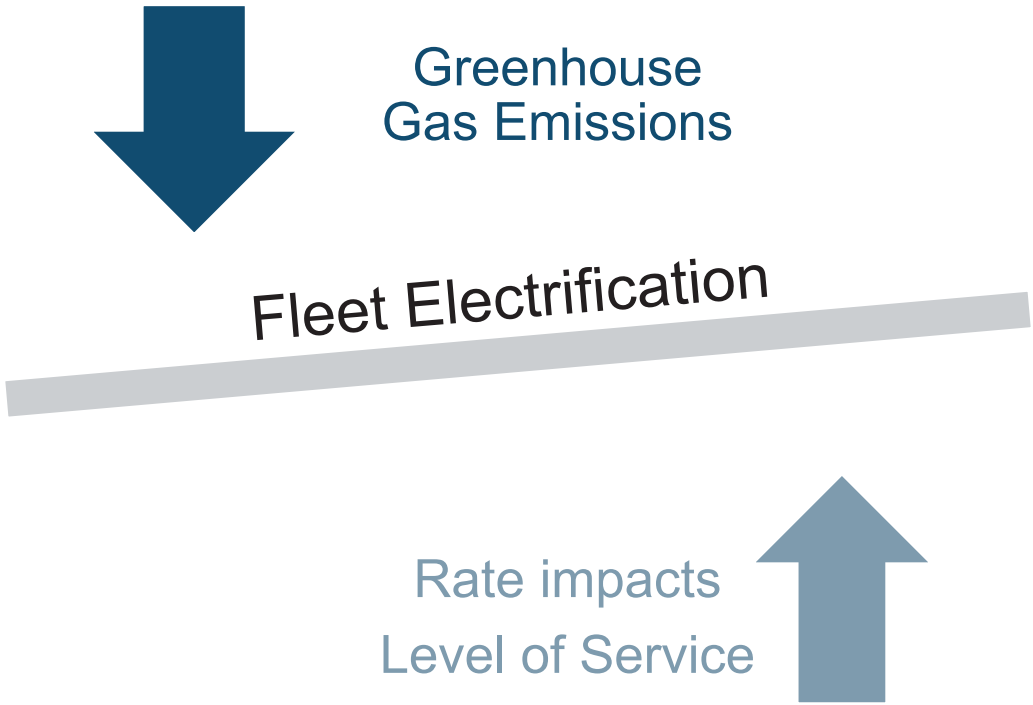
Alternatives Evaluation and Prioritization



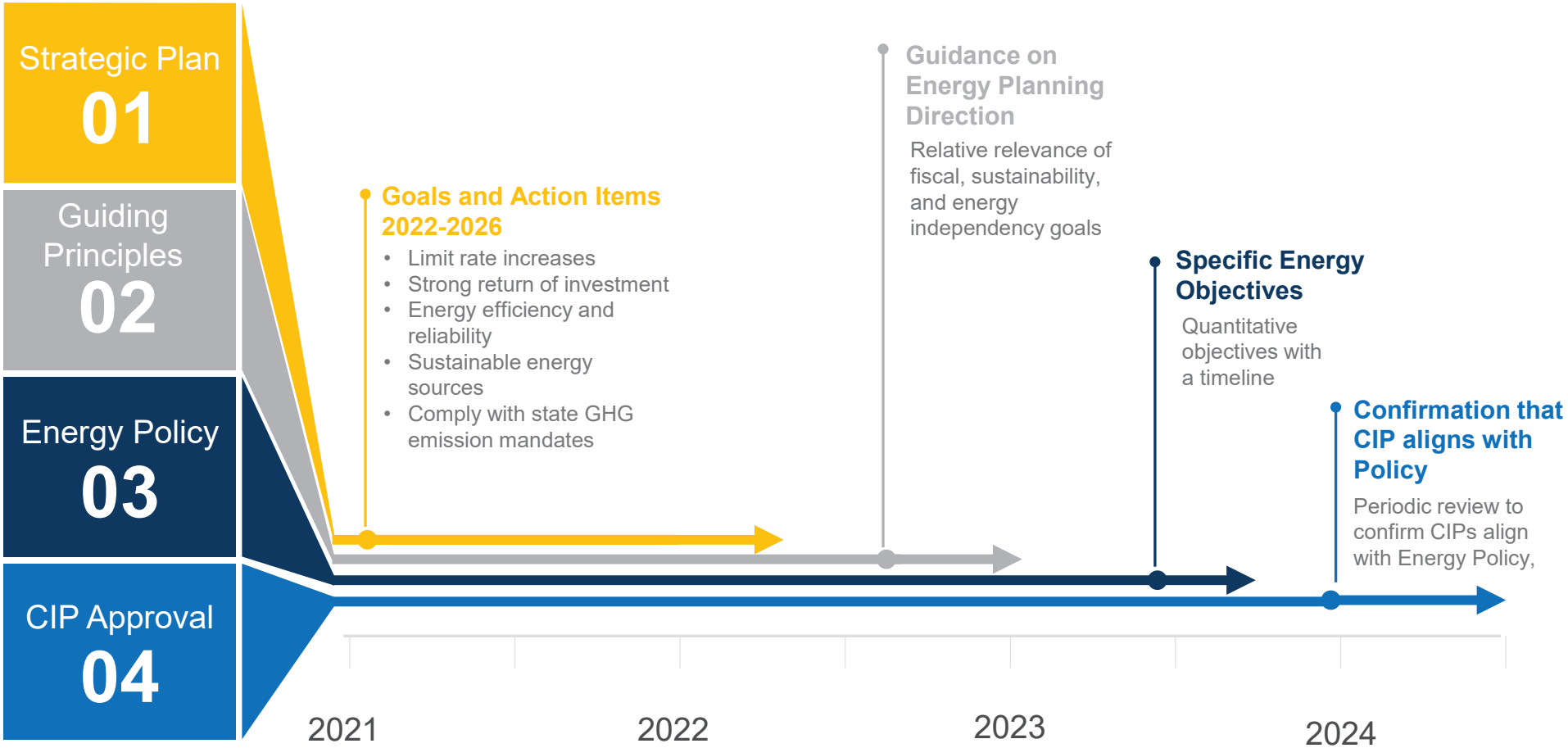
// Examples of competing project objectives



// Examples of competing project objectives



// How the Board helps guide the energy CIP development

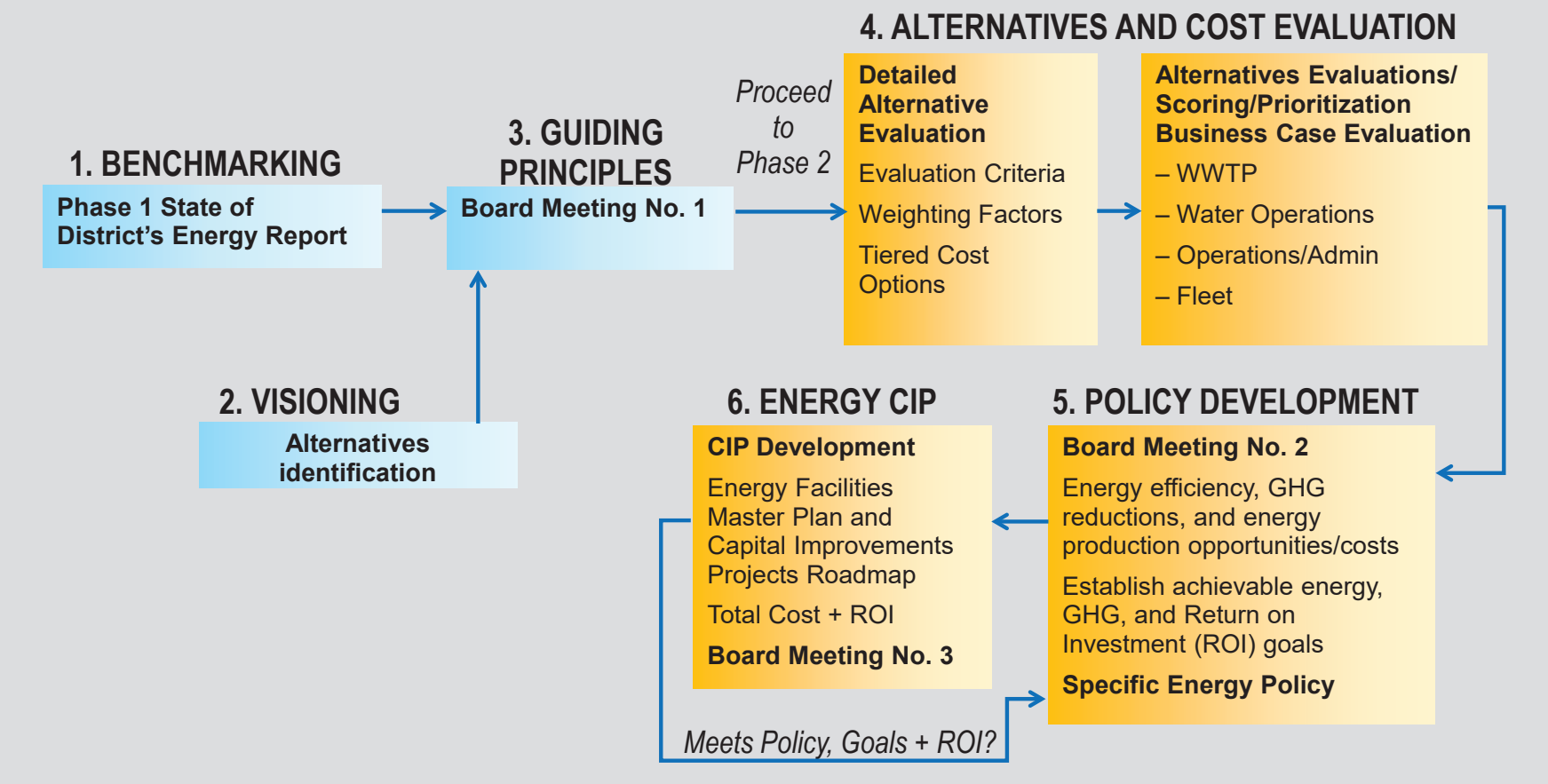


// Complexities of energy and GHG master planning

- Environmental stewardship
- Industry leadership
- GHG reduction goals
- Future regulations
- Sustainable energy sources

- Return of investment
- Sunk costs in existing infrastructure
- Reliability and Resiliency
- Limit rate increases
- Resource limitations

// How the Board's Guiding Principles help develop the Masterplan and CIP



// Energy Guiding Principles & Policy

A general statement of DSRSD's values to help guide decision making process.

A prescribed commitment for an energy objective with quantitative goal and timeline

Example
"DSRSD shall strive to find and proactively implement cost-effective means to reduce GHG emission, increase renewable energy production, and improve energy efficiency."

Example
"DSRSD shall implement infrastructure upgrades for energy improvements with a payback period of less than 10 years."

// Suggestions for DSRSD Board's consideration in developing Energy Guiding Principles

1. Comply with all regulatory energy and GHG related mandates and **strive to exceed** them when related investments are **cost-effective** with consideration to the anticipated payback period and life cycle cost.
2. Strive to establish a **diverse, reliable, and resilient** energy supply portfolio for operation of its facilities.
3. Properly plan and **budget for staffing needs and training** to employ, operate, and maintain any additional energy related infrastructure.
4. Capital improvements shall **consider the impact** on energy demand, energy efficiency, and GHG impacts where relevant.
5. Seek opportunities to **offset any additional future energy demands** with renewable energy production.
6. Strive to **lead the industry** in supporting the development of new promising energy technologies in the spirit of the guiding principles and objectives.

Discussion on Guiding Principles

Next Steps

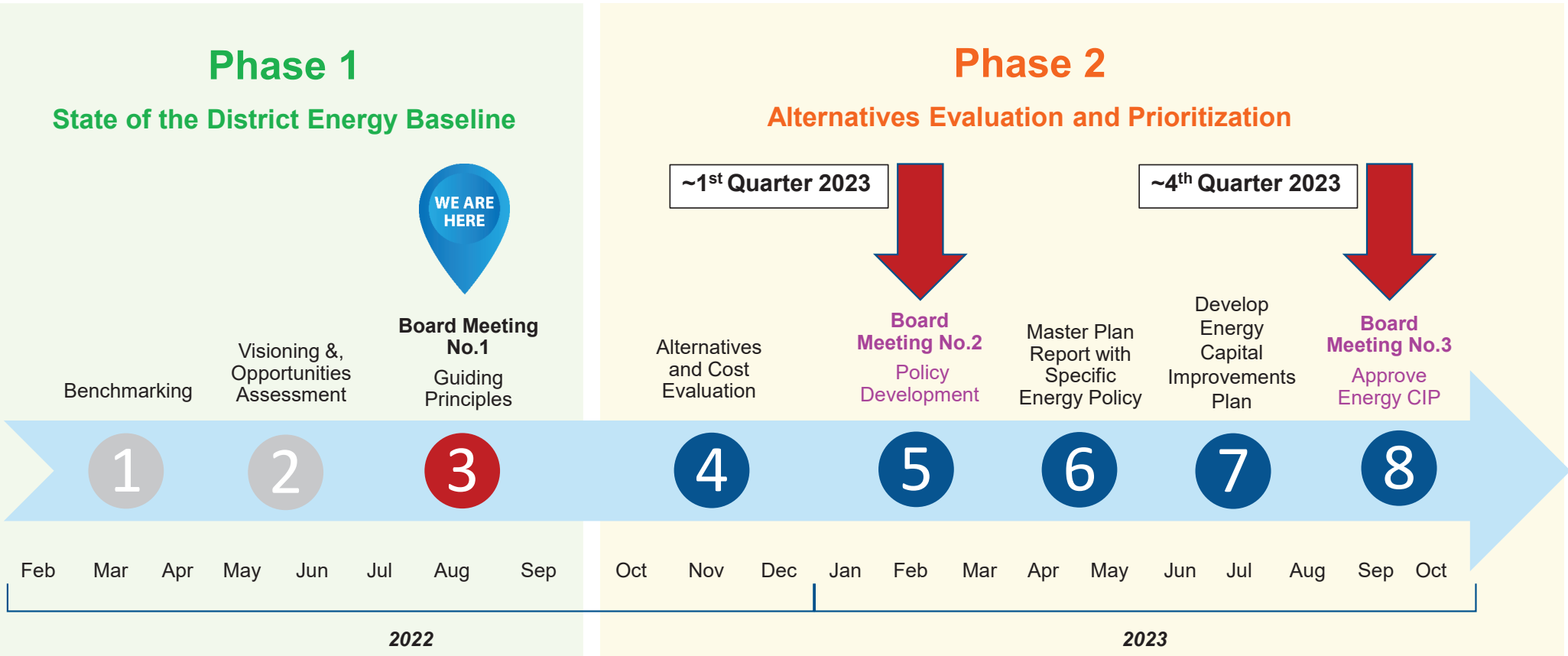
// Scope of Phase 1 and 2 of this planning project

Phase 1

State of the District Energy Baseline

Phase 2

Alternatives Evaluation and Prioritization



Questions

Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 2
ENERGY AND GREENHOUSE GAS OPPORTUNITIES AND FINANCIAL IMPACTS

FINAL | June 2024

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2.3.1 Identification of Potential Opportunities 2-9

2.3.2 Evaluation Process and Results 2-9

2.4 Partnerships and Financing Opportunities 2-11

Appendices

Appendix 2A Energy Guiding Principles

Appendix 2B Description of Potential Energy Opportunities

Appendix 2C Implementability and Impact Scores of Potential Energy Opportunities

Appendix 2D Potential Energy Opportunities Scores

Appendix 2E List of Energy Alternatives Selected for Further Evaluation

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Figure 2.2 Total Number of Potential Opportunities by Category 2-9

Figure 2.3 Number of Selected and Eliminated Projects by Category 2-10

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Abbreviations

Carollo	Carollo Engineers
CEPT	chemically enhanced primary treatment
CIP	capital improvements plan
DERWA	Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority
DLD	dedicated land disposal
DO	dissolved oxygen
DSRSD	Dublin San Ramon Services District
FOG	fat, oil, and grease
GHG	greenhouse gas
HSW	high strength waste
HVAC	heating, ventilation, and air conditioning
I&I	inflow and infiltration
kWh	kilowatt-hour
LAVWMA	Livermore-Amador Valley Water Management Agency
O&M	operations and maintenance
OPS	operations and support
ORT	organic Rankine cycle
PG&E	Pacific Gas & Electric Company
SRT	solids retention time
TM	technical memorandum
VFD	variable frequency drive
WWTP	wastewater treatment plant

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Technical Memorandum 2

ENERGY AND GREENHOUSE GAS EMISSIONS OPPORTUNITIES AND FINANCIAL IMPACTS

Executive Summary

The project team compiled a list of 108 potential opportunities for the Dublin San Ramon Services District (DSRSD) to reduce energy consumption, produce more onsite energy production, increase the fraction of renewable energy sources, and reduce greenhouse gas (GHG) emissions. All potential opportunities were compiled in an excel database and evaluated at a high level based on key evaluation criteria describing the implementability, costs, energy and GHG impacts of each option. Each criterion received a semi-quantitative score and the overall scores of each opportunity were used to screen the 108 potential opportunities down to 66 project alternatives that will be evaluated in more detail during Phase 2 of this Energy Facilities Master Plan.

Figure 2.1 provides an overview of the process for evaluating potential opportunities in this project into final projects recommended to be included in DSRSD's capital improvements plan (CIP). This technical memorandum (TM) summarizes the process for narrowing the "Universe of Options" into 66 alternatives.

2.1 Objectives

The purpose of this TM is to present a high-level overview of opportunities for DSRSD to a) reduce energy demand, b) increase energy production, and/or c) reduce GHG emissions across its facilities. Consistent with the 2024 to 2028 Strategic Plan, the potential opportunities include improvements that will improve DSRSD's energy efficiency, reliability, and energy resilience. The potential improvements target the following facilities:

1. Wastewater treatment facility.
2. Potable water distribution system.
3. Vehicle fleet.
4. Administrative building.
5. Other ancillary buildings.

The Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority's (DERWA) and Livermore-Amador Valley Water Management Agency's (LAVWMA) facilities were not included in this evaluation. DSRSD operates a small number of recycled water pump stations that are part of the scope of this project, the majority of recycled water pump stations falls under DERWA and was not included in this TM and Phase 2 analysis.

2.2 Methodology

2.2.1 Overview

A comprehensive list of 108 energy- and GHG-related opportunities was identified and presented to DSRSD staff and management in a workshop on August 18, 2022. The opportunities included options ranging from equipment upgrades or replacements, operational changes, process additions or modifications, and renewable energy productions. Energy opportunities were also informed by the results of the condition assessment that was conducted by Carollo Engineers (Carollo) in 2022 (see TM 3). The opportunities were compiled from various sources:

1. Previous DSRSD Energy Master Plan and other related efforts.
2. Interviews with DSRSD management and other key staff.
3. Carollo's databases of energy and GHG opportunities for wastewater and water treatment facilities.

Each opportunity was introduced and briefly discussed at the meeting. Based on DSRSD's input and Carollo's recommendations, the list was narrowed from 108 to 66 alternatives that will be carried forward into Phase 2 with a more detailed, thorough evaluations of the costs and impacts of the proposed projects. In Phase 2, the project prioritization will also be informed by the District's Energy Guiding Principles (see Appendix 2A) and Energy Policy (adopted by DSRSD Board on February 20,2024) to help prioritize feasible alternatives, develop logical process combinations, and schedule selected projects into DSRSD's overall CIP. This overall process is illustrated in Figure 2.1.

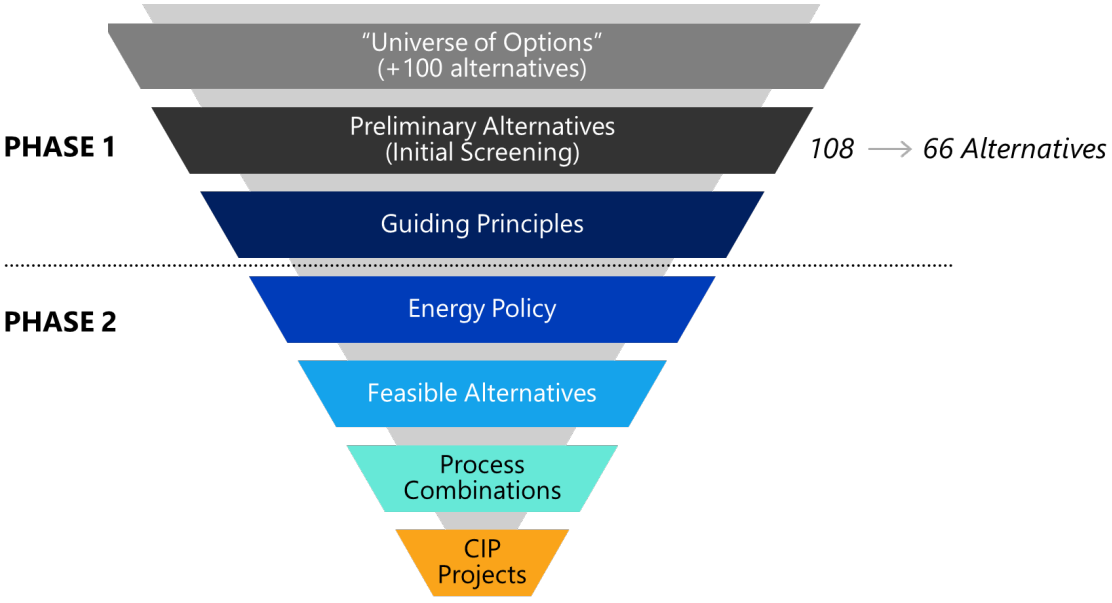

Figure 2.1 Energy Opportunities Evaluation Process Overview

2.2.2 Evaluation Criteria and Scoring Approach

Each potential project was evaluated across three criteria related to the "implementability" of the opportunity for DSRSD and four criteria related to the "impact" the opportunity would have on DSRSD's energy and GHG management:

1. Implementability:
    a. Capital cost.
    b. Operations and maintenance (O&M) costs.
    c. Impact on staffing resources.
2. Impact:
    a. Operational or regulatory reliability or flexibility.
    b. Infrastructure resilience or ability to address aging or capacity-limited infrastructure.
    c. Energy demand or greenhouse gas emissions.
    d. Energy independence and the generation and use of renewable energy.

Each of the seven criteria received a score between one and five, with "1" being the least favorable and "5" the most favorable score for the respective opportunity. Each criterion and numerical factor are defined in Table 2.1. The scoring was semi-quantitative and the definitions of each criterion were largely independent, with some minor overlap exists between a few criteria.

These opportunity scores were then combined to create a score representing the overall "implementability" and "impact", as well as the total score of an opportunity. At this initial screening stage, all seven criteria were weighted equally.

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Table 2.1 Definition of Evaluation Criteria and Numerical Factors

Criteria	Weight	Factor	Factor Definition
Implementation: **Capital costs**	**14.3%**	**1**	**Very high** *Greater than $10 million and no notable return on investment*
		2	**Significant** *$1-$10 million and no notable return on investment*
		3	**Moderate** *$0.2-$1 million and no notable return on investment or greater than $1 million with a notable return on investment*
		4	**Minor** *Less than $0.2 million with or without a notable return on investment*
		5	**None** *No investment costs*
Implementation: **O&M costs** *Includes costs for consumables, chemicals, energy, etc. Does not include costs for personnel.*	**14.3%**	**1**	**Significant increase** *Project will significantly increase O&M costs (greater than 1% increase to OPS operating budget or more than $225,000 per year based on average OPS O&M costs budgeted for fiscal year '22/'23)*
		2	**Moderate increase** *Project will moderately increase O&M costs (0.1-1% increase to OPS operating budget or $25,000-$225,000 per year based on average OPS O&M costs budgeted for fiscal year '22/'23)*
		3	**Negligible impact** *Project will have negligible impact to O&M costs*
		4	**Moderate decrease** *Project will moderately decrease O&M costs (0.1-1% decrease to OPS operating budget or $25,000-$225,000 per year based on average OPS O&M costs budgeted for fiscal year '22/'23)*
		5	**Significant decrease** *Project will significantly decrease O&M costs (greater than 1% decrease to OPS operating budget or more than $225,000 per year based on average OPS O&M costs budgeted for fiscal year '22/'23)*
Implementation: **Impact on staffing resources**	**14.3%**	**1**	**Additional staff required** *Requires new staffing resources and/or additional personnel*
		2	**Moderate impact** *The project, on its own, may not need additional staff resources; however, if additional projects are also implemented, additional staffing may be required*
		3	**Minor impact** *Requires new training and tools for O&M staff but will only minorly impact staffing resources; current staffing levels should be able to support this project even If additional projects are implemented*
		4	**Negligible impact** *The project will have a negligible impact on current staffing resources*
		5	**Reduction** *Reduces burden on staffing resources*
Impact: **Operational and regulatory reliability or flexibility** *Operational flexibility allows for accommodation of changes and brings potential benefit through the reduction of cost, generation of revenue that offsets costs, or avoidance of risk under possible conditions more than ten years in the future (for example process changes or treatment needs).* *Regulatory reliability and flexibility support compliance with current or future anticipated regulatory requirements.* *Operational reliability refers to the ability of an asset or system to continue to provide its expected level of service under normal operating conditions.*	**14.3%**	**1**	**Reduces operational reliability and reduces operational flexibility**
		2	**Maintains operational reliability and limits operational flexibility**
		3	**Maintains operational reliability and has no impact on operational flexibility** *Maintains the current level of power, gas, or thermal heat service and treatment under normal operating conditions and power supply; does not provide additional regulatory, treatment, or process operational flexibility*
		4	**Maintains operational reliability and improves operational flexibility** *Maintains the current level of power, gas, or thermal heat service and treatment under normal operating conditions and power supply; increases regulatory, treatment, or process operational flexibility*
		5	**Improves operational reliability and flexibility** *Increases the current level of power, gas, or thermal heat service and treatment under normal operating conditions and power supply; increases regulatory, treatment, or process operational flexibility*

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Table2.1 Definition of Evaluation Criteria and Numerical Factors (continued)

Criteria	Weight	Factor	Factor Definition
Impact: **Infrastructure resilience or improvements to aging or capacity-limited infrastructure** *Infrastructure resiliency refers to the ability to adapt to and recover from a utility or DSRSD power outage while maintaining an adequate level of service. Potential outages include electricity, natural gas, biogas, or wastewater thermal heat supply.* *Aging infrastructure includes mechanical, structural, or electrical elements of treatment systems found to be corroded, unsafe, inefficient, or difficult to maintain.*		**1**	**Maintains or worsens infrastructure resiliency** *Maintains or could worsen infrastructure resiliency, replaces infrastructure prematurely years ahead of its end of useful life, and/or does not impact infrastructure resiliency for treatment or energy supply*
		2	**>10 years remaining useful life and has no impact to infrastructure resiliency** *Replaces infrastructure that has more than ten years of useful life remaining and/or does not impact infrastructure resiliency for treatment or energy supply*
		3	**5-10 years of remaining useful life and improves infrastructure resiliency** *Replaces infrastructure that is within 5-10 years of its end of useful life and/or does not have a substantial impact on infrastructure resiliency for treatment and energy supply*
		4	**2-5 years of remaining useful life and improves infrastructure resiliency** *Replaces infrastructure that is within 2-5 years of its end of useful life, moderately enhances infrastructure resiliency for treatment and energy supply, and/or moderately increases the capacity of treatment processes*
		5	**<2 years of remaining useful life and improves infrastructure resiliency** *Replaces critical infrastructure that is within two years of its end of useful life, significantly enhances infrastructure resiliency for treatment and energy supply, and/or significantly increases the capacity of treatment processes*
Impact: **Energy demand or GHG emissions**		**1**	**Significant increase** *Project will increase GHG emissions by more than five percent of 2021 baseline (i.e., by more than 350 tons/year) or will increase annual electricity demand by two percent of 2021 baseline (i.e., by more than 350,000 kWh/year)*
		2	**Moderate increase** *Project will increase GHG emissions by 2-5 percent of 2021 baseline (i.e., by 150-350 tons/year) or will increase annual electricity demand by 0.1-1 percent of 2021 baseline (i.e., by 175,000-350,000 kWh/year)*
		3	**Negligible impact** *Project will increase or decrease GHG emissions by less than two percent of the 2021 baseline (i.e., by less than 150 tons/year) or will increase or decrease annual electricity demand by less than 0.1 percent of 2021 baseline (i.e., by less than 175,000 kWh/year)*
		4	**Moderate decrease** *Project will decrease GHG emissions by 2-5 percent of 2021 baseline (i.e., by 150-350 tons/year) or will decrease annual electricity demand by 0.1-1 percent of 2021 baseline (i.e., by 175,000-350,000 kWh/year)*
		5	**Significant decrease** *Project will decrease GHG emissions by more than five percent of 2021 baseline (i.e., by more than 350 tons/year) or will decrease annual electricity demand by more than two percent of 2021 baseline (i.e., by more than 350,000 kWh/year)*
Impact: **Energy independence and generation of renewable energy** *Energy independence refers to reducing the frequency of use and/or extent of the energy supply from PG&E to DSRSD. Though reducing energy demand also promotes energy independence, reductions in energy demand are covered in the "energy demand or greenhouse gas emissions" criterion.* *Renewable energy includes energy from non-fossil sources that are constantly replenished, such as wind, solar, water flow (hydro), hydrothermal, geothermal, and biogas.*		**1**	**Decrease** *Option may reduce renewable energy production, limit such options in the future, or increase dependence on PG&E*
		2	**No impact** *No impact on renewable energy production or dependence on PG&E*
		3	**Negligible increase** *Project will have negligible impacts to renewable energy production (0.1-5 percent increase in renewable energy production based on the 2021 baseline, or less than 850,000 kWh/yr) and will have some but little impact on reducing dependence on PG&E*
		4	**Notable increase** *Project will notably increase renewable energy production (5-10 percent increase in renewable energy production based on the 2021 baseline, or 850,000-1,700,000 kWh/yr) or will notably reduce dependence on PG&E*
		5	**Significant increase** *Project will significantly increase renewable energy production (>10 percent increase in renewable energy production based on the 2021 baseline, or more than 1,700,000 kWh/yr) and will notably reduce dependence on PG&E*

Notes:
kWh - kilowatt-hour; OPS - operations and support; PG&E - Pacific Gas & Electric Company.

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2.3 Opportunities for Energy and Greenhouse Gas Reduction Evaluation

2.3.1 Identification of Potential Opportunities

The DSRSD and Carollo team identified a total 108 potential projects for initial screening. The potential projects were categorized into the following seven categories:

1. Wastewater liquid stream.
2. Biosolids.
3. Potable water distribution.
4. Buildings heating, ventilation, and air conditioning (HVAC) and lighting.
5. Renewable energy.
6. District-wide opportunities.
7. Emerging technologies.

Thirty-six emerging technologies (Category 7) of potential interest to DSRSD were summarized and verbally evaluated according to their perceived merit to DSRSD, but not included in the count of the 108 opportunities. Emerging technologies are summarized in Table 2C.7. DSRSD is encouraged to look actively for opportunities to participate in research opportunities that help advance technologies of strategic value to DSRSD.

The 108 potential opportunities distributed relatively evenly among the categories 1 through 6 (see Figure 2.2). About one third of the identified opportunities were related to biosolids treatment and solids handling. All potential opportunities are listed and briefly described in Appendix 2B.

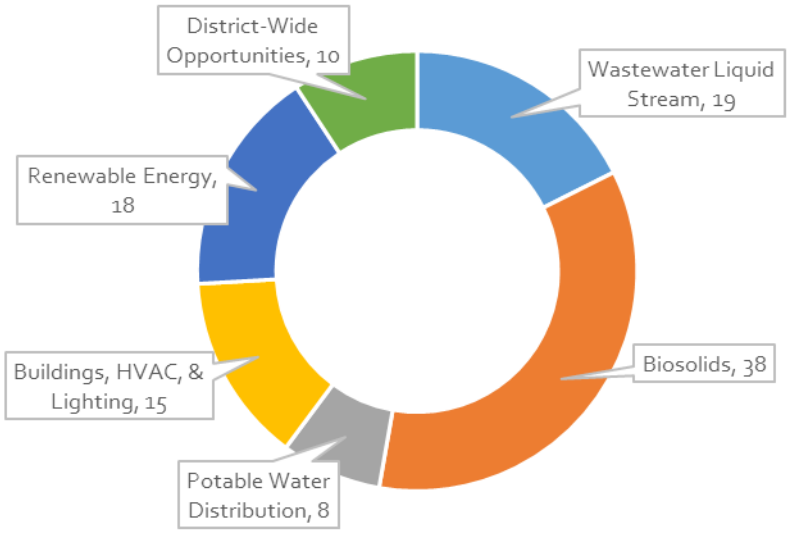

Figure 2.2 Total Number of Potential Opportunities by Category

2.3.2 Evaluation Process and Results

The criteria score that Carollo applied to each of the 108 potential opportunities are presented in Appendix 2C. A brief justification for the scoring is included in Appendix 2D for each criterion. Based on the score results and the feasibility of the options for DSRSD, Carollo and District staff reviewed and narrowed the number of options from 108 to 66 alternatives. 42 options were eliminated from further consideration. The 66 alternatives selected for further investigation in

Phase 2 of this project distributed among the six categories introduced in Section 2.3.1 as summarized in Figure 2.3.

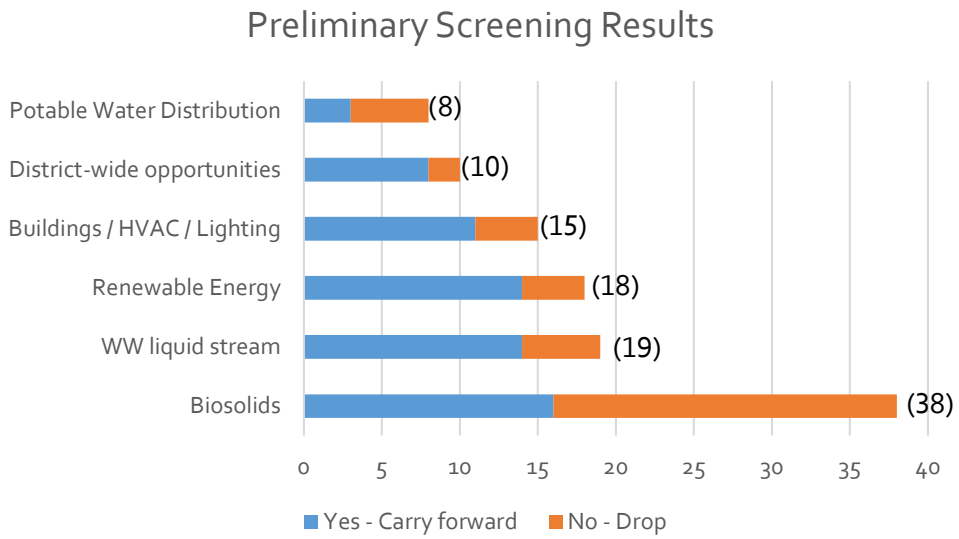

Figure 2.3 Number of Selected and Eliminated Projects by Category

Appendix 2C shows a graphical representation of the impact versus implementability scores for each opportunity by category (in these charts, the scores were normalized to fall between -1 and 1). The projects selected for further evaluation are marked in green in these figures. Selected projects generally had positive impact and implementation scores.

Appendix 2D summarizes each opportunity's criteria scores, impact score, implementation score, and final evaluation result along with a rationale for why or why not an opportunity was selected for further evaluation.

The remaining 66 alternatives were further categorized into the following five types of project groups:

1. Alternatives that would become potentially relevant for DSRSD in more than 5 to 10 years.
2. Alternatives that would provide flexibility for future anticipated regulations.
3. Alternatives that require more detailed evaluation by Carollo.
4. Alternatives that are recommended and that DSRSD can move forward with independently in their CIP (no further evaluation by Carollo needed).
5. Projects that are already underway (no further evaluation by Carollo needed).

Table 2.2 summarizes the number of Alternatives sorted into each of the five groups.

Table 2.2 Type of Alternatives Selected for Further Evaluation in Phase 2

Type of Opportunity / Project	Number of Alternatives
CATEGORY 1: Projects relevant in longer than 5-10 years.	2
CATEGORY 2: Flexibility for future regulations.	3
CATEGORY 3: Recommended for detailed evaluation by Carollo.	46
CATEGORY 4: No detailed evaluation from Carollo needed. Carollo to include year and budget for CIP.	9
CATEGORY 5: Projects already in progress. No further evaluation needed.	6
Total number of Alternatives	**66**

Alternatives under Category 1 (projects relevant in longer than 5 to 10 years) include LS-3 (improve carbon diversion from primaries to digester with chemically enhanced primary treatment [CEPT]) and RE-3 (solar field at dedicated land disposal [DLD] sites); and alternatives under Category 2 (flexibility for future regulations) include BS-17 (Drying and Pyrolysis) and BS-18 (Drying and Gasification). A number of alternatives identified through this study are either already in progress by DSRSD (i.e., Category 5) or are currently planned in the near-term (i.e., Category 4); these alternatives include LS-19 (replace basin 4 effluent pumping motor variable frequency drives [VFD]) and LS-11 (reduce number of units in service) respectively.

A total of 46 alternatives fell under Category 3 and were selected for detailed evaluation in Phase 2. These alternatives are listed in Appendix 2E.

2.4 Partnerships and Financing Opportunities

Carollo conducted a first cursory review of potential funding opportunities for energy projects that DSRSD may be able to benefit from depending on the type of projects selected for implementation and their timing. Primary funding sources are provided through the State Revolving Fund, United States Treasury, and the Department of Energy.

- **Energy Efficiency Projects:**
  - State of California Clean Water State Revolving Fund/Green Project Reserve.
  - Department of Energy: Energy Efficiency Block Grants.
  - United States Bureau of Reclamation: Water and Energy Efficiency Grant.
- **Green Power Generation Projects:**
  - California Energy Commission: Energy Conservation Assistance Act, Electric Program Investment Charge, Alternative and Renewable Fuel/Vehicle Technology Program.
  - United States Bureau of Reclamation: Water and Energy Efficiency Grant (requires water and energy to be competitive).
  - United States Treasury: Clean Electricity Investment Tax Credit and Clean Electricity Investment Tax Credit.
- **Biogas (waste to energy) Projects:**
  - CalRecyle: Co-Digestion Grant Program and Organics Grant Program ($154M).
  - United States Treasury: Clean Energy Tax Incentives (Inflation Reduction Act).
  - California: California Alternative Energy and Advanced Transportation Financing Authority Sales and Use Tax Exclusion (Revenue and Taxation Code Section 6010.8).

- **Fleet Electrification and Charging Stations:**
  - California Energy Commission: Alternative and Renewable Fuel and Vehicle Technology Program.
- **General Energy Related Program/Projects:**
  - Environmental Protection Agency Water Infrastructure Finance and Innovation Act Program.
  - State of California Clean Water State Revolving Fund.

Appendix 2A

ENERGY GUIDING PRINCIPLES

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ENERGY GUIDING PRINCIPLES

The following Energy Guiding Principles were proposed by DSRSD's staff to its Board at the February 21, 2023, Board Meeting:

1. Strive to establish a **diverse, reliable, and resilient** energy supply portfolio for operation of its facilities.
2. Comply with all regulatory energy and GHG related mandates and **strive to exceed** them when related investments are **cost-effective** with consideration to the anticipated payback period and life cycle cost.
3. Capital improvements shall **consider the impact** on energy demand, energy efficiency, and GHG impacts where relevant.
4. Seek opportunities to **offset any additional future energy demands** with renewable energy production.

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Appendix 2B

DESCRIPTION OF POTENTIAL ENERGY OPPORTUNITIES

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Table 2B.1 **Wastewater Liquid Stream Opportunities**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
Liquid Process Stream										
LS1	Influent Flow Equalization	Reestablish influent or primary effluent flow equalization	Requires odor control solution	Would require covering basins, adding structural colums, tying into oder control system, and increasing odor control capacity. No flow or pumping modifications would be needed.	O&M includes fan operation, odor control maintenance, and washown of basins. Could create $200-300k in peak demand charge savings per year in summer months.	None	None	None	Power consumption and GHG emissions would not change overall.	None
LS2	Selector Mixing	Large bubble mixing in liquid process (anoxic/anaerobic zones)	Like EnviroMix or Pulsair, etc.	New blowers would be needed. Big bubble diffusers would cost around $200k.	Big bubble plates would need occasional maintenance and replacement -- possibly more than mixers because of the possibility of clogging and fouling.	None	None	Existing mixers have a remaining life of more than 10 years.	Replacing mixer horsepower with air compressor horsepower yields negligible energy demand reduction.	None
LS3	Primary Clarification	Improve carbon diversion from primaries to digester with chemically-enhanced primary treatment (CEPT)	Further enhance carbon removal in primaries from 50% to a maximum of 60% through CEPT. Redirect more carbon to anaerobic digesters to recover as biogas and reduce aeration energy.	Construction of chemical storage facility for CEPT	Chemical costs are likely comparable to current annual costs for alum at DERWA (<$250k per year).	Once installed, no substantial daily maintenance or oversight required.	Would improve operational reliability by reducing reliance on grid power.	Improves infrastructure resiliency by reducing reliance on grid power. Does not replace aging equipment.	Current biogas production creates about 800 tons/year in offsets. 10% more primary sludge BOD is estimated to result in less than 150 tons/year additional offsets.	None
LS4	Primary Clarification	Improve carbon diversion from primary treatment to digester with biofiltration	Further enhance carbon removal in primaries from 50% to 70-80% through biofiltration to redirect more carbon to anaerobic digesters to recover as biogas.	Construction of new biofilters for primary treatment	No chemical addition, major predictable repairs, etc.	Once installed, no substantial daily maintenance or oversight required.	Would improve operational reliability by reducing reliance on grid power.	Improves infrastructure resiliency by reducing reliance on grid power. Does not replace aging equipment.	Would decrease aeration demand in secondary treatment by an estimated 500-800 kWh/year.	Would decrease biogas production due to carbon degradation in primary biofilter.
LS5	Secondary Treatment	Real-time SRT Control	Use real time SRT control to stay out of nitrification year round and improve SVI.	Cost of real time SRT controllers are about $50-100k.	Negligible impact on O&M costs	Reduces effort of O&M staff on decision making for wasting and SVI management.	Improves reliability and operational flexibility.	No impact on existing infrastructure	Negligible impact	Negligible impact
LS6	Secondary Treatment	Model predictive aeration control	Tighten aeration control for additional aeration savings and lowering DO setpoints	Cost of real-time advanced aeration controllers are about $100-150k without probes.	Advanced aeration controls might decrease aeration demand by 10-30%.	Reduces effort of O&M staff for aeration control decisions and monitoring.	Improves reliability and operational flexibility.	No impact on existing infrastructure	A minimum reduction of 10% of aeration demand on average equates to about 200,000-300,000 kWh/year.	Negligible impact
LS7	Secondary Treatment	Low DO operation	With proper DO control, reduce DO setpoints to low DO treatment.	Cost of real-time advanced aeration controllers are about $100-150k without probes.	Advanced aeration contraols might decrease aeration deminad by 20-50 %. Note that, to Carollo's knowledge, low DO operation has only been done at nitrification facilities so far.	Assumes that more operation retention is initially required as safety margins are reduced for aeration and BOD removal.	Could result in BOD breakthrough or SVI increase if low DO operation is not properly controlled and dialed in.	No impact on existing infrastructure	A possible reduction of 30% aeration demand on average equates to about 600,000-900,000 kwh per year in savings.	Negligible impact

Table 2B.1 **Wastewater Liquid Stream Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
LS8	Secondary Treatment	RAS pump 4 VFD	Replace VFD	VFDs cost around $50k-$75k.	No daily/weekly maintenance required	No impact on staff workload after initial installation/startup	Improves operational flexibility with the ability to run the pump at different flow rates.	Existing VFD has less than 10 years of remaining useful life.	Would reduce the energy input to that pump.	No change to renewable energy generation
LS9	Secondary Treatment	Take AB out of service	Run fewer basins in summer months	No investment costs	No changes to operation except fewer basins in service	No change or possibly slightly reduced staff workload with fewer basins in service	Slightly reduced reliability during outlier events (e.g., peak flow event or equipment issues). Would take time/effort to transfer to out of service basins	No change to infrastructure resiliency	5% decrease in overall secondary treatment electricity use	No change to renewable energy generation
LS10	Secondary Clarifiers	Improve secondary clarifier hydraulics to reduce solids in final effluent.	Install baffles or improved EDI structure to improve secondary quality with lower UV disinfection energy and less chemical addition at DERWA facility.	Approximately $50k per clarifier for three clarifiers total	Less chemical addition = moderate O&M cost decrease	No impact on staff workload after initial installation/startup	Improves reliability by improving clarifier performance. Improves flexibility by reducing UV bank demand.	Would allow operators to take some UV banks out of service to use as redundant banks	Could result in as much as 20% chemical reduction at DERWA which is equivalent to about 120 ton/year CO_2 emission savings. No change to energy demand anticipated.	No change to renewable energy generation
LS11	Secondary Clarifiers	Reduce number of units in service	Operate less equipment for energy savings	No investment costs	No changes to operation except fewer basins in service	No change or possibly slightly reduced staff workload with fewer basins in service	Slightly reduced reliability during outlier events (e.g., peak flow events, equipment issues, or slugs of unexpected solids in the treatment process).	No change to infrastructure resiliency	Would reduce energy demand, but not by a substantial percentage. Clarifiers do not represent major energy demand at the WWTP.	No change to renewable energy generation
LS12	Diffusers	Change to more energy efficient diffusers	For example panel diffusers	Diffuser cost would be on the order of $500k. Plus piping and ancillary improvements, the project could cost around $1M total.	Will need to budget for diffuser replacement every ~10 years	No impact on staff workload after initial installation/startup	No change to operational reliability or flexibility	Diffusers are within 5 years of end of useful life. Assume moderate increases in process capacity might be possible (up to 10%).	Up to 10% of aeration energy demand could be saved (400k kwh/yr).	No change to renewable energy generation
LS13	Blowers	Upgrade to more efficient blowers	Gas-powered blowers or venturi air induction blowers/Neuros blowers	For 8,500 cfm blowers, equipment costs near $1M	No changes to operational costs	No impact on staff workload after initial installation/startup	Could replace two blowers with three smaller ones for more flexibility	Existing blowers have less than 10 years useful life remaining	Would reduce energy demand, but not by a substantial percentage.	No change to renewable energy generation
LS14	Blowers	Green power ramp	Install green power ramp for blowers to reduce peak demand charges	Relatively small capital investment	Moderate decrease in peak demand costs	No impact on staff workload after initial installation/startup	No change to operational reliability or flexibility	No impact	No impact	No change to renewable energy generation
LS15	Blowers	Jockey blower	Jockey blower to cover peak or low flow period loads	Assumes new blower is added and can be fit into existing blower building including electrical	Reduces air supply to better match oxygen demand	No impact on staff workload after initial installation/startup	Increases reliability and flexibility in blower operation	Existing blowers have less than 10 years useful life remaining	A minimum reduction of 10% aeration demand on average equates to about 200,000-300,000 kwh per year.	No change to renewable energy generation

Table 2B.1 **Wastewater Liquid Stream Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
LS16	Preaeration blowers	Preaeration blowers	Replace preaeration PD blowers in influent channels with lower energy alternative	Pre-aeration blowers are small, 275-360 cfm. I would assume less than $200k capital costs.	No changes to operational costs	No impact on staff workload after initial installation/startup	No change to operational reliability or flexibility	Existing PD blowers only have 2-5 years of useful life remaining. Operation is critical for plant operations.	Would reduce energy demand, but not by a substantial percentage	No change to renewable energy generation
Wastewater Pumping										
LS17	Influent pumping	Replace influent pumps and motor VFDs	Replace the pumps and motor VFDs with more energy-efficient units	Substantial capital costs to replace one 15 mgd (10,400 gpm) pump and three 25 mgd (17,400 gpm) pumps	No changes to operational costs	No impact on staff workload after initial installation/startup	No change to operational reliability or flexibility	Motors were recently rebuilt on three of the four pumps.	The influent pumps are some of the most energy-intensive pieces of equipment at the WWTP. A 10% improvement in efficiency would equate to 143,000 kWh per year.	No change to renewable energy generation
LS18	Existing Equipment	Install VFDs	Install VFDs on all relevant pumps	VFDs are on the order of $50k each, so this could represent a substantial capital investment.	No changes to operational costs	No impact on staff workload after initial installation/startup	No change to operational reliability or flexibility	No change to infrastructure resiliency unless they replace some existing VFDs.	Substantial impact to energy demand	No change to renewable energy generation
LS19	Basin 4 effluent pumping	Basin 4 effluent pumping motor VFD	Replace the Basin 4 effluent pumping motor VFDs	Assume capital costs around $100k.	No changes to operational costs	No impact on staff workload after initial installation/startup	No change to operational reliability or flexibility	Current VFDs have less than 10 years in useful life.	Minor reduction to overall energy demand	No change to renewable energy generation

Table 2B.2 **Biosolids Opportunities**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
Primary Sludge & Secondary Sludge										
BS1	Primary Sludge Pumping	Replace primary sludge pumps VFDs	N/A	None	None	None	None	None	None	None
Digestion Pretreatment, Digestion Enhancements, Thickening, Dewatering, & Post-Dewatering Processing										
BS2	Thickening	Alternative WAS and PS thickening technology to DAF (combined or separate)	Thicken PS with gravity thickeners and WAS with mechanical thickening (RDT or GBT) or thicken PS and WAS with mechanical thickening	Gravity thickener and mechanical thickening cost estimated at ~10-15M based on recent Carollo cost estimates, assuming new thickening building is needed.	O&M costs estimated at ~$100,000-150,000 based on recent Carollo cost estimates.	Existing staff may be able to handle additional thickening process.	Option could reduce operational flexibility. Co-thickening in DAFT gives DSRSD a more forgiving system than mechanical thickening.	DAFT equipment was replaced in 2013 and has 11 years of useful life remaining. Motor for DAFT Thickening sludge has less than 10 years of useful life. Mechanical thickening would substantially increase digester feed %TS and digestion capacity.	Thickening would use about 50,000 kWh/yr and building HVAC would use about 125,000 kWh/yr.	Potential small increase in biogas production due to longer SRT. Assuming 5% biogas increase would increase biogas cogen energy production by ~250,000 kWh/yr.
BS3	Digestion Pretreatment	Class A high temp thermal hydrolysis	Implement high temperature thermal hydrolysis (e.g., Cambi) for all solids to produce Class A product.	Full Cambi cost estimated at ~$30-40M based on recent Carollo cost estimates.	Increase in O$M costs from mesophilic digestion to full Cambi estimated at ~$650,000/yr based on recent Carollo cost estimates.	The process requires a steam-certified operator to be on-site 24/7, which would require several new staff and/or several existing staff to get trained and certified.	Process produces class A which gives more regulatory flexibility regarding solids.	Full Cambi would substantially increase the capacity of the digesters (more than any other digestion modification). The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	Full Cambi would increase energy demand (mostly for pre-THP dewatering) by ~260,000 kWh/yr. The additional biogas production would be used to run the process.	No net change. The additional biogas production would be used for process operation.
BS4	Digestion Pretreatment	Class B high temp thermal hydrolysis	Implement high temperature thermal hydrolysis (e.g., Cambi) for WAS only to produce Class B product with better digestability and dewaterability	WAS-only Cambi cost estimated at $10-20M based on recent Carollo cost estimates.	Increase in O&M costs from mesophilic digestion to WAS-only Cambi estimated at ~$300,000/yr based on recent Carollo cost estimates.	The process requires a steam-certified operator to be on-site 24/7, which would require several new staff and/or several existing staff to get trained and certified.	None	Process would increase digestion capacity. The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	WAS-only Cambi would increase energy demand (mostly for pre-THP dewatering) by ~200,000 kWh/yr. The additional biogas production would be used to run the process.	No net change. The additional biogas production would be used for process operation.
BS5	Digestion Pretreatment	Class B thermo-chemical hydrolysis	Implement thermo-chemical hydrolysis that uses caustic and low grade heat to lyse cells, improve digestion and dewatering (e.g. Pondus)	None	None	None	None	The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	Process would increase electricity use slightly.	Potential small increase in biogas production due to longer SRT. Assuming 5% biogas increase would increase biogas cogen energy production by ~250,000 kWh/yr.
BS6	Digestion Pretreatment	Class B (or Class A) Biological Hydrolysis	Small reactors in series for biological hydrolysis upstream of methane-phase mesophilic digestion. Small reactors are acid-phase digesters, operated in series to increase hydrolysis. If Class A required time/temp are maintained in one of the reactors operated in batch mode (e.g., thermophilic temps for 24 hours), could meet Class A requirements. Marketed by Suez (previously GE, Monsal). No Class A full scale installations. Multiple Class B installations, mostly in UK and one in Guelph, ON.	Two new batch digester would be needed for Class A.	Increase in O&M costs to operate and maintain new batch digesters estimated at $300,000 based on recent Carollo cost estimates.	None	Process may produce a class A product which gives more regulatory flexibility regarding solids.	The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	Process would increase electricity use slightly.	Potential small increase in biogas production due to longer SRT. Assuming 5% biogas increase would increase biogas cogen energy production by ~250,000 kWh/yr.

Table 2B.2 **Biosolids Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
BS7	Digestion Enhacement	Recuperative Thickening	Send digestate through a mechanical thickener to increase solids concentration and return filtrate to plant for treatment similar to recycle streams associated with dewatering. This separates SRT from HRT, allows for higher organic loading rates to the digester, increases percent solids inside the digester and increases digester capacity. May also require high solids mixers to handle thicker digestate within digesters. (e.g. Anaergia's Omnivore system).	Recuperative thickening retrofit cost estimated at $7-15M based on recent Carollo cost estimates.	Increase in O&M costs from mesophilic digestion to RT estimated at ~$130,000/yr based on recent Carollo cost estimates.	Existing staff may be able to handle additional thickening process.	Process would increase digestion capacity.	The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	RT would increase energy demand (thickening and mixing) by ~240,000 kWh/yr.	Potential small increase in biogas production due to longer SRT. Assuming 5% biogas increase would increase biogas cogen energy production by ~250,000 kWh/yr.
BS8	Digestion Enhancement	Thermophilic Digestion for Class A Biosolids	Switch from mesophilic to thermophilic digestion and produce Class A biosolids (liquid or cake).	Replacing boilers, heat exchangers, and hot water circulation pumps estimated at $3-5M based on recent Carollo cost estimates.	None	None	May have a minor negative impact if heat recovered from cogen is not sufficient for thermophilic digestion, which would require additional natural gas use.	The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	No increase in power use. Increase in heat required for digester heating, which may require an increase in natural gas use.	Potential small increase in biogas production due to thermophilic digestion. Assuming 5% biogas increase would increase biogas cogen energy production by ~250,000 kWh/yr.
BS9	Digestion Enhancement	Acid Phase Digestion	Add acid phase digester upstream of mesophilic digesters	New acid phase tank estimated at $10-20M based on recent Carollo cost estimates.	Increase in O&M costs to operate and maintain new acid-phase digester estimated at $300,000 based on recent Carollo cost estimates.	None	None	Process would increase digestion capacity. The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/ upgrades of the digestion equipment.	Process would increase electricity use slightly.	Potential small increase in biogas production due to acid-phase digestion. Assuming 5% biogas increase would increase biogas cogen energy production by ~250,000 kWh/yr.
BS10	Digestion Enhancement	Low Energy Digester Mixing	Using lower energy mixing technologies like large bubble or linear motion for digesters. In particular, retrofit digesters' 1 and 2 mixers (which are the oldest and have less than 10 years useful life remaining). These digester mixers do not have VFDs.	New mixing estimated at $3-5M.	Depending on current electricity use for digester mixing, this could have a negligible to moderate impact.	None	None	Digester 4 is new (2017) and digester 3 is currently retrofitted. Digester 1 and 2 are older and equipment on top of digester (mixers etc.) are not explosion proof (do not comply with current NFPA 8820 regulations). The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades	Current mixers are relatively low energy. Likely the energy savings will not offset capital cost.	No change in biogas production/renewable energy potential
BS11	Digester sludge pumps	Replace digester sludge pumps	replace digester sludge pumps with more energy efficient units -(recirc pumps or digested sludge pumps)	None	None	None	None	Existing pumps have less than 10 years of useful life remaining.	None	None
BS12	Dewatering	Implement Dewatering post FSL	Post-FSL dewatering prior to hauling	New dewatering facility estimated at ~$10-30M.	Dewatering O&M costs estimated at ~$150,000-400,000. However, the O&M costs for the FSL and DLDs would need to be subtracted out.	Additional staff would be required to operate dewatering and cake loadout.	Produces a cake product with more potential end uses than current operations	None	Potentially a substantial decrease in GHG emissions due to negative emissions from biosolids land application (carbon sequestration and fertilizer offset)	No change in biogas production/renewable energy potential

Table 2B.2 **Biosolids Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
BS13	Dewatering	Implement dewatering post digestion	Centrifuges with off-peak dewatering operation	New dewatering facility estimated at ~$10-30M.	Dewatering O&M costs estimated at ~$150,000-400,000	Additional staff would be required to operate dewatering and cake loadout.	Produces a cake product with more potential end uses than current operations	Eliminates use of FSLs and DLDs	Potentially a substantial decrease in GHG emissions due to negative emissions from biosolids land application (carbon sequestration and fertilizer offset).	No change in biogas production/renewable energy potential
BS14	Thermal Processing	Air drying	Implement air drying to reduce solids volumes and achieve Class A biosolids	New dewatering facility estimated at ~$10-30M + new air drying facility estimated at $5-20M.	Dewatering O&M costs estimated at ~$150,000-400,000 + air drying estimated at ~$100,000.	Additional staff needed to operate dewatering and air drying	Produces a dried Class A product with more end uses than current operations. However, it increases risk of vectors and odors.	None	Potentially a substantial decrease in GHG emissions due to negative emissions from biosolids land application (carbon sequestration and fertilizer offset)	No change in biogas production/renewable energy potential
BS15	Thermal Processing	Solar drying	Implement solar drying to reduce solids volumes and achieve Class A biosolids	New dewatering facility estimated at ~$10-30M + new solar drying facility estimated at $30-40M.	Dewatering O&M costs estimated at ~$150,000-400,000 + solar drying estimated at $100,000-$200,000.	Additional staff needed to operate dewatering and solar drying.	Produces a dried Class A product with more outlets than current operations.	None	Potentially a substantial decrease in GHG emissions due to negative emissions from biosolids land application (carbon sequestration and fertilizer offset)	No change in biogas production/renewable energy potential
BS16	Thermal Processing	Low temperature thermal drying (belt drying)	Implement low-temperature (190-300 deg F) drying to reduce solids volumes and achieve Class A biosolids. Low temperature drying is typically limited to belt dryers, which are more capacity-limited (larger footprint) than high temperature options, but can utilize waste heat from typical waste heat recovery processes and digestion hot water systems. Produces low dust dried product, but less aesthetically pleasing product compared to drum dryer pellets.	Belt drying facility estimated at $30-50M based on recent Carollo cost estimates.	Dewatering O&M costs estimated at ~$150,000-400,000 + belt drying estimated at $200,000-$500,000.	Additional staff needed to operate dewatering and belt drying.	Improves operational flexibility by producing a Class A dried product.	None	Process increases power use and could substantially increase natural gas use since there will most likely not be sufficient heat recovered from cogen to both heat the digesters and run the drier.	Process would use up all waste heat from cogen and would require additional biogas or natural gas to run the dryer.
BS17	Thermal Processing	Drying + pyrolysis	Thermal or bio-drying followed by pyrolysis to produce syngas or bio-oil used within process and a Class A/EQ biochar product. Requires dewatered cake for feed. BioForceTech has a full-scale facility at Silicon Valley Clean Water with 3+ years of successful operations, and there are several other facilities planned.	Drying and pyrolysis facility estimated at $40-100M based on recent Carollo cost estimates.	Dewatering O&M costs estimated at ~$150,000-400,000 + drying and pyrolysis estimated at $200,000-$500,000.	Additional staff needed to operate dewatering and drying + pyrolysis.	Improves operational flexibility by producing a biochar dried product	None	When drying is paired with pyrolysis, the energy from the pyrolyser (in the form of syngas or bio-oil) can be used to run the dryer. Would still have a substantial increase in power use of >250,000 kWh/yr.	Process is net thermal energy neutral since heat and energy products from pyrolysis are used to run the dryer.
BS18	Thermal Processing	Drying + gasification	Drying followed by gasification or single-vessel drying/pyrolysis/gasification to produce syngas used within process and either Class A/EQ fertilizer type product or ash. Ecoremedy Fluid Lift Gasification provides the single vessel system. Requires dewatered cake for feed. Ecoremedy system was constructed at Morrisville Municipal Authority, Pennsylvania and testing underway.	Drying and gasification facility estimated at $40-100M based on recent Carollo cost estimates.	Dewatering O&M costs estimated at ~$150,000-400,000 + drying and gasification estimated at $200,000-$500,000.	Additional staff needed to operate dewatering and drying + gasification.	Improves operational flexibility by producing a Class A/EQ fertilizer product or ash.	None	When drying is paired with gasification, the energy from the gasifier (syngas or bio-oil) can be used to run the dryer. Would still have a substantial increase in power use of >250,000 kWh/yr.	Process is net thermal energy neutral since heat and energy products from gasification are used to run the dryer.

Table 2B.2 **Biosolids Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
BS19	Thermal Processing	Incineration with Energy Recovery	Uses incineration to combust biosolids and recovered heat to dry/combust the incoming sludge. Requires dewatered cake to allow for autogenous operation. Generate steam for power generation and use final solids/ash for cement.	None	None	None	None	None	None	None
BS20	Other	Class A with Onsite Composting	Implement onsite composting to produce a Class A biosolids product. Would require bulking material (sawdust, wood chips, etc), size reduction, and large area onsite for material delivery, compost rows, material turnover, etc. Would also require machinery for bulk material movement/tranport and row turnover. May need to be covered to reduce odors.	New dewatering facility estimated at ~$10-30M + composting estimated at $10-30M.	Dewatering O&M costs estimated at ~$150,000-400,000 + composting estimated at $100,000-$200,000.	Additional staff needed to operate dewatering and composting.	Produces a compost Class A product with more outlets than current operations.	Eliminates use of FSLs and DLDs	Potentially a substantial decrease in GHG emissions due to negative emissions from biosolids land application (carbon sequestration and fertilizer offset).	No change in biogas production/renewable energy potential.
BS21	Other	Class A with offsite Composting	Partner with City for offsite composting to produce a Class A biosolids product	New dewatering facility estimated at ~$10-30M.	Dewatering O&M costs estimated at ~$150,000-400,000. Composting tipping fee estimated at $250,000-$1M.	Additional staff would be required to operate dewatering and cake loadout.	Produces a compost Class A product with more outlets than current operations.	Eliminates use of FSLs and DLDs	Potentially a substantial decrease in GHG emissions due to negative emissions from biosolids land application (carbon sequestration and fertilizer offset).	No change in biogas production/renewable energy potential.
BS22	Other	Lystek thermo-chemical hydrolysis	Send dewatered cake to the FSSD Lystek facility for off-site processing.	New dewatering facility estimated at ~$10-30M.	Dewatering O&M costs estimated at ~$150,000-400,000. Lystek hauling, processing, and land application fee estimated at $500,000-$1M.	Additional staff would be required to operate dewatering and cake loadout.	Produces a Class A certified fertilizer product with more outlets than current operations.	Eliminates use of FSLs and DLDs	Potentially a substantial decrease in GHG emissions due to negative emissions from biosolids land application (carbon sequestration and fertilizer offset).	Depending on dewatering technology (BFPs would be lower power use, centrifuges would be highest power use) could increase power use by 100,000-500,000 kWh/yr.
Codigestion										
BS23	Co-digestion for biogas	Co-digest fats, oils, and grease (FOG) (all digesters)	Receive fats/oils/grease (FOG) for co-digestion in all digesters to increase biogas production in new FOG receiving station. If biogas utilization allows for receipt of RINs, co-digestion in all digesters would produce a lower-value biogas relative to RINs. Gas collection, metering, and utilization systems remain common for all digesters. Feedstock to maintain consistent gas production in digesters.	Food waste slurry receiving station estimated at $4-10M based on recent Carollo cost estimates.	Increase in O&M costs estimated at $200,000-$1M/yr.	None	Would substantially increase biogas production resulting in increased power reliability	The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	Co-digestion would substantially increase biogas production reducing the amount of natural gas needed to run the cogen.	Substantial increase in biogas production would result in increased renewable energy from biogas cogen.

Table 2B.2 **Biosolids Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
BS24	Co-digestion for biogas	Co-digest food waste slurry/HSW (all digesters)	Co-digest food waste slurry (from a solid waste base source; pre-processed offsite by waste management firm), food and beverage processing waste, or other high strength wastes (HSW) in all digesters to increase biogas production. Includes new waste receiving station and needed appurtenances. If biogas utilization allows for receipt of RINs, co-digestion in all digesters would produce a lower-value biogas relative to RINs.	FOG receiving station estimated at $2-8M based on recent Carollo cost estimates.	Increase in O&M costs estimated at $500,000-$2M/yr.	None	Substantially increases biogas production resulting in increased power reliability	The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	Potentially substantial decrease in GHG emissions from co-digesting food waste relative to landfilling, which would reduce methane emissions at landfill. Co-digestion would also substantially increase biogas production reducing the amount of natural gas needed to run the cogen.	Substantial increase in biogas production would result in increased renewable energy from biogas cogen.
BS25	Partial Co-digestion	Co-digest food waste slurry from solid waste (some digesters)	Same as option BS24 but co-digest in separate digesters to avoid getting RIN categorization downgraded.	Food waste slurry receiving station estimated at $4-10M based on recent Carollo cost estimates. In addition, digester and biogas modifications for handling two separate biogas streams estimated at $1M.	Increase in O&M costs estimated at $500,000 - $2M/yr.	None	Substantially increases biogas production resulting in increased power reliability. However, separate digestion and biogas stream handling reduces operational flexibility and reliability.	The majority of the digestion equipment was installed in 2000-2002. Any digester modifications could include replacement/upgrades of the digestion equipment.	Potentially substantial decrease in GHG emissions from co-digesting food waste relative to landfilling, which would reduce methane emissions at landfill. Co-digestion would also substantially increase biogas production reducing the amount of natural gas needed to run the cogen.	Substantial increase in biogas production would result in increased renewable energy from biogas cogen.
Biogas										
BS26	Gas conditioning and storage	Improve gas conditioning system throughput and replace aging equipment	Modify/expand gas conditioning sytem to alleviate flow restrictions from media plugging or condensation freezing	None	None	None	None	None	None	None
BS27	Gas conditioning and storage	Biological sulfur removal	Clean biogas with biological sulfur removal process to capture sulfur (from acid digester and/or mainline digesters) at a lower O&M cost as compared to media-based systems	Cost of gas conditioning system estimated at ~$1M based on recent Carollo cost estimates.	Potential moderate reduction of O&M costs due to cost of media	Negligible impact	No impact	New process would address aging infrastructure. Current gas conditioning skid estimated to have 3-10 yrs useful life remaining.	Negligible impact. Reduction in media (chemical) use and transport estimated at less than 150 tons/yr.	No impact
BS28	Gas conditioning and storage	Increase biogas storage	Increased biogas storage allows for increased biogas utilization during peak hours (ramp up generator output during peak hours for peak shaving) and would reduce times of biogas flaring.	Cost of gas storage estimated at ~1.5-2 M based on recent Carollo cost estimates.	Negligible impact on O&M costs	Negligible impact	Improves operational flexibility. Allows for peak shaving and reduces biogas flaring.	Negligle impact	Assuming 5% reduction in biogas flaring which would result in a 5% reduction in natural gas use results in a >150 ton/yr GHG reduction. Currently flaring 12% of biogas.	Neglible increase. A 5% increase in cogen power generation from biogas would provide about 500,000 kWh/yr.
BS29	Gas conditioning and storage	Fuel skid gas compressor motor	Replace fuel skid gas compressor motor with a more energy efficient unit	None	None	Negligible impact	None	None	None	None
BS30	Electricity Generation	Status quo operation (cogen Engines; boilers) with replacement of aging equipment	Continue use of biogas for existing cogen and boilers; replace aging equipment as needed	Minor capital costs to upgrade existing equipment	No change to O&M costs	No impact	Negligible impact	Negligible impact	No impact	No impact
BS31	Electricity Generation	Replace cogen with new higher efficiency engine generators	Replace existing cogen engines currently operating at ~32% electrical efficiency with newer engines at ~38% electrical efficiency.	New cogen estimated at ~2-10 M based on recent Carollo estimates.	Moderate increase in energy savings from increased power generation. Moderate increase to O&M costs due to addition of exhaust treatment.	Minor impact due to addition of exhaust treatment.	New cogen would increase operational reliability and reduce cogen downtime.	Replaces existing cogen with new system resulting in increased infrastructure resiliency. Existing engines were installed in 1998 and 2008 and are near or at the end of their useful lives.	New engines would increase power production by ~1,800,000 kWh/yr, resulting in the same reduction in energy import. GHG emissions reduction estimated at ~400 ton/yr.	Increase in power production from biogas estimated at ~750,000 kWh/yr, just from engine efficiency improvement.

Table 2B.2 **Biosolids Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
BS32	Electricity generation	Replace cogen with microturbines	Replace existing cogeneration engines with new microturbines	New cogen estimated at ~$2-10 M based on recent Carollo estimates.	No change to O&M costs	No impact	New cogen would increase operational reliability and reduce cogen downtime	Replaces existing cogen with new system resulting in increased infrastructure resiliency. Existing engines were installed in 1998 and 2008 and are near or at the end of their useful lives.	No impact. Microturbines have same electrical efficiency as existing old cogen engines.	No impact
BS33	Electricity generation	Replace cogen with fuel cell	Technology has advanced and offering 20 year guaranteed contracts	New fuel cell estimated at $5-15M based on recent Carollo estimates.	Moderate increase in energy savings from increased power generation. Moderate increase to O&M costs due to periodical fuel cell stack replacement.	Minor impact due to increase in required operational vigilance to keep biogas very clean for fuel cells.	New cogen would increase operational reliability and reduce cogen downtime.	Replaces existing cogen with new system resulting in increased infrastructure resiliency. Existing engines were installed in 1998 and 2008 and are near or at the end of their useful lives.	Fuel cells would increase power production by ~3,900,000 kWh/yr, resulting in the same reduction in energy import. GHG emission reduction estimated at ~870 ton/yr.	Increase in power production from biogas estimated at ~1,600,000 kWh/yr.
BS34	Electricity generation	Upgrade cogeneration to handle all WWTP electricity needs (microgrid)	Install centralized co-generation facility to produce all needed electricity on site using combination of biogas and/or natural gas. Elminates risks associated with connection to electricity grid. Can recover excess waste heat.	New cogen engines with redundant engine estimated at ~$5-15M based on recent Carollo estimates. May be even more expensive if the building needs to be expanded or a new building is needed.	Moderate increase in energy savings from increased power generation. Moderate increase to O&M costs due to addition of exhaust treatment.	Minor impact due to addition of redundant engine and exhaust treatment.	Redundant engine increases operational reliability. Allows for peak shaving and reduces biogas flaring.	Replaces existing cogen with new system resulting in increased infrastructure resiliency. Existing engines were installed in 1998 and 2008 and are near or at the end of their useful lives.	New engines would increase power production by ~1,800,000 kWh/yr and reduce GHG emissions by ~400 ton/yr just due to the efficiency improvement. Increasing power generation to supply 100% of WWTP power needs would require 2% increase in natural gas use (assuming no additional co-digestion.), resulting in increase in GHG emissions of 100 ton/yr.	Increase in power production from biogas estimated at ~750,000 kWh/yr, just from engine efficiency improvement.
BS35	Electricity generation	Increase cogen capacity and number of units to avoid peak demand charges during downtime, and for unit redundancy	Increase biogas sent to cogen and boilers. Size engines without DERWA demand.	New cogen engines with redundant engine estimated at ~$5-15M based on recent Carollo estimates. May be even more expensive if the building needs to be expanded or a new building is needed.	Moderate increase in energy savings from increased power generation. Moderate increase to O&M costs due to addition of exhaust treatment.	Minor impact due to addition of redundant engine and exhaust treatment.	Redundant engine increases operational reliability. Allows for peak shaving and reduces biogas flaring.	Replaces existing cogen with new system resulting in increased infrastructure resiliency. Existing engines were installed in 1998 and 2008 and are near or at the end of their useful lives.	New engines would increase power production by ~1,800,000 kWh/yr and reduce GHG emissions by ~400 ton/yr.	Increase in power production from biogas estimated at ~750,000 kWh/yr, just from engine efficiency improvement.
BS36	Renewable natural gas	Condition biogas for use as vehicle fuel	Produce vehicle fuel for use on-site or to send to off-site CNG fueling station. Consider conversion of biosolids fleet to CNG. Capture RIN credits.	New gas upgrading and fueling station estimates at $5-10M based on recent Carollo cost estimates.	Increase in revenue from RIN credits compared to power generation is slightly larger than increase in O&M costs to operate gas upgrading compared to cogen. Net savings estimated to increase by ~$70,000 based on recent Carollo estimates.	Minor impact. Requires new training but no new staff.	New biogas use system increases operational reliability. System uptime is slightly better than cogen.	New system increases infrastructure resiliency. Existing engines were installed in 1998 and 2008 and are at the end of their useful life and 6 years to the end of their useful life, respectively.	Natural gas offsets from producing renewable natural gas would exceed 350 tons/yr, even accounting for increased power usage of upgrading system and compressors.	Same renewable energy production from biogas but in the form of renewable natural gas rather than power.
BS37	Renewable natural gas	Condition biogas for pipeline injection	Condition biogas to NG standards and inject into pipeline. Capture RIN credits. Would be in lieu of using cogen since doing RNG injection and cogen in parallel does not make financial sense and there is not enough biogas.	New gas upgrading and fueling station estimates at $5-10M based on recent Carollo cost estimates.	Increase in revenue from RIN credits compared to power generation is slightly larger than increase in O&M costs to operate gas upgrading compared to cogen. Net savings estimated to increase by ~$70,000 based on recent Carollo estimates.	Minor impact. Requires new training but no new staff.	New biogas use system increases operational reliability. System uptime is slightly better than cogen. Eliminating cogen would reduce electrical resiliency.	New system increases infrastructure resiliency. Existing engines were installed in 1998 and 2008 and are at the end of their useful life and 6 years to the end of their useful life, respectively.	Natural gas offsets from producing renewable natural gas would exceed 350 tons/yr, even accounting for increased power usage of upgrading system and compressors.	Same renewable energy production from biogas but in the form of renewable natural gas rather than power.
BS38	Gas	Gas-to-liquid processes	Convert biogas to liquified natural gas (LNG)	Upgrade estimated between $1-10 M .	None	Moderate cost increase anticipated.	Moderate staff impact for new system O7M	None	Project anticipated to reduce GHG emissions due to fossil fuel offsets.	Notable increase in renewable energy fuel and independence from fuel proviers.

Table 2B.3 **Potable Water Distribution Opportunities**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
Pumping										
PWD1	Optimization	Optimize fire storage boundary conditions	None	None	Negligible	Negligible	Allows for reliable fire protection, increased fire storage can increase water quality concerns	Decreases risk of inadequate fire storage	No impact	No impact
PWD2	Pump efficiency	Assess pump condition	Use SCADA data to determine if pumps are operating below pump curve indicating pump damage	Results will be used to prioritize pump replacement	Damaged pumps increase operation costs	Negligible	Replacement of damaged pumps increases reliability	Replacement of damaged pumps increases resiliency	Replacement of damaged pumps reduces energy use	No impact
PWD3	Pump efficiency	Assess pump design point	Use SCADA data to determine if pumps are operating near the point of best efficiency	Results will be used to prioritize pump replacement	Inefficient pumps increase operation costs	Negligible	Replacement of improperly sized pumps increases operational flexibility	Replacement of improperly sized pumps improves inefficient infrastructure	Replacement of improperly sized pumps reduces energy use	No impact
PWD4	Water loss reduction	Leak detection	Install leak detection sensor technology in the distribution system	Assume pilot project covering a section of the distribution system	Increased costs to operate and maintain leak detection system, but potential reduced costs due to reduction in water loss	Increased staff time to operate & maintain leak detection system	Potential increase in reliability and flexibility due to decreased water loss	Potential increased resilence due to reduced water loss	Reduced energy demand due to reduced water loss, but not likely more than 1% of total DSRSD annual usage	No impact
PWD5	Shift energy use from peak demand period	Time of use pumping	TOU pumping considering water quality considerations	None	Shifts electrical use to lower cost period	Increased operator attention to minimize adverse water quality impacts	Reduces operator flexibiity	Reduced ability to respond to outages	No impact	No impact
PWD6	Reduce need for storage tank drawdown	Enhance turnover in reservoirs	Additional inlet/outlet piping to support turnover in storage tanks/help with water quality.	Assume average $400K cost each for 4 reservoirs	Possible minor reduction	Negligible	Could increase operational flexibility	No impact	Negligible	No impact
PWD7	Reduce need for storage tank drawdown	Nitrification inhibition in water tanks	Inhibit nitrite production through UV in water tanks	Cost likely in the millions of dollars	Increased electricity cost	O&M for UV numerous UV systems	Increased operational flexibility due to added tool for controlling nitrification	No impact	Increased energy use	No impact
PWD8	Reduce chemical transportation	Onsite hypochlorite generation	Onsite hypochlorite generation at Res 1A	Equipment cost for 1000 lb/d system $277K in 2017.	Increased electricity use, reduced hypochlorite purchase	Reduced transport of hypo, increased time to operate onsite hypo system,.	Decreased dependence on purchased hypo.	No impact	Increased electricity use, reduced transportation of imported hypo	No impact

Table 2B.4 **Buildings HVAC Lighting Opportunities**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
Adjustments										
BLG1	Adjustments	Occupancy-based HVAC & lighting	Use smart systems to only heat/cool/light buildings or specific zones of buildings when occupied	Minor costs (<$200K)	Project will moderately decrease O&M costs (~$25K-$225K/yr)	Negligible impact on staffing	Does not provide additional regulatory, treatment, or process operational flexibility	improves resilience of building infrastructure to energy supply	Less than 175,000 kWh/yr energy reduction	No impact
BLG2	Adjustments	Adjust lighting/temperature schedules	Adjust lighting schedules, and temperature setpoints and timing for heating/cooling in buildings	No capital costs	Project will moderately decrease O&M costs (~$25K-$225K/yr)	Negligible impact on staffing	Does not provide additional regulatory, treatment, or process operational flexibility	Does not have a noticeable impact	Less than 175,000 kWh/yr energy reduction	No impact
BLG3	Adjustments	Adjust ventilation schedules	Turn down ventilation rates when no one present in high ventilation areas (headworks, biosolids, etc.)	No capital costs	Project will moderately decrease O&M energy costs (~$25K-$225K/yr)	Negligible impact on staffing. Assumes there are reliable times during the day or week when staff is not entering certain high ventiltion areas	Does not provide additional regulatory, treatment, or process operational flexibility	Does not have a noticable impact.	Less than 175,000 kWh/yr energy reduction	No impact
BLG4	Adjustments	Reduced Grounds Lighting at Night	Reduce energy demands for grounds lighting at night, and reduce light pollution.	No capital costs.	Project will moderately decrease O&M costs (~$25K-$225K/yr).	Negligible impact on staffing	Assumes reducing lights at night will not impact operations activities during night shifts.	Does not have a noticable impact.	Less than 175,000 kWh/yr energy reduction	No impact
BLG5	Landscaping to cool	Tree shading	Landscaping larger trees where possible to shade buildings can help reduce cooling energy in summer.	<$1500 for trees and irrigation.	Likely very low changes in energy demand.	Negligible impact on staffing	Negligible impact	Does not have a noticable impact.	Negligible impact	No impact
BLG6	Demand	Allow Continued/More Remote Work / Tele communiting	Allow remote work to reduce energy from commuting, reduce energy demands in office spaces (less lighting, power for computers, space heating & cooling), less total office space to house district workforce each day.	No capital costs. Assumes no purchase of doublicate computers or other office equipment for home offices.	small, moderate reduction in energy costs.	Negligible impact on staffing	Reduces operational flexibility due to less staff onsite	Does not have a noticable impact on infrastructure resiliency.	Negligible impact	No impact
Component Replacements										
BLG7	Components	Metal Building Insulation	Insulate Metal Buildings and reduce Energy Intensity Units of Buildings.	<100k per building, assumes 5 Metal buildings. With HVAC	Assumes that about 10% of building energy for HVAC can be saved.	Negligible impact on staffing	Negligible impact	no impact.	Insulation can achieve R20 for building walls and R30 on roofs. Estimated current HVAC related electricity consumption for WWTP is about X kwh. 10% of this are XXX kwh.	No generation of energy
BLG8	AHU	Screen Room Air Handling Unit	Replace existing Air Handling Unit with energy efficient model	< $100k in capital costs.	Moderate decrease in energy costs (~$25K-$225K/yr)	Negligible impact on staffing	Negligible impact	less than 5 years of remaining useful life	neglegible impact (less than 175,000 kWh/yr).	No generation of energy

Table 2B.4 **Buildings HVAC Lighting Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
BLG9	AHU	Building A and C Air Handling Unit 2	Replace Air Handling Unit with energy effiicient model	< $100k in capital costs.	Moderate decrease in energy costs (~$25K-$225K/yr)	Negligible impact on staffing	Negligible impact	less than 10 years of remaining useful life	neglegible impact (less than 175,000 kWh/yr).	No generation of energy
BLG10	Bar Screen Building Exhaust Fan	Bar Screen Building Exhaust Fan Motor	Replace Bar Screen Building Exhaust Fan Motor with more energy efficient unit	< $100k in capital costs.	Moderate decrease in energy costs (~$25K-$225K/yr)	Negligible impact on staffing	Negligible impact	less than 10 years of remaining useful life	neglegible impact (less than 175,000 kWh/yr).	No generation of energy
New Systems										
BLG11	Components	HVAC Energy Recovery	Recover energy lost from high air exchange requirements. Implement energy recovery ventilation (ERV) to reduce heating and cooling loads through the use of air-to-air heat exchangers within HVAC system for pre-cooling or pre-heating of outdoor air stream.	<100k per building. Assumes application for all X buildings onsite with HVAC.	Assumes energy cost reduction of less than $225k as a result of about 50% energy reduction for HVAC in buildings. (Heat exchanger will recover about 70% of the heat in the air.)	Negligible impact on staffing. Maintenance of systems could be contracted out.	Negligible impact	Improves resilience of building infrastructure to energy supply.	Less than 175,000 kWh/yr energy reduction for building HVAC energy (assumes up to 20 %)	No impact
BLG12	Components	Solar Thermal Heating	Install solar panels or collectors and thermal heat recovery/water distribution systems on south-facing spaces.	<100k per building. Assumes application for all X buildings onsite with HVAC.	Assumes that up to 100% of building heating costs could be substituted. Estimated at $ per year. (~$25K-$225K/yr).	Neglegible impact on staffing. Maintenance of systems could be contracted out.	Does not provide additional regulatory, treatment, or process operational flexibility.	Improves resilience of building infrastructure to energy supply.	Up to x kWh/yr energy reduction for building HVAC energy (assumes up to 100% of heating demand supplied by solar thermal)	Up to x kWh/yr renewable energy production from building solar thermal.
BLG13	Components	Wastewater Thermal Energy Use for onsite Building heating and cooling.	Use heat pumps to transfer heat to/from wastewater for use in building heating/cooling or water systems. Done at Philadelphia's Southeast Water Pollution Control Plant, MWRDGC's James C. Kirie WRP, Metro Water Recovery (Denver)	Capital costs are proportionate to heating and cooling capacity of heat pump system. Can be implemented on a per building basis or for several buildings supplied by same heat pump system. All occupied buildings we estimate capacity needed at around X MW for a cost of about $X. Estimated payback period for these systems are about 10-15 years for existing building retrofits.	Assumes that up to 100% of building heating costs could be substituted. Estimated at $ per year. (~$25K-$225K/yr).	Minor impact on staffing. Depending on heat pump vendor system could be maintained by vendor or be maintained by plant staff which would reuqire additional staff time.	Does not provide additional regulatory, treatment, or process operational flexibility. Assumes temperature will not be a regulated polluntant for DSRSD in the future.	Improves resilience of building infrastructure to energy supply.	Up to x kWh/yr energy reduction for building HVAC energy (assumes up to 100% of heating and cooling demand supplied heat pump system)	Up to x kWh/yr renewable energy production from wastewater thermal heat use for building heating and cooling .
BLG14	Variable refrigerant system	Refrigerant HVAC system.	Circulate refrigerant through facility HVAC system (not air). This allows moving the heat between different areas of the WWTP site and optimize the use of energy where needed.	Estimated at less than $200k fortarget buildings.	Assumes a reduction of up to 20% for HVAC energy (about X kWh/y) or x$.	Minor impact on staffing	Does not provide additional regulatory, treatment, or process operational flexibility.	Improves resilience of building infrastructure to energy supply.	10-20% energy reduction	No impact
BLG15	Economized cooling	Fan addition	Add fans to HVAC systems to economize energy use (e.g. in electrical rooms) etc. when HVAC not needed.	<$50k for targeted buidlings.	Assumes a reduction of up to 5% for HVAC energy (about X kWh/y) or x$.	No impact on staffing	Negligible impact	Does not have a noticeable impact on infrastructure resiliency for treatment and energy supply	Small energy reduction (assumes less than 5% of HAVC energy).	No impact

Table 2B.5 **Renewable Energy Opportunities**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
Renewable Energy Production										
RE1	Solar	Solar installation on-site at WWTP	Install solar on various building roofs and/or in holding basins. Coverage about 1 acre. Power put into PG&E net.	Assumes $2.20 per W installed or $88,000 for 40 kW capacity per acre	No significant O&M costs for solar cells, could be contracted out	Little impact on staffing	Maintains current reliability and flexibility	No impact on existing infrastructure. Resiliency not increased in case of future outage (without battery storage).	Less than 175,000 kwh reduction in electricity demand. No improvement on independence from PG&E as power put into net.	Assumes onsite acreage of about one acre solar panels for about 40 kW of net solar capacity. (110,000 kWh/a, assuming 2.2 kwh per 330 W panel in CA.)
RE2	Solar	Solar field offsite	Install solar field on District owned property near WWTP (Gleason Property). Assumed here 5 acres of solar area installation possible. Need acreage of this property for solar or wind installation.	Assumes $2.20 per W installed or $440,000 for 200 kW capacity per acre.	No significant O&M costs for solar cells, could be contracted out	Little impact on staffing	Maintains current reliability and flexibility	No impact on existing infrastructure. Resiliency increased in case of future outages (without battery storage).	More than 350,000 kwh reduction in electricity demand. No improvement on independence from PG&E as power put into net.	Assumes onsite acreage of about five acres of solar panels for about 200 kW of net solar capacity. (540,000 kWh/a, assuming 2.2 kwh per 330 W panel in CA.)
RE3	Solar	Solar field at DLDs	Install solar field over DLD's. Would require implementation of different biosolids handling approach or method for solids land application.	Assumes $2.20 per W installed or $440,000 for 200 kW capacity per acre.	No significant O&M costs for solar cells, could be contracted out. DLD operation/biosolids handling would need to change bringing higher costs.	Staffing impacts due to modified biosolids handling practices.	Would need to modify solids land disposal method or change to different method.	No impact on existing infrastructure. Resiliency increased in case of future outages (without battery storage).	More than 350,000 kwh reduction in electricity demand. No improvement on independence from PG&E as power put into net.	Assumes onsite acreage of about five acres of solar panels for about 200 kW of net solar capacity. (540,000 kWh/a, assuming 2.2 kwh per 330 W panel in CA.)
RE4	Solar Charging	Electric vehicle fleet recharged using solar power	None	About $40,000 for five electric charging stations. About $5000 for 2.2kW solar system.	No significant O&M costs for solar cells, could be contracted out.	Little impact on staffing	Maintains current reliability and flexibility. Since only passanger cars and non-critical trucks are replaced with EV, no impact on flexibility.	No impact on existing infrastructure. Resiliency not increased in case of future outage (without battery storage).	Less than 150 tpy GHG emission reduction. No improvement on independence from PG&E as power put into net.	Less than 850,000 kwh/a of electricity production. Small increase.
RE5	Wind	Wind energy	Large wind turbine(s) on or offsite	Assumes similar costs to solar installation ($2.20 per W installed or $440,000 for 200 kW capacity per acre.)	No significant O&M costs for wind turbines could be contracted out.	Little impact on staffing	Maintains current reliability and flexibility	No impact on existing infrastructure. Resiliency increased in case of future outages (without battery storage).	Assumes similar power production compared to solar cells in option RE2 (more than 350,000 kwh reduction in electricity demand. No improvement on independence from PG&E as power put into net.) CP to ask Christine T.	Assumes wind turbines for about 200 kW of net capacity. (540,000 kWh/a). CP to ask Christine T.

Table 2B.5 **Renewable Energy Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
RE6	Produce Power	Hydroelectric generation	Install kinetic energy recovery devices on gravity liquid streams, such as gravity pipes, mixed liquor channel, etc. effluent discharge pipe not considered here as not operated by DSRSD.	Cost depend on capacity (kW of turbine system) assumed here below 1 M	Some energy required, but overall net producing	Increases reliability of DSRSD power supply	No impact on existing infrastructure	Not a promising solution (many pump stations, long flat pumped ocean outfall)	Need to verify whether there are suitable locations	Need to verify whether there are suitable locations
RE7	Partnerships	Renewable generation partnerships	Partner with property neighbors to install renewable energy generation for use at pump stations	Assumes $2.20 per W installed or $572,000 for 260 kW capacity per acre. Assume solar offset for PS 20B or 200A annual average demand.	No significant O&M costs for solar cells, could be contracted out.	Little impact on staffing	Maintains current reliability and flexibility	No impact on existing infrastructure. Resiliency increased in case of future outages (without battery storage).	More than 700,000 kwh reduction in electricity demand.	Assumes onsite acreage of about 6.5 acres of solar panels for about 260 kW of net solar capacity. (700,000 kWh/a, assuming 2.2 kwh per 330 W panel in CA.) No improvement on independence from PG&E as power put into net.
RE8	Partnerships	Purchase green power	For portion of power purchased from utility, expand on green power purchase program. Consider allowing customers to opt into higher rate structure to cover cost for green energy purchase or generation.	No capital costs if purchase of solar power from others can be accomodated.	Marginal energy cost increases, if any. kWh costs are similar between PG&E and community choice aggregation.	No impact on onsite staffing	Maintains current reliability and flexibility	No impact on existing infrastructure. Resiliency increased in case of future outages (without battery storage).	Potentially very high greenhouse gas reduction (> 350,000 kWh/a offsets).	Potential for over 850,000 kWh/a offsets from solar power purchases.
RE9	Produce Power	Onsite hydroelectric generation	Install kinetic energy recovery devices on gravity liquid streams, such as gravity pipes, UV channel outfall, west plant aeration tank outfall to mixed liquor channel, etc.	Cost depend on capacity (kW of turbine system) assumed here below 1 M	some energy required, but overall net producing	Increases reliability of DSRSD power supply	No impact on existing infrastructure	Not a promising solution (many pump stations, long flat pumped ocean outfall)	Need to verify whether there are suitable locations	Need to verify whether there are suitable locations

Table 2B.5 **Renewable Energy Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
Energy Storage										
ES1	Electric	Battery storage and microgrid	This alternative involves installation of battery storage and a microgrid system to increase DSRSD's use of renewable energy sources, allow for peak shaving to reduce electrical costs, and to provide a short-term backup for power outages to increase resiliency.	Check on Federal Investment Tax Credits. Estimate $1-2 M in capital construction and $1.3-2.7M total project costs based on evaluation in 2021 for MMSD by Carollo.	Annual O&M savings for this alternative in the form of a reduced electrical cost for peak demand charges from PG&E. This savings is estimated to be $100-200k or more based on comparison to MMSD. Includes both overall reduction in energy purchase from PG&E as well as peak demand charge reduction.	Little impact on staffing, could be outsourced to 3rd party. This alternative is not anticipated to require significant operator attention beyond monitoring and preventative maintenance of equipment.	While more a concern in smaller electronic devices with less sophisticated charging mechanisms, lithium chemistries have an added risk of overheated electrolytes if the battery management system is unable to keep the cells from overcharging, resulting in fire or explosion. Grid or industrial scale systems include very robust controllers to help prevent this from happening.	No impact on existing infrastructure. Resiliency increases in case of future outage.	Does not reduce overall energy demand, but evens out peak demands.	On its own this option will not produce renewable energy. Needs to be paired with renewable energy production option.
ES2	Battery Storage	Battery storage for equipment / processes driving peak demand charges	Battery supplement for PSR1 to reduce peak energy charges	Estimate $1-2 M in capital construction	Annual O&M savings for this alternative in the form of a reduced electrical cost for peak demand charges from PG&E. This savings is estimated to be $100-200k or more based on comparison to MMSD. Includes both overall reduction in energy purchase from PG&E as well as peak demand charge reduction.	Little impact on staffing, could be outsourced to 3rd party.	Increased reliability and power flexibility.	No impact on existing infrastructure. Resiliency increases in case of future outage.	Does not reduce overall energy demand, but evens out peak demands.	On its own this option will not produce renewable energy. Needs to be paired with renewable energy production option.
Thermal Energy Recovery										
TH1	Heat recovery	Recovery thermal energy from influent/effluent (i.e., heat pump)	Capture heat from influent/effluent for onsite use to replace natural gas, e.g. for building heating (e.g., Adm. Bldg., Fleet Office Maintenance Bldg., or Field Operations Fac.)	Estimated costs about $4M for a 5 MW capacity heat pump system.	Savings after about 5-10 years	None, maintenance services could be contracted out.	Improves reliability of gas energy uses	Moderately increases resilience for energy supply	Moderate decrease in GHG	Some renewable energy production depending on system sizing (0.5 to 4 MW capacity typical for commercial buildings
TH2	Heat recovery	Capture heat from collection system to sell to larger commercial buildings in service area (e.g. new Cosco)	Recovery thermal energy from influent/effluent (i.e., heat pump).	Would be paid by customer	DSRSD would receive money for offering thermal wastewater.	None, maintenance services could be contracted out	No impact on DSRSD, outside the fence system.	No impact on DSRSD, outside the fence system.	Moderate decrease in GHG by 3rd party system operator	Some renewable energy production depending on system sizing (0.5 to 4 MW capacity typical for commercial systems)
TH3	Waste heat to power	Install Organic Rankine Cycle (or similar)	Use ORC system (or other) to capture low grade waste heat and/or exhaust heat to generate more electricity	Moderate capital costs	This would moderately save energy costs	Moderate impact on staffing	Moderately increases process flexibility	Little change	Moderate decrease	Negligible decrease

Table 2B.5 **Renewable Energy Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
TH4	Heat loop expansion	Expand heat loop	Expand system and increase thermal energy conveyance ability across plant.	Estimated costs for heat loop expansion from digesters to other buildings on site.	This would save energy costs after payoff period	Moderate impact on staffing	Improves reliability of gas energy uses	Moderately increases resilience for energy supply	Moderate decrease in GHG	Some renewable energy production depending on system sizing (0.25 to 1 MW capacity estimated for DSRSD commercial buildings.
TH5	Heat loop improvements	Use steam	Increase use of steam instead of hot water in order to utilize advantages of higher temperature driving force. Use waste heat to generate steam. Could be used for heat exchange, steam pumps, biosolids drying, etc.	Estimated in lower $1M	Slight increase in O&M costs because of new system.	Minor impact on staffing	Improves process operation	No change	Negligible impact	Some increase in GHG offsets
TH6	Heat uses	Use heat for more process needs	Expand heat loop to provide process heat needs (i.e. polymer makedown, scum/grease separation, future codigestion receiving station, enhanced WAS fermentation/phosporous release, or evaporate water to thicken sludge prior to dewatering)	Estimated in lower millions	Negligible impact as these uses may currently not be supplied by heat.	Minor impact on staffing	Improves process operation	Little change	Negligible impact	Negligible decrease
TH7	Heat uses	Use for advanced biosolids processing	Expand thermal heat recovery to provide heat for advanced biosolids treatment (thermo-chemical hydrolysis, thermal hydrolysis, drying)	Estimated in lower millions	Operational cost benefit not substantial unless solids handling process may be changed.	Minor impact on staffing	Maintains operational reliability; improves operational flexibility	Moderately increases the capacity of solids treatment processes	Moderate decrease	No change

Table 2B.6 **District-Wide Opportunities**

Option ID	Process Area	Option Name	Option Description	Qualitative Criteria Evaluations						
				Implementation Criteria			Impact Criteria			
				Capital Costs	Operational Costs	Impact on Staffing Resources	Operational or Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy
Advanced Controls										
AC1	Data Management	Alternative power monitoring than Foreseer	Strengthen SCADA integration; Power monitoring for operators, reestablish powernet interface in SCADA Real time visualization of power generation, demand, purchase	No investment costs	Potential to moderately decrease O&M costs (~$25K-$225K/yr).	Minor impact	Maintains operational reliability; improves operational flexibility.	Does not have a noticable impact on infrastructure resiliency for treatment and energy supply.	Negligible impact	No Impact
AC2	System-wide	Artificial intelligence	Plan for artificial intelligence for advanced energy management. Reduce demand for aeration process. Control to better match diurnal load demand. Better aeration control. Control blends of energy production or storage.	Minor costs. <$200K	Potential to moderately decrease O&M costs (~$25K-$225K/yr).	Negligible impact	Maintains operational reliability; no impact on operational flexibility.	Does not have a noticable impact on infrastructure resiliency for treatment and energy supply.	Moderate decrease	No impact
AC3	System-wide	Pump diagnostics	Use AI tools for pump diagnostics - vibration sensors and maintenance	Minor costs. <$200K	Negligible impact	Potential to reduce staffing burden	Maintains operational reliability; improves operational flexibility.	Moderately enhances infrastructure resiliency for treatment.	Negligible impact	No impact
AC4	Management	Energy decision management tools	Low hanging fruit - identify what controls and monitoring equipment are suitable under this option.	Minor costs. <$200K	Potential to moderately decrease O&M costs (~$25K-$225K/yr).	Minor impact	Maintains operational reliability; no impact on operational flexibility.	Does not have a noticeable impact on infrastructure resiliency for treatment and energy supply.	Moderate decrease	No impact
AC5	Electricity capacity management	Load bank	Load bank for higher spike of voltages to be absorbed	Minor costs. <$200K	Negligible impact	Minor impact	Maintains operational reliability; improves operational flexibility.	Moderately enhances infrastructure resiliency for treatment.	Negligible impact	No impact
Supporting Appurtenances										
SA1	Odor Control	ORT effluent supply Pump 2 motor	Replace ORT effluent supply Pump 2 motor with more energy efficient unit.	Minor costs. <$200K	Potential to moderately decrease O&M costs (~$25K-$225K/yr).	No impact	Maintains operational reliability; improves operational flexibility.	Does not have a noticable impact on infrastructure resiliency for treatment and energy supply.	Negligible impact	No impact
SA2	Hot Water Loop	HRS Primary Loop Pump 1 and 2	Replace HRS Primary Loop Pump 1 and 2 with more energy efficient units	Minor costs. <$200K	Potential to moderately decrease O&M costs (~$25K-$225K/yr).	Current pumps have less than 10 years in useful life. DSRSD is in process of replacing these pumps.	Maintains operational reliability; improves operational flexibility.	Does not have a noticeable impact on infrastructure resiliency for treatment and energy supply.	Negligible impact	No impact
SA3	System-wide	Water conservation and I&I reduction	None	Very high costs depending on extent of asset replacement.	Potential to moderately decrease O&M costs (~$25K-$225K/yr).	Additional staff would be required.	Has the potential to improve operational reliability and flexibility.	Moderately enhances infrastructure resiliency for treatment and moderately increases the capacity of treatment processes.	Moderate decrease	No impact
SA4	Odor Control	Replace current odor control technology (1 biotower, 2 biofilters) with more energy efficient process.	Odor control technology alternatives (Tricoal canister, Biobeds- energy efficient, ORT)	High cost to replace existing infrastructure	Similar operational costs	Minor impact	No impact	Does not have a noticeable impact on infrastructure resiliency for treatment and energy supply.	Negligible impact	No impact
SA5	System-wide	Low maintenance landscaping	Reduce demands for mowing and edge trimming by adding alternative landscaping features (converts grass stips to mulch/rock, add un-grassed buffer around tanks, etc) or let green spaces return to prairie	No investment costs	Negligible impact	Potential to reduce staffing burden	Maintains operational reliability; no impact on operational flexibility.	Does not have a noticeable impact on infrastructure resiliency for treatment and energy supply.	Negligible impact	No impact

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Table 2B.7 **Emerging Technologies Opportunities**

Option ID	Process Area	Option Name	Option Description
Innovative but Mature Technologies			
ET1	Digestion pretreatment	Enzyme conditioning	Enzymes added to thickening and digestion systems to degrade organics, increase dewaterability and reduce odors
ET 2	Digestion enhancement	Biocatalytic digestion	Use enzyme biocatalysts to enhance anaerobic digestion, producing more biogas, higher quality biogas with fewer contaminants, and increasing VSR (e.g. Hycura AD MET granules or Drylet). Biocatalysts primarily aim to enhance cellular lysis of secondary sludge to improve digestion. Some may also include targeted microbes to also enhance other digestion steps (acidogenesis, acetogenesis, methanogenesis) through bioaugmentation. Biocatalysts may take the form of engineered porous media seeded with specific microbes identified through genomic analyses and modeling.
ET3	Digestion pretreatment	Phagotrophic algae biosolids pretreatment	Pretreatment of sludge prior to digestion with algae. Low energy requirement, potential for algae harvesting (oil and biomass recovery), improves anaerobic VSR and gas production, minimized footprint for solids stabilization, better dewatering, no light source required.
ET4	Potential future dewatering	Hydraulic piston press	Batch operated hydraulic piston press. Increases cake solids content with lower energy requirements (tested at Inland Empire Utilities Agency, California). Thames Water has standardized on these with THP systems in UK. Batch process with limited capacity requries multiple units. Drier cake produced than centrifuges with lower polymer consumption, but at relatively high capital. No US installations so questions about local service.
ET5	Potential future dewatering	Chemical drying	Solids dried with chemical reaction, dried product mixed with nutrients for fertilizer value
ET6	Resource recovery	Biosolids injection into cement kiln	Use biosolids as a fuel in cement kilns and reduces NOx emissions while serving as an alternative fuel source (Mitsubishi Luverne Valley Cushenberry Plant in California, Heidelberg cement in Maryland, and examples in Europe)
Pilot Necessary			
ET7	Digestion pretreatment	Electrocoagulation (conditioning)	Uses electrical current to dissolve a sacrificial anode and introduce chemically reactive aluminum. Increase rate of anaerobic digestion, improve sludge settling, promote recovery of biogas, facilitate denitrification. (Vancouver Shipwards, British Columbia)
ET8	Digestion pretreatment	Chemical/pressure cell destruction (Microsludge/MicroPOP)	Destroys cell membranes in WAS and increase performance of ADs
ET9	Digestion pretreatment	Biological cell destruction / Biological hydrolysis	Promotes biological disintegration of organic matter into CO2, reducing sludge volume. Enzymic hydrolysis can meet class A Biosolids in a series of small selectors
ET10	Digestion	Biosolids hydrothermal liquefaction	Sludge to fuels (bio-crude oil and/or natural gas) under moderate temperature and high pressure, undigested solids.
ET11	Dewatering	Electrodewatering	Enhance conventional dewatering using electric current
ET12	Dewatering	Flash drying	The process combines centrifuge dewatering with flash air drying to produce a solids product with 50 to 60 percent solids.
ET13	Other	Vermicomposting of Biosolids	Uses earthworms and microbes to achieve pathogen reduction and produce land application quality compost from biosolids. Requires pre-composting step for stabilization and homogenization for proper mixing and size reduction required for optimal composting by worms. Was practiced at Granville Junction WWTF, PA, but now decommisioned.
ET14	Thermal processing	Direct Microwave Drying	Use of multimode microwaves to excite water within biosolids, deactivate pathogens, and achieve drier solids. (e.g. Burch Hydro BioWave Process)
ET15	Resource recovery	Convert biogas to diesel fuel	Conversion of biogas to syngas through catalytic reactions and then to hydrocarbon fuels. (T2C-Energy)
ET16	Resource recovery	Potassium Recovery	Recovery as potassiumstruvite($MgKPO_4 \cdot 6H_2O$) from centrate. Requires high pH >11. Potential collaboration with Ostara to modify precipitation process for K recovery.

Table 2B.7 **Emerging Technologies Opportunities (continued)**

Option ID	Process Area	Option Name	Option Description
ET17	Resource recovery	Ammonia Recovery	Recovery of ammonia as ammonium sulfate under addition of sulfuric acid. Full scale facilities in operation in other countries but not in US to our knowledge.
Candidates for Research Collaborations			
ET18	Digestion pretreatment	Bioelectrochemical systems/ Microbial fuel cells	Pretreatment of solids/gas production; Electrical production
ET19	Digestion	Plasma assisted sludge oxidation	Low operating temperatures, high combustion efficiency; 500-700 deg C rotary kiln incineration with low power plasma arc; needs 20% VS by weight for energy; can recover heat
ET20	Dewatering	Electroacoustic dewatering	Uses electric and ultrasonic fields that improved water removal over conventional processes;
ET21	Dewatering	Electroosmotic dewatering	Enhance conventional dewatering with electric field that forces ionic particles in biosolids mixture to migrade to attactive electrodes
ET22	Resource recovery	Hydrogen generation	Renewable hydrogen from biogas can be used in fuel cell electric vehicles (FCEVs)
ET23	Resource recovery	Syngas fermentation to VFA or simple alcohols production	Ferment syngas to VFAs or simple alcohols
Not Recommended			
ET24	Digestion	Supercritical Water Oxidation	Implement supercritical water oxidation for biosolids, Reduces the volume of biosolids and produces class A biosolids
ET25	Digestion	Deep shaft wet air oxidation	Autothermophilic aerobic digestion process that increases energy efficiency and produces class A biosolids
ET26	Digestion	Cannibal process	Biological biosolids reduction without digestion, thickening, dewatering, or polymer
ET27	Dewatering	DAB System (dehydration unit)	Conical gravity flow filtration-drainer mechanism separates sludge liquids and solids, producing 90% solids product
ET28	Dewatering	Geotube container	Geotextile tube used for on-site, low-maintenance, cost-effective dewatering (Saticoy Sanitary District, California and City of Cambridge WWTP in Ohio)
ET29	Dewatering	Oxygen enhanced incineration (combustion)	Improve the performance of biosolids and sludge furnaces
ET30	Resource recovery	SlurryCarb (fuel production)	Convert biosolids to renewable fuel with lower temperature and pressure and shorter reaction time than pyrolysis (City of Rialto, California)
ET31	Resource recovery	Minergy vitrification	Convert biosolids to construction material and industrial feed stocks that are marketable (done in Winnecone and Nennah, WI)
ET32	Digestion pretreatment	Ultrasonic cell destruction	Applies acoustic waves to solids prior to digestion. Increase rate of anaerobic digestion, improve sludge settling, promote recovery of biogas, facilitate denitrification (Bad Bramstedt Sewage Works in Germany, and Mangere WWTP in New Zealand)
ET33	Digestion pretreatment	Electric pulse cell destruction	Electric pulses to lyse cells
ET34	Liquid stream treatment	Mainline anaerobic treatment	Convert activated sludge process to anaerobic process. Add secondary steps for nitrogen and phosphorus removal/recovery
ET35	Liquid stream treatment	Change to more energy efficient diffusers.	Nano bubble generation
ET36	Components	Adsorptive Chillers	Use excess heat and adsorptive chillers for cooling in the summer.

Appendix 2C

IMPLEMENTABILITY AND IMPACT SCORES OF POTENTIAL ENERGY OPPORTUNITIES

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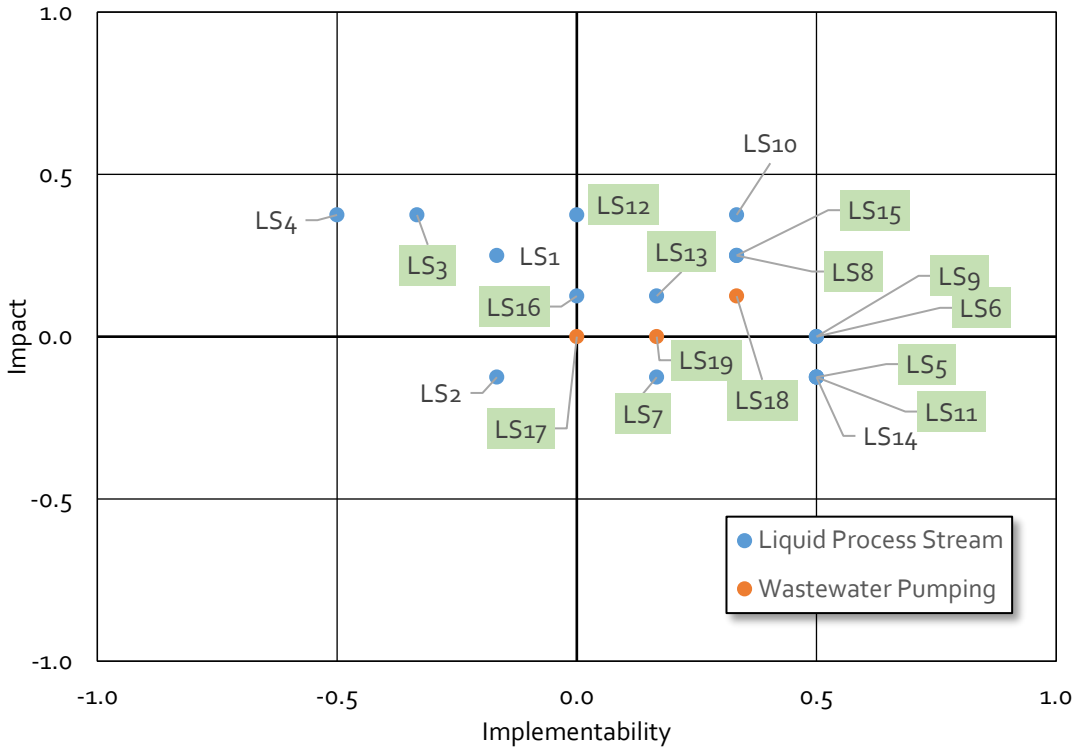

Figure 2C.1 Wastewater Liquid Stream Opportunities: Implementability vs. Impact Scores

LS-1: Influent flow equalization

LS-2: Large bubble mixing

LS-3: Improve carbon diversion to digester (CEPT)

LS-4: Improve carbon diversion to digester (biofiltration)

LS-5: Real-time solids retention time (SRT) control

LS-6: Model predictive aeration control

LS-7: Low dissolved oxygen (DO) operation

LS-8: RAS Pump 4 VFD

LS-9: Take AB out of service

LS-10: Improve secondary clarifier hydraulics

LS-11: Reduce units in service

LS-12: Switch to energy efficient diffusers

LS-13: Upgrade to more efficient blowers

LS-14: Green power ramp

LS-15: Jockey blower

LS-16: Preaeration blowers

LS-17: Replace influent pumps and VFDs

LS-18: Install VFDs

LS-19: Basin 4 effluent pumping motor VFD

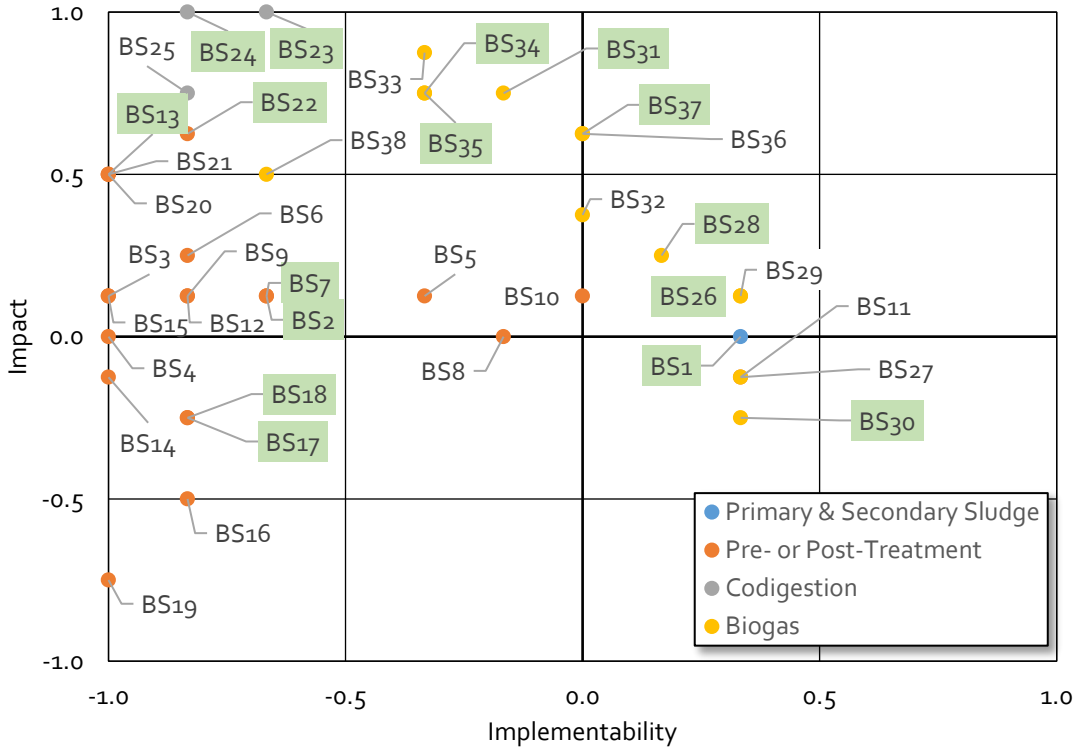

Figure 2C.2 Biosolids Opportunities: Implementability vs. Impact Scores

BS-1: Replace sludge pump VFDs

BS-2: Alternative thickening

BS-3: Class A high temp thermal hydrolysis

BS-4: Class B high temp thermal hydrolysis

BS-5: Class B thermos-chemical hydrolysis

BS-6: Class B biological hydrolysis

BS-7: Recuperative thickening

BS-8: Thermophilic digestion for class A biosolids

BS-9: Acid phase digestion

BS-10: Low energy digester mixing

BS-11: Replace digester sludge pumps

BS-12: Implement dewatering post facultative sludge lagoon

BS-13: Implement dewatering post digestion

BS-14: Air drying

BS-15: Solar drying

BS-16: Low temperature thermal drying

BS-17: Drying + Pyrolysis

BS-18: Drying + Gasification

BS-19: Incineration with energy recovery

BS-20: Class A with onsite composting

BS-21: Class A with offsite composting

BS-22: Lystek thermo-chemical hydrolysis

BS-23: Co-digest fats, oils, and grease (FOG)

BS-24: Co-digest food waste slurry/high strength waste (HSW)

BS-25: Co-digest food waste slurry from solid waste

BS-26: Improve gas conditioning system

BS-27: Biological sulfur removal

BS-28: Increase biogas storage

BS-29: Fuel skid gas compressor motor

BS-30: Status quo operation with replacement of aging equipment

BS-31: Replace cogen with higher efficiency engine generators

BS-32: Replace cogen with microturbines

BS-33: Replace cogen with fuel cell

BS-34: Upgrade cogeneration to handle all wastewater treatment plant (WWTP) electricity needs (microgrid)

BS-35: Increase cogen capacity and number of units

BS-36: Condition biogas for use as vehicle fuel

BS-37: Condition biogas for pipeline injection

BS-38: Gas-to-liquid processes

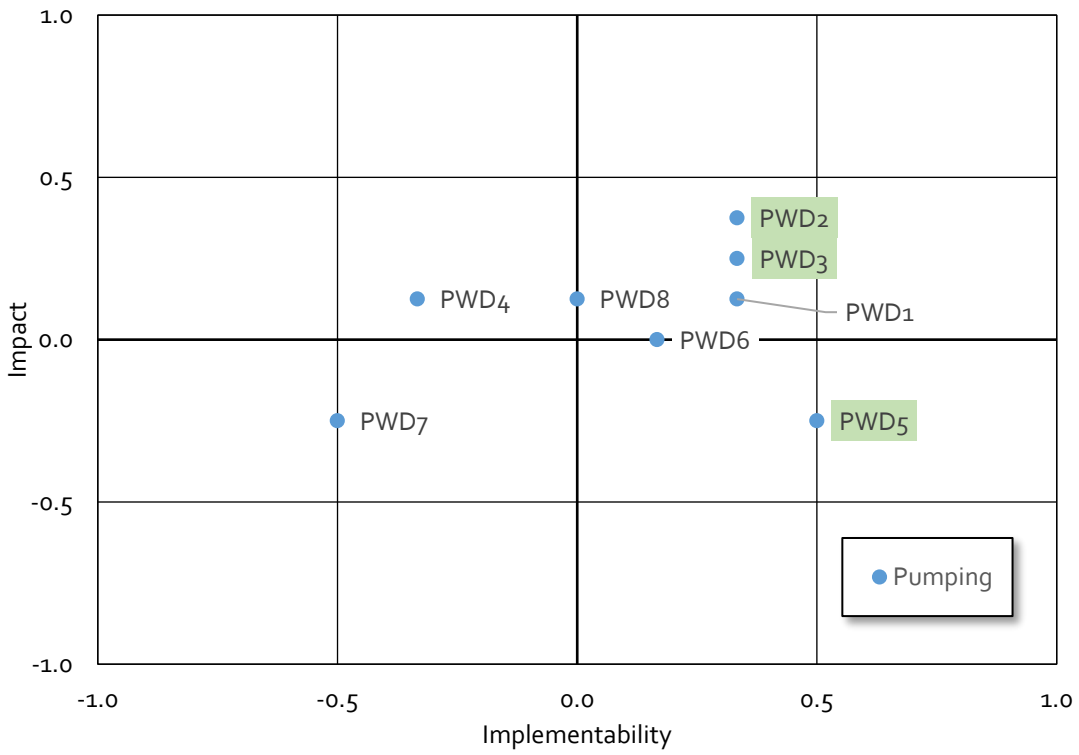

Figure 2C.3 Potable Water Distribution Opportunities: Implementability vs. Impact Scores

PWD-1: Optimize fire storage boundary conditions

PWD-2: Assess pump condition

PWD-3: Assess pump design point

PWD-4: Leak detection

PWD-5: Time of use pumping

PWD-6: Enhance turnover to reservoirs

PWD-7: Nitrification inhibition in water tanks

PWD-8: Onsite hypochlorite generation

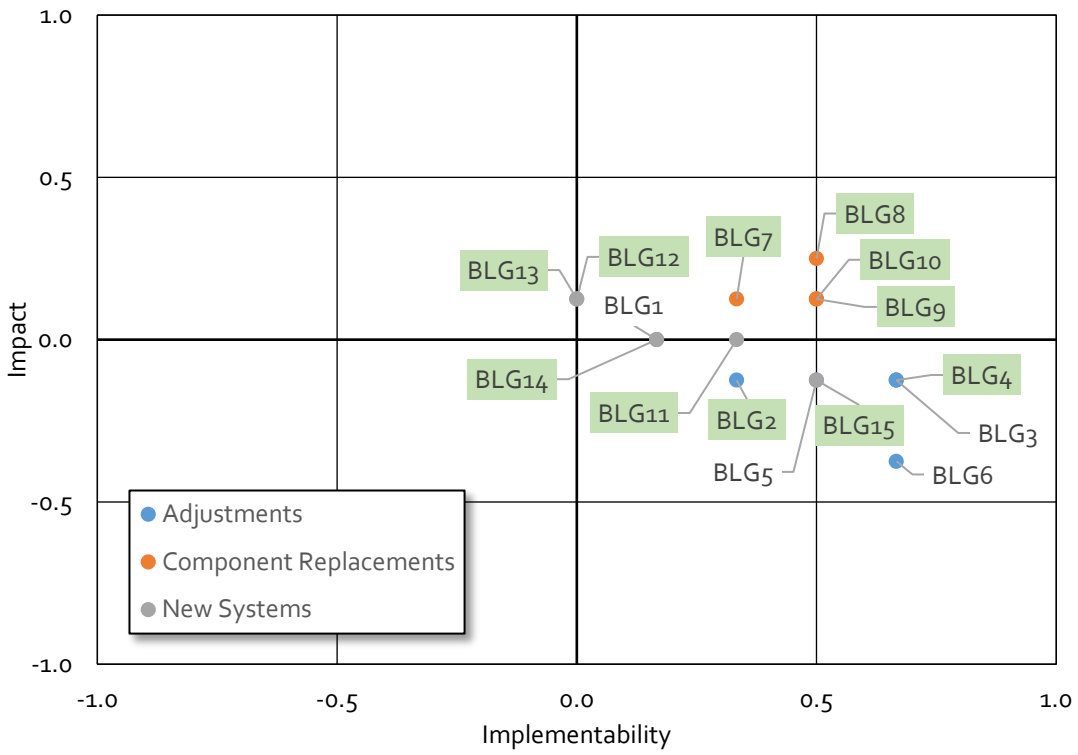

Figure 2C.4 Buildings, HVAC, and Lighting Opportunities: Implementability vs. Impact Scores

BLG-1: Occupancy-based HVAC and lighting

BLG-2: Adjust lighting / temperature schedules

BLG-3: Adjust ventilation schedules

BLG-4: Reduced grounds lighting at night

BLG-5: Tree shading

BLG-6: Allow continued / more remote work / telecommuting

BLG-7: Metal building insulation

BLG-8: Screen room air handling unit

BLG-9: Building A and C air handling unit 2

BLG-10: Bar screen building exhaust fan

BLG-11: HVAC energy recovery

BLG-12: Solar thermal heating

BLG-13: Wastewater thermal energy use for onsite heating and cooling

BLG-14: Refrigerant HVAC systems

BLG-15: Fan addition

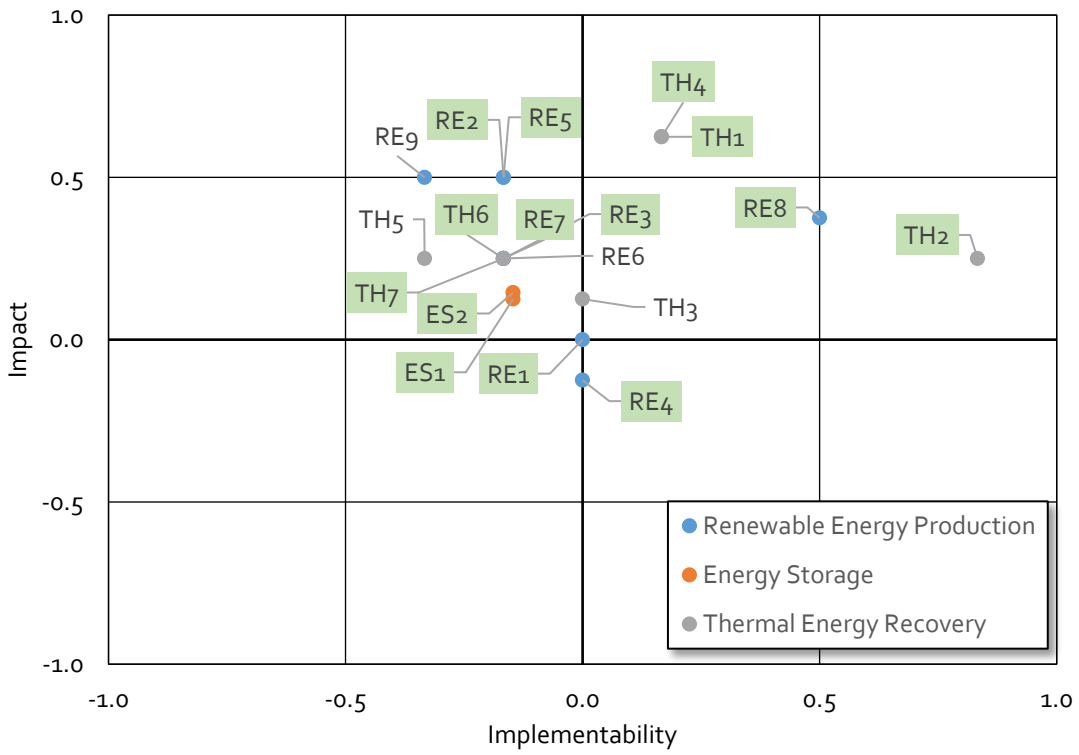

Figure 2C.5 Renewable Energy Projects: Implementability vs. Impact

RE-1: Solar installation on-site at WWTP

RE-2: Solar field offsite

RE-3: Solar field at DLDs

RE-4: Electric vehicle fleet recharged using solar power

RE-5: Wind power

RE-6: Hydroelectric generation

RE-7: Renewable generation partnerships

RE-8: Purchase green power

RE-9: Onsite hydroelectric generation

ES-1: Battery storage and microgrid

ES-2: Battery storage for equipment / processes driving peak demand charges

TH-1: Recover thermal energy from influent / effluent

TH-2: Capture heat from collection system to sell to larger commercial buildings

TH-3: Install Organic Rankine Cycle (ORT)

TH-4: Expand heat loop

TH-5: Use steam

TH-6: Use heat for process needs

TH-7: Use heat for advanced biosolids processing

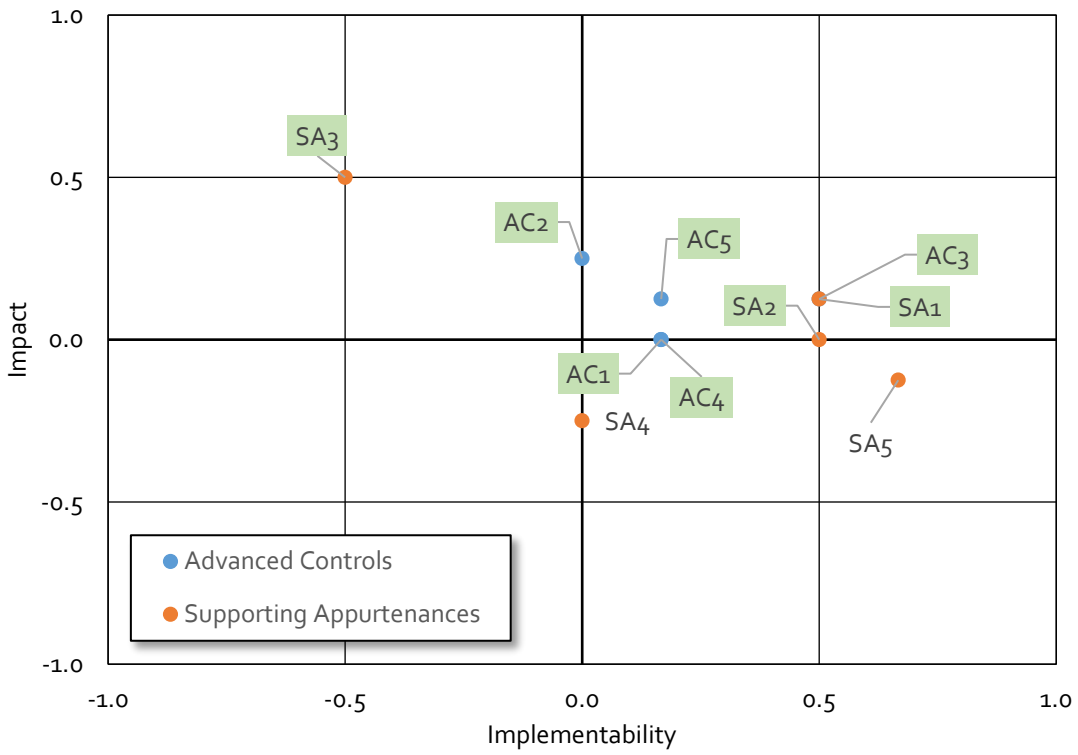

Figure 2C.6 District-Wide Opportunities: Implementability vs. Impact Scores

AC-1: Alternative power monitoring than Foreseer

AC-2: Artificial intelligence

AC-3: Pump diagnostics

AC-4: Energy decision management loads

AC-5: Load bank

SA-1: ORT effluent supply Pump 2 motor

SA-2: HRS primary loop Pump 1 and 2

SA-3: Water conservation and inflow and infiltration (I&I) reduction

SA-4: Replace current odor control technology with more energy efficient process.

SA-5: Low maintenance landscaping

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Appendix 2D

POTENTIAL ENERGY OPPORTUNITIES SCORES

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Table 2D.1 **Wastewater Liquid Stream Opportunities Scores**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		14%	14%	14%	14%	14%	14%	14%					
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
Liquid Process Stream													
LS1	Reestablish influent or primary effluent flow EQ	1	2	5	4	5	3	2	3.14	-0.17	0.25	No	Influent equalization with odor control and nighttime treatment at lower energy costs. Evaluation Result is a "No" due to challenges with odors and the difficulty and costs associated with implementing odor control for these facilities.
LS2	Large bubble mixing in liquid process (anoxic/anaerobic zones)	3	2	3	4	2	3	2	2.71	-0.17	-0.13	No	District currently has submersible mixers.
LS3	Improve carbon diversion from Primaries to digester (CEPT)	2	2	3	5	4	3	3	3.14	-0.33	0.38	Yes	This was discussed between DSRSD and HDR during the primary design and not implemented. However, additional vetting may be needed to determine if it could make sense at some point in the future.
LS4	Improve carbon diversion from Primaries to digester (Biofiltration)	1	3	2	5	4	5	1	3.00	-0.50	0.38	No	
LS5	Real time SRT Control	4	3	5	5	1	3	2	3.29	0.50	-0.13	Yes	
LS6	Model predictive aeration control	4	3	5	5	1	4	2	3.43	0.50	0.00	Yes	Jeff noted it may already be implemented, need to confirm.
LS7	Low DO operation	4	3	3	3	1	5	2	3.00	0.17	-0.13	Yes	Assumes that an advanced aeration controller is required to allow accurate control under low DO operations. Low DO operations for BOD and TSS require a removal target of less than 0.7 mg/L DO in most, if not all, aeration basin zones that are aerated.
LS8	RAS pump 4 VFD	4	3	4	5	3	3	3	3.57	0.33	0.25	Yes	
LS9	Take AB out of service	5	3	4	2	3	4	3	3.43	0.50	0.00	Yes	

Table 2D.1 **Wastewater Liquid Stream Opportunities Scores (continued)**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		14%	14%	14%	14%	14%	14%	14%					
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
LS10	Improve SC hydraulics to reduce solids in final effluent	3	4	4	5	4	3	3	3.71	0.33	0.38	No	Filtration is done prior to UV so unclear if this would reduce UV energy. Potential to model the current EDI's using CFD to see what benefit replacing them would have.
LS11	Reduce number of units in service	5	3	4	2	3	3	3	3.29	0.50	-0.13	Yes	Jeff noted this is already in progress.
LS12	Change to more energy efficient diffusers.	3	2	4	3	4	5	3	3.43	0.00	0.38	Yes	
LS13	Upgrade to more efficient blowers	3	3	4	4	3	3	3	3.29	0.17	0.13	Yes	
LS14	Green power ramp	4	4	4	3	3	3	2	3.29	0.50	-0.13	No	
LS15	Jockey blower	3	4	4	5	3	4	2	3.57	0.33	0.25	Yes	
LS16	Preaeration blowers	2	3	4	3	4	3	3	3.14	0.00	0.13	Yes	
Wastewater Pumping													
LS17	Remaining Influent pumps and motor VFDs	2	3	4	3	3	3	3	3.00	0.00	0.00	Yes	
LS18	Install VFDs	4	3	4	3	3	4	3	3.43	0.33	0.13	Yes	Most equipment currently has VFDs except for the Digesters and a few other areas.
LS19	Basin 4 effluent pumping motor VFD	3	3	4	3	3	3	3	3.14	0.17	0.00	Yes	

Table 2D.2 **Biosolids Opportunities Scores**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		14%	14%	14%	14%	14%	14%	14%					
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
Primary Sludge & Secondary Sludge													
BS1	Replace Primary Sludge Pumps VFDs	4	3	4	3	4	3	2	3.29	0.33	0.00	Yes	Recommend carrying forward if VFDs have yet to be replaced. This is a cheap and easy solution with a slight energy reduction benefit.
Digestion Pretreatment, Digestion Enhancements, Thickening, Dewatering, and Post-Dewatering Processing													
BS2	Alternative WAS and PS Thickening Technology to DAF (combined or separate)	1	2	2	3	4	3	3	2.57	-0.67	0.13	Yes	Recommend carrying forward as a digestion capacity expansion option to allow for increased co-digestion. Pre-thickening is a simpler retrofit than recuperative thickening.
BS3	Class A High Temp Thermal Hydrolysis	1	1	1	4	5	2	2	2.29	-1.00	0.13	No	Recommend eliminating due to high cost and complexity. From recent Carollo biosolids alternatives analyses, Cambi is the most expensive option for increasing digestion capacity, compared to improved thickening, recuperative thickening, or digestion expansion. This process typically does not make financial sense for facilities less than 50 mgd that are not capacity or footprint limited and do not have a strong driver for Class A.
BS4	Class B High Temp Thermal Hydrolysis	1	1	1	3	5	2	2	2.14	-1.00	0.00	No	Recommend eliminating due to high cost and complexity.
BS5	Class B Thermo-chemical hydrolysis	2	2	3	3	5	2	3	2.86	-0.33	0.13	No	Could be considered as a simple option to slightly increase VSR and biogas production.
BS6	Class B (or Class A) Biological Hydrolysis	1	1	2	4	5	2	3	2.57	-0.83	0.25	No	Recommend eliminating due to high cost and complexity.
BS7	Recuperative Thickening	1	2	2	3	5	2	3	2.57	-0.67	0.13	Yes	Recommend carrying forward as a digestion capacity expansion option to allow for increased co-digestion.
BS8	Thermophilic Digestion for Class A Biosolids	2	3	3	2	5	2	3	2.86	-0.17	0.00	No	Recommend eliminating because, unlike other options (thickening, recuperative thickening, acid-phase digestion), it does not increase digestion capacity and the VSR/biogas benefits are not well proven. Additionally, there is no strong driver for Class A in California.
BS9	Acid Phase Digestion	1	1	2	3	5	2	3	2.43	-0.83	0.13	No	Could be considered as a simple option to slightly increase digestion capacity as well as VSR and biogas production.
BS10	Low Energy Digester Mixing	2	3	4	3	4	4	2	3.14	0.00	0.13	No	
BS11	Replace digester sludge pumps	4	3	4	3	3	3	2	3.14	0.33	-0.13	No	The existing pumps are relatively new and commonly used for this application. Energy efficiency on the chopper pumps is decent and has improved with newer models.

Table 2D.2 **Biosolids Opportunities Scores (continued)**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		14%	14%	14%	14%	14%	14%	14%					
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
BS12	Implement Dewatering post FSL	1	2	1	4	2	5	2	2.43	-0.83	0.13	No	Recommend eliminating and evaluating post-digestion dewatering instead.
BS13	Implement Dewatering post digestion	1	1	1	4	5	5	2	2.71	-1.00	0.50	Yes	Recommend carrying forward due to substantial GHG benefits of biosolids land application (carbon sequestration and fertilizer offset). Cake trucking GHG emissions are typically negligible. This option would also benefit from elimination of the FSLs and DLDs.
BS14	Air Drying	1	1	1	2	2	5	2	2.00	-1.00	-0.13	No	Not recommended as it does not provide any additional energy or GHG benefits over dewatering and cake land application.
BS15	Solar Drying	1	1	1	4	2	5	2	2.29	-1.00	0.13	No	Not recommended as it does not provide any additional energy or GHG benefits over dewatering and cake land application.
BS16	Low Temperature Thermal Drying (Belt Drying)	1	2	1	4	2	1	1	1.71	-0.83	-0.50	No	Not recommended as it does not provide any additional energy or GHG benefits over dewatering and cake land application.
BS17	Drying + Pyrolysis	1	2	1	4	2	2	2	2.00	-0.83	-0.25	Yes	This is likely the most expensive and complex biosolids treatment process listed. The only reason it will be considered is if future PFAS regulations require it and PFAS becomes a potential issue down the road for land-applied biosolids. Included for this reason per DSRSD's request.
BS18	Drying + Gasification	1	2	1	4	2	2	2	2.00	-0.83	-0.25	Yes	This is likely the most expensive and complex biosolids treatment process listed. The only reason it will be considered is if future PFAS regulations require it and PFAS becomes a potential issue down the road for land-applied biosolids. Included for this reason per DSRSD's request.
BS19	Incineration with Energy Recovery	1	1	1	1	2	1	2	1.29	-1.00	-0.75	No	Not recommended as it is nearly impossible to permit new incinerators in California, incineration would not be recommended for this small of a plant, and the energy benefits are lower compared to other thermal processes like gasification and pyrolysis.
BS20	Class A with Onsite Composting	1	1	1	4	5	5	2	2.71	-1.00	0.50	No	Not recommended as it does not provide any additional energy or GHG benefits over dewatering and cake land application.
BS21	Class A with Offsite Composting	1	1	1	4	5	5	2	2.71	-1.00	0.50	No	Not recommended as it does not provide any additional energy or GHG benefits over dewatering and cake land application.
BS22	Lystek Thermo-Chemical Hydrolysis	2	1	1	4	5	5	3	3.00	-0.83	0.63	Yes	Recommend carrying forward due to substantial GHG benefits of biosolids land application (carbon sequestration and fertilizer offset). Cake trucking GHG emissions are typically negligible. Lystek injects their product which further reduces GHG emissions.

Table 2D.2 **Biosolids Opportunities Scores (continued)**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		14%	14%	14%	14%	14%	14%	14%					
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
Codigestion													
BS23	Co-Digest Fats, Oils, Grease (FOG) (All Digesters)	2	1	2	5	5	5	5	3.57	-0.67	1.00	Yes	Related to start up of the existing FOG station.
BS24	Co-Digest Food Waste Slurry/HSW (All Digesters)	1	1	2	5	5	5	5	3.43	-0.83	1.00	Yes	Recommend evaluating due to the substantial energy and GHG benefits of co-digestion.
BS25	Co-Digest Food Waste Slurry from Solid Waste (Some Digesters)	1	1	2	5	3	5	5	3.14	-0.83	0.75	No	Not recommended because separate digestion will most likely not be needed. Latest discussions with EPA indicate they will resolve the RIN categorization issue by establishing a baseline biogas production from sludge, which receives the cellulosic (higher value) RIN categorization and any additional biogas would be assumed to be from co-digestion and receive the advanced (lower value) RIN credit.
Biogas													
BS26	Improve gas conditioning system throughput and replace aging equipment	4	3	4	4	3	3	3	3.43	0.33	0.13	Yes	May already be in design.
BS27	Biological sulfur removal	3	4	4	3	3	3	2	3.14	0.33	-0.13	No	Not recommended because this will not provide a major energy nor GHG benefit.
BS28	Increase biogas storage	3	3	4	5	2	4	3	3.43	0.17	0.25	Yes	Suggest carrying forward due to benefits to cogen operation reliability and reduction of peak charges.
BS29	Fuel Skid Gas Compressor Motor	3	4	4	4	4	3	2	3.43	0.33	0.13	No	Recommend carrying forward. This is a cheap an easy solution with a small energy use reduction benefit.
BS30	Status Quo Operation (Cogen Engines; Boilers) with replacement of aging equipment	4	3	4	3	2	3	2	3.00	0.33	-0.25	Yes	DSRSD is interested in this option.
BS31	Replace cogen with new higher efficiency engine generators	2	3	3	5	5	5	3	3.71	-0.17	0.75	Yes	Addresses aging infrastructure concerns. Suggest evaluating as baseline biogas use alternative.
BS32	Replace cogen with microturbines	2	3	4	5	5	3	2	3.43	0.00	0.38	No	No efficiency benefits. Definitely eliminate.

Table 2D.2 **Biosolids Opportunities Scores (continued)**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		14%	14%	14%	14%	14%	14%	14%					
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
BS33	Replace cogen with fuel cell	1	3	3	5	5	5	4	3.71	-0.33	0.88	No	Addesses aging infrastructure concerns and provides maximum electrical efficiency. However, capital and O&M costs are typically much higher compared to engines. Consider eliminating except if District wants to include.
BS34	Upgrade cogeneration to handle all WWTP electricity needs (microgrid)	1	3	3	5	5	5	3	3.57	-0.33	0.75	Yes	Relevant as it increases independence from PG&E.
BS35	Increase Cogen Capacity and number of units to avoid peak demand charges during downtime, and for unit redundancy	1	3	3	5	5	5	3	3.57	-0.33	0.75	Yes	Not recommended because biogas storage is a less expensive solution for reliability and reducing peak charges than a redundant engine.
BS36	Condition biogas for use as vehicle fuel	2	4	3	5	5	5	2	3.71	0.00	0.63	No	No DSRSD interest
BS37	Condition biogas for pipeline injection	2	4	3	5	5	5	2	3.71	0.00	0.63	Yes	Addresses aging infrastructure concerns because it replaces cogen. Based on recent Carollo biogas use alternatives analyses, RNG options have the potential for substantial financial and GHG benefits. Suggest carrying forward.
BS38	Gas-to-liquid processes	2	2	1	4	4	4	4	2.43	-0.67	0.50	No	Converts biogas to LNG for the use as biofuel. Assumes more biogas capacity would be provided.

Table 2D.3 **Potable Water Distribution Opportunities Scores**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
Pumping													
PWD1	Optimize fire storage boundary conditions	5	3	3	4	4	3	2	3.14	0.33	0.13	No	Some DSRSD staff are concerned that the District is not maintaining required fire storage.
PWD2	Assess pump condition	3	4	4	5	4	4	2	3.43	0.33	0.38	Yes	Conduct analysis to identify damaged pumps.
PWD3	Assess pump design point	3	4	4	4	4	4	2	3.29	0.33	0.25	Yes	Conduct analysis to identify improperly sized pumps.
PWD4	Leak detection	3	2	2	4	4	3	2	2.57	-0.33	0.13	No	
PWD5	Time of use pumping	5	4	3	2	3	3	2	2.86	0.50	-0.25	Yes	Carry forward to analyze feasibility.
PWD6	Enhance turnover in reservoirs	3	3	4	4	3	3	2	2.86	0.17	0.00	No	
PWD7	Nitrification inhibition in water tanks	2	2	2	4	2	2	2	2.00	-0.50	-0.25	No	Maintaining chloramine residual would likely be much more cost effective.
PWD8	Onsite hypochlorite generation	3	3	3	4	4	3	2	2.86	0.00	0.13	No	

Table 2D.4 **Buildings, HVAC, Lighting Opportunities Scores**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		14%	14%	14%	14%	14%	14%	14%					
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
		5	5	**5**	5	5	**5**	**5**	5.00	1.00	1.00		
		1	1	**1**	1	1	**1**	**1**	1.00	-1.00	-1.00		
Adjustments													
BLG1	Occupancy-Based HVAC & Lighting	4	4	2	3	4	3	2	2.86	0.17	0.00	No	Would not provide much benefits for energy consumption or GHG emissions.
BLG2	Adjust Lighting/Temperature Schedules	5	4	2	3	3	3	2	2.86	0.33	-0.13	Yes	Would not provide much benefits for energy consumption or GHG emissions.
BLG3	Adjust Ventilation Schedules	5	4	4	3	3	3	2	3.14	0.67	-0.13	No	Allowable option per NFPA 20.
BLG4	Reduced Grounds Lighting at Night	5	4	4	3	3	3	2	3.14	0.67	-0.13	Yes	Included based on concerns from operations staff.
BLG5	Tree shading	5	3	4	3	3	3	2	3.00	0.50	-0.13	No	Would not provide much benefits for energy consumption or GHG emissions.
BLG6	Allow Continued/More Remote Work / Tele communiting	5	4	4	1	3	3	2	2.86	0.67	-0.38	No	Would not provide much benefits for energy consumption or GHG emissions. Energy savings may be small since building systems stay on even with reduced staffing levels on-site.
Component Replacements													
BLG7	Metal Building Insulation	3	4	4	4	3	3	3	3.00	0.33	0.13	Yes	
BLG8	Screen Room Air Handling Unit	4	4	4	4	4	3	3	3.29	0.50	0.25	Yes	Analyze if HVAC operates at its best efficiency and if VFD installation would be beneficial. Could potentially be completed by an HVAC vendor.
BLG9	Building A and C Air Handling Unit 2	4	4	4	4	3	3	3	3.14	0.50	0.13	Yes	
BLG10	Bar Screen Building Exhaust Fan Motor	4	4	4	4	3	3	3	3.14	0.50	0.13	Yes	
New Systems													
BLG11	HVAC Energy Recovery	3	4	4	3	4	3	2	3.00	0.33	0.00	Yes	Typically most efficient in headworks, sludge pump stations, solids handling buildings, and most buildings not normally occupied with high ventilation., except where process solids begin to remove.
BLG12	Solar Thermal Heating	3	4	2	3	4	3	3	2.71	0.00	0.13	Yes	
BLG13	Wastewater Thermal Energy Use for onsite Building heating and cooling.	2	4	3	3	4	3	3	2.71	0.00	0.13	Yes	
BLG14	Refridgerant HVAC system.	2	4	4	3	4	3	2	2.86	0.17	0.00	Yes	
BLG15	Fan addition	4	4	4	3	3	3	2	3.00	0.50	-0.13	Yes	Decouple air movement from HVAC systems through the addition of fans when HVAC is not needed, electrical rooms could be considered as an example.

Table 2D.5 **Renewable Energy Opportunities Scores**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
Renewable Energy Production													
RE1	Solar installation on-site at WWTP.	4	3	2	3	3	3	3	2.57	0.00	0.00	Yes	The 2017 Master Plan identifies potential areas at the WWTP for solar installation that equate to roughly 2.3 acres of solar panel area. Holding basin requirements are estimated to be roughly 1.7 acres of the 2.3 acres required.
RE2	Solar field offsite	3	3	2	3	3	5	5	2.71	-0.17	0.50	Yes	Is this property large enough for solar and battery storage? Would this exclude other potentially important uses in future?
RE3	Solar field at DLD's	3	3	2	1	3	5	5	2.43	-0.17	0.25	Yes	The 2017 Master Plan estimates area for solar installation on portion of DLDs at about 25.7 acres. For this purpose, the assumed area of solar cells is limited to 5 acres.
RE4	Electric vehicle fleet recharged using solar power	4	3	2	3	3	2	3	2.43	0.00	-0.13	Yes	Estimate assumes the following: 1) The support of a unit of five electric vehicles will be needed. 2) Installation of one electric charging station per electric vehicle at the WWTP will be required. 3) Total installation cost for each vehicle charging station equals $8,000. 4) 60 kWh would equate to approximately 200 miles. 5) An average VMT per vehicle of 2,200 miles per year will be reasonable, which would require approximately 3,300 kWh of electricity for five EV passenger vehicles per year.
RE5	Wind energy	3	3	2	3	3	5	5	2.71	-0.17	0.50	Yes	Construct wind turbines on-site at DSRSD or consider purchasing off-site renewable energy farms through PG&E or others instead.
RE6	Hydroelectric generation	2	4	2	3	3	4	4	2.57	-0.17	0.25	No	For each 1 mgd increase and 3 ft elevation decrease, estimate is nearly 0.4 kW or 3700 kWh/acre.
RE7	Renewable generation partnerships	3	3	2	3	3	5	3	2.71	-0.17	0.25	Yes	Focus on the pump stations with high electrical demand, such as pump stations 20B or 200A which exceed 700,000 kWh/acre. Pump stations 300B or 20A, which exceed 400,000 kWh/acre are also viable candidates. Recycle Water Pump Stations use less demand, such as pump station R200B which has the highest demand at 274,000 kWh/acre.
RE8	Purchase green power	5	3	4	3	3	5	4	3.29	0.50	0.38	Yes	DSRSD paid ¢15 on average in 2021 for solar power from the Community Choice Aggregation. Consider purchasing additional power from CCA or PG&E.
RE9	Onsite hydroelectric generation	2	3	2	5	3	4	4	2.71	-0.33	0.50	No	For each 1 mgd increase and 3 ft elevation decrease, estimate is nearly 0.4 kW or 3700 kWh/acre.

Table 2D.5 **Renewable Energy Opportunities Scores (continued)**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
Energy Storage													
ES1	Battery storage and microgrid	2	4	2	3	5	3	2	2.71	-0.15	0.13	Yes	A microgrid is a localized energy grid with multiple energy sources that can operate if connected or disconnected from the traditional electrical grid provided by PG&E. Energy feed to microgrid would consist of solar, cogen, or PG&E. Currently, there are two 250 kW lithium-ion batteries assumed for storage. This should be revisited if the option is carried forward to be properly sized for DSRSD. Install microgrid systems and controls to reduce reliance on external electricity, such as batteries, cogeneration, wind, or
ES2	Battery storage for equipment / processes driving peak demand charges	2	4	2	3	5	3	2	2.71	-0.15	0.15	Yes	PSR1 used about 2,200 MWh per year in 2021. Option requires analysis of battery storage capacity for peak demand buffering.
Thermal Energy Recovery													
TH1	Recovery thermal energy from influent/effluent (i.e., heat pump).	2	4	4	5	4	4	4	3.29	0.17	0.63	Yes	Commercial systems available from SHARC or Huber. Recover thermal energy from effluent for new heat loads from solids processing. Each of these building uses about 2,000 to 7,000 therms per year.
TH2	Capture heat from collection system to sell to larger commercial buildings in service area (e.g. new Costco)	5	5	4	3	3	4	4	3.43	0.83	0.25	Yes	Commercial systems available from SHARC or Huber. Recover thermal energy from effluent for new heat loads from solids processing.
TH3	Install Organic Rankine Cycle (or similar)	3	4	2	3	3	4	3	2.71	0.00	0.13	No	
TH4	Expand heat loop	2	4	4	5	4	4	4	3.29	0.17	0.63	Yes	
TH5	Use steam	2	2	3	4	3	3	4	2.43	-0.33	0.25	No	
TH6	Use Heat for More Process Needs	2	3	3	5	3	3	3	2.71	-0.17	0.25	Yes	
TH7	Use for advanced biosolids processing	2	3	3	4	4	4	2	2.86	-0.17	0.25	Yes	Recommend moving forward if those processes are moving forward as well.

Table 2D.6 **District-Wide Opportunities Scores**

Option ID	Option Name	Quantitative Criteria Evaluations (Ranked 1-5)							Weighted Overall Score	Normalized Implementation Score (-1 to +1)	Normalized Impact Score (-1 to +1)	Evaluation Result	Rationale for Recommendation
		Implementation Criteria			Impact Criteria								
		14%	14%	14%	14%	14%	14%	14%					
		Capital Costs	Operational Costs	Impact on Staffing Resources	Operational of Regulatory Reliability or Flexibility	Infrastructure Resilience or Ability to Address Aging or Capacity Limiting Infrastructure	Energy Demand Reduction or Greenhouse Gas Emissions Reduction	Energy Independence & the Generation and Use of Renewable Energy					
		5	5	**5**	5	5	**5**	**5**	5.00	0.38	1.00		
		1	1	**1**	1	1	**1**	**1**	1.00	-1.13	-1.00		
Advanced Controls													
AC1	Alternative power monitoring than Foreseer	5	4	1	4	3	3	2	3.14	0.17	0.00	Yes	
AC2	Artificial Intelligence	4	4	1	5	3	4	2	3.29	0.00	0.25	Yes	
AC3	Pump diagnostics	4	3	5	4	4	3	2	3.57	0.50	0.13	Yes	This option would provide a negligible impact.
AC4	Energy decision management tools	4	4	2	3	3	4	2	3.14	0.17	0.00	Yes	
AC5	Load Bank	4	3	3	4	4	3	2	3.29	0.17	0.13	Yes	This will go into the CIP since it is part of the Electrical Master Plan but is not energy related.
Supporting Appurtenances													
SA1	ORT effluent supply Pump 2 motor	4	4	4	4	3	3	3	3.57	0.50	0.13	Yes	
SA2	HRS Primary Loop Pump 1 and 2	4	4	4	4	3	3	2	3.43	0.50	0.00	Yes	
SA3	Water Conservation and I&I reduction	1	4	1	5	5	4	2	3.14	-0.50	0.50	Yes	
SA4	replace current odor control technology (1 biotower, 2 biofilters) with more energy efficient process.	2	3	4	3	2	3	2	2.71	0.00	-0.25	No	
SA5	Low maintenance landscaping	5	3	5	3	3	3	2	3.43	0.67	-0.13	No	

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Appendix 2E

LIST OF ENERGY ALTERNATIVES SELECTED FOR FURTHER EVALUATION

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Table 2E.1 List of Selected Alternatives for Further Evaluation in Phase 2

Option ID	Energy Opportunity
1. Projects relevant in longer than 5-10 years = 2	
LS3	Improve carbon diversion from primaries to digester (CEPT)
RE3	Solar field at DLDs
2. Flexibility for future regulations = 3	
BS17	Drying + Pyrolysis
BS18	Drying + Gasification
TH6	Use for advanced biosolids processing
3. Recommended for detailed evaluation by Carollo = 46	
LS5	Real time SRT control
LS6	Model predictive aeration control
LS7	Low DO operation
LS12	Change to more energy efficient diffusers
LS13	Upgrade to more efficient blowers
LS15	Jockey blower
LS16	Preaeration blowers
LS18	Install VFDs
BS2	Alternative Waste Activated Sludge and Primary Sludge Thickening Technology to Dissolved Air Flotation (combined or separate)
BS7	Recuperative thickening
BS13	Implement dewatering post digestion
BS22	Lystek Thermo-Chemical Hydrolysis
BS23	Co-Digest FOG (All Digesters)
BS24	Co-Digest Food Waste Slurry/HSW (All Digesters)
BS28	Increase biogas storage
BS30	Status quo operation (cogen engines; boilers) with replacement of aging equipment
BS31	Replace cogen with new higher efficiency engine generators
BS34	Upgrade cogeneration to handle all WWTP electricity needs (microgrid)
BS35	Increase cogen capacity and number of units to avoid peak demand charges during downtime, and for unit redundancy
BS37	Condition biogas for pipeline injection
PWD2	Assess pump condition for distribution system and DSRSD's recycled water distribution system
PWD3	Assess pump design point for distribution system and DSRSD's recycled water distribution system
PWD5	Time of use pumping for distribution system and DSRSD's recycled water distribution system
BLG7	Metal building insulation
BLG10	Bar screen building exhaust fan motor
BLG11	HVAC energy recovery
BLG12	Solar thermal heating
BLG13	Wastewater thermal energy use for onsite building heating and cooling
BLG14	Refrigerant HVAC system

Option ID	Energy Opportunity
BLG15	Fan addition
RE1	Solar installation on-site at WWTP
RE2	Solar field offsite
RE4	Electric vehicle fleet recharged using solar power
RE5	Wind energy
RE7	Renewable generation partnerships
RE8	Purchase green power
ES1	Battery storage and microgrid
ES2	Battery storage for equipment / processes driving peak demand charges
TH1	Recovery thermal energy from influent/effluent (i.e., heat pump)
TH2	Capture heat from collection system to sell to larger commercial buildings in service area (e.g. new Costco)
TH3	Install ORT (or similar)
TH5	Use heat for more process needs
AC1	Alternative power monitoring than Foreseer
AC2	Artificial intelligence
AC4	Energy decision management tools
AC5	Load bank
4. No detailed evaluation needed. Carollo to include year and budget for CIP = 9	
LS9	Take AB out of service
LS11	Reduce number of units in service
BLG2	Adjust lighting / temperature schedules
BLG4	Reduced grounds lighting at night
BLG8	Screen room air handling unit
BLG9	Building A and C air handling unit 2
SA1	ORT effluent supply Pump 2 motor
SA2	HRS primary loop Pump 1 and 2
SA3	Water conservation and I&I reduction
5. Projects already in progress. No further evaluation needed = 6	
LS8	RAS pump 4 VFD
LS17	Remaining Influent pumps and motor VFDs
LS19	Basin 4 effluent pumping motor VFD
BS1	Replace primary sludge pumps VFDs
BS26	Improve gas conditioning system throughput and replace aging equipment
AC3	Pump diagnostics
	Total Number of Alternatives = 66

Dublin San Ramon Services District
Water, wastewater, recycled water

Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 3
STATE OF THE ASSETS REVIEW: WASTEWATER TREATMENT PLANT

FINAL | June 2024

carollo

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Abbreviations

AMF	asset management framework
Carollo	Carollo Engineers
CIP	capital improvement program
CMMS	computer maintenance management system
DAFT	dissolved air floatation thickener
DERWA	Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority
DSRSD	Dublin San Ramon Services District
EUL	estimated useful life
EPS	effluent pump station
evRUL	evaluated remaining useful life
FOD	field operations division
FSL	facultative sludge lagoon
HB	holding basin
hp	horsepower
HVAC	heating, ventilation, and air conditioning
kW	kilowatt
LAVWMA	Livermore-Amador Valley Water Management Authority
LED	light emitting diode
MCC	motor control center
O&M	operations and maintenance
POF	probability of failure
RAS	return activated sludge
RUL	remaining useful life
TM	technical memorandum
VFD	variable frequency drive
WAS	waste activated sludge
WWTP	wastewater treatment plant

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Technical Memorandum 3

STATE OF THE ASSETS REVIEW: WASTEWATER TREATMENT PLANT

3.1 Introduction

This technical memorandum (TM) reviews the current state of the energy-related assets located at the Dublin San Ramon Services District's (DSRSD) wastewater treatment plant (WWTP) and evaluates this facility's overall energy production and consumption. This effort includes reviewing assets in DSRSD's database prior to gathering asset information in the field to determine remaining useful life (RUL), energy capacity and consumption, and asset replacement costs. This TM specifically reviews all electrical and mechanical assets that either contribute or consume energy. Only assets in the DSRSD WWTP were assessed. All equipment and facilities associated with the Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority (DERWA) and Livermore-Amador Valley Water Management Authority (LAVWMA) were excluded from this evaluation. The evaluation consisted of the following steps:

- Reviewed and summarized data provided by DSRSD to check for consistency and inclusion of necessary data to perform the assessment recommended under industry best management practices.
- Following the data review, the project team reviewed specific assets at the WWTP to gather information that was missing from the provided data and assessed the condition of electrical and mechanical equipment that is 5 horsepower (hp) or larger.
- Meetings were held with DSRSD staff including asset management lead, operations, and maintenance staff to discuss current status of assets and operational performance and reliability concerns.

Once the necessary information for all assets was gathered, the state of the assets analysis was performed by assessing the RUL, energy capacity and demands, rehabilitation and replacement timing associated with probability of failure, and overall cost for each asset. This TM supports Question 1 of the Core Management Questions represented in Figure 3.1.

Figure 3.1 Asset Management Framework (AMF) Core Management Questions

3.2 Background

As part of this effort, Carollo Engineers (Carollo) documented the WWTP mechanical and electrical assets, identified the parent-child relationship of those assets, and assessed their current conditions. The resulting condition assessment conclusions have been used to determine their respective asset replacement timing. The probability of failure (POF) scores represent the condition-based score or the age-based score for the assets (if the former was otherwise unavailable).

A layout of the WWTP facilities with the approximate year of original construction is shown on Figure 3.2. The following sections detail the AMF components as they apply to these facilities.

3.2.1 Asset Management Framework

The AMF represents the data, analyses, and documentation that supports decisions for allocating resources to mitigate risk and optimize the life-cycle cost of managing DSRSD's systems of assets. The "Five Core Asset Management Questions," which are shown in Figure 3.1, represent the foundation of the AMF; responses to these questions help asset managers select the best processes and practices for the assets that they are responsible for maintaining.

3.2.1.1 Asset Definition

For DSRSD, assets are defined as those items that have a purchase or replacement cost of at least $5,000, in addition to either: 1) a minimum expected useful life of two years or more; or 2) being critical to the system that it supports and as such assigned preventative maintenance.

The electrical and mechanical assets that were evaluated under this scope are located at the WWTP and have a motor nameplate rating of 5 hp or more.

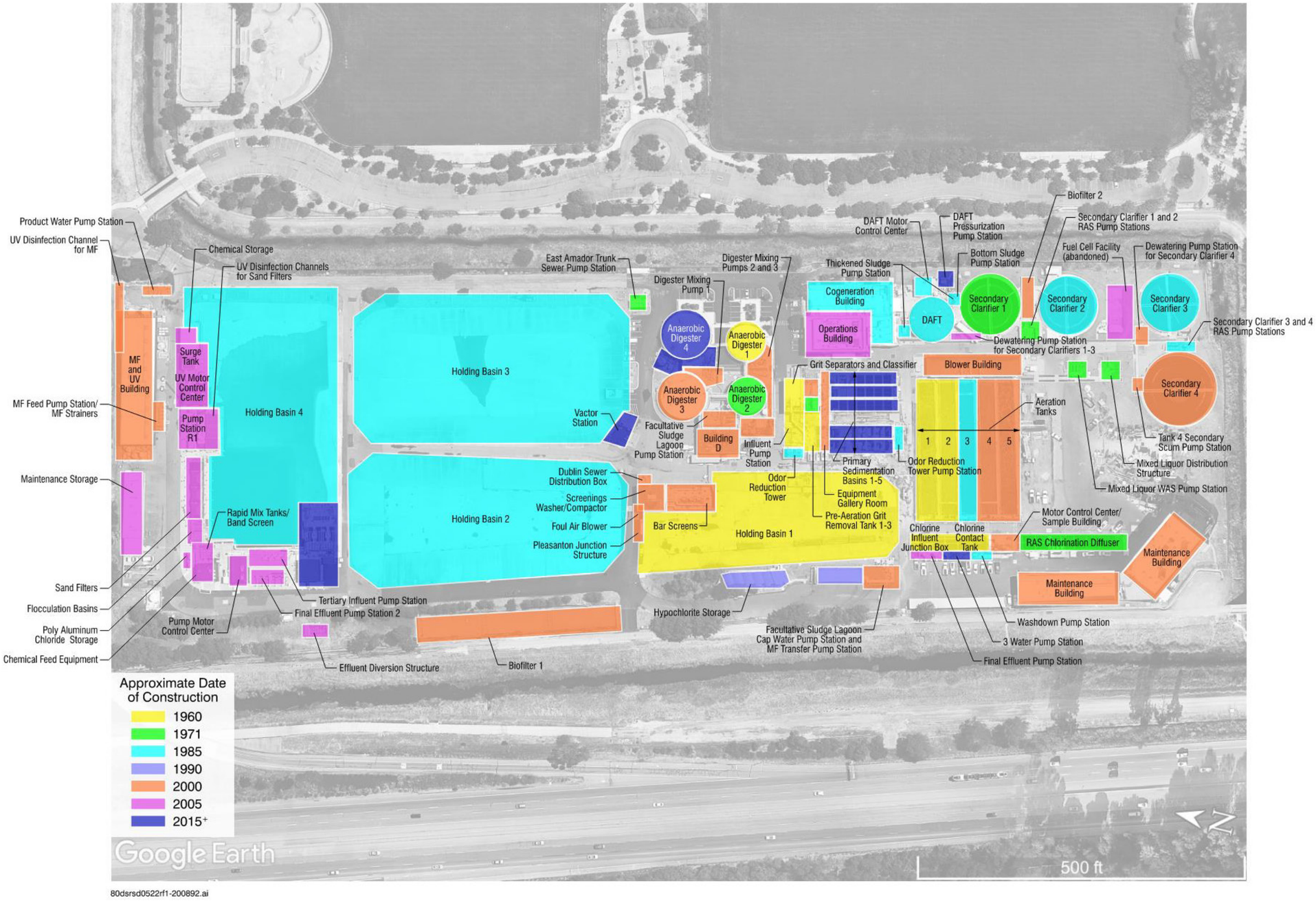

Figure 3.2 DSRSD WWTP Age of Existing Facilities

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3.2.1.2 Asset Register

The asset register serves as the data framework supporting asset management implementation (and the related assessment of asset condition). The asset register is a database of assets and their attributes.

Data for the WWTP was exported from CentralSquare, DSRSD's computer maintenance management system (CMMS), and imported into the asset register template developed for the AMF. Assets not included in the export were manually added using DSRSD's CentralSquare asset hierarchy and location protocol as they were discovered in the field. The assets were matched to asset types and hierarchy designations based on available information. The complete list of asset types evaluated is presented in Appendix 3C.

3.2.1.3 Asset Hierarchy

The assets are organized by treatment process into an asset hierarchy. The hierarchy is a visual representation of the parent-child relationship for each WWTP process, sub-process, and asset type. There are 368 assets that were identified for evaluation. Figure 3.3 illustrates the hierarchy for the WWTP through level 2 (process or sub-system). Note, Figure 3.3 does not include any redundant level 2 processes; it is understood that these processes will be consolidated to maintain an organized database.

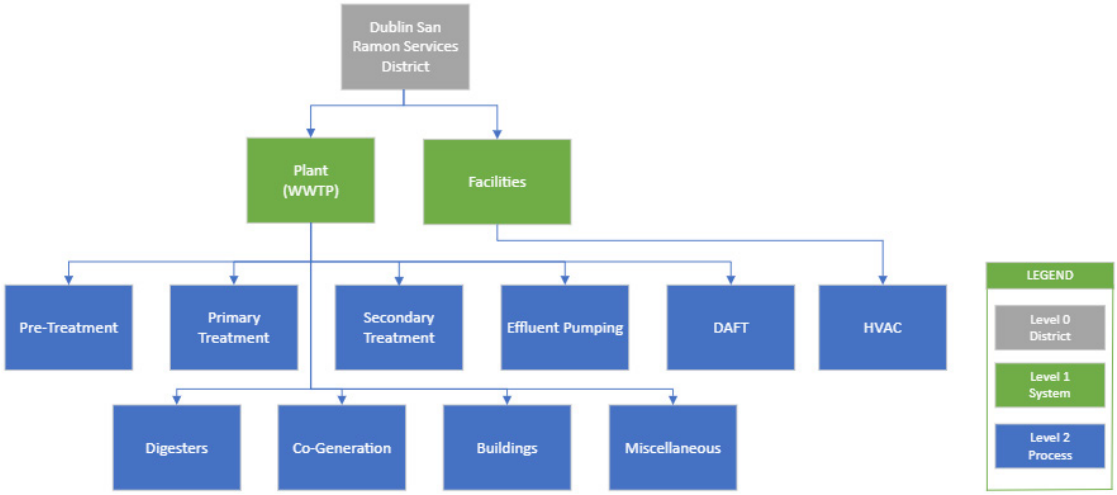

Figure 3.3 WWTP Asset Hierarchy

3.2.1.4 Estimated Useful Life (EUL) and Remaining Useful Life

The EUL of an asset is the reasonable time, in years, that an asset is expected to satisfactorily perform under normal and routine operations and maintenance (O&M) practices. The EUL is the starting point for understanding the current state of the assets. Using the EUL and the age of the asset, which is determined using equation 1, the RUL, represented in years, can then be calculated as shown in equation 2. In equation 1, the best available installation date (preferred) or the plant commissioning date is used.

Equation 1

$$Age\ (years) = Today's\ date - Installation\ date$$

Equation 2

$$RUL\ (years) = EUL - Age$$

Equation 3

$$\%\ Life\ Consumed = \left(1 - \frac{RUL}{EUL}\right) \times 100\%$$

3.2.1.5 Condition Rating System

For assets that have been evaluated in the field (i.e., through condition assessments, inspections, or other tests), a condition-based assessment score is used. The condition scoring (condition and performance) is based on a scale of one to five, as described in Table 3.1.

Table 3.1 General Condition Scores

Condition or POF Score	General Description	Percent Life Consumed
0	**Unknown/N/A**	-
1 (Best)	**Good:** Asset is in good condition (no defects).	0-39
2	**Acceptable:** Asset has minor defects.	40-64
3	**Fair:** Asset has significant defects that will affect reliability or efficiency.	65-79
4	**Poor:** Asset is highly unreliable or inefficient.	80-89
5 (Worst)	**Failed:** Asset is no longer able to function in its current condition.	90-100

The resulting condition scores are translated to a percent life consumed for the asset using the upper value of each range listed in Table 3.1. An evaluated remaining useful life estimate (evRUL), represented in years, is calculated using equation 4.

Equation 4

$$evRUL = \%\ Life\ Consumed\ \times EUL$$

The scores for performance, operations, and maintenance, obsolescence, and reliability are incorporated into an overall performance score that is compared with the condition score to establish the POF for calculating risk. The estimated life remaining information gathered from the assessment team is also compared with the projected replacement timing calculated from the POF results. Assets with significant differences between the estimated life remaining observations and the replacement timing results are noted for further review.

Section 3.4 contains more details on how the POF scores are calculated.

3.2.1.6 Asset Replacement Cost

The asset replacement cost was determined using general industry best management practices. As the CMMS database contains replacement costs that were approximately updated in 2019, asset costs were escalated to 2022 cost values using the Engineering News Record Construction Cost Index. The costs were then evaluated based on engineering judgment and adjusted based

on similar equipment from current construction cost estimates. Refer to Appendix 3D for the updated replacement cost of each asset.

3.3 Initial Data Review

This section summarizes the desktop data analysis completed prior to the field assessment.

3.3.1 Asset Review

Two datasets summarizing the assets were provided by DSRSD. The first dataset was an export from the CentralSquare CMMS, dated February 17, 2022, which cataloged DSRSD's assets along with information such as age, location, and energy demands, and POF. The second dataset is a spreadsheet that is used to plan the replacement or rehabilitation timing of assets along with associated costs. The spreadsheet is an output of DSRSD's asset replacement model. The assets included in both spreadsheets were compared using the unique equipment code assigned to each asset to identify gaps in the information needed to complete the State of the Assets analysis.

3.3.2 Summary of Findings

The majority of assets provided in the CMMS dataset were also included in the asset replacement model export dataset. A summary of the assets not included in the asset replacement model export is summarized in Appendix 3A. Note, all of the assets in the asset replacement model export dataset were included in the CMMS dataset.

3.4 Probability of Failure

The POF is the measure of likelihood that an asset will fail or degrade to a point where it is not meeting its required level of service. The AMF includes a POF scoring approach that is represented by the condition-based score, or the age-based score when not field-assessed. Figure 3.4 shows the difference and criteria needed to determine the age-based and condition-based POF scores, as described in the following subsections. Table 3.1 can be used to convert age-based percent life consumed data to a POF score and, vice versa, to calculate percent life consumed from a condition-based POF score to determine the evRUL.

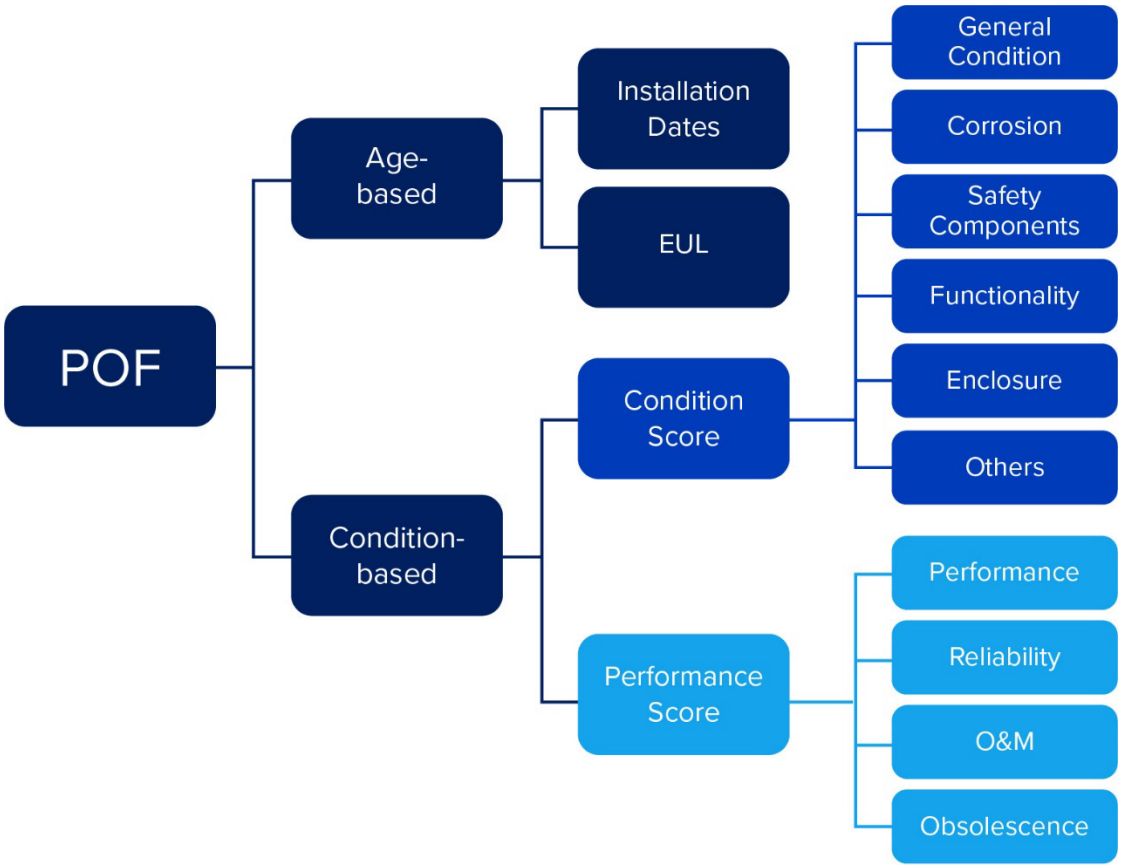

Figure 3.4 Difference between Age-Based POF and Condition-Based POF Scores

3.4.1 Age-Based Probability of Failure

Age-based POF scores were calculated for each asset not assessed in the field using the installation date and its EUL to calculate the POF score (i.e., the POF score is determined using equations 1 through 3, then the percent life consumed is translated to a POF score as shown in Table 3.1). As some assets do not have documented installation dates, the installation date for critical assets was estimated based on the known age of surrounding process equipment. These critical assets did not undergo assessment in the field and are listed along with their estimated installation dates in Appendix 3B. Verification of the assumed installation dates is recommended to further refine the POF scores.

The EUL estimates are defined by asset type and assigned to each asset according to the table provided in Appendix 3C. In this assessment, the EUL estimates from DSRSD's existing CMMS database were updated with recommended EUL estimates based on general industry best management practices. Appendix 3C lists both DSRSD's EUL values and the recommended EUL values, but only the recommended EUL estimates were used in this asset review. It should also be noted that several asset types were not given EUL values in the DSRD database and general EUL estimates of 25 years were assumed for the following: longitudinal collectors, miscellaneous mechanical equipment (e.g., Bar Screen Building Fluid Power System Accumulation Bank), scum skimmers, progressive cavity pumps, and "P-Pumps" (pumps that were not identified by specific type in the CMMS database, i.e., centrifugal, vertical turbine, etc.).

Overall, the condition-based POF evaluation method (field evaluation approach) provides a more representative assessment because of the nature of the POF score being based on visual observations of the asset, as well as feedback from staff on the asset performance. However, it is not always feasible to visually assess every asset; therefore, the age-based POF evaluation method (desktop evaluation approach) is useful in providing a generally conservative estimate for projecting asset replacement timing.

3.4.2 Condition Based Probability of Failure

For each asset, the maximum score from each discipline-specific condition and performance assessment was used to represent the overall POF score for the asset and was then translated to percent life consumed per Table 3.1. The criteria used to assess the assets' condition score and performance score is shown in Table 3.2 and Table 3.3, respectively; scores ranging from 1 (best) to 5 (worst) are assigned to the asset condition and performance criteria. Condition scores are based on Carollo field assessment, while performance scores are based on feedback from District O&M staff. In developing condition scores, Carollo inspected assets in the field and provided an evaluation of the asset's general condition, including but not limited to evidence of corrosion, an assessment of the asset's exterior condition, an assessment of the asset's operating condition - vibration, functionality, temperature, the condition of other appurtenances (piping, fasteners, connections, etc.) and safety components. In developing performance scores, Carollo interviewed DSRSD staff. From that discussion, a performance score was developed from 4 main criteria: performance, reliability, operations and maintenance and replacement obsolescence.

Table 3.2 Condition Score Criteria

Discipline	Asset Type	Criteria	
MECHANICAL	All	• General Condition • Corrosion • Exterior • Vibration • Functionality • Elements	• Temperature • Piping • Fasteners, Belts, Caps, Washers, etc. • Connection/Anchor Point
ELECTRICAL	All except motors	• General Condition • Deterioration • Wiring/Cable Condition • Enclosure	• Equipment • Functionality • Fasteners, Belts, Caps, Washers, etc. • Safety Components
ELECTRICAL	Motors	• General Condition • Deterioration • Wiring/Cable Condition • Enclosure • Equipment	• Functionality • Fasteners, Belts, Caps, Washers, etc. • Vibration • Temperature • Safety Components

Table 3.3 Performance Score Criteria

Discipline	Asset Type	Criteria
ALL	All	Performance
		Reliability
		O&M
		Obsolescence

The maximum of the condition score and performance score is used to determine the overall POF score for each asset as shown in equation 5.

Equation 5

$$POF_{(Condition-Based)} = Max(Condition\ score, Performance\ score)$$

Using the maximum score of the condition score and performance score to determine the condition-based POF (rather than the average), focuses attention on assets that might otherwise be overlooked due to averaging. This is important for identifying assets that have a high POF score and represent a high risk. In some cases, the cost to remedy an individual condition issue may be minor but could have a significant impact on risk reduction. As a rule of thumb, if condition and performance scores are not available, then an age-based POF score is used as the overall POF score.

3.4.3 Probability of Failure Results

A total of 368 assets at the WWTP were identified for evaluation. Of those assets, 287 (78 percent) were assessed in the field via visual inspection and 81 (22 percent) were assessed using the age-based method. As such, the inaccessible assets were given a POF score using the age-based method.

The distribution of POF scores of the assets at the WWTP using equation 5 is illustrated on Figure 3.5. This includes both age-based and condition-based POF methods.

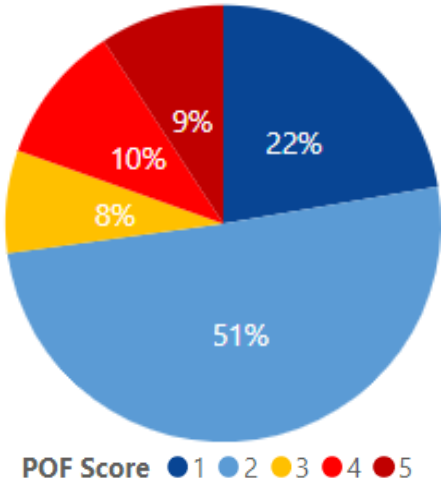

Figure 3.5 WWTP POF Scores

The percent of assets in each POF score, along with the average percent life consumed of the assets, presents the overall health of the system of assets. The results indicate that approximately 81 percent of the assets are in good, acceptable, or fair condition and approximately 19 percent of the assets are in poor or failing condition.

Figure 3.6 demonstrates the variability between the calculated age-based POF scores and field-assessed condition-based POF scores. Not all assets have a condition-based POF score since not all assets were accessible in the field during the condition assessment; thus, assets that were not evaluated in the field have an age-based POF score that relies on the documented date of installation. As noted earlier, assets without known installation dates were given approximate installation dates based on known install dates of surrounding process equipment (see Appendix 3B). Each asset is assigned at least one POF score (age-based or condition-based). Refer to Appendix 3D for the calculated age and condition-based scores of each asset.

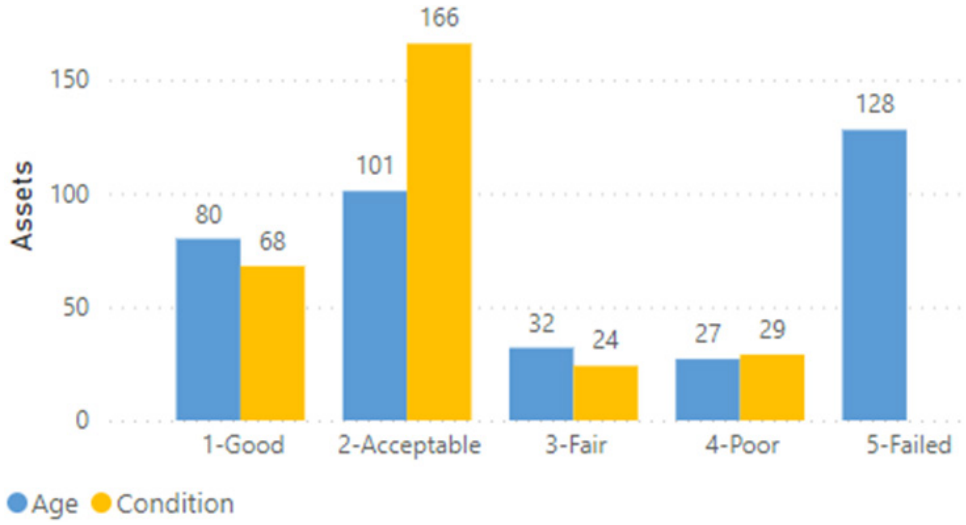

Figure 3.6 Condition- and Age-Based POF Score Comparison

Figure 3.6 shows that far more assets were assigned a condition score of two, compared to their age-based counterparts. This may be primarily due to inaccurate installation date information; the installation date provided from the CMMS data was used to calculate the age for each asset (unless more accurate information was provided). Additionally, assets replaced in the field may not have been reflected in the CMMS data. Observations from the field assessment indicate that these assets were installed or replaced more recently than the date represented in the CMMS database.

The age-based analysis will improve with more accurate asset installation (or replacement) dates updated in the CMMS database for future assessments. Additionally, observations from the field assessments can be used to update EUL values for asset classes or sub-classes to better represent the operating environment of the facility. For instance, if the field-evaluated conditions suggest that the EUL of a class of assets is longer (or shorter) than previously assigned, the EUL can be adjusted to "calibrate" the age-based results. Refer to Appendix 3C for recommended EUL values to incorporate into the CMMS database for future assessments.

Note, a limited number of assets were excluded from the POF analysis because they were not located, decommissioned, out of service for rehabilitation, or in the process of being refurbished or replaced at the time of the site visit. These assets are:

- Basin Return Pump 1.
- Basin Return Pump 1 Motor.
- Basin Return Pump 2.
- Basin Return Pump 2 Motor.

While a limited number of assets were out of service for rehabilitation at the time of the site visit, the following assets are included in the POF analysis based on successful rehabilitation and refurbishment per the District's feedback on December 12, 2022. These assets were analyzed by the age-based POF method with an updated RUL to reflect the rehabilitation effort.

- Digester 3 Mechanical Mixer 1.
- Digester 3 Mechanical Mixer 1 Motor.
- Digester 3 Mechanical Mixer 2.

- Digester 3 Mechanical Mixer 2 Motor.
- Digester 3 Mechanical Mixer 3.
- Digester 3 Mechanical Mixer 3 Motor.

3.5 State of the Assets

This section provides an overview of the findings from the field assessment.

3.5.1 Remaining Useful Life

The RUL is the expected number of years an asset can operate before requiring rehabilitation or replacement. The average percent life consumed of the 368 assets assessed as part of this study is 64 percent. This information is shown by discipline on Figure 3.7.

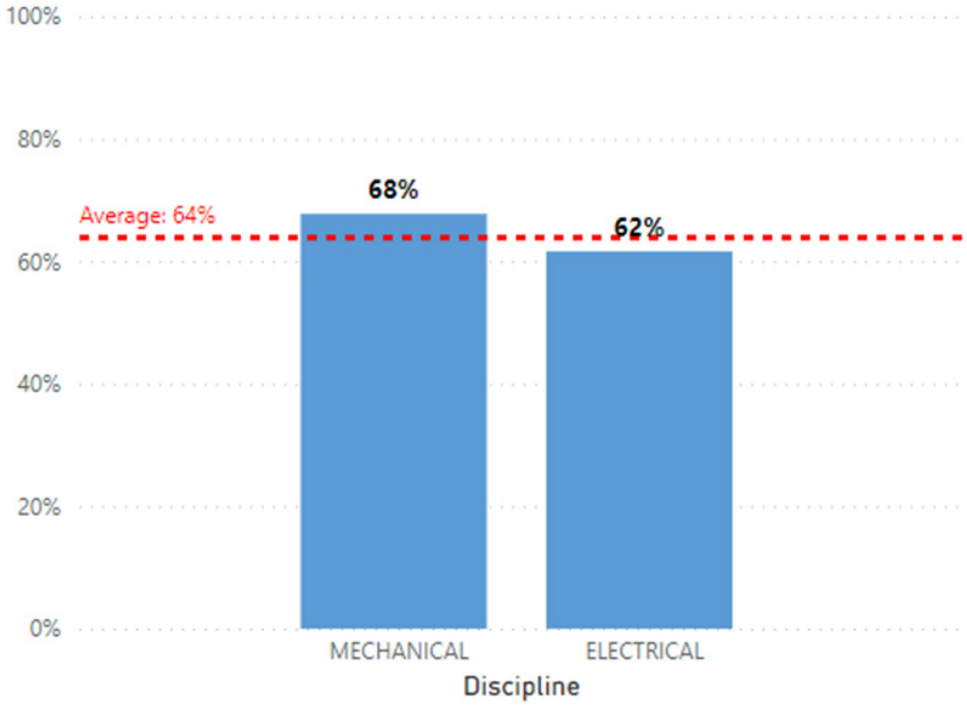

Figure 3.7 WWTP RUL Asset Categories

As illustrated in Figure 3.7, the percent life consumed is similar for both electrical and mechanical assets. Based on the field assessment, it is evident that DSRSD has done an excellent job of replacing or rehabilitating aged assets on a regular basis.

As illustrated in the replacement profile in Figure 3.8, approximately 9 percent are projected to need replacement in the next couple years, another 13 percent in the following five years (2025 to 2029), and another 10 percent requiring replacement in the subsequent 5 years (2030 to 2034). The most assets (32 percent) are projected for replacement between 2035 and 2039. Only one cycle of replacement is included for each asset.

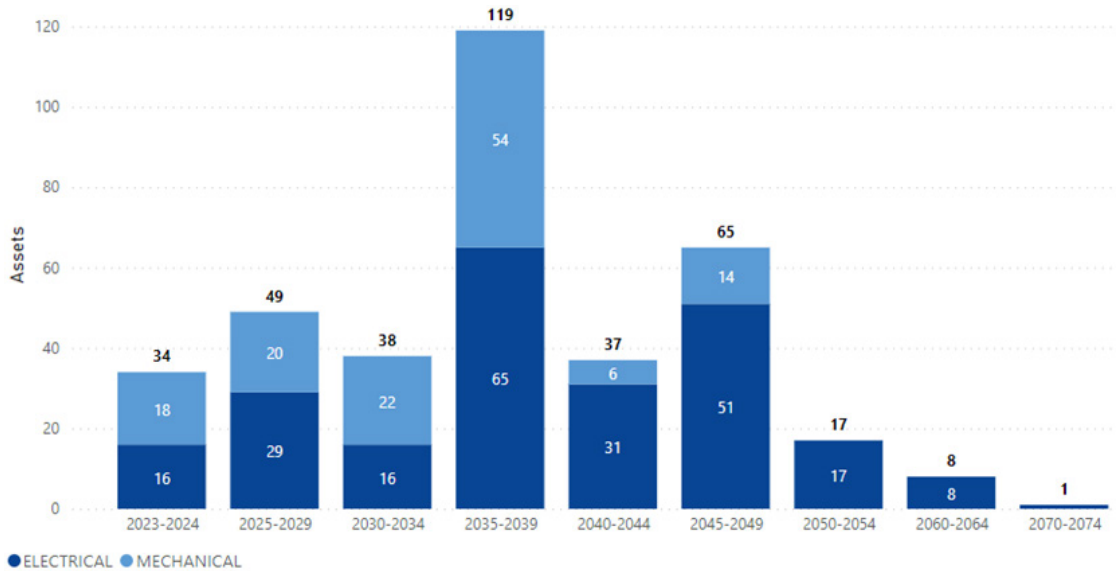

Figure 3.8 Replacement Profile

Using industry best practices, replacement costs were determined for each asset in terms of 2022 United States Dollars. See Section 3.2.1.6 for more information and refer to Appendix 3D for the detailed list of each asset, replacement year, and replacement cost.

3.5.2 Results by Discipline

The results of the condition assessment are further illustrated by discipline on Figure 3.9. Following the figure is a more detailed discussion of specific asset findings identified during the condition assessment by Carollo discipline leads, with the focus on assets that have a POF score of four or five.

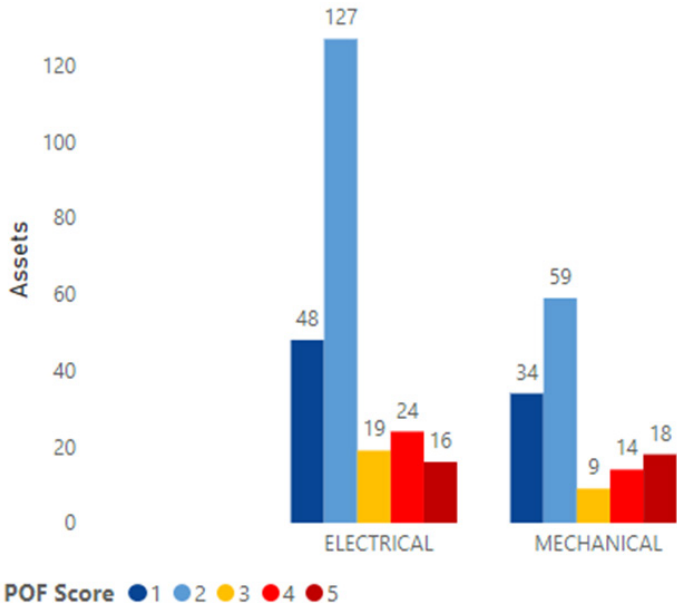

Figure 3.9 POF Score by Discipline

3.5.2.1 Electrical

A total of 234 electrical assets were evaluated, with 189 of them assessed in the field based on condition. The electrical assets include motors, panels, switchgears, transformers, variable frequency drives (VFD), and more. Assets that could not be accessed or located were assessed based on age. The distribution of POF scores is shown on Figure 3.10.

Assets Receiving a POF Score of Four

Twenty-four, or 10 percent of, electrical assets received a POF score of four.

Of these, 20 electrical assets received a **condition-based** POF score of four and are described below by process:

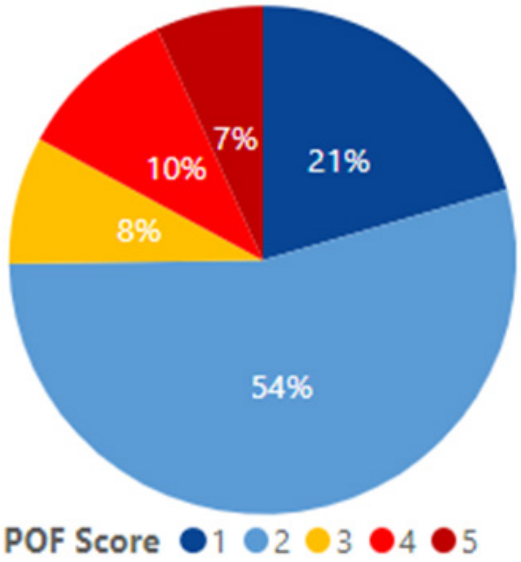

Figure 3.10 POF Score Distribution of Electrical Assets

- Pre-Treatment:
  - Influent Pump 2 Motor, which was installed in 1986, is reaching the end of its useful life. The motor operates under severe conditions.
  - Influent Pump 4 Motor, which was installed in 1986, is reaching the end of its useful life. The motor operates under severe conditions and shows visible signs of wear and corrosion.
- Secondary Treatment:
  - Return activated sludge (RAS) PUMP 4 VFD is nearing the end of its useful life over the course of the assessment. Although still functional, the VFD is nearing obsolescence the District is planning a VFD upgrade soon.
- Effluent Pumping Station No. 1:
  - EFFLUENT PUMPING STATION NO. 1, Pump No. 1, 3, and 5 VFD'S are nearing their end of useful life over the course of the assessment. Although they are still functional, they are nearing obsolescence and the District is planning VFD upgrades soon.
- Dissolved Air Floatation Thickener (DAFT):
  - DAFT Pressurization Pump 1 Motor has system inefficiencies that lead to routine pump cavitation. While the DAFT equipment was refurbished in 2011, the system is still inefficient due to the amount of air required.
  - DAFT Pressurization Pump 2 Motor has system inefficiencies that lead to routine pump cavitation. While the DAFT equipment was refurbished in 2011, the system is still inefficient due to the amount of air required.
- Co-Generation:
  - Motor Control Center (MCC)-E has outdated hardware that is potentially unable to be serviced by the manufacturer. Additionally, due to the age of the equipment spare parts would be considered obsolete and difficult to procure. This asset has already been submitted as a District capital improvement program (CIP) request.
  - MCC-Y, has outdated hardware that is potentially unable to be serviced by the manufacturer. Additionally, due to the age of the equipment spare parts would be considered obsolete and difficult to procure. This asset has already been submitted as a District CIP request.
  - SWGR-DPA, a low-voltage switchgear, indicates November 1993 on the nameplate. It shows visible signs of wear and is nearing the end of its useful life. This gear is

outdated and may be difficult or impossible to service by the manufacturer. There is no immediate concern, however, it should be included in the next CIP for replacement. This asset has already been submitted as a District CIP request.

- Buildings:
  - MCC-F1, has visible corrosion and outdated hardware. Similar to the previous motor control centers, the equipment is obsolete and is potentially unable to be serviced by the manufacturer. The difficulty of procuring spare parts is also a concern. This asset has already been submitted as a District CIP request.
  - POST CHLORINATION METERING PUMPS 1, 2, and 3 VFD's are nearing their end of useful life over the course of the assessment. Although they are still functional, they are nearing obsolescence and will need to be replaced in the near future.
  - PRE CHLORINATION RAS METERING PUMPS 1 and 2 VFD's are nearing their end of useful life over the course of the assessment. Although they are still functional, they are nearing obsolescence and will need to be replaced in the near future.
- Effluent Pump Station No. 2:
  - EFFLUENT PUMPING STATION NO. 2, Pump No. 3, 4, and 5 VFD's are nearing their end of useful life over the course of the assessment. Although they are still functional, they are nearing obsolescence and the District is planning VFD upgrades soon.

Four electrical assets received an **age-based** POF score of four and are discussed further by process below:

- Secondary Treatment:
  - MIXER 1, 2, 3, and 4 MOTORS were unable to be accessed in the field and are reaching the end of their useful life. With a RUL of four years, they will require replacement soon.

Assets Receiving a POF Score of Five

No electrical assets received a **condition-based** POF score of five.

Sixteen, or 7 percent of, electrical assets received an **age-based** POF score of five, and are described below by process:

- Pre-Treatment:
  - BAR SCREEN 2, 3, and 4 MOTOR VFDs are located in motor control centers, therefore, an in depth assessment of the equipment could not be performed. Hardware and solid state circuit boards internal to the VFD may or may not be available for replacement depending on the manufacturer's policies and procedures. As a result, the condition of the VFDs has been determined as reaching the end of their useful life and requiring replacement considering the age of equipment.
- Secondary Treatment:
  - MIX LIQUOR waste activated sludge (WAS) PUMP 1 and 3 VFD are located in MCCs, therefore, an in depth assessment of the equipment could not be performed. Hardware and solid state circuit boards internal to the VFD may or may not be available for replacement depending on the manufacturer's policies and procedures. As a result, the condition of the VFDs has been determined as reaching the end of their useful life and requiring replacement considering the age of equipment.

- RAS PUMP 1, 2, and 3 VFDs are located in motor control centers, therefore, an in depth assessment of the equipment could not be performed. Hardware and solid state circuit boards internal to the VFD may or may not be available for replacement depending on the manufacturer's policies and procedures. As a result, the condition of the VFDs has been determined as reaching the end of their useful life and requiring replacement considering the age of equipment.
- Co-Generation:
  - STARTING AIR COMPRESSOR 1 MOTOR has reached the end of its useful life and requires replacement.
  - COGEN ENGINE ROOM SUPPLY FAN 1 and 2 MOTOR have reached the end of their useful life and requires replacement.
- Buildings:
  - FUME HOOD 2 SUPPLY FAN EF-1 MOTOR has reached the end of its useful life and requires replacement and identified for replacement in the current CIP (CIP 22-P010 WWTP HVAC Replacement Project).
- Building D:
  - DIGESTED SLUDGE PUMP 1 and 2 VFDs are located in motor control centers, therefore, an in depth assessment of the equipment could not be performed. Hardware and solid state circuit boards internal to the VFD may or may not be available for replacement depending on the manufacturer's policies and procedures. As a result, the condition of the VFDs has been determined as reaching the end of their useful life and requiring replacement considering the age of equipment.
- Pump Station:
  - BASIN 4 EFFLUENT PUMP 2 and 6 MOTOR VFDs are located in MCCs, therefore, an in depth assessment of the equipment could not be performed. Hardware and solid state circuit boards internal to the VFD may or may not be available for replacement depending on the manufacturer's policies and procedures. As a result, the condition of the VFDs has been determined as reaching the end of their useful life and requiring replacement considering the age of equipment. The following notes were made based on visual assessments and from discussions with DSRSD O&M staff.
- MCC-FSL at the facultative sludge lagoon (FSL)/designated land disposal area is old and has been submitted as a District CIP request.
- DSRSD staff noted that some electrical gear may currently be undersized. Carollo is evaluating this under a separate task.
- DSRSD has a project underway to replace the large VFDs for the influent pumps and effluent pumps.
- VFDs for Influent Pump No. 3 and 4; Effluent Pump Station Pump No. 1, 3, and 5; Effluent Pump Station Pump No. 2, 3, and 4; and RAS Pump No. 4 are scheduled to be replaced in the Fall of 2023.

3.5.2.2 Mechanical

There are 134 mechanical assets included in the evaluation, with 97 of them assessed in the field based on condition. These assets include blowers, pumps, diesel generators, engines, heating, ventilation, and air conditioning (HVAC) units, bar screens, air compressors, and more. Assets that could not be accessed or located were assessed based on age. The distribution of POF scores is shown on Figure 3.11.

Assets Receiving a POF Score of Four

Fifteen, or 10 percent of, mechanical assets received a POF score of four.

Of these, nine mechanical assets received a **condition-based** POF score of four and are described below by process:

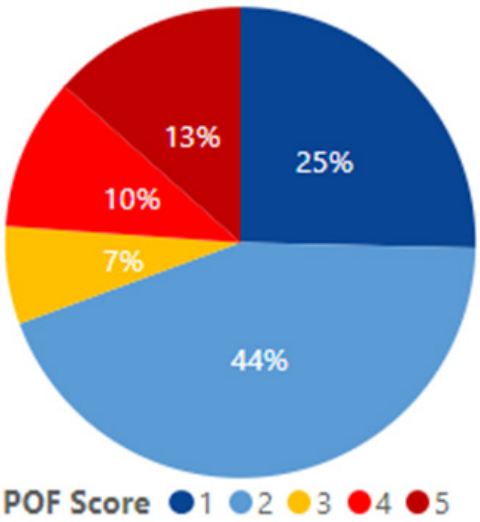

Figure 3.11 POF Score Distribution of Mechanical Assets

- Pretreatment:
  - INFLUENT PUMP 2, which was installed in 1986, is reaching the end of its useful life. The pump operates under severe conditions and maintenance staff noted that sand in the waste from the DERWA ballasted flocculation process may be leading to increased wear and premature failure of these pumps.
  - INFLUENT PUMP 4, which was installed in 1986, is reaching the end of its useful life. The pump operates under severe conditions and the fasteners show deterioration. Maintenance staff noted that sand in the waste from the DERWA ballasted flocculation process may be leading to increased wear and premature failure of these pumps.
- Secondary Treatment:
  - RAS PUMP 1 has been having issues with failure of the mechanical seal. During field assessment the seal was leaking slightly, and the pump had some vibration.
- DAFT:
  - DAFT Pressurization Pump 1, undergoes frequent cavitation under normal operation. This prematurely wears the backing plates and impellers, leaving the system unreliable.
  - DAFT Pressurization Pump 2, undergoes frequent cavitation under normal operation. This prematurely wears the backing plates and impellers, leaving the system unreliable.
- Co-Generation:
  - Cogeneration Engine 1, is approaching the end of its useful service life. Although DSRSD staff has done an excellent job of maintaining this equipment and has stocked a large quantity of spare parts, staff estimates about 5 years of parts remaining and is not sure they will be able to continue to service them adequately after that point. Institutional knowledge transfer for maintaining this equipment is another concern as staff retire.
  - Cogeneration Engine 2, is approaching the end of its useful service life and has been alarming on vibration. Although DSRSD staff has done an excellent job of maintaining this equipment and has stocked a large quantity of spare parts, staff estimates about 5 years of parts remaining and is not sure they will be able to continue to service them adequately after that point. Institutional knowledge transfer for maintaining this equipment is another concern as staff retire.

  - Cogeneration Engine 3, is approaching the end of its useful service life. Although DSRSD staff has done an excellent job of maintaining this equipment and has stocked a large quantity of spare parts, staff estimates about 5 years of parts remaining and is not sure they will be able to continue to service them adequately after that point. Institutional knowledge transfer for maintaining this equipment is another concern as staff retire.
- Standby Power:
  - Diesel Standby Generator 750 kilowatts (kW), is reaching the end of its useful life and should be replaced in the near future. The generator has moderate corrosion, piping deficiencies, and exterior defects. In addition, when Effluent Pump Station (EPS) No. 1 is not operating, as is typical 8 months out of the year, the generator is oversized and just idles when put in service. A load bank is required to allow the generator to run properly under this scenario.

Five mechanical assets that received an **age-based** POF score of four are described below by process:

- Pre-Treatment:
  - INFLUENT SUMP PUMP 1 and 2 have reached the end of their useful life and requires replacement.
- DAFT:
  - DAFT SOUTH PIT SUMP PUMP 1 and 2 have reached the end of their useful life and requires replacement.
- HVAC:
  - BLDG A AIR HANDLING UNIT 6 has reached the end of its useful life and requires replacement.

Assets Receiving a POF Score of Five

No mechanical assets received a **condition-based** POF score of five.

Eighteen, or 13 percent of, mechanical assets received an **age-based** POF score of five, and are described below by process:

- Secondary Treatment:
  - MIXER 1, MIXER 2, MIXER 3, and MIXER 4 have reached the end of their useful life and requires replacement. The mixers are submersible and were unable to be assessed in the field.
  - MIXED LIQUOR WAS PUMP 1 and MIXED LIQUOR WAS PUMP 3 are identified as failed assets that require replacement. The submersible pumps were unable to be assessed in the field.
  - BLDG B-AIR HANDLING UNIT 2 has reached the end of its useful life and requires replacement.
- Co-Generation:
  - COGEN ENGINE ROOM SUPPLY FAN 2 has reached the end of its useful life and requires replacement. This asset has already been submitted as a District CIP request.
- HVAC:
  - BLDG S – AIR HANDLING UNITS 1, 2, and 3 have reached the end of their useful life and requires replacement.

  - BLDG T AIR COMPRESSOR and AIR HANDLING UNIT 1 has reached the end of its useful life and requires replacement.
  - BLDG A – AIR HANDLING UNITS 1, 2, and 3 have reached the end of their useful life and requires replacement. Unit 2 is scheduled for replacement next fiscal year.
- Buildings:
  - FUME HOOD 2 SUPPLY FAN EF-1 has reached the end of its useful life and requires replacement.
  - BUILDING D- AIR HANDLING UNIT has reached the end of its useful life and requires replacement.

Mechanical Assets Field Notes

The following notes were made based on visual assessments and from discussions with DSRSD O&M staff. Refer to Appendix 3E for the complete list of observations made by DSRSD O&M staff from the site visit on May 10-11, 2022.

- Pretreatment – screening conveyors were replaced with a screen bucket lift and should be removed from the asset data base.
- The aeration blowers are reliable and in good condition but are nearing 20 years of age and therefore will approach the end of their useful service life within the next 10 years. The 18,000 hour service was recently performed on the blowers. One blower (blower no. 2) had some knicks in the rotor but was still operational.
- The aeration system control scheme is inefficient, and the blowers and aeration control valves may not have room for further optimization in a mostly open-valve control scenario. Additionally, while the staff replaces diffuser membranes every five years to maximize oxygen transfer efficiency, the fine bubble diffusers in the aeration tanks have been experiencing some failures (four failures in the past eight months). The aeration system and controls may need to be replaced with a more efficient system.
- EPS-1 pumps sit idle for long periods of time and sometimes have trouble starting when they are needed. The District will begin investigating the use of the EPS-1 pumps to fill Holding Basin (HB)-4.
- Gas treatment skid motors are due for replacement. A current project is in preliminary design looking at replacement of this skid.
- Plant maintenance staff is in the process of replacing all chiller and heat loop pumps.
- None of the boilers are currently operational as the digesters use the waste gas heat from the cogeneration engines. DSRSD maintenance staff is not confident the old boilers can be reliably operated if the cogeneration system is offline. DSRSD operations staff noted that on cold days, if only two cogeneration engines are running, the plant struggles to maintain the digesters adequately heated. Operations staff in these instances cuts heating to Buildings T and S to keep sufficient heat to the digesters.
- The HVAC system in Building A is due for replacement. It was noted that a $200,000 budget was allocated for replacement of this system but costs came in at $1.3 million.
- About 90 percent of the interior lighting and 100 percent of exterior lighting at the WWTP has been replaced with light emitting diode (LED) lighting. The Field Operations Division (FOD) Building has older lighting fixtures rather than LED lighting. All exterior lighting at the WWTP is triggered by photocell control and stays on throughout the night.

Additionally, as of December 12, 2022, DSRSD noted that they purchased a new Digester 3 Heat Exchanger to replace the failing asset. While this asset is not included in the condition assessment, asset information including manufacturer, model, and serial number will need to be updated in the CMMS database.

3.6 Data Management Improvements

Based on the desktop analysis and condition assessment, the following data management practices would improve CMMS data accuracy:

- Review Appendix 3A to confirm these assets should be excluded. As needed, review the business rules to accurately reflect asset replacement costs in the Asset Replacement Model.
- Remove any redundant level 2 hierarchies and consolidate assets into common level 2 hierarchies in the CMMS database. Some assets appear to be duplicates and are located under different hierarchy levels.
- Create a new "GE_TYPE_TY" type for the following assets:
  - "Switchgear – Low Voltage" and recategorize the following assets in this category:
    - "SWG-DPG".
    - "SWGR-DPA".
    - "SWGR-DPD".
  - "Transformer – Low Voltage" and recategorize the following assets in this category:
    - "PANEL 6075 TRANSFORMER".
    - "PANEL 6076 TRANSFORMER".
    - "PANEL 6077 TRANSFORMER".
- Assess functionality of the CMMS such that a user-friendly mobile application is available for operators to make real-time updates in the field.
- Review the business rules, provide a standard operating procedure and training such that O&M staff understand the threshold for including assets in the CMMS.
- For any new assets, include install date information in the CMMS.
- For any asset replacement, update replacement date information in the CMMS.
- Observations from the field assessment can be used to update the EUL for asset classes or sub-classes to better represent the operating environment of the facility (e.g., if the field-evaluated conditions suggests that the EUL of a class of assets is longer (or shorter) than previously assigned, the EUL can be adjusted to "calibrate" the age-based results). Refer to Appendix 3C for recommended EUL values based on general industry best management practices.

3.7 Next Steps

The findings from the asset review and condition assessment will be used to inform the recommendations that will be incorporated into both the Energy Facilities Master Plan CIP and the Electrical Master Plan CIP efforts. Understanding what assets are nearing the end of their useful service life is important for a criticality-based prioritization of projects in the CIP to provide operational reliability both in the near-term and in the future.

3.8 Implications of Energy Consumption Based on the Condition Assessment

Some of the findings from this review of assets present DSRSD with opportunities for significantly improving the efficiency of its facilities. These key items are summarized below and will be carried forward to the energy project alternatives evaluation.

- The influent pumps are aged although some have been recently rehabilitated. Given the size of these pumps, criticality, and the frequency of use, replacing them with newer more efficient pumps could result in considerable energy savings and improved reliability for a critical plant asset.
- The aeration blowers will likely need to be replaced within the next 10 years. Given the amount of energy consumed by this process, this presents an opportunity for DSRSD to optimize the efficiency of the aeration system when replacing these blowers. Additionally, DSRSD staff noted that data trending in supervisory control and data acquisition for the aeration system operating parameters is currently not available. Having trending data available would allow staff to better track and optimize the performance of this system.
- DSRSD operations staff noted that the fine bubble diffusers within the aeration tanks are approaching the end of their useful service life as they have been experiencing some failures of the diffuser system (four failures in the past eight months alone). Staff replace the diffuser membranes every five years as is recommended for maximizing the oxygen transfer efficiency. However, replacement of this system presents the opportunity to evaluate alternative systems that could provide improved oxygen transfer efficiency such as plate diffusers or nano-bubble technologies.
- DSRSD operations staff noted that the current aeration system control scheme is not optimal and that the blowers and aeration control valves may not be optimized under a most-open-valve control scenario. Evaluating the current aeration system controls and options for improving this efficiency could result in considerable energy savings without much capital investment. Staff noted that a recent assessment was made by a third party (BCV) and that the evaluation is still under review.
- The aging DAFT equipment and operational concerns with the pumps present an opportunity to look at more energy-efficient process options for solids thickening. It will be important, however, to also consider operational flexibility and chemical use in assessing alternative thickening systems.
- Evaluate more efficient options for digester mixing given the age of the existing mixers in digester nos. 1 and 2.
- The gas treatment skid equipment is aged and due for replacement. This could be an opportunity to optimize this system in coordination with potential expansion of gas utilization or storage. The gas treatment skid has been submitted as a District CIP request and will be entering the design phase in the near-term.
- The cogeneration engines are nearing the end of their useful service life per plant staff which presents an opportunity to replace them with newer more efficient models and to also evaluate optimal sizing for this facility.
- The FOD building has two large chillers that were used to cool the warehouse but that is no longer needed given how DSRSD currently uses the facility. This presents an opportunity to design the HVAC system for this building in a more efficient manner.

- Six HVAC units in Buildings A, M, R and O are due for replacement in the near term (less than five years); the air handling units in building A are already included in the condition assessment, but the others are not since they are DERWA equipment. The specific assets are listed below. This presents an opportunity to replace these with more energy efficient units.
  - BLDG A - AIR HANDLING UNIT 1 and UNIT 2 (it is noted Unit 2 is scheduled for replacement next fiscal year).
  - BLDG M - AIR HANDLING UNIT 1 and UNIT 2.
  - BLDG R - AIR HANDLING UNIT.
  - BLDG O - AIR HANDLING UNIT 1.
- The lighting system in the FOD building could be replaced with LED lighting for greater energy efficiency. This opportunity will be further evaluated during Phase 2 of the project.

Appendix 3A

ASSETS OMITTED FROM THE ASSET REPLACEMENT MODEL

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Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
0100JT	EALS POWER SUPPLY
1002SLR	STARTER EXHAUST SILENCER
10-190-0001-UPS-01	FOF UNINTERRUPTIBLE POWER SUPPLY
1020AMME	ENGINE ROOM TROLLEY
1020BMME	ENGINE ROOM BRIDGE
10-DOA-0001-AHU-01	DO-ADMIN AIR HANDLING UNIT 1
10-DOA-0001-BLR-01	DOA -BOILER UNIT 1
10-DOA-0002-AHU-01	DO-ADMIN AIR HANDLING UNIT 2
10-DOA-0003-AHU-01	DO-ADMIN AIR HANDLING UNIT 3
10-DOA-0004-AHU-01	DO-ADMIN AIR HANDLING UNIT 4
10-DOA-0005-AHU-01	DO-ADMIN AIR HANDLING UNIT 5
10-DOA-0006-AHU-01	DO-ADMIN AIR HANDLING UBNIT 6
10-DOA-0007-AHU-01	DO-ADMIN AIR HANDLING UNIT 7
10-FOF-0001-AHU-01	FOF-AIR HANDLING UNIT 1
10-FOF-0001-BLR-01	FOF-BOILER UNIT 1
10-FOF-0001-DOR-01	FOF FRONT LOBBY DOORS
10-FOF-0002-AHU-01	FOF-AIR HANDLING UNIT 2
10-FOF-0003-AHU-01	FOF-AIR HANDLING UNIT 3
10-FOF-0004-AHU-01	FOF-AIR HANDLING UNIT 4
10-FOF-0005-AHU-01	FOF-AIR HANDLING UNIT 5
10-FOF-0006-AHU-01	FOF-AIR HANDLING UNIT 6
180675MCN	WASH DOWN SYSTEM PUMP MOTOR STARTER
1951MME	RS SAMPLER 1
2001HPO	HEAT PUMP OUTDOOR UNIT
20-100-1003-SGT-01	DUBLIN LIFT STATION 1 RED TOP PRESSURE SLIDE GATE
2010SLG	INFLUENT SLUICE GATE 1
2011SLG	INFLUENT SLUICE GATE 2
2013TST	SCREEN ROOM THERMOSTAT
2301MME	GRIT CLASSIFIER 1
2302MME	GRIT CLASSIFIER 2
2510PS	HEADWORKS MCC ROOM PRESSURE SWITCH
2905GAL	INFLUENT PUMP GALLERY
30-021-1911-SLG-01	DUBLIN TRUNK SEWER SLUICE GATE
30-022-1903-SGT-01	PLEASANTON SEWER DIVERSION SLIDE GATE
30-022-1912-HOP-01	PLEASANTON TRUNK SEWER SLUICE GATE HYDRAULIC OPERA
30-022-1912-SLG-01	PLEASANTON TRUNK SEWER SLUICE GATE
30-111-1913-SGT-01	CHANNEL 4 INLET SLIDE GATE
30-111-1914-SGT-01	CHANNEL 4 OUTLET SLIDE GATE

Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
30-111-1915-SGT-01	CHANNEL 2 INLET SLIDE GATE
30-111-1916-SGT-01	CHANNEL 2 OUTLET SLIDE GATE
30-111-1917-SLG-01	BAR SCREEN 1 CHANNEL DRAIN SLUICE GATE
30-111-1918-SLG-01	BAR SCREEN 2 CHANNEL DRAIN SLUICE GATE
30-111-1921-SGT-01	CHANNEL 3 INLET SLIDE GATE
30-111-1922-SGT-01	CHANNEL 3 OUTLET SLIDE GATE
30-111-1923-SGT-01	CHANNEL 1 INLET SLIDE GATE
30-111-1924-SGT-01	CHANNEL 1 OUTLET SLIDE GATE
30-111-1925-SLG-01	BAR SCREEN 3 CHANNEL DRAIN SLUICE GATE
30-111-1926-SLG-01	BAR SCREEN 4 CHANNEL DRAIN SLUICE GATE
30-111-1955-OHD-01	BAR SCREEN BUILDING OVERHEAD DOOR 1
30-111-1956-OHD-01	BAR SCREEN BUILDING OVERHEAD DOOR 2
30-111-1963-FLP-01	BAR SCREEN BUILDING FLUID POWER SYSTEM ACCUM BANK
30-123-2102-FLG-01	INFLUENT PUMP 2 DISCHARGE FLAP GATE
30-123-2102-SGT-01	INFLUENT PUMP 2 DISCHARGE CHANNEL SLIDE GATE
30-123-2103-FLG-01	INFLUENT PUMP 3 DISCHARGE FLAP GATE
30-123-2103-SGT-01	INFLUENT PUMP 3 DISCHARGE CHANNEL SLIDE GATE
30-123-2104-FLG-01	INFLUENT PUMP 4 DISCHARGE FLAP GATE
30-123-2104-SGT-01	INFLUENT PUMP 4 DISCHARGE CHANNEL SLIDE GATE
30-123-2105-SGT-01	WEST INF DISTRIBUTION CHANNEL INLET SLIDE GATE
30-123-2106-SGT-01	EAST INF DISTRIBUTION CHANNEL INLET SLIDE GATE
30-123-2113-TST-01	INFLUENT PUMP ROOM THERMOSTAT
30-123-2707-SGT-01	EAST INF DISTRIBUTION CHANNEL ISOLATION SLIDE GATE
30-128-2998-PMP-01	BASIN RETURN PUMP 1
30-128-2999-PMP-01	BASIN RETURN PUMP 2
30-131-2701-SLG-01	PREAERATION GRIT REMOVAL TANK 3 INLET SLIDE GATE
30-131-2702-SLG-01	PREAERATION GRIT REMOVAL TANK 2 INLET SLIDE GATE
30-131-2703-SGT-01	PREAERATION GRIT REMOVAL TANK 1 INLET SLIDE GATE
30-131-2704-SGT-01	PREAERATION GRIT REMOVAL TANK 4 INLET SLIDE GATE
30-131-2711-SLG-01	PREAERATION GRIT REMOVAL TANK 3 OUTLET SLIDE GATE
30-131-2712-SLG-01	PREAERATION GRIT REMOVAL TANK 2 OUTLET SLIDE GATE
30-131-2713-SLG-01	PREAERATION GRIT REMOVAL TANK 1 OUTLET SLIDE GATE
30-131-2714-SLG-01	PREAERATION GRIT REMOVAL TANK 4 OUTLET SLIDE GATE
30-131-2731-SGT-01	PREAERATION GRIT REMOVAL TANK 3 SCUM SLIDE GATE
30-131-2732-SGT-01	PREAERATION GRIT REMOVAL TANK 2 SCUM SLIDE GATE
30-131-2733-SGT-01	PREAERATION GRIT REMOVAL TANK 1 SCUM SLIDE GATE
30-131-2734-SGT-01	PREAERATION GRIT REMOVAL TANK 4 SCUM SLIDE GATE
30-132-2914-MTR-01	GRIT PUMP 4 MOTOR

Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
30-132-2914-PMP-01	GRIT PUMP 4
30-132-2931-MTR-01	GRIT SCUM PUMP 2 MOTOR
30-132-2931-PMP-01	GRIT SCUM PUMP 2
30-135-2923-BLR-01	PREAERATION BLOWER 3
30-135-2923-MTR-01	PREAERATION BLOWER 3 MOTOR
30-136-2315-TST-01	GRIT STORAGE ROOM THERMOSTAT
30-136-2405-TST-01	MCC ROOM THERMOSTAT
30-211-2821-SLG-01	PRIMARY 4 INLET SLIDE GATE 1
30-211-2822-SLG-01	PRIMARY 4 INLET SLIDE GATE 2
30-211-2823-SLG-01	PRIMARY 4 INLET SLIDE GATE 3
30-211-2824-SLG-01	PRIMARY 3 INLET SLIDE GATE 1
30-211-2825-SLG-01	PRIMARY 3 INLET SLIDE GATE 2
30-211-2826-SLG-01	PRIMARY 3 INLET SLIDE GATE 3
30-211-2827-SLG-01	PRIMARY 2 INLET SLIDE GATE 1
30-211-2828-SLG-01	PRIMARY 2 INLET SLIDE GATE 2
30-211-2829-SLG-01	PRIMARY 2 INLET SLIDE GATE 3
30-211-2830-SLG-01	PRIMARY 1 INLET SLIDE GATE 1
30-211-2831-SLG-01	PRIMARY 1 INLET SLIDE GATE 2
30-211-2831-XSH-01	PRIMARY 1 SCUM SKIMMER HIGH CURRENT LIMIT SWITCH
30-211-2832-SLG-01	PRIMARY 1 INLET SLIDE GATE 3
30-211-2833-SLG-01	PRIMARY 5 INLET SLIDE GATE 1
30-211-2834-SLG-01	PRIMARY 5 INLET SLIDE GATE 2
30-211-2834-XSH-01	PRIMARY 4 SCUM SKIMMER HIGH CURRENT ALARM SWITCH
30-211-2835-DVU-02	PRIMARY 5 SCUM SKIMMER DRIVE UNIT
30-211-2835-MTR-02	PRIMARY 5 SCUM SKIMMER MOTOR
30-211-2835-SKM-01	PRIMARY 5 SCUM SKIMMER
30-211-2835-SLG-01	PRIMARY 5 INLET SLIDE GATE 3
30-211-2841-DVU-02	PRIMARY 4 SCUM SKIMMER DRIVE UNIT
30-211-2841-MTR-02	PRIMARY 4 SCUM SKIMMER MOTOR
30-211-2841-SKM-01	PRIMARY 4 SCUM SKIMMER
30-211-2841-XSH-01	PRIMARY 1 SLUDGE LONG COL HIGH CURRENT LIMIT SWITCH
30-211-2841-YSH-01	PRIMARY 1 SLUDGE LONG COL SHEAR PIN LIMIT SWITCH
30-211-2844-COL-01	PRIMARY 1 SLUDGE COLLECTOR
30-211-2844-DVU-01	PRIMARY 1 SLUDGE COLLECTOR DRIVE UNIT
30-211-2844-MTR-01	PRIMARY 1 SLUDGE COLLECTOR MOTOR
30-211-2844-SGT-01	PRIMARY 1 EFFLUENT ISOLATION SLIDE GATE
30-211-2844-WGT-01	PRIMARY 1 EFFLUENT WEIR GATE
30-211-2845-COL-01	PRIMARY 5 SLUDGE COLLECTOR

Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
30-211-2845-DVU-01	PRIMARY 5 SLUDGE COLLECTOR DRIVE UNIT
30-211-2845-MTR-01	PRIMARY 5 SLUDGE COLLECTOR MOTOR
30-211-2845-SGT-01	PRIMARY 5 EFFLUENT ISOLATION SLIDE GATE
30-211-2845-WGT-01	PRIMARY 5 EFFLUENT WEIR GATE
30-211-2855-SGT-01	PRIMARY 4 EFFLUENT BOX SLIDE GATE
30-211-2856-SGT-01	PRIMARY EFFLUENT BOX SLIDE GATE 2
30-211-2858-SGT-01	PRIMARY 4 EFFLUENT BOX SLIDE GATE
30-213-2851-SGT-01	PRIMARY EFFLUENT FLOW CONTROL SLIDE GATE 1
30-213-2852-SGT-01	PRIMARY EFFLUENT FLOW CONTROL SLIDE GATE 2
30-213-2853-SGT-01	PRIMARY EFFLUENT FLOW CONTROL SLIDE GATE 3
30-213-2854-SGT-01	PRIMARY EFFLUENT FLOW CONTROL SLIDE GATE 4
30-221-2934-MTR-01	PRIMARY SCUM PUMP 1 MOTOR
30-221-2934-PMP-01	PRIMARY SCUM PUMP 1
30-221-2935-MTR-01	PRIMARY SCUM PUMP 2 MOTOR
30-222-2907-GAL-01	PRIMARY SLUDGE PUMP GALLERY
30-311-3009-SLG-01	RAS SLUICE GATE 1
30-311-3044-SLG-01	RAS SLUICE GATE 2
30-313-3000-SGT-01	SLIDE GATE FROM INNER SEWER
30-313-3001-SGT-01	SETTLED SEWAGE CHANNEL SLIDE GATE 1
30-313-3002-SGT-01	SETTLED SEWAGE CHANNEL SLIDE GATE 2
30-313-3003-SGT-01	SETTLED SEWAGE CHANNEL SLIDE GATE 3
30-313-3016-SLG-01	SETTLED SEWAGE CHANNEL DRAIN GATE
30-314-3004-SLG-01	INTER-AERATION TANK SLUICE GATE 1
30-314-3005-SLG-01	INTER-AERATION TANK SLUICE GATE 2
30-314-3006-SLG-01	AERATION TANK 1 DRAIN SLUICE GATE
30-314-3007-SLG-01	AERATION TANK 2 DRAIN SLUICE GATE
30-314-3008-SLG-01	AERATION TANK 3 DRAIN SLUICE GATE
30-314-3014-SGT-01	AERATION TANK 1 INLET SLIDE GATE
30-314-3017-SLG-01	CROSSOVER GATE AERATION BASIN 2
30-314-3018-SLG-01	AERATION BASIN 3 CROSSOVER GATE
30-314-3025-SGT-01	AERATION TANK 2 SCUM SLIDE GATE
30-314-3031-SGT-01	AERATION TANK 3 INLET SLIDE GATE
30-314-3031-SLG-01	AERATION TANK 3 SLUICE GATE
30-314-3032-SLG-01	AERATION TANK 3 SLUICE GATE 2
30-314-3041-SLG-01	AERATION TANK 4 TANK DRAIN SLUICE GATE
30-314-3042-SLG-01	AERATION TANK 4 SLUICE GATE
30-314-3043-SLG-01	AERATION TANK 4 SLUICE GATE 2
30-314-3051-SLG-01	AERATION TANK 5 DRAIN SLUICE GATE

Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
30-314-3052-SGT-01	AERATION TANK 5 INLET SLIDE GATE
30-316-3540-PLC-01	MAIN BLOWER CONTROL PANEL PLC-LCP
30-316-3541-PLC-01	BLOWER 1 LOCAL CONTROL PANEL PLC-B1
30-316-3542-PLC-01	BLOWER 2 LOCAL CONTROL PANEL PLC-B2
30-316-3543-PLC-01	BLOWER 3 LOCAL CONTROL PANEL PLC-B3
30-322-6501-SLG-01	INFLUENT SLUICE GATE
30-322-7998-PMP-01	CAUSTIC PUMP 1
30-322-7999-PMP-01	CAUSTIC PUMP 2
30-323-7906-AUH-01	BLDG F- AIR HANDLING UNIT 1
30-333-4403-SLG-01	TANK 4 DRAIN SLUICE GATE
30-333-4405-SGT-01	SECONDARY CLARIFIER TANK 4 OUTLET SLIDE GATE
30-334-4813-SGT-01	MIXED LIQUOR WAS PUMPING STATION SLIDE GATE 1
30-334-4814-SGT-01	MIXED LIQUOR WAS PUMPING STATION SLIDE GATE 2
30-334-4815-SGT-01	MIXED LIQUOR WAS PUMPING STATION SLIDE GATE 3
30-336-4012-SLG-01	RAS PUMP STATION 1 SLUICE GATE
30-336-4013-SLG-01	RAS PUMP STATION 2 SLUICE GATE
3033SG	AERATION TANK 3 SCUM GATE 1
30-411-2012-SGT-01	EFFLUENT DIVERSION STRUCTURE SLIDE GATE
30-411-6505-SLG-01	GRAVITY FLOW TRANSITION SLUICE GATE
30-411-6506-SLG-01	FINAL EFFLUENT DIVERSION SLUICE GATE
30-521-6502-SLG-01	DIVERSION SLUICE GATE
30-521-6504-SLG-01	BASIN 1 DIVERSION SLUICE GATE
30-522-0002-BSN-01	HB 2
30-522-1933-SLG-01	HB 2 SLUICE GATE
30-523-0003-BSN-01	HB 3
30-523-2723-SGT-01	BASIN 3 FLOW DIVERSION WEIR SLIDE GATE 1
30-523-2724-SGT-01	BASIN 3 FLOW DIVERSION WEIR SLIDE GATE 2
30-610-5855-MTR-01	DAFT BUILDING EXHAUST FAN 2 MOTOR
30-611-5843-SGT-01	PLANT INNER SEWER SLIDE GATE
30-612-5862-BLV-01	DAFT AIR COMPRESSOR 1 COOLING WATER BALL VALVE
30-612-5863-BLV-01	DAFT AIR COMPRESSOR 2 COOLING WATER BALL VALVE
30-612-5864-BLV-01	DAFT AIR COMPRESSOR 3 COOLING WATER BALL VALVE
30-612-5867-HEX-01	DAFT AIR THERMAL DRY COOLER HEAT EXCHANGER
30-624-5081-MXR-01	DIGESTER 4 SLUDGE MIXER 1 (EAST)
30-624-5082-MXR-01	DIGESTER 4 SLUDGE MIXER 2 (SOUTH)
30-624-5083-MXR-01	DIGESTER 4 SLUDGE MIXER 3 (NORTH)
30-630-9014-SLG-01	SLUICE GATE
30-640-5015-MTR-01	FOG HOT WATER PUMP MOTOR

Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
30-700-1030-LSH-01	OIL LEVEL SWITCH
30-700-1031-PMP-01	LUBE OIL (CLEAN) TRANSFER PUMP
30-700-1032-PMP-01	WASTE OIL PUMP
30-741-5216-CTV-01	DIGESTER GAS CONDENSATE TANK 3 MAKE UP WATER VALVE
30-741-5343-PRV-01	GLYCOL SYSTEM MAKE-UP WATER VALVE
30-811-2600-ORT-01	ODOR REDUCTION TOWER
30-940-0016-AHU-01	BLDG S- AIR HANDLING UNIT 3
30-940-0017-AHU-01	BULD T- AIR HANDLING UNIT 1
30-940-1806-AHU-01	BLDG A-AIR HANDLING UNIT 3
30-940-1807-AHU-01	BLDG A- AIR HANDLING UNIT 4
30-940-1808-AHU-01	BLDG A-AIR HANDLER UNIT 5
30-940-1809-AHU-01	BLDG A-AIR HANDLING UNIT 6
40-230-2002-PMP-01	MF FEED PUMP 2
40-230-2003-PMP-01	MF FEED PUMP 3
40-230-2004-PMP-01	MF FEED PUMP 4
40-430-7211-SGT-01	RAPID MIX BASIN 1 SCUM WEIR GATE
40-430-7211-SLG-01	RAPID MIX BASIN 1 INLET SLUICE GATE
40-430-7212-SGT-01	RAPID MIX BASIN 2 SCUM WEIR GATE
40-430-7212-SLG-01	RAPID MIX BASIN 2 INLET SLUICE GATE
40-430-7213-SLG-01	BYPASS SLUICE GATE 1
40-430-7214-SLG-01	BYPASS SLUICE GATE 2
40-440-7221-SGT-01	FLOCCULATION BASIN 1 SCUM WEIR GATE
40-440-7221-SLG-01	FLOCCULATION BASIN 1 SLUICE GATE 1
40-440-7222-SLG-01	FLOCCULATION BASIN 1 SLUICE GATE 2
40-440-7223-SGT-01	FLOCCULATION BASIN 2 SCUM WEIR GATE
40-440-7223-SLG-01	FLOCCULATION BASIN 2 SLUICE GATE 1
40-440-7224-SLG-01	FLOCCULATION BASIN 2 SLUICE GATE 2
40-470-7313-SGT-01	FILTER INLET CHANNEL DRAIN GATE
40-480-7300-SGT-01	FILTER DRAIN WET WELL SCUM WEIR GATE
40-480-7341-SGT-01	REJECT WATER WELL DRAIN GATE
40-485-7442-ACT-01	EMERGENCY BYPASS TO HB4 SLUICE GATE ACTUATOR
40-485-7442-SLG-01	EMERGENCY BYPASS TO HB4 SLUICE GATE
40-495-7331-PMP-01	REJECT WATER PUMP 1
40-495-7332-PMP-01	REJECT WATER PUMP 2
40-510-7443-SLG-01	CLEARWELL INLET SLUICE GATE
40-530-7410-SLG-01	SF UV CHANNEL 1 INLET GATE
40-530-7410-WGT-01	SF UV CHANNEL 1 WEIR GATE
40-540-7420-SGT-01	SF UV CHANNEL 2 OUTLET GATE

Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
40-540-7420-SLG-01	SF UV CHANNEL 2 INLET GATE
40-540-7420-WGT-01	SF UV CHANNEL 2 WEIR GATE
40-550-7441-SLG-01	SF UV EFFLUENT CHANNEL DRAIN GATE
40-600-7244-COL-01	BF TRAIN 1 SLUDGE SCRAPER
40-600-7244-PLT-01	BF TRAIN 1 LAMELLA PLATE SETTLER
40-600-7245-SGT-01	BF TRAIN 1 EFFLUENT GATE
40-600-7254-COL-01	BF TRAIN 2 SLUDGE SCRAPER
40-600-7254-PLT-01	BF TRAIN 2 LAMELLA PLATE SETTLER
40-600-7255-SGT-01	BF TRAIN 2 EFFLUENT GATE
40-940-0001-AHU-01	BLDG N-AIR HANDLING UNIT 1
40-940-0002-AHU-01	BLDG N-AIR HANDLING UNIT 2
40-940-0003-AHU-01	BLDG N-AIR HANDLING UNIT 3
40-940-0004-AHU-01	BLDG N-AIR HANDLING UNIT 4
40-940-0005-01	BLDG M-AIR HANDLING UNIT 1
40-940-0006-01	BLDG M-AIR HANDLING UNIT 2
40-940-0007-01	BLDG O - AIR HANDLING UNIT 1
4910G	SECONDARY CLARIFIER INFLUENT GATE 1
4920G	SECONDARY CLARIFIER INFLUENT GATE 2
4930G	SECONDARY CLARIFIER INFLUENT GATE 3
4940G	SECONDARY CLARIFIER INFLUENT GATE 4
50-221-2500-UPS-01	RES R20 UNINTERRUPTIBLE POWER SUPPLY
5302SKIDPA	FUEL SKID SODA ASH PUMP
5362PRV	ZERO GAS GOVERNER 1
5371CV	DILUTED NG CONTROL VALVE 2
5372PRV	ZERO GAS GOVERNER 2
5802MME	DAFT LEVEL CONTROL GATE
5818SV	AIR BLEED VALVE 1
6001AHU	BLDG G-AIR HANDLING UNIT 1
60-121-1000-UPS-01	RES 1A UNINTERRUPTIBLE POWER SUPPLY
60-122-1000-UPS-01	RES 1B UNINTERRUPTIBLE POWER SUPPLY
60-124-9200-UPS-01	RES 10A UNINTERRUPTIBLE POWER SUPPLY
60-125-2300-UPS-01	RES 10B UNINTERRUPTIBLE POWER SUPPLY
60-215-1000-MTS-01	PS 20B MANUAL TRANSFER SWITCH
60-313-0800-MTS-01	PS 3C MANUAL TRANSFER SWITCH
60-316-1000-MTS-01	PS 300B MANUAL TRANSFER SWITCH
60-321-1100-UPS-01	RES 3A UNINTERRUPTIBLE POWER SUPPLY
60-325-3400-UPS-01	RES 300B UNINTERRUPTIBLE POWER SUPPLY
60-421-5100-RIO-01	RES 4A RIO

Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
60-421-5100-UPS-01	RES 4A UNINTERRUPTIBLE POWER SUPPLY
7721MEE	POLYMER FEED SYSTEM 1
7722MEE	POLYMER FEED SYSTEM 2
80-120-09100-VLT-02	LIVERMORE LINE 091+00 BALL VALVE VAULT L-7
80-300-0621-SLG-01	SECONDARY EFFLUENT DISCHARGE BY-PASS SLUICE GATE
80-300-0622-SLG-01	MAIN SECONDARY EFFLUENT DISCHARGE SLUICE GATE
80-300-0623-SLG-01	EMERGENCY DISCHARGE SLUICE GATE
80-400-0601-SLG-01	BASIN 1 EXIT SLUICE GATE
80-400-0602-SLG-01	BASIN 2 EXIT SLUICE GATE
80-400-0603-SLG-01	BASIN 3 EXIT SLUICE GATE
80-400-0611-ACT-01	BASIN 1 INLET SLIDE GATE ACTUATOR
80-400-0611-SGT-01	BASIN 1 INLET SLIDE GATE
80-400-0612-ACT-01	BASIN 2 INLET SLUICE GATE ACTUATOR
80-400-0612-SLG-01	BASIN 2 INLET SLUICE GATE
80-400-0613-SGT-01	BASIN 3 INLET SLIDE GATE
80-400-0631-SLG-01	BASIN 1 EFFLUENT SLUICE GATE
80-400-0632-SLG-01	BASIN 2 EFFLUENT SLUICE GATE
80-400-0633-SLG-01	BASIN 3 EFFLUENT SLUICE GATE
80-400-0634-SLG-01	SECONDARY EFFLUENT DISCHARGE SLUICE GATE 1
80-400-0635-SLG-01	SECONDARY EFFLUENT DISCHARGE SLUICE GATE 2
80-400-0636-SLG-01	SECONDARY EFFLUENT DISCHARGE SLUICE GATE 3
80-400-0637-SLG-01	SECONDARY EFFLUENT DISCHARGE SLUICE GATE 4
80-400-0638-SLG-01	SECONDARY EFFLUENT DISCHARGE SLUICE GATE 5
80-520-00125-FLG-01	EXPORT PIPELINE 2 001+25 EMERGENCY FLAP GATE (2000-03) C-217/C-220
BIOFTRA	HEADWORKS BIO-FILTER
BIOFTRB	DAFT BIO-FILTER
FLT-0416G	PORTABLE GENERATOR
FLT-0420G	PORTABLE DIESEL GENERATOR 275kW
FLT-0421G	PORTABLE DIESEL GENERATOR 275kW
FLT-0422G	PORTABLE DIESEL GENERATOR 150kW
FLT-0423G	PORTABLE DIESEL GENERATOR 150kW
FLT-0424G	PORTABLE DIESEL GENERATOR 150kW
FLT-0529E	SAND BLASTING CABINET
FLT-0548E	PORTABLE DIESEL GENERATOR LOAD BANK 500kW
FSL1	FACULTATIVE SLUDGE LAGOON 1
FSL2	FACULTATIVE SLUDGE LAGOON 2
FSL3	FACULTATIVE SLUDGE LAGOON 3

Assets Omitted from the Asset Replacement Model (RPM Cost Projection Excel File)	
FSL4	FACULTATIVE SLUDGE LAGOON 4
FSL6	FACULTATIVE SLUDGE LAGOON 6
FSL7	FACULTATIVE SLUDGE LAGOON 7
PLC-1	MF PLC 1
PLC-2	MF TRAINS MASTER CONTROLS PLC
PLC-4	MF PLC 2
PLC-CMFU1	MF TRAIN 1 PLC
PLC-CMFU2	MF TRAIN 2 PLC
PLC-CMFU3	MF TRAIN 3 PLC
PLC-CMFU4	MF TRAIN 4 PLC
PLC-CMFU5	MF TRAIN 5 PLC
PLC-M1	SF AND TIPS PLC
PLC-MFUV	MF UV PLC
PLC-N1	PS R1 PLC
PLC-SFUV	SF UV PLC
WWTP-H	WWTP HISTORIAN SERVER COMPUTER

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Appendix 3B

ASSETS WITH ESTIMATED INSTALLATION DATES

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Asset Name	Asset Type	Estimated Installation Date
21 KV MAIN SWITCH GEAR	Switchgear - Medium Voltage	2005
480V MOTOR CONTROL CENTER B3	Motor Control Center	2005
480V MOTOR CONTROL CENTER B4	Motor Control Center	2005
480V MOTOR CONTROL CENTER B5	Motor Control Center	2005
480V MOTOR CONTROL CENTER B6	Motor Control Center	2005
480V MOTOR CONTROL CENTER K	Motor Control Center	2005
480V MOTOR CONTROL CENTER L	Motor Control Center	2021
BLDG F- AIR HANDLING UNIT 1	HVAC - Air Handling Unit	2021
Condenser Cooling Water Pump	Pump - Centrifugal	2000
DAFT SOUTH PIT SUMP PUMP 1	Pump - Centrifugal	2003
DAFT SOUTH PIT SUMP PUMP 2	Pump - Centrifugal	2003
DAFT THICKENED SLUDGE PUMP 2 (TWAS) MOTOR	Motor - VFD Service Motor	2000
DIESEL STANDBY GENERATOR 750 kW	Diesel Generator	1995
DIGESTER 4 CIRCULATION PUMP MOTOR	Motor - Constant Speed	2017
DIGESTER 4 HEAT EXCHANGER HRS PUMP MOTOR	Motor - Constant Speed	2017
DIGESTER 4 SLUDGE MIXER 1 (EAST)	Mixer - Rapid Mix	2017
DIGESTER 4 SLUDGE MIXER 2 (SOUTH)	Mixer - Rapid Mix	2017
DIGESTER 4 SLUDGE MIXER 3 (NORTH)	Mixer - Rapid Mix	2017
DPA-A	Panel - Distribution	2003
DPEC	Switchgear - Medium Voltage	2012
Engine 1 cooling pump	Pump - Centrifugal	2000
FUEL SKID GAS COMPRESSOR 331 MOTOR	Motor - Constant Speed	1995
FUEL SKID GAS COMPRESSOR 371 MOTOR	Motor - Constant Speed	1995
GRIT PUMP 1	Pump - Centrifugal	2019
GRIT PUMP 1 MOTOR	Motor - Constant Speed	2019
GRIT PUMP 3	Pump - Centrifugal	2019
GRIT PUMP 3 MOTOR	Motor - Constant Speed	2019
GRIT PUMP 4	Pump - Centrifugal	2019
GRIT PUMP 4 MOTOR	Motor - Constant Speed	2019
GRIT SCUM PUMP 2	Pump - Progressive Cavity	2019
GRIT SCUM PUMP 2 MOTOR	Motor - Constant Speed	2019
HOT WATER LOOP CIRCULATION PUMP 1 MOTOR	Motor - Constant Speed	2019
HOT WATER LOOP CIRCULATION PUMP 2 MOTOR	Motor - Constant Speed	2019
HRS PRIMARY LOOP PUMP 1 MOTOR	Motor - Constant Speed	2019
LP11	Panel - Load Center	2009
LP-21	Panel - Load Center	2009
LP22	Panel - Distribution	2009
LP23	Panel - Load Center	2009
LP24	Panel - Load Center	2009
MCC-E	Motor Control Center	2000
MCC-F1	Motor Control Center	2000
MCC-R	Motor Control Center	2000
MCC-S	Motor Control Center	2000
MCC-X	Motor Control Center	2000
MCC-Y	Motor Control Center	2000
MOTOR CONTROL CENTER D1	Motor Control Center	2005
MOTOR CONTROL CENTER D2	Motor Control Center	2005
MOTOR CONTROL CENTER D3	Motor Control Center	2005
MOTOR CONTROL CENTER D4	Motor Control Center	2005
MOTOR CONTROL CENTER G1	Motor Control Center	2003
MOTOR CONTROL CENTER G2	Motor Control Center	2003

Note: highlighted rows indicate assets added during Carollo's condition assessment in May 2022.

Asset Name	Asset Type	Estimated Installation Date
MOTOR CONTROL CENTER HA	Motor Control Center	2000
MOTOR CONTROL CENTER HD	Motor Control Center	2005
MOTOR CONTROL CENTER HE	Motor Control Center	2005
MOTOR CONTROL CENTER HN	Motor Control Center	2000
MV TRANSFORMER 1	Transformer - Medium Voltage	2000
MV TRANSFORMER 2	Transformer - Medium Voltage	2000
MV TRANSFORMER 4	Transformer - Medium Voltage	2000
MV TRANSFORMER 5	Transformer - Medium Voltage	2004
MVS-1A	Switchgear - Medium Voltage	2003
MVS-1B	Switchgear - Medium Voltage	2003
MVS-2A/2B	Switchgear - Medium Voltage	2003
MVS-3A/3B - XFMR-3	Switchgear - Medium Voltage	2003
MVS-4A/4B XFMR-7	Switchgear - Medium Voltage	2005
MVS-5A/5B	Switchgear - Medium Voltage	2003
MVS-6A/B XFMR-6	Switchgear - Medium Voltage	2005
MVS-7A/7B - XFMR-7	Switchgear - Medium Voltage	2003
MVS-S	Switchgear - Medium Voltage	2003
PANEL 1HA 480, 3-ph	Panel - Load Center	2003
PANEL 6075 TRANSFORMER	Transformer - Medium Voltage	2003
PANEL 6076 TRANSFORMER	Transformer - Medium Voltage	2003
PANEL 6077 TRANSFORMER	Transformer - Medium Voltage	2003
PANEL BB	Panel - Load Center	2007
PANEL M-1	Panel - Load Center	2000
PANEL R-1, 120/208,3-ph	Panel - Load Center	2000
PANEL S-1, 120/240, 1 PH	Panel - Load Center	2000
Panel V	Panel - Load Center	2000
PANEL X-1, 120/208, 3-ph	Panel - Load Center	2000
PANEL Y-1, 120/240, 1PH	Panel - Load Center	2000
PNL 6075/XFMR 6075	Panel - Load Center	2003
PNL 6076	Panel - Load Center	2003
PNL 6077	Panel - Load Center	2003
PNL3571	Panel - Load Center	2005
PNL3572	Panel - Load Center	2005
PNL3573	Panel - Load Center	2005
PNL8066	Panel - Load Center	2005
PNL-8070	Panel - Load Center	2005
PNL8071	Panel - Load Center	2005
Post chlorination metering pump 1 P7911	Variable Frequency Drive	2003
POST CHLORINATION METERING PUMP 3 VFD	Variable Frequency Drive	2003
Post chlorination pump 2 P7912	Variable Frequency Drive	2003
PP12	Panel - Distribution	2009
PP21	Panel - Distribution	2009
PRE CHLORINATION RAS METERING PUMP 1 VFD	Variable Frequency Drive	2003
PRE CHLORINATION RAS METERING PUMP 2 VFD	Variable Frequency Drive	2003
Preaeration Blower 1 B2921 VFD	Variable Frequency Drive	2015
PREAERATION BLOWER 2 VFD	Variable Frequency Drive	2015
Preaeration Blower 3 B2923 VFD	Variable Frequency Drive	2019
PRIMARY SLUDGE GRINDER	Grinder	2016
PRIMARY SLUDGE GRINDER MOTOR	Motor - Constant Speed	2017
Primary sludge pump 2 VFD	Variable Frequency Drive	2021
PRIMARY SLUDGE PUMP 3 VFD	Variable Frequency Drive	2021

Note: highlighted rows indicate assets added during Carollo's condition assessment in May 2022.

Asset Name	Asset Type	Estimated Installation Date
PRIMARY SLUDGE PUMP 4 VFD	Variable Frequency Drive	2021
PRIMARY SLUDGE PUMP 5 VFD	Variable Frequency Drive	2021
Primary sludge pump 1 PMP2944 VFD	Variable Frequency Drive	2021
SECONDARY CLARIFIER TANK 1 COLLECTOR DRIVE UNIT MOTOR	Motor - Constant Speed	2016
SECONDARY CLARIFIER TANK 1 SCUM PUMP	Pump - Centrifugal	2016
SECONDARY CLARIFIER TANK 1 SCUM PUMP MOTOR	Motor - Constant Speed	2016
SECONDARY CLARIFIER TANK 2 COLLECTOR DRIVE UNIT MOTOR	Motor - Constant Speed	2016
SECONDARY CLARIFIER TANK 2 SCUM PUMP	Pump - Centrifugal	2016
SECONDARY CLARIFIER TANK 3 SCUM PUMP MOTOR	Motor - Constant Speed	2016
SWGR DPA	Switchgear - Medium Voltage	2003
SWGR DPC	Switchgear - Medium Voltage	2003
SWGR DPE	Switchgear - Medium Voltage	2005
XFMR-7 SWBD	Switchgear - Medium Voltage	2003

Note: highlighted rows indicate assets added during Carollo's condition assessment in May 2022.

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Appendix 3C

ASSET TYPE TABLE

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Asset Type	Discipline	DSRSD EUL[1]	Recommended EUL[2]
Air Compressor	MECHANICAL	15	10
Barscreen	MECHANICAL	25	25
Battery Bank	ELECTRICAL	15	15
Blowers	MECHANICAL	25	25
Chiller	MECHANICAL	20	20
Diesel Generator	MECHANICAL	20	30
Drive Unit	MECHANICAL	20	20
Engine	MECHANICAL	30	30
Engine Generator	ELECTRICAL	20	20
Fluid Power Unit	MECHANICAL	20	25
Grinder	MECHANICAL	1.5	20
Grit Classifier	MECHANICAL	20	20
HVAC - Air Handling Unit	MECHANICAL	15	15
HVAC - Exhaust Fan	MECHANICAL	20	20
HVAC - Turbine Ventilator	MECHANICAL	20	20
Longitudinal Collector	MECHANICAL	-	25
Mixer - Rapid Mix	MECHANICAL	5	20
MME-MISC MECH EQUIPMENT	MECHANICAL	-	25
Motor - Constant Speed	ELECTRICAL	25	25
Motor - Constant Speed-Submersible	ELECTRICAL	25	25
Motor - Gearmotor-Submersible	ELECTRICAL	25	25
Motor - VFD Service Motor	ELECTRICAL	25	25
Motor Control Center	ELECTRICAL	30	40
Panel - Distribution	ELECTRICAL	25	30
Panel - Load Center	ELECTRICAL	25	30
P-PUMP[3]	MECHANICAL	-	25
Pump - Centrifugal	MECHANICAL	25	25
Pump - Centrifugal-Submersible	MECHANICAL	10	15
Pump - Positive Displacement	MECHANICAL	10	15
Pump - Progressive Cavity	MECHANICAL	-	15
Pump - Vertical Turbine	MECHANICAL	25	25
Screenings Conveyor	MECHANICAL	20	20
Scum Skimmer	MECHANICAL	-	25
Secondary Clarifier Collector	MECHANICAL	20	25
Switchgear - Medium Voltage	ELECTRICAL	25	40
Transformer - Medium Voltage	ELECTRICAL	40	50
VFD	ELECTRICAL	12	15
Washer Compactor	MECHANICAL	25	25

Notes:
(1) EUL values are from the DSRSD CMMS database. These values were not used in asset analysis in this TM.
(2) Recommended EUL values based on general industry best management practices. These values were used in asset analysis in this TM.
(3) "P-Pumps" are pumps that were not identified by specific type in the CMMS database, i.e., centrifugal, vertical turbine, etc.

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Appendix 3D

ASSET CONDITION RESULTS

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							AGE-BASED ASSESSMENT					CONDITION-BASED ASSESSMENT																
Level 1	Level 2	Level 3	Discipline	Asset Name	Type	Install Date	Age	EUL	RUL	Percent Life Consumed	Age-based POF Score	Condition Score	Performance Score	Condition-based POF Score	POF Score	Percent Life Remaining	Years Remaining	Replacement Year	Carollo Field Assessment Notes	Serial_Number	Manufacturer	Model	Size_Capacity	HP	VFD Driven	Updated Replacement Cost	Source of Updated Replacement Costs
PLANT	Blower Building	Electrical Room	ELECTRICAL	21 KV MAIN SWITCH GEAR	Switchgear - Medium Voltage	2005	18	40	22	45%	2	2	2	2	2	60%	24	2046	Just needs to be maintained		IEM	7149599	27 KV, 1200 amp			400000	EATON
PLANT	OUTSIDE	GROUND FLOOR	MECHANICAL	3 WATER PUMP 1	Pump - Vertical Turbine	2017	6	25	19	24%	1	2	2	2	2	60%	15	2037		19006-2	FAIRBANKS MORSE PUMP	12M-7000AW		75		41800	Escalated using ENR values from the replacement costs
PLANT	OUTSIDE	GROUND FLOOR	ELECTRICAL	3 WATER PUMP 1 MOTOR	Motor - VFD Service Motor	2005	18	25	7	72%	3	2	2	2	2	60%	15	2037			GE			75	Y	17300	Escalated using ENR values from the replacement costs
PLANT	Effluent Pump Station		ELECTRICAL	3 WATER PUMP 1 MOTOR VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2005	18	15	0	100%	5	2	2	2	2	60%	9	2031	IN MCC G1							30000	RSMEANS
PLANT	OUTSIDE	GROUND FLOOR	MECHANICAL	3 WATER PUMP 2	Pump - Vertical Turbine	2017	6	25	19	24%	1	1	2	2	2	60%	15	2037		19006-3	FAIRBANKS MORSE PUMP	12M-7000AW		75		41800	Escalated using ENR values from the replacement costs
PLANT	OUTSIDE	GROUND FLOOR	ELECTRICAL	3 WATER PUMP 2 MOTOR	Motor - VFD Service Motor	2005	18	25	7	72%	3	1	2	2	2	60%	15	2037		RWG51582C	GE MOTORS		1790 rpm	75	Y	17300	Escalated using ENR values from the replacement costs
PLANT	Effluent Pump Station		ELECTRICAL	3 WATER PUMP 2 MOTOR VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2005	18	15	0	100%	5	1	2	2	2	60%	9	2031	IN MCC-G2							30000	RSMEANS
PLANT	OUTSIDE	GROUND FLOOR	MECHANICAL	3 WATER PUMP 3	Pump - Vertical Turbine	2017	6	25	19	24%	1	2	2	2	2	60%	15	2037		19006-1	FAIRBANKS MORSE PUMP	12M-7000AW		75		41800	Escalated using ENR values from the replacement costs
PLANT	OUTSIDE	GROUND FLOOR	ELECTRICAL	3 WATER PUMP 3 MOTOR	Motor - VFD Service Motor	2005	18	25	7	72%	3	1	2	2	2	60%	15	2037		RWG51582B	GE MOTORS		1790 rpm	75	Y	17300	Escalated using ENR values from the replacement costs
PLANT	Effluent Pump Station		ELECTRICAL	3 WATER PUMP 3 MOTOR VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2005	18	15	0	100%	5	2	2	2	2	60%	9	2031	IN MCC G1							30000	RSMEANS
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	480V MOTOR CONTROL CENTER B3	Motor Control Center	2005	18	40	22	45%	2	2	2	2	2	60%	24	2046			Cutler Hammer	Advantage series 2100	800A			132000	Historical cost estimate data
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	480V MOTOR CONTROL CENTER B4	Motor Control Center	2005	18	40	22	45%	2	1	2	2	2	60%	24	2046			Cutler Hammer	Advantage series 2100	800A			132000	Historical cost estimate data
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	480V MOTOR CONTROL CENTER B5	Motor Control Center	2005	18	40	22	45%	2	1	1	1	1	100%	40	2062			Cutler Hammer	Advantage series 2100	2000A			21000	Historical cost estimate data
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	480V MOTOR CONTROL CENTER B6	Motor Control Center	2005	18	40	22	45%	2	1	2	2	2	60%	24	2046			Cutler Hammer	Advantage series 2100	2000A			48000	Historical cost estimate data
PLANT	07 - DAFT		ELECTRICAL	480V MOTOR CONTROL CENTER K	Motor Control Center	2005	18	40	22	45%	2	1	2	2	2	60%	24	2046			Cutler Hammer	Advantage series 2100	800A			115000	Historical cost estimate data
PLANT	08 - DIGESTERS		ELECTRICAL	480V MOTOR CONTROL CENTER L	Motor Control Center	2021	2	40	38	5%	1	2	2	2	2	60%	24	2046			Cutler Hammer	Advantage	600A			69000	Historical cost estimate data
PLANT	Building D	Electric Room	ELECTRICAL	8068 PNL	Panel - Load Center	2003	20	30	10	67%	3	2	2	2	2	60%	18	2040			Cutler Hammer	PRL-1A	100 amps			5000	Historical cost estimate data
PLANT	12 - MISCELLANEOUS	2 - HOT/COLD WATER LOOPS	MECHANICAL	ABSORPTION CHILLER HRS PUMP	Pump - Centrifugal	2001	22	25	3	88%	4	2	1	2	2	60%	15	2037		030474	BELL AND GOSSET	80 3X9.5 8.625BR		7.5		7300	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	2 - SCREENING	MECHANICAL	BAR SCREEN 1	Barscreen	2007	16	25	9	64%	2	0	0	0	2	60%	15	2037	Manual screen		Fabricated					287500	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	2 - SCREENING	ELECTRICAL	BAR SCREEN 2 MOTOR VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2008	15	15	0	100%	5	0	0	0	5	10%	2	2024	Inside MCC-D2							30000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	2 - SCREENING	ELECTRICAL	BAR SCREEN 3 MOTOR VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2008	15	15	0	100%	5	0	0	0	5	10%	2	2024								30000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	2 - SCREENING	ELECTRICAL	BAR SCREEN 4 MOTOR VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2008	15	15	0	100%	5	0	0	0	5	10%	2	2024	Inside MCC-D4							30000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	2 - SCREENING	ELECTRICAL	BAR SCREEN BUILDING AIR HANDLING UNIT 1 MOTOR	Motor - Constant Speed	2001	22	25	3	88%	4	2	2	2	2	60%	15	2037	Motor appears to have been recently replaced	BW06-04	Marathon Electric	80P3701	5	5	N	1000	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	2 - SCREENING	MECHANICAL	BAR SCREEN BUILDING EXHAUST FAN 1	HVAC - Turbine Ventilator	2001	22	20	0	100%	5	2	2	2	2	60%	12	2034	In good condition, rust visible on metallic components	V10662 100	NY BLOWER		15000 cfm	75		23000	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	2 - SCREENING	ELECTRICAL	BAR SCREEN BUILDING EXHAUST FAN 1 MOTOR	Motor - Constant Speed	2001	22	25	3	88%	4	2	2	2	2	60%	15	2037	Some corrosion noted on motor, junction box, and disconnect. Junction box is not NEMA 7 enclosure, most other enclosures are in this room	01MAN94680C002JD	RELIANCE ELECTRIC	E198662	75	75	N	17300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	01 - PRE-TREATMENT	2 - SCREENING	MECHANICAL	BAR SCREEN BUILDING EXHAUST FAN 2	HVAC - Turbine Ventilator	2001	22	20	0	100%	5	2	2	2	2	60%	12	2034		V10662 105	NY BLOWER		15000cfm	75		23000	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	2 - SCREENING	ELECTRICAL	BAR SCREEN BUILDING EXHAUST FAN 2 MOTOR	Motor - Constant Speed	2001	22	25	3	88%	4	1	2	2	2	60%	15	2037	Some corrosion noted on the motor. Junction box is not nema 7 enclosure	01MAN94680C001JD	RELIANCE ELECTRIC			75		17300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	01 - PRE-TREATMENT	2 - SCREENING	MECHANICAL	BAR SCREEN BUILDING FLUID POWER SYSTEM	Fluid Power Unit	2002	21	25	4	84%	4	1	1	1	1	100%	25	2047	In good condition	DBL-FON-HY-001	PWS motion control		5gpm at 2950psi			50000	Cost estimated in the field based on engineering judgment
PLANT	01 - PRE-TREATMENT	2 - SCREENING	ELECTRICAL	BAR SCREEN BUILDING FLUID POWER SYSTEM BATTERY BAN	Battery Bank	2000	23	15	0	100%	5	1	1	1	1	100%	15	2037		0402104	American Battery Charging Inc	CBC1ABC12-24-15	15 Amp			3500	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	2 - SCREENING	MECHANICAL	BAR SCREEN WASHER COMPACTOR 1 (WEST)	Washer Compactor	2012	11	25	14	44%	2	1	1	1	1	100%	25	2047		108932-1-1	JWC Environmental	SWM3018-XE		5 for grinder motor 3 for auger		157000	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	2 - SCREENING	MECHANICAL	BAR SCREEN WASHER COMPACTOR 2 (EAST)	Washer Compactor	2012	11	25	14	44%	2	1	2	2	2	60%	15	2037		109385-1-1	JWC Environmental	Wm3018-60-xe		5 for grinder 3 for auger		157000	Escalated using ENR values from the replacement costs
PLANT	PUMP STATION	BASIN 4 EFFLUENT	MECHANICAL	BASIN 4 EFFLUENT PUMP 2	Pump - Vertical Turbine	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		1021653-2	FAIRBANKS MORSE PUMP	VTSH				70400	Escalated using ENR values from the replacement costs
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 2 MOTOR	Motor - VFD Service Motor	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		H10 03024304-100R-01	US ELECTRIC MOTOR	JVC14			Y	40000	Historical cost estimate data
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 2 MOTOR VARIABLE FREQUENCY D	Variable Frequency Drive	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024			Cutler Hammer					55000	Historical cost estimate data
PLANT	PUMP STATION	BASIN 4 EFFLUENT	MECHANICAL	BASIN 4 EFFLUENT PUMP 3	Pump - Vertical Turbine	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		1021653-1	FAIRBANKS MORSE PUMP	VTSH				70400	Escalated using ENR values from the replacement costs
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 3 MOTOR	Motor - VFD Service Motor	2000	23	25	2	92%	5	1	2	2	2	60%	15	2037		H10 03024304-100R-03	US ELECTRIC MOTOR	JVC14			Y	40000	Historical cost estimate data
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 3 MOTOR VARIABLE FREQUENCY D	Variable Frequency Drive	2000	23	15	0	100%	5	1	4	4	4	20%	3	2025								55000	Historical cost estimate data
PLANT	PUMP STATION	BASIN 4 EFFLUENT	MECHANICAL	BASIN 4 EFFLUENT PUMP 4	Pump - Vertical Turbine	2000	23	25	2	92%	5	1	2	2	2	60%	15	2037		1021653-0	FAIRBANKS MORSE PUMP	VTSH				70400	Escalated using ENR values from the replacement costs
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 4 MOTOR	Motor - VFD Service Motor	2000	23	25	2	92%	5	1	2	2	2	60%	15	2037		H10 03024304-100R-02	US ELECTRIC MOTOR	JVC14			Y	40000	Historical cost estimate data
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 4 MOTOR VARIABLE FREQUENCY D	Variable Frequency Drive	2000	23	15	0	100%	5	2	4	4	4	20%	3	2025			Robicon					55000	Historical cost estimate data
PLANT	PUMP STATION	BASIN 4 EFFLUENT	MECHANICAL	BASIN 4 EFFLUENT PUMP 5	Pump - Vertical Turbine	2006	17	25	8	68%	3	2	2	2	2	60%	15	2037		1021702-0	FAIRBANKS MORSE PUMP	VTSH-AWF		75		41800	Escalated using ENR values from the replacement costs
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 5 MOTOR	Motor - VFD Service Motor	2006	17	25	8	68%	3	2	2	2	2	60%	15	2037		H10 03024307-02	US ELECTRIC MOTOR	TVC14		75	Y	17300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 5 MOTOR VARIABLE FREQUENCY D	Variable Frequency Drive	2006	17	15	0	100%	5	0	4	4	4	20%	3	2025			Robicon					30000	Historical cost estimate data
PLANT	PUMP STATION	BASIN 4 EFFLUENT	MECHANICAL	BASIN 4 EFFLUENT PUMP 6	Pump - Vertical Turbine	2006	17	25	8	68%	3	2	2	2	2	60%	15	2037	Pump was recently recoated	1021702-1	FAIRBANKS MORSE PUMP	VTSH-AWF		75		70400	Escalated using ENR values from the replacement costs
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 6 MOTOR	Motor - VFD Service Motor	2006	17	25	8	68%	3	1	2	2	2	60%	15	2037		H10 03024307-100R-01	US ELECTRIC MOTOR	TVC14		75	Y	17300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	PUMP STATION	BASIN 4 EFFLUENT	ELECTRICAL	BASIN 4 EFFLUENT PUMP 6 MOTOR VARIABLE FREQUENCY D	Variable Frequency Drive	2006	17	15	0	100%	5	0	0	0	5	10%	2	2024			Cutler Hammer					30000	Historical cost estimate data
PLANT	12 - MISCELLANEOUS	3 - HVAC	MECHANICAL	BLDG A- AIR HANDLING UNIT 2	HVAC - Air Handling Unit	1994	29	15	0	100%	5	1	3	3	3	35%	5	2027	Old unit, works well but should replace	29004	GOVERN AIR	RSA-01-E		7.5		4600	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	7 - MEC AUXILIARY	MECHANICAL	BLDG B- AIR HANDLING UNIT 1	HVAC - Air Handling Unit	2016	7	15	8	47%	2	0	0	0	2	60%	9	2031		0916U21393	CARRIER	4ORUQU16T3A6				12700	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	7 - MEC AUXILIARY	MECHANICAL	BLDG B- AIR HANDLING UNIT 2	HVAC - Air Handling Unit	2001	22	15	0	100%	5	0	0	0	5	10%	2	2024		0008-1775		06488-FE-L				35200	Escalated using ENR values from the replacement costs
FACILITIES	PLACEHOLDER	3 - HVAC	MECHANICAL	BLDG F- AIR HANDLING UNIT 1	HVAC - Air Handling Unit	2021	2	15	13	13%	1	0	0	0	1	100%	15	2037		1110620182		CPG6048090 4BXXXBA				4600	Estimate based on size of unit
PLANT	BLANK	BLANK	MECHANICAL	BLDG S- AIR HANDLING UNIT 1	HVAC - Air Handling Unit	2007	16	15	0	100%	5	0	0	0	5	10%	2	2024		K09A41788A	TRAIN	TSCB025UF00000000CCB0A26 2.5				4600	Escalated using ENR values from the replacement costs
PLANT	BLANK	BLANK	MECHANICAL	BLDG S- AIR HANDLING UNIT 2	HVAC - Air Handling Unit	2007	16	15	0	100%	5	0	0	0	5	10%	2	2024		BDN022980	FUJITSU	A0U12CQ				4600	Escalated using ENR values from the replacement costs
FACILITIES	PLACEHOLDER		MECHANICAL	BLDG S- AIR HANDLING UNIT 3	HVAC - Air Handling Unit	2009	14	15	1	93%	5	0	0	0	5	10%	2	2024		HBN005807	FUJITSU	AOU36CLX1				4600	Estimate based on matching other similar sized equimpent.
PLANT	BLANK	BLANK	MECHANICAL	BLDG T AIR COMPRESSOR	Air Compressor	2007	16	10	0	100%	5	0	0	0	5	10%	1	2023		1067	KAESER	ASD 40T				29900	Escalated using ENR values from the replacement costs
PLANT	BLDG T	BLANK	MECHANICAL	BLDG T COLD CHILL WATER PUMP 1	Pump - Centrifugal	2009	14	25	11	56%	2	0	0	0	2	60%	15	2037		HV-C103838-1	PATTERSON PUMP COMPANY	E2F7A-1-01				4900	Escalated using ENR values from the replacement costs
PLANT	BLDG T	BLANK	MECHANICAL	BLDG T COLD CHILL WATER PUMP 2	Pump - Centrifugal	2009	14	25	11	56%	2	0	0	0	2	60%	15	2037		HVAC-C087825-04	PATTERSON PUMP COMPANY	E2F7A-1				4900	Escalated using ENR values from the replacement costs
PLANT	BLDG T	BLANK	MECHANICAL	BLDG T HOT CHILL WATER PUMP 1	Pump - Centrifugal	2009	14	25	11	56%	2	0	0	0	2	60%	15	2037			PATTERSON PUMP COMPANY	E2S17A-1				4900	Escalated using ENR values from the replacement costs
PLANT	BLDG T	BLANK	MECHANICAL	BLDG T HOT CHILL WATER PUMP 2	Pump - Centrifugal	2009	14	25	11	56%	2	0	0	0	2	60%	15	2037			PATTERSON PUMP COMPANY					4900	Escalated using ENR values from the replacement costs
PLANT	BLDG T	BLANK	MECHANICAL	BLDG T HOT CHILL WATER PUMP 3	Pump - Centrifugal	2009	14	25	11	56%	2	0	0	0	2	60%	15	2037			PATTERSON PUMP COMPANY	E2F7A-1				4900	Escalated using ENR values from the replacement costs
PLANT	BLANK	BLANK	MECHANICAL	BLDG T-AIR HANDLING UNIT 1	HVAC - Air Handling Unit	2009	14	15	1	93%	5	0	0	0	5	10%	2	2024		T09A79197	TRANE	BCHC				4600	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	MECHANICAL	BLOWER 1	Blowers	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		5267	TURBLEX	KA105V-GL210	8500 cfm max, 3825 CFC at 9 psi	400		400000	Cost estimated in the field based on engineering judgment
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	BLOWER 1 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037			GENERAL ELECTRIC	5KS 509E H1167H	3570 rpm	400	N	50000	Historical cost estimate data
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	MECHANICAL	BLOWER 2	Blowers	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037			TURBLEX	KA105V-GL210	8500 cfm, 3825 cfm min	400		400000	Cost estimated in the field based on engineering judgment
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	BLOWER 2 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037			GE MOTOR	5KS509EN1167M		400		50000	Historical cost estimate data
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	MECHANICAL	BLOWER 3	Blowers	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		5268	TURBLEX	KA105V-GL210	3825/8500	400		400000	Cost estimated in the field based on engineering judgment
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	BLOWER 3 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037			US ELECTRIC MOTOR	5KS509EN1167M	3570	400		50000	Historical cost estimate data
PLANT	11 - BUILDINGS	6 - BUILDING D	MECHANICAL	BUILDING D- AIR HANDLING UNIT	HVAC - Air Handling Unit	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024		1701F78513	CARRIER	40RM-012-136JOHC				4600	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	2 - SCREENING	MECHANICAL	BULDG C- AIR HANDLING UNIT 1	HVAC - Air Handling Unit	2001	22	15	0	100%	5	3	3	3	3	35%	5	2027		3301V105221	CARRIER	39NC13				38000	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	ELECTRICAL	COGEN ENGINE ROOM SUPPLY FAN 1 MOTOR	Motor - Constant Speed	1982	41	25	0	100%	5	0	0	0	5	10%	3	2025			LINCOLN	TEFC				1200	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	MECHANICAL	COGEN ENGINE ROOM SUPPLY FAN 2	HVAC - Exhaust Fan	1982	41	20	0	100%	5	0	0	0	5	10%	2	2024								1200	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	ELECTRICAL	COGEN ENGINE ROOM SUPPLY FAN 2 MOTOR	Motor - Constant Speed	1982	41	25	0	100%	5	0	0	0	5	10%	3	2025		2948323	LINCOLN	TEFC				1200	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	MECHANICAL	Condenser Cooling Water Pump	Pump - Centrifugal	2000	23	25	2	92%	5	3	3	3	3	35%	9	2031	Oil on the outside of the pump	1200-5659	Ingersoll-Dressor pumps		500 gpm at TDH 63			15000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	ELECTRICAL	CONDENSER COOLING WATER PUMP MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		ZTP2495MQ04A	General Electric	5KS284XAB208	1775 rpm	25	N	5800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	07 - DAFT	3 - FLOATATION	MECHANICAL	DAFT AIR COMPRESSOR 1	Air Compressor	2013	10	10	0	100%	5	1	1	1	1	100%	10	2032		1039	KAESER	BSD 40T	193 cfm @ 125 psi	40		29900	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	3 - FLOATATION	ELECTRICAL	DAFT AIR COMPRESSOR 1 MOTOR	Motor - Constant Speed	2013	10	25	15	40%	2	0	0	0	2	60%	15	2037	Was inside enclosure not visible	1039	KAESER	BSD-40-T		40	N	8100	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	3 - FLOATATION	MECHANICAL	DAFT AIR COMPRESSOR 2	Air Compressor	2013	10	10	0	100%	5	1	1	1	1	100%	10	2032		1041	KAESER	BSD 40T		40		29900	Escalated using ENR values from the replacement costs

Note: highlighted cells indicate asset information updates in the DSRSD CMMS dataset export; updates are based on Carollo's condition assessment in May 2022.

							AGE-BASED ASSESSMENT					CONDITION-BASED ASSESSMENT															
Level 1	Level 2	Level 3	Discipline	Asset Name	Type	Install Date	Age	EUL	RUL	Percent Life Consumed	Age-based POF Score	Condition Score	Performance Score	Condition-based POF Score	POF Score	Percent Life Remaining	Years Remaining	Replacement Year	Carollo Field Assessment Notes	Serial_Number	Manufacturer	Model	Size_Capacity	HP	VFD Driven	Updated Replacement Cost	Source of Updated Replacement Costs
PLANT	07 - DAFT	3 - FLOATATION	ELECTRICAL	DAFT AIR COMPRESSOR 2 MOTOR	Motor - Constant Speed	2013	10	25	15	40%	2	0	0	0	2	60%	15	2037	Inside the blower enclosure, not visible or accessible	1041	KAESER	BSD-40-T		40	N	8100	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	07 - DAFT	3 - FLOATATION	MECHANICAL	DAFT AIR COMPRESSOR 3	Air Compressor	2013	10	10	0	100%	5	1	1	1	1	100%	10	2032		1040	KAESER	BSD 40T		40		29900	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	3 - FLOATATION	ELECTRICAL	DAFT AIR COMPRESSOR 3 MOTOR	Motor - Constant Speed	2013	10	25	15	40%	2	0	0	0	2	60%	15	2037	Located inside the blower enclosure, unable to access	1040	KAESER	BSD-40-T		40	N	8100	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	07 - DAFT	7 - MEC AUXILIARY	MECHANICAL	DAFT BUILDING MAIN SUPPLY FAN	HVAC - Exhaust Fan	2013	10	20	10	50%	2	0	0	0	2	60%	12	2034			LOREN COOK COMPANY					1200	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	7 - MEC AUXILIARY	ELECTRICAL	DAFT BUILDING MAIN SUPPLY FAN MOTOR	Motor - Constant Speed	2013	10	25	15	40%	2	0	0	0	2	60%	15	2037	Unable to access							UNKNOWN	Unable to access and not enough information is provided to determine a replacement cost
PLANT	07 - DAFT	3 - FLOATATION	MECHANICAL	DAFT PRESSURIZATION PUMP 1	Pump - Centrifugal	2013	10	25	15	40%	2	2	4	4	4	20%	5	2027		1000-2667*B	Ingersoll Rand		1600 gpm at 195 TDH	125		44000	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	3 - FLOATATION	ELECTRICAL	DAFT PRESSURIZATION PUMP 1 MOTOR	Motor - Constant Speed	2013	10	25	15	40%	2	2	4	4	4	20%	5	2027		GL.C07102-1	TECO-WESTINGHOUSE	AEEA-NE001	1775 rpm	125	N	10000	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	3 - FLOATATION	MECHANICAL	DAFT PRESSURIZATION PUMP 2	Pump - Centrifugal	2013	10	25	15	40%	2	2	4	4	4	20%	5	2027		1000-2667*A	Ingersoll Rand			150		44000	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	3 - FLOATATION	ELECTRICAL	DAFT PRESSURIZATION PUMP 2 MOTOR	Motor - Constant Speed	2013	10	25	15	40%	2	2	4	4	4	20%	5	2027	Motor not premium efficiency	A1206212003	BALDOR-RELIANCE	A44-2428-1778		150	N	11800	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	MECHANICAL	DAFT SOUTH PIT SUMP PUMP 1	Pump - Centrifugal	2003	20	25	5	80%	4	0	0	0	4	20%	5	2027		9860023	FLYGT					4900	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	MECHANICAL	DAFT SOUTH PIT SUMP PUMP 2	Pump - Centrifugal	2003	20	25	5	80%	4	0	0	0	4	20%	5	2027		9810129	FLYGT					4900	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	MECHANICAL	DAFT THICKENED SLUDGE PUMP 1 (TWAS)	Pump - Positive Displacement	2001	22	15	0	100%	5	2	2	2	2	60%	9	2031	Pump stator housing appears to have been recently replaced.	15593	NETZSCH NEMO	NM0905Y		25		24200	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	ELECTRICAL	DAFT THICKENED SLUDGE PUMP 1 (TWAS) MOTOR	Motor - VFD Service Motor	2013	10	25	15	40%	2	2	2	2	2	60%	15	2037		N105855X20961-P0102	BALDOR	M22A-92051772-04		25	Y	5800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	ELECTRICAL	DAFT THICKENED SLUDGE PUMP 1 (TWAS) VARIABLE FREQ	Variable Frequency Drive	2013	10	15	5	67%	3	0	0	0	3	35%	5	2027								15000	Historical cost estimate data
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	MECHANICAL	DAFT THICKENED SLUDGE PUMP 2 (TWAS)	Pump - Centrifugal	2013	10	25	15	40%	2	2	2	2	2	60%	15	2037		080304	PENN VALLEY PUMP	4DDX30CNU				24200	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	ELECTRICAL	DAFT THICKENED SLUDGE PUMP 2 (TWAS) MOTOR	Motor - VFD Service Motor	2000	23	25	2	92%	5	3	2	3	3	35%	9	2031	Looks old						Y	UNKNOWN	HP can not be confirmed from photo - therefore replacement cost is not confirmed
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	ELECTRICAL	DAFT THICKENED SLUDGE PUMP 2 (TWAS) VARIABLE FREQ	Variable Frequency Drive	2013	10	15	5	67%	3	0	0	0	3	35%	5	2027								15000	Assumed at 25hp to match DAFT THICKENED SLUDGE PUMP 1/2 (TWAS) MOTORS. Replacement cost determined using historical cost estimate data
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	MECHANICAL	DAFT THICKENED SLUDGE PUMP 3 (TWAS)	Pump - Positive Displacement	2018	5	15	10	33%	1	2	1	2	2	60%	9	2031	TWAS piping and valves associated with this pump is showing corrosion.	B159803	NETZSCH NEMO	NM0905Y02S08K		25		24200	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	ELECTRICAL	DAFT THICKENED SLUDGE PUMP 3 (TWAS) MOTOR	Motor - VFD Service Motor	2013	10	25	15	40%	2	2	2	2	2	60%	15	2037			BALDOR	0105752037-000010		25	Y	5800	Escalated using ENR values from the replacement costs
PLANT	07 - DAFT	4 - SOLIDS REMOVAL	ELECTRICAL	DAFT THICKENED SLUDGE PUMP 3 (TWAS) VARIABLE FREQ	Variable Frequency Drive	2013	10	15	5	67%	3	0	0	0	3	35%	5	2027								15000	Historical cost estimate data
PLANT	BLDG A	EMERGENCY GENERATOR	MECHANICAL	DIESEL STANDBY 1250 kW GENERATOR	Diesel Generator	2004	19	30	11	63%	2	2	2	2	2	60%	18	2040	In good condition	33160017	CUMMINS	KTA50-G9	1800 rpm	22200		196100	Escalated using ENR values from the replacement costs
PLANT	BLDG J	BLANK	MECHANICAL	DIESEL STANDBY GENERATOR 750 kW	Diesel Generator	1995	28	30	2	93%	5	3	4	4	4	20%	6	2028	Operations has indicated it is oversized and requires a load bank to start up. If EPS-1 is running, operations needs it. Has been rehabbed in the past 2 years (some parts of the generator)		Caterpillar					117700	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND FLOOR	MECHANICAL	DIGESTED SLUDGE PUMP 1	Pump - Positive Displacement	2007	16	15	0	100%	5	2	1	2	2	60%	9	2031			NETZSCH NEMO					24200	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND FLOOR	ELECTRICAL	DIGESTED SLUDGE PUMP 1 MOTOR	Motor - VFD Service Motor	1960	63	25	0	100%	5	2	2	2	2	60%	15	2037			BALDOR	92051772-03	1770 rpm	25	N	5800	Escalated using ENR values from the replacement costs
PLANT	Building D	Electric Room	ELECTRICAL	DIGESTED SLUDGE PUMP 1 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024	Inside MCC-D1		MFR STD					15000	Historical cost estimate data
PLANT	08 - DIGESTERS	GROUND LEVEL	MECHANICAL	DIGESTED SLUDGE PUMP 2	Pump - Positive Displacement	2013	10	15	5	67%	3	2	1	2	2	60%	9	2031			NETZSCH NEMO					24200	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND LEVEL	ELECTRICAL	DIGESTED SLUDGE PUMP 2 MOTOR	Motor - VFD Service Motor	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037			BALDOR	92051772-01		25		5800	Escalated using ENR values from the replacement costs
PLANT	Building D	Electric Room	ELECTRICAL	DIGESTED SLUDGE PUMP 2 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024			MFR STD					15000	Historical cost estimate data
PLANT	08 - DIGESTERS	3 - DIGESTER 3	MECHANICAL	DIGESTED SLUDGE PUMP 3	Pump - Centrifugal	2000	23	25	2	92%	5	3	3	3	3	35%	9	2031		9348LP	Chesterton			25		24200	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	3 - DIGESTER 3	ELECTRICAL	DIGESTED SLUDGE PUMP 3 MOTOR	Motor - VFD Service Motor	2000	23	25	2	92%	5	3	1	3	3	35%	9	2031		10C151W373	BALDOR	M4103T	1760 rpm	25	N	5800	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	1 - DIGESTER 1	MECHANICAL	DIGESTER 1 CIRCULATION PUMP	Pump - Centrifugal	2021	2	25	23	8%	1	1	1	1	1	100%	25	2047	Pump and motor were recently replaced	62435A	VAUGHN	H4P6SB	600 gpm	15		14500	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	1 - DIGESTER 1	ELECTRICAL	DIGESTER 1 CIRCULATION PUMP MOTOR	Motor - Constant Speed	2021	2	25	23	8%	1	1	1	1	1	100%	25	2047			RLIANCE ELECTRIC MOTOR	284T		15	N	1800	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND LEVEL	MECHANICAL	DIGESTER 1 HEAT EXCHANGER HRS PUMP	Pump - Centrifugal	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037	Pump is older but appears in good condition other than needing some coating.	1200-5657 *A	INGERSOLL DRESSER PUMPS	HOC3+		3		5400	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	1 - DIGESTER 1	MECHANICAL	DIGESTER 1 MECHANICAL MIXER	Mixer - Rapid Mix	2002	21	20	0	100%	5	3	2	3	3	35%	7	2029	Enclosures are not explosion proof rated	SMII 18530 LI	WESTECH		9400-12500gpm			63300	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	1 - DIGESTER 1	ELECTRICAL	DIGESTER 1 MECHANICAL MIXER MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037			US ELECTRIC MOTOR	A627		10	N	1400	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND LEVEL	MECHANICAL	DIGESTER 2 CIRCULATION PUMP	Pump - Centrifugal	2001	22	25	3	88%	4	1	2	2	2	60%	15	2037		62435B	Vaughan	H4P6SB	1170 rpm	15		14500	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND LEVEL	ELECTRICAL	DIGESTER 2 CIRCULATION PUMP MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		01MAN93944	RELIANCE ELECTRIC	841XL	1180 rpm	15	N	1800	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND LEVEL	MECHANICAL	DIGESTER 2 HEAT EXCHANGER HRS PUMP	Pump - Centrifugal	2000	23	25	2	92%	5	3	2	3	3	35%	9	2031		1200-5657 *B	INGERSOLL DRESSER PUMPS	HOC3+	220 gpm at 26 TDH	3		2900	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	2 - DIGESTER 2	MECHANICAL	DIGESTER 2 MECHANICAL MIXER	Mixer - Rapid Mix	2002	21	20	0	100%	5	3	2	3	3	35%	7	2029			Westech			10		63300	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	ROOF	ELECTRICAL	DIGESTER 2 MECHANICAL MIXER MOTOR	Motor - Constant Speed	1971	52	25	0	100%	5	3	2	3	3	35%	9	2031	Electrical connections not rated for classified area.		US ELECTRIC MOTOR	A627		10	N	1400	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	3 - DIGESTER 3	MECHANICAL	DIGESTER 3 CIRCULATION PUMP 1	Pump - Centrifugal	2000	23	25	2	92%	5	1	1	1	1	100%	25	2047	Looks brand new - installation date is incorrect. Missing nameplate		Vaughan					14500	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	3 - DIGESTER 3	ELECTRICAL	DIGESTER 3 CIRCULATION PUMP 1 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037			RELIANCE ELECTRIC	01MAN93944 G003 ED		15	N	1800	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND LEVEL	MECHANICAL	DIGESTER 3 HEAT EXCHANGER HRS PUMP	Pump - Centrifugal	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037						3		5800	Escalated using ENR values from the replacement costs
PLANT	BLANK	BLANK	MECHANICAL	DIGESTER 4 CIRCULATION PUMP	Pump - Centrifugal	2018	5	25	20	20%	1	1	1	1	1	100%	25	2047		138431	VAUGHAN	HE4T6CSB	600 gpm	15		25000	Cost estimated in the field based on engineering judgment
PLANT	08 - DIGESTERS	GROUND FLOOR	ELECTRICAL	DIGESTER 4 CIRCULATION PUMP MOTOR	Motor - Constant Speed	2017	6	25	19	24%	1	1	1	1	1	100%	25	2047	Looks new	C1802200562	BALDOR		1180 rpm	15	N	1800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	08 - DIGESTERS	GROUND LEVEL	MECHANICAL	DIGESTER 4 HEAT EXCHANGER HRS PUMP	Pump - Centrifugal	2018	5	25	20	20%	1	1	1	1	1	100%	25	2047	In good shape	1266492CHP002A	FLOWSERVE	MK3-STD				5800	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	GROUND LEVEL	ELECTRICAL	DIGESTER 4 HEAT EXCHANGER HRS PUMP MOTOR	Motor - Constant Speed	2017	6	25	19	24%	1	1	1	1	1	100%	25	2047	Looks new, in great condition	X18D1M66797	BALDOR			5	N	1000	Escalated using ENR values from the replacement costs
PLANT	BLANK	BLANK	MECHANICAL	DIGESTER 4 SLUDGE MIXER 1 (EAST)	Mixer - Rapid Mix	2017	6	20	14	30%	1	1	1	1	1	100%	20	2042		1727-20C	OLYMPUS TECHNOLOGIES, INC.	10N3		10		15000	Cost estimated in the field based on engineering judgment
PLANT	BLANK	BLANK	MECHANICAL	DIGESTER 4 SLUDGE MIXER 2 (SOUTH)	Mixer - Rapid Mix	2017	6	20	14	30%	1	1	1	1	1	100%	20	2042	Enclosures are explosion proof rated	1727-20B	OLYMPUS TECHNOLOGIES, INC.	10N3		10		15000	Cost estimated in the field based on engineering judgment
PLANT	BLANK	BLANK	MECHANICAL	DIGESTER 4 SLUDGE MIXER 3 (NORTH)	Mixer - Rapid Mix	2017	6	20	14	30%	1	2	1	2	2	60%	12	2034		1727-20A	OLYMPUS TECHNOLOGIES, INC.	10N3		10		15000	Cost estimated in the field based on engineering judgment
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	DP11	Panel - Distribution	2009	14	30	16	47%	2	1	2	2	2	60%	18	2040			Eaton	PRL4	600A			80000	Historical cost estimate data
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	DPA-A	Panel - Distribution	2003	20	30	10	67%	3	2	2	2	2	60%	18	2040			Eaton	PRL3A	600 amp			8500	Historical cost estimate data
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	DPEC	Switchgear - Medium Voltage	2012	11	40	29	28%	1	2	2	2	2	60%	24	2046			Thomson Technology	GCS	100 amps			115000	Historical cost estimate data
PLANT	10 - CO-GENERATION	1 - GENERATOR 1	MECHANICAL	ENGINE 1	Engine	1982	41	30	0	100%	5	4	3	4	4	20%	6	2028		C-10724/1	WAUKESHA	F3521GSID	1200 rpm	889 (in kW)		920000	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	1 - GENERATOR 1	MECHANICAL	Engine 1 cooling pump	Pump - Centrifugal	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037	Added asset						5		Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	2 - GENERATOR 2	MECHANICAL	ENGINE 2	Engine	1995	28	30	2	93%	5	4	3	4	4	20%	6	2028			WAUKESHA	F3521GLD				920000	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	2 - GENERATOR 2	MECHANICAL	ENGINE 2 COOLING PUMP	Pump - Centrifugal	1995	28	25	0	100%	5	3	1	3	3	35%	9	2031			BELL & GOSSETT	P85855-16815		5		4900	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	3 - GENERATOR 3	MECHANICAL	ENGINE 3	Engine	2008	15	30	15	50%	2	4	3	4	4	20%	6	2028			WAUKESHA	F2895GSI				920000	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	3 - GENERATOR 3	MECHANICAL	ENGINE 3 COOLING PUMP	Pump - Centrifugal	2008	15	25	10	60%	2	2	1	2	2	60%	15	2037			BELL & GOSSETT	P85855-16815	800 rpm	5		4900	Escalated using ENR values from the replacement costs
PLANT	06 - EFFLUENT PUMPING	9 - MISCELLANEOUS	MECHANICAL	FINAL EFFLUENT PUMP 1	Pump - Vertical Turbine	2005	18	25	7	72%	3	2	2	2	2	60%	15	2037		967824-0	FAIRBANKS MORSE PUMP	VTSH		250		70400	Escalated using ENR values from the replacement costs
PLANT	06 - EFFLUENT PUMPING	NORTH BLDG G	ELECTRICAL	FINAL EFFLUENT PUMP 1 MOTOR	Motor - VFD Service Motor	2005	18	25	7	72%	3	1	2	2	2	60%	15	2037			GE MOTORS	5KAF84466600201		250	Y	40000	Historical cost estimate data
PLANT	06 - EFFLUENT PUMPING	9 - MISCELLANEOUS	ELECTRICAL	FINAL EFFLUENT PUMP 1 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2005	18	15	0	100%	5	2	4	4	4	20%	3	2025	Robicon was bought by another company		Robicon					55000	Historical cost estimate data
PLANT	06 - EFFLUENT PUMPING	9 - MISCELLANEOUS	MECHANICAL	FINAL EFFLUENT PUMP 3	Pump - Vertical Turbine	2005	18	25	7	72%	3	2	0	2	2	60%	15	2037		967824-1	FAIRBANKS MORSE PUMP			250		70400	Escalated using ENR values from the replacement costs
PLANT	06 - EFFLUENT PUMPING	NORTH BLDG G	ELECTRICAL	FINAL EFFLUENT PUMP 3 MOTOR	Motor - VFD Service Motor	2005	18	25	7	72%	3	1	2	2	2	60%	15	2037			GE MOTORS	5KAF8446660021		250	Y	40000	Historical cost estimate data
PLANT	06 - EFFLUENT PUMPING	9 - MISCELLANEOUS	ELECTRICAL	FINAL EFFLUENT PUMP 3 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2005	18	15	0	100%	5	2	4	4	4	20%	3	2025	Robicon was bought		Robicon					55000	Historical cost estimate data
PLANT	06 - EFFLUENT PUMPING	9 - MISCELLANEOUS	MECHANICAL	FINAL EFFLUENT PUMP 5	Pump - Vertical Turbine	2003	20	25	5	80%	4	2	2	2	2	60%	15	2037		967824-2	FAIRBANKS MORSE PUMP	VTSH		250		70400	Escalated using ENR values from the replacement costs
PLANT	06 - EFFLUENT PUMPING	NORTH BLDG G	ELECTRICAL	FINAL EFFLUENT PUMP 5 MOTOR	Motor - VFD Service Motor	2003	20	25	5	80%	4	2	2	2	2	60%	15	2037			GE MOTORS	5KAF84466600201		250	Y	40000	Historical cost estimate data
PLANT	06 - EFFLUENT PUMPING	9 - MISCELLANEOUS	ELECTRICAL	FINAL EFFLUENT PUMP 5 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2005	18	15	0	100%	5	2	4	4	4	20%	3	2025	Robicon was bought out		Robicon					55000	Historical cost estimate data
PLANT	10 - CO-GENERATION	4 - GAS MANAGEMENT	ELECTRICAL	FUEL SKID GAS COMPRESSOR 331 MOTOR	Motor - Constant Speed	1995	28	25	0	100%	5	3	1	3	3	35%	9	2031	Added Asset.		NIDEC	CU92	1780 rpm	40	N	8100	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	4 - GAS MANAGEMENT	ELECTRICAL	FUEL SKID GAS COMPRESSOR 371 MOTOR	Motor - Constant Speed	1995	28	25	0	100%	5	3	1	3	3	35%	9	2031	Added asset.		NIDEC	CU92	1780 rpm	40	N	8100	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	11 - BUILDINGS	3 - LABORATORY	MECHANICAL	FUME HOOD 2 SUPPLY FAN EF-1	HVAC - Exhaust Fan	1994	29	20	0	100%	5	0	0	0	5	10%	2	2024								1200	Escalated using ENR values from the replacement costs
PLANT	11 - BUILDINGS	3 - LABORATORY	ELECTRICAL	FUME HOOD 2 SUPPLY FAN EF-1 MOTOR	Motor - Constant Speed	1994	29	25	0	100%	5	0	0	0	5	10%	3	2025								1000	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	1 - GENERATOR 1	ELECTRICAL	GENERATOR 1	Engine Generator	2014	9	20	11	45%	2	2	3	3	3	35%	7	2029		87382-2	KATO	500-683361111	1200 rpm			92700	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	2 - GENERATOR 2	ELECTRICAL	GENERATOR 2	Engine Generator	2015	8	20	12	40%	2	2	3	3	3	35%	7	2029		13997	KATO	A270830000	500 kw			92700	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	3 - GENERATOR 3	ELECTRICAL	GENERATOR 3	Engine Generator	2016	7	20	13	35%	1	3	3	3	3	35%	7	2029		97529	KATO	KCR760				100300	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	GRIT DUMPSTER WINCH MOTOR	Motor - Constant Speed	1985	38	25	0	100%	5	3	2	3	3	35%	9	2031		12J07W213-A	BALDOR		1160 rpm	25	N	5800	Cost estimated in the field based on engineering judgment, and updated based on historical data
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	MECHANICAL	GRIT PUMP 1	Pump - Centrifugal	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047		19DW12259-01	WEMCO	MODEL C	250GPM AT 65 HEAD			20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	GRIT PUMP 1 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	1	2	2	2	60%	15	2037			BALDOR			20	N	5300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	MECHANICAL	GRIT PUMP 3	Pump - Centrifugal	2019	4	25	21	16%	1	1	2	2	2	60%	15	2037		19DW12259-04	WEMCO	MODEL C	250GPM AT 65 FT HEAD			20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	GRIT PUMP 3 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	1	2	2	2	60%	15	2037		Z1906140197	BALDOR			20	N	5300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	Headworks and Primary Sediment	Equipment Gallery	MECHANICAL	GRIT PUMP 4	Pump - Centrifugal	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047		19DW12259-03	WEMCO	MODEL C	250GPM AT 65 FT HEAD	20		20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	GRIT PUMP 4 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047		Z1906140192	BALDOR			20	N	5300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)

Note: highlighted cells indicate asset information updates in the DSRSD CMMS dataset export; updates are based on Carollo's condition assessment in May 2022.

							AGE-BASED ASSESSMENT					CONDITION-BASED ASSESSMENT																
Level 1	Level 2	Level 3	Discipline	Asset Name	Type	Install Date	Age	EUL	RUL	Percent Life Consumed	Age-based POF Score	Condition Score	Performance Score	Condition-based POF Score	POF Score	Percent Life Remaining	Years Remaining	Replacement Year	Carollo Field Assessment Notes	Serial_Number	Manufacturer	Model	Size_Capacity	HP	VFD Driven	Updated Replacement Cost	Source of Updated Replacement Costs
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	GRIT REMOVER (ORT) EXHAUST FAN MOTOR	Motor - Constant Speed	2021	2	25	23	8%	1	0	0	0	1	100%	25	2047	Unable to access		TECO-WESTINGHOUSE					UNKNOWN	Unable to access and not enough information is provided to determine a replacement cost
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	MECHANICAL	GRIT SCUM PUMP 2	Pump - Progressive Cavity	2019	4	15	11	27%	1	1	1	1	1	100%	15	2037		19DW12259-02	WEMCO	MODEL C	250GPM AT 65 HEAD			20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	GRIT SCUM PUMP 2 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047		Z1006140202	BALDOR			20	N	5300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	HOT WATER LOOP CIRCULATION PUMP 1 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047	Added asset, not in the CMMS database. Looks new.	Z1403130051	BALDOR	EM3774T	1760 rpm	10	N	1400	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	HOT WATER LOOP CIRCULATION PUMP 2 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047	Added asset, not included in the CMMS database. Looks new.	Z1403130101	BALDOR	EM3774T	1760 rpm	10	N	1400	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	MECHANICAL	HRS PRIMARY LOOP PUMP 1	Pump - Centrifugal	1983	40	25	0	100%	5	2	2	2	2	60%	15	2037	Some cracks in the coating, corrosion on the anchor bolts	1971112524-10	Grundfos					7300	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	ELECTRICAL	HRS PRIMARY LOOP PUMP 1 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	2	2	2	2	60%	15	2037	Looks new - was not installed in 2000 and the serial number is different.		US MOTORS	DB4S	2860-3505 rpm	10	N	1400	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	MECHANICAL	HRS PRIMARY LOOP PUMP 2	Pump - Centrifugal	1983	40	25	0	100%	5	2	2	2	2	60%	15	2037			Paco		160 gpm @ 20 TDH	10		7300	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	ELECTRICAL	HRS PRIMARY LOOP PUMP 2 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	1	1	1	1	100%	25	2047	Motor appears to be new, recently replaced. Info in CMMS needs updating	F0302141753	US Motor	DB4S		10	N	1400	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	DOWNSTAIRS	BLDG H	MECHANICAL	INFLUENT PUMP 1	Pump - Centrifugal	1986	37	25	0	100%	5	1	1	1	1	100%	25	2047		K3N1060754-0	FAIRBANKS MORSE		14 MGD at 21 TDH			58700	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT PUMP 1 MOTOR	Motor - Constant Speed	2001	22	25	3	88%	4	1	2	2	2	60%	15	2037		E0299117695-001R-02	US MOTORS			200	Y	35000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT PUMP 1 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	1	1	1	1	100%	15	2037			AB			300		70000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	MECHANICAL	INFLUENT PUMP 2	Pump - Centrifugal	2000	23	25	2	92%	5	3	4	4	4	20%	5	2027		K3N1060754-1	FAIRBANKS MORSE		14 MGD at 21TDH			58700	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT PUMP 2 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	4	4	4	20%	5	2027		E0299117695-001R-03	US MOTORS			200	Y	35000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT PUMP 2 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	1	1	1	1	100%	15	2037			AB		300 hp	300		70000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	MECHANICAL	INFLUENT PUMP 3	Pump - Centrifugal	1986	37	25	0	100%	5	1	2	2	2	60%	15	2037		K3N1060754-2	FAIRBANKS MORSE PUMPS					58700	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT PUMP 3 MOTOR	Motor - Constant Speed	2003	20	25	5	80%	4	1	2	2	2	60%	15	2037		E0299117695-001R-01	US MOTORS			200	Y	35000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT PUMP 3 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	2	3	3	3	35%	5	2027			Robicon/Cutler-Hammer					50000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	MECHANICAL	INFLUENT PUMP 4	Pump - Centrifugal	2000	23	25	2	92%	5	2	4	4	4	20%	5	2027		K3N1060754-3	FAIRBANKS MORSE PUMPS					58700	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT PUMP 4 MOTOR	Motor - Constant Speed	2003	20	25	5	80%	4	3	4	4	4	20%	5	2027		E0299117695-001R-04	US MOTORS			200	Y	35000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT PUMP 4 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	2	3	3	3	35%	5	2027	Robicon has been bought by semens		Robicon/Cutler-Hammer					50000	Historical cost estimate data
PLANT	OUTSIDE	GROUND FLOOR	MECHANICAL	INFLUENT PUMP ROOM AIR HANDLING UNIT	HVAC - Air Handling Unit	1985	38	15	0	100%	5	1	1	1	1	100%	15	2037								4600	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	MECHANICAL	INFLUENT SUMP PUMP 1	Pump - Centrifugal	2003	20	25	5	80%	4	0	0	0	4	20%	5	2027		2229J467.779 E03	WELL PUMP	2229				4900	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT SUMP PUMP 1 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	1	2	2	2	60%	15	2037		12366	BALDOR	2229	1750 rpm	5	N	1000	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	MECHANICAL	INFLUENT SUMP PUMP 2	Pump - Centrifugal	2003	20	25	5	80%	4	0	0	0	4	20%	5	2027		2229J467-778 E03	WELL PUMP	2229				4900	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	INFLUENT SUMP PUMP 2 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	1	1	1	1	100%	25	2047		12367	BALDOR INDUSTRIAL MOTORS	2229	1750 RPM	5	N	1000	Escalated using ENR values from the replacement costs
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	LP11	Panel - Load Center	2009	14	30	16	47%	2	2	1	2	2	60%	18	2040			Eaton	PRL1a	100A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	LP115	Panel - Load Center	2009	14	30	16	47%	2	2	2	2	2	60%	18	2040			EATON	PRL1A	208;120V 70 A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	LP121	Panel - Load Center	2009	14	30	16	47%	2	2	2	2	2	60%	18	2040			Eaton	PRL1A	208/120V 100A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	LP-21	Panel - Load Center	2009	14	30	16	47%	2	2	2	2	2	60%	18	2040			Cutler hammer	PRL1A	150A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	LP22	Panel - Distribution	2009	14	30	16	47%	2	2	2	2	2	60%	18	2040			Eaton	PRL3A	400 amp			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	LP23	Panel - Load Center	2009	14	30	16	47%	2	2	2	2	2	60%	18	2040	Subfed from LP21		Eaton	PRL1A	208/120V 100A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	LP24	Panel - Load Center	2009	14	30	16	47%	2	1	1	1	1	100%	30	2052	Picture of panel board transformer is included		Eaton	PRL1a	225A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	LP79	Panel - Load Center	2004	19	30	11	63%	2	2	2	2	2	60%	18	2040	Transformer pictures are in this asset too		Eaton	PRL1A	100 amp			5000	Historical cost estimate data.
PLANT	06 - EFFLUENT PUMPING	8 - ELE/INS AUXILIARY	ELECTRICAL	MCC M-3	Motor Control Center	2017	6	40	34	15%	1	1	1	1	1	100%	40	2062			Eaton	Freedom series 2100	600A			103500	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	MCC-E	Motor Control Center	2000	23	40	17	58%	2	3	4	4	4	20%	8	2030								33000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	MCC-F1	Motor Control Center	2000	23	40	17	58%	2	2	4	4	4	20%	8	2030			Klockner-Moeller	Series 200	600A			22000	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	MCC-R	Motor Control Center	2000	23	40	17	58%	2	3	3	3	3	35%	14	2036			Cutler Hammer					44000	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	MCC-S	Motor Control Center	2000	23	40	17	58%	2	3	3	3	3	35%	14	2036			Cutler Hammer					44000	Historical cost estimate data.
PLANT	10 - CO-GENERATION		ELECTRICAL	MCC-X	Motor Control Center	2000	23	40	17	58%	2	3	3	3	3	35%	14	2036			Cutler Hammer					55000	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	MCC-Y	Motor Control Center	2000	23	40	17	58%	2	4	3	4	4	20%	8	2030			Cutler Hammer					55000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	MIXED LIQUOR WAS PUMP 1	Pump - Centrifugal-Submersible	2001	22	15	0	100%	5	0	0	0	5	10%	2	2024	Submersible pumps not visible for assessment		FLYTE					29000	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	MIXED LIQUOR WAS PUMP 1 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024			Cutler Hammer					18000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	MIXED LIQUOR WAS PUMP 2	Pump - Centrifugal	2013	10	25	15	40%	2	0	0	0	2	60%	15	2037	Submersible pump not visible for assessment							29000	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	MIXED LIQUOR WAS PUMP 2 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2013	10	15	5	67%	3	0	0	0	3	35%	5	2027		205 4842						18000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	MIXED LIQUOR WAS PUMP 3	Pump - Centrifugal-Submersible	2001	22	15	0	100%	5	0	0	0	5	10%	2	2024	Submersible pump not visible for assessment		FLYTE					29000	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	MIXED LIQUOR WAS PUMP 3 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024								18000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	1 - AERATION	MECHANICAL	MIXER 1	Mixer - Rapid Mix	2000	23	20	0	100%	5	0	0	0	5	10%	2	2024	Mixer submersible not accessible to view		LANDIA	12542				19600	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	1 - AERATION	ELECTRICAL	MIXER 1 MOTOR	Motor - Gearmotor-Submersible	2001	22	25	3	88%	4	0	0	0	4	20%	5	2027			MFR STD	DK6940		9	N	800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	1 - AERATION	MECHANICAL	MIXER 2	Mixer - Rapid Mix	2000	23	20	0	100%	5	0	0	0	5	10%	2	2024			LANDIA					19600	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	1 - AERATION	ELECTRICAL	MIXER 2 MOTOR	Motor - Gearmotor-Submersible	2001	22	25	3	88%	4	0	0	0	4	20%	5	2027			MFR STD	DK6940		9	N	800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	1 - AERATION	MECHANICAL	MIXER 3	Mixer - Rapid Mix	2000	23	20	0	100%	5	0	0	0	5	10%	2	2024			LANDIA					19600	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	1 - AERATION	ELECTRICAL	MIXER 3 MOTOR	Motor - Gearmotor-Submersible	2001	22	25	3	88%	4	0	0	0	4	20%	5	2027	Unable to access		MFR STD	DK6940		9	N	800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	1 - AERATION	MECHANICAL	MIXER 4	Mixer - Rapid Mix	2000	23	20	0	100%	5	0	0	0	5	10%	2	2024			LANDIA					19600	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	1 - AERATION	ELECTRICAL	MIXER 4 MOTOR	Motor - Gearmotor-Submersible	2001	22	25	3	88%	4	0	0	0	4	20%	5	2027			MFR STD	DK6940			N	800	Escalated using ENR values from the replacement costs
PLANT	Building D	BLANK	ELECTRICAL	MOTOR CONTROL CENTER D1	Motor Control Center	2005	18	40	22	45%	2	2	2	2	2	60%	24	2046			Cutler hammer	Freedom-series 2100	800 amps		N	80500	Historical cost estimate data.
PLANT	Building D	BLANK	ELECTRICAL	MOTOR CONTROL CENTER D2	Motor Control Center	2005	18	40	22	45%	2	2	2	2	2	60%	24	2046			Cutler Hammer	Advantage series 2100	800 amps		N	108000	Historical cost estimate data.
PLANT	Building D	BLANK	ELECTRICAL	MOTOR CONTROL CENTER D3	Motor Control Center	2005	18	40	22	45%	2	2	2	2	2	60%	24	2046			Cutler Hammer	Advantage series 2100	600 amps		N	108000	Historical cost estimate data.
PLANT	Building D	BLANK	ELECTRICAL	MOTOR CONTROL CENTER D4	Motor Control Center	2005	18	40	22	45%	2	2	2	2	2	60%	24	2046			Cutler Hammer	Advantage series 2100	600 amps		N	108000	Historical cost estimate data.
PLANT	Effluent Pump Station		ELECTRICAL	MOTOR CONTROL CENTER G1	Motor Control Center	2003	20	40	20	50%	2	1	2	2	2	60%	24	2046			Cutler hammer	Advantage series 2100	600A			60000	Historical cost estimate data.
PLANT	Effluent Pump Station		ELECTRICAL	MOTOR CONTROL CENTER G2	Motor Control Center	2003	20	40	20	50%	2	1	2	2	2	60%	24	2046			Cutler Hammer	Advantage Series 2100	600A			69000	Historical cost estimate data.
PLANT	Headworks and Primary Sediment		ELECTRICAL	MOTOR CONTROL CENTER HA	Motor Control Center	2000	23	40	17	58%	2	1	1	1	1	100%	40	2062			Eaton	Freedom series 2100	600 amp		N	57500	Escalated using ENR values from the replacement costs
PLANT	Headworks and Primary Sediment		ELECTRICAL	MOTOR CONTROL CENTER HD	Motor Control Center	2005	18	40	22	45%	2	1	1	1	1	100%	40	2062			Cutler Hammer	Advantage series 2100	600 amp		N	57500	Escalated using ENR values from the replacement costs
PLANT	Headworks and Primary Sediment		ELECTRICAL	MOTOR CONTROL CENTER HE	Motor Control Center	2005	18	40	22	45%	2	1	1	1	1	100%	40	2062			Eaton	Freedom 2100	600 amp		N	57500	Escalated using ENR values from the replacement costs
PLANT	Headworks and Primary Sediment		ELECTRICAL	MOTOR CONTROL CENTER HN	Motor Control Center	2000	23	40	17	58%	2	1	1	1	1	100%	40	2062	Couldn't locate MCC-HEA, replaced withMCC-HN		Eaton	Freedom series 2100	12000 amp		N	57500	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	MV TRANSFORMER 1	Transformer - Medium Voltage	2000	23	50	27	46%	2	2	2	2	2	60%	30	2052		970426-A1	SQUARE-D CO					105000	Historical cost estimate data.
PLANT	Building D	Outside	ELECTRICAL	MV TRANSFORMER 2	Transformer - Medium Voltage	2000	23	50	27	46%	2	2	2	2	2	60%	30	2052		012600815	COOPER		1500/1680 - 1725/1932 KVA			105000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	MV TRANSFORMER 4	Transformer - Medium Voltage	2000	23	50	27	46%	2	2	2	2	2	60%	30	2052		012600835	COOPER		2000/2240-2300/2576 KVA			125000	Historical cost estimate data.
PLANT	06 - EFFLUENT PUMPING	8 - ELE/INS AUXILIARY	ELECTRICAL	MV TRANSFORMER 5	Transformer - Medium Voltage	2004	19	50	31	38%	1	2	2	2	2	60%	30	2052		PJD-0273	CUTLER-HAMMER		1500/1680-1725/1932 kVA			105000	Historical cost estimate data.
PLANT	OUTSIDE		ELECTRICAL	MVS-1A	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			Square D					55000	EATON
PLANT	OUTSIDE		ELECTRICAL	MVS-1B	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			IEM					55000	EATON
PLANT	Building D	Outside	ELECTRICAL	MVS-2A/2B	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			IEM	Metal enclosed L.I. Switchgear				110000	EATON
PLANT	OUTSIDE		ELECTRICAL	MVS-3A/3B - XFMR-3	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			IEM					110000 / 105000	EATON
PLANT	OUTSIDE		ELECTRICAL	MVS-4A/4B XFMR-7	Switchgear - Medium Voltage	2005	18	40	22	45%	2	0	0	0	2	60%	24	2046								110000	EATON
PLANT	OUTSIDE		ELECTRICAL	MVS-5A/5B	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			Cutler Hammer					110000	EATON
PLANT	OUTSIDE		ELECTRICAL	MVS-6A/B XFMR-6	Switchgear - Medium Voltage	2005	18	40	22	45%	2	0	0	0	2	60%	24	2046			Cutler Ha,mer					110000 / 105000	EATON

Note: highlighted cells indicate asset information updates in the DSRSD CMMS dataset export; updates are based on Carollo's condition assessment in May 2022.

							AGE-BASED ASSESSMENT					CONDITION-BASED ASSESSMENT																
Level 1	Level 2	Level 3	Discipline	Asset Name	Type	Install Date	Age	EUL	RUL	Percent Life Consumed	Age-based POF Score	Condition Score	Performance Score	Condition-based POF Score	POF Score	Percent Life Remaining	Years Remaining	Replacement Year	Carollo Field Assessment Notes	Serial_Number	Manufacturer	Model	Size_Capacity	HP	VFD Driven	Updated Replacement Cost	Source of Updated Replacement Costs
PLANT	OUTSIDE		ELECTRICAL	MVS-7A/7B - XFMR-7	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			Cutler Hammer		20,800V from SWGR 52-1			110000 / 145000	EATON
PLANT	OUTSIDE		ELECTRICAL	MVS-S	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			Eaton					625000	Historical cost estimate data.
PLANT	01 - PRE-TREATMENT	6 - BIO-FILTERS	MECHANICAL	ORT EFFLUENT SUPPLY PUMP 1	Pump - Centrifugal	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037	Nameplate is missing	846681	Gorman-Rupp	U4860-B				9700	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	6 - BIO-FILTERS	ELECTRICAL	ORT EFFLUENT SUPPLY PUMP 1 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037	Corrosion Under the anchor plate	7967/NO1L298RO48F	US ELECTRIC MOTOR			10	N	1400	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	6 - BIO-FILTERS	MECHANICAL	ORT EFFLUENT SUPPLY PUMP 2	Pump - Centrifugal	2000	23	25	2	92%	5	1	1	1	1	100%	25	2047	Equipment appears to be in good shape just signs of minor corrosion.	846682	Gorman Rupp	U4860-B		10		15000	Cost estimated in the field based on engineering judgment
PLANT	01 - PRE-TREATMENT	6 - BIO-FILTERS	ELECTRICAL	ORT EFFLUENT SUPPLY PUMP 2 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		7967/NO1L298RO48G	US ELECTRIC MOTOR			10	N	1400	Escalated using ENR values from the replacement costs
PLANT	11 - BUILDINGS	2 - OPERATIONS BUILDING	ELECTRICAL	PANEL 1HA 480, 3-ph	Panel - Load Center	2003	20	30	10	67%	3	2	2	2	2	60%	18	2040			Cutler Hammer	PRL2	100 amp			5000	Historical cost estimate data.
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	PANEL 2780 TRANSFORMER	Transformer - Medium Voltage	2000	23	50	27	46%	2	0	0	0	2	60%	30	2052								46000	Escalated using ENR values from the replacement costs
PLANT	11 - BUILDINGS	2 - OPERATIONS BUILDING	ELECTRICAL	PANEL 2HA 480, 3-ph	Panel - Load Center	1995	28	30	2	93%	5	1	1	1	1	100%	30	2052			Eaton	PRL2	225A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	2 - OPERATIONS BUILDING	ELECTRICAL	PANEL 2LA 120/208, 3-ph	Panel - Load Center	1995	28	30	2	93%	5	2	2	2	2	60%	18	2040			Cutler Hammer	PRL1	208/120V 150A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	2 - OPERATIONS BUILDING	ELECTRICAL	PANEL 2LB 120/208,3-ph	Panel - Load Center	1995	28	30	2	93%	5	1	1	1	1	100%	30	2052			Eaton	PRL1	225A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	2 - OPERATIONS BUILDING	ELECTRICAL	PANEL 2LC 120/208,3-ph	Panel - Load Center	1995	28	30	2	93%	5	2	2	2	2	60%	18	2040			Cutler Hammer	PRL1	208/120V 225A			5000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	8 - ELE/INS AUXILIARY	ELECTRICAL	PANEL 3571 TRANSFORMER	Transformer - Medium Voltage	2000	23	50	27	46%	2	2	2	2	2	60%	30	2052			Cutler Hammer	Series B	30 kVA			46000	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	8 - ELE/INS AUXILIARY	ELECTRICAL	PANEL 3572 TRANSFORMER	Transformer - Medium Voltage	2000	23	50	27	46%	2	1	2	2	2	60%	30	2052			Cutler Hammer	Series A	15 kVA			46000	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	8 - ELE/INS AUXILIARY	ELECTRICAL	PANEL 3573 TRANSFORMER	Transformer - Medium Voltage	2000	23	50	27	46%	2	2	2	2	2	60%	30	2052			Cutler Hammer	Series B	30 kVA			46000	Escalated using ENR values from the replacement costs
PLANT	Effluent Pump Station		ELECTRICAL	PANEL 6075 TRANSFORMER	Transformer - Medium Voltage	2003	20	50	30	40%	2	2	2	2	2	60%	30	2052	LV XFMR Not high voltage		Eaton	Series B	30kVA			46000	Escalated using ENR values from the replacement costs
PLANT	Effluent Pump Station		ELECTRICAL	PANEL 6076 TRANSFORMER	Transformer - Medium Voltage	2003	20	50	30	40%	2	2	2	2	2	60%	30	2052	LV XFMR Not medium voltage		Eaton	Series A	15 kVA			46000	Escalated using ENR values from the replacement costs
PLANT	Effluent Pump Station		ELECTRICAL	PANEL 6077 TRANSFORMER	Transformer - Medium Voltage	2003	20	50	30	40%	2	1	1	1	1	100%	50	2072	Need to create new asset type "Transformer-Low voltage" for this asset		Eaton					46000	Escalated using ENR values from the replacement costs
PLANT	11 - BUILDINGS	6 - BUILDING D	ELECTRICAL	PANEL 8066 TRANSFORMER	Transformer - Medium Voltage	2000	23	50	27	46%	2	1	2	2	2	60%	30	2052		J01H00686	Cutler Hammer	Series B	30 kVA			46000	Escalated using ENR values from the replacement costs
PLANT	11 - BUILDINGS	2 - OPERATIONS BUILDING	ELECTRICAL	PANEL BB	Panel - Load Center	2007	16	30	14	53%	2	0	0	0	2	60%	18	2040								5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	2 - OPERATIONS BUILDING	ELECTRICAL	PANEL M	Panel - Load Center	1995	28	30	2	93%	5	2	2	2	2	60%	18	2040			CUTLER-HAMMER	PRL1	225A			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	2 - OPERATIONS BUILDING	ELECTRICAL	PANEL M-1	Panel - Load Center	2000	23	30	7	77%	3	2	2	2	2	60%	18	2040			Eaton		125 amps 208/120			5000	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	PANEL R-1, 120/208,3-ph	Panel - Load Center	2000	23	30	7	77%	3	2	2	2	2	60%	18	2040			Cutler Hammer	Type CHB	100 amps			5000	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	PANEL S-1, 120/240, 1 PH	Panel - Load Center	2000	23	30	7	77%	3	2	2	2	2	60%	18	2040			Cutler Hammer	Type PB				5000	Historical cost estimate data.
PLANT	07 - DAFT	9 - MISCELLANEOUS	ELECTRICAL	Panel V	Panel - Load Center	2000	23	30	7	77%	3	2	2	2	2	60%	18	2040			Westinghouse	W22B	100 amp			5000	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	PANEL X-1, 120/208, 3-ph	Panel - Load Center	2000	23	30	7	77%	3	2	2	2	2	60%	18	2040			Cutler Hammer	Type CHB	100 amps			5000	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	PANEL Y-1, 120/240, 1PH	Panel - Load Center	2000	23	30	7	77%	3	2	2	2	2	60%	18	2040			Cutler Hammer	PB				5000	Historical cost estimate data.
PLANT	06 - EFFLUENT PUMPING	NORTH BLDG G	ELECTRICAL	PNL 6075/XFMR 6075	Panel - Load Center	2003	20	30	10	67%	3	2	2	2	2	60%	18	2040			Eaton	PRL1A	100 amp			5000	Historical cost estimate data.
PLANT	06 - EFFLUENT PUMPING	NORTH BLDG G	ELECTRICAL	PNL 6076	Panel - Load Center	2003	20	30	10	67%	3	1	1	1	1	100%	30	2052			Eaton	POW-R-Line C	50A			5000	Historical cost estimate data.
PLANT	06 - EFFLUENT PUMPING	NORTH BLDG G	ELECTRICAL	PNL 6077	Panel - Load Center	2003	20	30	10	67%	3	1	1	1	1	100%	30	2052			Eaton	Pow-R-Line C	100A			5000	Historical cost estimate data.
PLANT	Blower Building	Electrical Room	ELECTRICAL	PNL3571	Panel - Load Center	2005	18	30	12	60%	2	2	2	2	2	60%	18	2040			IEM	PIU	100 amp			5000	Historical cost estimate data.
PLANT	Blower Building	Electrical Room	ELECTRICAL	PNL3572	Panel - Load Center	2005	18	30	12	60%	2	2	2	2	2	60%	18	2040			IEM		100 amp			5000	Historical cost estimate data.
PLANT	Blower Building	Electrical Room	ELECTRICAL	PNL3573	Panel - Load Center	2005	18	30	12	60%	2	2	2	2	2	60%	18	2040			IEM	PIU	225 amp			5000	Historical cost estimate data.
PLANT	Building D	Electric Room	ELECTRICAL	PNL8066	Panel - Load Center	2005	18	30	12	60%	2	2	2	2	2	60%	18	2040			IEM	PIU	100 amps			5000	Historical cost estimate data.
PLANT	Building D	Electric Room	ELECTRICAL	PNL-8070	Panel - Load Center	2005	18	30	12	60%	2	2	2	2	2	60%	18	2040			Eaton	PRL1a	100 amps			5000	Historical cost estimate data.
PLANT	Building D	Electric Room	ELECTRICAL	PNL8071	Panel - Load Center	2005	18	30	12	60%	2	2	2	2	2	60%	18	2040			IEM	PIU DELTA	100 amps			5000	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	Post chlorination metering pump 1 P7911	Variable Frequency Drive	2003	20	15	0	100%	5	2	4	4	4	20%	3	2025							UNKNOWN	HP can not be confirmed from photo - therefore replacement cost is not confirmed
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	POST CHLORINATION METERING PUMP 3 VFD	Variable Frequency Drive	2003	20	15	0	100%	5	2	4	4	4	20%	3	2025							UNKNOWN	HP can not be confirmed from photo - therefore replacement cost is not confirmed
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	Post chlorination pump 2 P7912	Variable Frequency Drive	2003	20	15	0	100%	5	2	4	4	4	20%	3	2025			Cutler hammer				UNKNOWN	HP can not be confirmed from photo - therefore replacement cost is not confirmed
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PP11	Panel - Load Center	2009	14	30	16	47%	2	2	2	2	2	60%	18	2040			Eaton	PRL3a	208/120V 500 A			7500	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PP12	Panel - Distribution	2009	14	30	16	47%	2	2	2	2	2	60%	18	2040			Eaton	PRL3A	200A			7500	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PP21	Panel - Distribution	2009	14	30	16	47%	2	1	1	1	1	100%	30	2052			Eaton	Pow R Line C	500A			7500	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PP22	Panel - Distribution	2009	14	30	16	47%	2	2	2	2	2	60%	18	2040			Eaton	PRL3A	480 V 100 A			7500	Historical cost estimate data.
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PRE CHLORINATION RAS METERING PUMP 1 VFD	Variable Frequency Drive	2003	20	15	0	100%	5	2	4	4	4	20%	3	2025	In bldg f						UNKNOWN	HP can not be confirmed from photo - therefore replacement cost is not confirmed
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PRE CHLORINATION RAS METERING PUMP 2 VFD	Variable Frequency Drive	2003	20	15	0	100%	5	2	4	4	4	20%	3	2025							UNKNOWN	HP can not be confirmed from photo - therefore replacement cost is not confirmed
PLANT	GROUND LEVEL	4 - GRIT REMOVAL	MECHANICAL	PREAERATION BLOWER 1	Blowers	2015	8	25	17	32%	1	2	0	2	2	60%	15	2037		2062	KAESER	881003.00100		25		3800	Escalated using ENR values from the replacement costs
PLANT	03 - PRIMARY TREATMENT		ELECTRICAL	Preaeration Blower 1 B2921 VFD	Variable Frequency Drive	2015	8	15	7	53%	2	0	0	0	2	60%	9	2031			Allen-Bradley					15000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	PREAERATION BLOWER 1 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	1	2	2	2	60%	15	2037		CMFT068S041	GE	5KS2845AA208D5		25	N	5800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	GROUND LEVEL	4 - GRIT REMOVAL	MECHANICAL	PREAERATION BLOWER 2	Blowers	2015	8	25	17	32%	1	2	2	2	2	60%	15	2037		2063	KAESER	881003.00100				1300	Escalated using ENR values from the replacement costs
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	PREAERATION BLOWER 2 MOTOR	Motor - Constant Speed	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		D10-00006312GT2	US MOTORS			25	N	5800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PREAERATION BLOWER 2 VFD	Variable Frequency Drive	2015	8	15	7	53%	2	0	0	0	2	60%	9	2031	IN MCC-HA							15000	Historical cost estimate data.
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	MECHANICAL	PREAERATION BLOWER 3	Blowers	2021	2	25	23	8%	1	1	1	1	1	100%	25	2047	Equipment is newly installed							10000	Cost estimated in the field based on engineering judgment
PLANT	03 - PRIMARY TREATMENT		ELECTRICAL	Preaeration Blower 3 B2923 VFD	Variable Frequency Drive	2019	4	15	11	27%	1	0	0	0	1	100%	15	2037			Allen-Bradley					15000	Historical cost estimate data
PLANT	01 - PRE-TREATMENT	4 - GRIT REMOVAL	ELECTRICAL	PREAERATION BLOWER 3 MOTOR	Motor - Constant Speed	2021	2	25	23	8%	1	1	1	1	1	100%	25	2047	Pump and blower are new	KNFT2965019	GE	5KS2845AA208D5M		25	N	5800	Cost estimated in the field based on engineering judgment, and updated based on historical data
PLANT	Headworks and Primary Sediment	Equipment Gallery	MECHANICAL	PRIMARY SCUM PUMP 1	Pump - Progressive Cavity	2020	3	15	12	20%	1	1	1	1	1	100%	15	2037		B178605	NETZSCH NEMO		150gpm at 75 psi	15		25000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	Headworks and Primary Sediment	Equipment Gallery	ELECTRICAL	PRIMARY SCUM PUMP 1 MOTOR	Motor - Constant Speed	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047		Z1050479013	NETZSCH NEMO		1765rpm	15	N	1800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	3 - DIVERT/RETURN	ELECTRICAL	PRIMARY SCUM PUMP 2 MOTOR	Motor - Constant Speed	2021	2	25	23	8%	1	1	1	1	1	100%	25	2047	Equipment is new recently installed. Nameplates coated over.		WEG				N	1800	Assumed at 25hp to match PRIMARY SCUM PUMP 1 MOTOR. Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	3 - DIVERT/RETURN	MECHANICAL	PRIMARY SLUDGE GRINDER	Grinder	2016	7	20	13	35%	1	2	2	2	2	60%	12	2034		27742	JWC ENVIRONMENTAL	30004T-1206				47200	Escalated using ENR values from the replacement costs
PLANT	03 - PRIMARY TREATMENT	3 - DIVERT/RETURN	ELECTRICAL	PRIMARY SLUDGE GRINDER MOTOR	Motor - Constant Speed	2017	6	25	19	24%	1	2	2	2	2	60%	15	2037			BALDOR			3	N	1000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	MECHANICAL	Primary Sludge Pump 1	Pump - Progressive Cavity	2020	3	15	12	20%	1	1	0	1	1	100%	15	2037		B178554	NEMO PUMP	NM063BY01L07K-2	100-117 gpm			20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	ELECTRICAL	Primary Sludge Pump 1 Motor	Motor - VFD Service Motor	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047		Z1050479012	WEG	T01518ET3ER254TC-W22		15	Y	1800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	MECHANICAL	Primary Sludge Pump 2	Pump - Progressive Cavity	2019	4	15	11	27%	1	1	1	1	1	100%	15	2037		B178557	NEMO PUMP	NM063BY01L07K-2	100-117 gpm	15		20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	ELECTRICAL	Primary Sludge Pump 2 Motor	Motor - VFD Service Motor	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047		Z1050479020	WEG	T01518ET3ER254TC-W22		15	Y	1800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	Primary sludge pump 2 VFD	Variable Frequency Drive	2021	2	15	13	13%	1	0	0	0	1	100%	15	2037	In MCC-HA							10000	Historical cost estimate data.
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	MECHANICAL	Primary Sludge Pump 3	Pump - Progressive Cavity	2020	3	15	12	20%	1	1	1	1	1	100%	15	2037		B178556	NEMO PUMP	NM063BY01L07K-2	100-117 gpm	15		20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	ELECTRICAL	Primary Sludge Pump 3 Motor	Motor - VFD Service Motor	2020	3	25	22	12%	1	1	1	1	1	100%	25	2047		Z1050479019	WEG	T01518ET3ER254TC-W22		15	Y	1800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PRIMARY SLUDGE PUMP 3 VFD	Variable Frequency Drive	2021	2	15	13	13%	1	0	0	0	1	100%	15	2037	IN MCC-HA							10000	Historical cost estimate data.
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	MECHANICAL	Primary Sludge Pump 4	Pump - Progressive Cavity	2020	3	15	12	20%	1	1	1	1	1	100%	15	2037		B178429	NEMO PUMP	NM063BY01L07K-2	100-117 gpm			20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	ELECTRICAL	Primary Sludge Pump 4 Motor	Motor - VFD Service Motor	2020	3	25	22	12%	1	1	1	1	1	100%	25	2047		Z1050479021	WEG	T01518ET3ER254TC-W22		15	Y	1800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PRIMARY SLUDGE PUMP 4 VFD	Variable Frequency Drive	2021	2	15	13	13%	1	0	0	0	1	100%	15	2037	IN MCC HD							10000	Historical cost estimate data.
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	MECHANICAL	Primary Sludge Pump 5	Pump - Progressive Cavity	2020	3	15	12	20%	1	1	1	1	1	100%	15	2037		B178555	NEMO PUMP	NM063BY01L07K-2	100-117 gpm			20000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	ELECTRICAL	Primary Sludge Pump 5 Motor	Motor - VFD Service Motor	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047		Z1050479011	WEG	T01518ET3ER254TC-W22		15	Y	1800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	11 - BUILDINGS	8 - ELE/INS AUXILIARY	ELECTRICAL	PRIMARY SLUDGE PUMP 5 VFD	Variable Frequency Drive	2021	2	15	13	13%	1	0	0	0	1	100%	15	2037	IN MCC HD							10000	Historical cost estimate data.
PLANT	03 - PRIMARY TREATMENT		ELECTRICAL	Primary sludge pump 1 PMP2944 VFD	Variable Frequency Drive	2021	2	15	13	13%	1	0	0	0	1	100%	15	2037			Allen-Bradley					10000	Historical cost estimate data.
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	MECHANICAL	PSC Pump 1	Pump - Progressive Cavity	2020	3	15	12	20%	1	1	1	1	1	100%	15	2037		B178425	NETZSCH NEMO	NM063BY01L07K-2	50 gpm			15000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	ELECTRICAL	PSC Pump 1 Motor	Motor - Constant Speed	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047			WEG	01018ET3ER215TC-W22		10	N	1400	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	MECHANICAL	PSC Pump 2	Pump - Progressive Cavity	2020	3	15	12	20%	1	1	1	1	1	100%	15	2037		B178426	NEMO PUMP	NM063BY01L07K-2	50 gpm			15000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	03 - PRIMARY TREATMENT	2 - SOLIDS REMOVAL	ELECTRICAL	PSC Pump 2 Motor	Motor - Constant Speed	2019	4	25	21	16%	1	1	1	1	1	100%	25	2047			WEG	01018ET3ER215TC-W22		10	N	1400	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	RAS PUMP 1	Pump - Centrifugal	2001	22	25	3	88%	4	2	4	4	4	20%	5	2027	Pump seal appears to be leaking slightly. Some vibration noted in belt.	1242703N	GORMAN RUPP	112G60-B		60		33400	Escalated using ENR values from the replacement costs

Note: highlighted cells indicate asset information updates in the DSRSD CMMS dataset export; updates are based on Carollo's condition assessment in May 2022.

							AGE-BASED ASSESSMENT					CONDITION-BASED ASSESSMENT															
Level 1	Level 2	Level 3	Discipline	Asset Name	Type	Install Date	Age	EUL	RUL	Percent Life Consumed	Age-based POF Score	Condition Score	Performance Score	Condition-based POF Score	POF Score	Percent Life Remaining	Years Remaining	Replacement Year	Carollo Field Assessment Notes	Serial_Number	Manufacturer	Model	Size_Capacity	HP	VFD Driven	Updated Replacement Cost	Source of Updated Replacement Costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	RAS PUMP 1 MOTOR	Motor - VFD Service Motor	2001	22	25	3	88%	4	2	1	2	2	60%	15	2037	Pump and motor recently recoated	04KL513300-HDT2	RELIANCE ELECTRIC	L2149A		60	Y	13800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	RAS PUMP 1 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024	In MCC-G1							25000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	RAS PUMP 2	Pump - Centrifugal	2020	3	25	22	12%	1	1	1	1	1	100%	25	2047	Pump and motor were recently recoated.	1734082	GORMAN RUPP	112G60-B		60		33400	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	RAS PUMP 2 MOTOR	Motor - VFD Service Motor	2001	22	25	3	88%	4	2	1	2	2	60%	15	2037		04KL513300-HDT1	RELIANCE ELECTRIC	L2149A		60	Y	13800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	RAS PUMP 2 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024	In MCC-G2							25000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	RAS PUMP 3	Pump - Centrifugal	2000	23	25	2	92%	5	2	1	2	2	60%	15	2037	Pump and motor were recently recoated	1242701N	GORMAN RUPP	112G60-B		60		33400	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	RAS PUMP 3 MOTOR	Motor - VFD Service Motor	2016	7	25	18	28%	1	2	1	2	2	60%	15	2037	Pump and motor were recently recoated	04KL513300-HDT3	RELIANCE ELECTRIC	L2149A		60	Y	13800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	RAS PUMP 3 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024			Cutler Hammer					25000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	RAS PUMP 4	Pump - Centrifugal	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037	Pump is running a bit loud compared to others.	1242937N	GORMAN RUPP	112G60-B		60		33400	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	RAS PUMP 4 MOTOR	Motor - VFD Service Motor	2001	22	25	3	88%	4	2	2	2	2	60%	15	2037		03KL513300-HDT1	RELIANCE ELECTRIC	L1178A		125	Y	20000	Historical cost estimate data.
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	RAS PUMP 4 VARIABLE FREQUENCY DRIVE	Variable Frequency Drive	2000	23	15	0	100%	5	2	4	4	4	20%	3	2025			Robicon					45000	Historical cost estimate data.
PLANT	09 - FSL/DLD	7 - MEC AUXILIARY	MECHANICAL	RECLAIMED WATER PUMP 1	Pump - Centrifugal	2001	22	25	3	88%	4	2	1	2	2	60%	15	2037		0194NS00014-1	INGERSOLL-DRESSER	125KH-3		75		72500	Escalated using ENR values from the replacement costs
PLANT	09 - FSL/DLD	7 - MEC AUXILIARY	ELECTRICAL	RECLAIMED WATER PUMP 1 MOTOR	Motor - Constant Speed	2001	22	25	3	88%	4	1	2	2	2	60%	15	2037			US ELECTRIC MOTOR	E03-00032835-100R-01		75	N	173000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	BLANK	BLANK	MECHANICAL	RECLAIMED WATER PUMP 2	Pump - Centrifugal	2018	5	25	20	20%	1	1	2	2	2	60%	15	2037		81122-1-1	WEIR FLOWAY	10DKL-VTP	500 gpm	10		28100	Escalated using ENR values from the replacement costs
PLANT	BLANK	BLANK	ELECTRICAL	RECLAIMED WATER PUMP 2 MOTOR	Motor - Constant Speed	2018	5	25	20	20%	1	1	2	2	2	60%	15	2037		LMFT3175052	GE MOTORS	5KS215DAE6423			N	1400	Assumed at 10hp, as originally indicated in the DSRSD asset database. Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	01 - PRE-TREATMENT	3 - INFLUENT PUMPING	ELECTRICAL	SCREEN ROOM (TO ORT) EXHAUST FAN 2 MOTOR	Motor - Constant Speed	1987	36	25	0	100%	5	2	3	3	3	35%	9	2031			NEW YORK BLOWER BALDOR	ECP377CT		Not visible, larger than 5	N	1200	Cost estimated in the field based on engineering judgment, and updated based on historical data
PLANT	01 - PRE-TREATMENT	2 - SCREENING	MECHANICAL	SCREEN ROOM AIR HANDLING UNIT	HVAC - Air Handling Unit	1987	36	15	0	100%	5	2	3	3	3	35%	5	2027								4600	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	SECONDARY CLARIFIER TANK 1 COLLECTOR DRIVE UNIT MOTOR	Motor - Constant Speed	2016	7	25	18	28%	1	2	2	2	2	60%	15	2037			SEW-EURODRIVE			0.75	N	500	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	SECONDARY CLARIFIER TANK 1 SCUM PUMP	Pump - Centrifugal	2016	7	25	18	28%	1	2	2	2	2	60%	15	2037		115158	Vaughan	V3F	200gpm at 25 ft head	5		10000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	SECONDARY CLARIFIER TANK 1 SCUM PUMP MOTOR	Motor - Constant Speed	2016	7	25	18	28%	1	2	2	2	2	60%	15	2037		06H770X20361	Baldor Reliance		1750 rpm	5		1000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	SECONDARY CLARIFIER TANK 2 COLLECTOR DRIVE UNIT	Drive Unit	2007	16	20	4	80%	4	2	2	2	2	60%	12	2034		EW01366-100A	Door-Oliver Elmco					1800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	SECONDARY CLARIFIER TANK 2 COLLECTOR DRIVE UNIT MOTOR	Motor - Constant Speed	2016	7	25	18	28%	1	2	2	2	2	60%	15	2037		80.10.21430.6/1	SEW-EURODRIVE		1700 rpm	0.75	N	500	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	MECHANICAL	SECONDARY CLARIFIER TANK 2 SCUM PUMP	Pump - Centrifugal	2016	7	25	18	28%	1	1	1	1	1	100%	25	2047			Vaughan	V3F	200 gpm	5		10000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	SECONDARY CLARIFIER TANK 2 SCUM PUMP MOTOR	Motor - Constant Speed	2007	16	25	9	64%	2	1	1	1	1	100%	25	2047			RELIANCE ELECTRIC	P1861174A		5	N	1000	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	SECONDARY CLARIFIER TANK 3 COLLECTOR DRIVE UNIT	Drive Unit	2016	7	20	13	35%	1	2	2	2	2	60%	12	2034		RSW0000646-01A	Ovivo					1800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	SECONDARY CLARIFIER TANK 3 SCUM PUMP	Pump - Centrifugal	2015	8	25	17	32%	1	2	2	2	2	60%	15	2037		128558	Vaughan	V3F	200 gpm at 25 ft head	5		10000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	SECONDARY CLARIFIER TANK 3 SCUM PUMP MOTOR	Motor - Constant Speed	2016	7	25	18	28%	1	2	2	2	2	60%	15	2037			Crown Triton	HKS184PR235R	1760 rpm			1000	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	SECONDARY CLARIFIER TANK 4 COLLECTOR DRIVE UNIT	Drive Unit	2000	23	20	0	100%	5	2	2	2	2	60%	12	2034		CA0010946		CVVU-S 4215DAY-354	175 rpm			1800	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	MECHANICAL	SECONDARY CLARIFIER TANK 4 SCUM PUMP	Pump - Centrifugal	2000	23	25	2	92%	5	2	2	2	2	60%	15	2037		62436	Vaughan	V3F	1750 rpm	5		17300	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	2 - SECONDARY SEDIMENTATION	ELECTRICAL	SECONDARY CLARIFIER TANK 4 SCUM PUMP MOTOR	Motor - Constant Speed	2009	14	25	11	56%	2	2	2	2	2	60%	15	2037			Reliance Electric		1750 rpm	5	N	1000	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	MECHANICAL	SECONDARY CLARIFIER TANK DRAINAGE PUMP 1	Pump - Centrifugal	2005	18	25	7	72%	3	1	1	1	1	100%	25	2047		946910N	GORMAN-RUPP	TA3-B		25		19400	Escalated using ENR values from the replacement costs
PLANT	04 - SECONDARY TREATMENT	3 - SOLIDS REMOVAL	ELECTRICAL	SECONDARY CLARIFIER TANK DRAINAGE PUMP 1 MOTOR	Motor - Constant Speed	2005	18	25	7	72%	3	1	2	2	2	60%	15	2037			Maratron electric			25	N	5800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	1 - GENERATOR 1	MECHANICAL	STARTING AIR COMPRESSOR 1	Air Compressor	2003	20	10	0	100%	5	1	1	1	1	100%	10	2032	Most of unit not visible due to enclosure. Could not confirm Hp.		KAESER	SK-19				8200	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	1 - GENERATOR 1	ELECTRICAL	STARTING AIR COMPRESSOR 1 MOTOR	Motor - Constant Speed	1982	41	25	0	100%	5	0	0	0	5	10%	3	2025	Motor inside compressor enclosure, not accessible		KAESER	SK-19				1800	Escalated using ENR values from the replacement costs
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	MECHANICAL	STARTING AIR COMPRESSOR 2	Air Compressor	2016	7	10	3	70%	3	1	2	2	2	60%	6	2028	In good condition	UTY702267	QUINCY	BM370SB 0				8200	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	10 - CO-GENERATION	7 - MEC AUXILIARY	ELECTRICAL	STARTING AIR COMPRESSOR 2 MOTOR	Motor - Constant Speed	2016	7	25	18	28%	1	2	2	2	2	60%	15	2037	In good condition	Z1603090411	BALDOR	EM2513T	1785 rpm	15	N	1800	Replacement cost updated to match other equipment with the same HP value (which was escalated using ENR values)
PLANT	BLDG A		ELECTRICAL	SWBD DPB	Switchgear - Medium Voltage	2005	18	40	22	45%	2	2	2	2	2	60%	24	2046			Eaton	Pow r line c switchboard	4000 amp			230000	Historical cost estimate data.
PLANT	06 - EFFLUENT PUMPING	NORTH BLDG G	ELECTRICAL	SWG-DPG	Switchgear - Medium Voltage	2004	19	40	21	48%	2	2	2	2	2	60%	24	2046	Need to create new asset type "Switchgear - Low Voltage" for this equipment		Eaton	Magnum DS	3200A			575000	Historical cost estimate data.
PLANT	10 - CO-GENERATION		ELECTRICAL	SWGR DPA	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			Thomson Technology	GCS	100 KA			575000	Historical cost estimate data.
PLANT	10 - CO-GENERATION		ELECTRICAL	SWGR DPC	Switchgear - Medium Voltage	2003	20	40	20	50%	2	2	2	2	2	60%	24	2046			Thomson Technology	GCS	100 kA			805000	Historical cost estimate data.
PLANT	Blower Building	Electrical Room	ELECTRICAL	SWGR DPE	Switchgear - Medium Voltage	2005	18	40	22	45%	2	2	2	2	2	60%	24	2046			Cutler Hammer		3200 amp			460000	Historical cost estimate data.
PLANT	10 - CO-GENERATION	8 - ELE/INS AUXILIARY	ELECTRICAL	SWGR-DPA	Switchgear - Medium Voltage	1993	30	40	10	75%	3	3	4	4	4	20%	8	2030	This is a low voltage switchgear. Need a low voltage switchgear asset selection		Westinghouse	DS	3000			575000	Historical cost estimate data.
PLANT	Building D	Electric Room	ELECTRICAL	SWGR-DPD	Switchgear - Medium Voltage	2001	22	40	18	55%	2	1	1	1	1	100%	40	2062	Low voltage swgr, need new category		Cutler Hammer	Magnum DS	3200 amp			460000	Historical cost estimate data.
PLANT	OUTSIDE		ELECTRICAL	XFMR-7 SWBD	Switchgear - Medium Voltage	2003	20	40	20	50%	2	1	1	1	1	100%	40	2062			Eaton		4000A			100000	Historical cost estimate data.
PLANT	08 - DIGESTERS	3 - DIGESTER 3	MECHANICAL	DIGESTER 3 MECHANICAL MIXER 1	Mixer - Rapid Mix	2001	22	20	20	0%	1	0	0	0	1	100%	20	2042	Currently out of service, undergoing rehab (2022). Asset remaining useful life (RUL) updated to 20 years from rehab effort	SMII 18530 F-2	WESTECH					43700	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	3 - DIGESTER 3	MECHANICAL	DIGESTER 3 MECHANICAL MIXER 2	Mixer - Rapid Mix	2001	22	20	20	0%	1	0	0	0	1	100%	20	2042	Currently out of service, undergoing rehab (2022). Asset remaining useful life (RUL) updated to 20 years from rehab effort	SMII 18530 F-1	WESTECH					43700	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	3 - DIGESTER 3	ELECTRICAL	DIGESTER 3 MECHANICAL MIXER 2 MOTOR	Motor - Constant Speed	2001	22	25	20	20%	1	0	0	0	1	100%	25	2047	Currently out of service, undergoing rehab (2022). Asset remaining useful life (RUL) updated to 20 years from rehab effort		US ELECTRIC MOTOR	YC10P3B-P				1400	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	3 - DIGESTER 3	ELECTRICAL	DIGESTER 3 MECHANICAL MIXER 3 MOTOR	Motor - Constant Speed	2001	22	25	20	20%	1	0	0	0	1	100%	25	2047	Currently out of service, undergoing rehab (2022). Asset remaining useful life (RUL) updated to 20 years from rehab effort		US ELECTRIC MOTOR	YC10P3B-P				1400	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	3 - DIGESTER 3	MECHANICAL	DIGESTER 3 MECHANICAL MIXER 3	Mixer - Rapid Mix	2001	22	20	20	0%	1	0	0	0	1	100%	20	2042	Currently out of service, undergoing rehab (2022). Asset remaining useful life (RUL) updated to 20 years from rehab effort	SMII 18530 F-3	WESTECH					43700	Escalated using ENR values from the replacement costs
PLANT	08 - DIGESTERS	3 - DIGESTER 3	ELECTRICAL	DIGESTER 3 MECHANICAL MIXER 1 MOTOR	Motor - Constant Speed	2001	22	25	20	20%	1	0	0	0	1	100%	25	2047	Currently out of service, undergoing rehab (2022). Asset remaining useful life (RUL) updated to 20 years from rehab effort		US ELECTRIC MOTOR	YC10P3B-P				1400	Escalated using ENR values from the replacement costs
FACILITIES	12 - MISCELLANEOUS	3 - HVAC	MECHANICAL	BLDG A- AIR HANDLING UNIT 1	HVAC - Air Handling Unit	1994	29	15	0	100%	5	0	0	0	5	10%	2	2024	Not assessed - unable to locate	29003	GOVERN AIR	RSA-30-E	0	0	0	4600	Replacement cost updated to match other equipment with smilar size
PLANT	WWTP	ADMIN	MECHANICAL	BLDG A-AIR HANDLER UNIT 5	HVAC - Air Handling Unit	2008	15	15	0	100%	5	0	0	0	5	10%	2	2024	Not assessed - unable to locate	1108G20621		48TMD009-601	0	0	0	5000	Replacement cost updated to match other equipment with smilar size
PLANT	WWTP	ADMIN	MECHANICAL	BLDG A-AIR HANDLING UNIT 6	HVAC - Air Handling Unit	2010	13	15	2	87%	4	0	0	0	4	20%	3	2025	Not assessed - unable to locate	5009C35969		50EZ-A24-30	0	0	0	5000	Replacement cost updated to match other equipment with smilar size
PLANT	WWTP	LAB	MECHANICAL	BLDG A- AIR HANDLING UNIT 4	HVAC - Air Handling Unit	2015	8	15	7	53%	2	0	0	0	2	60%	9	2031	Not assessed - unable to locate	1XU02607A	MITSUBUSHI	TSC060G4R0A01K000A	0	0	0	5000	Replacement cost updated to match other equipment with smilar size
PLANT	WWTP	LAB	MECHANICAL	BLDG A-AIR HANDLING UNIT 3	HVAC - Air Handling Unit	2000	23	15	0	100%	5	0	0	0	5	10%	2	2024	Not assessed - unable to locate	0YU00207A	MITSUBUSHI	PUZ-A24NHA4	0	0	0	5000	Replacement cost updated to match other equipment with smilar size

Note: highlighted cells indicate asset information updates in the DSRSD CMMS dataset export; updates are based on Carollo's condition assessment in May 2022.

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Appendix 3E

DSRSD O&M STAFF NOTES

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MEETING MINUTES

CONDITION ASSESSMENT OPERATION AND MAINTENANCE STAFF NOTES

Dublin San Ramon Services District (DSRSD)

Issue Date: June 27, 2022

Project No.: 200892

Purpose:	To receive feedback from DSRSD operation and maintenance staff about the condition, functionality, operation, and maintenance of mechanical and electrical assets.	
Meeting Date:	May 10, 2022; 7:30-8:30AM & 11:15AM-12:15PM	
Meeting Location:	Maintenance Building Training Room 1	
Prepared By:	Micaela Robertson	
Attendees:	**DSRSD:**	**Carollo:**
	Jason Ching	Richard Gutierrez
	Shawn Quinlan	Micaela Robertson
	Virgil Sevilla	Jamshid Dorafsha
	Maurice Atendido	Aubrey Harrison
Distribution:	Attendees	

Meeting Notes

The DSRSD staff discussed the following items:

1. Pretreatment – screening conveyors were replaced with a screen bucket lift and should be removed from the asset data base.
2. The plant influent pumps and associated motors are nearing the end of their useful service life given they were originally installed in 1986 and operate under severe conditions. DSRSD has provided excellent maintenance to this equipment and two of the pumps (Pumps 1 and 3) have been recently rehabilitated. Maintenance staff noted that it appears that sand in the waste from the DERWA ballasted flocculation process may be leading to increased wear and premature failure of these pumps. With recent rebuilds a special coating was added to the impellers to hopefully reduce wear. The pumps were also retrofitted with newer mechanical seals in recent years.
    a. Plant operations staff noted that the pump station operates based off of only one bubbler for level control. Sometimes level control is lost at this facility which turns into an operational nightmare for staff. Replacing with two radar level sensors would significantly increase the reliability of this pump station.
    b. It was noted that the hydraulic power unit which operates the influent gates is not reliable and the plant is looking to replace it with REXA operators.

3. The aeration blowers are reliable and in good condition but are nearing 20-years of age and therefore will approach the end of their useful service life within the next 10 years. 18,000 hour service was recently performed on the blowers. One blower (Blower No.2) had some knicks in the rotor but was still operational.
4. Effluent Pump Station No.1 (EPS-1) pumps sit idle for long periods of time and sometimes have trouble starting when they are needed.
5. One of the RAS pumps was recently replaced. RAS Pump No.1 has been having issues with failure of the mechanical seal. RAS Pump No.3 motor was recently refurbished.
6. The DAFT equipment was refurbished in 2011. Some changes were made at that time to the pressurization pumps however the system is still inefficient due to the amount of air required. The pressurization pumps cavitate frequently under normal operating conditions which prematurely wears the backing plates and impellers. The 2011 improvements helped but did not fully mitigate this operational issue.
    a. DSRSD operations staff noted that there is no redundancy for the double disk diaphragm style pump used to pump grit from the bottom of the DAFT. There is only a shelf spare pump that can be swapped if it fails. The pressurization and TWAS pumps do have full redundancy.
7. Digester No.3 mixers are currently in the process of being rebuilt. Digester Nos. 1 and 2 have very old mixers which need to be replaced in the near future. All digester recirculation pumps were recently replaced with new chopper pumps.
    a. DSRSD operations staff noted that with the newer Digester No.4 now available, there is now redundancy in this process to take units out of service. Currently Digester No.3 is out of service as the mixers are being replaced.
8. Gas treatment skid motors are due for replacement. A current project is in preliminary design looking at replacement of this skid.
9. Cogeneration Engine No.2 has been alarming on vibration. In general, all three cogeneration engines are approaching the end of their useful service life. Although DSRSD staff has done an excellent job of maintaining this equipment and has stocked a large quantity of spare parts, staff estimates about 5 years of parts remaining and is not sure they will be able to continue to service them adequately after that point. Institutional knowledge transfer for maintaining this equipment is another concern as staff retire.
10. The 750 kW standby generator as reached the end of its useful service life and should be replaced in the near future. In addition, when EPS-1 is not operating, as is typical 8 months out of the year, the generator is too large and just idles when put in service. A load bank is required to allow the generator to run properly under this scenario. With the current plant standby power configuration, the 1250 kW generator can power approximately two-thirds of the plant load.
11. The odor tower was shutdown in 2020 due to COVID concerns (the process produces a lot of vapor). May need to restart this system in the near future.
12. Plant maintenance staff is in the process of replacing all chiller and heat loop pumps.
13. None of the boilers are currently operational as the digesters use the waste gas heat from the cogeneration engines. DSRSD maintenance staff is not confident the old boilers can be reliably operated if the cogeneration system is offline. DSRSD operations staff noted that on cold days, if only two cogeneration engines are running, the plant struggles to maintain the digesters adequately heated. Operations staff in these instances cuts heating to Buildings T and S to keep sufficient heat to the digesters.

14. The HVAC system in Building A is due for replacement. It was noted that a $200,000 budget was allocated for replacement of this system but costs came in at $1.3 million.
15. 3W pumps were recently replaced in 2018.
16. DSRSD staff noted that some electrical gear may currently be undersized. Carollo is evaluating this under a separate task.
17. DSRSD has a project underway to replace the large VFDs for the influent pumps and effluent pumps.

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Dublin San Ramon Services District
Water, wastewater, recycled water

Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 4
ENERGY DEMAND AND PRODUCTION CAPACITY PROJECTIONS

FINAL | June 2024

carollo

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Abbreviations

%TS	percent total solids
ADAF	average daily annual flows
CCA	Community Choice Aggregation
CH4	methane
DAFT	dissolved air floatation thickener
DERWA	Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority
DLD	dedicated land disposal
DSRSD	Dublin San Ramon Services District
FSL	facultative sludge lagoon
GHG	greenhouse gas
HVAC	heating ventilation, and air conditioning
kW	kilowatt
kWh	kilowatt-hour
MG	million gallons
mgd	million gallons per day
MMBtu/hr	one million British thermal units per hour
MWh	megawatt-hour
MT CO2e	metric tons of carbon dioxide equivalent
NdN	nitrification/denitrification
N2O	nitrous oxide
PFAS	per- and poly-fluoroalkyl substances
PG&E	Pacific Gas & Electric Company
ppd	pounds per day
PS	primary sludge
scf	standard cubic foot
TM	technical memorandum
WAS	waste activated sludge
WWTP	wastewater treatment plant

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Technical Memorandum 4

ENERGY DEMAND AND PRODUCTION CAPACITY PROJECTIONS

4.1 Introduction

The purpose of this technical memorandum (TM) is to quantify the projected energy demand, greenhouse gas (GHG) emissions, and production capacity of Dublin San Ramon Services District (DSRSD) facilities over the 25-year planning horizon. The projections are based on average annual flow and load conditions using 2021 as the base year. DSRSD facilities included in this analysis consist of the following:

- Wastewater treatment plant (WWTP) and collection system.
- Potable water distribution.
- DSRSD Recycled water distribution (excludes Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority [DERWA] recycled water treatment plant and recycled water distribution).
- Administrative and field operations office facilities.
- Vehicle fleet

4.2 Objectives

The objectives of projecting energy demand and production capacities over the planning period are to provide DSRSD with the ability to:

- Assess the estimated future energy demand and GHG emissions status quo conditions in consideration of the impact of potential future energy efficiency measures and future energy costs.
- Estimate adequate capacities for energy production equipment.
- Determine future energy supply needs and renewable energy sources to satisfy desired target fraction for DSRSD's future energy demand and energy supply systems.

4.3 Uncertainties in Energy Demand and Production Projections

Projections have inherent uncertainties associated with the available information used at the time the projections are made. The following key assumptions were used in the energy demand, GHG emissions, and energy production projections in this TM:

1. Refer to TM 1 for data on the 2021 energy demand and production baseline for existing conditions and wastewater influent flow and load projections. These data are used as the starting point for the projections developed in this TM.
2. The projections assume that the WWTP will continue to provide the same level of liquid and solids treatment, use the same processes and unit operations, and the same equipment energy efficiencies as in Baseline Year 2021 (summarized in TM 1).

3. No significant regulatory changes will result in changes to energy consumption. This assumption would need to be revised in the event additional permit limits, e.g. nitrate effluent or per- and poly-fluoroalkyl substances (PFAS) are implemented in the future. (Reference TM 1, Section 1.5.3, for a discussion on potential future regulatory drivers.)
4. Wastewater load projections are assumed to grow proportionately to average daily annual flows (ADAF).
5. DSRSD will continue to receive a similar blend of domestic, industrial, and commercial wastewater as in 2021.
6. Efficiencies, GHG emissions reductions, and increased energy production from projects considered for this masterplan do not factor into these projections.

4.4 Energy Demand Projections

4.4.1 Wastewater Treatment Plant and Collection System

4.4.1.1 Electricity Consumption Projections

It was assumed that the electricity consumption of the WWTP and collection system will grow proportionately to its influent flow and loading. This is a conservative assumption as certain electricity demands (for example lighting, heating, ventilation, and air conditioning [HVAC], laboratory, clarifier equipment, thickening, or mixing systems) do not necessarily have increasing energy use proportional to flow increase.

In 2021, the WWTP consumed 857 megawatt-hour (MWh) of electricity per million gallons (MG) of ADAF. This electricity consumption factor was applied to the ADAF projections summarized in TM 1, which estimate that the WWTP's influent flow and loading will increase 1.16 percent per year, proportional to the population growth rate for the service area. The projections, as well as the historical ADAF and annual electricity consumption between 2017 and 2021, are summarized in Table 4.1 and Figure 4.1. The projections are based on the *Wastewater Treatment and Biosolids Facilities Master Plan* (West Yost Associates 2017).

Table 4.1 Projected WWTP Influent Flows and Electricity Consumption

Year	ADAF (mgd)	Annual Electricity Consumption - WWTP (MWh)	Annual Electricity Consumption - Collection System (MWh)
2021[(1)(2)]	11.7	10,021	10.4
2035[(3)]	13.7	11,777	11.6
2047[(3)]	15.8	13,526	13.3

Notes:
mgd - million gallons per day.
(1) Baseline year for this Energy Facilities Master Plan. Electricity consumption includes electricity imported from the grid (460 MWh) and electricity from cogeneration (9,561 MWh).
(2) Reference TM 1, Section 1.5.2, Table 1.11.
(3) Developed based on a linear projection of the 2021 baseline using a 1.16 percent annual population growth rate.

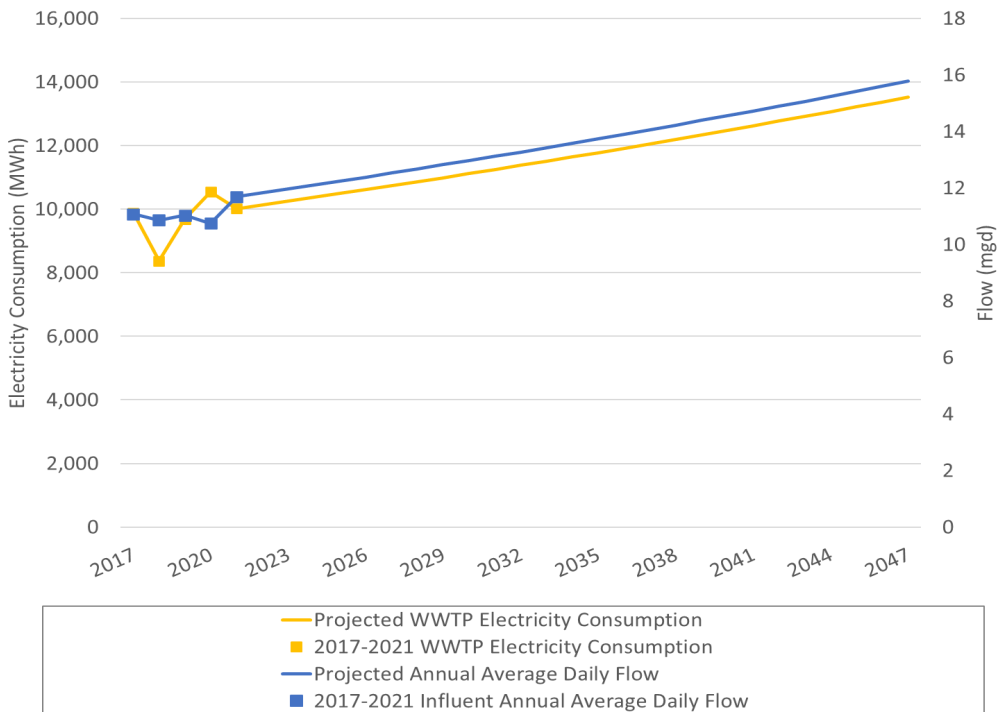

Figure 4.1 WWTP Influent Flow and Annual Electricity Consumption Projections

4.4.1.2 Primary Energy Demand Projections

The primary energy sources for the WWTP include natural gas for heating and cooling of buildings, heating of water, natural gas used as fuel in the cogeneration equipment, and diesel used for backup emergency generators.

The WWTP currently meets a substantial portion of its electricity demand by combusting purchased natural gas in addition to biogas in its cogeneration engines. In 2021, the engines produced 95 percent of the annual electricity demand of the WWTP. Although the electricity demand at the WWTP is projected to rise by 1.16 percent per year over the planning period, the demand for fuel to the existing cogeneration engines would remain the same without equipment changes as the existing cogeneration engines operate close to their production capacity (the current installed cogeneration capacity is approximately 1,400 kilowatts (kW) with a typical output of the system of 1,200 kW). Additionally, as the digester gas production increases as a result of projected load increases to the WWTP, the natural gas consumption in the engines decreases.

The WWTP used approximately 325,000 therms of thermal energy in 2021. This thermal energy demand at the WWTP is used primarily for heating of the anaerobic digesters, heating and cooling for various buildings, and heating of water. This demand was entirely met using the cogeneration engines' heat recovery system. While the digester heating thermal energy demand will increase over time proportional to increasing sludge flow to the digesters, it is expected that the cogeneration system's heat recovery system will continue to fully supply this heat demand, so no additional natural gas use will be needed to supply this heat. The existing three cogeneration engines can produce a maximum total of approximately 7.5 one million British thermal units per hour (MMBtu/hr) thermal heat available for recovery, equivalent to 657,000 therms annually, which is well above the WWTP's thermal energy needs.

The projected digester gas and natural gas consumption in the cogeneration engines, the digester heating demand, and the thermal energy recovery from cogeneration are summarized in Table 4.2 and Figure 4.2.

Table 4.2 Projected WWTP Cogeneration Natural Gas and Digester Heating Demand

Year	Annual Digester Gas Consumption in Cogeneration Engines (therms)[2][4]	Annual Natural Gas Consumption in Cogeneration Engines (therms)[3]	Annual Digester Heating Demand (therms)[2][4]	Thermal Energy Recovery from Cogeneration (therms)
2021[1]	511,836	660,195	150,000	657,000
2035	601,526	570,505	167,456	657,000
2047	690,812	481,219	192,312	657,000

Notes:
(1) Baseline year for this Energy Facilities Master Plan.
(2) Digester gas and digester heating demand were developed based on a linear projection of the 2021 baseline using a 1.16 percent annual population growth rate.
(3) Natural gas consumption in cogeneration engines decreases over time as digester gas production increases. It was assumed that the total fuel (natural gas + biogas) would remain constant from 2021 to 2047.
(4) Conversion from standard cubic feet to therms was based on a higher heating value of 1025 and 599 British thermal units/standard cubic foot (scf) for natural gas and digester gas, respectively.

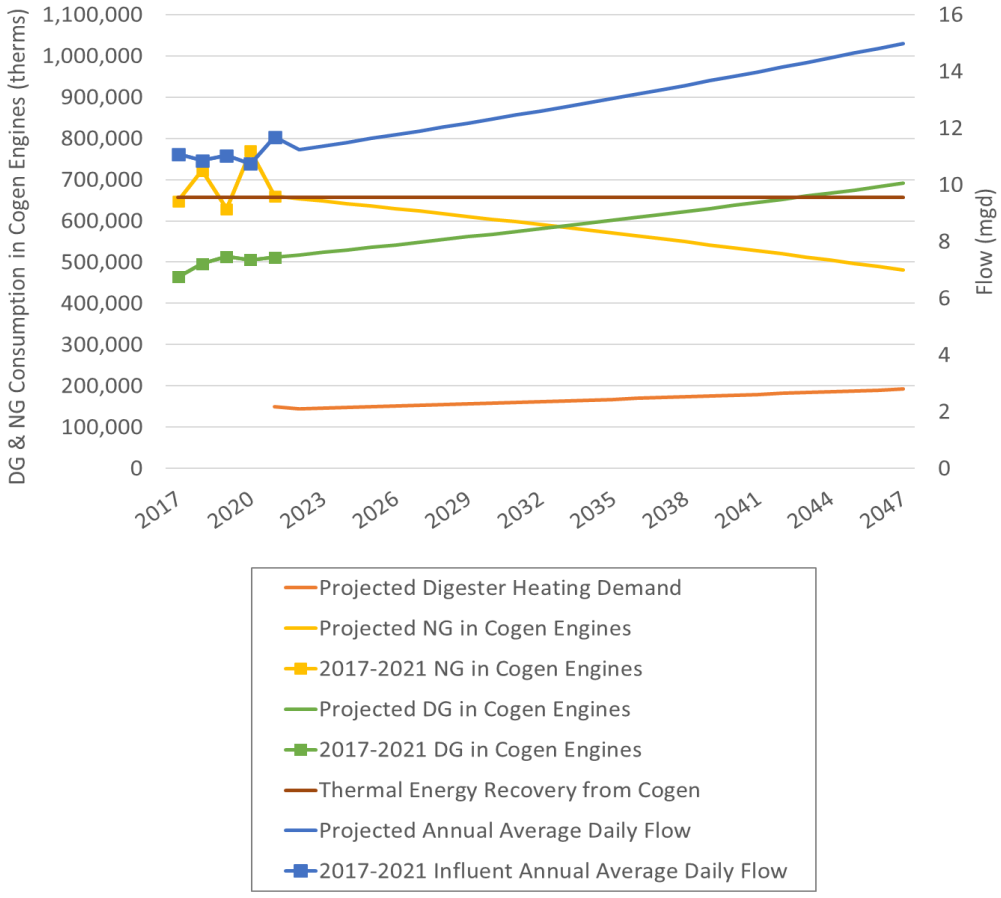

Figure 4.2 Annual WWTP Cogeneration Natural Gas and Digester Heating Demand Projections

4.4.1.3 Greenhouse Gas Emission Projections

The WWTP's GHG emissions were projected proportionately to the influent flow and loading projections with the following exceptions: assuming existing cogeneration capacity will remain constant, the GHG emissions associated with avoided purchased electricity through onsite electricity generation will remain the same as in 2021, and the natural gas needed in the engines will decrease relative to 2021 as the digester gas production increases. For this reason, the future GHG emissions are projected to be lower in the future. The current and future GHG emissions for the WWTP process are summarized in Table 4.3. The majority of the emissions are from natural gas combustion in the cogeneration engines.

Table 4.3 WWTP Projected GHG Emissions

	Emissions in 2021[1] (MT CO_2e)	Emissions in 2035 (MT CO_2e)	Emissions in 2047 (MT CO_2e)
Avoided Purchased Electricity[2]	-702	-702	-702
Purchased Electricity – WWTP + Collection System[2]	737	904	1,143
Offsite Natural Gas Production - Cogeneration	103	89	75
Onsite Natural Gas Combustion - Cogeneration	3,507	3,030	2,556
Biogas Combustion (excludes biogenic GHG emissions)	14	17	19
Diesel Gas Combustion - FSLs and DLDs	34	38	43
Treatment Process (N_2O)[3]	179	200	229
Effluent Discharge (N_2O)	1.9	2.1	2.4
FSLs (CH_4)	16	17	20
Chemicals Production	2.6	3.0	3.4
Chemicals Transport	4.3	4.8	5.6
Replacement Materials Production	14	16	19
Replacement Materials Transport	4.2	4.7	5.4
Total WWTP GHG Emissions	**3,914**	**3,624**	**3,419**

Notes:
CH_4 - methane; DLD - dedicated land disposal; FSL - facultative sludge lagoon; MT CO_2e - metric tons of carbon dioxide equivalents; N_2O - nitrous oxide.

(1) Baseline year for this Energy Facilities Master Plan.

(2) To be conservative, the baseline and projected GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the Community Choice Aggregation (CCA) and Pacific Gas & Electric Company (PG&E) portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.

(3) Nitrous oxide emissions from the conventional secondary treatment process (non-nitrifying) is based on the process emission factor without nitrification/denitrification (NdN). The emission factor for this process is 3.2g (N_2O)/person-year. The emission factor for plants with NdN is higher at 7 g N_2O/person-year. (Source: Local Government Operations Protocol. August 2008, Equation 10.7, Page 105). Note that there is still scientific uncertainty and various sources list different emission factors.

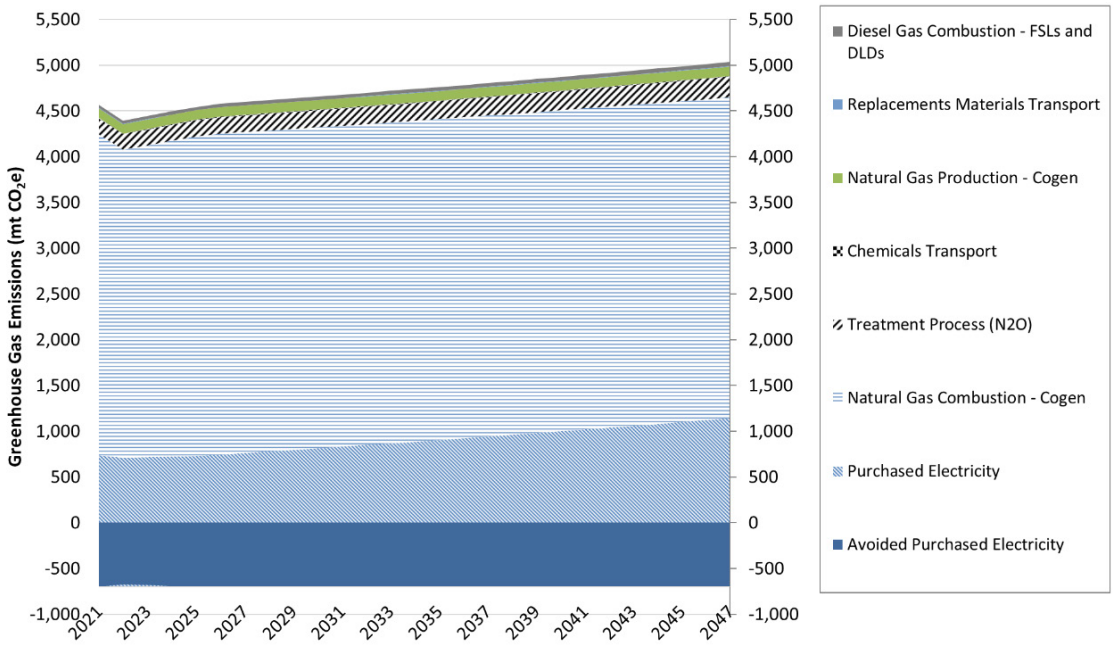

Figure 4.3 Annual WWTP GHG Emissions Projections

4.4.2 Potable Water Distribution

4.4.2.1 Electricity Consumption Projections

West Yost Associates developed potable water demand projections through 2045 as part of DSRSD's *2020 Urban Water Management Plan*. This projection accounted for future developments within DSRSD's service area, particularly in the Dublin area. In 2021, DSRSD consumed 3,917 MWh of electricity to distribute 3,471 MG of potable water. This unit electricity consumption (1.13 MWh/MG) was applied to the potable water demand projections to estimate the future electricity consumption associated with the potable water distribution system. The baseline values and projections are summarized in Table 4.4 and Figure 4.4.

Table 4.4 Projected Potable Water Demand and Electricity Consumption

Year	Annual Potable Water Demand (MG)	Potable Water Demand Annual Electricity Consumption (MWh)
2021(1)	3,471	3,917
2035(2)	4,499	5,078
2047(2)	4,573	5,161

Notes:
(1) Baseline year for this Energy Facilities Master Plan.
(2) Developed based on the potable water demand projections in the *2020 Urban Water Management Plan* prepared for DSRSD by West Yost Associates.

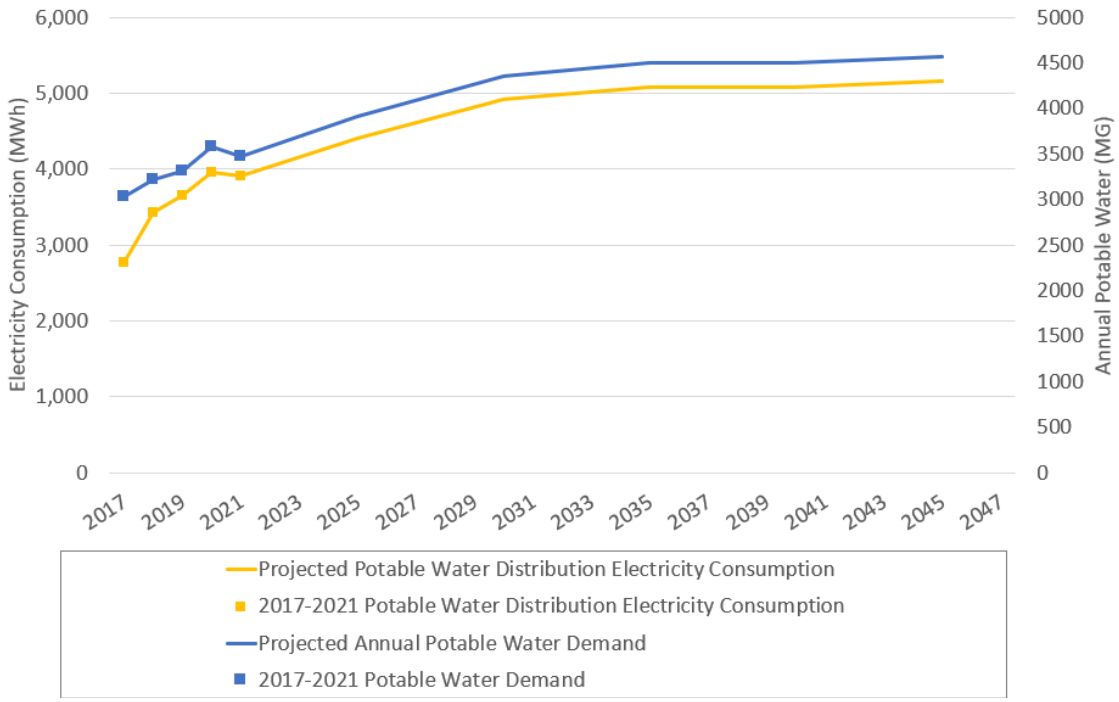

Figure 4.4 Annual Potable Water Demand and Electricity Consumption Projections

4.4.2.2 Greenhouse Gas Emission Projections

GHG emissions were projected in proportion to the future potable water demand discussed in Section 4.4.3.1. The baseline and projected GHG emissions for the potable water distribution system are summarized in Table 4.5 and Figure 4.5. The bulk of these emissions were associated with purchased electricity.

Table 4.5 Projected Potable Water Distribution GHG Emissions

	Emissions in 2021[1] (MT CO_2e)	Emissions in 2035[2] (MT CO_2e)	Emissions in 2047[2] (MT CO_2e)
Purchased Electricity[3]	288	373	379
Chemicals Production	2.6	3.3	3.4
Chemicals Transport	4.2	5.5	5.5
Total Annual GHG Emissions	**294**	**382**	**388**

Notes:
(1) Baseline year for this Energy Facilities Master Plan.
(2) Developed based on the potable water demand projections in the *2020 Urban Water Management Plan* prepared for DSRSD by West Yost Associates.
(3) To be conservative, the baseline and projected GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.

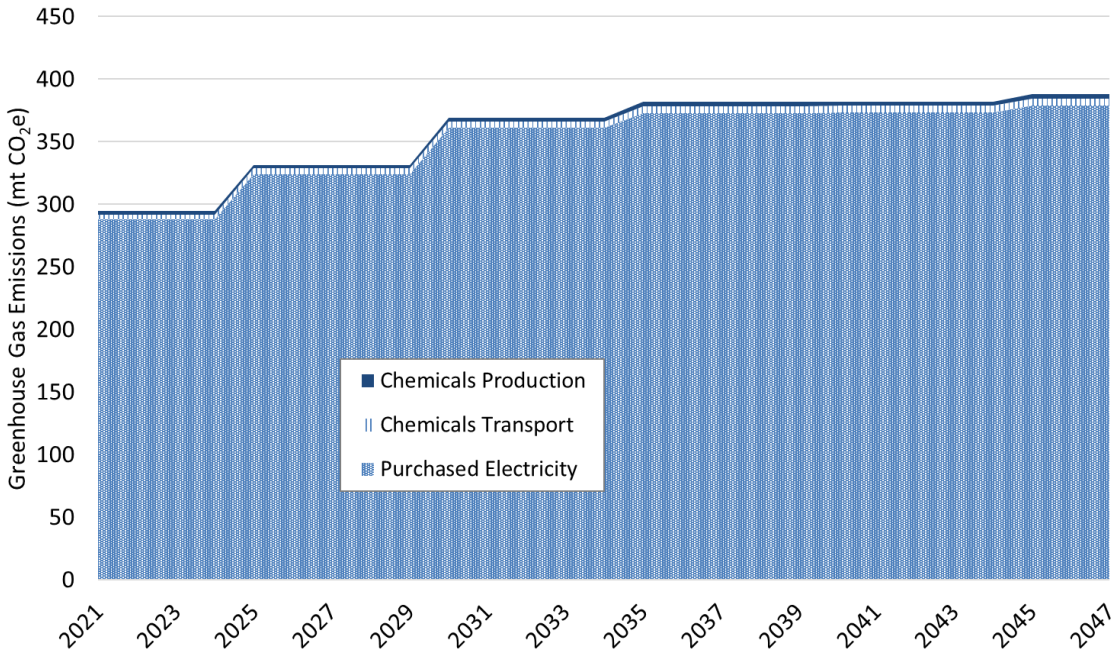

Figure 4.5 Potable Water Distribution Annual GHG Emissions Projections

4.4.3 Recycled Water Distribution

As described in DSRSD's *2020 Urban Water Management Plan*, the recycled water program has reached its maximum capacity during peak months. DSRSD is not planning to connect new recycled water customers unless the water supply used to make recycled water is increased. Therefore, the electricity use and GHG emissions associated with the recycled water production are assumed to stay the same over the planning period (Table 4.6).

Table 4.6 Projected Electricity Consumption and GHG Emissions for the DSRSD Recycled Water Distribution

	2021(1)	2035(2)	2047(2)
Annual Recycled Water Production (MG)		992	
Annual Electricity Consumption (MWh)		301	
Annual GHG Emissions (MT CO_2e)(3)		22	

Notes:
(1) Baseline year for this Energy Facilities Master Plan.
(2) Developed based on the potable water demand projections in the *2020 Urban Water Management Plan* prepared for DSRSD by West Yost Associates.
(3) To be conservative, the baseline and projected GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the State goal of 100 percent zero-carbon electricity by 2045.

4.4.4 Administrative and Other Buildings

The electricity use, natural gas use, and GHG emissions associated with DSRSD's administrative and maintenance buildings are not expected to change over the planning period (Table 4.7).

Table 4.7 Projected Electricity Consumption and GHG Emissions for the Administrative and Other Buildings

		2021[1]	2035[2]	2047[2]
Field Operations Facility	Annual Electricity Consumption (MWh)		308	
	Annual Natural Gas Consumption (therms)		3,333	
	Annual GHG Emissions (MT CO_2e)[3]		41	
District Administrative and Utility Buildings	Annual Electricity Consumption (MWh)		291	
	Annual Natural Gas Consumption (therms)		7,190	
	Annual GHG Emissions (MT CO_2e)[3]		62	
Fleet Office Maintenance Building	Annual Electricity Consumption (MWh)[4]		--	
	Annual Natural Gas Consumption (therms)		2,167	
	Annual GHG Emissions (MT CO_2e)[3]		12	
Total Annual GHG Emissions (MT CO_2e)[3]			115	

Notes:
(1) Baseline year for this Energy Facilities Master Plan.
(2) Energy consumption and GHG emissions are expected to remain constant over the planning period for DSRSD's buildings.
(3) The annual electricity consumption associated with the fleet office maintenance building cannot be separated from the WWTP's overall electricity consumption. However, it can be assumed that the fleet office maintenance building represents an insignificant fraction of the WWTP's overall electricity use.
(4) To be conservative, the baseline and projected GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.

4.4.5 Vehicle Fleet

Similar to its buildings, DSRSD's vehicle fleet's usage is not expected to increase with increases in the WWTP's or potable water distribution system's energy use. The fleet's 2021 baseline fuel consumption and GHG emissions are summarized in Table 4.8. The values in the table below represent the fleet's baseline emissions and future GHG emissions under a "business as usual" scenario, which involves continued use of gasoline- and diesel-fueled vehicles. The fleet conversion to zero-emission vehicles and their associated GHG impact is discussed in detail in TM 7.

Table 4.8 Projected Vehicle Fleet Fuel Usage and GHG Emissions

	2021[1]	2035[2]	2047[2]
Fleet Annual Vehicle Miles Traveled		80,204	
Annual Gasoline Consumption (gallons)		9,348	
Annual Diesel Consumption (gallons)		628	
Annual GHG Emissions (MT CO_2e)		89	

Notes:
(1) Baseline year for this Energy Facilities Master Plan.
(2) The baseline fuel consumption and GHG emissions for DSRSD's fleet are expected to remain constant under "business as usual" operation.

4.5 Energy Production Capacity Projection

4.5.1 Wastewater Solids and Biogas Production

As the influent organic loading to the WWTP increases, its biosolids and biogas production will increase proportionately. Similar to the WWTP's energy consumption, it was assumed that sludge production would increase 1.16 percent per year proportionately to the WWTP's influent flow. However, rather than using 2021 as the baseline year, the average of 2017 to 2022 excluding 2021 was used as the baseline. This is because, as shown in Figure 4.6, an analysis of the 2017 to 2022 historical data found 2021 to be an outlier. Based on prior analysis by others, it is hypothesized that 2021 might be an outlier due to higher loads due to more people working from home during the pandemic as well as impacts from the primary clarifier improvements construction that was done in 2021.

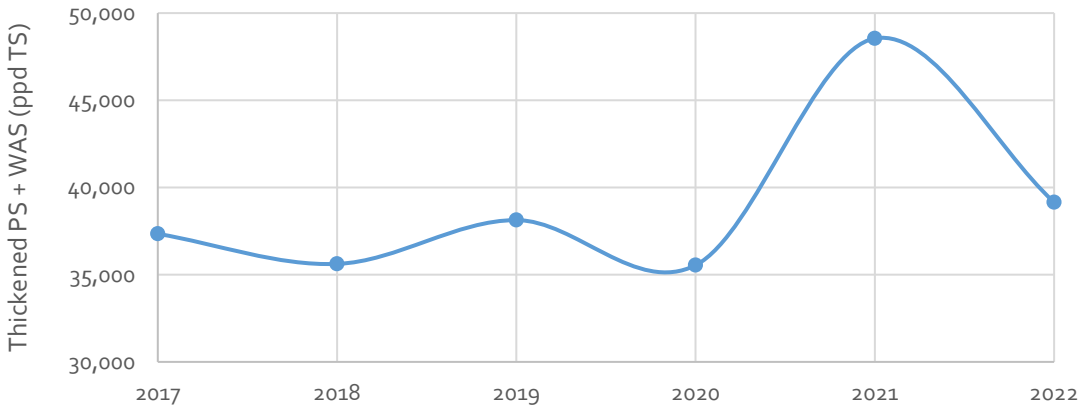

Figure 4.6 Historical Sludge Data Shows 2021 to be an Outlier

The process data that was used as a basis for the primary sludge (PS), waste activated sludge (WAS), and thickened WAS and PS solids projections is presented in Table 4.9. Note that the solids loading data for PS and WAS were only available from 2020 to 2022, so the thickened solids data was used as a basis for the projections. The PS and WAS quantities were then back-calculated based on the historical dissolved air floatation thickener (DAFT) capture rate and the historical PS ratio.

Table 4.9 Historical Process Data used as Basis for Solids Projections

Parameter	Value	Notes/references
Thickened PS + WAS TS, ppd	37,158	2017-2022 average (excluding 2021); basis for projections
PS %TS	1.64	2020-2022 average (excluding 2021)
WAS %TS	0.112	2017-2022 average (excluding 2021)
Thickened PS + WAS %TS	4.0	2017-2022 average (excluding 2021)
DAFT capture rate	96	2020-2022 average (excluding 2021)
% of load from PS	56	2020-2022 average (excluding 2021)

Notes:
ppd - pounds per day; %TS - percent total solids.

The current and projected PS, WAS, and thickened PS + WAS values are summarized in Table 4.10.

Table 4.10 WWTP Solids Projections

		Baseline[1]	2035[2]	2047[2]
PS	Sludge Flow (mgd)	0.16	0.18	0.21
	Solids Loading (ppd)	21,675	25,181	28,919
WAS	Sludge Flow (mgd)	1.8	2.1	2.4
	Solids Loading (ppd)	17,031	19,785	22,722
Thickened Solids (PS + WAS)	Sludge Flow (mgd)	0.11	0.13	0.15
	Solids Loading (ppd)	37,158	43,168	49,576

Notes:
(1) The baseline for the solids projections was selected to be the average of 2017 to 2022 (excluding 2021) thickened solids quantity because 2021 was identified to be an outlier. Using the 2021 outlier as a baseline would result in an overestimate of the solids projections.
(2) Developed based on a linear projection of the baseline unit values using a 1.16 percent annual population growth rate.

Table 4.11 and Figure 4.7 show the current and projected biogas production assuming biogas volume increases at the same rate as PS, WAS and TWAS production. The projected electricity generated from biogas is based on DSRSD's 2021 current electricity production rate of 0.069 kilowatt-hour (kWh)/scf of biogas produced (including a small amount of biogas sent to flare). This electricity projection assumes that DSRSD will combust more biogas in the future in the cogeneration engines, and proportionately reduce the amount of supplemental natural gas used.

Table 4.11 WWTP Biogas Projections

Year	Annual Biogas Production (1,000 scf)	Annual Electricity Produced from Biogas (MWh)
2021[1]	89,288	6,202
2035[2]	104,934	7,289
2047[2]	120,509	8,371

Notes:
(1) Baseline year for this Energy Facilities Master Plan.
(2) Developed based on a linear projection of the 2021 baseline using a 1.16 percent annual population growth rate.

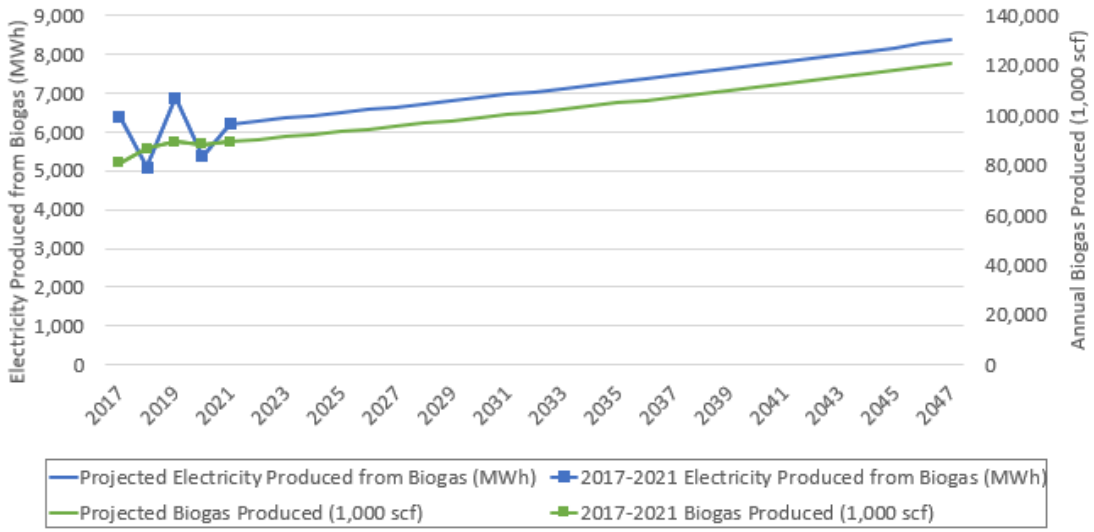

Figure 4.7 Biogas and Electricity Production From Biogas Projections

4.5.2 Thermal Energy Production Capacity

The thermal energy produced by the cogeneration engines will remain the same assuming that the existing cogeneration capacity will not be increased and the additional biogas production in future years will replace natural gas use. The three cogeneration engines can produce a maximum total of approximately 7.5 MMBtu/hr thermal heat available for recovery. The current total hot water demand at the plant is 3.52 MMBtu/hr in the summer and 3.68 MMBtu/hour in the winter. Therefore, there is currently excess heat available that could be utilized to satisfy the additional digester heating demand and for additional building or process heating opportunities.

4.5.3 Other Energy Production Capacity

DSRSD has a 5 kW solar array pilot project installed on the roof of Building T. However, this solar system has not been maintained and is estimated to be producing less than half the rated capacity. There are currently no other sources of onsite energy production at the DSRSD facilities.

4.6 Conclusions

This TM summarized the projected energy demand and production over the planning period for DSRSD's current baseline operation based on 2021 data. These projections will be used in subsequent TMs to compare baseline conditions against alternatives to:

- Assess the estimated future energy demand and GHG emissions status quo conditions in consideration of the impact of potential future energy efficiency measures and future energy costs.
- Estimate adequate capacities for energy production equipment.
- Determine future energy supply needs and renewable energy sources to satisfy desired target fraction for DSRSD's future energy demand and energy supply systems.

Dublin San Ramon Services District
Water, wastewater, recycled water

Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 5
ENERGY SAVINGS AND EFFICIENCY OPPORTUNITIES ASSESSMENT

FINAL | June 2024

carollo

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Abbreviations

ACH	air changes per hour
AI	artificial Intelligence
ASHRAE	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
BLG	building
BOD	biochemical oxygen demand
BS	biosolids
Carollo	Carollo Engineers
CDD70	cooling degree days for 70 degrees Fahrenheit
CIP	capital improvement program
DAFT	dissolved air flotation thickener
DERWA	Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority
DO	dissolved oxygen
DSRSD	Dublin San Ramon Sanitation District
EI&C	electrical, instrumentation and controls
EPDM	ethylene propylene diene terpolymer
EPRI	Electric Power Research Institute
ERV	energy recovery ventilation
F	Fahrenheit
GHG	greenhouse gas
HDD50	heating degree days for 50 degrees Fahrenheit
hp	horsepower
HVAC	heating, ventilation, and air conditioning
kWh	kilowatt-hour
LAVWMA	Livermore-Amador Valley Water Management Agency
LS	liquid stream
MABR	membrane aerated biofilm reactor
MAU	makeup air unit
mgd	million gallons per day
mg/L	milligrams per liter
MLSS	mixed liquor suspended solids
mm	millimeter
MOV	most open valve
O&M	operations and maintenance
OTE	oxygen transfer efficiency

PD	positive displacement
psi	pounds per square inch
psia	pounds per square inch absolute
PWD	potable water distribution
RAS	return activated sludge
SCADA	supervisory control and data acquisition
scfm	standard cubic feet per minute
SRT	solids retention time
TM	technical memorandum
TS	total solids
TSS	total suspended solids
VFD	variable frequency drive
VRF	variable refrigerant flow
WAS	waste activated sludge
WWTP	wastewater treatment plant

Technical Memorandum 5

ENERGY SAVINGS AND EFFICIENCY OPPORTUNITIES ASSESSMENT

5.1 Introduction

With its numerous facilities, equipment, and processes, Dublin San Ramon Services District (DSRSD) is in a prime position to reduce its energy consumption and greenhouse gas (GHG) emissions. Technical Memorandum (TM) 2 identified strategies to reduce energy consumption, produce more onsite energy production, increase the fraction of renewable energy sources, and reduce GHG emissions. The opportunities for potential energy savings and energy efficiency measures are further evaluated in this TM and listed in Table 5.1. The opportunities identified in TM 2 for energy generation and improved system reliability are further evaluated in TM 6. Those related solely to GHG emissions reductions are presented in TM 7. These assessments (TM 2, TM 5, TM 6 and TM 7) are exclusive to DSRSD facilities and have excluded any opportunities for the Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority (DERWA) and Livermore-Amador Valley Water Management Agency (LAVWMA) facilities.

Table 5.1 Overview of Energy Savings and Efficiency Opportunities Evaluated in this TM

Process Area	Opportunity ID	Opportunity Name
LS Treatment Efficiency Opportunities	LS-5	Real Time SRT Control
	LS-6	Model Predictive Aeration Control
	LS-7	Low DO Operation
	LS-12	Switch Aeration Diffusers
	LS-13,15	Upgrade Aeration Blowers, Jockey Blower
	LS-16	Upgrade Pre-Aeration Blowers
	LS-18	Install Additional VFDs
BS Treatment Efficiency Opportunities	BS-2A	DAFT Optimization
BLG System Operations Optimization	BLG-2	Adjust Lighting and Temperature Schedules
	BLG-4	Reduced Ground Lighting at Night
	BLG-7	Metal Building Insulation
	BLG-8	Screen Room Air Handling Unit Replacement
	BLG-9	Building A and C Air Handling Unit Replacement
	BLG-10	Bar Screen Building Exhaust Fan Motor
	BLG-11	HVAC Energy Recovery
	BLG-14	Refrigerant HVAC System
	BLG-15	Economized Cooling via Fan Addition

Process Area	Opportunity ID	Opportunity Name
PWD System Opportunities	PWD-2	Assess Pump Condition
	PWD-3	Assess Pump Design Point
	PWD-5	Time of use pumping for distribution system and DSRSD's recycled water distribution system.
Energy Management and AC Opportunities	AC-1	Alternative Power Monitoring
	AC-2	AI
	AC-4	Energy Decision Management Tools
	AC-5	Install Load Bank (Reference TM 10 for analysis of this alternative)

Notes:
AC - advanced control; AI - artificial intelligence; BLG - building; BS - biosolids; DO - dissolved oxygen; HVAC - heating, ventilation, and air conditioning; LS - liquid stream; PWD - potable water distribution; SRT - solids retention time; VFD - variable frequency drive.

5.2 Objectives

This TM evaluates technologies, strategies, and opportunities for reducing energy demands and increasing energy efficiency facilities wide for DSRSD. This evaluation was conducted considering existing and forthcoming federal and state level regulations initiatives, and incentives, primarily driven by GHG emissions reductions via direct reductions in energy and improved energy efficiency toward achieving statewide carbon neutrality by 2045, as well as DSRSD's energy guiding principles and adopted energy policy.

Energy reduction and efficiency improvement opportunities were identified for five key areas:

1. Secondary treatment process control and aeration.
2. Solids thickening.
3. Building system operations.
4. Pumping optimization in the potable and recycled water distribution systems.
5. Indirectly through improved real-time energy management data tracking.

Opportunities under each of these five areas are introduced and evaluated in the following sections.

5.3 Wastewater Treatment Plant (WWTP) Opportunities

5.3.1 Liquid Stream Treatment Efficiency Alternatives

Based on the energy benchmarking analysis summarized in TM 1, the liquid stream treatment including liquid process flow pumping consumes 70 percent of the total annual electricity consumption at the WWTP. The secondary treatment alone uses approximately 43 percent of the plant wide electricity consumption. For this reason, liquid stream treatment is the first area to investigate energy efficiency opportunities.

Aeration accounts for most of the energy consumption within the secondary treatment. Reducing aeration demand will have major impacts on the energy efficiency for the entire wastewater treatment process.

5.3.1.1 Real Time Solids Retention Time Control (LS-5)

Real-time SRT control refers to control systems that allow maintaining a certain setpoint SRT in the secondary system at any point in time with very high accuracy (less than about 0.2 days variability around the setpoint on a minute-by-minute basis).

Typically, utilities will make period wasting adjustments on a daily or weekly basis based on laboratory data (e.g., total suspended solids) received days after the samples have been collected. As a result, actual SRTs around the intended setpoint can vary by several days.

Real-time, accurate SRT control has been demonstrated to result in two benefits relevant to this energy evaluation:

1. Significantly improved sludge settleability.
2. Potential to reduce DO setpoints.

DSRSD is wasting solids from mixed liquor. This controls SRT more accurately than wasting solids from the return activated sludge (RAS). However, this operation is more energy intensive due to increased pumping of waste activated sludge mixed liquor flows that are two to three times higher compared to the concentrated RAS process stream.

Real-time SRT control can easily be implemented in DSRSD's secondary treatment process, since the wasting amount can be easily calculated based on the real time measurement of the average mixed liquor suspended solids (MLSS) concentration in the aeration basins. Figure 5.1 shows that the aerobic SRT in the aeration basins at DSRSD is actually already very stable and kept year-round at approximately 1.5 days to prevent nitrification. Therefore, DSRSD is not anticipated to see drastic benefits from implementing advanced SRT control.

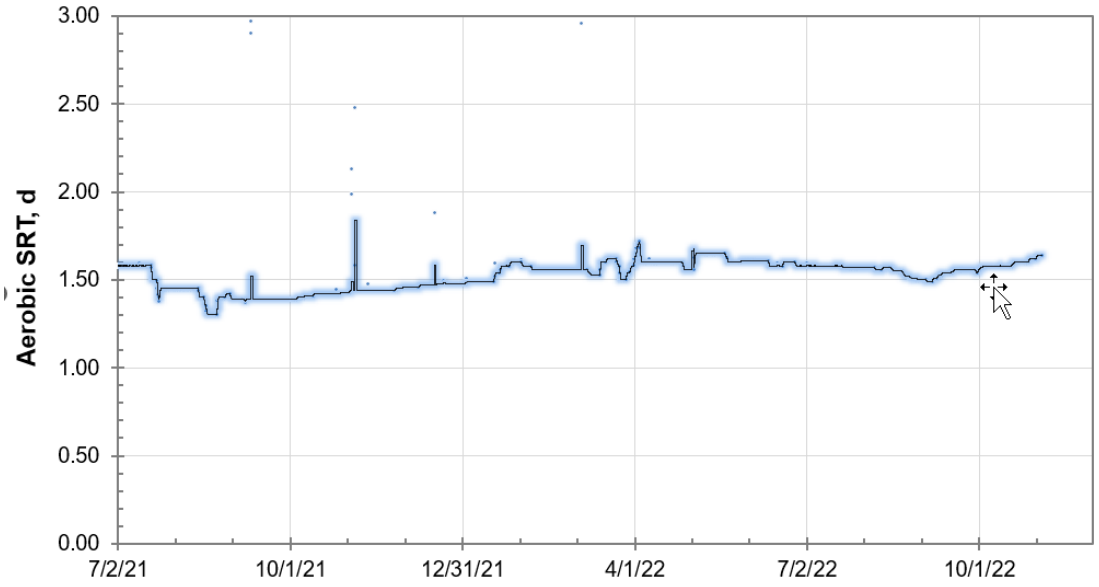


Figure 5.1 Hourly Aerobic SRT in the Aeration Basins (July 2021 to November 2022)

One option could be to tie real-time SRT control to in-situ ammonia or nitrite probes in the aeration basins to operate at elevated SRTs (which might improve sludge settleability) while still avoiding nitrification. Improved settleability at higher SRT operation can result in lower chemical demand at DERWA and therefore a reduction in associated operations and maintenance (O&M)

costs and GHG emissions. This mode of operation could be considered, tested, and if found to be beneficial, implemented by operations staff and a program integrator. It does not require a dedicated Capital Improvement Program (CIP) project placeholder. The testing or implementation costs would include:

1. Equipping each aeration basin with total suspended solids (TSS) and nitrite probes (sensors; control panel; electrical, instrumentation, and controls [EI&C]; supervisory control and data acquisition [SCADA] integration) (ammonia probes are already in place at four locations).
2. Probe maintenance.
3. SRT controller programming.

Recommendation: Carollo Engineers (Carollo) recommends that DSRSD commence the planning/preliminary engineering phase of an "Aeration System Upgrade" CIP project in 2030/2031. The scope of this study should include an assessment of integrating real-time SRT control within the aeration basins, including the use of in-situ ammonia or nitrate probes. The study should also include assessments for the implementation of predictive aeration control (LS-6), energy-efficient air diffuser types (LS-12) and energy-efficient blower system technologies (LS-13).

5.3.1.2 Model Predictive Aeration Control (LS-6)

In 2021, DSRSD used approximately 8000 kilowatt-hour (kWh)/day for treating an annual average daily flow of 11.5 million gallons per day (mgd). This falls right in line with the energy benchmark of 7,200 kWh for aeration of a 10 mgd facility that is not nitrifying,[1] indicating DSRSD can achieve the lower end of energy efficiency margins typical for similar water resource recovery facilities.

DSRSD is currently controlling aeration to each aeration basin using DO setpoint control and most open valve (MOV). DO probes are located at the east and west end of each aeration basin. Each basin is supplied by two aeration zones that are controlled with automated air flow control valves. The flow regime through the aeration basins is shown in Figure 5.2 when the first basin is operated as an anaerobic selector. This operation is preferred as it improves sludge settleability.

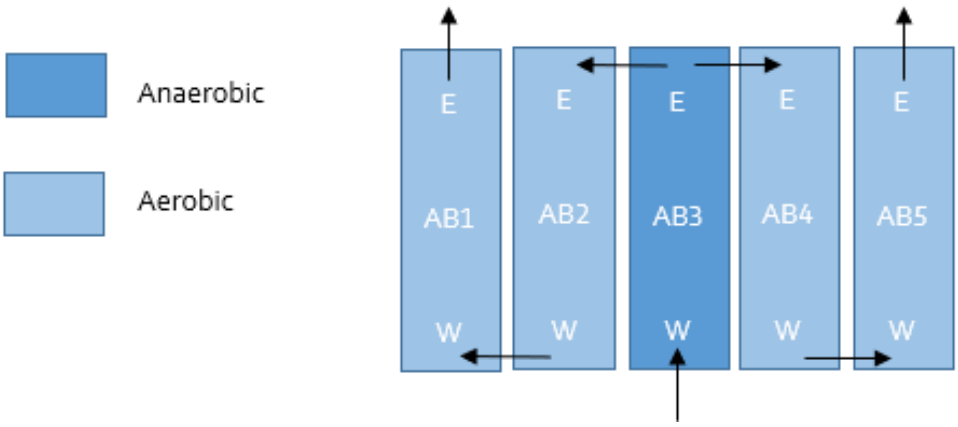


Figure 5.2 Aeration Basin Operation With Anaerobic Selector Configuration

[1] Electric Power Research Institute (EPRI). November 2013. *Electricity Use and Management in the Municipal Water Supply and Wastewater Industries.*

The MOV programming was optimized in early 2022, as can be seen in Figure 5.3 that shows the maximum hourly valve positions. The increase in the most open valve position results in a decrease in blower energy consumption.

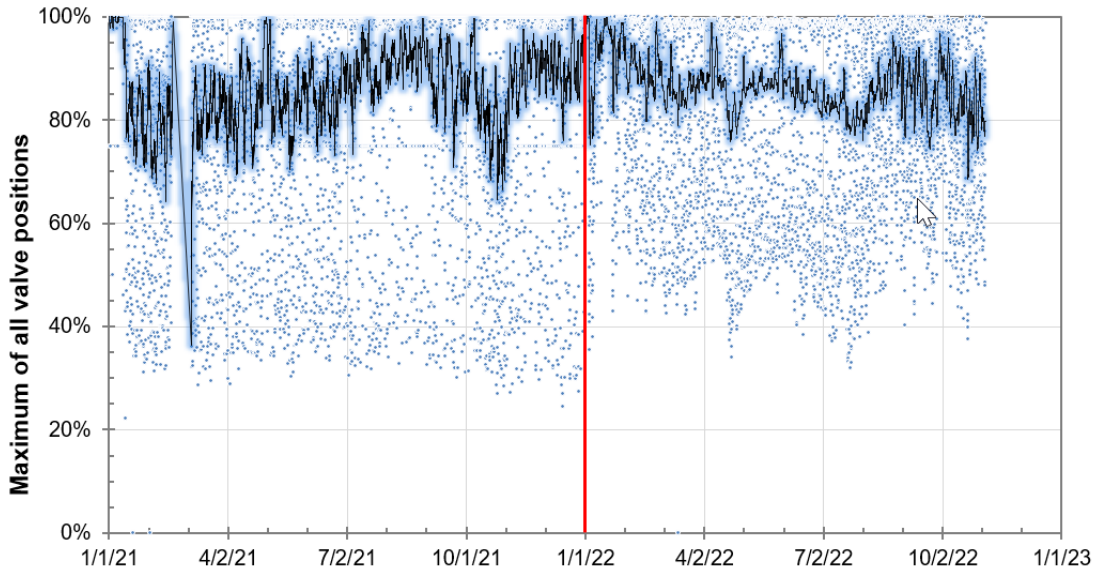


Figure 5.3 Aeration Basin Operation With Anaerobic Selector Configuration

Appendix 5A shows the DO concentrations in the basins and other relevant aeration system data. DSRSD has already put several energy efficiency measures into place:

1. The DO setpoints in the aeration basins are typically set to range between 1.0 to 1.5 milligrams per liter (mg/L). For a conventional activated sludge process (biochemical oxygen demand [BOD] removal only), these DO setpoints are at the lower end of the typical DO range (1 to >2.5 mg/L).
2. DSRSD has reduced the blower discharge pressure in November 2021 from about 8.1 pounds per square inch (psi) to 7.8 psi.
3. Air losses from air piping are expected to be minimal. The air piping is short and routed above ground.

In addition, for brief periods in May 2021, June 2022, and February 2023, DSRSD operated AB 3 as an anaerobic/anoxic selector, due to various operational limitations. DSRSD could consider operating AB 3 as an anaerobic/anoxic selector permanently or more regularly since this mode of operation provides additional energy/aeration savings through improved settling and by removing a fraction of the influent BOD under unaerated conditions.

The data plots included in Appendix 5A indicate some potential for further aeration control optimization. The variability of hourly DO concentrations around the DO setpoint is relatively high in some of the aeration basin zones, ranging from 10 to over 50 percent as the coefficient of variation over a 24-hour period (see for example the cyclic DO concentrations in AB 2, East Zone). The coefficient of variation (relative standard deviation) is a statistical measure of the dispersion of data points around the mean, calculated as the ratio of standard deviation and the mean in percent. Other aeration basin zones in DSRSD's aeration basins achieve a much lower coefficient of variation of about 0 to 20 percent of hourly data over a 24-hour period (e.g., AB 2, West Zone).

Given that some aeration basin zones achieve a good level of DO control accuracy (coefficient of variation of about 15 percent or less) compared to others indicate that the aeration control system can likely be better tuned to achieve a more consistent control accuracy in all zones.

Improving the control accuracy in all zones may not directly result in a noticeable reduction of airflows and blower aeration energy. However, the experience at other facilities has shown potential for the following indirect energy and GHG emissions:

- Improved sludge settleability (reduced sludge volume index values).
- Ability to further reduce DO concentration setpoints.

Proprietary advanced aeration control systems might improve the accuracy and reliability of aeration control. Programs typically include statistical programs that recognize and exclude faulty sensor input readings. The programs also have the capacity to make continuous aeration control adjustments to stay as close as possible to the control setpoints any time of day. Proprietary systems however bear the disadvantage that certain program components are typically not accessible to utilities.

Carollo recommends that DSRSD start with a tuning touch up on the few remaining basin zones that show higher DO variability using the existing aeration control program followed by an evaluation of the long-term benefits on sludge settleability and energy savings. Additional aeration control program upgrades could be evaluated as part of a future aeration system CIP project.

Recommendation: Carollo recommends that DSRSD commence the planning/preliminary engineering phase of an "Aeration System Upgrade" CIP project in 2030/2031. The scope of this study should include an assessment of integrating predictive aeration control. The study should also include assessments for the implementation of real-time SRT control (LS-5), energy-efficient air diffuser types (LS-12) and energy-efficient blower system technologies (LS-13).

5.3.1.3 Low Dissolved Oxygen Operation (LS-7)

A few utilities in the United States have successfully converted their activated sludge processes from conventional DO concentrations (>1 mg/L) to suboxic redox conditions, operating at DO concentrations below 0.7 mg/L throughout all aerated zones. This type of operation has reduced aeration energy by up to 50 percent, depending on the initial aeration efficiency of the process. Carollo estimates that DSRSD might achieve an estimated 15 to 25 percent of aeration savings if the process was to be converted to suboxic operation.

Our current industry-wide understanding of successful suboxic operation indicates that the following are necessary factors for a successful process conversion:

1. Accurate aeration control allowing to reduce DO setpoints in a very controlled fashion to avoid the proliferation of low DO filaments. DO setpoints should be reduced no more than 0.1 to 0.2 mg/L approximately every 10 days.
2. Sufficient instrumentation to assure consistent DO profiles through the aeration basins.

To date, Carollo is not aware of facilities operating under suboxic conditions without nitrification. In principle, there is no reason why a BOD removal process could not be operated under suboxic conditions. If DSRSD was interested in this mode of operation, Carollo recommends a stepwise approach that starts initially with the recommendations summarized under LS-6, followed by a gradual reduction of DO setpoints to adapt the biomass to suboxic conditions. It is advised to

involve the support of an experienced process engineer when field testing suboxic process conversion.

Recommendation: Carollo recommends that DSRSD commence the planning/preliminary engineering phase of an "Aeration System Upgrade" CIP project in 2030/2031. The scope of this study should include assessments for the implementation of real-time SRT control (LS-5), predictive aeration control (LS-6), energy-efficient air diffuser types (LS-12) and energy-efficient blower system technologies (LS-13).

If Aeration System Upgrade project implements alternatives LS-5 and/or LS-6, Carollo recommends that DSRSD consider further evaluation of LS-7. If neither LS-5 nor LS-6 are implemented as part of DSRSD overall operation, LS-7 does not need to be considered.

5.3.1.4 Switch Aeration Diffusers (LS-12)

DSRSD currently has fine bubble diffusers in all aeration basins. The diffuser grid system has an estimated remaining useful life of approximately 5 to 10 years. The District replaces the diffuser membranes every 5 to 7 years.

Figure.5.4 Sanitaire Disc Fine Bubble Diffuser

Many different types of diffusers are available in various sizes and shapes. For the purpose of this project, the Carollo project team focused on fine bubble diffusers, which are classified as producing a nominal 2-millimeter (mm) diameter bubble. In actual practice, fine bubble diffusers release a wide distribution of bubble sizes depending on the air flow through the diffuser and the wastewater environment around the diffusers. Maintaining a small bubble size is important to maintain a high surface area (relative to bubble size) and promote efficient gas transfer. An example of the Sanitaire membrane disc fine bubble diffuser is shown in Figure 5.4.

Currently eight manufacturers worldwide supply the majority of the fine bubble diffusers in the North American market. Of these, the first four listed in Table 5.2 (Xylem-Sanitaire, Environmental Dynamics International, SSI Aeration, Aquarius Technologies) have the largest market share and are the most widely used.

Table 5.2 Fine Bubble Diffuser Suppliers

Manufacturer/Headquarters	Product Shapes	Diffuser materials
Xylem – Sanitaire/Brown Deer, Wisconsin	Disc	Ceramic and EPDM membrane
Environmental Dynamics International/ Columbia, Missouri	Tube, mini-panel, and disc	EPDM, Urethane, and Advanced membrane
SSI Aeration, Inc/Poughkeepsie, New York	Tube and disc	EPDM, Urethane, and Advanced membrane
Aquarius Technologies, LLC/Saukville, Wisconsin	Disc	Ceramic and EPDM membrane
Evoqua Water Technologies/Pittsburgh, Pennsylvania	Disc	Ceramic and EPDM membrane

Manufacturer/Headquarters	Product Shapes	Diffuser materials
Ovivo USA, LLC/Salt Lake City, Utah	Mini-panel	Urethane
Parkson Corporation/Fort Lauderdale, Florida	Panel	Urethane
Ott Group/Lagenhagen/Germany	Tube and Disc	EPDM, Silicone and Advanced membrane

Notes:
EPDM - ethylene propylene diene terpolymer.

In recent years the United States market for diffuser products has broadened and unique diffusers have entered the marketplace that offer performance improvements compared to traditional product manufacturers.

Both Ovivo with their Aerostrip mini panel and Parkson with their Messner panel offer high head loss membrane diffusers that produce smaller bubbles and offer greater floor coverage, resulting in higher oxygen transfer efficiency (OTE) compared to standard 9-inch disc grid designs. The Aerostrip product originated in Austria (see Figure 5.5). The Messner panel originated in Germany (see Figure 5.6). Carollo conducted a recent life cycle cost analysis for another project comparing Ovivo's Aerostrip panels to Xylem-Sanitaire's 9-inch disc diffusers. As part of that analysis the Aerostrip system was determined to be approximately 1 percent more efficient, however with significantly higher capital costs. The energy savings from the higher efficiency Aerostrip system did not result in a positive payback when analyzed over the 25-year equipment life cycle.

Figure 5.5 Aerostrip Mini Panel

Figure 5.6 Parkson Messner Panel

Both the Ovivo and Parkson panel diffuser products lack a consistently positive track record in the United States market. The Carollo project team is aware of at least two United States installations of the Aerostrip product that have encountered significant problems. At one installation, a replacement disc grid system was installed. The Messner panel system has also encountered issues, especially in the early installations. The Carollo project team is also aware of poor diffuser product quality installations from other established high efficiency diffuser manufacturers. Because of the mixed performance history, the Carollo project team cautions against committing at this time to replacing diffusers with high efficiency panel type diffusers for DSRSD even though they offer a higher OTE and installation density compared to disc diffusers without conducting a more thorough market review. These diffusers may be suitable technology for portions of the aeration basins but not the primary oxygen transfer mechanism. It is worth noting that a high-density low flux disc diffuser grid can minimize the OTE difference between disc diffusers and panel diffusers.

In recent years new, innovative diffuser products have entered the wastewater market that promise greater energy efficiency than established products. These include microbubble generation by fluidic oscillation (Perlemax) (tracked for DSRSD under opportunity ET35), which was tested by Metro Vancouver (Figure 5.7). These diffusers generate bubbles in the 600 micrometer size range by coupling conventional diffusers with an oscillator, thereby increasing the bubble surface area about five-fold. Perlemax claims a reduction in energy usage of about 25 percent solely based on this diffuser and technology as compared to conventional diffuser technologies. To date, this type of diffuser has not been installed and operated for extended periods of time in large-scale treatment applications.

Figure 5.8 Perlemax Microbubbles Generated by Fluidic Oscillation

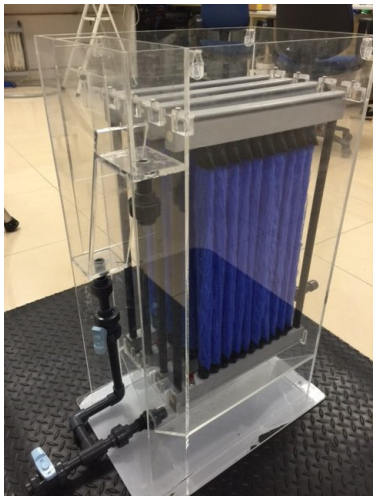


Figure 5.7 Model of a MABR Module

Gas diffusion membranes (Figure 5.8) are beginning to be introduced to the market in the form of a new fixed film activated sludge system, referred to as membrane aerated biofilm reactor (MABR). These systems can provide an OTE above 50 percent (compared to OTEs of fine bubble diffuser systems of 10 to 20 percent). If the process driver for considering MABR systems is limited to energy efficiency (vs. for example footprint and treatment capacity limitations), Carollo's experience has been that MABRs are too costly to justify the investment.

The cost of diffuser replacements in all basins are estimated to approximate $500,000 in material costs and about $1 million in total project costs. Carollo recommends including a thorough comparison of diffuser types in the CIP for year 2028 when the existing diffusers reach their anticipated end of useful life.

Recommendation: Carollo recommends that DSRSD commence the planning/preliminary engineering phase of an "Aeration System Upgrade" CIP project in 2030/2031. The scope of this study should include an evaluation of alternative energy-efficient aeration diffuser replacement options. The study should also include assessments for the implementation of real-time SRT control (LS-5), predictive aeration control (LS-6), and energy-efficient blower system technologies (LS-13).

5.3.1.5 Upgrade Aeration Blowers and Jockey Aeration Blower (LS-13, LS-15)

The 2000 Stage 4 Improvements Project included three 450 horsepower (hp) Turblex KA10SV-GL210 single-stage integrally geared centrifugal turbo compressors to provide aeration air to the activated sludge system and channel agitation air to the settled sewage (primary effluent) channel and mixed liquor channel. The blowers use both variable-position inlet guide vanes and variable-position outlet diffusers to provide a rated capacity of 3,825 to 8,500 standard cubic feet per minute (scfm) at a discharge pressure of 9.0 pounds per square

inch gauge (23.5 pounds per square inch absolute [psia] assuming 14.7 psia barometric pressure and 0.2 psi inlet pressure drop). An aeration air blower master control panel provides automatic control of the blower inlet guide vanes, outlet diffusers, and aeration air flow control valves in the aeration basins.

Factory test data were obtained from the manufacturer to calculate blower mechanical efficiency from the measured shaft power and calculated adiabatic power. At standard conditions (14.7 psia barometric pressure, 68 degrees Fahrenheit [F], and 36 percent relative humidity), the calculated efficiency ranged from 68 percent at 3,500 scfm to 74 percent at the design capacity of 8,500 scfm; the maximum calculated efficiency was 76 percent at 6,800 scfm (20 percent capacity turndown). The calculated efficiency increased by several percentage points at the highest design temperature (100 degrees F, 36 percent relative humidity) and decreased by several percentage points at the lowest design temperature (25 degrees F, 20 percent relative humidity).

The specific blower power in units of kilowatts per thousand standard cubic feet per minute for the specified design conditions was calculated from the blower mechanical efficiency and the specified minimum electrical motor efficiency of 94.8 percent and is shown in Figure 5.9.

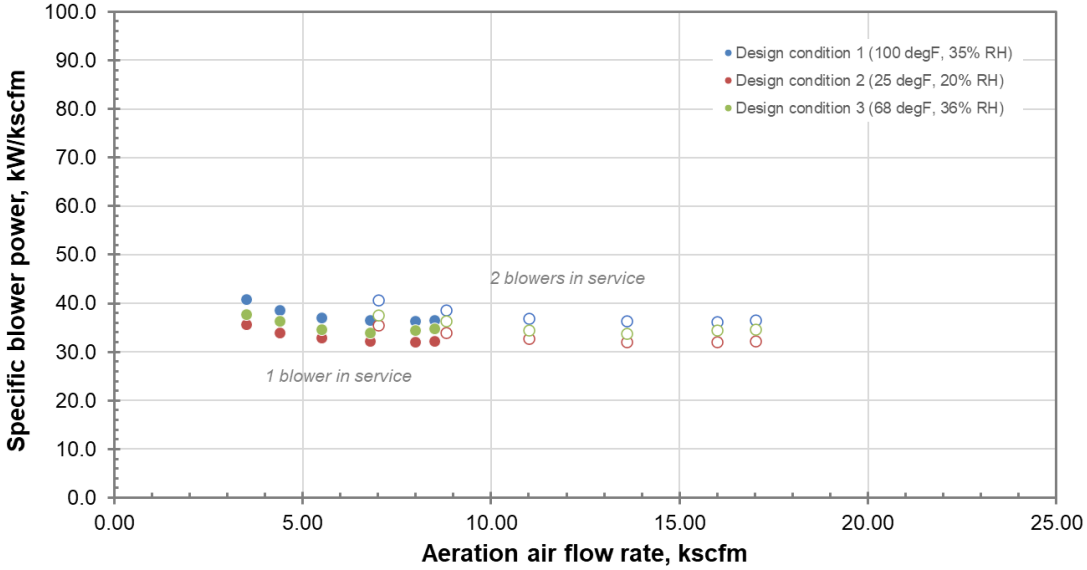


Figure 5.9 Calculated Specific Aeration Air Blower Power

The figure shows that the significant turndown provided by the inlet guide vanes and outlet diffusers results in an overlap in 1- or 2-blower operation between approximately 7,000 and 8,500 scfm. If possible, 1-blower operation should be used in this region for optimum electrical energy efficiency.

The efficiency of the existing Turblex aeration air blowers is very similar to that of other high-speed turbo blowers (e.g., APG Neuros blowers) that have entered the market over the past 20 years. Due to the age of the existing blowers, Carollo recommends an aeration system CIP project within the next 10 years to replace the blowers. As part of this evaluation, alternative blower technologies should be evaluated along with the implementation of alternative diffusers that are recommended from any aeration diffuser studies (see recommendations for LS-12). The blower replacement will be triggered by asset replacement requirement needs rather than

energy savings from high-speed turbo magnetic-drive blowers. Today, the estimated costs for replacing the existing blowers with high efficiency turbo blowers is estimated as $7.5 million. Sizing of the replacement blowers will need to consider turndown for achieving minimum air demands. The existing Turblex blowers have good turndown and analysis of the aeration data indicates they are currently able to achieve the necessary turndown during low flow conditions.

Recommendation: Carollo recommends that DSRSD commence the planning/preliminary engineering phase of an "Aeration System Upgrade" CIP project in 2030/2031. The scope of this study should include an evaluation of alternative energy-efficient blower system replacement options. The study should also include assessments for the implementation of real-time SRT control (LS-5), predictive aeration control (LS-6), and energy-efficient air diffuser types (LS-12).

5.3.1.6 Upgrade Pre-Aeration Blowers (LS-16)

The existing pre-aeration blowers are two rotary lobe style positive displacement (PD) blowers which provide aeration to coarse bubble channel diffusers to prevent solids deposition in the channels upstream of the headworks facility. These blowers are relatively small, 25 hp, but run continuously. The blowers are currently on VFDs. PD blowers are generally less efficient (~40 percent) compared with other blowers such as centrifugal, high-speed turbo, or hybrid PD. However, PD blowers have performed better in conditions with variable pressures such is the case in the influent channels where water surface levels can vary resulted in pressure changes. Hybrid PD blowers are more efficient (~70 percent) and can tolerate these pressure fluctuations as well, however manufacturers only offer these blowers in sizes 50 hp 400 scfm and larger. This is much larger than required for this application. Therefore, there are no recommendations for improving the energy efficiency of the pre-aeration blowers as more efficient equipment is currently unavailable for this application.

Recommendation: At this time, Carollo does not recommend including this project as part of the Energy Facilities CIP.

5.3.1.7 Install Additional Variable Frequency Drives (LS-18)

Most of the large pumps (over 5 hp) at the WWTP are currently on VFDs. The exceptions are the dissolved air flotation thickener (DAFT) pressurization pumps (discussed under BS-2A - DAFT Optimization alternative below) and the digester circulation pumps (15 hp each). Adding VFDs to the digester circulation pumps is unlikely to provide much benefit given these pumps are typically just operated intermittently at a set speed to maintain a certain recirculation energy. For this reason, there is little opportunity for optimization of the existing facility by installing additional VFDs.

Recommendation: Carollo does not recommend including this project as part of the Energy Facilities CIP.

5.3.2 Biosolids Treatment Efficiency Alternatives

5.3.2.1 Dissolved Air Flotation Thickener Optimization: (BS-2A)

The DAFT system at DSRSD co-thickens waste activated sludge (WAS) from the aeration basins and primary sludge from the primary clarifiers. As previously stated, WAS is wasted from the aeration basins as mixed liquor rather than RAS. The thickening system consists of a single DAFT tank, 65 feet diameter with a surface area of 3,318 square feet, with a design maximum loading rate of 0.7 pound/square foot-hour.

The DAFT process is estimated to consume approximately 12 percent of the total electricity consumption at the DSRSD's WWTP (see TM 1). The main energy uses of the DAFT process are three air compressors (2 duty + 1 standby) at 40 hp each, two pressurization pumps at 125 hp and 150 hp, and three thickened sludge pumps at 25 hp each.

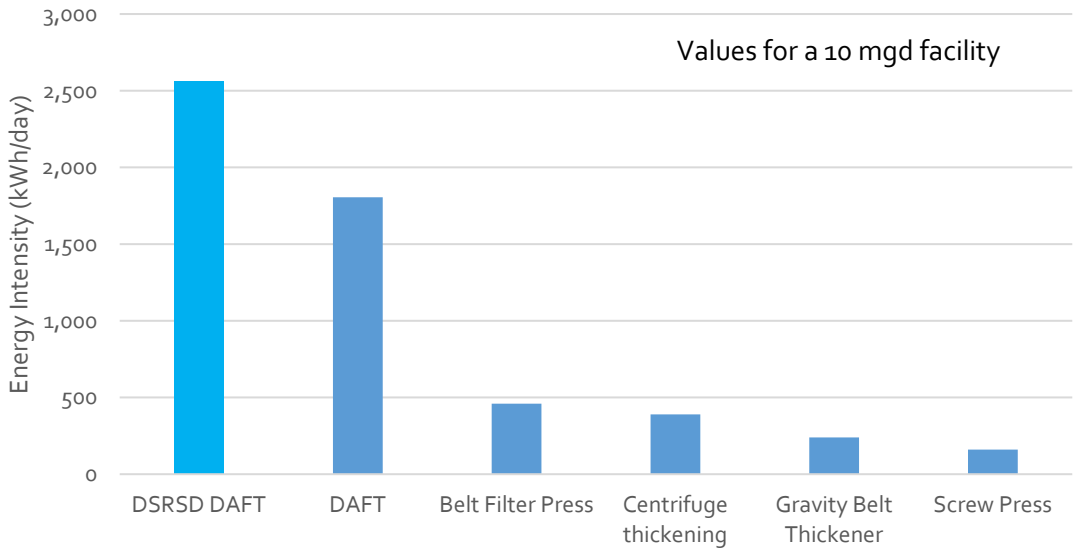
Benchmarking data for the electrical consumption of DAFT systems among different wastewater facilities is limited. EPRI reports an estimated energy intensity of 1,805 kWh/day for a 10 mgd facility. In comparison, DSRSD's DAFT electricity demand is 2,560 kWh/day per 10 mgd average annual daily flow treated in 2021. (This metric is based on the estimated annual electricity consumption and ratioed from 11.5 mgd average daily annual flow in 2021.). Two reasons why DSRSD's specific energy consumption is higher than the industry comparison are that a) mixed liquor instead of WAS is pumped into the DAFT, and b) primary sludge is co-thickened with mixed liquor.

Motor efficiency. DSRSD's DAFT air compressors and pressurization pumps are powered by high-efficiency motors (94 and 95 percent efficiency, respectively), leaving little opportunity for energy savings.

VFD installations. Carollo does not foresee that installation of VFDs on either the air compressors or recirculation pump motors would provide substantial additional energy savings. The recirculation pumps have very little turn down needs / capability since the tanks need to be maintained at a certain pressure. The compressors would likely compensate with longer run times if operating at a lower speed. VFDs reduce the energy efficiency of the equipment motors continuously by about 3 to 5 percent, so anticipated energy efficiency benefits would need to exceed these VFD losses.

Improving thickening efficiency. A potential process optimization opportunity is for DSRSD to consider adding a polymer to the DAFT to further increase the thickened sludge solids concentration from the current value of 4 percent total solids (TS) to up to 5 percent TS (an estimated additional 1 percent TS). This would result in lower pumping demands for the thickened sludge and reduced heating requirement in the digesters. Note that polymer addition would result in additional chemical demand which would both increase operating costs and increase scope 3 GHG emissions associated with chemical manufacturing and transport.

DAFT replacement. Replacing the DAFT system with another thickening process that is less energy intensive is another option. DAFT processes are significantly higher in energy consumption compared to other thickening process alternatives (see Figure 5.10). In addition, a major driver of mechanical thickening is the potential to increase the solids concentration of the digester feed, which would increase digestion capacity, to accommodate potential FOG and food waste co-digestion loads in the future. A digestion capacity analysis estimated that the existing digester capacity is sufficient to accommodate FOG and food waste co-digestion in the future assuming that the digester feed is thickened to a minimum of 6 percent TS.



Light blue: Data specific to DSRSDs DAFT system (2021 Average)
Dark blue: (EPRI 2013)

Figure 5.10 Comparison of Estimated Electric Energy Intensities of Solids Thickening Processes

An advantage of the existing DAFT process is that it can handle variable hydraulic and solids loadings better than mechanical thickening processes. Operations staff is generally satisfied with the existing DAFT operation and performance.

Three options are briefly discussed here:

- Alternative 1: Mechanical thickening with mixed liquor wasting.
- Alternative 2: Mechanical thickening with WAS wasting (from RAS pipe).
- Alternative 3: Mechanical thickening addition downstream of DAFT.

Alternative 1: Mechanical thickening with mixed liquor wasting. This alternative would involve replacing the existing DAFT with mechanical thickening, which would thicken primary sludge and WAS, assuming the District continues mixed liquor wasting. With mixed liquor wasting, the WAS concentration is approximately 0.1 percent TS and the combined WAS and primary sludge concentration which would be fed to the mechanical thickener is approximately 0.2 percent TS. According to conversations with several thickening manufacturers, mechanical thickening of this thin sludge (at 0.2 percent TS) is not expected to be able to achieve a 6 percent TS thickened sludge concentration.

Alternative 2: Mechanical thickening with WAS wasting from RAS. This alternative would involve replacing the existing DAFT with mechanical thickening and switching to RAS rather than mixed liquor wasting. WAS would be wasted from the RAS pipe at a solids concentration of about 0.4 percent TS and the combined primary sludge and WAS concentration would be approximately 0.6 percent TS. Unlike Alternative 1, Alternative 2 would be able to achieve a 6 percent solids concentration as digester feed, allowing DSRSD to accept FOG and food waste in the future, without requiring digestion expansion. This alternative is discussed in opportunity BS-2C in TM 6.

Alternative 3: Mechanical thickening addition downstream of DAFT. This alternative would involve adding mechanical thickening downstream of the existing DAFT system. However, Carollo would not recommend this alternative without further evaluation of its feasibility, given that this process configuration is not common. This alternative is discussed in opportunity BS-2B in TM 6.

Because the DAFT is currently functioning well, Carollo recommends that DSRSD maintains their DAFT in operation until DSRSD approaches digester capacity limits. At that time, Carollo recommends that DSRSD evaluates the cost/benefits of replacing the existing DAFT with mechanical thickening and switching from ML to RAS wasting (as described in Alternative 2 above), as well as other potential options for increasing digestion capacity.

Recommendation: Carollo recommends a "Food waste Co-digestion and Digester Capacity Upgrades" CIP project in 2026. The planning/preliminary engineering phase of the project should include an evaluation of mechanical thickening options, as well as other potential options for increasing digestion capacity.

5.3.3 Building System Operations Optimization

5.3.3.1 Lighting Efficiency Improvements

Adjust Lighting Schedules (BLG-2) and Reduce Ground Lighting at Night (BLG-4)

Energy reduction for lighting can be implemented at relatively minor costs. However, any lighting improvements should consider the potential disadvantage of a more complicated system which may require higher maintenance. Lighting control options that DSRSD should consider implementing in buildings and outdoors (if not already in place) include:

1. Automatic turning lights off when they are not needed through installation of motion sensors, occupancy sensors, photosensors, and timers.
2. Reducing light levels when less brightness is acceptable through installation of light-emitting diode lightbulbs that can be designed to be operated with dimmers.

Energy saving measures for outdoor workplace lighting cannot compromise safe work practices, the reduction of work-related injuries, and site security. However, reduced lighting operation may be acceptable in certain places with the additional benefit of reducing light pollution.

The American National Standards Institute has published "Workplace Lighting Standards" that include energy performance standards specifying practices for minimizing energy requirements and efficient allocation in various indoor and outdoor workspaces.

Carollo recommends a systematic evaluation of all indoor and outdoor spaces to assess the existing level of light and control to determine appropriate energy efficient light control upgrades for the respective occupancy and safety needs.

Recommendation: DSRSD should assess potential energy savings related to any proposed project of this kind and implement energy efficiency measures based on availability of internal resources and budgetary allowances.

5.3.3.2 Heating, Ventilation, and Air Conditioning Efficiency Improvements

Adjust Temperature Schedules (BLG-2)

Although adjusting the lighting and temperature schedules in buildings is expected to provide less than 175,000 kWh/year of energy reduction for the District, it can still provide some GHG

and energy demand reductions at low investment costs. Adjusting temperature schedules in various occupied spaces requires no capital costs while providing moderate O&M costs savings depending on its extent of use estimated at $25,000 to $40,000 per year. Once heating and cooling schedules are automated through programmable thermostats, there is little impact on existing staffing resources.

Recommendation: DSRSD should assess potential energy savings related to any proposed project of this kind and implement energy efficiency measures based on availability of internal resources and budgetary allowances. Carollo recommends DSRSD work directly with energy building contractors who can provide customized cost estimates and estimated energy savings for HVAC efficiency improvements. This is recommended for implementation in 2025.

Metal Buildings Insulation (BLG-7)

DSRSD owns several metal buildings located at the WWTP. These buildings could be insulated to reduce the energy demand of the building envelope for building temperature control during the heating and cooling seasons.

Climate characteristics typical for the DSRSD were researched from the 2021 *American Society of Heating, Refrigerating, and Air-Conditioning Engineers* (ASHRAE) *Handbook*. ASHRAE indicates 84 heating degree days for 50 degrees Fahrenheit (HDD50) for this location and 105 cooling degree days for 70 degrees Fahrenheit (CDD70). HDD50 measures the number of days per year that buildings require to be heated, while CDD70 measures the number of days per year that buildings require to be cooled. Values of 84 and 105 days, respectively, are low given the moderate climate for both summer and winter in the Bay area when compared to other regions in the United States. DSRSD cooling demands may be higher for buildings that house mechanical equipment that produce significant waste heat.

As an example, the capital costs to insulate a 2,000-square-foot metal building is estimated to be about $20,000 (assumes $10,000 for materials, $10,000 for labor). This would save an estimated $700 per year in energy costs resulting in a payback period of approximately 24 to 30 years (see Appendix 5B for an exemplary building insulation quote.

In addition to saving approximately 80 percent of peak building heat loads and related HVAC O&M costs, insulation can assist in preventing condensation, which is a major cause of reduced lifecycle in steel and metal buildings. Carollo recommends DSRSD work directly with energy building contractors who can provide customized cost estimates and energy savings for target buildings that are currently heated (and/or cooled) with natural gas.

Recommendation: Although preliminary analysis indicated there could be potential savings associated with this alternative, further investigation discussed in TM 11 revealed that most of the buildings were already insulated and only one small building was not. The cost versus benefit of insulating this small building did not pencil out. The payback for insulating the building was over 30 years due to the infrequent need for heating and cooling this space. Therefore this alternative was removed for consideration in TM 11.

Air Handling Unit Replacement and Heating, Ventilation, and Air Conditioning Reduction (BLG-8, BLG9, BLG-10)

Enclosed areas with off-gases from hazardous materials (such as sewage wastewater) are designed per fire and electrical codes requiring minimum air changes per hour (ACH) that can add significant costs and complex design features to Class 1 Division 1 facilities, such as

headworks. Due to the high ACH requirements, efficient HVAC equipment in these process areas is important (e.g., efficient HVAC models and/or VFDs). The following list of high-capacity HVAC units approaching the end of useful life, deserves priority attention for lowering HVAC energy demands by replacement with energy efficient units:

- Screen Room Air Handling Unit (BLG-8).
- Building A (Operations) and C (Bar Screen) Air Handling Units (BLG-9).
- Bar Screen Building Exhaust Fan (BLG-10).

The screen room air handling unit has less than 5 years of useful life remaining, while the others have less than 10 years of useful life. Carollo recommends reviewing and replacing air handling units by 2028 with energy efficient units. In addition, these individual HVAC systems should be connected to the District-wide environmental controls software system, Desigo (Siemens), so that District staff can better monitor and control their operation. Other buildings including Buildings A and S, the Field Operations Facility, and the DSRSD office are already tied to the Desigo system.

The replacement of the Building A air handling unit is currently scheduled for FYE 26 of the CIP Ten-Year Plan -Fiscal Years 2024-2033. However, the replacement might be moved to this year (FYE 2023) due to a recent failure of Building A's rooftop air-cooled chiller.

Recommendation: Replace Screen Handling Air Unit (BLG-8) Building A and Building C Air Handling Units (BLG-9) and Replace Bar Screen Exhaust Fan (BLG-10) in FYE 2025 as all of these have been identified as being at the end of their useful service life. Connect these individual HVAC systems to the District-wide environmental controls software system.

Heating, Ventilation, and Air Conditioning Energy Recovery (BLG-11)

Energy recovery for HVAC systems implement energy recovery ventilation (ERV) technology to reduce heating and cooling loads through the use of air-to-air heat exchangers. These heating and cooling loads are then used for the additional pre-cooling and/or pre-heating of outdoor air streams. Buildings with 100 percent outside air streams, such as a headworks facility, could save up to 70 percent of the HVAC energy demand by recovering heat loads from exhaust to pre-heat supply air.

As an example, a typical 2,000-square-foot screening, grit removal, or dewatering facility requires 12 ACH to meet applicable fire and electrical hazard codes. DSRSD's Headworks facility closely matches this 2,000-square foot assumption, so Table 5.3 displays the cost comparison for equipping this building with ERV technology versus a traditional makeup air unit (MAU).

Table 5.3 ERV and MAU Price Comparison

	ERV	MAU
Capital Costs ($)	60,000(1)	30,000
Energy Savings ($/year)	1,000(2)	-
Payback Period (years)	20+(3)	-

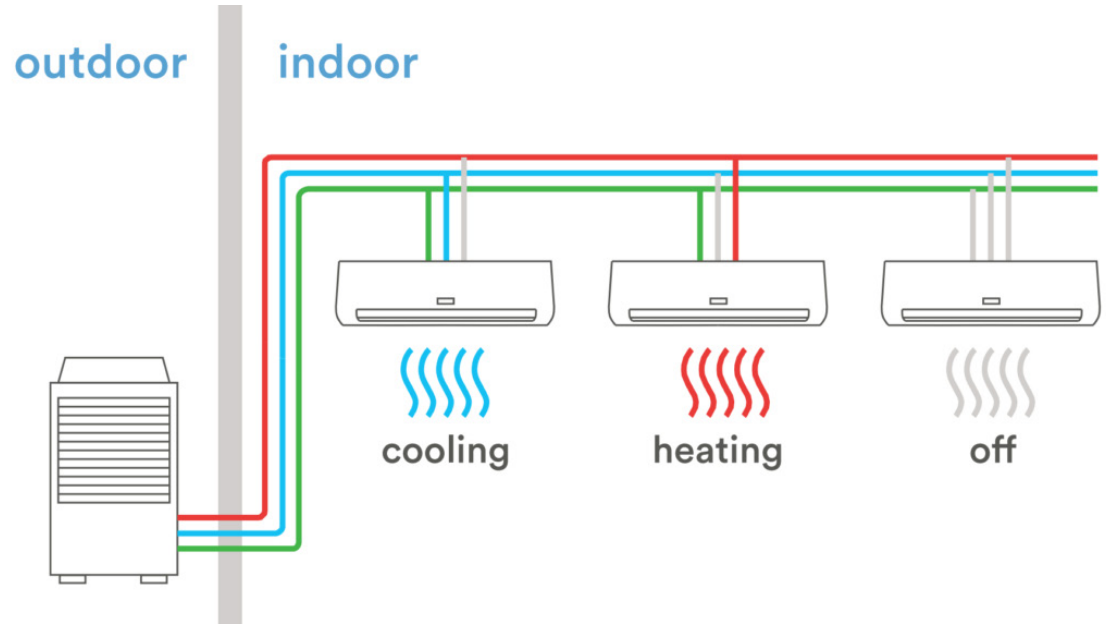
Notes:
(1) An energy recovery unit may result in doubling the equipment cost to achieve sufficient ventilation.
(2) As previously stated, the District only requires 84 HDD, resulting in minimal energy savings due to the mild climate.

The example calculation shows that the payback period is extensive and makes ERV units not the most cost-effective energy efficiency measures that DSRSD could implement.

Recommendation: At this time, Carollo does not recommend including this project as part of the Energy Facilities CIP.

Refrigerant Heating, Ventilation, and Air Conditioning System (BLG-14)

Variable refrigerant flow (VRF) technology is effective at transferring heat between occupied and unoccupied building spaces at different temperatures without additional air transfer. Incorporating VRF allows for linking heat sources and heat sinks, such as heat from rooms that encounter direct sunlight being transferred to cooler rooms due to increased shading. Figure 5.11 shows a simplified schematic of the VRF technology.



Source: Building Energy Exchange. July 2019. "Variable Refrigerant Flow (VRF)." https://be-exchange.org/tech_primer/tech-primer-variable-refrigerant-flow-vrf-systems/.
The VRF connects one outdoor unit with various building spaces that can be heating and cooled using heat recovery. This requires a third refrigerant line.

Figure 5.11 Variable Refrigerant Flow Schematic

A water-cooled chiller unit may be more efficient but is generally harder to control. Linking heat sinks and sources is much easier with a VRF. As a result, a 10 percent savings on chiller loads may be practical, while a VRF system, that can replace a typical roof top unit, results in energy savings of 20 percent in the Bay area.

According to California's *2022 Building Energy Efficiency Standards for Residential and Nonresidential Buildings*, economizers used for VRF have demonstrated to be cost-effective over a 15-year period of analysis. VRF installation systems can range from $4,000 to $8,600 per air conditioning tonnage depending on heat recovery capabilities. A typical 2,000-square-footbuilding may require 4 tons resulting in a total installation cost of $16,000 to $34,400 with estimated annual energy savings of approximately $2.8 per square foot.

The Environmental Protection Agency has proposed a ban of commonly used refrigerants named R134a, R410A, and R407C in lieu of more efficient and less GHG emissive compounds, such as R-32 and R-454B refrigerants. The phase out will begin with new chillers being barred from utilizing the older refrigerants leading to a gradual phase out due to increasing prices and less supply. DSRSD should plan to switch refrigerants in the near future to abide by the new regulations.

In case DSRSD has buildings with temperature gradients between rooms for which VRF technology may be a possible fit, Carollo recommends DSRSD to work directly with energy building contractors who can provide customized cost estimates and energy savings for target buildings.

Recommendation: Replace refrigerants at time of next HVAC in-kind replacement project (or earlier, if regulations require) with less GHG emissive compounds, such as R-32, R-454B or other refrigerants, as permitted by regulation. Carollo recommends DSRSD work directly with energy building contractors who can provide customized recommendations for the refrigerant HVAC system.

Economized Cooling via Fan Addition (BLG-15)

Economized cooling is utilized by configuring supply and exhaust fans in HVAC systems to conserve energy use via outdoor air for heating and cooling. Although this will require additional capital costs, energy savings are estimated to be 6 percent for fan operation, 12 percent for cooling, and 3 percent for heating. This results in significant net cost and energy savings for the expected lifecycle of the economizer technology.

As part of the 2022 update to the *California Energy Code, Title 24, Part 6 Building Energy Efficiency Standards*, building code requirements have recently been updated to include the economizer cooling arrangement, size, and fault telemetry requirements. This means that future HVAC projects that DSRSD undertakes will be required to have economized cooling to sufficiently meet energy efficiency standards. Buildings whose permit applications are applied for on or after January 1, 2023, must comply with the 2022 Energy Code.

Recommendation: For future HVAC upgrade projects, economized cooling technology must be implemented to comply with building code requirements.

5.4 Potable and Recycled Water Distribution System Opportunities (PWD-2 and PWD-3)

Carollo evaluated DSRSD's 16 potable water booster stations and three recycled water booster stations that are currently in operation for energy inefficiencies and opportunities for improvements. The potable water pump stations are located throughout the DSRSD service area, and operate in eight different pressure zones (Zones 1, 2, 3, 4, 20, 30, 200, and 300). The recycled water pump stations are located in eastern Dublin and Dougherty Valley.

Information provided by DSRSD for this review included SCADA operating data, manufacturer pump curves, and record drawings for each pump station. DSRSD provided hourly SCADA data for two months for the potable pump station analysis, January 2021 and August 2021, which consisted of suction and discharge pressure values, total flowrates, and quantity of pumps in operation. The data set for January and August were selected for this evaluation as these months represent the low and high demand seasonality experienced throughout the Dublin San Ramon

service area in the baseline year for this Energy Facilities Master Plan. DSRSD staff subsequently noted that 2021 may not have been a representative year for the potable water pump stations due to increased work from home due to COVID. In addition, staff noted that some pumping changes were made during 2021 to more fully drain and fill reservoirs. The recycled water pump station analysis was subsequently added to the scope of the evaluation, and was based on data from January and August 2022.

SCADA data provided by DSRSD was used to evaluate the operating conditions at each pump station. Recorded operating points were compared against the manufacturer pump and efficiency curves to determine if pumps were operating at, or near, their optimal rated points. Inefficient pumps may indicate inappropriate pump selections for the station, excessive pump wear or damage, inefficient station piping or appurtenances, or changing system hydraulics that are unfavorable to the existing equipment.

The majority of the pump stations were operating at acceptable energy efficiency ranges and did not show signs of damage. Key observations are summarized in Table 5.4 and discussed in more detail in the following sections for those pump stations that showed energy inefficiencies or damage, including recommendations for follow up actions. A full compilation of charts and data, including all of the 16 potable water pump stations currently in operation is included in Appendix 5C.

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Table 5.4 Summary of Pump Station Operations Analysis

Pump Station	No Issues Detected	Low Pump Efficiency	Potential Pump Damage	Notes	Energy Efficiency Recommendations
1A		X	X	Recommend inspecting impellers for damage.	Minimize running 1 or 2 pumps due to poor efficiency and potential for cavitation.
2A	X			Recommend checking for a possible stuck valve; high minor losses compared to PS2B.	
2B			X	Pump 2 running well below pump curve, recommend inspecting impeller for damage.	
2C	X				
3A	X				
3B	X			High minor losses, modification is difficult due to space constraints.	
3C			X	Recommend checking for a possible stuck valve; high minor losses. Pump 1 flow is very low, recommend inspecting impeller for damage.	Repair Pump 1.
4A		X			Minimize running 3 pumps, only small increase in flow.
4B		X			Replacing pumps or impellers would significantly increase efficiency.
10A				Not in service.	
20A	X				
20B			X	Possible cavitation, recommend inspecting impellers for damage. Discharge valve is typically throttled, flow meter just upstream of throttled valve.	Recommend a pump station evaluation to determine optimal pump sizing for full range of hydraulic conditions.
30A	X				
200A	X				Minimize running 3 pumps, only small increase in flow.
300A		X			Replacing pumps or impellers would significantly increase efficiency.
300B	X				
300C		X	X	Pump performance worsened between January and August.	Replacing pumps or impellers would significantly increase efficiency.
R20		X			Conduct an analysis of pump speed to determine why pumps appear to be operating at reduced speed.
R300A		X			Review 2023 performance data to assess whether the irrational data at the end of the 2022 data set are still occurring. Inspect, calibrate, or replace pump station instrumentation if necessary.
R300B					Pump station operates based on pressure set point since there is no storage tank in Zone R300B, and pump speed is not recorded. It is therefore not possible to compare pump operation to the published full speed pump curve and efficiency curve.

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5.4.2 Potable Water Pump Stations

Pump Station 1A

Pump Station 1A, located near the intersection of Amador Valley Boulevard and Stagecoach Road, draws water from both Zone 7's transmission pipeline and the Dougherty Reservoir to fill Reservoir 1A, which creates high suction pressure conditions. While the original pump station was constructed in the early 1980s, the current Weir/Floway vertical turbine pumps were installed in 2011.

2021 data provided for this analysis shows the station in almost continuous operation throughout both low and high demand seasons. As shown in Figure 5.12, hourly SCADA recordings from pressure instruments upstream and downstream of the pumps and the station effluent flowmeter reveal problematic hydraulic conditions during one-pump operation. With one pump running, the station operates in very low head conditions which may have resulted in pump damage as indicated by the pumps operating well below the manufacturer's pump curves.

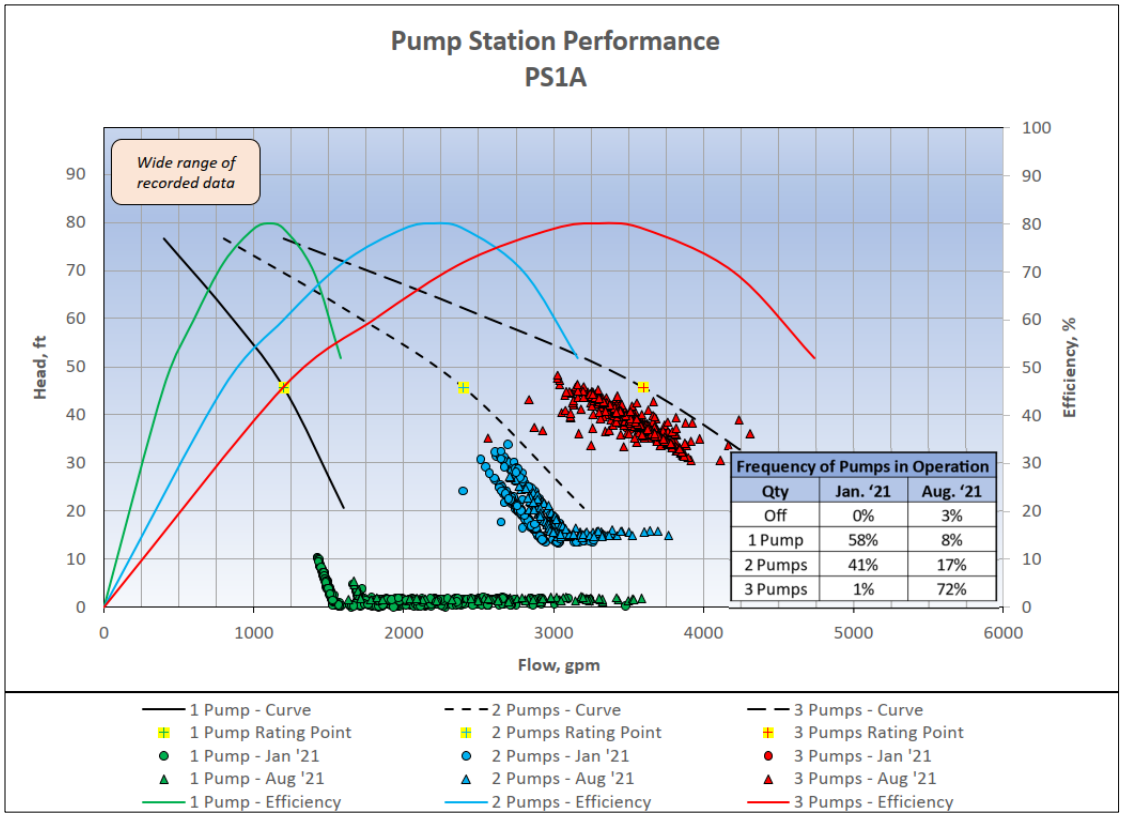


Figure 5.12 Pump Station 1A 2021 Performance

Two-pump operation shows better hydraulic performance; however it is still relatively inefficient and in low head conditions which may damage the pumps. three-pump operation results in expected performance with the data points plotting close to the manufacturer pump curve and designed rating point.

Recommendation: The District currently has a project in the CIP Two-Year Budget Fiscal Years 2024 and 2025 to re-design the pump station and address these hydraulic inefficiencies. This project is

anticipated to be completed in FYE 2025. Until the re-design is completed, it is recommended that the reservoir level pump control setpoints be set to favor three-pump operation.

Pump Station 2B

Pump Station 2B, located on Hansen Drive in Dublin, serves to convey water from Zone 1 to Zone 2 and Reservoir 2A. The two Peerless Pump Company inline centrifugal pumps were installed in 2008 within a below-grade pump station vault.

As shown in Figure 5.13, 2021 data provided for analysis shows the station operates most frequently in two-pump operation. The data reveal that overall operation is relatively efficient with data points close to the manufacturer pump performance curves. However, the data showed that Pump No.2 operates under reduced performance when compared to Pump No. 1.

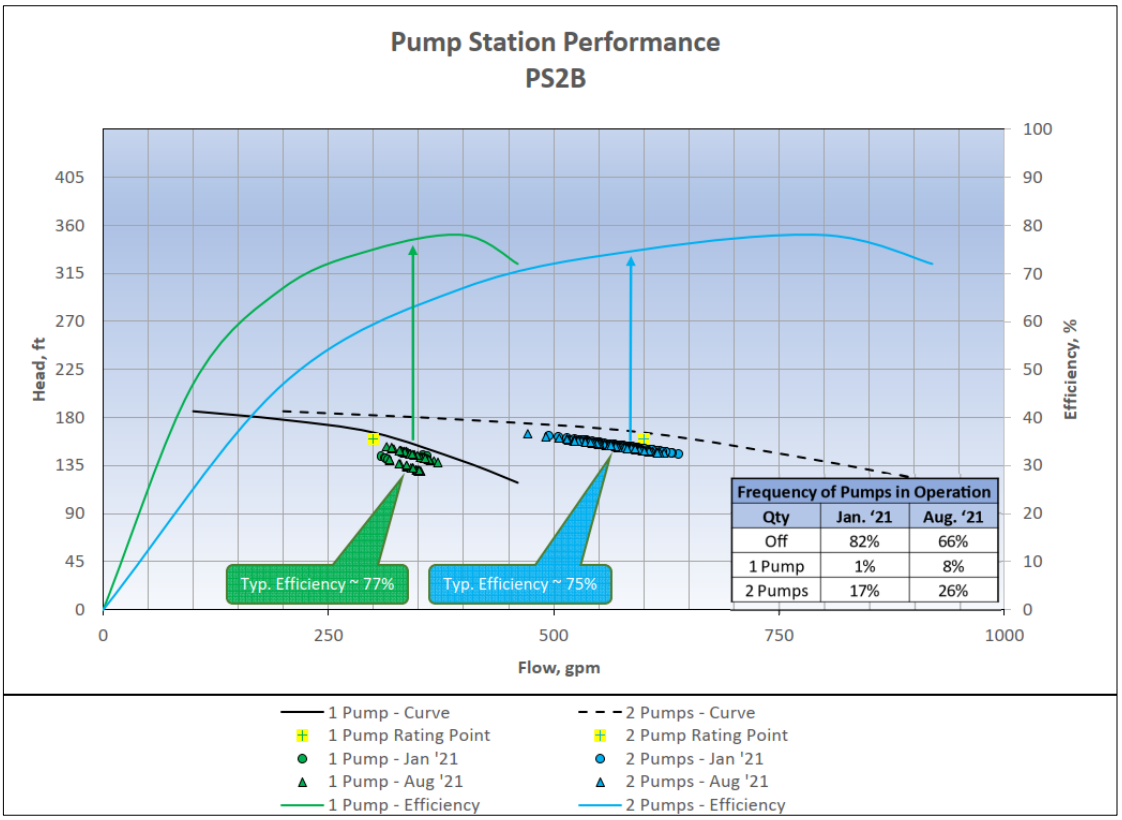


Figure 5.13 Pump Station 2B 2021 Performance

Recommendation: Inspect Pump No. 2 impeller, and associated Pump No. 2 appurtenances, for possible damage as a preventive maintenance item.

Pump Station 3C

Pump Station 3C, located at the west end of Betlen Drive in Dublin, serves to convey water from Zone 2/Reservoir 2A to Zone 3. The three Peerless Pump Company inline centrifugal pumps were installed in 2008 within a below-grade pump station vault.

As shown in Figure 5.14, 2021 data provided for analysis shows the station operates most often with two pumps in service. The data reveals a wide range of recorded flowrates plotted well below the manufacturer pump curve, indicating minor losses in the system possibly due to a

partially closed valve or other pipeline obstruction. Additionally, Pump No. 1 produces very low flow rates indicating possible damage.

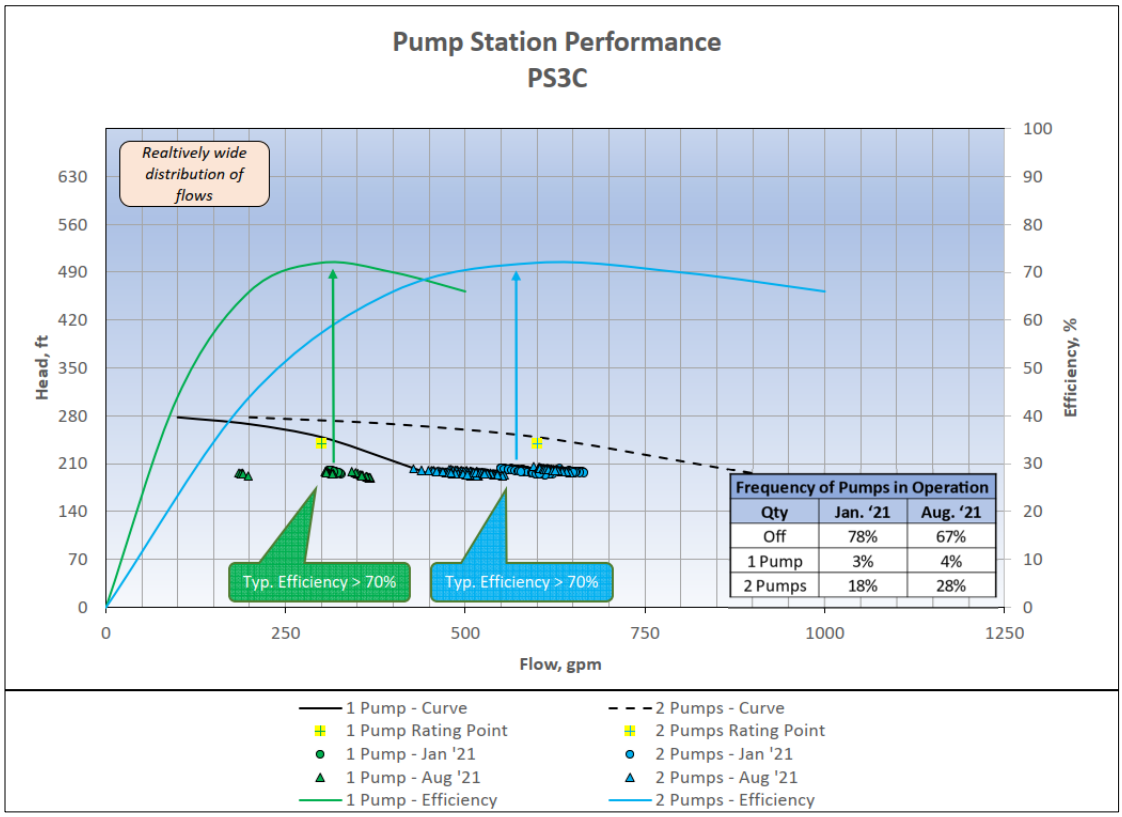


Figure 5.14 Pump Station 3C 2021 Performance

<u>Recommendation</u>: Inspect Pump No. 1 impeller, and pump station appurtenances, for correct functionality and possible damage as a preventive maintenance item.

Pump Station 4A

Pump Station 4A, located on Dublin Boulevard in western Dublin, pumps to Reservoir 4A and distributes water to the Schaefer Ranch development. The three canned vertical turbine pumps were installed in 2007.

2021 data provided for analysis shows that when the station operates, all three pumps are typically in service. As shown in Figure 5.15, the data reveal that three-pump operation is minimally more productive than two-pump operation, with the third pump typically only adding around 100 gallons per minute. Additionally, both two-pump and three-pump operation data points are significantly below their design ratings.

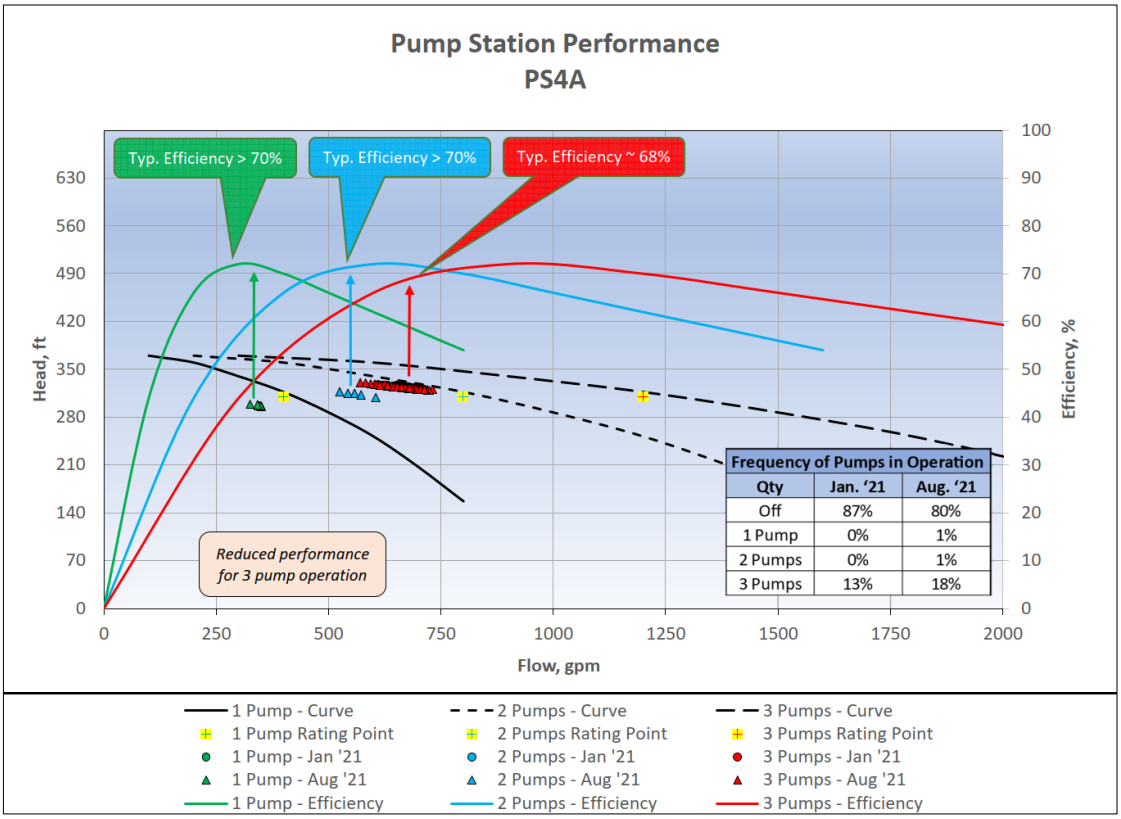


Figure 5.15 Pump Station 4A 2021 Performance

<u>Recommendation</u>: Set the reservoir level pump control points such that the station primarily runs with two pumps in service to improve energy efficiency. If flow from two pumps is not sufficient, evaluate a pump or impeller replacement or increased conveyance pipe capacity to reduce friction head and provide increased flows with three pumps in operation.

Pump Station 4B

Pump Station 4B, located in western Dublin, distributes water to both the Schaefer Ranch and Clifden Park developments. The two Flowserve vertical turbine pumps were last replaced in 2012 as part of a larger reconfiguration of water distribution in the region.

2021 data provided for analysis shows the station operates infrequently in both summer and winter seasons, and the limited operation is noticeably inefficient. As shown in Figure 5.16, the reported operating conditions indicate the pump station operates with less than 50 percent efficiency.

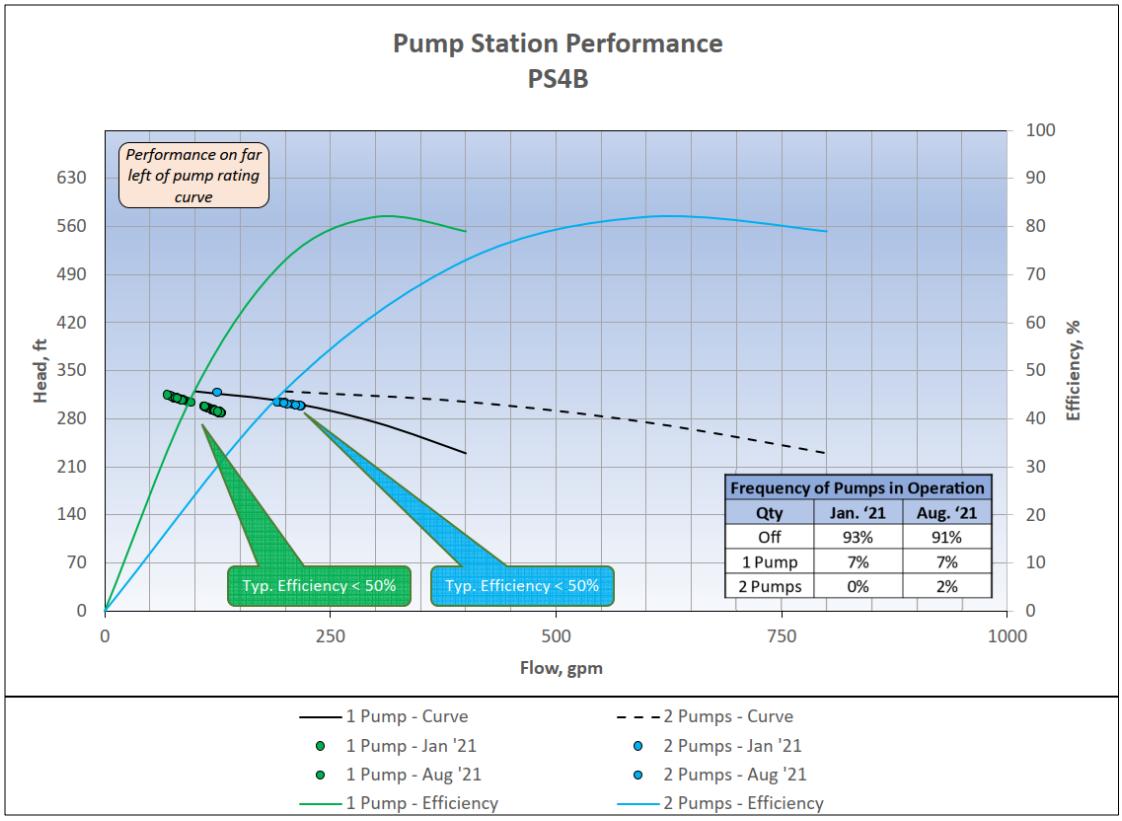


Figure 5.16 Pump Station 4B 2021 Performance

<u>Recommendation</u>: If Zone 4 demands are anticipated to increase, or if Pump Station 4B is to become a larger part of the Zone 4 supply, it is recommended the pump station be reevaluated at the revised design conditions. If the District continues current infrequent use of the pump station, pump replacement or station modification is not warranted at this time.

Pump Station 20B

Pump Station 20B, located on Fallon Road in eastern Dublin, serves to convey water from Turnout #5 to Zone 1 to Zone 20. The four Flowserve split-case centrifugal pumps were installed with original construction of the pump station in 2006.

As shown in Figure 5.17, the data reveal pump performance well below the manufacturer's rated pump curves indicating possible cavitation conditions and pump damage. Additionally, a throttling effluent valve was installed on the 14-inch diameter station discharge pipeline which creates higher head conditions resulting in significant extra energy use. The throttling valve is also located very close to the station effluent flow meter, possibly affecting accuracy of the instrument.

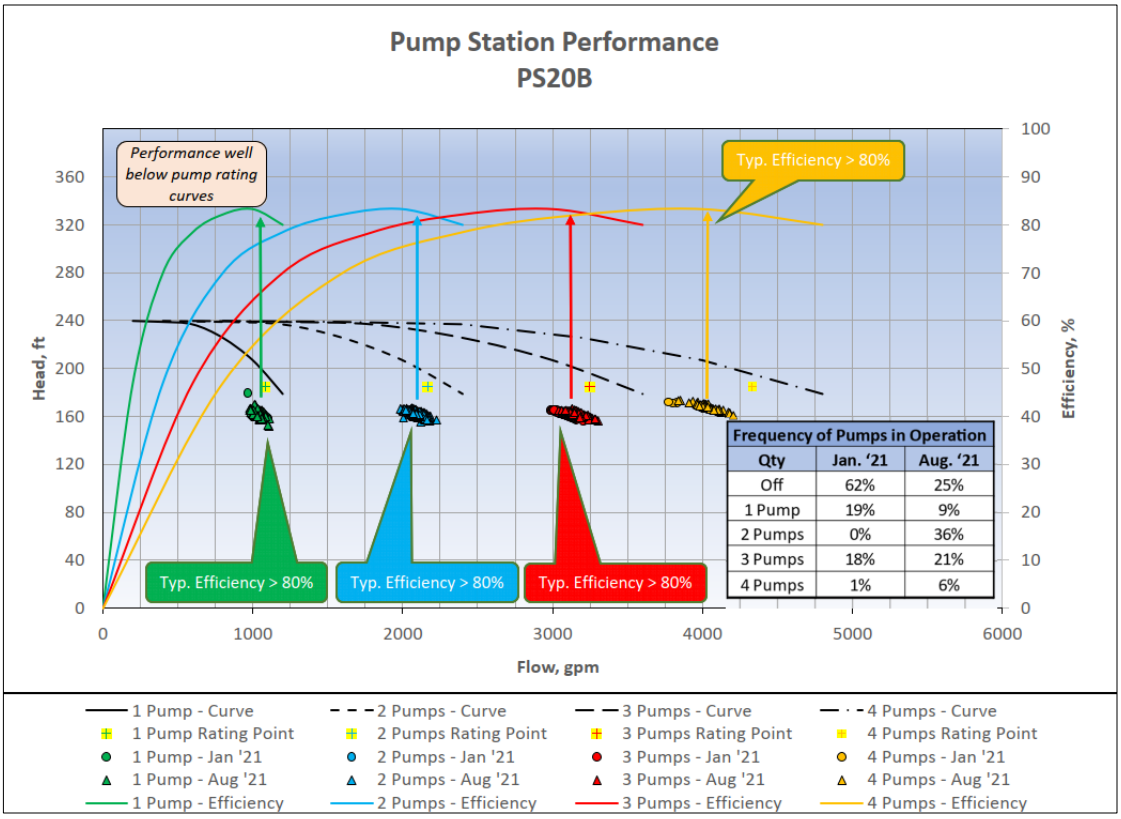


Figure 5.17 Pump Station 20B 2021 Performance

<u>Recommendation</u>: Conduct a PS20B hydraulic evaluation as a CIP project or as part of the upcoming Water Master Plan Update to determine optimal pump sizing for the full range of hydraulic conditions.

Pump Station 200A

Pump Station 200A, located on Dougherty Road in Alameda County, conveys water from Zone 1 to Zone 200 in Dougherty Valley. The four horizontal split-case pumps (three duty and one standby) were installed in 2000.

2021 data provided for analysis shows the station is least efficient with three pumps in service. As shown in Figure 5.18, the data reveal that three-pump operation is minimally more productive than two-pump operation and produced flows are significantly below expected values. The station is located approximately 1.5 miles from its first customer which may be a contributing factor to weak three-pump station performance.

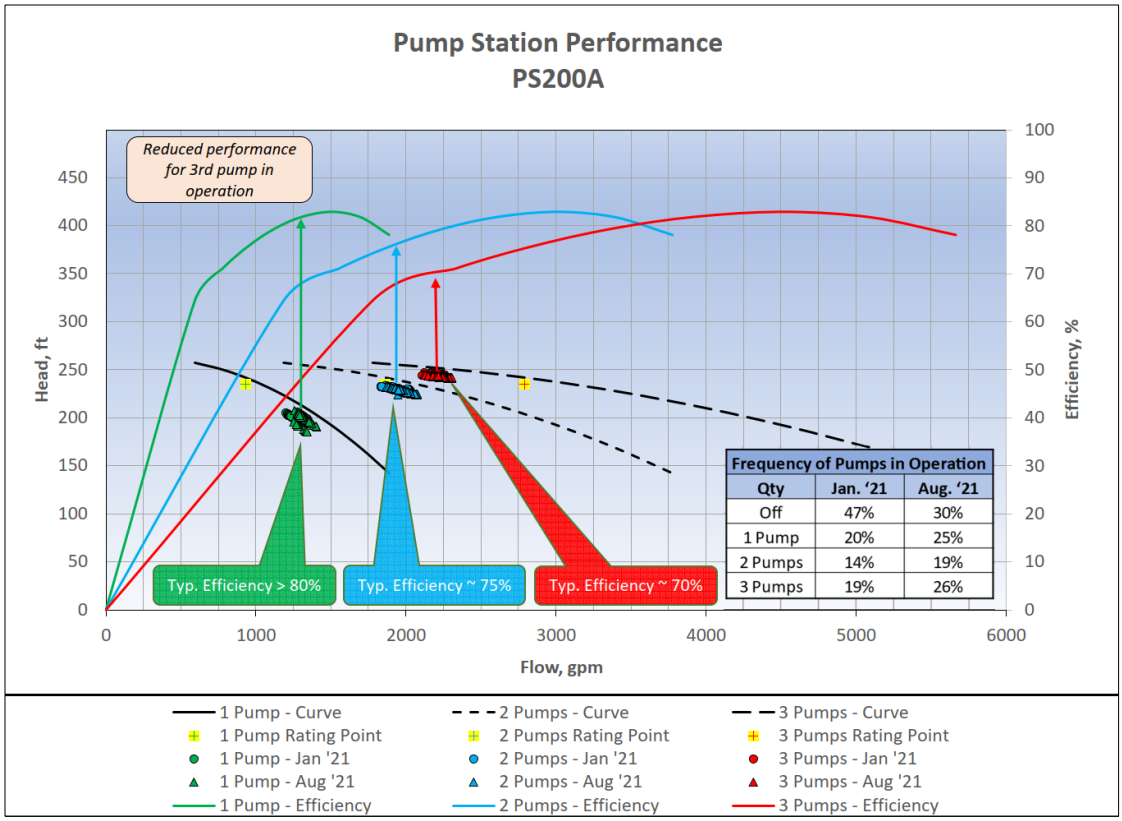


Figure 5.18 Pump Station 200A 2021 Performance

<u>Recommendation</u>: Set the reservoir level pump control points such that the station primarily runs with two pumps in service to improve energy efficiency. If the flow from two pumps is not sufficient to meet demands, evaluate pump replacement or increased conveyance capacity to provide increased flows with three pumps in operation.

Pump Station 300A

Pump Station 300A, located at the corner of Bollinger Canyon Road and East Branch Parkway in Dougherty Valley, serves primarily residential customers on the east side of San Ramon. The three horizontal split-case pumps were installed in 2000.

2021 data provided for analysis show the station operates primarily with one pump in service in both winter and summer seasons. The one-pump operation is towards the left-side of the pump curve, with operational efficiencies often 10 to 15 percent below optimal performance (Figure 5.19).

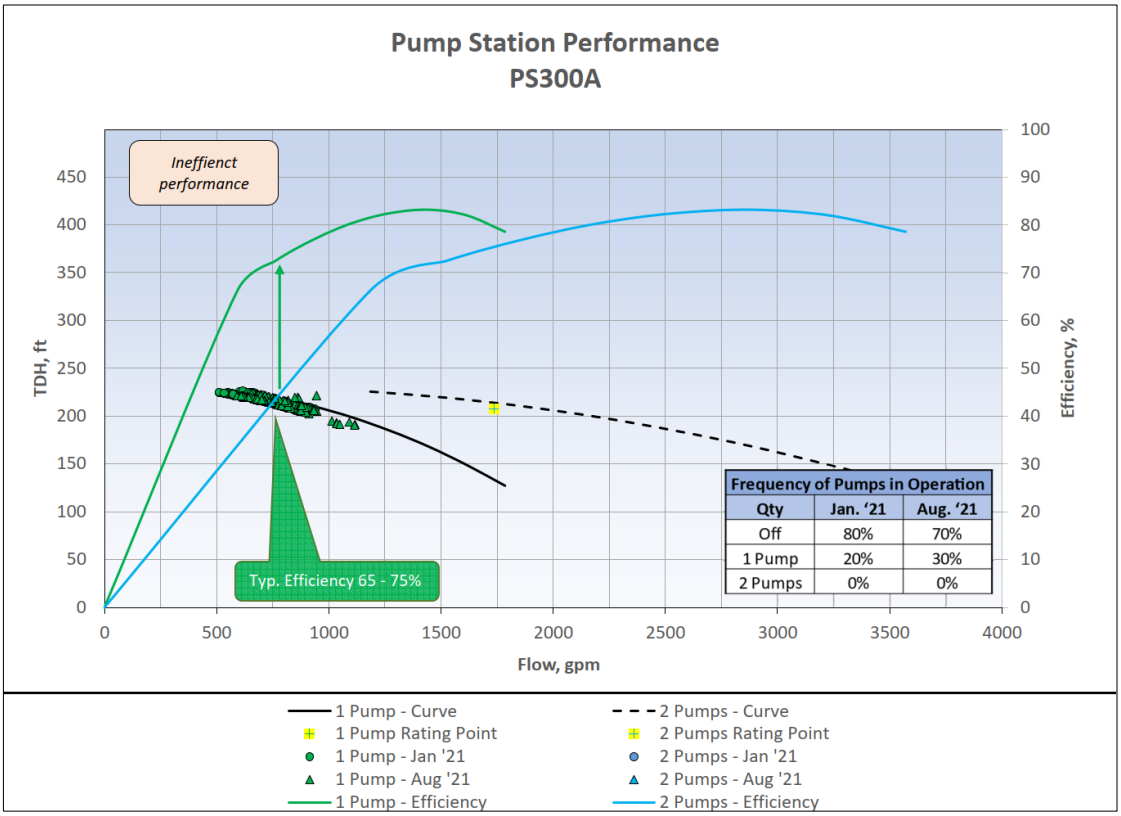


Figure 5.19 Pump Station 300A 2021 Performance

<u>Recommendation</u>: Modifying or replacing the pumps to better match hydraulic conditions would significantly increase efficiency. Since the pump station is seldomly run, however, major modifications do not appear to be warranted at this time. However, Zone 300 pumping from all of the pump stations pumping into the zone should be reviewed as part of the next Water Master Plan Update.

Pump Station 300C

Pump Station 300C, located at the intersection of Bollinger Canyon Road and Main Branch Road in Doughery Valley, serves primarily residential customers on the east side of San Ramon. The three horizontal split-case pumps were installed in 2005.

2021 data provided for analysis shows the station operates primarily with one pump in service in both winter and summer seasons. The one-pump operation is towards the left-side of the pump curve, with operational efficiencies in the 40 to 60 percent range (Figure 5.20).

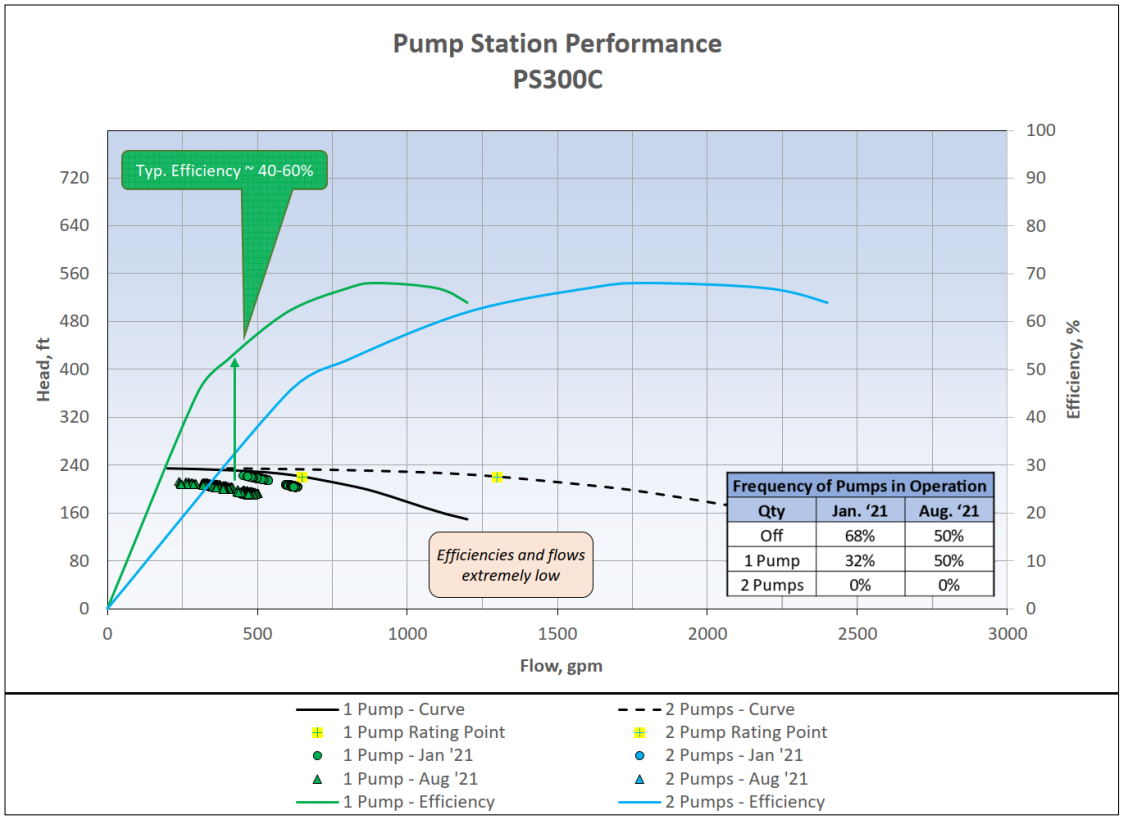


Figure 5.20 Pump Station 300C 2021 Performance

Additionally, it was noted that during the sample of data provided, Pump No. 3 was the only pump to be placed into service.

It was also noted that pump performance worsened between January and August.

Recommendation: Modifying or replacing the pumps to better match hydraulic conditions would significantly increase efficiency. Since the pump station is seldomly run, however, major modifications do not appear to be warranted at this time. However, Zone 300 pumping from all of the pump stations pumping into the zone should be reviewed as part of the next Water Master Plan Update. In addition, Pump No. 3 should be inspected for damage as a preventative maintenance item, and it should be verified that the lead-lag programming is set to cycle operation between each pump evenly to extend pump station life and minimize maintenance requirements.

5.4.3 Recycled Water Pump Stations

Pump Station R20

Record drawings indicate that VFDs were installed at PSR20 in 2006. Operating staff note that the VFDs has since been replaced with reduced voltage starters. Pump pressure and flow data, however, indicate that the pumps operate at reduced speeds, most frequently at approximately 92 percent of what would be expected at full speed, as shown in Figure 5.21. The clumps of data indicating the most frequent operating points suggest that the pumps operate at a high efficiency assuming they are operating at approximately 92 percent speed.

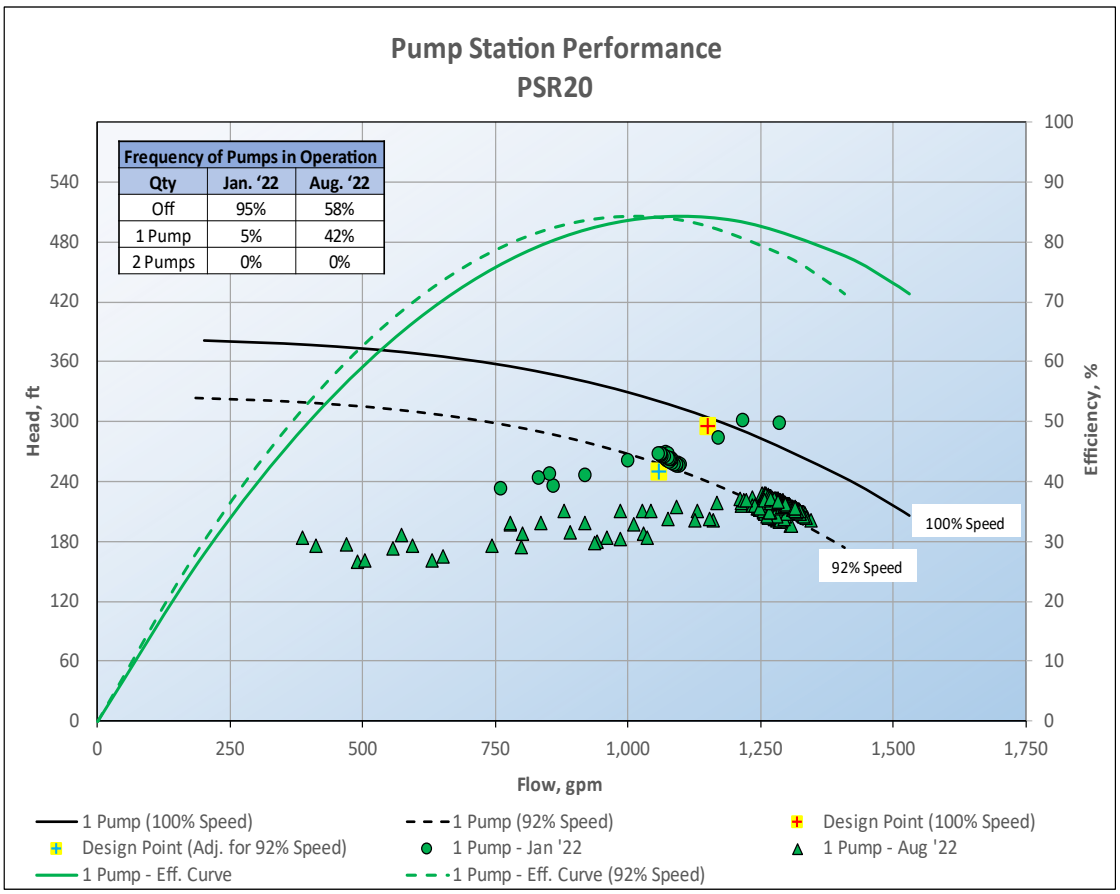


Figure 5.21 Pump Station R20 2022 Performance

<u>Recommendation</u>: Conduct an analysis of pump speed to determine why pumps appear to be operating at reduced speed.

Pump Station R300A

Data provided for analysis indicate PSR300A pumps operate most frequently at 99 percent speed. Figure 5.22 plots the 2022 SCADA data points filtered to just the most frequent operating speed. The plot shows suboptimal efficiency during both one-pump and two-pump operation, with most data points occurring near the left-end of the manufacturer pump curve. Additionally, January 2022 data depart from the observed trend, and indicate performance far from the manufacturer pump curve. Additional analysis was performed on the data to better understand the poor performance.

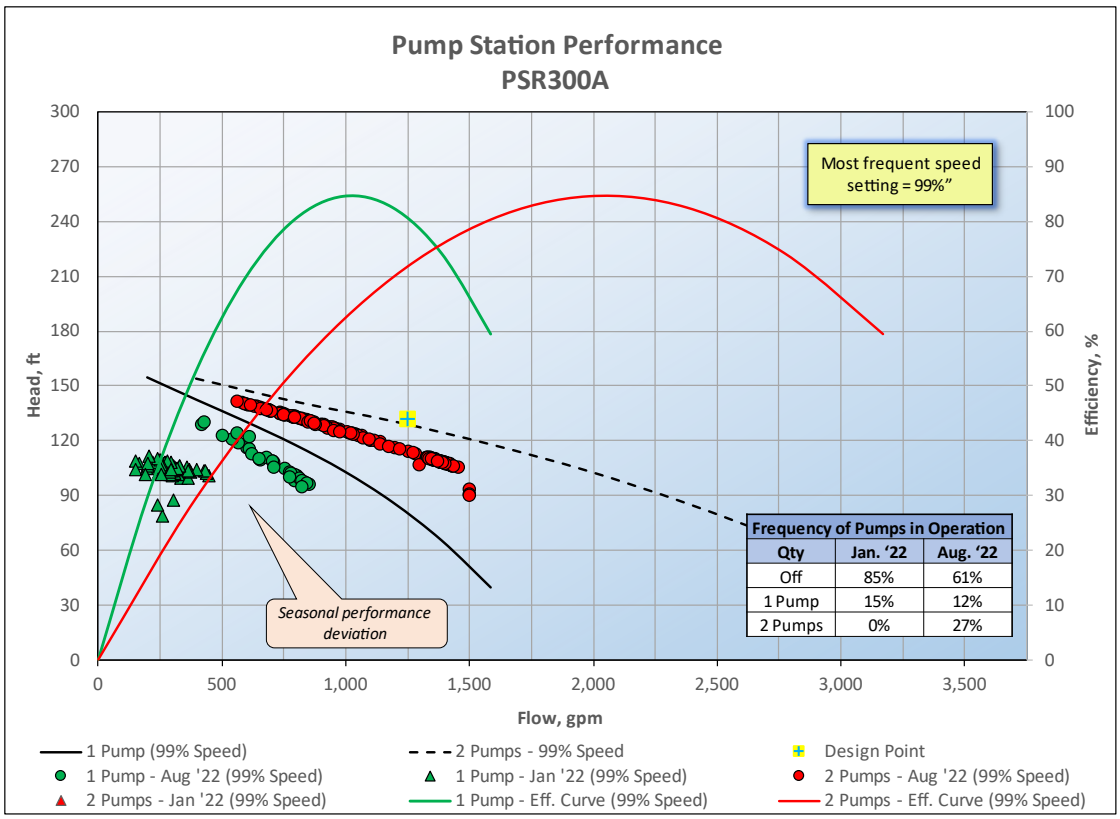


Figure 5.22 Pump Station 300A 2022 Performance

Figure 5.23, plotting only one-pump operation scenarios, provides a comparison PSR200 performance for each month throughout 2022. The plot reveals three noteworthy trends in pump station performance:

1. During the January to April months, the station operated at reduced flow output.
2. During the May to September months, the station operated as expected with data points close the manufacturer pump curve.
3. During the October to December months, the station data are widely scattered and irrational for the 99 percent speed VFD setting and provided pump curve.

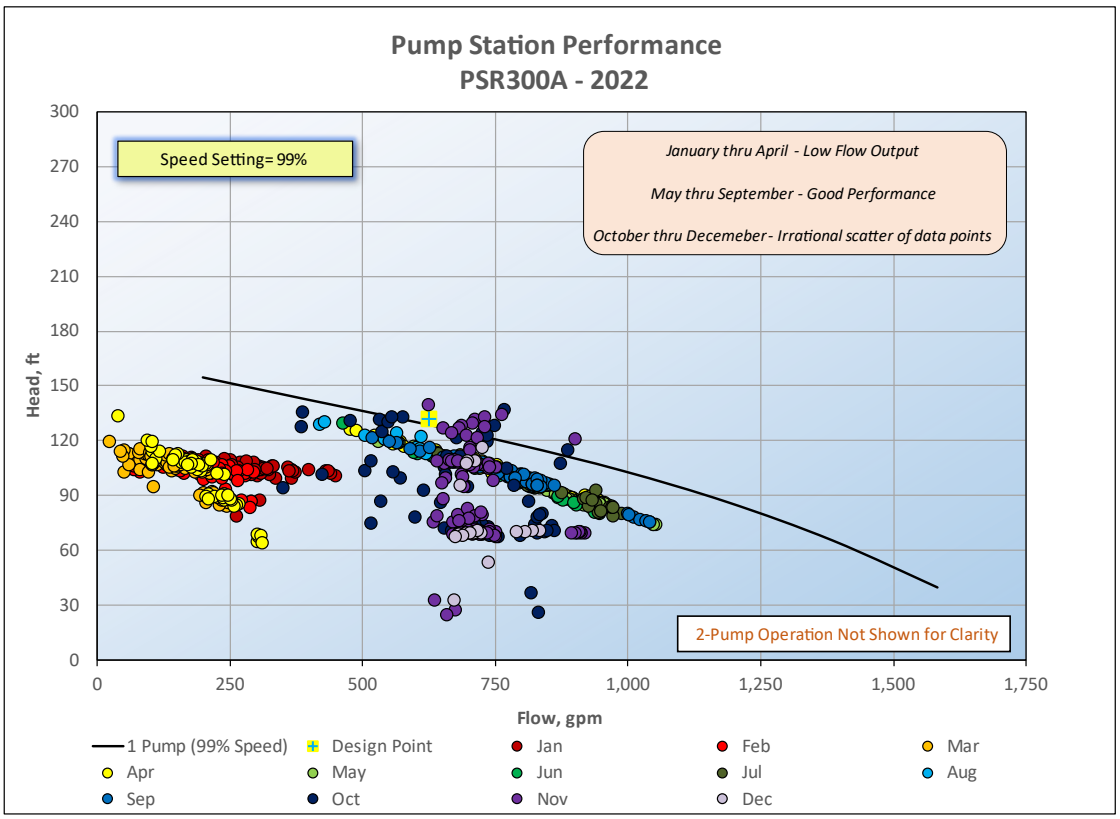


Figure 5.23 Pump Station 300A 2022 Monthly Comparison

Recommendations:

- *Review operator logs and correspondence to determine if valve(s) or instrumentation issue was remedied circa April/May 2022 to explain the sudden shift of performance data around that time.*
- *Review 2023 performance data to assess whether the irrational data at the end of the 2022 data set are still occurring. Inspect, calibrate, or replace pump station instrumentation if necessary.*
- *When pumps are due to be replaced, re-visit system design analysis and pump selection to improve energy efficiency.*

Pump Station R300B

Data provided for analysis for PSR300B are shown in Figure 5.24. PSR300B operates differently than the other recycled water distribution pump stations in that the pump speed varies to maintain a pressure set point since there is no storage tank in Zone R300B, and pump speed is not recorded. It is therefore not possible to compare PSR300B pump operation to the published full speed pump curve and efficiency curve.

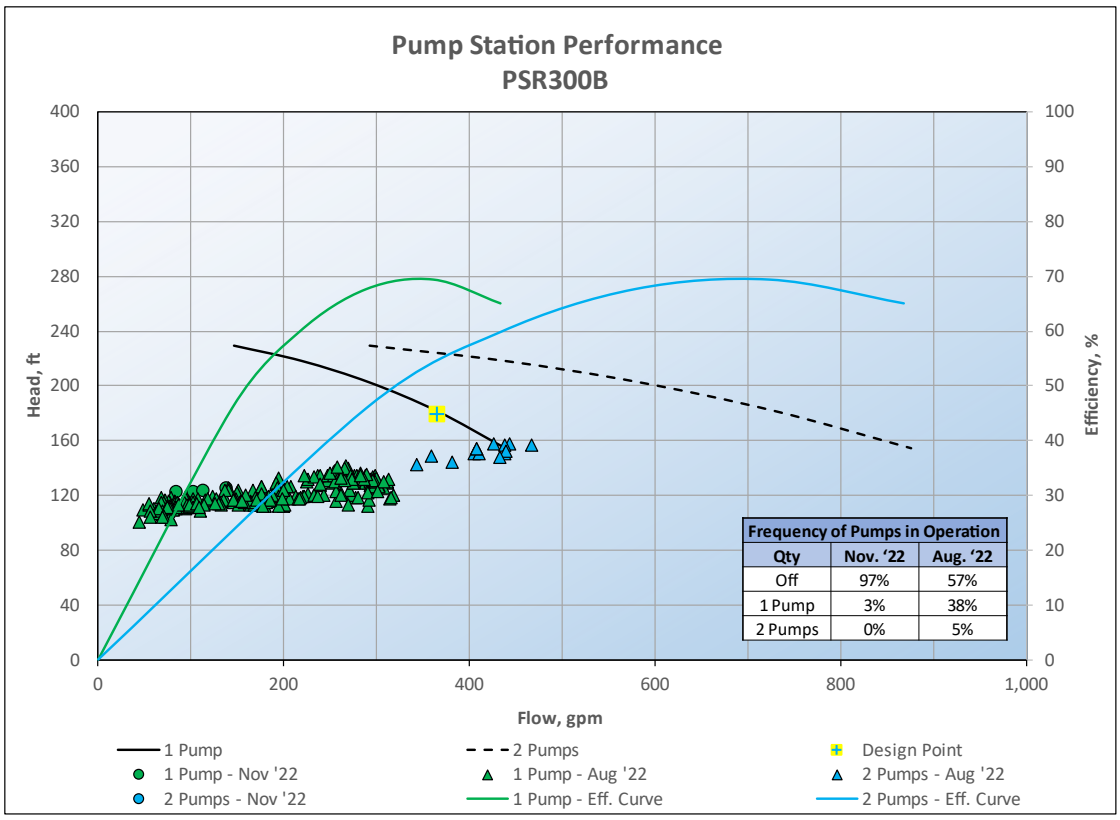


Figure 5.24 Pump Station 300B 2022 Performance

Recommendation: None.

5.5 Energy Management and Advanced Control Opportunities

Energy management software tools and advanced control systems are essential in supporting utilities in implementing energy efficiency measures. Effective energy data collection, tracking, analysis, and visualization help with the following critical goals:

- Identify district-wide energy reduction opportunities.
- Estimate potential cost savings.
- Query and share historical data for specific analyses.
- Implement target strategies.
- Communicate energy management achievements to internal and external stakeholders.

Three specific opportunities are further discussed as they hold potential for DSRSD in supporting its energy efficiency and GHG reduction goals:

1. Power monitoring software tools.
2. Using artificial intelligence and advance process control tools to improve energy management, reduce energy demand and manage renewable energy production.
3. Energy decision making management tools.

5.5.1 Alternative Power Monitoring (AC-1)

DSRSD has used various power monitoring software systems in past years, but all by the same manufacturer (Eaton). Previously DSRSD used PowerNet (Eaton). This software collected power data from various power management systems and compiled this data into a database for periodic reports. PowerNet also had the ability to remotely open and close breakers that were connected to breaker interface modules. This helped staff to trip breakers remotely during planned power outages. Staff was also able to use PowerNet to upload new settings to breakers and get readily informed of system faults.

Eaton phased this product out and split the monitoring and control functions PowerNet provided into two separate products. DSRSD continued to use the electrical power monitoring system Foreseer (Eaton). The monitoring system connects facility-wide electrical devices and tracks a large amount of real-time power data. This software does not support the control communication conveniences PowerNet previously provided to DSRSD staff.

Options for future energy data monitoring include:

1. Continued use of Foreseer (status quo).
2. Integration of the relevant electrical monitoring data into SCADA.
3. Procurement of an Alternative Energy Decision Management Tools (AC-4).

In addition to selecting an alternative energy management solution, special staffing focus will be needed from the District to oversee implementation of these tools and review the data on an ongoing basis to make energy optimization recommendations.

Continued use of Foreseer (status quo)

Within DSRSD, Foreseer is actively used primarily by District staff who runs data report queries for other departments upon request. The system provides access to comprehensive data diagnostics; however, plant staff uses only a subfraction of this information. The departments requesting Foreseer reports include operations, maintenance, and engineering and the information requested is limited to the power rating (kilowatt), energy consumption (kWh), and amperage of devices.

DSRSD holds a maintenance contract with Eaton for Foreseer that costs $20,000 per year and includes the software license, upgrades, up to four site visits, web-based training, and 24-hour support.

While Foreseer comprehensively tracks electrical system data, it is not an energy management system that serves DSRSD as a decision support tool for evaluating and improving energy efficiency and energy costs effectiveness of daily operations. For example, DSRSD currently does not have easy access to the following information real-time:

- What energy fraction is produced onsite or purchased.
- Trending data on electricity demands and production.

Regardless of the energy management tool selected, Foreseer should be kept as a troubleshooting tool for power issues, such as wave form captures. Foreseer captures power/energy data in milliseconds which should not be integrated into SCADA as it will bog down the SCADA network.

Integration of the Relevant Electrical Monitoring Data Into SCADA or Data Reporting Dashboards

DSRSD has invested and continues to invest into sensors and monitoring equipment for state of the industry energy and process control. Currently, this data is tracked and stored but not easily accessible to staff in a report format that would allow evaluation of the success of energy efficiency measures or identification of future energy improvements.

Integrating the most relevant energy data used by operations, maintenance, and engineering staff into SCADA and/or via dashboards using data reporting software (i.e. OSI PI or eRIS) would make its access simpler for real-time monitoring and operational decision making. Carollo recommends DSRSD to include at minimum the following real-time data for immediate and frequent access by staff:

- Real time power consumption and amperage of main equipment.
- Total power consumption of the WWTP.
- Total power production of all sources (cogeneration, solar, etc.).
- Net power purchased from Pacific Gas & Electric Company.
- Key specific power consumption metrics relevant for operational performance tracking and decision making. These could include:
  - Electricity consumption (kWh) per mgd treated.
  - Electricity consumption (kWh) per mass of BOD removed (kWh/tons BOD_5 removed).
  - Electricity produced by cogeneration per mass of solids (kWh/tons TS).

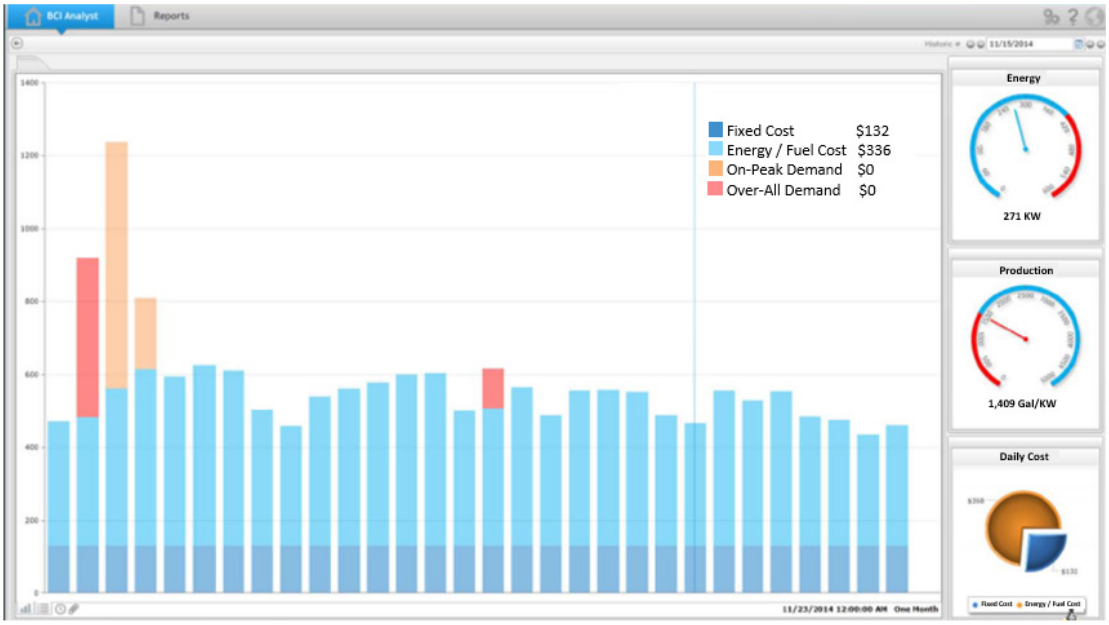
While DSRSD could add the breaker control to SCADA, this comes with potential cybersecurity concerns (e.g., access to switchgears by past employees). Control functions of critical electrical equipment may therefore be better kept separately from SCADA.

Recommendation: Alternative AC-1 should be implemented in combination with Alternative AC-4. The proposed scope includes evaluation of the following options: a) assigning special staffing focus to oversee implementation of these tools and review the data on an ongoing basis to make energy optimization recommendations; b) ending the use of Foreseer as the platform for energy management monitoring (but maintaining it as a troubleshooting tool for power issues); c) adding a new project in FYE 25, or appending the current SCADA Upgrade project, to integrate critical energy data into SCADA in a useful format that allows for energy optimization; and d) selecting and implementing an alternative energy management software solution.

5.5.2 Alternative Energy Decision Management Tools (AC-4)

Various systems are currently on the market that provide data management, customized reporting, and visualizations of energy production, demand, and purchase data for utilities to support real-time monitoring and decision making. Power and energy monitoring systems can be developed by utilities to fit their reporting requirements using software such as OSI PI, SCADA, or Microsoft Power BI. Vendor-provided software products beside Eaton include for example, software products by Schneider Electric.

The advantage of customized energy management systems is that energy data can be paired with DSRSD's power cost rate schedule to produce real-time cost data for purchased energy that can help staff optimize setpoints and equipment operation. Figure 5.25 and Figure 5.26 show examples of energy report graphics that help utility staff make smart energy decisions using peak demand charge trigger warnings and specific energy efficiency metrics.



Source: Hillsborough County, Florida

Figure 5.25 Example Visual Report for Tracking of Fixed, Energy, and Fuel Costs and Demand Charges

Source: Hillsborough County, Florida

Figure 5.26 Example Visual Report for Real-time Energy Consumption Tracking and Peak Demand Thresholds

Regardless of the software product used, the setup and maintenance of energy management reports that are customized to DSRSD's energy goals, cost triggers, and process metrics require time and resources that DSRSD staff does not have. Carollo recommends that the initial set up be supported by a suitable engineering contractor as part of a CIP project. This contractor would help DSRSD select an appropriate software platform and define the layout, content, and format of pertinent energy reports.

The maintenance and upkeep of the system is subsequently best conducted by DSRSD itself. To provide the necessary staffing resources for this effort, DSRSD's board would need to redirect staff focus toward ongoing monitoring of the energy data. Carollo estimates that the energy savings that can be achieved with the focus this position would be able to bring would result in a short payback of the additional salary costs.

Recommendation: Alternative AC-4 should be implemented in combination with Alternative AC-1. The proposed scope includes evaluation of the following options: a) assigning special staffing focus to oversee implementation of these tools and review the data on an ongoing basis to make energy optimization recommendations; b) ending the use of Foreseer as the platform for energy management monitoring (but maintaining it as a troubleshooting tool for power issues); c) adding a new project in FYE 25, or appending the current SCADA Upgrade project, to integrate critical energy data into SCADA; and d) selecting and implementing an alternative energy management software solution.

5.5.3 Artificial Intelligence (AC-2)

Water resource recovery facilities within and outside of the United States are beginning to successfully implement artificial intelligence-based solutions for advanced energy management. These systems are using real time probe, sensor, or soft sensor data to make timely operational decisions that minimize energy consumption and maximize the benefit of energy produced on-site.

Often, energy management is not even the primary driver for implementing these technologies. Stable process operation and/or reduced effluent compliance risk are among the primary reasons for utilities to implement AI solutions. Energy efficient operations become welcome secondary benefits.

Examples of AI applications in the wastewater industry include:

- Predictive control systems and soft sensors to predict influent flows in sewer systems impacted by infiltration and inflow.
- Model predictive aeration control in aeration basins to better accommodate diurnal load fluctuations.
- Model predictive aeration control for disinfection dosing or solids dewatering.
- Data-driven decision making to better match onsite energy production of various green energy sources with DSRSD's energy consumption.

DSRSD already has substantial infrastructure in place to monitor real-time energy production, demand, pump operation, and process operation. WIFI and Bluetooth are in place to transmit data for central data acquisition. AI diagnostics are in place for some pumps. DSRSD will continue to benefit from advanced process control systems that allow making the most of this data already collected to further minimize operational costs. Payback periods for such software solutions can be as short as two years.

The identification of AI opportunities, selection of suitable tools, as well as the management, maintenance, and operational integration of such systems will require additional staffing resources in the future. Carollo recommends that these responsibilities should be led among DSRSD staff with a focus on energy and optimization.

Recommendation: At this time, Carollo does not recommend including this project as part of the Energy Facilities CIP. However, District staff should look for opportunities to implement AI were beneficial as this technology becomes more prevalent.

5.6 Summary of Recommendations

Table 5.5 provides a summary of our recommendations for the efficiency opportunities evaluated. These included the estimated potential for energy reduction or savings as well as estimated capital costs for each alternative that is recommended for implementation or further consideration.

Table 5.5 Summary of Energy Efficiency Opportunities Evaluation Recommendations

Opp. ID	Name	Estimated Potential for Energy Reduction/Savings	Estimated Capital Cost ($)	Recommendation	Comment / Justification
LS Treatment Efficiency Opportunities					
LS-5	Real Time SRT Control	No anticipated energy savings, possibly improved sludge settling and chemical savings.	$50K	Evaluation of integration of advanced SRT and aeration control systems in CIP project "Aeration System Upgrades Design" in 2030/2031.	DSRSD currently operates at lower end of DO setpoints for given process and control accuracy. Lowering DO setpoints further may result in temporary oxygen deprivation and lower effluent quality (as observed in recent years when blower operation was capped to two units. Advanced SRT and DO control systems (e.g., model predictive control) may allow further DO setpoint reduction without compromising effluent.
LS-6	Model Predictive Aeration Control	430,000 kWh/year (15% blower energy savings).	$100-150K	Evaluation of integration of advanced SRT and aeration control systems in CIP project "Aeration System Upgrades Design" in 2030/2031.	
LS-7	Low DO Operation	865,000 kWh/year (30% blower energy savings).	Same as LS-6.	Evaluate low DO operation (further reduction of DO setpoints) post implementation of CIP project "Aeration System Upgrades Design" and after implementation of advanced DO and SRT control tools.	
LS-12	Switch Aeration Diffusers	430,000 kWh/year (15% blower energy savings).	$1M	Evaluate alternative energy efficient diffusers for replacement in CIP project "Aeration System Upgrades Design" in 2030/2031.	Recent diffuser breakage warrant re-evaluation in combination with blower replacement evaluation. Include detailed assessment of the cost/benefits of energy efficient alternative diffusers available on the market.
LS-13	Upgrade Aeration Blowers	170,000 kWh Marginal energy efficiency gains (up to 5%).	$7.6M	Evaluate alternative high-efficiency blower technologies for replacement in CIP project "Aeration System Upgrades Design" in 2030/2031.	Blowers are older than 20 years. Include detailed assessment of energy efficient alternative blower technologies.
LS-15	Jockey Blower	No anticipated energy savings.	Not quantified.	Not recommended.	Current blowers provide sufficient turn-down.
LS-16	Upgrade Pre-Aeration Blowers	No anticipated energy savings.	Not quantified.	Do not pursue further at this time.	More efficient hybrid PD blowers are currently not available in the sizes required for this application.
LS-18	Install Additional VFDs	No anticipated energy savings.	Not quantified.	Not recommended.	Little opportunity available for energy improvements as most of the larger pumps and blowers are already on VFDs.
BS Treatment Efficiency Opportunities					
BS-2A	DAFT Optimization	Optimization: no significant energy savings. Replacement with mechanical thickening: 800,000 kWh/yr (75% of DAFT energy consumption).	Mechanical thickening: Not yet quantified.	Conduct detailed evaluation on thickening alternatives in approximately 2026 as part of the "Food waste Co-digestion and Digester Capacity Upgrades Project".	Continue DAFT operation. Consider overall cost/benefits of converting to energy efficient mechanical thickening and WAS wasting from RAS when digesters approach capacity limits (triggered by food waste co-digestion).
BLG System Operations Optimization					
BLG-2	Adjust Lighting and Temperature Schedules	10% of building power usage and 10% of NG for HVAC.	Minimal cost: Not quantified.	DSRSD to assess potential risks/benefits and implement energy efficiency measures internally.	Does not require a CIP project definition.
BLG-4	Reduced Ground Lighting at Night	10% of outdoor lighting.	Minimal cost: Not quantified.	DSRSD to assess potential risks/benefits and implement energy efficiency measures internally.	Does not require a CIP project definition.
BLG-7	Metal Building Insulation	10% of building energy.	$20K per 2,000 square feet building.	Alternative was recommended but then removed after further evaluation in TM 11.	Not recommended since only uninsulated metal building is infrequently used.

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Table 5.6 Summary of Energy Efficiency Opportunities Evaluation Recommendations (continued)

Opp. ID	Name	Estimated Potential for Energy Reduction/Savings	Estimated Capital Cost ($)	Recommendation	Comment / Justification
BLG-8	Screen Room Air Handling Unit Replacement	Nominal savings from newer higher efficiency unit.	$20K	Schedule replacements in CIP for year 2025 with energy efficient unit.	The screen room air handling unit has less than 5 years of useful life remaining.
BLG-9	Building A and C Air Handling Unit Replacement	Nominal savings from newer higher efficiency unit.	$20K	Schedule replacements in CIP for year 2025 with energy efficient unit.	The air handling units have less than 10 years of useful life remaining.
BLG-10	Bar Screen Building Exhaust Fan Motor	Nominal savings from newer higher efficiency unit.	$20K	Schedule replacements in CIP for year 2025 with energy efficient unit.	The screen room exhaust fan has less than 10 years of useful life remaining.
BLG-11	HVAC Energy Recovery	No anticipated energy savings.	Not quantified.	Do not pursue further at this time.	The estimated payback period for this technology is extensive.
BLG-14	Refrigerant HVAC System	Normal savings from higher efficiency system.	$4K – 9K per air conditioning tonnage.	Schedule replacement at time of next HVAC in-kind replacement project (or earlier if CA require to do so). DSRSD to work directly with energy building contractors.	Replacement of certain refrigerants in HVAC units is required by CA regulations.
BLG-15	Economized Cooling via Fan Addition	Not quantified: Must comply to regulations regardless.	Not quantified.	This technology will be implemented based on updated building code requirements in future HVAC upgrades projects. No extra CIP project required.	Future HVAC projects that DSRSD undertakes will be required to have economized cooling to meet CA energy efficiency standards.
PWD System Opportunities					
PWD-2	Assess Pump Condition	Not qualified at this time		Review pump stations identified in this TM that operate below target efficiencies or show signs of potential damage or other issues. Plan for pump station upgrades as required in years 2025-2027.	The pump stations identified with potential damage or other issues include: 1A, 2B, 3C, 20B, and 300C.
PWD-3	Assess Pump Design Point	Not qualified at this time			The pump stations that were identified to operate significantly off their design point include: 1A, 4B, 300A, and 300C.
Energy Management and AC Opportunities					
AC-1	Alternative Power Monitoring System	49,000 kWh when combined with AC 4. (0.5% system-wide savings based on other utilities).		Include Project as non-CIP project for 2025 to integrate critical energy data into SCADA. Replace foreseer with SCADA (and as needed other simpler data systems). Combine with AC-4.	Advanced aeration control is included in Opportunity LS-6. DSRSD staff focus on energy management, understanding overall efficiency, and looking for opportunities to achieve energy goals and targets. Lead identification and implementation of AI opportunities for DSRSD.
AC-2	AI	No anticipated energy savings.	Not quantified.	No CIP action needed at this time.	
AC-4	Energy Decision Management Tools	Combine with AC-1.	Combine with AC-1.	Include as non-CIP project in 2025 to select and implement energy decision management support system and develop customized energy management performance reports. Combine with AC-1.	

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Appendix 5A

DO CONCENTRATION PROFILES IN THE AERATION BASINS

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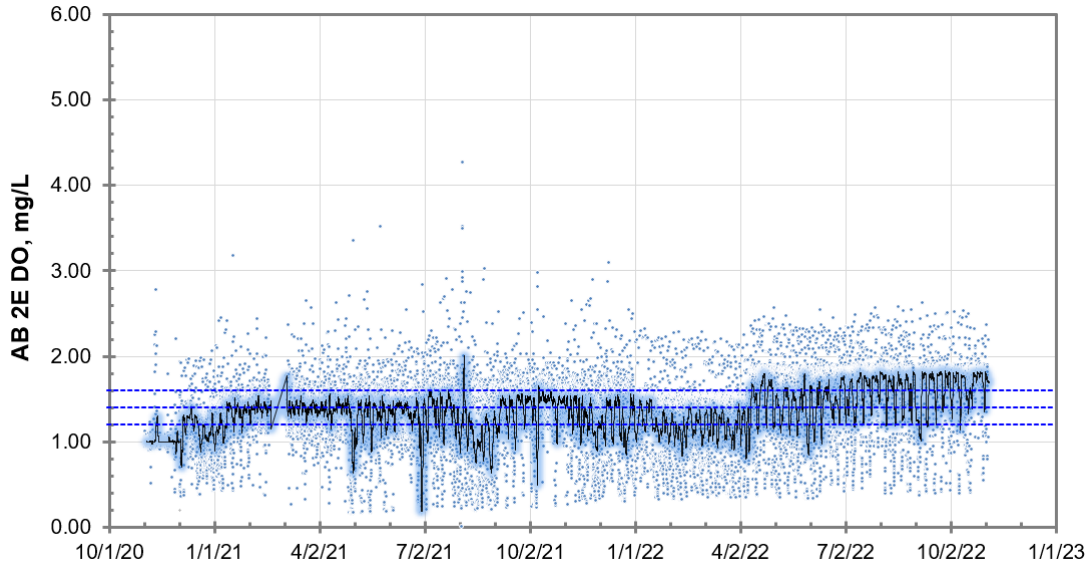

Figure 5A.1 DO Concentrations in AB 2 East (2020 to 2023)

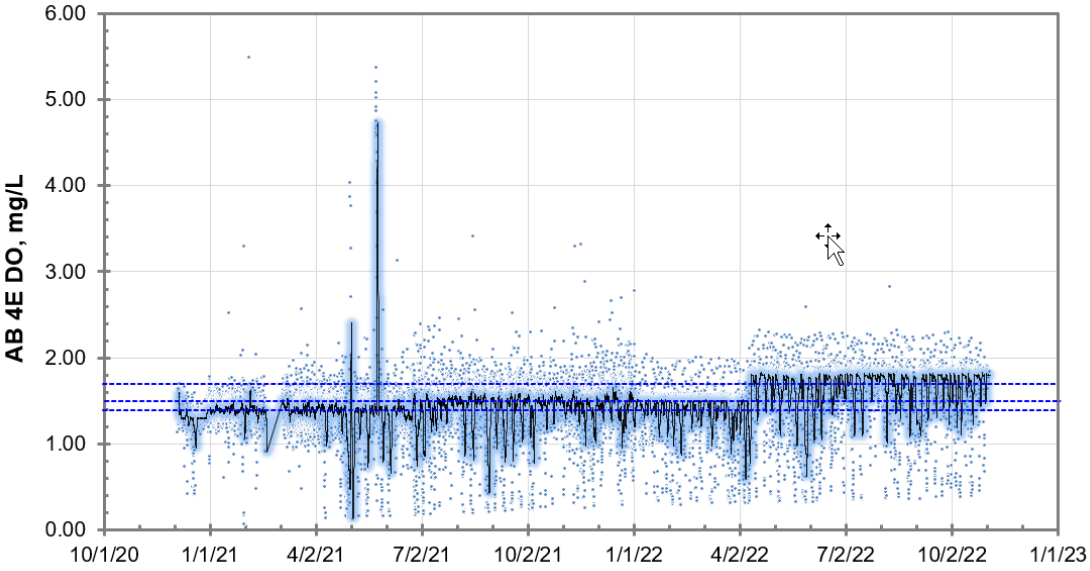

Figure 5A.2 DO Concentrations in AB 4 East (2020 to 2023)

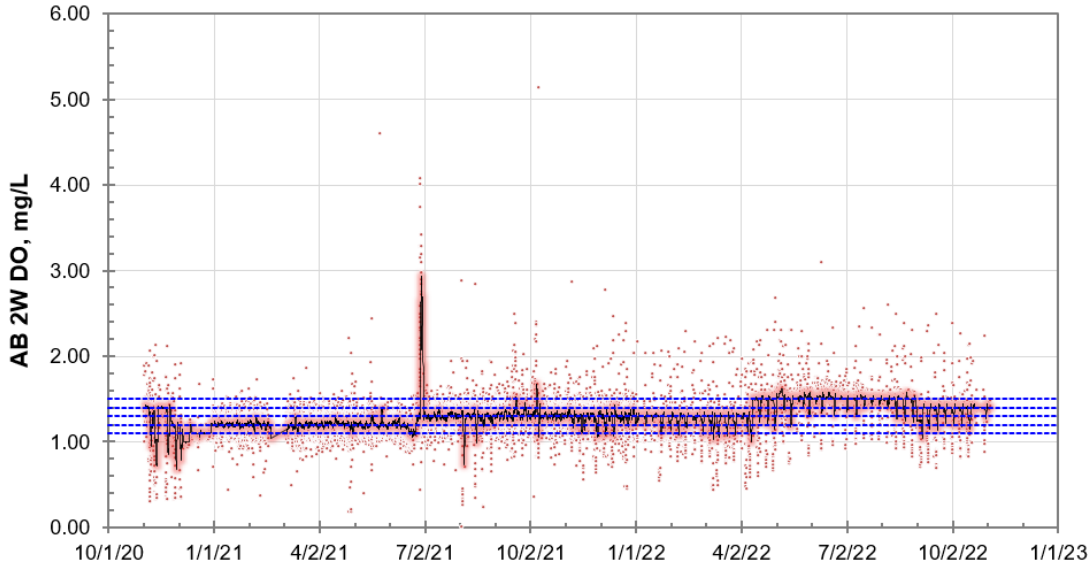

Figure 5A.3 DO Concentrations in AB 2 West (2020 to 2023)

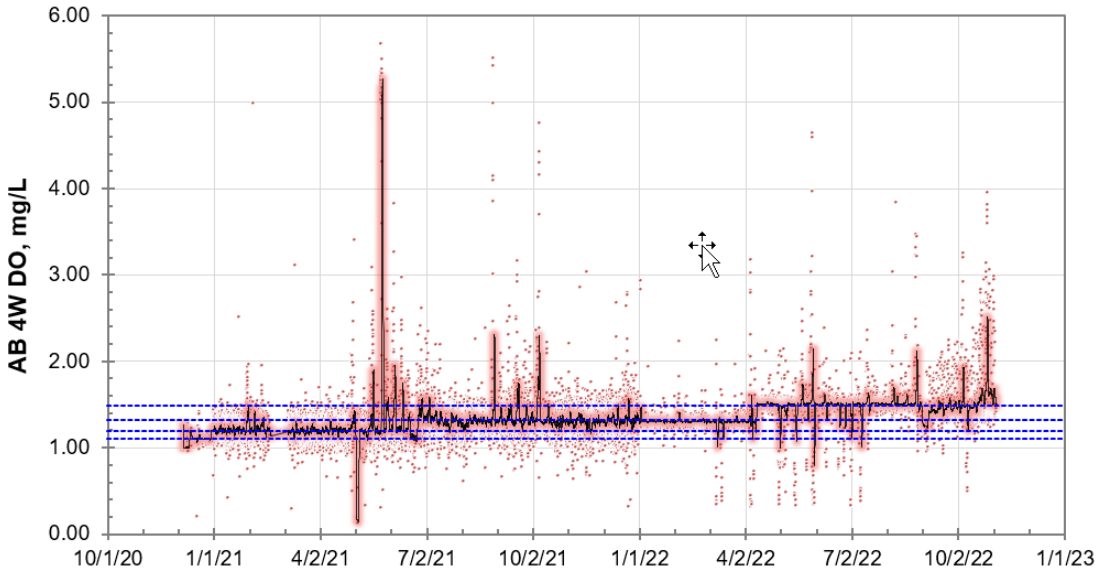

Figure 5A.4 DO Concentrations in AB 4 West (2020 to 2023)

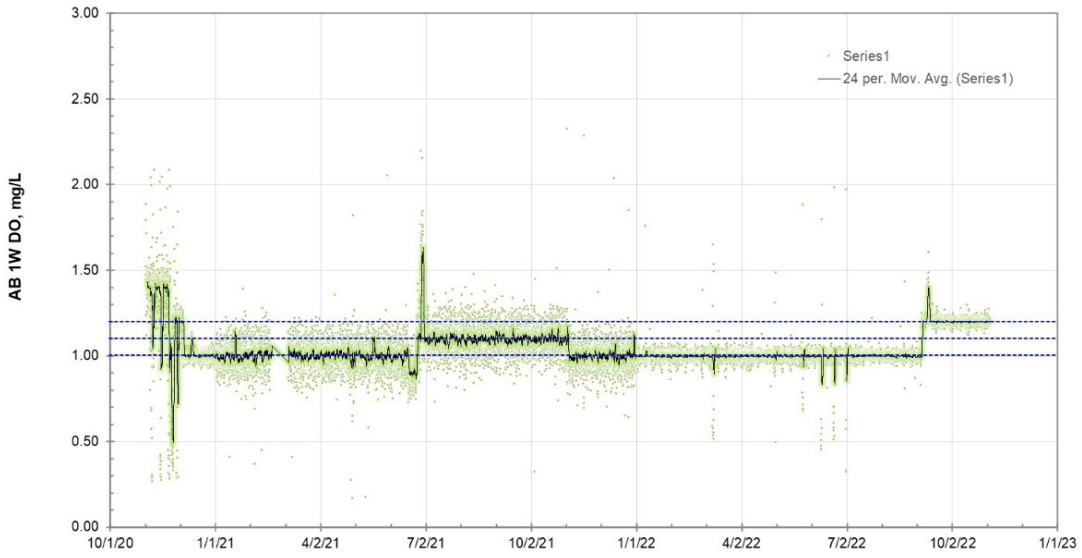

Figure 5A.5 DO Concentrations in AB 1 West (Example) (2020 to 2023)

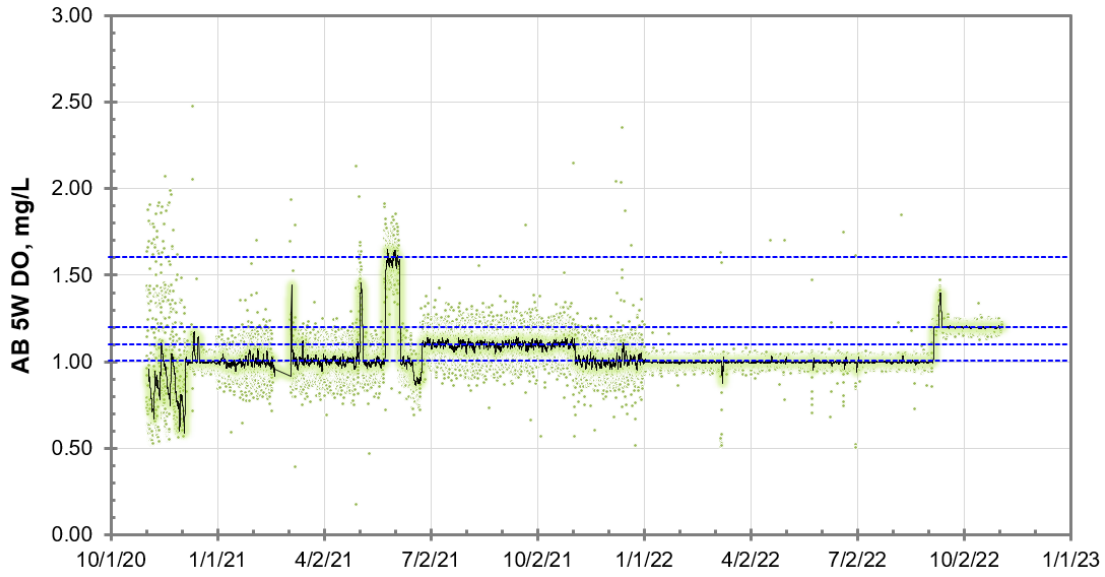

Figure 5A.6 DO Concentrations in AB 5 West (2020 to 2023)

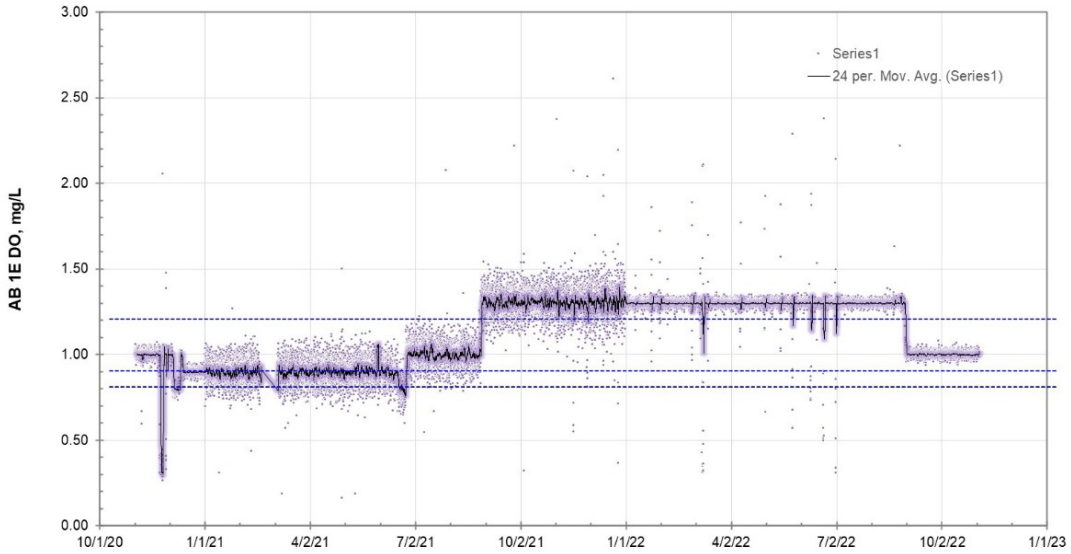

Figure 5A.7 DO Concentrations in AB 1 East (Example) (2020 to 2023)

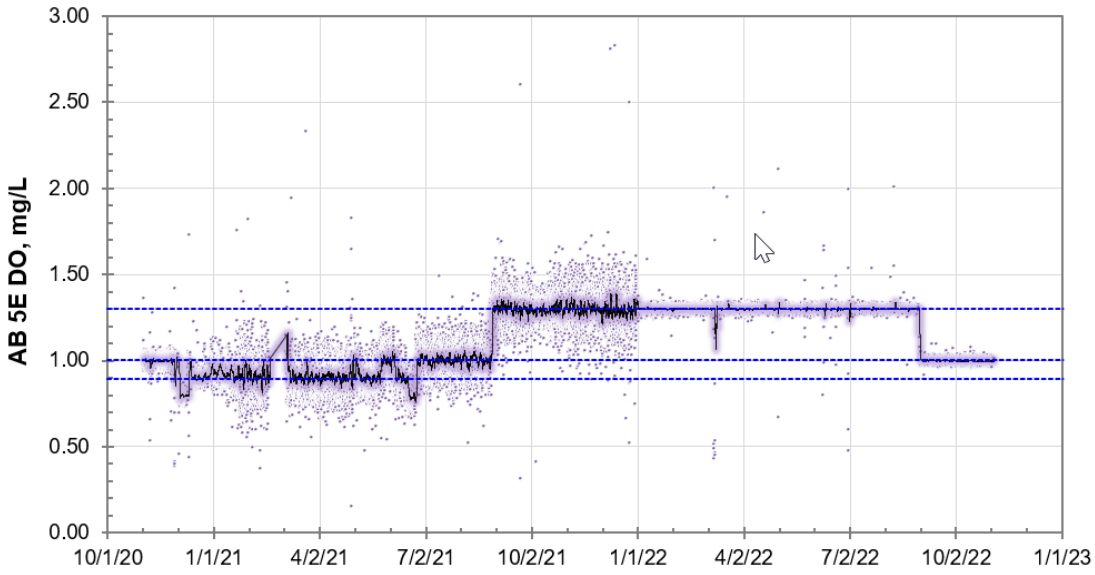

Figure 5A.8 DO Concentrations in AB 5 East (2020 to 2023)

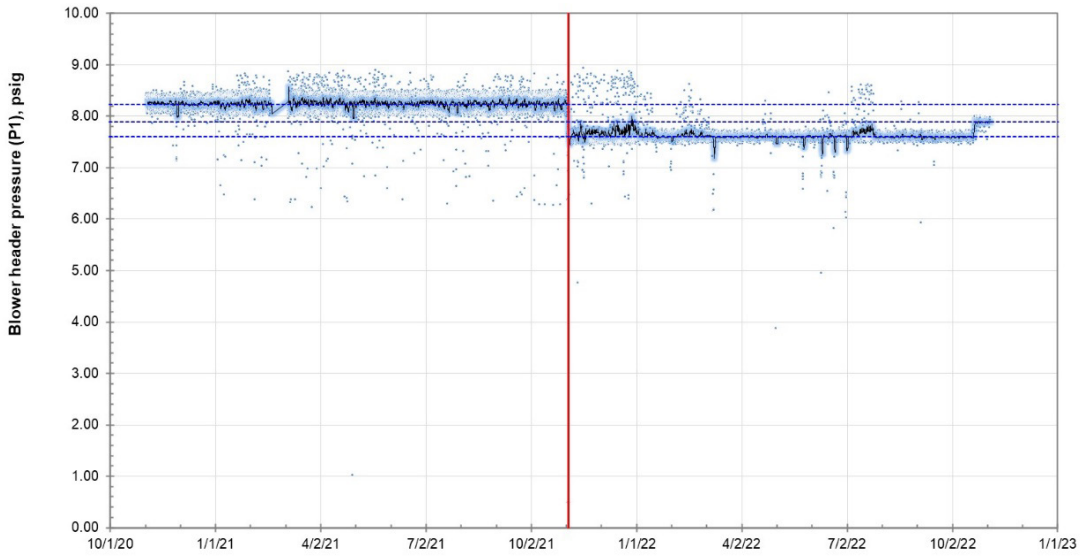

Figure 5A.9 Blower Header Pressure (P1) (2020 to 2023)

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Appendix 5B

STEEL BUILDING INSULATION QUOTE

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Date:	**3/21/2023**
Cust Svc Rep:	**Steve Paulukovich**
Email:	stevep@buildingoutlet.com

STEEL BUILDING INSULATION
A DIVISION OF BUILDING OUTLET CORP

REMIT TO: Building Outlet Corp.
7631 Shaffer Parkway Unit C
Littleton, CO 80127
1-800-486-8415 Fax 303-948-2059

Purchase Order / Quote

Quoted To:	
Buyer's Name	
Contact:	Carter Biesemeyer
Address:	To Be Determined
City, State, Zip:	San Ramon, CA 94582
Phone:	303-404-6361
Fax:	
Email:	cbiesemeyer@carollo.com

Ship To:	
Contact:	
Address:	
City, State, Zip:	
Phone:	
Alt Phone:	

Bldg Dimensions and Info						
	Width:	**40**	**Roof Pitch:**	**1:12**	**Bldg Type:**	**PEMB**
	Length:	**50**				
	Height:	**15**	**Roof Type:**	**Gable**	**Job Type:**	**Retro Fit**

Quantity	Item Description	Unit Price	Amount
Roof	8" (R-25) Faced w/ WMP-VRR+ and 1 Taped Tab		Included
Walls	6" (R-19) Faced w/ WMP-VRR+ and 1 Taped Tab		Included
2	500' Coil of Steel Banding - 20 Gauge - Painted White		Included
9	100' Coil of InsulHold - 20 Gauge		Included
700	Self-Tapping Tek Screw #12 - Painted White		Included
1	150' Roll of Patch Tape - White		Included
2	180' Roll of Double Sided Tape - White		Included
	Total Delivered to Jobsite		$8,627.00

Notes: Based on Standard Width Lengths

Lead time is typically 4-9 weeks.

Subtotal	$8,627.00
Sales Tax	Not Included
Freight	Included
Total US $	**$8,627.00**

Signature_____ **Date:**_____

All quotes subject to acceptance upon final review by an officer of Building Outlet Corporation. Actual delivery depends on parts / materials availability.

Subject to the terms listed on the website

Fill In And Fax To 303-948-2059

Credit Card Authorization Form

Fill In As Info Appears On Card

Name:					
Billing Address:					
City:		**State:**		**Zip:**	
Card Type:					
Card Number:					
Exp. Date:		**CVV2/CVC Code:**			
Charge Amount:		**Deposit Amount:**			
	Amount To Be Charged Upon Shipment:				

Cardholder Signature: _____ Date: _____

Cardholder acknowledge receipt of goods and/or services in the amount of the hereon and agree to perform the obligations set forth in the Cardholder's agreement with the issuer. Payment, terms and product warranties are subject to terms listed in the web site. Card holder agrees that seller can run card for any past due balances or for sales tax if applicable.

Wire Transfer Info

Call For Info

Mail In Check

Building Outlet Corporation
7631 Shaffer Pkwy Unit C
Littleton, CO 80127
Checks MUST be overnighted for Rush Orders

PAYMENT DUE IN FULL PRIOR TO PRODUCTION --- PAYMENT OPTIONS: Balance must be received before order goes to production. THIS ORDER IS SUBJECT TO THE PURCHASE TERMS POSTED ON THE WEBSITE OR YOU CAN REQUEST THE TERMS TO ACCOMPANY THIS AGREEMENT. BUILDING OUTLET CORP IS NOT RESPONSIBLE FOR CONSEQUENTIAL OR INCIDENTAL DAMAGES. PAYMENT CONSTITUTES ACCEPTANCE EVEN WITHOUT SIGNATURES. DELAYED SHIPMENTS OR WARRANTY CLAIMS DO NOT QUALIFY FOR REFUNDS. SELLER AGREES TO REMEDY APPROVED WARRANTY OR VALID AND NOTED SHIPPING CLAIMS.

This purchase is subject to sales tax or consumer use tax and the amount of the tax is not included in our price unless it is shown separately. Due to variations in tax rates in each state, the buyer is responsible for any and all sales tax or use taxes that apply to this purchase of building materials. By signing this agreement, you are agreeing to remit/pay the building materials sales tax, consumer use tax or difference on taxes not collected or rates improperly calculated by the supplier, Building Outlet Corporation. This obligation pertains to local sales and purchases made from suppliers and vendors located outside of your state whom do not collect or under collected a sales or use tax.

Appendix 5C

POTABLE WATER DISTRIBUTION PUMP STATION ENERGY EFFICIENCY ANALYSIS

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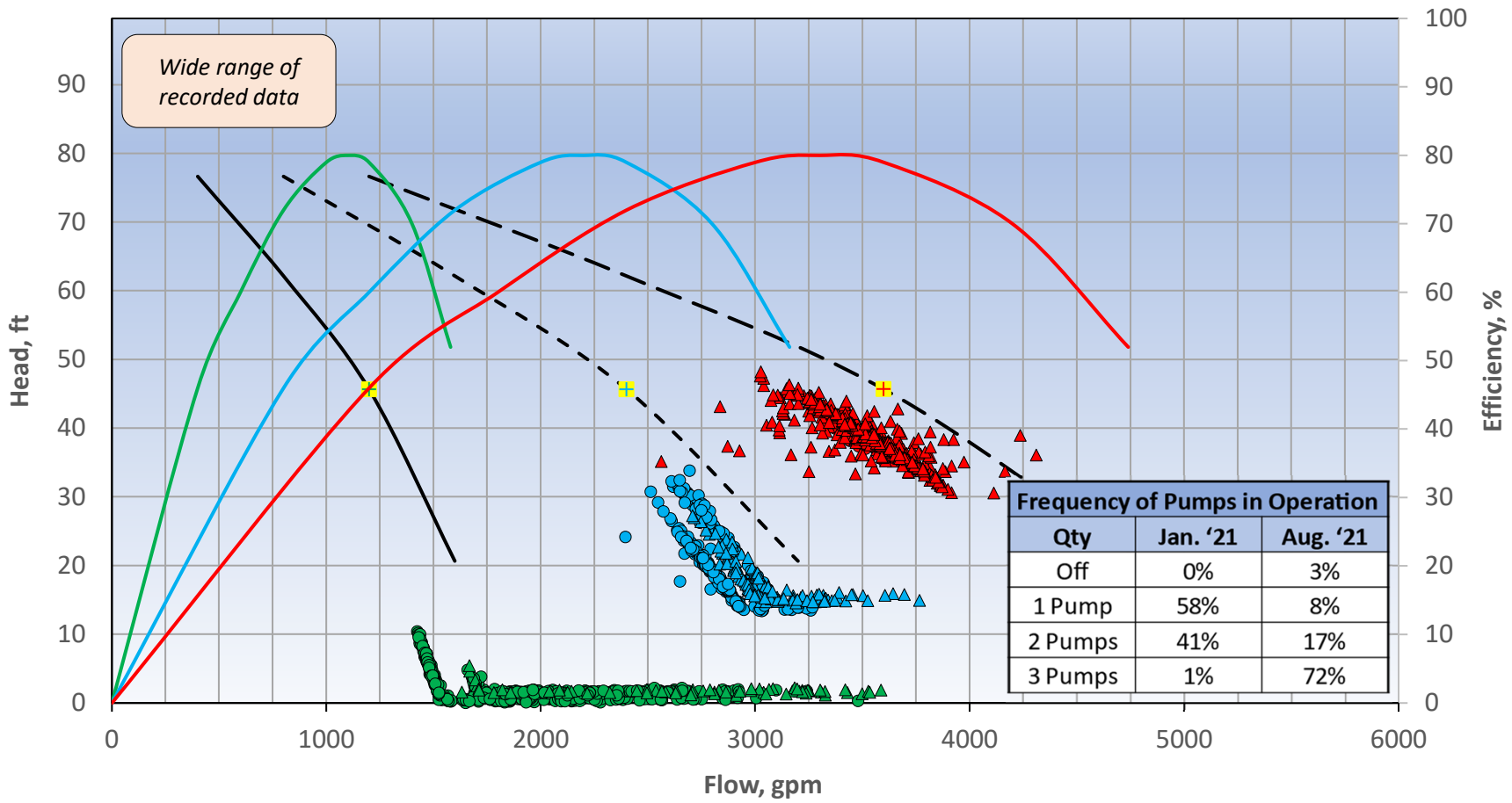
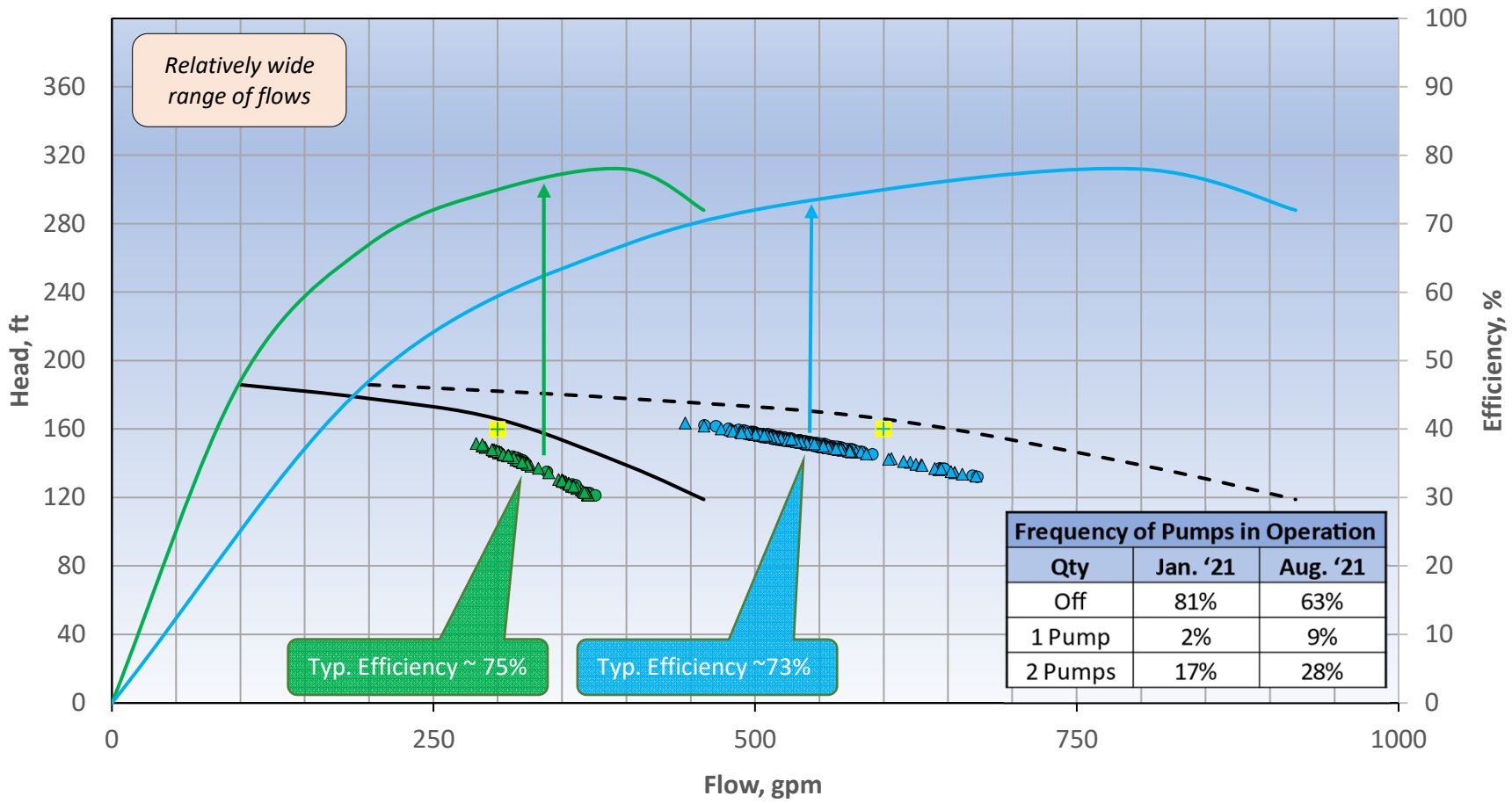
Pump Station Performance
PS1A



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	0%	3%
1 Pump	58%	8%
2 Pumps	41%	17%
3 Pumps	1%	72%

1 Pump - Curve
2 Pumps - Curve
3 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
3 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
3 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
3 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency
3 Pumps - Efficiency

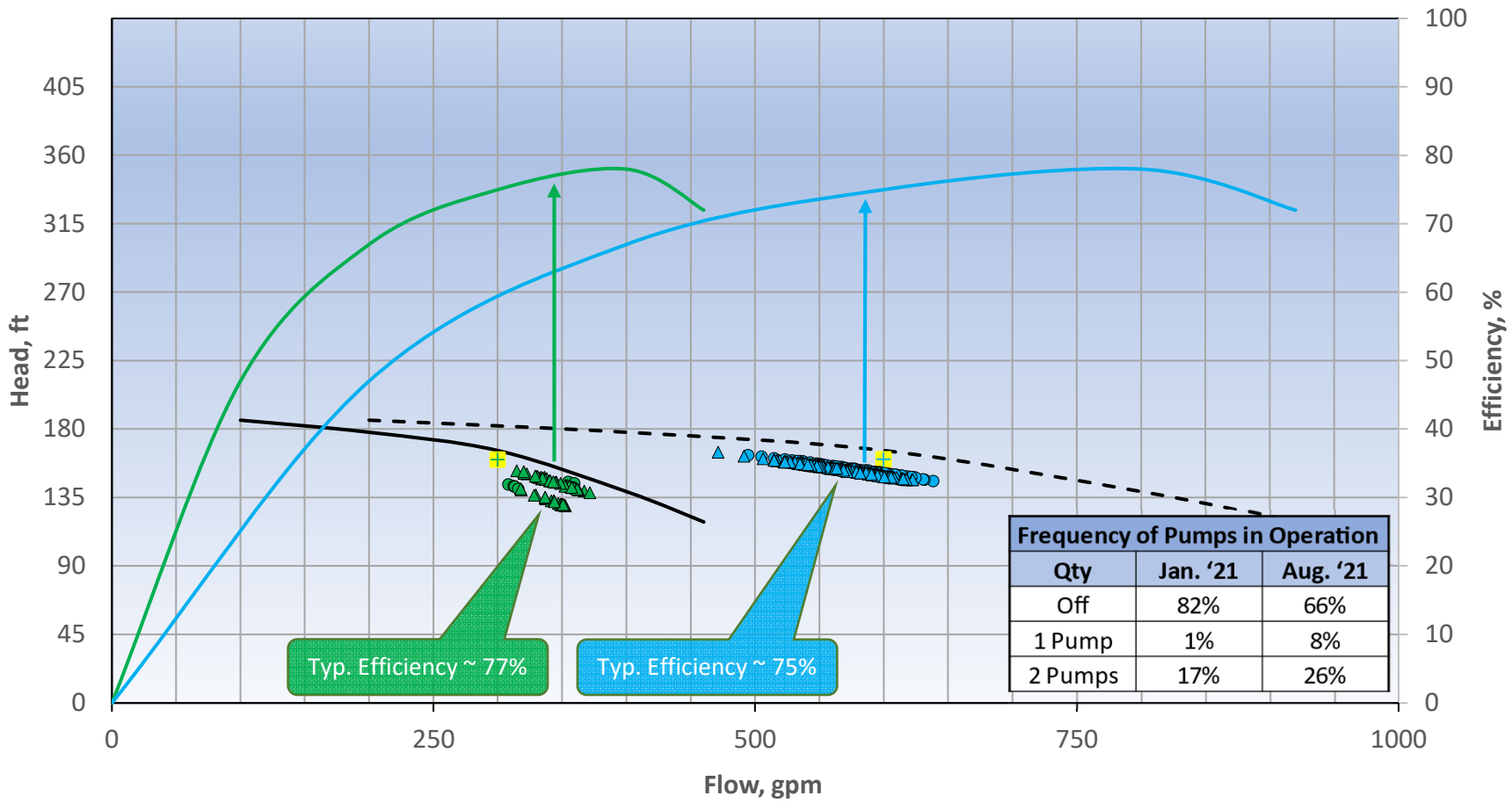
Pump Station Performance
PS2A



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	81%	63%
1 Pump	2%	9%
2 Pumps	17%	28%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pump Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

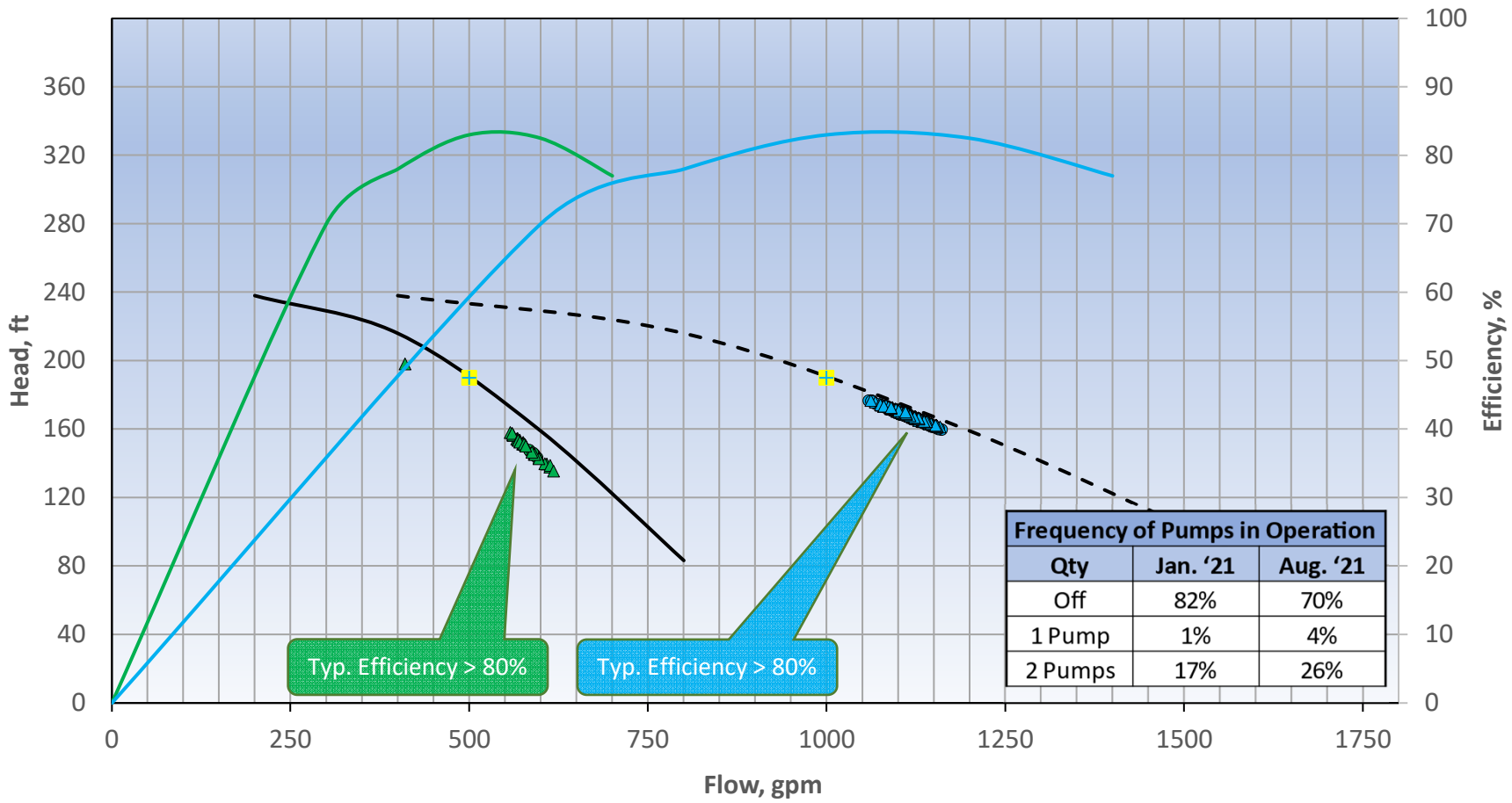
Pump Station Performance
PS2B



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	82%	66%
1 Pump	1%	8%
2 Pumps	17%	26%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pump Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

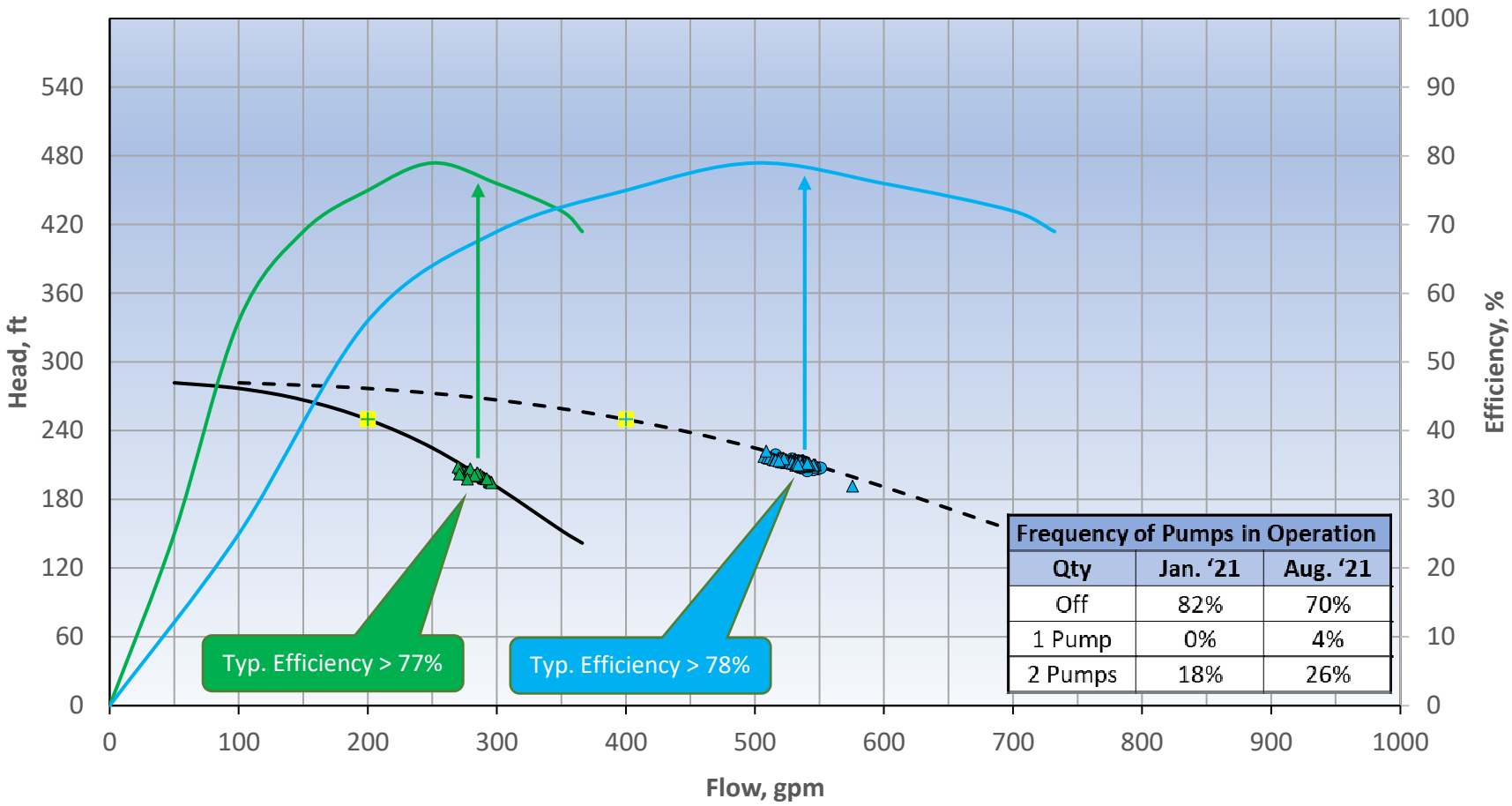
Pump Station Performance
PS2C



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	82%	70%
1 Pump	1%	4%
2 Pumps	17%	26%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

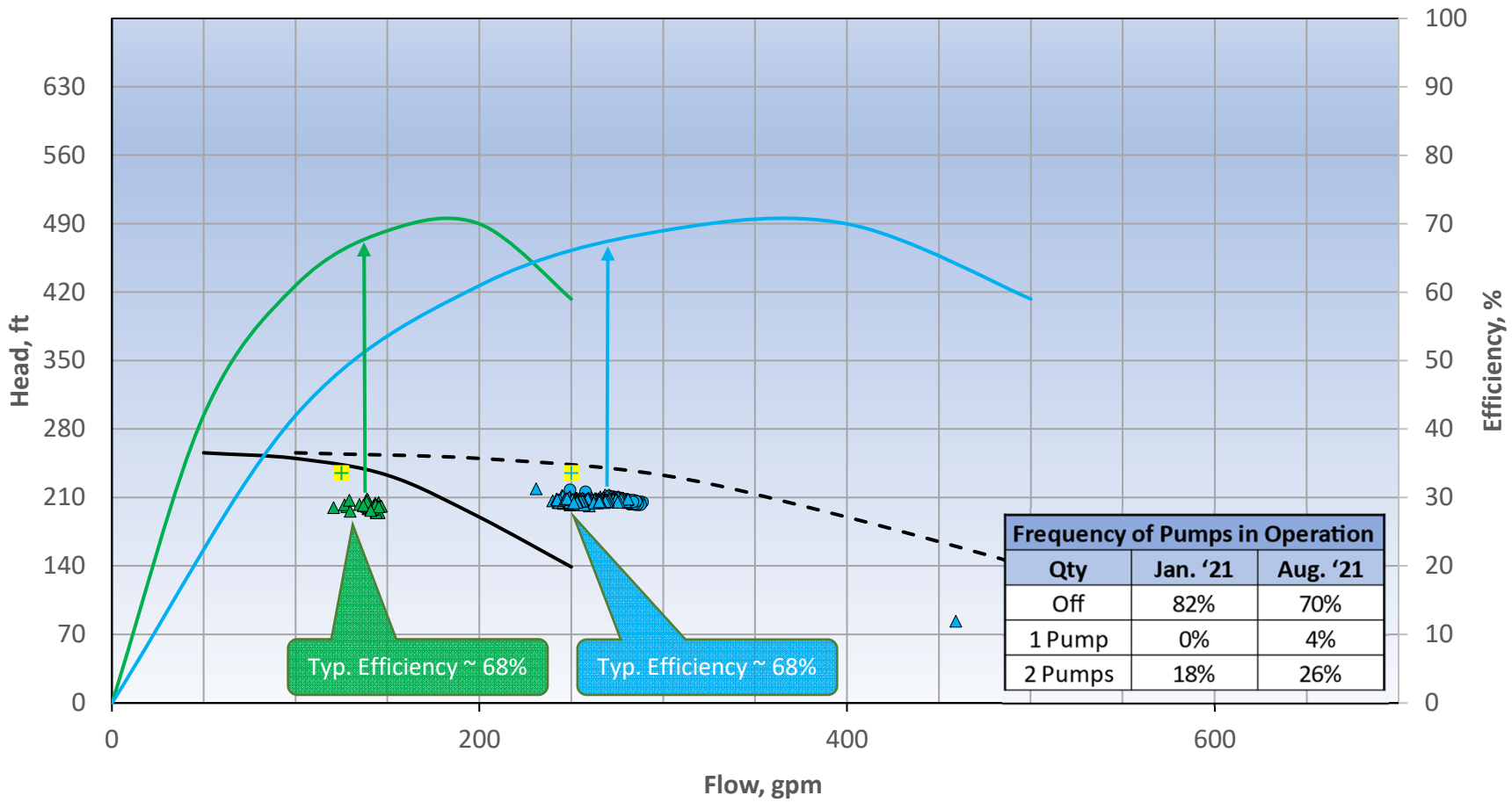
Pump Station Performance
PS3A



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	82%	70%
1 Pump	0%	4%
2 Pumps	18%	26%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

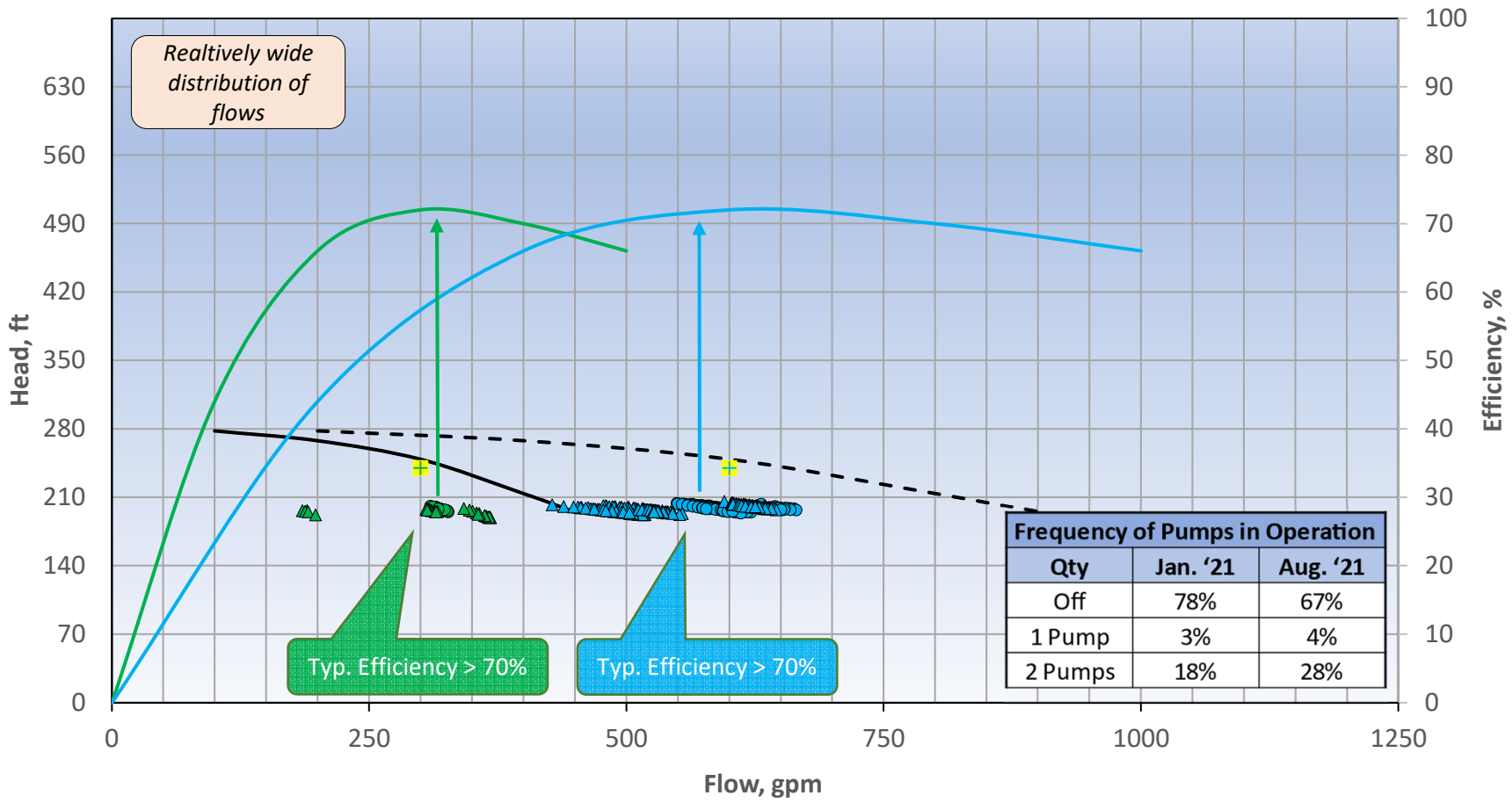
Pump Station Performance
PS3B



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	82%	70%
1 Pump	0%	4%
2 Pumps	18%	26%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

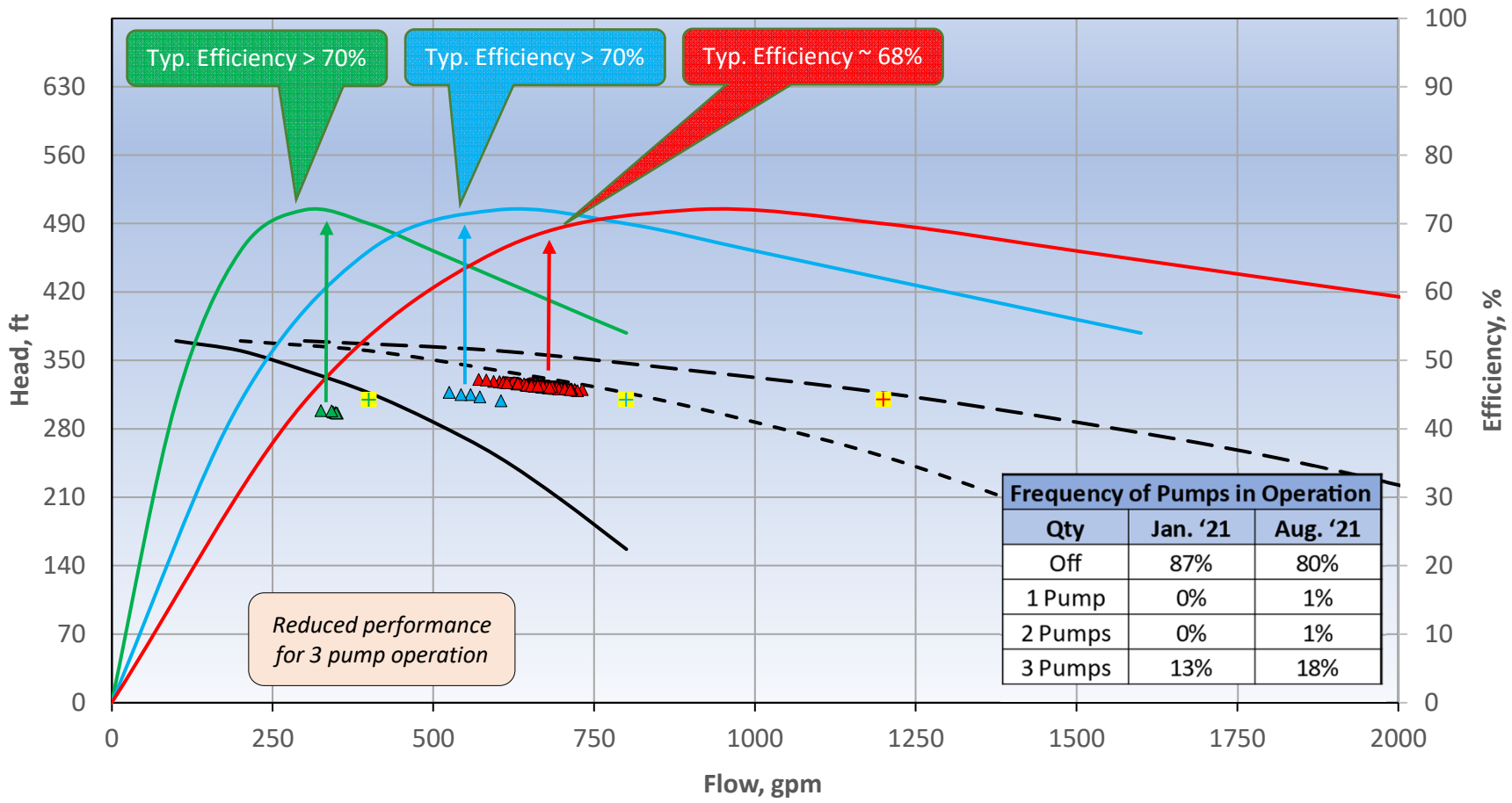
Pump Station Performance
PS3C



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	78%	67%
1 Pump	3%	4%
2 Pumps	18%	28%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

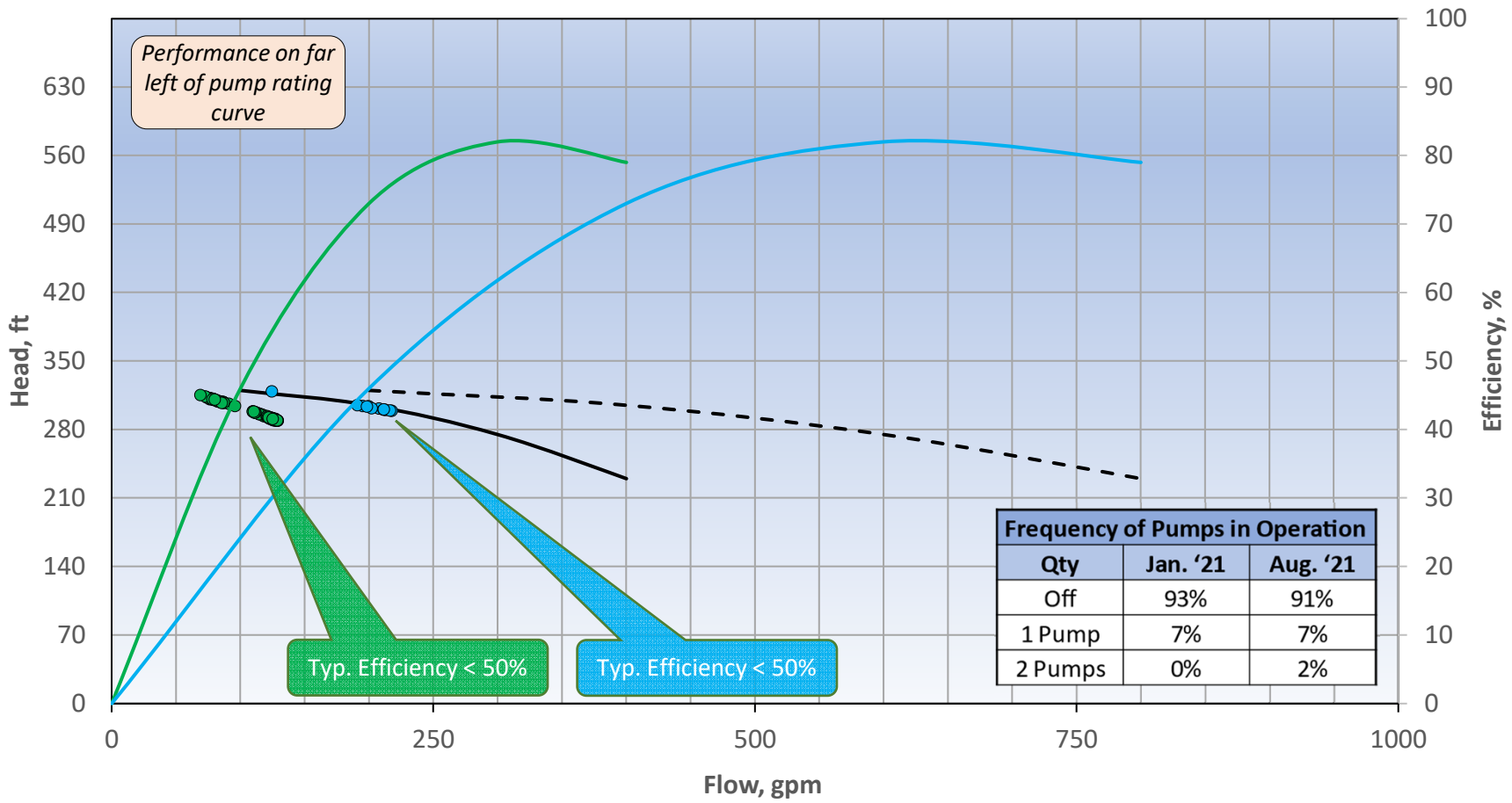
Pump Station Performance
PS4A



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	87%	80%
1 Pump	0%	1%
2 Pumps	0%	1%
3 Pumps	13%	18%

1 Pump - Curve
2 Pumps - Curve
3 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
3 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
3 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
3 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency
3 Pumps - Efficiency

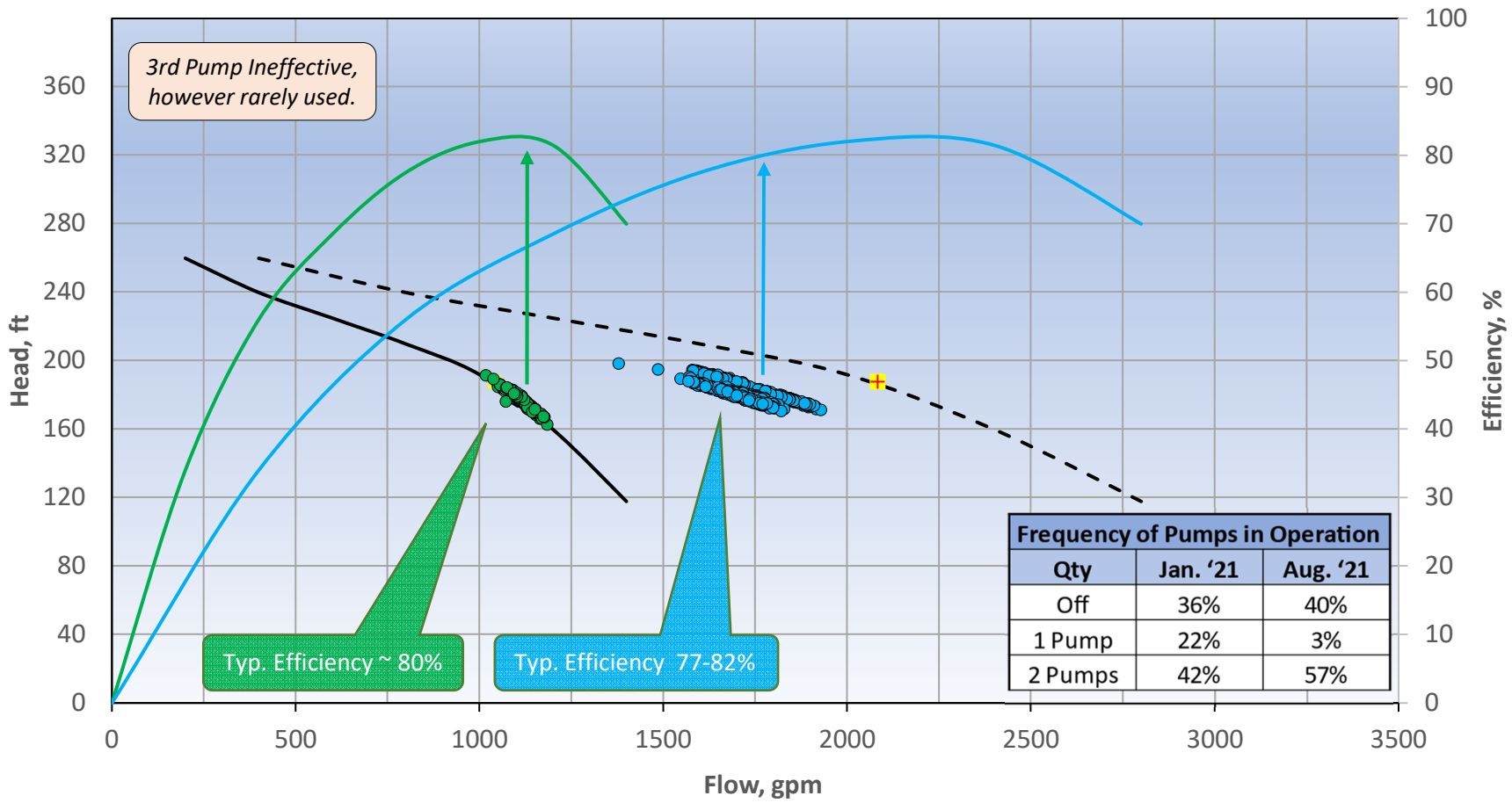
Pump Station Performance
PS4B



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	93%	91%
1 Pump	7%	7%
2 Pumps	0%	2%

1 Pump - Curve
2 Pumps - Curve
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

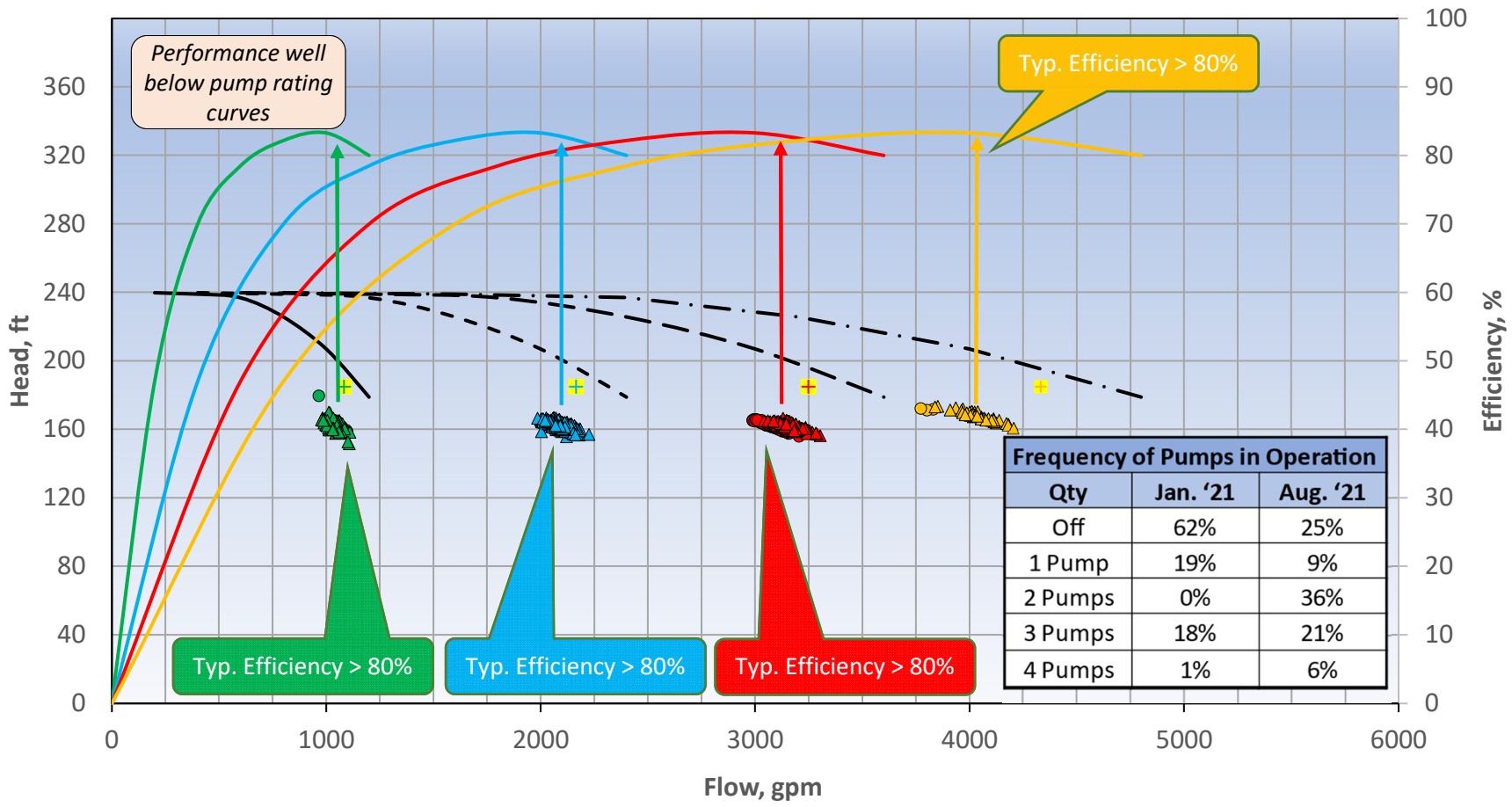
Pump Station Performance
PS20A



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	36%	40%
1 Pump	22%	3%
2 Pumps	42%	57%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

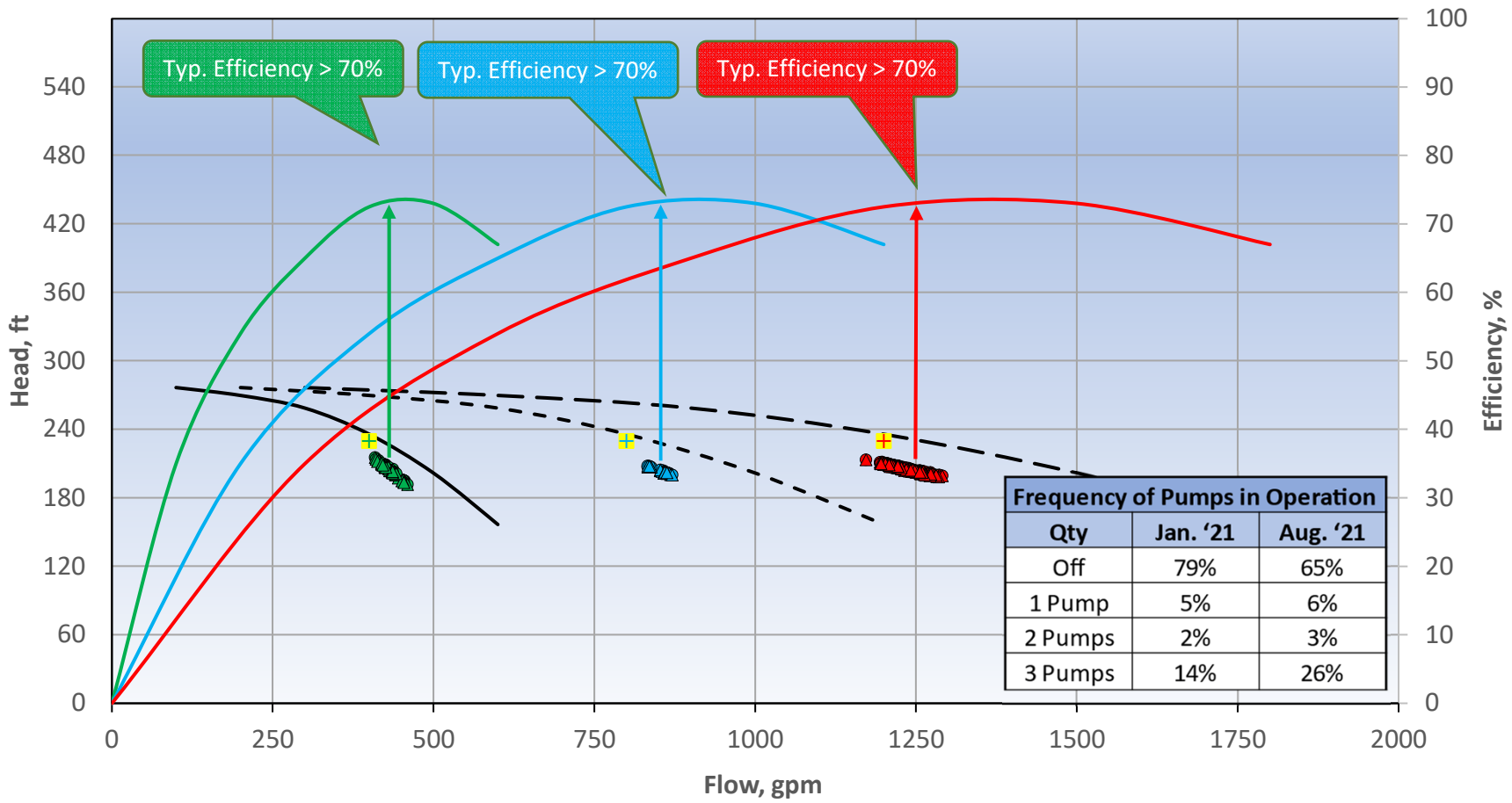
Pump Station Performance
PS20B



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	62%	25%
1 Pump	19%	9%
2 Pumps	0%	36%
3 Pumps	18%	21%
4 Pumps	1%	6%

1 Pump - Curve
2 Pumps - Curve
3 Pumps - Curve
4 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
3 Pumps Rating Point
4 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
3 Pumps - Jan '21
4 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
3 Pumps - Aug '21
4 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency
3 Pumps - Efficiency
4 Pumps - Efficiency

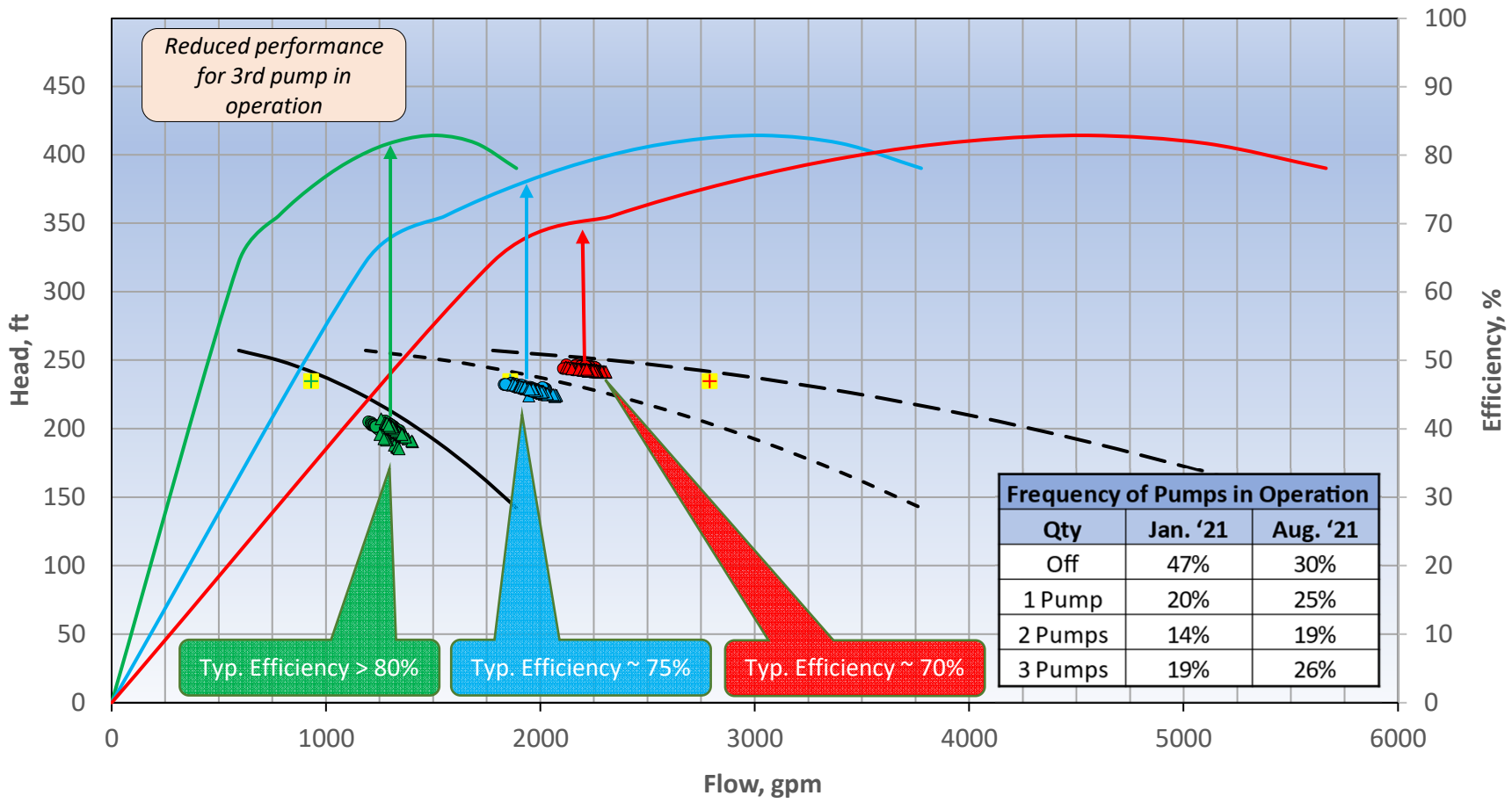
Pump Station Performance
PS30A



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	79%	65%
1 Pump	5%	6%
2 Pumps	2%	3%
3 Pumps	14%	26%

1 Pump - Curve
2 Pumps - Curve
3 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
3 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
3 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
3 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency
3 Pumps - Efficiency

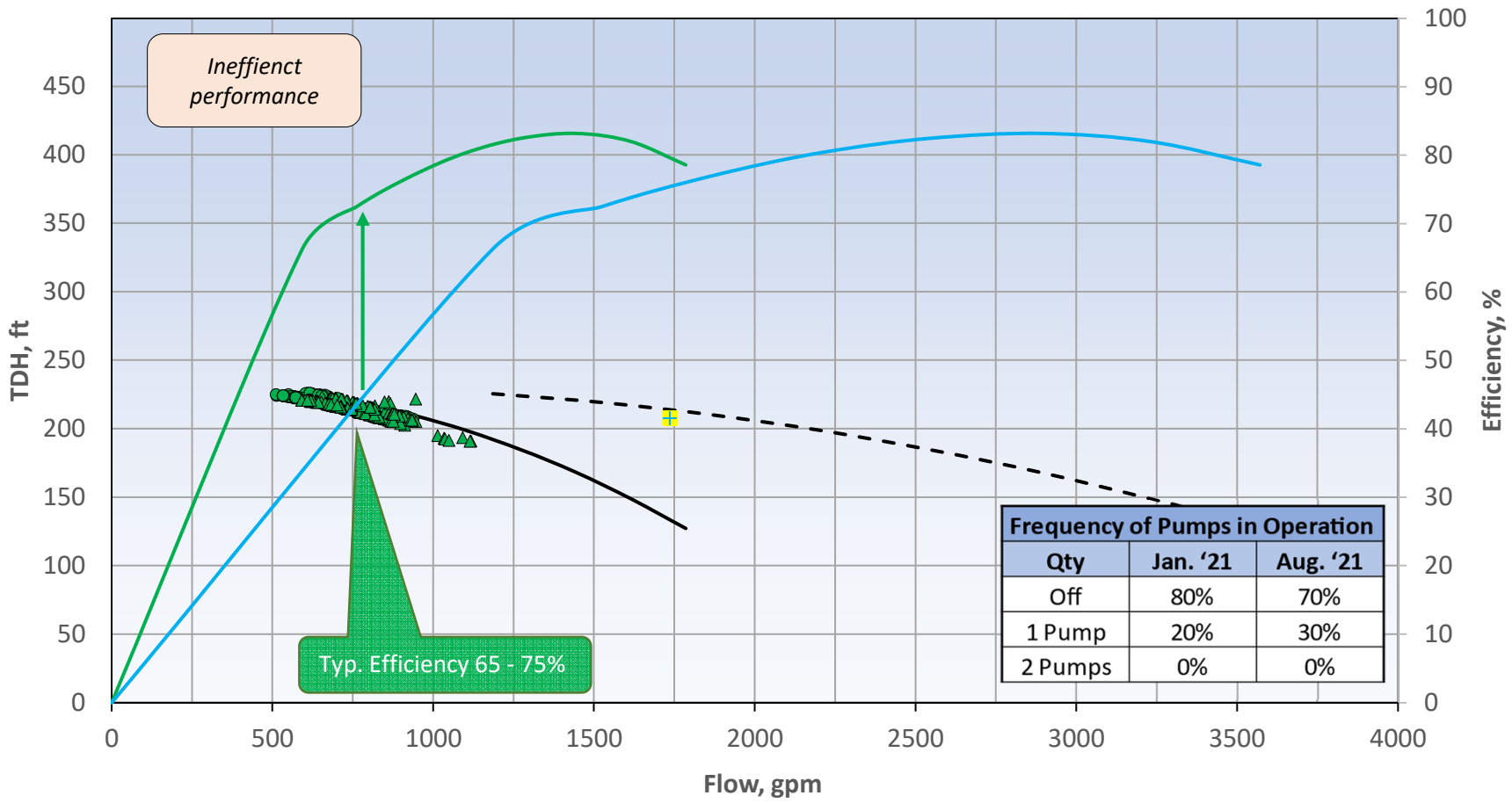
Pump Station Performance
PS200A



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	47%	30%
1 Pump	20%	25%
2 Pumps	14%	19%
3 Pumps	19%	26%

1 Pump - Curve
2 Pumps - Curve
3 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
3 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
3 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
3 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency
3 Pumps - Efficiency

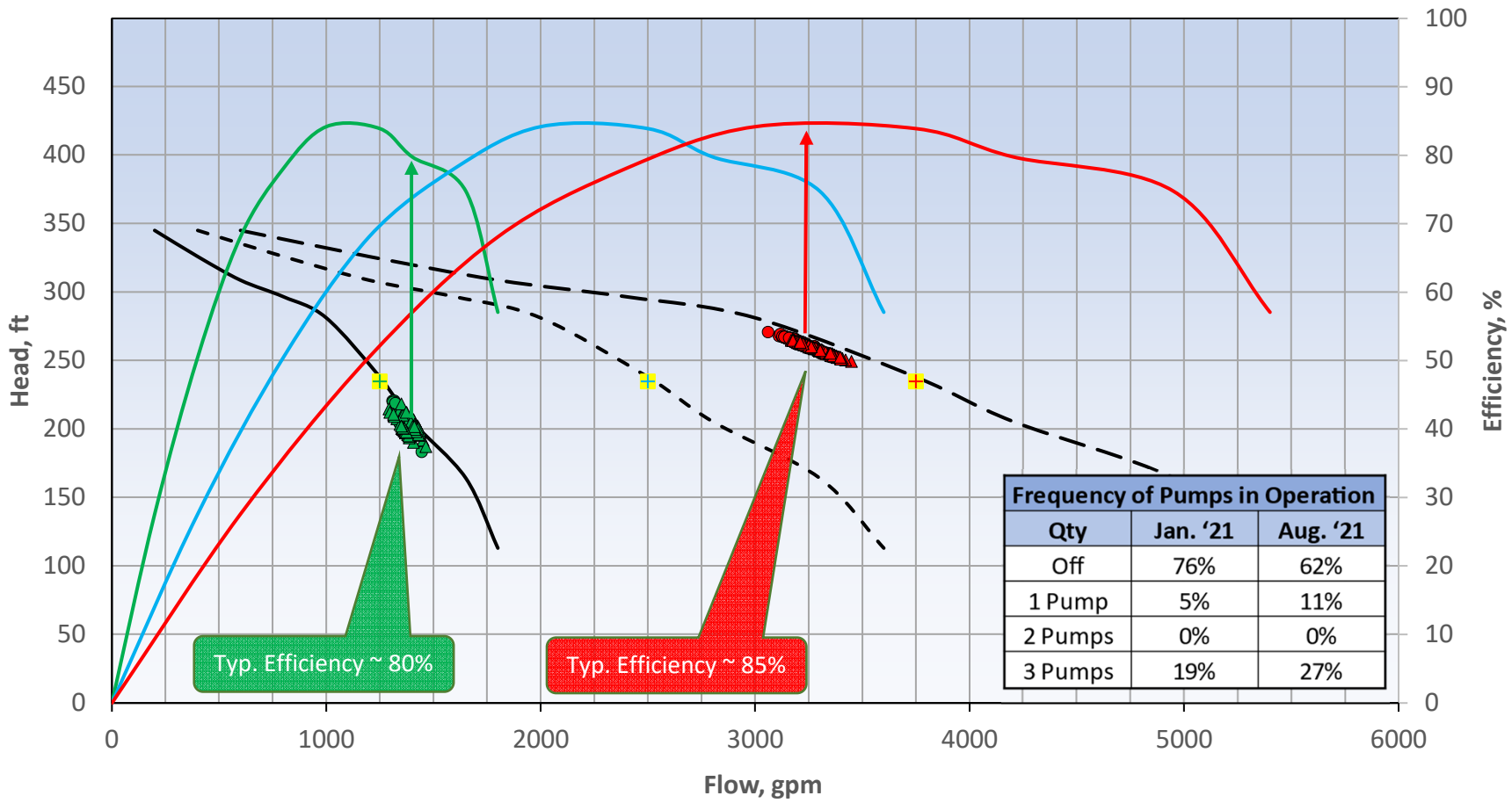
Pump Station Performance
PS300A



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	80%	70%
1 Pump	20%	30%
2 Pumps	0%	0%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

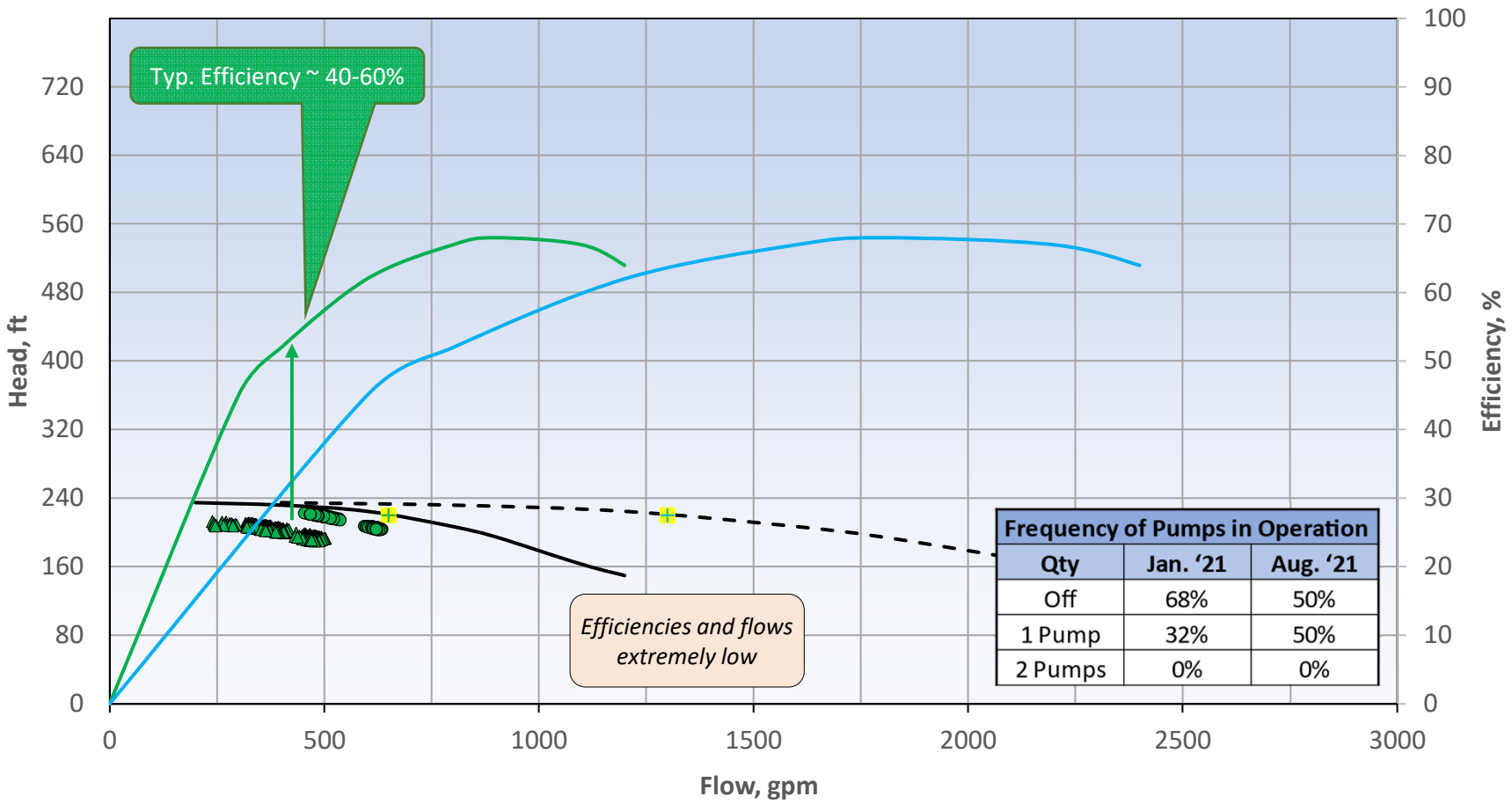
Pump Station Performance
PS300B



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	76%	62%
1 Pump	5%	11%
2 Pumps	0%	0%
3 Pumps	19%	27%

1 Pump - Curve
2 Pumps - Curve
3 Pumps - Curve
1 Pump Rating Point
2 Pumps Rating Point
3 Pumps Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
3 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
3 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency
3 Pumps - Efficiency

Pump Station Performance
PS300C



Frequency of Pumps in Operation		
Qty	Jan. '21	Aug. '21
Off	68%	50%
1 Pump	32%	50%
2 Pumps	0%	0%

1 Pump - Curve
2 Pumps - Curve
1 Pump Rating Point
2 Pump Rating Point
1 Pump - Jan '21
2 Pumps - Jan '21
1 Pump - Aug '21
2 Pumps - Aug '21
1 Pump - Efficiency
2 Pumps - Efficiency

Dublin San Ramon Services District
Water, wastewater, recycled water

Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 6
ENERGY GENERATION OPPORTUNITIES AND POWER SYSTEM RELIABILITY ASSESSMENT

FINAL | June 2024

carollo

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Abbreviations

AC	alternating current
BACT	best available control technology
BLG	building
BOD_5	biochemical oxygen demand
BS	solids stream
Carollo	Carollo Engineers
CEPT	chemically enhanced primary treatment
cf	cubic feet
CI	carbon intensity
CIP	capital improvements program
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
COP	coefficient of power
CPUC	California Public Utility Commission
DAFT	dissolved air flotation thickening
DC	direct current
DERWA	Dublin San Ramon Services District - East Bay Municipal Utility District Recycled Water Authority
DG	digester gas
DGS	Department of General Services
DLD	dedicated land disposal
DSRSD	Dublin San Ramon Services District
EERE	Office of Energy Efficiency and Renewable Energy
eRIN	electric renewable identification number
ES	energy storage
EV	electric vehicle
F	Fahrenheit
FOG	fats, oils, and grease
FSL	facultative sludge lagoon
FW	food waste
GBT	gravity belt thickener
GHG	greenhouse gas
gpd	gallons per day
gpm	gallons per minute
HOMER	hybrid optimization of multiple energy resources
HSW	high strength waste

ICE	internal combustion engine
IRA	Inflation Reduction Act
kW	kilowatt
kWh	kilowatt-hour
LAVWMA	Livermore-Amador Valley Water Management Agency
LCFS	low carbon fuel standard
Li-ion	lithium ion
LS	liquid storage
Lystek	Lystek International Ltd.
mg/L	milligrams per liter
MMBtu	million British thermal units
mph	miles per hour
MT	metric ton
MW	megawatt
MWh	megawatt hours
NEM	net energy metering
NG	natural gas
NOx	nitrogen oxides
NPV	net present value
NWS	National Weather Service
O&M	operations and maintenance
OMRC	Organic Material Recovery Center
PFAS	per- and polyfluoroalkyl substances
PG&E	Pacific Gas & Electric Company
PPA	power purchase agreement
PS	primary sludge
PV	photovoltaic
RDT	rotary drum thickener
RE	renewable energy
RES-BCT	Renewable Energy Self-Generation Bill Credit Transfer
RFS	renewable fuel standard
RIN	renewable identification number
RNG	renewable natural gas
ROI	return of investment
scfd	standard cubic feet per day
SCR	selective catalytic reduction
sf	Square feet
SGIP	self-generation incentive program
SOCWA	South Orange County Wastewater Authority

SRT	solids retention time
TH	thermal energy
TM	technical memorandum
TS	total solids
TSS	total suspended solids
VOC	volatile organic compound
WAS	waste activated sludge
WRRF	water resource recovery facility
WWTP	wastewater treatment plant

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Technical Memorandum 6

ENERGY GENERATION OPPORTUNITIES AND POWER SYSTEM RELIABILITY ASSESSMENT

6.1 Introduction

With its existing cogeneration system, Dublin San Ramon Services District (DSRSD) generates a substantial portion of DSRSD's Wastewater Treatment Plant's (WWTP) energy consumption onsite. Strategies to further increase, diversify, and maximize DSRSD's renewable energy production were identified in Technical Memorandum (TM) 2. The potential energy generation and energy storage opportunities that were identified for further evaluation in TM 2 are presented in Table 6.1 and are further discussed and evaluated in this TM. The feasibility and potential impacts of these opportunities are described in the sections below. The order in which they are presented does not in all cases match the table below as an effort was made to organize the TM such that related opportunities are grouped together. A summary of recommendations is included in Section 6.8.

Table 6.1 Overview of Energy Generation Opportunities Evaluated in This TM

Process Area	Opportunity ID	Opportunity Name
LS Treatment Process Energy Opportunities	LS-3	Improve Carbon Diversion from Primaries to Digester (CEPT)
BS Treatment Process Energy Opportunities	BS-2B	Mechanical Thickening Post-DAFT
	BS-2C	Mechanical Thickening in Lieu of DAFT
	BS-7	Recuperative Thickening
	BS-13	Dewatering Post Digestion
	BS-17	Drying and Pyrolysis
	BS-18	Drying and Gasification
	BS-22	Lystek Thermochemical Hydrolysis
	BS-23	Co-digest FOG
	BS-24	Co-digest FW Slurry and HSW
	BS-26	Improve Gas Conditioning System
	BS-28	Increase Biogas Storage
	BS-30	Replace Cogeneration with Similar Engines
	BS-31A	Replace Cogeneration with Higher Efficiency Engine Generators (1 x ICE 1.4 MW)
	BS-31B	Replace Cogeneration with Higher Efficiency Engine Generators (2 x ICE 700 kW)
	BS-34	Replace Cogeneration to Cover Peak Electricity Demand

Process Area	Opportunity ID	Opportunity Name
	BS-35	Increase Cogeneration to Cover Peak Electricity Demand and Redundancy
	BS-37	Condition Biogas for Pipeline Injection
BLG System Operations Optimization	BLG-12	Solar Thermal Heating
	BLG-13	Wastewater Thermal Energy Use for Heating and Cooling
RE Generation and Storage Opportunities	RE-1A	On-Site Solar Installation: Administration Building
	RE-1B	On-Site Solar Installation: Field Operations Facility
	RE-1C	On-Site Solar Installation: Solar Carports
	RE-2A	Off-Site Solar Installation: Gleason Property
	RE-2B	Off-Site Solar Installation: LAVWMA Full Area of Basins
	RE-2C	Off-Site Solar Installation: LAVWMA Edges of Basins
	RE-2D	Off-Site Solar Installation: Solar Carports Park N Ride Pleasanton
	RE-3	Off-Site Solar Installation: Gleason Property
	RE-4	Solar Power for EV Fleet Recharging Stations
	RE-5	On-Site or Off-Site Wind Energy
	RE-7	Renewable Energy Generation Partnerships
	RE-8	Green Power Purchasing
ES Opportunities	ES-1	Battery Storage and Microgrid System Installation
	ES-2	Battery Storage for Peak Demand Charges
TH Recovery Opportunities	TH-4	Expand Heat Loop
	TH-5	Use Heat for Process Needs
	TH-7	Use Heat for Advanced Biosolids Processing

Notes:
BLG - building; BS - solids stream; CEPT - chemically enhanced primary treatment; DAFT - dissolved air flotation thickening; ES - energy storage; EV - electric vehicle; FOG - fats, oils, and grease; FW - food waste; HSW - high strength waste; ICE - internal combustion engine; LAVWMA - Livermore-Amador Valley Water Management Agency; LS - liquid stream; Lystek - Lystek International Ltd.; MW - megawatt; RE - renewable energy; TH - thermal energy.

6.2 Objectives

This TM evaluates technologies, strategies, and opportunities for energy generation for DSRSD. This evaluation considers existing and forthcoming federal and state level regulations, initiatives, and incentives. Pertinent drivers primarily relate to greenhouse gas (GHG) emissions reduction targets that aim to reduce fossil energy consumption and improve energy efficiency to achieve statewide carbon neutrality by 2045 in California.

The GHG emission impacts of the opportunities discussed in this TM are presented in TM 7.

6.3 Wastewater Treatment Plant Opportunities

6.3.1 Liquid Stream Treatment Process Energy Opportunities

6.3.1.1 Improve Carbon Diversion from Primaries to Digester (LS-3)

DSRSD is currently using conventional primary clarification to remove solids and organics upstream of the aeration basins. Figure 6.1 shows the biochemical oxygen demand (BOD_5) and total suspended solids (TSS) removal in the primary clarifiers between 2016 and 2022. Prior to June 2019 the BOD_5 and TSS removal was about 30 to 40 percent. The clarification efficiency was noticeably increased in 2019 and again stabilized in 2021 when the fifth primary clarifier was brought online. From 2021, the BOD_5 and TSS removal in the primaries is approximately 50 percent and 60 percent, respectively.

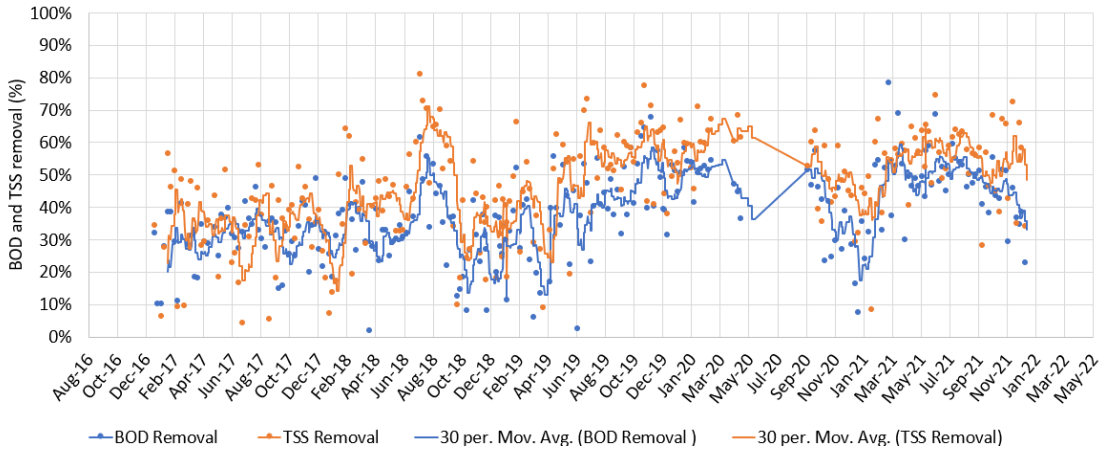


Figure 6.1 Primary Clarifier BOD_5 and TSS Removal (2016 to 2023)

Advanced primary treatment can increase the BOD_5 removed in primary treatment. Technologies that can achieve this include CEPT, or primary filtration (with or without biological treatment). Figure 6.2 provides typical ranges for BOD_5 and TSS removal in different enhanced primary treatment processes and compares these to the process with highest carbon diversion to anaerobic digestion (i.e., diversion of primary sludge [PS]) – anaerobic mainstream treatment (a process technology that is not yet demonstrated at full scale).

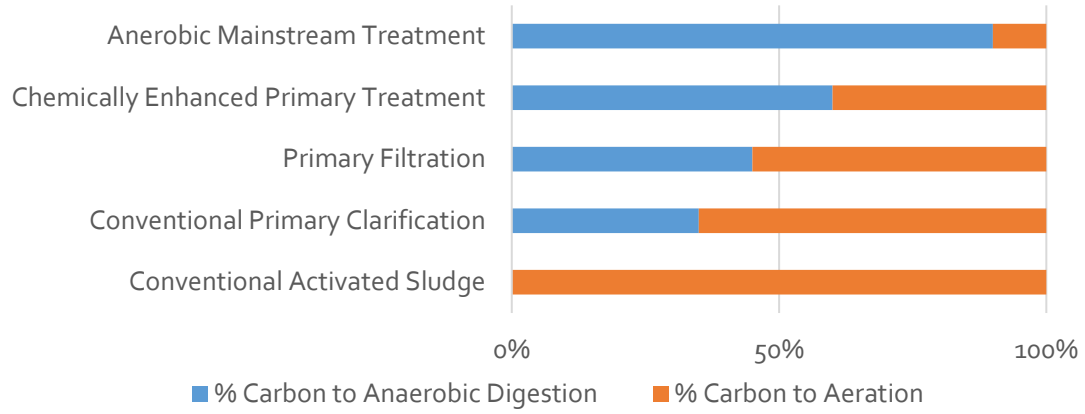


Figure 6.2 BOD_5 and TSS Removal in Various Enhanced Primary Treatment Processes

Primary filtration has the following advantages over primary clarifiers:

- 60 to 90 percent TSS removal, instead of 0 to 60 percent in clarifiers.
- 80 percent footprint reduction over primary clarifiers.
- 10 to 25 percent aeration energy reduction due to carbon diversion.
- 10 to 25 percent additional capacity provided in existing secondary treatment.
- 20 to 30 percent increase in gas production.

Several enhanced primary treatment filtration processes can achieve approximately 90 percent BOD_5 removal. This carbon can be diverted to the anaerobic digesters to recover additional biogas. In addition, lowering the secondary influent organic load significantly lowers the blower air demand and increases existing secondary treatment capacity. DSRSD does not have to remove nitrogen and phosphorus so a carbon limitation in the secondary process for nutrient removal is currently not a concern.

Enhanced primary treatment can be implemented into DSRSD's current process configuration in different ways:

1. Integrating CEPT upstream of the existing primary clarifiers.
2. Primary clarifiers are replaced with primary filters.
3. Primary filters are retrofitted into the existing primary clarifiers (the footprint of the filters is a fraction of conventional clarifiers at the same treatment capacity.
4. Integrating primary filtration downstream of the primary clarifiers (and repurposing the primary clarifiers, e.g., to flow equalization basins).

There are several established technology options for treatment of raw wastewater available on the United States market at this time. Among these:

- Micro screen (Huber Technology).
- Primary filtration with or without biological treatment (Tomorrow Water, Proteus filter).
- Cloth Media Filtration (Aqua-Aerobics Systems).
- Fuzzy filter (Schreiber LLC).

DSRSD has recently conducted an evaluation of whether CEPT should be used in the primary treatment expansion project that was completed in 2021. DSRSD decided at that time against implementing CEPT although enhanced primary treatment may be considered at a later date. Reference *Primary Sedimentation Expansion and Improvements Project Preliminary Design Report* dated January 2019 by West Yost Associates for additional information. Besides energy considerations there are currently no other reasons to consider this capital improvement. For these reasons, Carollo Engineers (Carollo) did not develop cost estimates for this option at this time.

Recommendation: DSRSD should keep enhanced primary treatment as a potential future option in mind, since it brings notable energy benefits in case other drivers become relevant (e.g., secondary treatment capacity limitations).

6.3.2 Solids Stream Treatment Process Energy Opportunities

The major source of GHG emissions at the WWTP is from natural gas (NG) combustion in the cogeneration engines. Increasing biogas production through co-digestion of FOG and FW slurry can reduce NG use by the engines. For co-digestion to be viable, DSRSD needs sufficient

anaerobic digestion capacity to accommodate the increase in flows and loads from FOG and FW slurry.

Carollo evaluated DSRSD's anaerobic digestion capacity and identified that, given the current influent flow and load projections and a DAFT thickened PS and waste activated sludge (WAS) total solids (TS) concentration average of 4 percent, the digesters would become capacity limited in 2046, within the planning period of this Energy Facilities Master Plan, assuming DSRSD will not accept any FOG or FW slurry for co-digestion. This digestion capacity was evaluated for two scenarios:

1. At annual average digester feed flows with one of the larger digesters out of service.
2. At maximum month digester feed flows with all digesters in service.

Scenario 1 (annual average digester feed flows with one digester out of service) was capacity limiting. The analysis indicates that with one of the larger digesters out of service (anaerobic digester nos. 3 or 4), the WWTP would become hydraulically limited in 2046, meaning the solids retention time (SRT) would be less than the 15 days, the time required to produce Class B biosolids.

This hydraulic limitation could be overcome by improving the thickening of PS and WAS upstream of the digesters. Alternative thickening technologies, including mechanical thickening and recuperative thickening, would create additional digestion capacity to accommodate FOG and FW co-digestion, as described below:

- Mechanical thickening (Opportunities BS-2B and BS-2C) is expected to increase the digester feed solids concentration to 6 percent TS, which would allow DSRSD to receive 33,000 gallons per day of FW slurry and 15,000 gallons per day of FOG, 5 days a week. The BS-2B/C co-digestion quantities are limited by the hydraulic capacity of the digesters.
- Recuperative thickening (Opportunity BS-7) is expected to increase the digester feed solids concentration to 11 percent TS, which would allow DSRSD to receive 41,000 gallons per day of FW slurry and 15,000 gallons per day of FOG, 5 days a week. The BS-7 co-digestion quantities are limited by a recommended maximum FW volatile solids ratio for stable digester operation of 45 percent.

6.3.2.1 Mechanical Thickening Post-DAFT (BS-2B) and Mechanical Thickening in Lieu of DAFT (BS-2C)

Several options exist for improving thickening performance. PS could be separately thickened using, for example, gravity thickeners, while WAS could be separately mechanical thickened, or co-thickened with PS. Mechanical thickening is evaluated here in addition to DAFT (BS-2B) and as an alternative to DAFT (BS-2C), to increase the solids concentration fed to the digesters and their hydraulic capacity.

An initial screening of three mechanical thickening alternatives was conducted to identify the best fit for DSRSD. This screening included a) gravity belt thickeners (GBT), b) rotary drum thickeners (RDT), and c) thickening centrifuges. Carollo contacted manufacturers to determine the number of units required, sizing, and cost information.

Currently, DSRSD wastes WAS as mixed liquor from the aeration basins rather than the secondary clarifiers, resulting in a WAS solids concentration of about 0.1 percent TS. The

combined PS and WAS DAFT-feed concentration is currently approximately 0.2 percent TS (2,000 milligrams per liter [mg/L]).

In the planning design year (2046) the combined PS and WAS flow to thickening, assuming that mechanical thickening would replace DAFT and the DSRSD continues mixed liquor wasting, is projected to be 1,815 gallons per minute (gpm). This would require 2 duty GBTs, 3 duty RDTs, or 1 duty centrifuge. Of these three technologies, Carollo considers RDTs to be the best fit for DSRSD given their lower operating energy usage compared to centrifuges and their lower energy usage for odor control compared to GBTs. GBTs are open to the atmosphere thus requiring odor control for the whole building in which the GBTs are housed, while RDTs can be enclosed which limits odor control to the air inside the units. Note that odor control is a substantial energy consumption for GBT facilities.

Several of the thickening technology manufacturers expressed concern over the thin PS and WAS feed concentration of 0.2 percent TS and noted that the thickening equipment may not be able to produce a target concentration of 6 percent TS thickened sludge (needed to provide sufficient capacity for allowing co-digestion and PS and WAS digestion through 2046).

A more energy-efficient option for DSRSD, briefly discussed in TM 5, would be to convert in the future to wasting WAS from the secondary clarifier return activated sludge, at a concentration of 0.35 percent TS. This would reduce process pumping and would require some additional instrumentation TSS probe and a flow meter on the WAS line to maintain the same level of SRT control. Wasting WAS from the return activated sludge line would reduce the flow to thickening from 1,815 gpm to 666 gpm, which would reduce the number of duty RDTs required from 3 to 2. Due to the energy benefits of eliminating the DAFT process, this option is further evaluated here as Opportunity BS-2C.

Another option briefly discussed in TM 5 includes retaining the current DAFT to thicken to 4 percent TS and adding mechanical thickening downstream to further thicken to 6 percent TS. Note that within the digesters, the concentration would only be about 3 percent TS due to volatile solids reduction. The flow to mechanical thickening would be reduced to 100 gpm, substantially reducing the capacity and capital costs of the mechanical thickening facility. Only one RDT would be needed. This option would not reduce but increase the energy consumption of the thickening process since it adds an additional mechanical thickening process post-DAFT. Due to the potentially low capital cost, this option is further evaluated here as BS-2B, while noting that Carollo recommends a detailed process and design evaluation in the future as sequencing two thickening processes is not a common configuration.

The construction cost, operation and maintenance (O&M) cost, and energy impact of Opportunity BS-2B, Mechanical Thickening Post-DAFT, are summarized in Table 6.2. The capital cost estimate includes two RDTs (one duty and one standby), a polymer feed system, two thickening feed pumps, and two new digester feed pumps capable of handling the higher solids thickness. The capital cost assumes that the RTDs would be located on a new concrete pad with a shade structure and includes odor control for the RDTs.

Table 6.2 BS-2B Mechanical Thickening Post-DAFT Cost Estimate and Energy Impacts

Parameter	Mechanical Thickening	Notes
Construction Cost ($)	5,600,000	Does not include escalation, engineering, construction management, and engineering support during construction.
O&M Cost ($/year)	392,000	Average of 20-year life-cycle period, assumed to be from 2027 to 2046.
Energy Use (kWh/year)	72,000	Average of 20-year life-cycle period.
Potential Increase in Biogas Production from Co-digestion (scfd)	279,000 (146,000 from FOG + 133,000 from FW)	Average of 20-year life-cycle period. Based on 33,000 gpd of FW slurry at 5 percent TS and 15,000 gpd of FOG; 5 days/week.

Notes:
gpd - gallons per day; kWh - kilowatt-hour; scfd - standard cubic feet per day.

The O&M cost includes costs for power usage for the RDTs and ancillary equipment as well as odor control blowers, equipment maintenance, O&M labor, and polymer consumption. While this opportunity does not in itself produce energy, it produces additional digestion capacity which is needed for co-digestion (described below as opportunities BS-23 and BS-24). The potential increase in biogas production assumes the digesters would receive 15,000 gpd of FOG and 33,000 gpd of FW slurry at 5 percent TS. With the additional biogas from co-digestion, the biogas production would approximately double, which would substantially reduce or possibly even eliminate NG used in cogeneration.

Carollo does not recommend including this Opportunity BS-2B in DSRSD's Capital Improvements Program (CIP). The DAFT system is estimated to use 1,535,000 kWh/year and cost $1,093,000 per year to operate and maintain. Adding mechanical thickening, post-DAFT, would increase energy consumption and O&M costs by an additional 72,000 kWh/year and $392,000 per year, respectively.

The construction cost, O&M cost, and energy impact of Opportunity BS-2C, Mechanical Thickening in lieu of DAFT (with return activated sludge wasting), are summarized in Table 6.3. The capital cost estimate includes three RDTs (two duty and one standby), a polymer feed system, two thickening feed pumps, and two new digester feed pumps capable of handling the higher solids thickness. The capital cost assumes that the RDTs would be located on a new concrete pad with a shade structure and includes odor control for the RDTs.

Table 6.3 BS-2C Mechanical Thickening In Lieu of DAFT Cost Estimate and Energy Impacts

Parameter	Mechanical Thickening	Notes
Construction Cost ($)	$20,500,000	Does not include escalation, engineering, construction management, and engineering support during construction.
O&M Cost ($/year)	$462,000 for mechanical thickening minus $1,093,000 for DAFT = -$630,000	Average of 20-year life-cycle period, assumed to be from 2027 to 2046.

Parameter	Mechanical Thickening	Notes
Energy Use (kWh/year)	90,000 for mechanical thickening minus 1,535,000 for DAFT = -$1,440,000	Average of 20-year life-cycle period.
Potential Increase in Biogas Production from Co-digestion (scfd)	279,000 (146,000 from FOG + 133,000 from FW)	Average of 20-year life-cycle period. Based on 33,000 gpd of FW slurry at 5 percent TS and 15,000 gpd of FOG; 5 days per week.

The O&M cost includes costs for power usage for the RDTs and ancillary equipment as well as odor control blowers, equipment maintenance, O&M labor, and polymer consumption. Since this opportunity would eliminate the DAFT operations, it results in an overall net reduction in O&M costs and power usage. While this opportunity does not in itself produce energy, it produces additional digestion capacity which is needed for co-digestion (described below as opportunities BS-23 and BS-24).

The potential increase in biogas production assumes the digesters would receive 15,000 gpd of FOG and 33,000 gpd of FW slurry at 5 percent TS. With the additional biogas from co-digestion, the biogas production would approximately double, which would substantially reduce or possibly even eliminate NG used in cogeneration. Detailed cost breakdowns are presented in Appendix 6A.

Recommendation: DSRSD should include Opportunity BS-2C in DSRSD's CIP for year 2036. The DAFT mechanical and structural asset is anticipated to be replaced in about 10 years as it is approaching its end-of-useful life. In addition, this would increase the digestion capacity and address the digestion capacity limitations which would occur in 2046 (without FOG and FW) and in 2036 if 15,000 gpd of FOG are added. At this time Carollo recommends replacing DAFT with mechanical thickening, specifically RDTs, which will substantially reduce energy consumption for the thickening process and increase anaerobic digestion capacity, allowing DSRSD to co-digest FOG and FW if desired.

Note that this technological change will need to be combined with plant modifications to allow wasting of solids from the return activated sludge line (instead of mixed liquor wasting practiced currently).

6.3.2.2 Recuperative Thickening (BS-7)

Recuperative thickening is another option for increasing the solids concentration in the digesters, thus substantially increasing the capacity of the existing digesters and DSRSD's ability to co-digest FOG and FW.

Recuperative thickening allows digesters to maintain the digested sludge at approximately 5 percent TS. To do this, the digested sludge is thickened to approximately 11 percent TS and returned to the digesters. This option involves the addition of two new sludge screw thickeners that could be installed on a new concrete pad with shade cover. Each sludge screw thickener pad includes feed and discharge pumps, polymer feed system, and filtrate drain piping to a new pump station.

With the thicker digested sludge, positive displacement pumps are needed for all pumping applications, including sludge heating and recirculation. Special high-torque, low-speed mixers must also be installed in the digesters (two per digester) to handle the higher solids concentration in the digesters. The process also requires replacing the existing heat exchangers with high-pressure stainless-steel tube-in-tube heat exchangers to accommodate the high solids concentrations.

The construction cost, O&M cost, and energy impact of BS-7 are summarized in Table 6.4. The O&M cost includes costs for power usage for the sludge screw thickeners and ancillary equipment, new digester mixers, and odor control blowers, equipment maintenance, O&M labor, and polymer consumption. While this opportunity does not in itself produce energy, it produces additional digestion capacity which is needed for co-digestion (described below as opportunities BS-23 and BS-24). The potential increase in biogas production assumes the digesters would receive 15,000 gpd of FOG and 41,000 gpd of FW slurry at 5 percent TS. Note that the FW quantity for this opportunity is higher than that for BS2-B/C. This is because recuperative thickening would increase the digester feed to 11 percent TS, which would increase the digestion capacity more than BS2-B/C, which thicken the digester feed to 6 percent TS. With the additional biogas from co-digestion, the biogas production would approximately double, which would substantially reduce or possibly even eliminate NG used in cogeneration. A detailed cost breakdown is presented in Appendix 6A for this alternative.

Table 6.4 BS-7 Recuperative Thickening Cost Estimate and Energy Impacts

Parameter	Recuperative Thickening	Notes
Construction Cost	$22,200,000	Does not include escalation, engineering, construction management, and engineering support during construction.
O&M Cost ($/year)	$799,000	Average of 20-year life-cycle period, assumed to be from 2027 to 2046.
Energy Use (kWh/year)	774,000	Average of 20-year life-cycle period. Digestion mixers power use was calculated as the difference between the new mixers and the existing mixers.
Potential Increase in Biogas Production from Co-digestion (scfd)	311,000 (146,000 from FOG + 165,000 from FW)	Average of 20-year life-cycle period. Based on 41,000 gpd of FW slurry at 5 percent TS and 15,000 gpd of FOG; 5 days per week.

Recommendation: Carollo does not recommend including Opportunity BS-7 at this time into DSRSD's CIP. Recuperative thickening would further increase the energy demand of the digestion process.

When DSRSD experiences capacity limitations in the anaerobic digesters at some point in the future, conversion from DAFT to mechanical thickening (Opportunity BS-2C) is a more favorable option.

6.3.2.3 Dewatering Post Digestion (BS-13)

Digested sludge is currently sent to facultative sludge lagoons (FSL) for dewatering and further stabilization before being injected via dedicated land disposal (DLD). Opportunity BS-13 involves construction of a new dewatering facility which would include new dewatering facilities and ancillary equipment installed in a new building, cake storage silos, and a new cake loadout bay for truck loading and offsite hauling.

Digested sludge would be pumped to the new dewatering facility assumed to be operated 24 hours per day, 5 days per week. Dewatering recycle streams would be pumped back to the headworks. Cake would be stored in silos and then loaded onto trucks for third-party hauling and land application.

This opportunity would increase DSRSD's energy consumption through mechanical dewatering. However, mechanical dewatering can provide substantial environmental and GHG emissions benefits by beneficially reusing Class B cake providing carbon sequestration and GHG offsets through fertilizer generation.

Carollo conducted an initial screening of three dewatering alternatives to identify the best technology fit for DSRSD. This screening involved contacting manufacturers of a) belt filter presses, b) screw presses, and c) centrifuges. Manufacturers provided input to determine the sizing, number of units, sizing, and conceptual cost estimates. The digestate solid load projections for mechanical dewatering in the planning design year 2046 would be 1,271 pounds per day. This would require 1 duty unit of any of the three technologies considered. Carollo deems screw presses to be the best fit for dewatering at DSRSD given their lower operational energy usage compared to centrifuges and lower odor control energy usage compared to belt filter presses.

With year-round mechanical dewatering, DSRSD would no longer need to operate the FSLs and DLDs. This provides an opportunity for repurposing or selling this land. For example, DSRSD may consider using the land for a new large-scale solar facility. Selling the land would provide substantial revenue given. Revenue from land sales and income from repurposing this land are not included in this analysis.

The construction cost, O&M cost, and energy impact of BS-13 are summarized in Table 6.5 and compared to the existing FSL and DLD operational costs and energy use. The capital cost estimate includes costs for two screw presses (one duty and one standby) and their ancillary equipment (which includes two feed pumps, a polymer feed system, and a polymer flocculation tank), a bridge crane for screw press maintenance, a cake storage silo and its associated conveyors, a truck scale, and odor control system. The capital cost includes costs for a new concrete masonry unit building and truck load-out bay. The O&M cost includes costs for power usage for the screw presses and ancillary equipment as well as odor control blowers, equipment maintenance, O&M labor, polymer consumption, and third-party Class B cake hauling and land application. A detailed cost breakdown for this alternative is presented in Appendix 6A.

Table 6.5 BS-13 Dewatering Post Digestion Cost Estimate and Energy Impacts

Parameter	Dewatering + Class B Land Application	FSL and DLDs	Net Impacts
Construction Cost ($)[1]	$43,000,000	N/A	$43,000,000
O&M Cost ($/year)[2]	$1,020,000 for dewatering + $1,890,000 for cake hauling and land application = $3,930,000	$820,000	$3,110,000
Energy Use (kWh/year)[2]	186,000	172,000 kWh/year 3,300 gallons/year of diesel	14,000 kWh/year -3,300 gallons/year of diesel

Notes:
(1) Does not include escalation, engineering, construction management, and engineering support during construction.
(2) Average of 20-year life-cycle period, assumed to be from 2027 to 2046.

Recommendation: Dewatering is not recommended since DSRSD does not have a driver to convert to mechanical dewatering in the foreseeable future. However, if hydraulic capacity limitations in the FSL's are a driver, dewatering alternatives should be considered but not as an energy savings alternative.

6.3.2.4 Drying and Pyrolysis (BS-17)

This opportunity involves construction of new dewatering, drying, and pyrolysis facilities for solids management. Many utilities are interested in pyrolysis as an emerging technology with potential to eliminate per- and polyfluoroalkyl substances (PFAS) from wastewater solids. Currently, pyrolysis is one of the few biosolids processes that indicates effective removal of PFAS from the end products.

BioForceTech Corporation, a commercial supplier of pyrolysis, monitored 38 PFAS compounds in the dried product feed to their pyrolysis process and in the final biochar product. None of the PFAS were detected in the biochar product. Note that these results represent a subset of the over 9,000 different PFAS compounds that exist. High temperature in the pyrolysis reactors breaks down the PFAS compounds into smaller compounds that likely become airborne with unknown characteristics and toxicity. To remove PFAS from the exhaust air, the pyrolysis process includes a regenerative thermal oxidizer that operates at temperatures above 1,650 degrees Fahrenheit (F). This process is currently the most developed and best suited to address potential future PFAS regulatory requirements in biosolids and air emissions.

The pyrolysis process receives a dried product with a solids content of at least 75 percent TS. The pyrolysis reactors operate between 660 degrees Fahrenheit (°F) and 1,650 degrees F without supplemental oxygen. The lack of oxygen results in the thermochemical decomposition of organic material, rather than combustion. The process produces biochar and syngas. The syngas produced in the pyrolysis process is typically used to run the dryer, reducing and sometimes completely eliminating the dryer's NG use. The biochar can be beneficially used as a soil amendment and fertilizer or other more specialized applications such as biosolids-based inks and plastics, animal feed, filtration media, or as an adder for concrete as an alternative to fly ash.

While pyrolysis is a well-established technology, its application in processing wastewater solids is relatively new. The first wastewater solids pyrolysis installation in the United States occurred at the Silicon Valley Clean Water WWTP in Redwood City, California, in 2017. This installation uses

BioForceTech biodrying and pyrolysis technology. Since then, BioForceTech has added five more installations to their reference list, one operational, two in manufacturing, and two in planning. The second operational facility is a small facility serving a hotel in Washington state.

There are two other pyrolysis equipment suppliers that offer this technology for wastewater solids as feedstock: CHAR Technologies and Anaergia. Neither of these technology suppliers have any installations to date processing only wastewater solids. CHAR Technologies has a reference facility in Canada which was completed in 2018 and processes a mix of organic waste digestate, wastewater solids, compost, and wood chips. Anaergia has plans to add drying and dewatering to their organic waste-to-energy facility in Rialto, California.

Table 6.6 summarizes the construction cost, O&M cost, and energy impacts of opportunity BS-17. Carollo recently conducted a cost estimate for a San Francisco Bay Area utility of similar size as DSRSD. The construction cost for the drying and pyrolysis facilities was approximately $40 million in 2022 dollars and the O&M cost was approximately $1 million per year. Since the District would also need to add a dewatering facility upstream of drying, the total capital cost would be approximately $83 million.

Table 6.6 BS-17 Drying and Pyrolysis Cost Estimate and Energy Impacts

Parameter	Drying and Pyrolysis	Notes
Construction Cost	$40,000,000 for drying and pyrolysis + $43,000,000 for dewatering = $83,000,000	Does not include escalation, engineering, construction management, and engineering support during construction.
O&M Cost ($/year)	$1,000,000 for drying and pyrolysis + $1,020,000 for dewatering = $2,020,000	Average of 20-year life-cycle period, assumed to be from 2027 to 2046.
Energy Use (kWh/year)	186,000 for dewatering	Average of 20-year life-cycle period. Additional energy use for drying and pyrolysis was not estimated since this opportunity is not recommended.

The energy and GHG impacts of this opportunity would be relatively minor (see TM 7 for details on the GHG impacts). Although NG may not be needed, the drying and pyrolysis facilities would use electricity and may require a centrifuge dewatering facility, which would also increase the energy use of the dewatering facility. The biochar can be used as an agricultural fertilizer, providing soil stabilization and carbon sequestration benefits. The carbon sequestration credits would be similar to those of Class B cake generation (Opportunity BS-13).

Recommendation: Since this technology has only one installation in the United States processing wastewater solids, a high capital and O&M cost, and minimal to negative energy benefits, Carollo does not recommend this technology for implementation in DSRSD's CIP currently. Unless DSRSD is required in the future to remove PFAS from biosolids prior to beneficial end use or disposal, Carollo does not recommend further consideration of this opportunity.

6.3.2.5 Drying and Gasification (BS-18)

Gasification of dried biosolids is another technology for eliminating PFAS from solids while recovering resources in the form of biochar and syngas.

This opportunity involves construction of new dewatering, drying, and gasification facilities. In gasification systems, a controlled amount of air or oxygen is added to produce an "oxygen-starved" environment. The syngas produced in the gasification process is typically used to run the dryer, reducing or sometimes eliminating the dryer's NG use.

There is currently only one active equipment supplier in the United States serving the wastewater solids market: Aries Clean Technologies. Aries has a reference facility in New Jersey that became operational in 2021 and processes wastewater solids. Compared to pyrolysis, gasification of wastewater solids is even less well-established.

The cost of a gasification system is expected to be in a similar range as the estimates provided for Opportunity BS-17, pyrolysis (see Table 6.6). The energy and GHG benefits are estimated to be similar to those of BS-17 as well.

Recommendation: Similar to the recommendation for BS-17, Carollo does not recommend this technology for further consideration by DSRSD at this time, given that this technology is even less established than pyrolysis in the United States, has high capital and O&M costs, and minimal to negative energy benefits. DSRSD could consider gasification as a possible alternative if PFAS treatment for biosolids becomes a requirement in the future.

6.3.2.6 Lystek International Ltd. Thermochemical Hydrolysis (BS-22)

Post-digestion thermo-chemical hydrolysis is a process that uses a caustic chemical, relatively low temperature (compared to other biosolids processes), and high shear mixing to produce a Class A liquid fertilizer.

Lystek owns and operates the Organic Material Recovery Center (OMRC) at the Fairfield-Suisun Sewer District in Solano County, California. The OMRC currently serves more than ten utilities and has a total capacity of 150,000 wet tons per year. They currently have sufficient spare capacity to process biosolids from DSRSD. DSRSD could contract with haulers to transport dewatered cake to the OMRC. Lystek would then be responsible for the treatment, distribution, and handling of the end-product, referred to as LysteGro. Lystek works with applicator contractors within a roughly 20-mile radius of the OMRC to inject LysteGro into the subsurface using conventional liquid manure handling equipment, most commonly on annual field crops.

For DSRSD this alternative would require construction of a dewatering and cake load-out facility as described above for BS-13. Similar to BS-13, the FSLs and DLDs would no longer be needed and could be decommissioned. Dewatered cake would then be transported to Lystek's processing facility. There, the dewatered cake is sent into storage hoppers where it is diluted to between 16 and 18 percent TS before being fed into the thermo-chemical hydrolysis process reactors. The reactors are fed with low-pressure steam and either caustic potash or caustic soda. A mechanical blade in the reactor mixes and shears the hydrolyzed solids. The reactors operate for 30 minutes at 175 degrees F, with a pH between 9.5 and 10. The result is a homogenized pumpable liquid product with a solids concentration up to 16 percent TS.

Lystek has obtained certifications for their product in Solano County, California, and is actively seeking certification in other California counties. The product is currently certified as a licensed

fertilizer by the California Department of Food and Agriculture. In Solano County, the product is managed as a fertilizer rather than as a biosolids product.

The construction cost, O&M cost, and energy impact of BS-22 are summarized in Table 6.7. A detailed cost breakdown is presented in Appendix 6A.

Table 6.7 BS-22 Lystek Thermochemical Hydrolysis Cost Estimate and Energy Impacts

Parameter	Dewatering + Lystek	FSLs and DLDs	Net Impact
Construction Cost ($)	$43,000,000	N/A	$43,000,000
O&M Cost ($/year)	$1,030,000,000 for dewatering + $3,540,000 for cake hauling, Lystek treatment, and land application = 4,560,000	820,000	$3,740,000
Energy Use (kWh/year)	170,000	172,000 kWh/year 3,300 gallons/year of diesel	14,000 kWh/year -3,300 gallons/year of diesel

Notes:
(1) Does not include escalation, engineering, construction management, and engineering support during construction.
(2) Average of 20-year life-cycle period, assumed to be from 2027 to 2046.

Recommendation: Because the cost for Lystek hauling, treatment, and land application is more than double the cost of third-party Class B cake hauling and land application (Opportunity BS-13), Carollo does not recommend pursuing this alternative further. DSRSD could reconsider this option if / when DSRSD converts to mechanical dewatering.

6.3.2.7 Co-digest Fats, Oils, and Grease (BS-23)

This opportunity involves co-digesting 15,000 gpd of FOG. This FOG quantity assumed in this analysis was adopted from previous evaluations conducted by DSRSD. This quantity allows for one day of FOG storage in the 15,000-gallon FOG storage tank. (Since FOG would only be received 5 days a week, FOG storage is important to provide a more consistent feed to the digesters which improves digester stability and evens out biogas production.) A FOG market analysis was not included in this evaluation.

FOG co-digestion requires sufficient anaerobic digestion capacity. As described in Opportunities BS-2B and BS-2C above, the anaerobic digesters are anticipated to reach their hydraulic capacity within the planning period by 2046 of this Energy Facilities Master Plan for PS and WAS. To increase anaerobic digestion capacity while accommodating co-digestion, DSRSD could implement Opportunity BS-2B, BS-2C, or BS-7 described above. Of these options, however, Carollo recommends that DSRSD only consider BS-2C.

The potential increase in biogas production assumes the digesters would receive 15,000 gpd of FOG; 5 days per week. This analysis assumes that DSRSD would use the additional biogas from FOG co-digestion to replace NG combustion in the cogeneration system and maintain the same cogeneration capacity. The additional biogas production from co-digestion is estimated to reduce the NG use in cogeneration by approximately one third to one half. Combined with FW co-digestion (Opportunity BS-24 described below), it could potentially eliminate NG use in the engines.

The O&M cost and energy impact of BS-23 are summarized in Table 6.8. The O&M costs include power usage, equipment maintenance, and O&M labor for the FOG receiving facility. A tipping fee for FOG receiving was not included but could help offset some of the O&M costs.

Table 6.8 BS-23 Co-digest FOG Cost Estimate and Energy Impacts

Parameter	FOG Co-digestion	Notes
Construction Cost	N/A	FOG receiving facility is already constructed.
O&M Cost ($/year)	$301,000	Average of 20-year life-cycle period, assumed to be from 2027 to 2046.
Cost Savings for NG Purchase ($/year)	($278,000)	Uses $8.4/MMBtu NG cost.
Energy Use (kWh/year)	114,000	Average of 20-year life-cycle period.
Increase in Biogas Production (scfd)	146,000	Average of 20-year life-cycle period.
Potential Decrease in Cogeneration NG Usage (therms/year)	(331,000)	Average of 20-year life-cycle period. Assumes FOG is received 5 days/week.

Notes:
MMBtu - million British thermal units.

Recommendation: DSRSD has already constructed all the necessary infrastructure for this alternative and plans to take the system into operation as soon as the permitting process is completed. Additional digestion capacity to accommodate 15,000 gpd of FOG could be needed by 2036. To provide additional digestion capacity, this opportunity needs to be paired with Opportunity BS-2C (mechanical thickening in lieu of DAFT). No further provisions need to be included in the CIP at this time.

6.3.2.8 Co-digest Food Waste Slurry and High Strength Waste (BS-24)

FW is another co-substrate DSRSD could use to increase the production of biogas and replace NG combustion in the cogen system.

This opportunity requires construction of a new FW slurry receiving facility. FW slurry is typically received at approximately 12 percent TS from trucks and pumped through a rock trap/macerator into a holding tank. From there, the slurry is pumped to a dilution tank where dilution water would be used to reduce the solids concentration to 5 percent TS before pumping through a strain press to remove any remaining contaminants. From there, the treated FW slurry would be pumped to the anaerobic digesters. Note that the dilution tank and strain press may not be needed depending on the level of contamination of the pre-treated FW slurry. However, this polishing step was included for a conservative cost estimate given that the quality of the FW slurry is unknown.

The assumed FW slurry quantity fed to the digesters is 33,000 gallons per day at 5 percent TS for mechanical thickening (BS-2B and BS-2C) and 41,000 gal/d at 5 percent TS for recuperative thickening (BS-13). The BS-2B/C quantity is limited by the hydraulic capacity of the digesters assuming sludge is fed to the digesters at 6 percent TS, while the BS-13 quantity is limited by a recommended maximum FW volatile solids ratio for stable digester operation of 45 percent. Note that a FW market analysis was not included as it is outside the scope of this Energy Facilities Master Plan. Thus, this evaluation assumes that these quantities of pre-treated FW slurry are available.

For FW co-digestion to be viable, there needs to be excess anaerobic digestion capacity. As described for BS-2B and BS-2C above, the anaerobic digesters will be hydraulic capacity limited within the planning period of this master plan. To increase anaerobic digestion capacity to accommodate co-digestion, DSRSD would need to implement either BS-2B, BS-2C, or BS-7, described above.

Like BS-23, this analysis assumes that DSRSD would use the additional biogas from FOG co-digestion to replace NG combustion in the cogeneration system and maintain the same cogeneration capacity. The additional biogas production from co-digestion is estimated to reduce the NG use in cogeneration by approximately one third to one half. Combined with FOG co-digestion (Opportunity BS-23 described above), it could potentially eliminate NG use in the engines.

The capital cost, O&M cost, and energy impact of BS-24 are summarized in Table 6.9 The capital costs for a new strain press, holding tank, blending tank, rock trap/macerator, and 3 transfer pumps, as well as odor control for the FW receiving facility. The FW receiving facility would be constructed on a concrete pad. The O&M costs include power usage, equipment maintenance, and O&M labor for the FW receiving facility. A tipping fee for FW receiving was not included. A detailed cost breakdown is presented for this alternative is presented in Appendix 6A.

Table 6.9 BS-24 Co-digest FW Slurry and HSW Cost Estimate and Energy Impacts

Parameter	FW Co-digestion	Notes
Construction Cost ($)	$3,000,000	Does not include escalation, engineering, construction management, and engineering support during construction.
O&M Cost ($/year)	$365,000	Average of 20-year life-cycle period, assumed to be from 2027 to 2046.
Cost Savings for NG Purchase ($/year)	($212,000)	Uses $8.4/MMBTU NG cost.
Energy Use (kWh/year)	343,000	Average of 20-year life-cycle period.
Increase in Biogas Production (scfd)	133,000 – 165,000	Average of 20-year life-cycle period. Lower value corresponds to 33,000 gpd (BS-2B/C) and higher value corresponds to 41,000 gpd (BS-7).
Potential Decrease in Cogeneration NG Usage (therms/year)	(252,000)	Average of 20-year life-cycle period. Lower value corresponds to 33,000 gpd (BS-2B/C) and higher value corresponds to 41,000 gpd (BS-7). Assumes FW is received 5 days/week.

<u>Recommendation</u>: The available digester capacity provides a relatively low cost of entry for this alternative which will significantly reduce the NG use and therefore the GHG footprint for the District. Given SB1383, this alternative also provides ability for DSRSD to collaborate with the Cities it serves. Future effluent nutrient limits could pose a challenge for implementation, however it is recommended that this opportunity be explored for near-term implementation in 2026.

6.3.2.9 Replace Cogeneration (BS-30, BS-31A, BS-31B, BS-34 and BS-35)

Opportunity BS-30 involves replacing the existing cogeneration engines in-kind with similar engines while Opportunity BS-31A and BS-31B involve replacing them with higher efficiency

engines. Opportunity BS-35 involves replacing the existing cogeneration engines with higher efficiency engines and providing additional capacity and redundancy to avoid peak demand charges when one engine is out of service.

Replace Cogeneration with Similar Engines (BS-30)

The existing Waukesha rich burn engines have a low electrical efficiency of less than 30 percent. New rich burn engines can be permitted within the Bay Area Air Quality Management District but due to stricter emission limits for new engines (carbon monoxide [CO], nitrogen oxides [Nox] and volatile organic compound [VOC] limits per the Environmental Protection Agency's Tier 4 emissions standards) three-way catalysts are required. There is no known recent reference project in the Bay Area for newly installed rich burn engines on digester gas (DG). In a preliminary design phase the permitting and design criteria (NG and DG blending, engine control integration) need to be further evaluated for the feasibility of this opportunity.

Replace Cogeneration with Higher Efficiency Engine Generators (BS-31A and BS-31B)

In 2021, the total net power output for engines nos. 1, 2, and 3 was 1,071 kilowatts (kW) at less than 30 percent electrical efficiency. Newer lean burn engines (from both Caterpillar/MWM or Jenbacher) have a higher electrical efficiency of 40 percent. The new engine generators could be sized for a maximum power output totaling 1,400 kW.

Figure 6.3 shows a photo of a recently installed similarly sized engine at the South Orange County Wastewater Authority (SOCWA), California.

Figure 6.3 CIP Engine Installed for SOCWA (Jenbacher J312 Engine)

For new lean burning engines an exhaust treatment system is needed to meet Bay Area Air Quality Management District requirements. For this purpose, selective catalytic reduction (SCR) is commonly applied using urea for selective conversion of NOx to nitrogen, as illustrated schematically in Figure 6.4. Oxidation catalysts are used to reduce CO and VOC emissions.

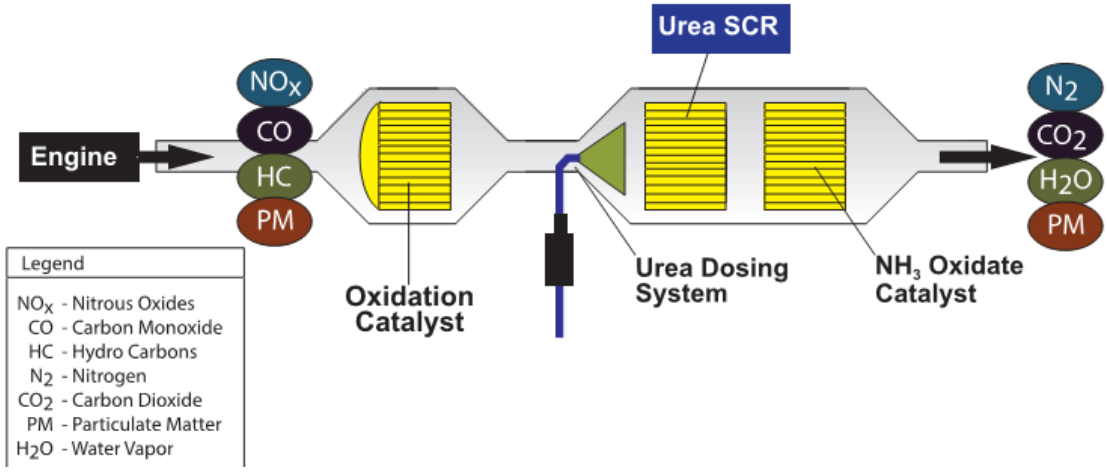


Figure 6.4 SCR With Urea Injection to Reduce NOx Emissions in Lean Burn Engines

The life cycle cost for the cogeneration alternative with one 1.4 MW ICE or two 700 kW ICEs is presented in Table 6.10. The costs include the capital and installation costs for the cogeneration equipment and the exhaust treatment system with SCR and CO catalyst.

Table 6.10 Net Present Life Cycle Costs for Various New ICE Alternatives

Alternatives	1 ICE 1.4 MW (BS-31A)	2 x ICE 700 kW (BS-31B)	2 x 1 MW (Using 80% NG) (BS-35)
Estimated Construction Cost	$17,600,000	$20,500,000	$26,000,000
Annual Costs (Revenues) ($/year)			
Value of Electricity Generated ($)	(72,800)	(72,800)	(104,100
Engine generator O&M, incl. SCR ($/year)	306,600	367,900	876,000
Biogas Conditioning O&M ($/year)	113,700	113,700	113,700
NG Costs ($/year)	534,200	534,200	885,279
Total O&M Costs ($/year)	**881,710**	**943,000**	**1,770,900**
20-Years Life Cycle Costs (Revenues)			
Value of Electricity Generated ($)	(1,457,000)	(1,457,000)	(2,184,800)
Gas Cleaning O&M Costs ($)	780,500	780,500	780,500
O&M Costs for Engines and SCR (Urea) ($)	2,237,500	2,237,500	2,528,900
Air Quality Management District Compliance (Source Testing, Other Permit Requirements) ($)	1,282,900	1,221,600	1,285,400
Total Net Annual Costs (2023 $)	**(26,072,500)**	**(24,893,200)**	**(20,979,700)**
Total 20-Year NPV (2023 $)	**(8,494,500)**	**(4,355,200)**	**5,007,300**
Payback (Years)	**13**	**16**	**24**

Notes:
(1) Detailed breakdown of capital costs is presented in Appendix 6..
(2) Assuming a Discount Rate of 4 percent.

The O&M costs include the carbon media replacement for the gas conditioning system, periodic maintenance for the ICEs, and catalyst and urea costs for the SCR and are estimated to be $306,000 per year. The power cost savings are for power otherwise purchased from Pacific Gas & Electric Company (PG&E) including the energy generation charges.

The initial capital investment is estimated to be between $17.6 million (for one engine rated at 1.4 MW) to $26 million for two new engines (rated at 1 MW each) located in the existing building. However, it is likely that the existing building will be inadequate for the new cogeneration engines and construction sequencing could be complicated, requiring shutdown of the existing cogeneration engines for an extended period of time. For budgeting purposes we have therefore assumed that a building will be required at a total project cost of $43 million.

Installation of two 700 kW cogeneration engines in the existing building results in a 20-year net present value (NPV) of approximately $4.4M. The return on investment (ROI), based on the net O&M costs due to savings in energy, is estimated to be about 16 years. Installation of a single larger engine would result in a better ROI; however, it would not offer the redundancy during maintenance and repairs. The turn-down of the larger engines is about 700 kW making the start-up and operation on solely DG more challenging and is therefore not recommended. ROI with a building included increases to 33 years. Funding options may be available to help reduce these capital costs and are discussed further in TM 8.

Replace Cogeneration to Cover Peak Electricity Demand (BS-34)

Opportunity BS-34 involves replacing the cogeneration system with higher efficiency engine generators (BS-31A or BS-31B) in combination with solar energy and battery storage to cover DSRSD's peak electricity demand. Cogen installation for one additional 700kW engine with SCR would cost approximately $5.8M in addition to the battery storage costs required for Opportunity ES-2 Battery Storage for Peak Demand Charges (see Section 6.6.2). Adding another engine which would need to operate on NG is shown in the next option BS-35. In short, this alternative is not recommended since the cogen and battery system would be largely oversized. It would provide redundancy but at large costs that may not be realistic for the District.

Replace Cogeneration to Cover Peak Electricity Demand and Redundancy (BS-35)

Current calculations involving the costs, energy savings, and payback periods for this alternative involve two cogen engines sized at 1MW each as shown in Table 6.10. In case DSRSD prefers a redundant cogeneration engine, opportunity BS-34 could be modified to add a third 700-kW or adding an additional engine at its current size to act as a standby engine unit (Opportunity BS-35). This option would add an estimated $5.3 Million in capital expenditure and with higher NG costs result in a payback of over 24 years. The third engine could be used as a standby unit or DSRSD could use it to run with additional future biogas or NG and sell the excess electricity not needed for the WWTP to Dublin San Ramon Services District - East Bay Municipal Utility District Recycled Water Authority (DERWA). This could reduce DERWA's electricity cost and provide a small income stream to DSRSD, but would increase DERWA's GHG emissions.

Replace Cogeneration: Engine Comparison and Recommendation

Although both rich burn and lean burn engines are allowed within the state of California, careful consideration must be made to determine which engine type would be the most suitable for DSRSD. The following Table 6.11 describes in detail the cogeneration applications of rich burn and lean burn engines operating on digester gas with technical specifications provided.

Table 6.11 Rich Burn and Lean Burn Engines

	Lean Burn	Rich Burn	Notes
Applications	Cogen in WWTPs, standby power	Cogen in oil and gas, some older municipal digester projects, standby power	Recent installations in WWTPs in California use lean burn. No reference for rich burn in 15 years.
Efficiency electricity/total with heat recovery	35 - 44%/up to 85+%	25 - 28%/65%	
Fuels	NG, DG (blending included)	NG, DG (blending by third party)	Blending system for Jenbacher is part of the unit. Waukesha does not offer blending system and third-party provider.
SGIP funding qualification	Yes, with jacket water heat recovery, total efficiency > 65%	With both jacket water and exhaust heat recovery (additional back pressure due to exhaust gas treatment to be examined)	Rich burn might not meet the efficiency requirements.
Emissions	Proven to meet BACT limits with SCR (urea injection required).	Can meet BACT limits with three-way catalyst. Non-selective catalytic reduction of NOx, CO with hydrocarbons (no ammonia injection).	
Manufacturers	INNIO Jenbacher, CATERPILLAR (MWM), Cummins, INNIO Waukesha	MAN, INNIO Waukesha,	IRA local content requirements need to be met. Many of these engines are not made in Canada (Waukesha) or Europe (MWM/CAT and Jenbacher).
Maintenance	Higher cost	Lower cost	Lean burn engines: higher catalyst replacement and urea usage costs, higher replacement costs for spark plugs, turbo replacement. More services need to be outsourced to a maintenance contract.

Notes:
BACT - best available control technology; IRA - Inflation Reduction Act; SGIP - self-generation incentive program.

<u>Recommendation</u>: Carollo recommends including the costs for Opportunity BS-31B into DSRSD's CIP with a minimum of two cogeneration engines. The need for this project is driven by asset replacement and energy efficiency and should begin implementation in 2026.

6.3.2.10 Improve Gas Conditioning System (BS-26)

Opportunity BS-26 (gas conditioning) is already being implemented by *DSRSD – Biogas Treatment System Improvements (CIP 16-P028).* Carollo reviewed the design criteria of this future system and confirmed that this design would be compatible with newly proposed cogeneration equipment described under opportunities BS-30, BS-31A/B, BS-34, or BS-35.

6.3.2.11 Condition Biogas for Pipeline Injection (BS-37)

As an alternative to cogeneration, the biogas can be upgraded to renewable natural gas (RNG). Pipeline construction costs ($3.7 million) and the capital costs associated with upgrading system to RNG ($19 million) for the relatively low volume of DG available and the uncertain value of the RNG and related credits would not make a pipeline injection project economically feasible.

The Low Carbon Fuel Standard (LCFS) credit values have been reduced significantly from $220 to $70, because of the lower demand for RNG in California with the electrification of truck fleets. Therefore, the long-term demand for RNG and related credits is anticipated to be reduced, and biogas uses are anticipated to shift to green power generation due to a higher demand for related electric renewable identification numbers (eRIN). For additional information regarding LCFS credits, please refer to TM 8, Section 8.6.6.1.

Recommendation: Unless the above noted economic conditions change, Carollo does not recommend RNG for DSRSD. RNG could otherwise be beneficial for DSRSD if the RNG can be used on-site for CNG truck fueling (e.g., for refuse collection fleet), or if the credits and RNG can be monetized within DSRSD by avoiding the broker fees for credits.

6.3.2.12 Increase Biogas Storage (BS-28)

DSRSD recently evaluated several options for biogas storage in a project conducted by Black and Veatch and summarized in a report in 2020. This project proposed bullet gas storage as the most suitable solution with project costs of over $2 million (including gas compression). The proposed DG storage would be sufficient to accommodate 4 to 6 hours of gas storage.

Compression of carbon dioxide (CO_2) in the biogas is uneconomical, especially because new engines operate a lower pressure (only requiring <20 pounds per square inch gauge). Also, if the engines are operated on a blend with NG, the blending ratio can be adjusted depending on the biogas supply pressure. With proper management of the organic feedstocks fed to the digesters, gas production can be managed within the existing digester headspaces and the usage of NG in the ICE fuel blending system can be lowered while increasing DG use to avoid the needs for gas storage. A small gas storage for a redundant buffer is a possible option but is typically not required for systems with multiple engines.

*Recommendation: Carollo does not recommend implementation of biogas storage as a cost-effective strategy for covering peak demands. This can be more cost-effectively achieved through battery storage (see Opportunity ES-2, Section 6.6.*2).

6.4 Building System Operations Optimization

6.4.1 Solar Thermal Heating (BLG-12)

Radiant solar heat can offset heating loads to provide more energy efficient buildings and reduce heating costs. The Office of Energy Efficiency and Renewable Energy (EERE) has developed a Solar Hot Water System Calculator to compare various energy sources with solar thermal

heating to determine whether a solar radiant system might be feasible for facilities. An estimated cost for a facility of panels and pumps with an exchanger would be approximately $8,000 per 100 gallons of hot water at 120 degrees F per person. Table 6.12 summarizes the assumptions and results for this analysis.

Table 6.12 Summary of EERE's Solar Calculations Compared to Other Heating Sources

		Electric Heating Comparison	NG Comparison	Air Source Heat Pump (COP 2.0) Comparison
Assumptions	Water Usage (gpd)	100 at 120 degrees F		
	Number of Person(s)	10		
	Water Heater Efficiency	0.88	0.57	2
	Fuel Price	$0.22/kWh	$20/1,000 cf	$0.22/kWh
Calculations	Annual Energy Savings (kW/year)	4,850	7,490	2,130
	Annual Cost Savings ($)	1,070	498	470
	Payback Period (years)	7.1	15.2	16.1
	GHG Reduction (pounds CO_2/year)	724	2,990	720

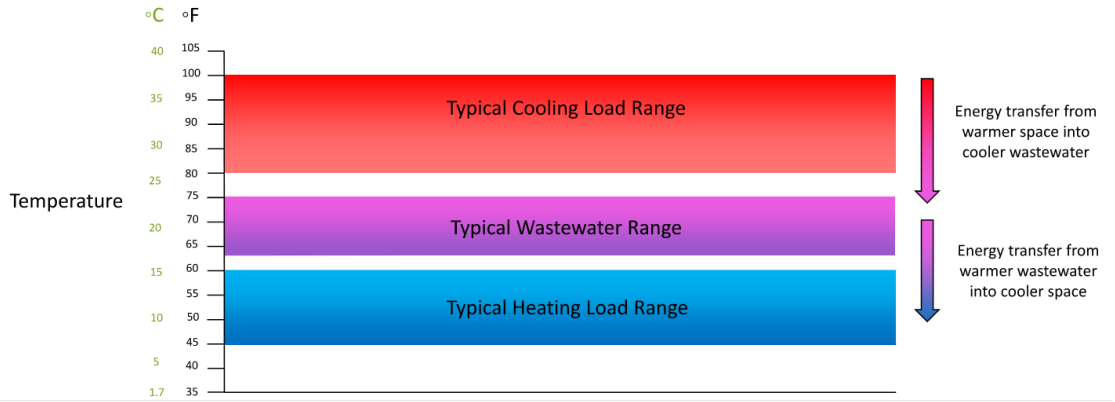
Notes:
cf - cubic feet; COP - coefficient of power.

DSRSD uses NG heating in administrative buildings offsite and certain buildings at the WWTP that are too remote to be connected to the heat loop using waste thermal energy. The payback periods for thermal solar heating systems in this case are estimated to be in the order of 10 years. Typically, today, suitable areas on rooftops or parking lots for solar systems is used to install photovoltaic rather than thermal system as the electricity provided can be efficiently used for various end uses (including heating).

Recommendation: Photovoltaic solar systems in lieu of solar thermal heating systems should be used to provide more flexibility in efficient electricity generation that can be used for many other purposes in addition to heating. Should DSRSD be interested in concrete price options for this solar thermal heating, Carollo recommends for DSRSD to solicit price and sizing quotes from companies specialized on thermal energy systems. These companies typically provide these estimates for free. Carollo did not develop further details for specific building proposals as part of this Energy Facilities Master Plan.

6.4.2 Wastewater Thermal Energy Use for Heating and Cooling (BLG-13)

So-called low-grade heating and cooling requirements for buildings can be very efficiently supplied by highly efficient heat pump systems using wastewater thermal energy as a heating or cooling source. The systems achieve today COP of 4.0. The COP measures the efficiency of a heat pump and is calculated as the ratio of the power (kWh) output to a pump for heating or cooling divided by the power (kWh) required to run the system compressor. Figure 6.5 shows that the year round temperature profile of domestic wastewater is uniquely suited to serve both as a year round heating and cooling source.



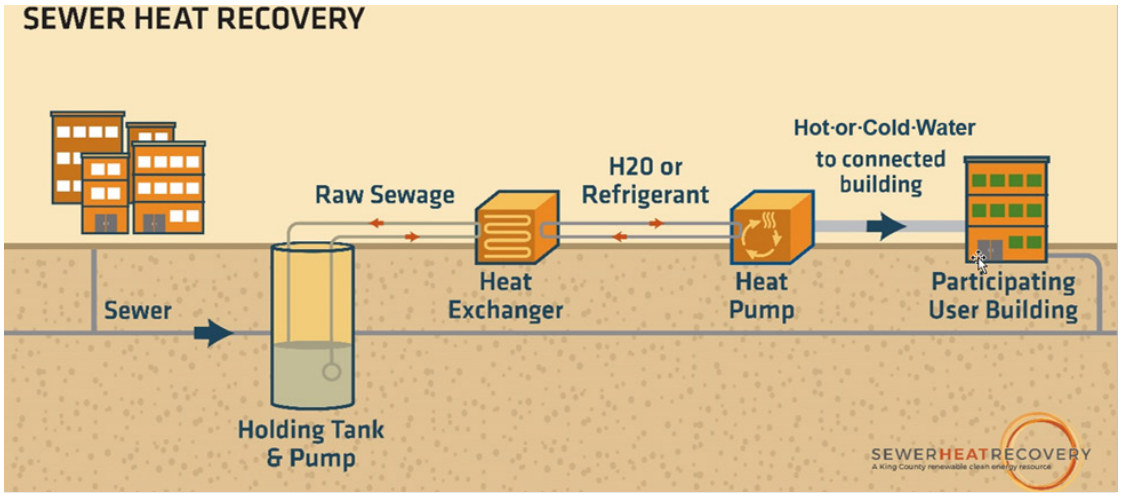
Source: SHARC Energy

Figure 6.5 Temperature Ranges of Typical Building Heating and Cooling Demands and Domestic Wastewater

6.4.2.1 System Description

Thermal energy use systems from wastewater all have the following general system components. Figure 6.6 shows a general system illustration and its components.

1. **Wastewater source:** This source is typically wastewater in a pipe located in a building, in the collection system in close vicinity to a building, or at the water resource recovery facility (WRRF).
2. **Heat exchanger:** The heat exchangers can be placed directly into the collection system pipe, may be integrated into the sewer pipe construction, or could be stand-alone systems to which the wastewater is pumped from the source.
3. **Heat pump:** The heat pump consists of a combination of heat exchangers, expansion valve, and compressor through which a working fluid is pumped. The heat pump takes advantage of the refrigeration cycle and the same system can be used for either heating or cooling purposes by reversing the pumping cycle (similar to a refrigerator).
4. **Working fluid:** Heat pumps in wastewater applications are designed for different working fluids including water and refrigerants (such as R-513A, a hydroflouro-olefin refrigerant with a global warming potential of 573, meaning it has 573 times the severity of CO_2 regarding climate change). (Note that several states have implemented bans of refrigerants with a global warming potential above 750. The global warming potential measures the global warming impact relative to the impact of the same quantity of CO_2 over a 100-year period.) The wastewater is kept separate from the working fluid in the refrigerant loop and the hot/cold water or air loop used in the building.
5. **Heating system:** This is the heating system in the building that distributes the heat to different areas. The heating systems can operate as water to air or working fluid to water.



Modified from King County, Washington

Figure 6.6 Wastewater Thermal Heat Use System Overview

6.4.2.2 Technology Status in the United States

The number of WRRFs that are in the process of systematically building the administrative, engineering, financial, and contractual programs for their service areas to make use of wastewater thermal energy for building air conditions is rapidly increasing. This trend is fueled by the following reasons:

1. 90 percent of the total energy in wastewater is thermal in nature, which can be recovered with today's technologies cost-effectively with payback periods of about 10 years.
2. First large cities in the United States have issued a ban on NG for new building construction, among these several cities in California. Especially for larger administration and commercial buildings wastewater thermal energy can be a competitive option to wind and solar that require additional footprint.
3. Several state agencies have started to regulate thermal discharge into surface waters for aquatic life protection.
4. Monetizing thermal energy in wastewater has created a separate income stream for municipalities that take advantage of grand funding for system construction and thermal renewable energy credits authorized by their state legislators.

Figure 6.7 provides an overview of some prominent thermal wastewater use systems in the United States and agencies that operate dedicated programs to promote and support such systems within their sewersheds.

Figure 6.7 Exemplary Wastewater Thermal Use Systems in the United States

6.4.2.3 Vendor Systems

There are two primary technology suppliers currently in the US that specialize on wastewater thermal energy system packages, their construction, and maintenance – SHARC Energy (https://www.sharcenergy.com/) and Huber Technologies (https://www.huber-technology.com/products/energy-from-wastewater/huber-heat-exchanger-rowin.html).

SHARC Energy has two product lines, the SHARC series for large heat pump capacity applications (0.7 to 3.3 MW) and the Piranha for smaller system capacity applications (range from 17 to 52 kW). Huber's RoWin system is sized for larger capacity applications. Both companies utilize screening and/or filtering of the wastewater prior to the heat exchangers to minimize scaling, biofouling, and clogging of equipment. The screened materials are directly returned to the sewer. Sewer diversion, pumping, and screening require design consideration for feasibility, and some level of O&M to maintain operation and efficient heat transfer.

Figure 6.8 shows an installation of a SHARC Energy system that can be placed in parking garages, building basements or utility rooms. Figure 6.9 shows the system provided by Huber Technologies.

Credits: SHARC Energy

Figure 6.8 SHARC Series System

Credits: Huber Technologies

Figure 6.9 Huber ThermWin System

Systems can also be designed and constructed around standard sizes of heat pump system equipment components available on the market.

6.4.2.4 DSRSD Project Identification, Economics, and Greenhouse Gas Reduction

DSRSD has several options for taking advantage of thermal energy in wastewater as a renewable energy source:

1. **WWTP:** Replacing NG used for heating and cooling in buildings too remote from the existing heat loop at the WWTP.
2. **DERWA:** Providing renewable energy to buildings owned and operated by DERWA.
3. **DSRSD's administrative buildings:** Administrative buildings located in the close vicinity of larger sewer lines, such as DSRSD's field operations facility, can be switched from NG to wastewater thermal energy as a renewable energy source for year-round heating and cooling.
4. **New construction projects in service area:** DSRSD could sell wastewater thermal energy to developers in their service area. These energy systems are specifically financially attractive as an alternative source for new large construction projects (commercial buildings, administrative buildings, hospitals, schools, recreation centers, etc.).

Table 6.13 summarizes the size, estimated payback periods, and GHG reduction of various projects in the United States. Payback periods for DSRSD depend on local construction and energy costs but are estimated to range between 5 and 12 years depending on the project scale and nature. GHG reduction estimates depend on the source of electricity that is used to power the heat pump of the system (e.g., the power mix of the local public power utility).

Table 6.13 Summary of Wastewater Thermal Energy Projects

Project Location	Building Type (all new construction)	System Capacity	Estimated CO_2e Offset	Payback Period
Boulder Commons, Boulder, Colorado	Mixed Use	18 kW	60 tons/year	5-7 years
National Western Center, Denver, Colorado	Mixed Use	4 MW	2,600 tons/year	Not available
Wall Center, Vancouver, British Columbia	Multi-family Residential	110 kW	260 tons/year	5-7 years
DC Water Administrative Building, Washington DC	Commercial, Administrative	224 kW	12.6 tons/year	Not available
IKEA, Berlin, Germany	Commercial	1,480 kW	120 tons/year	8 years
Philadelphia Water, Philadelphia, Pennsylvania	WWTF Building	290 kW	Not available	8 years

Notes:
CO_2e - carbon dioxide equivalents.

Some of the WWTF listed in Table 6.13 pay for the capital costs of the system, while in other cases the building owners pay for these costs and pay a margin to the utilities. In some cases, the utilities own the environmental attributes of the systems (and may lease them for additional income through local brokers), in other cases the environmental attributes are owned by the

building owners. DSRSD may receive financial benefits by setting up compensation agreements with developers for the thermal energy provided for heating and cooling and/or by applying for thermal renewable energy credits.

It is important for DSRSD to set opportune conditions in their service area for developers to become aware, consider, and implement this alternative energy source in their construction projects following the example that other WRRFs in the United States have successfully implemented.

Typically, new construction projects have a shorter payback period than building retrofits. For this reason, Carollo recommends the following steps for DSRSD under Opportunity BLG-13:

1. DSRSD is advised to assess the feasibility and costs of retrofitting its administrative buildings from NG to wastewater thermal energy heat pump systems for the specific local climate and with the support of one of the commercial system providers.
2. Collaborate with DERWA to assess the feasibility and costs of supplying wastewater thermal energy to building air conditioning owned and operated by DERWA.
3. Partner early with developers of larger commercial buildings located in DSRSD's service area that are in the vicinity of the newly constructed buildings to assess the costs and payback periods to the building owners of wastewater thermal energy heat pumps. If the economic and environmental benefits of such systems are attractive to developers, develop an administrative program to support such community projects.

Recommendation: This option is not a CIP project recommendation but a recommendation for further evaluation of financially beneficial partnerships by DSRSD in the coming years.

6.5 Renewable Energy Generation Opportunities

This section explores alternatives to produce renewable energy through solar, wind, strategic partnerships, and green power purchasing.

Figure 6.10 recaps that DSRSD could cover the total electrical demand of the WWTP in the future through independent power generation from a more efficient cogeneration system fueled by up to 40 percent by biogas and at least 60 percent NG (or directed biogas). The remaining electrical demand by DSRSD for recycling and potable water distribution, buildings and fleet could be fully covered through solar photovoltaics (PV) (or the equivalent via a power purchase agreement [PPA]).

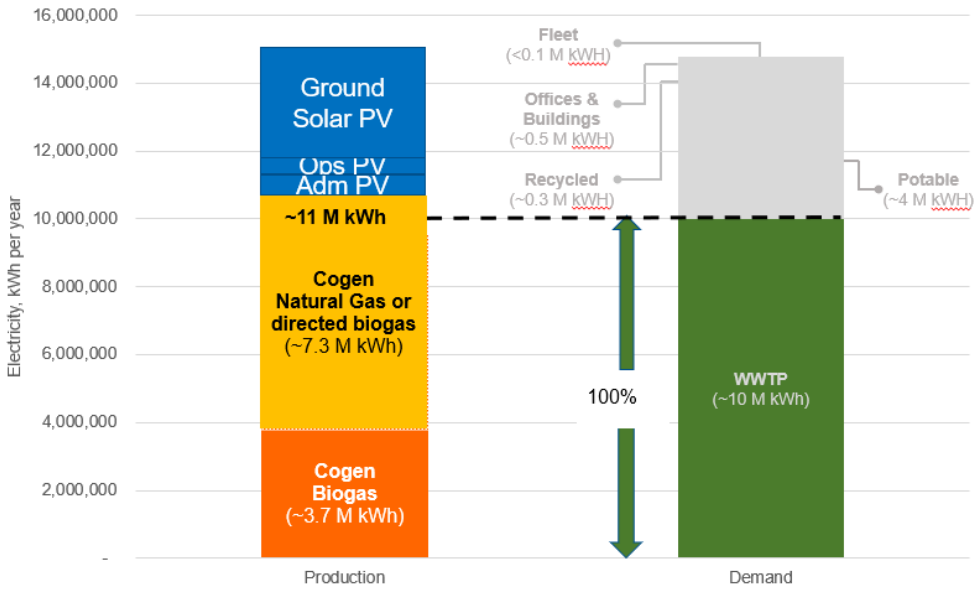


Figure 6.10 Example Source Portfolio to Cover All DSRSD's Future Electricity Demands

For projects less than 5 MW and project sites which have a time of use billing structure, PG&E offers Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT). Power generation value can be transferred to other site bills under conditions outlined below.

- **Meeting the project timeline before capacity of RES-BCT is reached.** Any project that meets the requirements for RES-BCT before PG&E's RES-BCT Program Cap of 105.25 MW is reached will be eligible for RES-BCT, regardless of when the project was submitted. For example, if a newer project passes all internal reviews and submits evidence of receiving final building permit approval before an earlier project, the newer project will be eligible for RES-BCT (as long as the RES-BCT Cap has not yet been reached) and will be counted towards the RES-BCT Cap. Therefore, applicants may apply for RES-BCT at any time prior to when the RES-BCT Cap is reached but with the understanding that projects already in the process of interconnection may suddenly be counted towards the Cap at any time.
  Once the RES-BCT Cap is reached, the RES-BCT program will be closed and all pending projects that have not yet met the requirements for RES-BCT will not be eligible for RES-BCT. Instead, these pending projects will be required to interconnect under another applicable Rule 21 agreement (e.g., uncompensated export).Once the cap is reached PG&E does not provide information if the program continues. At this point the cap is not reached.

The program should be considered for any of the renewable energy generation alternatives under consideration by DSRSD. Criteria for RES-BCT includes:

- A customer must be a city, county, special district, school district, university, California Native Tribe, political subdivision or other local public agency.
- The maximum generator size is 5 MW, and multiple arrangements are allowed.
- The benefiting account may be at remote locations within the same city or county.
- Generating and benefiting accounts in the "arrangement" must be on a time-of-use rate schedule.

More information can be found at the link below:

https://www.pge.com/en/about/doing-business-with-pge/interconnections/larger-self-generation.html#:~:text=Qualifications,%2Dof%2Duse%20rate%20schedule

6.5.1 On-Site Solar Installation (RE-1A, RE-1B, and RE-1C)

PV panels could be installed on the roofs of the Office Administration Building at 7051 Dublin Boulevard, Dublin (Opportunity RE-1A), the Field Operations Facility at 7035 Commerce Circle, Pleasanton (Opportunity RE-1B), and solar carports were considered next to the Office Administration Building since the roof may not be suitable for PV panels (Opportunity RE-1C).

6.5.1.1 Administration Building (RE-1A)

At the Administration Building the roof mounted solar PV and solar carports as shown in Figure 6.12 would yield an installed capacity of 351 kW direct current (DC). This is equivalent to a total output of 288 kW alternating current (AC) after accounting for the inverter efficiency, producing an annual electricity of 465 megawatt hours (MWh). As shown in Figure 6.11, the expected electricity generation would peak during the summer months. A possible panel layout is presented in Figure 6.12.

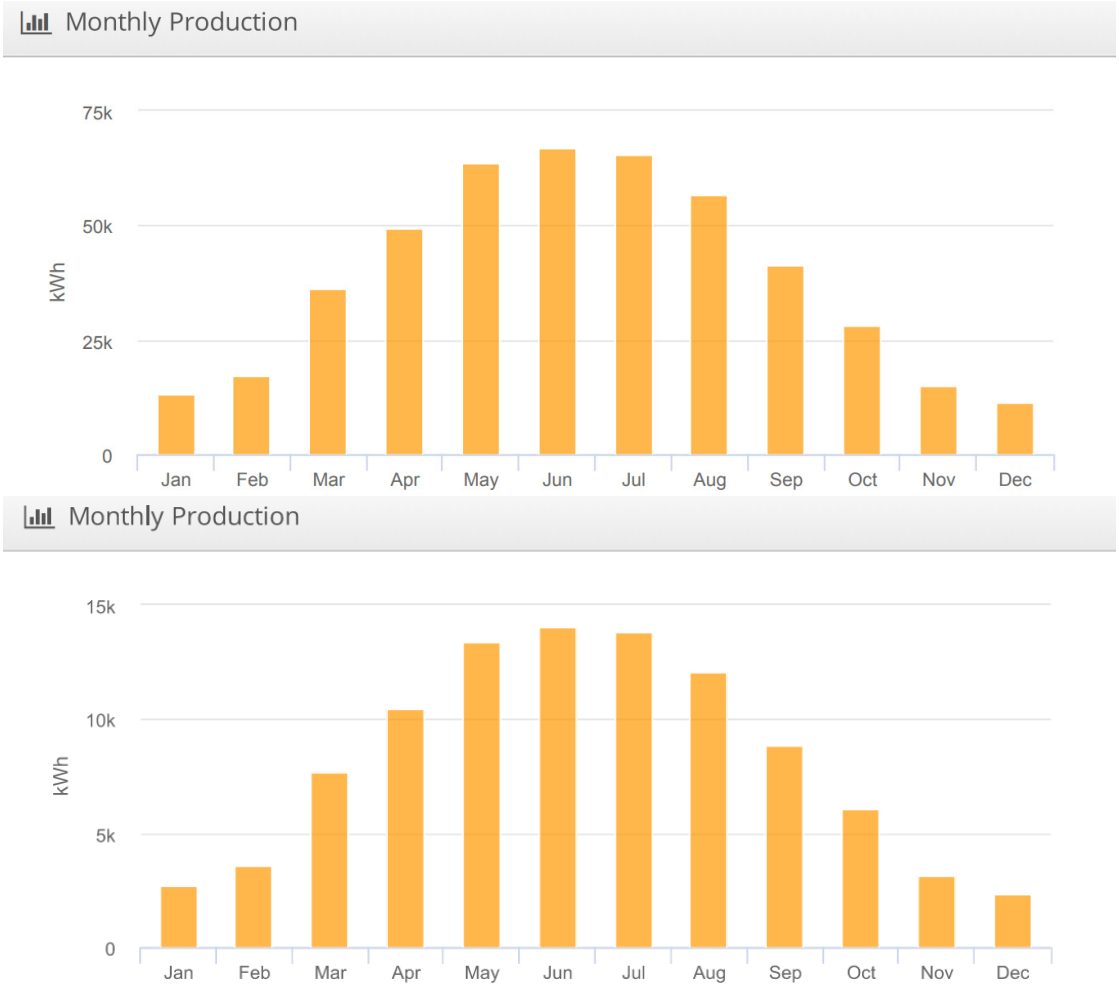


Figure 6.11 Projected Monthly Production From Both the Administration Building With Solar Carports PV System (Top) and the Administration Building PV System (Bottom)

Figure 6.12 Administration Building - Layout of Roof-Mounted Solar Panels With Solar Carports (Top) and the Administration Building PV System (Bottom)

6.5.1.2 Field Operations Facility (RE-1B)

The field operations facility has rooftop space for approximately 6,750 square feet (sf) of PV panels for a total installed solar PV capacity of 70 kW. The projected annual power production, as shown in Figure 6.13 totals 93 MWh. A possible panel layout is shown in Figure 6.14.

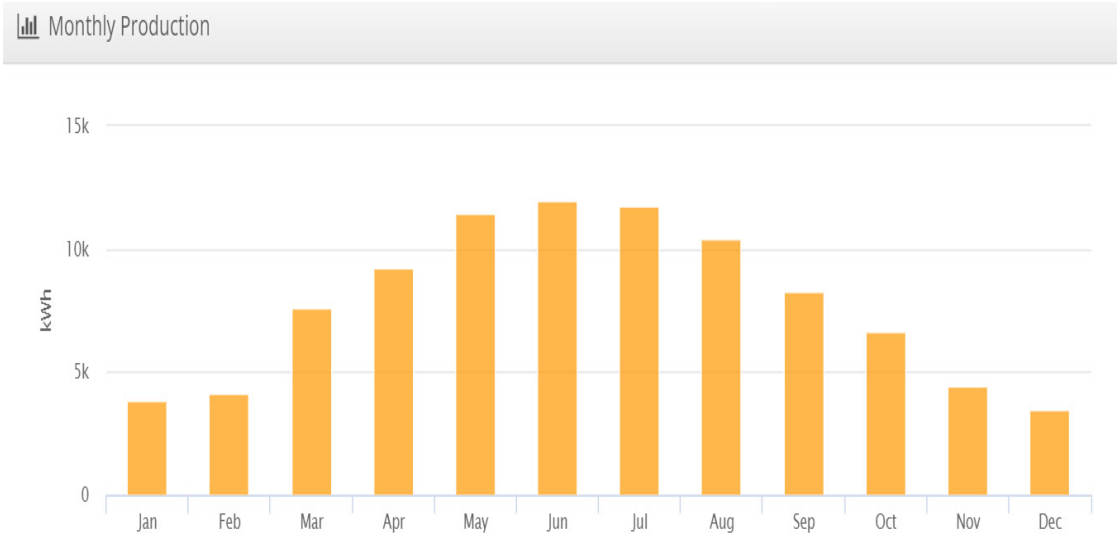


Figure 6.13 Projected Monthly Production From 70-kW Field Operations Facility PV System

Figure 6.14 Field Operations Facility - Layout of Roof-Mounted Solar Panels

Both sites will need temporary battery storage if overnight charging of EVs is desired. TESLA's "Megapack" energy storage system, which is further detailed in Section 6.6.2 (ES-2), was used to estimate the cost of the necessary storage. Tesla batteries were sized for 4 MWh, which would charge vehicles at 1 MW for 4 hours. This can be translated in a multitude of ways depending on the type of EV charger that would be used but a 350 kW DC fast charger, which is the fastest, most powerful, and most expensive type of charger on the market could work for up to 11 hours alone. Put another way, a total of six Level 2 chargers (19 kW), which are much more affordable

and readily available, can charge vehicles for 8 hours overnight. It is important to note that the number of vehicles being completely charged would be dependent on miles driven and vehicle type.

Table 6.14 outlines the estimated capital and operating expenses for these PV systems for the administration building and field operations building. The costs reflect a traditional project delivery model in which the systems would be bid and contracted to a qualified contractor with the final system fully owned and operated by DSRSD. The payback without incentives would be over 20 years. Taking advantage of the IRA cash incentive through the Department of Treasury for non-taxable entities such as DSRSD could reduce the payback period. For more information regarding these IRA cash incentives, please refer to TM 8, Section 8.7.1.

Table 6.14 Estimated Capital and Operating Costs for Proposed Roof-Mounted Solar PV Systems (Self-Construction)

	Administration Building (roof and carports)	Field Operations Facility (RE-1B)
System Capacity (kW)	288	70
Total Capital Costs without Batteries ($)	$1,485,000	$323,000
Total Capital Costs with Batteries ($)	$3,685,000	$2,523,000
Capital Costs without Batteries after Tax Rebates ($)	$1,039,500	$226,100
Capital Costs with Batteries after Tax Rebates ($)	$2,579,500	$1,766,100
Operating Costs without Batteries ($/year)(1)	$29,700	$6,500
Grid Power Costs Avoided Annually without Batteries(2) ($/year)	($61,380)	($11,800)
Payback period with IRA without Batteries	17	19
20-Year NPV of Operating Costs + Electricity Costs Saved without Batteries ($)(3)	($430,542)	($102,800)
20-Year NPV of Capital + Operating Costs without batteries ($)(4)	$1,054,458	$203,100

Notes:
(1) Annual operating costs are estimated at two percent of the total capital costs. See Section 6.6.2 (ES-2) for additional information and costs relating to the battery storage system. Operating costs and payback periods are too dynamic to accurately model at this time since they are dependent on vehicle miles driven, variable cost of electricity, and vehicle model type.
(2) Avoided costs are based on an electricity rate of $0.22/kWh. The monetary savings are estimated at 60 percent of the total value of the avoided electricity consumption to account for standby and other fixed charges.
(3) NPV is calculated using a four percent interest rate.
(4) Does not include tax rebates.
(5) Detailed cost breakdowns for these alternative scenarios are presented in Appendix 6A.

Despite the relatively long amortization phase of solar systems in California at this time, Carollo recommends both projects for CIP inclusion. The lifetime of solar systems is more than 20 years, meaning the investments will be cost neutral. PV installations on both buildings will visually project to the public DSRSD's commitment to clean energy. Based on the electricity baseline energy demand analysis, investment in these options could offset utility electrical demand for DSRSD's two administrative buildings by approximately 38 percent.

Recommendation: The solar PV market and incentive programs are dynamic so Carollo recommends continually tracking future opportunities to prioritize these and other PV opportunities when financial payback opportunities may become even more competitive. As shown, there are many options and paths toward renewable energy via solar PV systems as well as a multitude of options for EV overnight charging. DSRSD should include costs relating to solar PV systems paired with EV charging stations at both the administration building (RE-1A) and the field operations facility (RE-1B) within their CIP.

6.5.1.3 Solar Carports (RE-1C)

Carollo also reviewed potential locations for solar carports near the Administration building, because the roof is not in good structural condition. Although discussions with DSRSD have now verified that the proposed area of the roof with the solar panels is structurally sound, the opportunity below describes the effectiveness of only solar carports.

If DSRSD can use the shown segments for carports as shown in Figure 6.16 the total solar energy produced would be 249 kW producing 335 MWh per year as shown in Figure 6.15. This would avoid 67 percent of the power usage (this is without battery storage, which would be beneficial for this size of project and net energy metering [NEM] 3.0). The model shows that the parking area on the East side of the building near the trees is shaded and therefore not feasible; this shaded area is also visible in Figure 6.16.

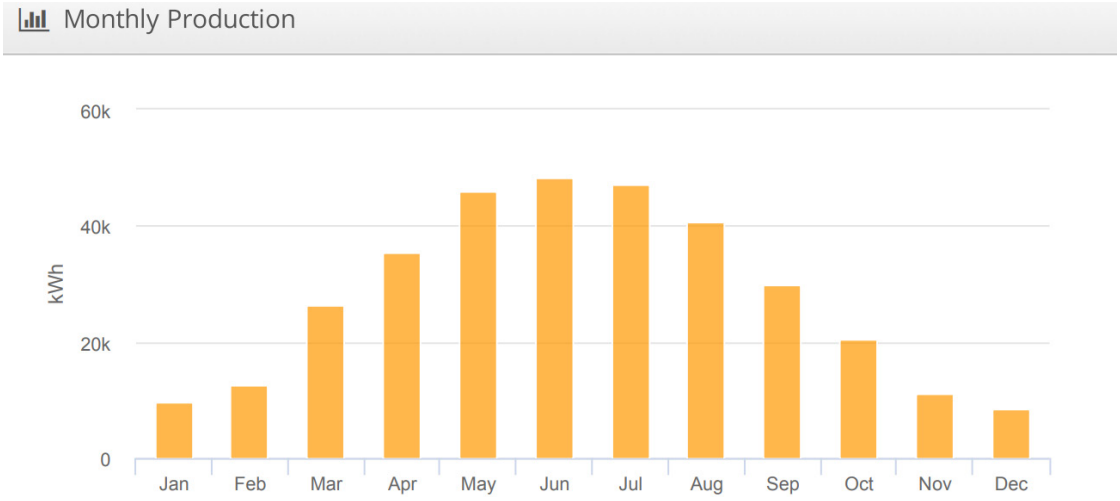


Figure 6.15 Projected Monthly Production From Solar Carport PV System

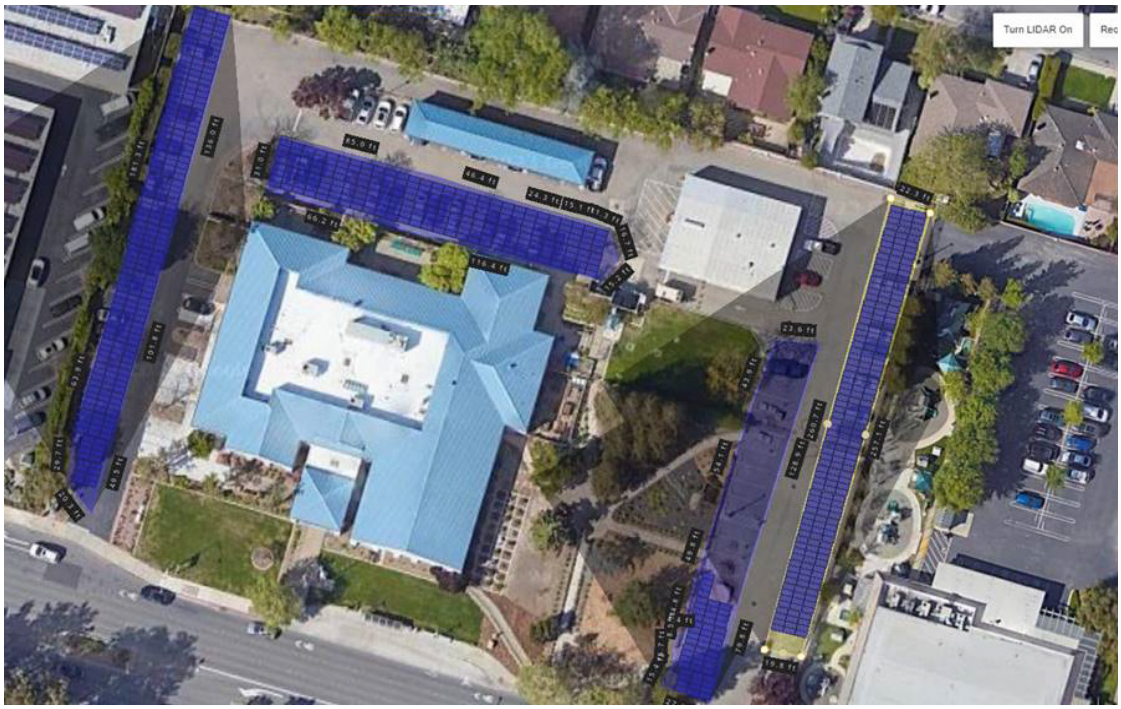


Figure 6.16 Solar Carport - Layout of Carport Solar Panels Near Administration Building

6.5.2 Off-Site Solar Installation (RE-2A, RE-2B, RE-2C, and RE-2D)

6.5.2.1 Gleason Property (RE-2A)

DSRSD owns approximately 5 acres of undeveloped land, referred to as the Gleason Property, at the corner of Tassajara Road and Central Parkway in Dublin. Approximately 200,000 sf of solar power could be installed on this green field. This equates to a solar installed capacity of approximately 2.1 MW DC and, after adjustment for inverter efficiency, produces a total output of 1.8 MW DC. The projected annual power generation would be 3,700 MWh.

Figure 6.17 shows the anticipated electricity production throughout the year at the Gleason Property. This off-site PV project requires grid connection to transfer power to the WWTP. PG&E will apply grid charges. The total costs of power generated from this system are estimated to be over 19 cents per kWh. The proposed panel layout is shown in Figure 6.18; additional coverage on the hill of this site could also be a potential area for future panels.

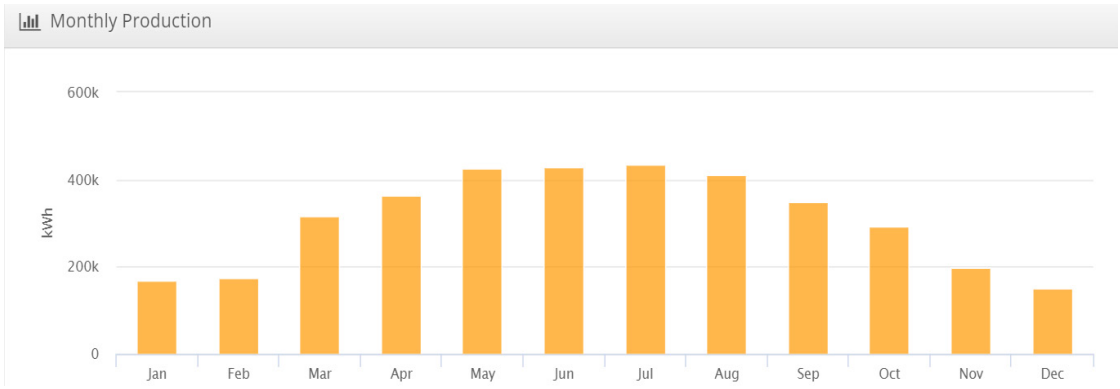


Figure 6.17 Projected Monthly Production From 2.1 MW Gleason Property PV System

Figure 6.18 Preliminary Layout for Ground-Mounted Solar PV System at Gleason and Arnold Road Property

Similar to a rooftop installation, a ground-mounted solar field (with an expected useful life of 25 years) could be funded and constructed through DSRSD's standard bidding and contracting process or through a PPA. Similar recent ground-mounted solar projects through a PPA for other water agencies in California were offered for a price of 9 to 10 cents per kWh. Lower costs for permitting, planning, and construction for a privately managed PPA project offer a higher NPV and lower financial risk to DSRSD compared to the model in which DSRSD owns, operates and maintains the PV system, as shown in Table 6.15.

Table 6.15 Estimated Capital and Operating Costs for a Ground-Mounted Solar PV System at the Gleason Property

	Solar PV System - Owned and Maintained by DSRSD	Solar PV System – PPA
System Capacity (MW)	2.1	2.1
Total Capital Costs ($)	7,237,000	0
Capital Costs after Tax Rebates ($)	5,066,000	0
Operating Costs ($/year)[1]	145,000	0
Grid Power Costs Avoided Annually[2] ($/year)	(488,000)	(154,000)
20-Year NPV of Operating Costs + Electricity Costs Saved ($)[3]	(4,671,000)	(2,112,000)

	Solar PV System - Owned and Maintained by DSRSD	Solar PV System – PPA
Payback Period with Tax Rebates (Years)	15	0
20-Year NPV of Capital + Operating Costs with Tax Rebates ($)[4]	395,000	(2,112,000)

Notes:
(1) Annual operating costs are estimated at two percent of the total capital costs.
(2) Avoided costs are based on an electricity rate of $0.22/kWh. The monetary savings are estimated at 60 percent of the total value of the avoided electricity consumption to account for standby and other fixed charges.
(3) NPV is calculated using a four percent interest rate.
(4) Includes 30 percent tax rebates.
(5) A detailed cost estimate for off-site alternatives is presented in Appendix 6A.

Recommendation: This option would preclude DSRSD using this available land for other purposes over the next two decades or longer or selling the property for a potentially higher return of investment, therefore DSRSD has decided not to pursue this opportunity further at this time.

6.5.2.2 Livermore-Amador Valley Water Management Agency Property (RE-2B and RE-2C)

Carollo evaluated the solar PV construction at the LAVWMA site owned by DSRSD using the Helioscope solar modeling software. Two PV system layout options were evaluated:

1. Option 1 (RE-2B): Using the full area of the basins for PV installation.
2. Option 2 (RE-2C): Installing solar PV on the edges of the basins.

Option 1: Using the Full Area of the Basins for PV Installation (RE-2B)

This site can produce an estimated 2.1 MW solar electricity based on the available footprint for ground mounted solar. This results in an estimated annual electricity production of 3,800 MWh (1711 kWh per kW peak).

The anticipated electricity production throughout the year at the LAVWMA property is shown in Figure 6.19, while the proposed layout is shown as Figure 6.20.

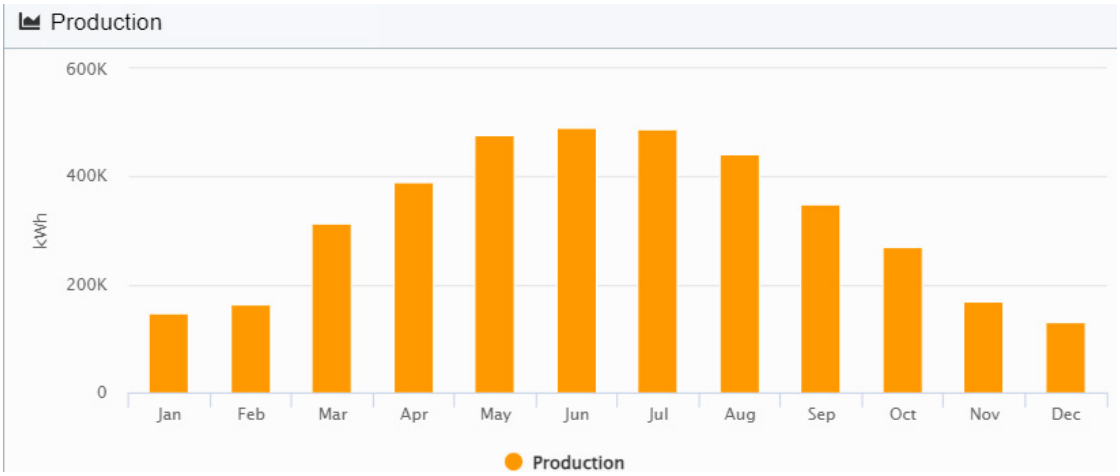


Figure 6.19 Projected Monthly Production for a 2.1 MW PV System at LAVWMA on Basins Area

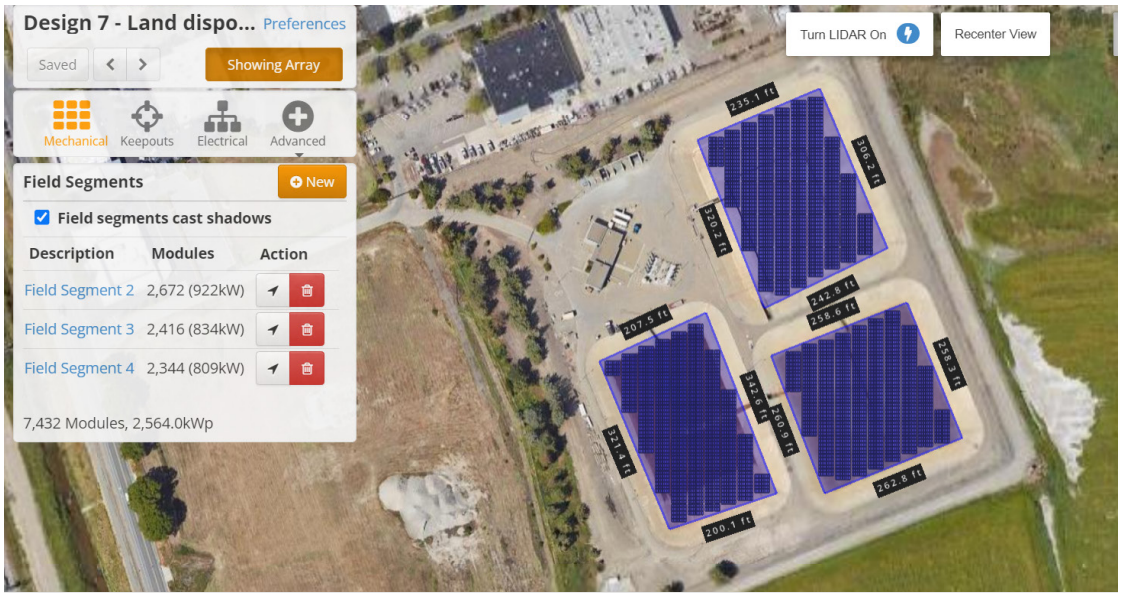


Figure 6.20 Preliminary Layout for the PV System at the LAVWMA Site on the Basin Area

The estimated cost for the project is $6.7 million without financial grants or other incentives. Applying IRA tax rebates this capital cost is estimated to lower to about $4.7 million. The net electricity cost savings (considering operational expenses and grid-related fixed charges, are estimated to be $450,00 per year. Table 6.16 summarizes these costs assuming DSRSD would construct, own, and operate this project and acquire tax rebates from the IRA. The lower capital costs would result in a favorable NPV (see Table 6.16). The simple payback would be 10 years with tax rebates (14.3 years without tax rebates) for a system with an expected useful life of 25 years.

Table 6.16 Estimated Capital and Operating Costs for a Solar PV System on the LAVWMA Basins Area (RE-2B)

	LAVWMA Property PV System in basins - Owned and Maintained by DSRSD	LAVWMA Property PV System in basins - PPA at 9 cents per kWh
System Capacity (MW, AC)	2.1	2.1
Annual Generation (MWh/year)	3,800	3,800
Total Capital Costs ($)	6,670,000	0
Capital Costs after 30% Tax Rebates (IRA) ($)	4,669,000	0
Operating Costs ($/year)[1]	134,000	0
Grid Power Costs Avoided Annually[2] ($/year)	(585,000)	(160,000)
20-Year NPV of Operating Costs + Electricity Costs Saved ($)[3]	(6,140,000)	(2,169,000)
20-Year NPV of Capital + Operating Costs ($)[4]	530,000	(2,169,000)

	LAVWMA Property PV System in basins - Owned and Maintained by DSRSD	LAVWMA Property PV System in basins - PPA at 9 cents per kWh
Payback Period with IRA Tax Incentives	10	0
20-Year NPV of Capital + Operating Costs NPV with IRA **($)**	(1,472,000)	(2,169,000)

Notes:
(1) Annual operating costs are estimated at two percent of the total capital costs.
(2) Avoided costs are based on an electricity rate of $0.22/kWh. The monetary savings are estimated at 70 percent of the total value of the avoided electricity consumption to account for standby and other fixed charges.
(3) NPV is calculated using a four percent interest rate.
(4) Does not include tax rebates.
(5) Using 9 cents based on recent solar PPA projects. Zone 7 has an annually adjusted PPA rate (and solar tracker system was more expensive) and is getting closer to 14 cents per kWh.

The ground-mounted PV system could also be pursued with a third-party PPA developer. DSRSD would then purchase the resulting electricity back from that developer. A PPA would not require upfront costs and has fixed (or annually inflation adjusted) rates which can typically be lower than self-constructed projects due to higher tax rebates and financial incentives available to corporations.

Based on a PPA rate of 9 cents per kWh (assumed based on the rate of other Southern California project) over a 20-year PPA period the power savings would amount to $2.1 Million (Table 6.16).

Option 2: Installing Solar PV on the Edges of the Basins (RE-2C)

Carollo evaluated a smaller solar PV construction at the LAVWMA site constructed around the edges of the basins on canopy structures (Figure 6.21). Note that ground mounted solar installations (RE-2B) maintain a larger spacing than solar installed on elevated canopies. As a result, the specific power production is higher for Option 2 (RE-2C).

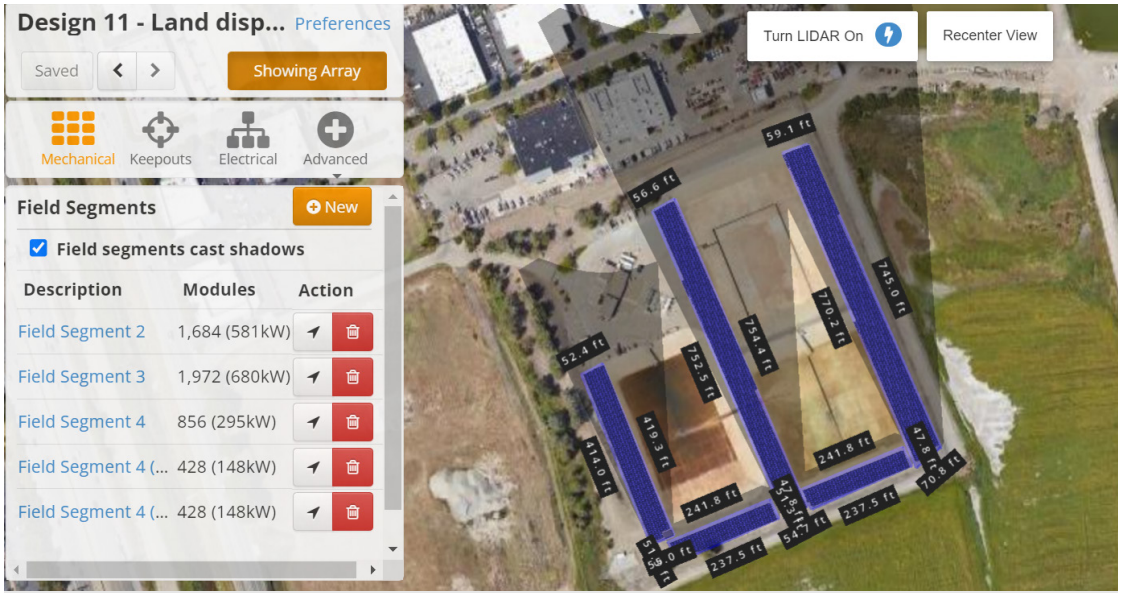


Figure 6.21 Layout of Canopy Mounted Solar PV System Located at LAVWMA Around the Edges of the Basins

The layout shown in Figure 6.21 can produce an estimated 1.5 MW peak of solar electricity. This would result in an estimated annual electricity production of 3,200 MWh (1,711 kWh per kW peak) (Figure 6.22).

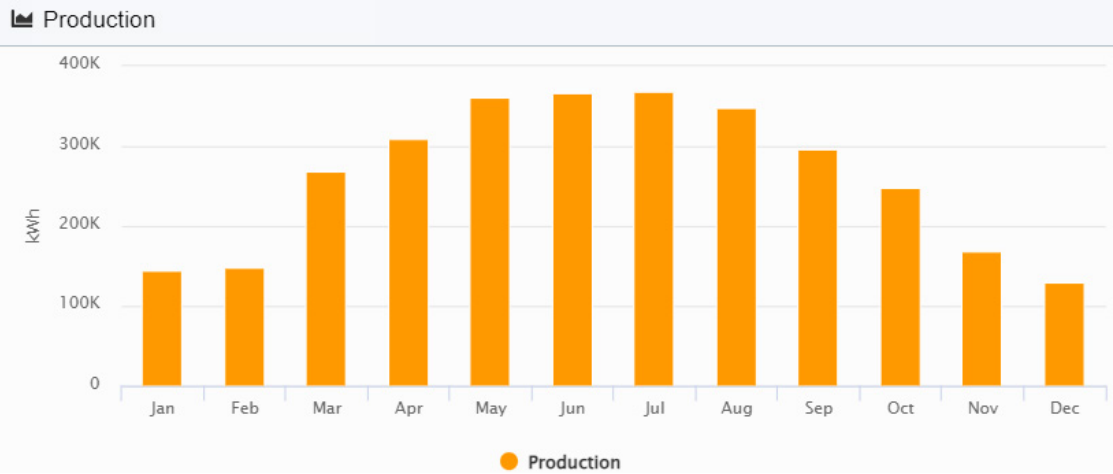


Figure 6.22 Projected Monthly Production for a PV System Located at LAVWMA Around the Edges of the Basins

Table 6.17 summarizes the costs for the case that either DSRSD or a PPA would construct, own, and operate this PV system.

Table 6.17 Estimated Capital and Operating Costs for Solar PV System Located Around the Edges of the Basins (RE-2C)

	LAVWMA Edges of Basins With Canopy PV System - Owned and Maintained by DSRSD	LAVWMA Edges of Basins PV System - PPA at 12 cents per kWh
System Capacity (MW, AC)	1.5	1.5
Annual Generation (MWh/year)	3,200	3,200
Total Capital Costs ($)	$6,670,000	0
Capital Costs after 30% Tax Rebates (IRA) ($)	$4,903,000	0
Operating Costs ($/year)(1)	$152,000	0
Grid Power Costs Avoided Annually(2) ($/year)	($492,800)	($109,000)
20-Year NPV of Operating Costs + Electricity Costs Saved ($)(3)	($4,631,900)	($1,479,000)
20-Year NPV of Capital + Operating Costs ($)(4)	$2,967,000	($1,479,000)
Payback Period with IRA Tax Incentives (years)	14	0
20-Year NPV of Capital + Operating Costs NPV with IRA ($)(4)	$109,000	($1,479,000)

Notes:
(1) Annual operating costs are estimated at two percent of the total capital costs.
(2) Avoided costs are based on an electricity rate of $0.22/kWh. The monetary savings are estimated at 60 percent of the total value of the avoided electricity consumption to account for standby and other fixed charges.
(3) NPV is calculated using a four percent interest rate.
(4) Include 30 percent tax rebates.
(5) Using a higher PPA rate for higher construction costs (+30 percent).

The cost for the structures and installation of the solar canopies is higher than for ground mounted solar (estimated at +40 percent). Capital costs are estimated to be $7 million for the 1.5 MW for DSRSD excluding interconnection and power transmission line fees. The payback would be over 20 years without tax rebates and 14 years with tax rebates when assuming that up to 60 percent of the grid charges can be saved; again, these solar systems have an expected useful life of 25 years.

For the PPA built solar project Carollo expects a proportionately higher cost for the canopy structures compared to ground mounted solar. For this case, the electricity cost to DSRSD is estimated to be about 12 cents per kWh (compared to 9 cents per kWh under Option 1). Over a 20-year PPA period the power savings would amount to $1.5 Million.

Recommendation: Carollo recommends planning for a solar PV installation at the LAVWMA site in DSRSD's CIP due to the sizable electricity capacity potential. Either Option 1 (RE-2B) or 2 (RE-2C) results in attractive NPVs especially if construction can occur through a PPA.

6.5.2.3 Solar Carports: Park N Ride Pleasanton (RE-2D)

DSRSD expressed interest in utilizing solar carports within the Park N Ride Pleasanton location near Johnson Drive. If DSRSD can use the carports shown in Figure 6.23, the total solar energy produced would be 149kW resulting in an annual production of 253 MWh. The monthly production of solar energy is presented in Figure 6.24. However, any offsite location suffers from losses and inefficiencies when compared to onsite installations.

Figure 6.23 Layout of canopy mounted solar PV system located at Park N Ride Pleasanton

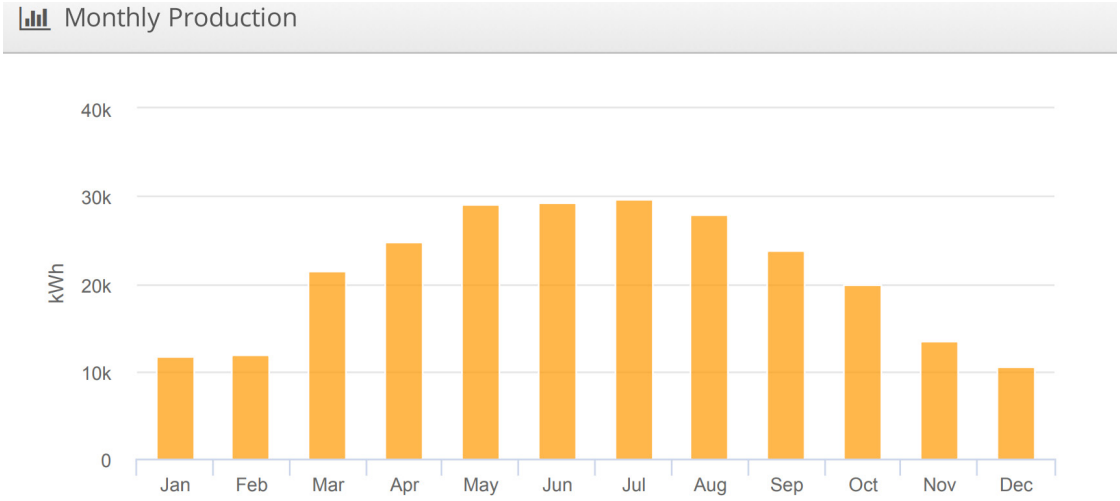


Figure 6.24 Projected Monthly Production for a PV System Located at Park N Ride Pleasanton

Recommendation: Because off-site installation of solar cells results in greater losses and inefficiencies relating to transmission, Carollo recommends DSRSD should prioritize onsite installations of solar PV systems with exceptions of the larger LAVWMA site.

6.5.3 Solar Installation at Dedicated Land Disposal Site (RE-3)

The DLD site is approximately 100 acres and could be converted to a substantial solar field with an output capacity of approximately 16.7 MW. However, since DSRSD currently uses this site for biosolids injection, this solar generation option would only be feasible if DSRSD pursued a different biosolids handling approach. If this was the case at some point in the future, the site will likely be in competing demands for other more economical uses.

Recommendation: DSRSD staff did not consider installation of solar cells on top of the DLD sites as a feasible option due to the access of sunlight needed for photosynthetic demands of algae as well as O&M requirements of the site. Carollo does not recommend this option to be included in the Energy CIP.

6.5.4 Solar Power for Electric Vehicle Fleet Recharging Station (RE-4)

DSRSD plans to comply with state mandates by transitioning its fleet to EVs in the future. Opportunity RE-4 evaluates powering the EV charging stations with on-site PV solar power. Opportunity RE-1 discussed above investigated the installation of solar PV on a) the roof of the administrative building, b) operations building, and c) ground mounted on-site solar. An additional opportunity includes solar arrays via canopies with an expected useful life of 25 years within the field operations parking lot that covers approximately 6,000 sf in size. The approximate size and location of this PV system is shown in Figure 6.25.

Figure 6.25 Preliminary Layout for Carport Canopy PV Installation on Field Operations Parking Lot

This carport installation requires the construction of canopy structures above existing parking locations. Electrical characteristics and associated costs for the solar carport installation are presented in Table 6.18. Battery storage would be required for overnight charging capabilities, but this is not included in the cost or payback calculations since energy storage opportunities are included in Section 6.6. This analysis assumes that level 2 chargers would be utilized at a typical power output of 7 to 19 kW; DC fast chargers are much faster at power outputs of 50 to 350 kW but come at a much heftier price tag.

Table 6.18 Estimated Costs of Solar Carport Installation at the Field Operations Building Parking Lot

Parameter	Unit	Quantity
Electrical and Site Characteristics		
Carport Area	sf	6,000
Carport Tilt Angle	degrees	16
Panel Rating	watts	325
Total Panel Quantity	number	335
Array Rating	kW	109
Per Unit Energy Production	kWh/kW	1,753

Parameter	Unit	Quantity
Annual Energy Production	kWh	191,000
Installation Cost Estimate		
High per Unit Estimate	$/W	4.0
Total High Installed Cost	$	436,000
Estimated Payback Period		
Average Energy Rate	$/kWh	0.16
Value of Annual Energy	$/year	30,600
Payback Periods	years	14

Recommendation: Carollo recommends this alternative be pursued for implementation in DSRSD's CIP. It comes with an attractive payback period which can be even further shortened if IRA funding can be secured. Additional information regarding funding via the IRA and other platforms is detailed within TM 8, Section 8.7.1. The California Code of Regulations Section 95488.1 – Fuel Pathway Classifications offers additional financial benefits to the District when solar power is used for EV fleet charging stations. For example, the regulation provides multiple pathways to earn eRIN credits that can then be sold to high carbon intensity (CI) fuel producers. Further specifics regarding EV charging stations and charging best practices is discussed in more detail within TM 7.

6.5.4.1 Solar Power for Electric Vehicle Charging: 7399 Johnson Drive

After discussing with DSRSD, one last site for inclusion of a solar PV system and EV charging stations was selected at 7399 Johnson Drive. If DSRSD can use the area shown in Figure 6.26, the total solar energy produced would be 120kW resulting in an annual production of 216 MWh. The monthly production of solar energy is presented in Figure 6.27.

Figure 6.26 Layout of Canopy Mounted Solar PV System Located at 7399 Johnson Drive

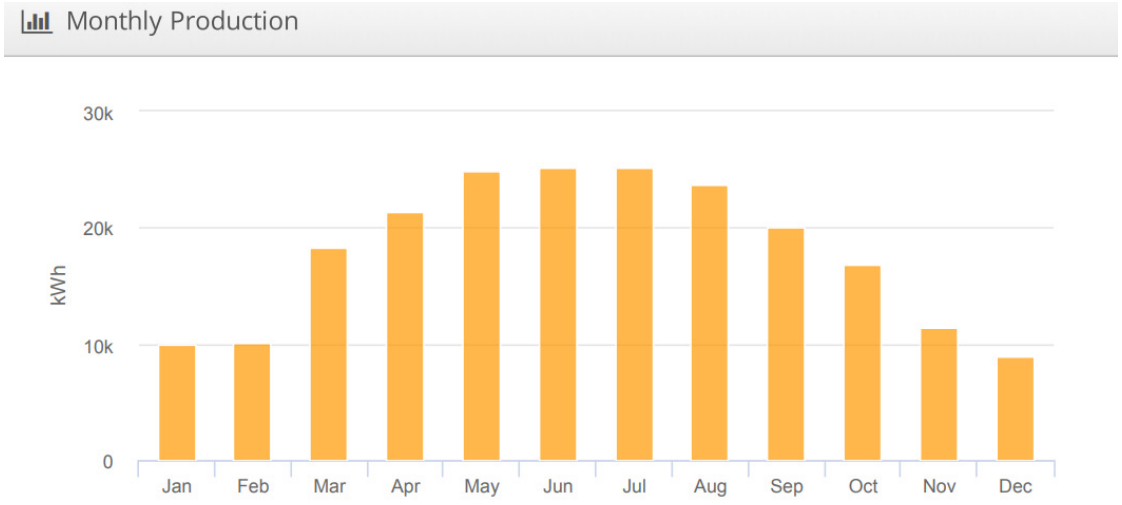


Figure 6.27 Projected Monthly Production for a PV System Located at 7399 Johnson Drive

<u>Recommendation</u>: If desired at this location, solar power canopies paired with EV charging stations for overnight charging should be included within the CIP along with the other solar PV system recommendations.

6.5.5 On-Site or Off-Site Wind Energy (RE-5)

Publicly available wind speed data was used to evaluate the potential for wind power generation across the DSRSD facilities. The closest National Weather Service (NWS) station is located at the Livermore Municipal Airport, which is located approximately 10 miles east of the WWTP. NWS hourly records for this station were reviewed for 2021. The monthly wind speed ranged from 3 to 9 miles per hour (mph), and the overall average for 2021 was 6.4 mph (Table 6.19).

Table 6.19 Average Wind Speeds in Dublin, California

Month	Average Wind Speed in 2021(1) (mph)
January	4.7
February	5.6
March	5.8
April	7.4
May	8.4
June	9.1
July	8.2
August	7.1
September	6.1
October	6.4
November	3.3
December	5.6
2021 Average	**6.4**

Notes:
(1) Wind speed was measured at the Livermore Municipal Airport (NWS Station ID 72492723285).

According to the Energy Information Administration, even small-scale wind turbines are recommended for locations where the annual average wind speeds are at least 9 mph, and the minimum recommended wind speed for a utility-scale project is 13 mph. The hourly data was statistically evaluated. Wind speeds were below 13 mph 85 percent of the time in 2021 (data not shown).

Given marginal local wind speeds, Carollo concludes that DSRSD's facilities are not located in an area that is conducive to on-site wind power generation, even at a small scale. Therefore, pursuing wind power projects on-site at the WWTP or other DSRSD properties is not recommended. DSRSD is encouraged to revisit onsite wind energy generation again in the future as turbine technology is progressing and this energy resource could become economically viable in the future even at lower wind speeds.

6.5.6 Renewable Energy Generation Partnerships (RE-7)

Partnerships for larger renewable energy generation projects include PPAs and third-party private funding. For example, financing companies can provide administrative support and access to funding sources. Technology vendors (e.g., for microturbine or biogas engine systems) or operations companies (such as Energy Service Companies) can provide the design, construction and operations services of energy related capital investments reducing the financial risk of larger projects for DSRSD.

The following sections briefly describe partnerships DSRSD can consider depending on the type of energy related projects selected to pursue in the future.

6.5.6.1 Partnerships With Pacific Gas & Electric Company or the Department of General Services (DGS)

Renewable Natural Gas Procurement

DSRSD currently purchases NG from PG&E. DSRSD could decide to purchase all or a portion of its primary energy as RNG along with its green attributes from alternative producers. The California DGS offers RNG supply contracts at a delivered cost ranging from $16 to $20 per MMBTU depending on the source of the RNG and the CI score. (The CI score measures all GHG emissions associated with the production, distribution, and consumption of a fuel.) For comparison, the current average cost of NG for DSRSD purchased from PG&E for cogen applications is $2 per MMBtu ($0.2/therm) (see TM 1).

Recommendation: Because of the cost difference between NG and renewable biogas, Carollo does not recommend this option for DSRSD currently.

Selling Renewable Natural Gas

PG&E offers programs under which DSRSD could sell its biomethane produced onsite to PG&E after bringing it to pipeline grade quality. The RNG procurement contracts offer different price tiers. A biomethane contract for Tier 1 pays up to $17.70 per MMBtu and does not require approval by the California Public Utility Commission (CPUC). This cost limit was derived from a study conducted by the California's State Water Resources Control Board. A biomethane contract for Tier 2 is priced between $17.70 per MMBtu and $26 per MMBtu; this cost tier includes the social cost of methane and requires CPUC approval in the form of a Tier 2 Advice Letter. A Tier 3 biomethane contract is priced above $26/MMBtu and requires a Tier 3 Advice Letter approval.

This program was established to support California's state-wide decarbonization goal for gas utilities. The proposed short-term 2025 target requires the gas utilities to prioritize biomethane procurement from standalone anaerobic digesters and wastewater treatment facilities that co-digest wastewater and organic waste diverted from landfills. Additional goals are set for medium-term 2030 targets.

Recommendation: Because power generation provides a higher economic value, the low DG volume generated would not justify the cost for RNG upgrading and pipeline interconnection which would not generate a payback within 20 years. Carollo does not recommend this opportunity for DSRSD.

6.5.6.2 Summary of Incentive Programs Applicable to Each Project Alternative

The Renewable Fuel Standard (RFS) program is a national policy that requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based fuel, where renewable fuel suppliers are incentivized via renewable identification number (RIN). Additionally, DSRSD could decide to increase its export of electricity generated from biogas and obtain credits in the form of eRINs under the LCFS program. eRINs are credits produced when qualifying biogas is used to generate renewable electricity for the charging of light-duty electric vehicles. Similar to traditional RINs, eRINs are then traded on the open market. (Participating in this program would mean that DSRSD could not keep the renewable energy credits in-house to claim GHG reduction credits as a qualification for receiving state funding. DSRSD should consult a GHG and air compliance specialist for best courses of action.) The final incentive program worth noting is the

Microgrid Incentive Program, which is a $200 million statewide program intended to fund clean energy microgrids to support the needs of vulnerable populations and water infrastructures.

Table 6.20 summarizes financial incentive programs associated with various energy infrastructure projects that DSRSD could utilize. For additional information regarding the RFS, LCFS and microgrid programs, please refer to the following sections located in TM 8:

- RFS: Section 8.7.2.2.
- LCFS: Section 8.6.6.1.
- Microgrid Incentive Program: Section 8.5.2.

Table 6.20 Incentive Programs for Various DSRSD's Energy Infrastructure Projects

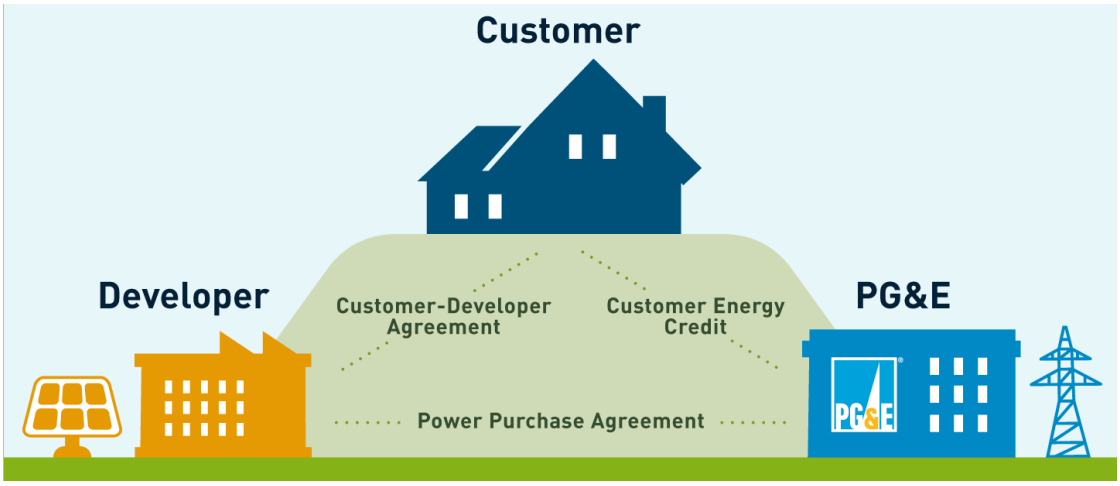
Projects	RFS and LCFS	eRIN	Microgrid Program
Biogas Engines (BS-31A, BS-31B, BS-34, and BS-35)	X	X	X
Future Hydrogen Storage (ES-1)	X	X	X
Battery Storage (ES-1)			X
Fuel Switching to RNG or Hydrogen (with new ICE or fuel cells)	X	X	X
Pump Stations			X

6.5.6.3 Green Power Purchasing (RE-8)

The Regional Renewable Choice program offered by PG&E allows businesses to purchase green electricity and provides additional incentives to reduce the cost of purchased electricity under this program. The program has three components:

1. **PPA**: The PPA is set up between DSRSD and PG&E to develop and sell electricity generated from a renewable energy project.
2. **Customer-Developer Agreement**: Agreement between DSRSD (developer) and customers that subscribe electricity from DSRSD directly.
3. **Customer Energy Credit**: A credit system between the customers and PG&E to earn credits and reduce electrical costs.

Figure 6.28 shows these program components schematically.



Source: PG&E

Figure 6.28 PG&E's Regional Renewable Choice Program Components

Through this and similar programs, green power can be purchased through PG&E through a variety of options. The following sections summarize other opportunities. These programs will become relevant for DSRSD if/when solar PV is installed onsite.

6.5.6.4 Solar Power Purchase Agreement Programs

Pacific Gas & Electric Company Solar Choice Program

Customers enrolled in the Solar Choice Program remain on the existing electric rate plan with PG&E and can choose to subscribe to either 50 percent or 100 percent of the monthly electricity usage generated from solar projects. New enrollments under this program will be offered again in 2025. The cost of the Solar Choice Program is currently an increase of 1.6 cents per kWh above existing electricity rates for a 100 percent subscription of renewable energy, or a 0.08 cents per kWh increase above existing electricity rates for a 50 percent subscription. (This example is based on rate schedule E-19.)

Further details on 2023 prices, terms, and conditions are accessible through PG&E's Solar Choice Program (https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/options/solar/solar-choice/CommunitySolarChoicePlan_TermsConditions.pdf).

Ava Community Energy Programs

Most of DSRSD's facilities are currently being served by Ava Community Energy. Notable exceptions are PG&E account number 4053823994 (WWTP, not eligible for the community energy program due to net metering with PG&E), and 6772573820 (field operations building, program was terminated).

Ava Community Energy offers two different purchase power plans:

1. **Bright Choice Service Plan**. This plan is priced at 5 percent below PG&E's generation rate.
2. **Renewable 100**. This plan offers 100 percent renewable energy and is priced at 3/4 of a penny ($0.0075) per kWh above PG&E's rates. Note that there currently is a waiting list for applications to this program, so it is not immediately available to DSRSD.

From a financial perspective, choosing a 100 percent renewable option might not be in the District's best interest. However, if DSRSD policies include objectives to reduce GHG emissions, this is a viable option, with the caveat that there is a financial cost for achieving this goal. Furthermore, this plan would be an alternative that would be easier to implement compared to building solar on-site. Table 6.21 summarizes the cost and GHG impact of this opportunity.

Table 6.21 Cost and GHG Impact of Green power Purchasing (RE-8)

	2021	2035	2047
Electricity Consumption (MWh/year)	14,848	17,767	19,600
Additional Cost ($/year)		190,000	300,000
Reduction in GHG Emissions (MT CO_2e/year)		1,305	1,440
Cost per MT CO_2e reduced ($/MT CO_2e)		$145	$207

Notes:
MT - metric ton.
(1) Total electricity consumption of DSRSD includes WWTP and collection system, potable water distribution, recycled water distribution, and administrative and other buildings. For further information regarding the values listed, see TM 4.
(2) Cost of Renewable 100 plan assumed to escalate at 3 percent annually from 2023 cost of $0.0075/kWh.
(3) To be conservative, the GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the Community Choice Aggregation and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.

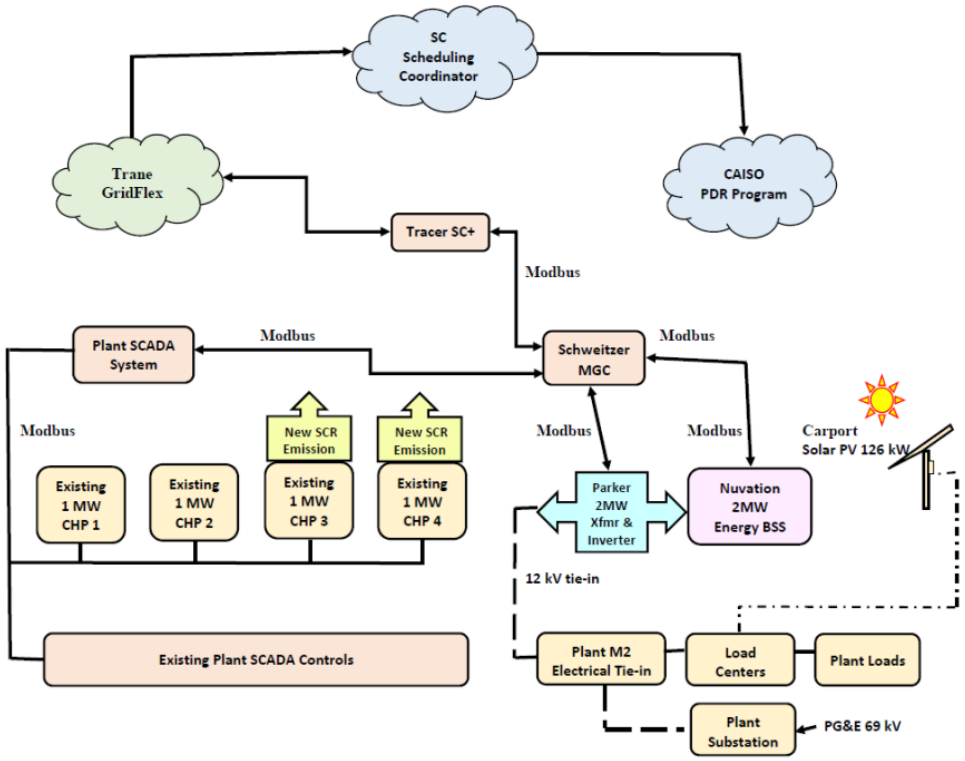
6.6 Energy Storage Opportunities

Microgrids are groups of energy loads and energy resources that can be operated as a single system in relation to the larger energy grid to manage both onsite energy production and onsite energy storage for DSRSD. Microgrids can either be connected to the electricity grid or operate independently to improve resilience against grid disturbances.

A recent project example of a microgrid system was funded in 2019 by the Energy Commission at Santa Rosa's Laguna WWTP. The components of the facility included:

- Solar PV carports with inverters.
- Battery energy storage system.
- Microgrid controller (Schweitzer SEL3555 Real-Time Automation Controller and SEL2407 Microgrid Management System).
- Coupling switchgear.
- Control software.

This project reduced Santa Rosa WWTP's electricity use and costs, resulting in estimated savings between $85,000 and $125,000 annually. DSRSD can participate in the California Independent System Operator Proxy Demand Resource One Day-ahead Market Program, which can generate an additional Revenue of $80,000 to $140,000 per year (https://www.energy.ca.gov/sites/default/files/2021-04/CEC-500-2019-063.pdf). Figure 6.29 shows the architecture of the microgrid at the Santa Rosa WWTP site.



Source: Trane U.S.

Figure 6.29 Microgrid Architecture at the Laguna Wastewater Plant (Santa Rosa, California)

The following sections evaluate energy storage and microgrid opportunities at DSRSD.

6.6.1 Energy Storage in Microgrid Systems (ES-1)

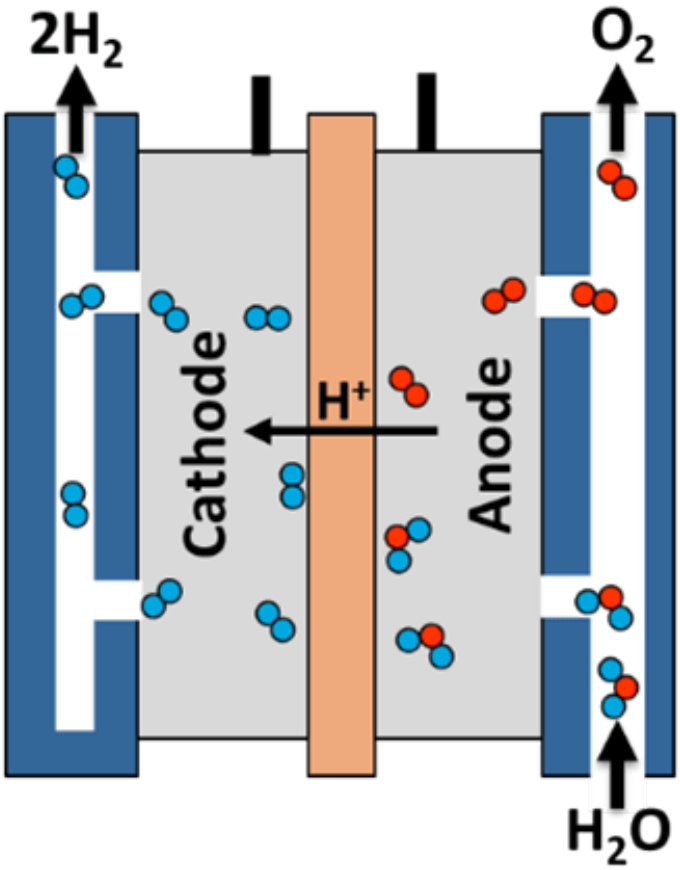
6.6.1.1 Battery Storage

Lithium-ion (Li-ion) batteries offer a short-term energy back-up power solution that can provide a few hours of power, which is applicable in times of emergency or during peak hour operation. With costs for Li-ion batteries still relatively high, the payback period becomes reasonable when obtaining SGIP funding designated for disadvantaged communities or other subsidies. DSRSD, however, would not qualify for this funding. The economics of adding batteries have been evaluated as part of Opportunity ES-2 (see Section 6.6.2).

6.6.1.2 Hydrogen Storage

Hydrogen production is quickly becoming a promising technology for carbon-free hydrogen production via the process of electrolysis. Electrolysis is the process of utilizing electricity to split water into hydrogen and oxygen; this reaction occurs in a piece of equipment known as an electrolyzer. A typical electrolyzer consists of an anode, electrolyte membrane, and a cathode to separate oxygen and hydrogen from water. The electrolysis process is detailed below, and Figure 6.30 shows a typical electrolyzer structure that is used for hydrogen production.

1. Water reacts at the anode to form oxygen and positively charged hydrogen ions.
2. Hydrogen ions then selectively move across an electrolyte or membrane.
3. The cathode then combines hydrogen ions with electrons from an external source to form hydrogen gas.



Source: Department of Energy. n.d. "Hydrogen Production: Electrolysis." *https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.*

Figure 6.30 Structure of a Typical Polymer Electrolyte Membrane Electrolyzer (EERE)

Additionally, electrolyzers can also be used for longer-term energy storage by producing hydrogen then storing the gas in pressurized vessels for later use in a similar method to traditional batteries; the three types of electrolyzers are as follows and differ based on electrolyte material:

- *Alkaline:* Utilizes a liquid electrolyte, typically either potassium hydroxide or sodium hydroxide.
- *Solid oxide:* Utilizes a solid oxide ceramic, typically zirconium dioxide.
- *Polymer electrolyte membrane:* Utilizes a solid semipermeable plastic membrane.

Recommendation: Based on current technology and costs, energy storage in the form of hydrogen is not yet cost effective. Over the next 10 years, however, costs for electrolyzers are anticipated to significantly decrease and may be a potential option for DSRSD to consider in the future. Carollo recommends evaluating this emerging technology again in the coming years as prices become cost-competitive with lithium battery storage. Possibilities for hydrogen generation onsite will only become more feasible as DSRSD becomes increasingly energy independent through the use of renewable energy systems.

6.6.2 Battery Storage for Peak Demand Charges (ES-2)

Sizing battery storage capacity to cover the peak demands at DSRSD's WWTP reduces battery storage costs while avoiding peak demand charges. Carollo evaluated the required battery sizing based on historical electricity demand data from the WWTP using two independent methods.

TESLA's "Megapack" is an energy storage system that is scalable to the space, power, and energy requirements of a site from 1 MWh to 1 gigawatt-hour as needed. As an example, a 1 MW battery (the smallest typical industrial capacity) installed costs approximately $2.4 million. Using an estimated peak power cost of $0.30/kWh, the estimated payback would be approximately 10 years including financial support through the SGIP. Battery storage system payback is based on power stored from solar PV, which would otherwise be sold back to the grid at a loss under NEM 3.0 (California policy that took effect on April 15, 2023). Also, battery installation may be required with new commercial solar projects. Hybrid Optimization of Multiple Energy Resources (HOMER) modeling resulted in a 1 MW sized system as the ideal size for the battery for the WWTP considering solar PV of 1 MW and existing cogeneration engine sizing. (see Appendix 6B for further details).

The National Renewable Energy Laboratory's software tool HOMER was used to estimate the sizing of the battery storage systems. HOMER assumes that the future energy mix will constitute of electricity provided by the grid, solar, the cogeneration engines, and battery storage. Past electrical billing rates from PG&E and schedule rate E19 – General Demand-Metered Time of Use Service – were used, along with an estimated spending of $1.17 million for electricity usage per year, of which an estimated 70 percent of this expenditure is accounted to demand charges (see TM 1).

Table 6.22 summarizes the key outputs from the HOMER analysis. Further details are included in Appendix 6C.

Table 6.22 Net Present Life Cycle Costs for Opportunity ES-2: Battery Storage for Peak Demand Charges

Parameter	Value
Power ratings	1.4 MW total Engine generators (BS-31A, BS-31B), 1 to 1.4 MW solar, 1 MW Li-ion battery storage
Estimated Construction Cost ($) (Solar 1 MW, battery storage 1 MWh) (does not include cogen)	5,600,000
Annual Savings of Energy and Demand Charges ($)(1)	up to $427,000 per year(2)
Total O&M Costs ($/year)	110,000
Total Net Annual Savings (2023 $)	320,000
Levelized Costs of Energy	Approximately 15.5 cents per kWh(3)
Payback (Years) (without incentives)	7
Payback (Years) (with SGIP)	5-6

Notes:
(1) Demand charges, standby charges may vary, at peak power costs 0.3 cents per kWh, $1,170 per day.
(2) Demand charge savings range from $330,000 to $427,000.
(3) Local rates based on HOMER model and PG&E rates E-20, 15-minute interval data can vary every year.

The levelized cost of energy - the minimum price at which energy must be sold for an energy project to break even - for the ICE with 1.4 MW (Opportunity BS-31A and BS-31B) is 15.5 cents per kWh. The 1 MW solar and 1 MW battery energy storage in combination with the new and more efficient cogeneration plant rated at 1.4 MW can reduce peak and max demand charges as well as peak energy and standby charges.

Recommendation: Due to the favorable payback period Carollo recommends including the 1 MW energy storage to cover peak demands and the 1 MW onsite solar system in DSRSD's CIP.

6.7 Thermal Energy Recovery Opportunities

6.7.1 Expand Heat Loop (TH-4)

Several of DSRSD's buildings are connected to the heat loop receiving waste thermal heat from the digester heat recovery system for building heating. Figure 6.31 shows all buildings currently connected to the heat loop (see also TM 1).

Orange: Buildings connected to the heat loop

Figure 6.31 Current WWTP Buildings Receiving Thermal Energy From the Heat Loop System

Recommendation: Although there is waste heat available, all easily accessible buildings that would benefit from heat loop expansion are already included as part of the heat loop so it is not recommended to pursue this alternative further.

6.7.2 Use Heat for Process Needs (TH-5) and Advanced Biosolids Processing (TH-7)

The digesters are currently heated using recovered heat from the cogeneration system. Excess heat could be used for drying of the biosolids post digestion. Biosolids drying is not a necessary treatment process currently.

Recommendation: Carollo recommends reevaluating this opportunity if/when DSRSD is required to change their solids handling process. There are no other significant process needs that would benefit from heating currently identified.

6.8 Summary of Approved Recommendations

Table 6.23 summarizes all opportunities discussed above with relevant information on costs, energy savings, whether it is recommended for inclusion into DSRSD's Energy CIP, further evaluation or other next steps. A brief rationale for each recommendation is included.

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Table 6.23 Overview of Energy Generation Opportunities Evaluated in This TM

Opportunity ID	Name	Estimated Potential for Energy Reduction/Savings	Estimated Capital Cost ($)	Recommendation	Comment/Justification
LS Treatment Process Energy Opportunities					
LS-3	Improve Carbon Diversion from Primaries to Digester (CEPT)	Not quantified as it is not recommended at this time.	Not quantified as it is not recommended at this time.	Not recommended at this time but keep as a potential future option.	Re-evaluate in 5 years.
BS Treatment Process Energy Opportunities					
BS-2B	Mechanical Thickening Post DAFT	Energy Use: 72,000 kWh/year Biogas Increase: 279,000 scfd	$5.6M	Not recommended.	Higher energy use than replacing DAFT with mechanical thickening.
BS-2C	Mechanical Thickening in Lieu of DAFT	Energy Use: (1,440,000) kWh/year Biogas Increase: 279,000 scfd	$7.5M	Recommended for implementation in year 2036	Recommended for replacing DAFT when DAFT is at the end of its useful service life. Provides significant energy savings compared to DAFT and increases digestion capacity.
BS-7	Recuperative Thickening	No anticipated savings. Estimated energy increase of 774,000 kWh/year.	$22M	Not recommended.	Not recommended as it would result in higher energy use and no advantages compared to BS-2C.
BS-13	Dewatering Post Digestion	Operational cost increase of $3.1M/yr. Estimated energy increase of 170,000 kWh/year.	$43M	Not recommended at this time but keep as a potential future option if DSRSD decides to accept FW.	Only driver is if DSRSD decides to accept FW as this would be necessary under SB 1383.
BS-17	Drying and Pyrolysis	Minimal anticipated savings	$83M	Not recommended	Reconsider if required based on future regulatory limits on PFAS.
BS-18	Drying and Gasification	Same as BS-17 above	Same as BS-17 above	Not recommended	Less established technology than pyrolysis (BS-17). Re-evaluate if necessary based on future regulatory limits on PFAS.
BS-22	Lystek Thermochemical Hydrolysis	Operational cost increase of $3.7M/yr. Estimated energy increase of 170,000 kWh/year	$43M	Not recommended	More costly than opportunity BS-13 with no significant advantages.
BS-23	Co-digest FOG	Estimated energy increase of 114,000 kWh/year offset by 146,000 scfd of biogas production	FOG Receiving Facility is already constructed	Recommended	Facility is already constructed and will significantly reduce GHG footprint. Additional digestion capacity would be needed by 2036, requiring pairing of this opportunity with BS-2C.
BS-24	Co-digest FW Slurry and HSW	Estimated energy increase of 343,000 kWh/year offset by 165,000 scfd of biogas production	$3.9M	Recommended	Available digester capacity can be utilized. Will significantly increase digester gas production for cogeneration facility offsetting NG use and reducing GHG footprint.
BS-26	Improve Gas Conditioning System	N/A	N/A	Not necessary as already under implementation	Upgrades currently being implemented.
BS-28	Increase Biogas Storage	No anticipated savings	$2M	Not recommended	Not cost-effective based on current cogen operations.
BS-30	Replace Cogeneration In-kind with Same Efficiency Engine Generators	No change	Not quantified	Not recommended	Current air quality standards do not allow for this alternative as lean burn engines are required.
BS-31A	Replace Cogeneration with Higher Efficiency Engine Generators (1 ICE at 1.4 MW)	Value of energy generated = $1,457,000, payback estimated at 16 yrs	$17.6M	Not recommended	Not recommended for lack of redundancy.
BS-31B	Replace Cogeneration with Higher Efficiency Engine Generators (2 ICE at 700 kW)	Value of energy generated = $1,457,000 per year	$44.4M	Recommended	Replaces infrastructure that is nearing the end of its useful life and provides power reliability.

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Table 6.23 Overview of Energy Generation Opportunities Evaluated in This TM (continued)

Opportunity ID	Name	Estimated Potential for Energy Reduction/Savings	Estimated Capital Cost ($)	Recommendation	Comment/Justification
BS-34	Replace Cogeneration to Cover Peak Electrical Demand	$430,000/year in annual energy and demand charges (See ES-2).	$5.8M (Not including cost of battery storage).	Not recommended	Not recommended due to long payback period consisting of both the energy storage system and redundant cogen engines.
BS-35	Increase Cogeneration to Cover Peak Electricity Demand and Redundancy	Value of energy generated = $2,184,800 payback estimated at 12 years	$9.6M	Recommended	Provides redundancy for energy production if an engine is out of service and allows for offsetting peak demand charges.
BS-37	Condition Biogas for Pipeline Injection	No anticipated savings	$22.7M	Not recommended	Unfavorable economics compared to cogeneration.
BLG System Operations Optimization					
BLG-12	Solar Thermal Heating	Minimal anticipated savings	$8k per 100 gallons	Recommend soliciting price and sizing quotes from specialized companies	May have return on investment of less than 10 years depending on pricing from specialized companies.
BLG-13	Wastewater Thermal Energy Use for Heating and Cooling	Not calculated	Not calculated	Recommended for offsite implementation. Investigate during future new commercial building construction within service area.	May have return on investment of less than 10 years depending on pricing from specialized companies.
RE Generation Opportunities					
RE-1A	On-Site Solar Installation: Administration Building (Including Battery Storage System)	465,000 kWh/year	$2,579,500/$0 (After tax rebates/PPA)	Recommended for implementation despite long payback periods (19 years).	Payback shorter than lifetime of systems (cost neutral). PV installations visually project to the public DSRSD's commitment to clean energy.
RE-1B	On-Site Solar Installation: Field Operations Facility (Including Battery Storage System)	93,000 kWh/year	$1,766,100/$0 (After tax rebates/PPA)	Recommended for implementation despite long payback periods (19 years).	Payback shorter than lifetime of systems (cost neutral). PV installations visually project to the public DSRSD's commitment to clean energy.
RE-1C	On-Site Solar Installation: Solar Carports	335,000 kWh/year	$750k/$0 (After tax rebates/PPA)	Not recommended.	Because the location of solar arrays on the roof of the Administration Building is suitable, RE-1A is recommended instead.
RE-2A	Off-Site Solar Installation: Gleason Property	3,700,000 kWh/year	$5.1M/$0 (After tax rebates/PPA)	Not recommended.	Properties and access needed for other purposes or operation of Gleason site.
RE-2B	Off-Site Solar Installation: LAVWMA – within Basins	3,800,000 kWh/year	$4.7 M/$0 (After tax rebates/PPA)	Not recommended.	Properties and access needed for other purposes or operation of LAVWMA site.
RE-2C	Off-Site Solar Installation: LAVWMA – edges of Basins	3,200,000 kWh/year	$4.9M/$0 (After tax rebates/PPA)	Recommended for implementation in 2025	*Results in attractive NPVs especially if construction can occur through a PPA.*
RE-2D	Off-Site Solar Installation: Solar Carports Park N Ride Pleasanton	253,000 kWh/year	$530k/$0 (After tax rebates/PPA)	Not recommended.	Losses and inefficiencies have a more notable impact with the smaller off-site layout when compared to the larger off-site installations.
RE-3	Solar Installation at the DLD Site	Not calculated	Not calculated	Not recommended	Not recommended based on impacts to DLD operations.
RE-4	Solar Power for EV Fleet Recharging Stations	See RE-1A & RE-1B	See RE-1A & RE-1B	Recommended	This includes battery storage system installation costs for overnight EV charging.
RE-5	On-Site or Off-Site Wind Energy	Not calculated	Not calculated	Not recommended at this time.	Local wind speeds do not allow for economical operation. However, turbine technology is improving and should be re-evaluated in the future.

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Table 6.23 Overview of Energy Generation Opportunities Evaluated in This TM (continued)

Opportunity ID	Name	Estimated Potential for Energy Reduction/Savings	Estimated Capital Cost ($)	Recommendation	Comment/Justification
RE-7	Renewable Energy Generation Partnerships	N/A	N/A	Recommended only if solar is implemented offsite	More economical than without partnerships.
RE-8	Green Power Purchasing	N/A	N/A	Recommended	Low additional cost for purchasing renewable power from PG&E.
ES Opportunities					
ES-1	Energy Storage in Microgrid Systems	Not calculated	Not calculated	Battery storage for offsetting peak demand recommended, see Opportunity ES-2 (Section 6.6.2). Hydrogen storage not recommended at this time	Hydrogen storage technology is emerging and currently not cost effective. Evaluate in future if determined to be cost effective.
ES-2	Battery Storage for Peak Demand Charges	$430,000/year in annual energy and demand charges.	$5.6M not including cogen	Recommended	Based on ROI of 5-7 years depending on grant availability, this alternative could provide significant cost savings benefits.
TH Energy Recovery Opportunities					
TH-4	Expand Heat Loop	Not calculated	Not calculated	Not recommended	Not economical based on distance to remaining buildings not currently on heat loop.
TH-5	Use Heat for Process Needs	Not calculated	Not calculated	Not recommended	Waste heat from cogeneration is already being used for digester heating, no other significant process heat requirements currently identified.
TH-7	Use Heat Advanced Biosolids Processing	Not calculated	Not calculated	Evaluate in future if advanced biosolids processing is implemented	Currently there is no need unless changes to biosolids processing are implemented in the future.

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Appendix 6A

DETAILED COST ESTIMATE

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
SCENARIO: BS-2B: New Thickening RDTs (Post DAFT)

ESTIMATE CLASS: 5
PREPARED BY: CP
DATE PREPARED: 3/21/2023
REVIEWED BY: RLG
DATE REVIEWED: 6/5/2023

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
3	**CONCRETE/STRUCTURES**					
	Thickener Pad	44	CY	$ 675	$ 30,000	
	Thickener Shade Structure	800	SF	$ 75	$ 60,000	
	Filtrate Wet Well Allowance	1	LS	$ 500,000	$ 500,000	
	Total					$ 590,000
11	**EQUIPMENT**					
	Thickening RDTs	2	EA	$ 204,757	$ 409,513	
	Polymer Feed System	1	LS	$ 150,000	$ 150,000	
	Thickening Feed Pumps	2	EA	$ 50,000	$ 100,000	
	Digester Feed Pumps	2	EA	$ 50,000	$ 100,000	
	Odor Control System	1	LS	$ 500,000	$ 500,000	
	Installation Allowance	30%			$ 227,854	
	Total					$ 1,487,000
	SUBTOTAL					**$ 2,077,000**
	Sitework & Yard Piping Allowance	15	%		$ 312,000	
	Process Mechanical Allowance	15	%		$ 312,000	
	Electrical, Instrumentation & Control Allowance	30	%		$ 623,000	
	Total					$ 1,247,000
	DIRECT COST SUBTOTAL					**$ 3,324,000**
	Estimating Contingency	30	%			$ 997,000
	SUBTOTAL					**$ 4,321,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$ 185,000
	SUBTOTAL					**$ 4,506,000**
	General Conditions, Contractor Overhead, & Profit	25	%			$ 1,127,000
	SUBTOTAL					**$ 5,633,000**
	TOTAL CONSTRUCTION COST					**$ 5,600,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
SCENARIO: BS-2C: New Thickening RDTs (Instead of DAFT; RAS wasting)

ESTIMATE CLASS: 5
PREPARED BY: CP
DATE PREPARED: 6/2/2023
REVIEWED BY: RLG
DATE REVIEWED: 6/5/2023

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
3	**CONCRETE/STRUCTURES**					
	Thickener Pad	67	CY	$ 675	$ 45,000	
	Thickener Shade Structure	1200	SF	$ 75	$ 90,000	
	Filtrate Wet Well Allowance	1	LS	$ 500,000	$ 500,000	
	Total					$ 635,000
11	**EQUIPMENT**					
	Thickening RDTs	3	EA	$ 204,757	$ 614,270	
	Polymer Feed System	1	LS	$ 150,000	$ 150,000	
	Thickening Feed Pumps	2	EA	$ 50,000	$ 100,000	
	Digester Feed Pumps	2	EA	$ 50,000	$ 100,000	
	Odor Control System	1	LS	$ 500,000	$ 500,000	
	Installation Allowance	30%			$ 289,281	
	Total					$ 1,754,000
	SUBTOTAL					**$ 2,389,000**
	Sitework & Yard Piping Allowance for RAS Wasting	20	%		$ 478,000	
	DAFT Demolition Allowance	1	LS		$ 500,000	
	Process Mechanical Allowance	15	%		$ 358,000	
	Electrical, Instrumentation & Control Allowance	30	%		$ 717,000	
	Total					$ 2,053,000
	DIRECT COST SUBTOTAL					**$ 4,442,000**
	Estimating Contingency	30	%			$ 1,333,000
	SUBTOTAL					**$ 5,775,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$ 247,000
	SUBTOTAL					**$ 6,022,000**
	General Conditions, Contractor Overhead, & Profit	25	%			$ 1,506,000
	SUBTOTAL					**$ 7,528,000**
	TOTAL CONSTRUCTION COST					**$ 7,500,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
SCENARIO: BS-7: Recuperative Thickening (New Thickening Facility + Digestion Mixers Retrofit)

ESTIMATE CLASS: 5
PREPARED BY: CP
DATE PREPARED: 3/22/2023
REVIEWED BY: RLG
DATE REVIEWED: 6/5/2023

DIVISION	DESCRIPTION	QUAN	UNIT	UNIT COST	SUBTOTAL	TOTAL
3	**CONCRETE/STRUCTURES**					
	Thickener Pad	44	CY	$ 675	$ 30,000	
	Thickener Shade Structure	800	SF	$ 75	$ 60,000	
	Filtrate Wet Well Allowance	1	LS	$ 500,000	$ 500,000	
	Digester Modifications - Mixer Box Pad	28	CY	$ 950	$ 27,022	
	Digester Structural Modifications	15,360	HR	$ 90	$ 1,382,400	
	Total					$ 1,999,000
11	**EQUIPMENT**					
	Omnivore Package	1	LS	$ 3,870,000	$ 3,870,000	
	Sludge Heating Pumps	4	EA	$ 50,000	$ 200,000	
	Hot water pumps	4	EA	$ 25,000	$ 100,000	
	High Pressure Tube-in-Tube Heat Exchangers	4	EA	$ 150,000	$ 600,000	
	Installation Allowance	30%			$ 1,431,000	
	Total					$ 6,201,000
	SUBTOTAL					**$ 8,200,000**
	Sitework & Yard Piping Allowance	15	%		$ 1,230,000	
	Process Mechanical Allowance	15	%		$ 1,230,000	
	Electrical, Instrumentation & Control Allowance	30	%		$ 2,460,000	
	Total					$ 4,920,000
	DIRECT COST SUBTOTAL					**$ 13,120,000**
	Estimating Contingency	30	%			$ 3,936,000
	SUBTOTAL					**$ 17,056,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$ 730,000
	SUBTOTAL					**$ 17,786,000**
	General Conditions, Contractor Overhead, & Profit	25	%			$ 4,447,000
	SUBTOTAL					**$ 22,233,000**
	TOTAL CONSTRUCTION COST					**$ 22,200,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
SCENARIO: BS-13 & BS-22: New Dewatering Screw Presses in New Building

ESTIMATE CLASS: 5
PREPARED BY: CP
DATE PREPARED: 3/21/2023
REVIEWED BY: RLG
DATE REVIEWED: 6/5/2023

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
3	**CONCRETE/STRUCTURES**					
	New Dewatering Building, 70 ft x 70 ft	4900	SF	$ 1,000	$ 4,900,000	
	New Truck Load-out Bay Building, 70 ft x 30 ft	2100	SF	$ 1,000	$ 2,100,000	
	Total					$ 7,000,000
11	**EQUIPMENT**					
	Screw Press Package	2	EA	$ 750,000	$ 1,500,000	
	Polymer Storage	1	LS	$ 200,000	$ 200,000	
	Feed Pumps	2	EA	$ 100,000	$ 200,000	
	Bridge Crane	1	EA	$ 200,000	$ 200,000	
	Truck Scale	1	EA	$ 130,000	$ 130,000	
	Cake Storage Silo / Conveyor Package	1	LS	$ 3,000,000	$ 3,000,000	
	Odor Control System	1	LS	$ 2,000,000	$ 2,000,000	
	Installation Allowance	50%	%		$ 1,115,000	
	Total					$ 8,345,000
	SUBTOTAL					**$ 15,345,000**
	Sitework & Yard Piping Allowance	20	%		$ 3,069,000	
	Process Mechanical Allowance	15	%		$ 2,302,000	
	Electrical, Instrumentation & Control Allowance	30	%		$ 4,604,000	
	Total					$ 9,975,000
	DIRECT COST SUBTOTAL					**$ 25,320,000**
	Estimating Contingency	30	%			$ 7,596,000
	SUBTOTAL					**$ 32,916,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$ 1,409,000
	SUBTOTAL					**$ 34,325,000**
	General Conditions, Contractor Overhead, & Profit	25	%			$ 8,581,000
	SUBTOTAL					**$ 42,906,000**
	TOTAL CONSTRUCTION COST					**$ 42,900,000**

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JOB # :	200892	**ATE PREPARATION DATE :**	1/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Renewable Energy	**REVIEW DATE :**	6/29/2023
SCENARIO:	RE 1 - Onsite Solar Installation Admin Building	**REVIEWED BY :**	RG

DESCRIPTION	QTY	UNIT	UNIT COST	TOTAL
Equipment				
Solar panels	77,300	W	$ 2.5	$ 193,250
Energy monitoring Package	1	LS	$ 20,000	$ 20,000
Switchgear interconnection installation allowance	10%	%		$ 21,325
Structures				
included			$ 1	$ -
SUBTOTAL				**$ 234,575**
EI&C allowance	10%	%		$ 23,000
TOTAL DIRECT COST				**$ 257,575**
Estimating Contingency	10%	%	$ 25,758	$ 283,000
Contractor General Conditions, Overhead and Profit Mar	10%	%	$ 28,300	$ 311,000
Sales Tax on 50% of Total Direct Cost Subtotal	7.4%	%	$ 9,505	$ 321,000
TOTAL CONSTRUCTION COST				**$ 321,000**
Engineering, Legal, Admin, Permitting, and Construction	10%	%	$ 32,100	**$ 353,000**
TOTAL PROJECT COST				**$ 353,000**

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JOB # :	200892	**ATE PREPARATION DATE :**	1/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Renewable Energy	**REVIEW DATE :**	6/29/2023
SCENARIO:	RE 1 - Onsite Solar Installation Field Office Building	**REVIEWED BY :**	RG

DESCRIPTION	QTY	UNIT	UNIT COST	TOTAL
Equipment				
Solar panels	70,000	W	$ 2.5	$ 175,000
Energy monitoring Package	1	LS	$ 20,000	$ 20,000
Switchgear interconnection installation allowance	10%	%		$ 19,500
Structures				
included			$ 1	$ -
SUBTOTAL				**$ 214,500**
EI&C allowance	10%	%		$ 21,000
TOTAL DIRECT COST				**$ 235,500**
Estimating Contingency	10%	%	$ 23,550	$ 259,000
Contractor General Conditions, Overhead and Profit Mar	10%	%	$ 25,900	$ 285,000
Sales Tax on 50% of Total Direct Cost Subtotal	7.4%	%	$ 8,690	$ 294,000
TOTAL CONSTRUCTION COST				**$ 294,000**
Engineering, Legal, Admin, Permitting, and Construction	10%	%	$ 29,400	**$ 323,000**
TOTAL PROJECT COST				**$ 323,000**

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JOB # :	200892	**PREPARATION DATE**	1/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Renewable Energy	**REVIEW DATE :**	6/29/2023
SCENARIO:	RE 2 - Offsite Solar Installation Gleason Site	**REVIEWED BY :**	RG

DESCRIPTION	QTY	UNIT	UNIT COST	TOTAL
Equipment				
Solar panels	2,170,000	W	$ 2.0	$ 4,340,000
Energy monitoring Package	1	LS	$ 20,000	$ 20,000
Switchgear interconnection installation allowance	10%	%		$ 436,000
Structures				
included			$ 1	$ -
SUBTOTAL				**$ 4,796,000**
EI&C allowance	10%	%		$ 480,000
TOTAL DIRECT COST				**$ 5,276,000**
Estimating Contingency	10%	%	$ 527,600	$ 5,804,000
Contractor General Conditions, Overhead and Profit Margin	10%	%	$ 580,400	$ 6,384,000
Sales Tax on 50% of Total Direct Cost Subtotal	7.4%	%	$ 194,684	$ 6,579,000
TOTAL CONSTRUCTION COST				**$ 6,579,000**
Engineering, Legal, Admin, Permitting, and Construction Mgt	10%	%	$ 657,900	**$ 7,237,000**
TOTAL PROJECT COST				***$ 7,237,000***

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JOB # :	200892	**PREPARATION DATE :**	1/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Renewable Energy	**REVIEW DATE :**	6/29/2023
SCENARIO:	RE 2 - Offsite Solar Installation LAVWMA	**REVIEWED BY :**	RG

DESCRIPTION	QTY	UNIT	UNIT COST	TOTAL
Equipment				
Solar panels	2,000,000	W	$ 2.0	$ 4,000,000
Energy monitoring Package	1	LS	$ 20,000	$ 20,000
Switchgear interconnection installation allowance	10%	%		$ 402,000
Structures				
included			$ 1	$ -
SUBTOTAL				**$ 4,422,000**
EI&C allowance	10%	%		$ 442,000
TOTAL DIRECT COST				**$ 4,864,000**
Estimating Contingency	10%	%	$ 486,400	$ 5,350,000
Contractor General Conditions, Overhead and Profit Margin	10%	%	$ 535,000	$ 5,885,000
Sales Tax on 50% of Total Direct Cost Subtotal	7.4%	%	$ 179,482	$ 6,064,000
TOTAL CONSTRUCTION COST				**$ 6,064,000**
Engineering, Legal, Admin, Permitting, and Construction Mgmt	10%	%	$ 606,400	**$ 6,670,000**
TOTAL PROJECT COST				**$ 6,670,000**

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JOB # :	200892	**PREPARATION DATE :**	1/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Renewable Energy	**REVIEW DATE :**	6/29/2023
SCENARIO:	RE 2 - Offsite Solar Installation LAVWMA Basin Edge	**REVIEWED BY :**	RG

DESCRIPTION	QTY	UNIT	UNIT COST	TOTAL
Equipment				
Solar panels	1,500,000	W	$ 2.7	$ 3,996,000
Energy monitoring Package	1	LS	$ 20,000	$ 20,000
Switchgear interconnection installation allowance	10%	%		$ 401,600
Structures				
included			$ 1	$ -
SUBTOTAL				**$ 4,417,600**
EI&C allowance	10%	%		$ 442,000
TOTAL DIRECT COST				**$ 4,859,600**
Estimating Contingency	10%	%	$ 485,960	$ 5,346,000
Contractor General Conditions, Overhead and Profit Margin	10%	%	$ 534,600	$ 5,881,000
Sales Tax on 50% of Total Direct Cost Subtotal	7.4%	%	$ 179,319	$ 6,060,000
TOTAL CONSTRUCTION COST				**$ 6,060,000**
Engineering, Legal, Admin, Permitting, and Construction Mgmt	10%	%	$ 606,000	**$ 6,666,000**
TOTAL PROJECT COST				**$ 6,666,000**

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JOB # : 200892 **ESTIMATE PREPARATION DATE :** 1/2/2023
LOCATION : San Ramon, CA **PREPARED BY :** CT
PROCESS: Internal Combustion Engines **REVIEW DATE :** 6/29/2023
SCENARIO: BS-30: Replace existing 3 x 450 kW with 1x 1,400 kW (40% DG and 60% NG) **REVIEWED BY :** RG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Concrete pad for conditioning system	800	SF	$100	$80,000	
	Allowance for cogen building retrofit	1	LS	$500,000	$500,000	
	Total					$580,000
2	**Equipment**					
	1400 kW Engine/Generator Cogeneration System (Jenbacher 420) with Heat Recovery Unit. and SCR	1	EA	$1,600,000	$1,600,000	
	Misc. Mechanical Equipment	1	LS	$205,000	$205,000	
	Misc. pumps, valves, piping	1	LS	$250,000	$250,000	
	Testing Allowance	1	LS	$75,000	$75,000	
	HVAC	1	LS	$100,000	$100,000	
	Fuel Conditioning system (siloxane, H2S removal)	1	EA	$2,000,000	$2,000,000	
	Equipment installation	1	LS	$687,000	$687,000	
	Total					$4,917,000
	SUBTOTAL					**$5,497,000**
3	**Allowances**					
	Process Mechanical Allowance	5	%		$275,000	
	EIC Allowance	30	%		$1,649,000	
	Yard Piping & Site Civil Allowance	10	%		$550,000	
	Coating/Painting Allowance	0	%		$0	
	Total					$2,474,000
	SUBTOTAL					**$7,971,000**
	Estimating Contingency	30	%			$2,391,000
	SUBTOTAL					**$10,362,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$443,000
	SUBTOTAL					**$10,805,000**
	General Conditions, Contractor Overhead, & Profit	25	%			$2,701,250
	SUBTOTAL					**$13,506,250**
	CONSTRUCTION COST SUBTOTAL					**$13,506,250**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$4,052,000
	PROJECT COST					**$17,558,000**

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JOB # :	200892	**ESTIMATE PREPARATION DATE :**	1/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Internal Combustion Engines	**REVIEW DATE :**	6/29/2023
SCENARIO:	BS-31: Replace existing 3x 450 kW with 2x 700 kW (40% DG and 60% NG)	**REVIEWED BY :**	RG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Concrete pad for conditioning system	1000	SF	$100	$100,000	
	Allowance for cogen building retrofit	1	LS	$500,000	$500,000	
	Total					$600,000
2	**Equipment**					
	700 kW Engine/Generator Cogeneration System (Jenbacher 3 series) with Heat Recovery Unit. and SCR	2	EA	$1,300,000	$2,600,000	
	Misc. Mechanical Equipment	2	LS	$250,000	$500,000	
	Misc. pumps, valves, piping	2	LS	$250,000	$500,000	
	Testing Allowance	2	LS	$75,000	$150,000	
	HVAC	2	LS	$100,000	$200,000	
	Fuel Conditioning system (siloxane, H2S removal)	1	EA	$2,000,000	$2,000,000	
	Equipment installation	1	LS	$687,000	$687,000	
	Total					$6,637,000
	SUBTOTAL					**$7,237,000**
3	**Allowances**					
	Process Mechanical Allowance	5	%		$362,000	
	EIC Allowance	30	%		$2,171,000	
	Yard Piping & Site Civil Allowance	10	%		$724,000	
	Total					$3,257,000
	SUBTOTAL					**$10,494,000**
	Estimating Contingency	30	%			$3,148,000
	SUBTOTAL					**$13,642,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$584,000
	SUBTOTAL					**$14,226,000**
	General Conditions, Contractor Overhead, & Profit	25	%			$3,557,000
	SUBTOTAL					**$17,783,000**
	CONSTRUCTION COST SUBTOTAL					**$17,783,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$5,335,000
	PROJECT COST					**$23,118,000**

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JOB # :	200892	**ESTIMATE PREPARATION DATE :**	1/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Internal Combustion Engines	**REVIEW DATE :**	6/29/2023
SCENARIO:	BS-35: Replace existing 3x 450 kW with 2x 1000 kW (40% DG and 60% NG)	**REVIEWED BY :**	RG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Concrete pad for conditioning system	1000	SF	$100	$100,000	
	Allowance for cogen building retrofit	1	LS	$500,000	$500,000	
	Total					$600,000
2	**Equipment**					
	1000 kW Engine/Generator Cogeneration System (Jenbacher 4 series) with Heat Recovery Unit. and SCR	2	EA	$1,550,000	$3,100,000	
	Misc. Mechanical Equipment	2	LS	$250,000	$500,000	
	Misc. pumps, valves, piping	2	LS	$250,000	$500,000	
	Testing Allowance	2	LS	$75,000	$150,000	
	HVAC	2	LS	$100,000	$200,000	
	Fuel Conditioning system (siloxane, H2S removal)	1	EA	$2,500,000	$2,500,000	
	Equipment installation	1	LS	$687,000	$687,000	
	Total					$7,637,000
	SUBTOTAL					**$8,237,000**
3	**Allowances**					
	Process Mechanical Allowance	5	%		$412,000	
	EIC Allowance	30	%		$2,471,000	
	Yard Piping & Site Civil Allowance	10	%		$824,000	
	Coating/Painting Allowance	0	%		$0	
	Total					$3,707,000
	SUBTOTAL					**$11,944,000**
	Estimating Contingency	30	%			$3,583,000
	SUBTOTAL					**$15,527,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$665,000
	SUBTOTAL					**$16,192,000**
	General Conditions, Contractor Overhead, & Profit	25	%			$4,048,000
	SUBTOTAL					**$20,240,000**
	CONSTRUCTION COST SUBTOTAL					**$20,240,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$6,072,000
	PROJECT COST					**$26,312,000**

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DETAILED COST ESTIMATE

JOB # :	200892	**ESTIMATE PREPARATION DATE :**	March 2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Internal Combustion Engines	**REVIEW DATE :**	6/29/2023
SCENARIO:	BS - 37 Pipeline Injection	**REVIEWED BY :**	RG

SPEC. NO.	DESCRIPTION	QUANTITY	UNIT	UNIT COST	SUBTOTAL	TOTAL
	Division 02 - Site Construction					
02300	Topsoil Strip & Stockpile On Site, To 500 Cy	550	CY	$9.40	$5,167	
	Total					**$5,167**
	Division 03 - Concrete					
03300	8" Flat Non-Formed S.O.G.	95	CY	$339	$32,214	
	Total					**$32,214**
	Division 11 - Equipment					
11000	Natural gas Conditioning System	1	LS	$3,700,000	$3,700,000	
11000	BioCNG 400 DP	1	EA	$2,858,087	$2,858,087	
11000	BioCNG Control Panel	1	EA	$150,000	$150,000	
11000	BioCNG 400 DP Winterization	1	EA	$319,200	$319,200	
11000	BioCNG Thermal Oxidizing Flare	1	EA	$410,280	$410,280	
11000	RNG Quality Monitoring Equipment	1	EA	$1,050,000	$1,050,000	
	Total					**$8,487,567**
	Division 15 - Mechanical					
15267	4" Sdr 11 Hdpe Pipe In Open Trench	10,000	LF	$54	$537,500	
15286	6" Sch 40S Buttwelded 316L Sst Pipe In A Bldg To 12' Ht.	200	LF	$116	$23,273	
	Pipeline interconnection fee	1	EA	$3,700,000	$3,700,000	
	Total					**$4,260,773**
	Division 16 - Electrical					
16000	EI&C Allowance	20%	% Div 11	$8,487,567	$1,697,513.45	
	Total					**$1,697,513**
	Contingency	30%	EA	$14,483,235	$4,344,970	
	General Contractor Overhead, Profit, and Risk	15%	EA	$18,828,205	$2,824,231	
	Escalation to Mid-Point (2025)	5%	EA	$21,652,436	$1,082,622	
	General Conditions					
	Total Estimated Construction Cost					**$22,735,058**

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Appendix 6B

MEGAPACK DATASHEET

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MEGAPACK

Megapack is an all-in-one utility-scale energy storage system that is scalable to the space, power, and energy requirements of any site from 1 MWh to over 1 GWh. Megapack is optimized for cost, performance, and ease of installation, and includes a standard system warranty of up to 15 years.

FULLY INTEGRATED SYSTEM

Megapack ships with battery modules, bi-directional inverter, thermal management system, and AC main breaker all pre-installed and pre-tested within a single enclosure. This turnkey system is designed to have the industry's fastest, lowest cost installation without sacrificing performance or reliability.

OPTIMIZATION SOFTWARE

Proprietary optimization software, developed in parallel with the Megapack hardware, learns and predicts local energy patterns, offering autonomous charge and discharge and seamless SCADA integration. Fast-response controls can integrate co-located renewables and enable market participation.

ENHANCED SYSTEM SAFETY

Parallel DC/DC converters, integrated heating and cooling at the cell level, and dedicated hazard venting are just a few of the safety and hazard mitigation features built into Megapack. Designed to meet international safety standards, Megapack helps ensure ease-of-permitting wherever it's installed.

INDUSTRY-LEADING RELIABILITY

A vertically integrated product from hardware design and sourcing to software development, Megapack offers significant reliability advantages over the competition. These design advantages are exemplified by a cooling system optimized specifically for Megapack that provides superior heating and cooling while factoring its HVAC energy consumption into its performance, and module-level DC/DC converters that can keep the system running uninterrupted in case of a partial failure.

LOWEST ENGINEERING, PROCUREMENT, AND CONSTRUCTION (EPC) COSTS

Megapack is shipped onsite fully assembled and pre-tested, offering customers the world's fastest utility-scale energy storage installation. Once on site, Megapack only requires seismic anchoring and connection of AC conductors and a communication cable. The EPC benefit is clear: no other current utility-scale solution offers such a simplified process.

GLOBAL SERVICE FOOTPRINT

As a vertically integrated manufacturer and supplier, Tesla provides a streamlined service offering on all components of Megapack. With Tesla, customers enjoy a single point of contact through all stages of product life. Our operational fleet of 2+ GWh provides valuable data that informs our maintenance models and our performance guarantees, and the entire Megapack system is covered by a standard warranty of up to 15 years, with the option of a 20-year Capacity Maintenance Agreement (CMA) in certain cases.

MEGAPACK SPECIFICATIONS

Specifications are subject to change.

Flexible offering designed for utility-scale projects
- Modular inverter Powerstages allow greater configuration flexibility
- Supports Capacity Maintenance Agreements (CMA)

Proven inverter and battery technology drives design efficiency
- One Megapack includes up to 17 independent battery modules
- Configurable for 2 to 6+ hour continuous charge/discharge
- Best-in-class round-trip efficiency and thermal system performance

Turnkey solution enables rapid and cost-effective deployment
- Up to 10% expected reduction in EPC costs compared to Powerpack
- Pre-assembled and pre-tested at Tesla's Gigafactory
- No DC connections required onsite

STANDARD SYSTEM SPECIFICATIONS

Megapack is a customizable energy system capable of being sized according to customer needs.

AC Power / Energy Available per Megapack[1]	2-hour: Up to 1341 kW / 2682 kWh (Scalable in increments of 89.4 kW / 178.8 kWh) 4-hour: Up to 770.1 kW / 3080.4 kWh (Scalable in increments of 45.3 kW / 181.2 kWh)

Below are specifications for selected system sizes. A light Megapack is optimized for global payload limits. A standard Megapack has the maximum number of energy modules.

	AC Power / Energy Available per Megapack[1]	Round-Trip System Efficiency[1]
2-Hour Standard	1341 kW / 2682 kWh	87%
2-Hour Light	1072.8 kW / 2145.6 kWh	
4-Hour Standard	770.1 kW / 3080.4 kWh	90%
4-Hour Light	543.6 kW / 2174.4 kWh	

[1]Nominal energy and RTE at 25°C (77°F) including thermal management loads, Day 1

ELECTRICAL

Inverter Size (at 480 V AC)	2-hour: Up to 1573 kVA 4-hour: Up to 929.5 kVA (Scalable in increments of 71.5 kVA)
Inverter Size (at 505 V AC)	2-hour: Up to 1654.9 kVA 4-hour: Up to 977.9 kVA (Scalable in increments of 75.224 kVA)
AC Voltage	380–505 V AC 3-phase
Nominal Frequency	50 or 60 Hz

MECHANICAL AND MOUNTING

Ingress Ratings	IP66/NEMA 3R (Main enclosure) IP20 (Thermal system)
Enclosure Dimensions	W: 7168 mm (282 1/4 in) D: 1659 mm (65 1/4 in) H: 2522 mm (99 1/4 in)
Maximum Shipping Mass	Standard: 25,400 kg (56,000 lb) Light: 20,400 kg (44,970 lb)
Operating Ambient Temperature	-30°C to 50°C (-22°F to 122°F)

REGULATORY

Lithium-Ion Cells	NRTL listed to UL 1642
System	NRTL listed to UL 1973, UL 9540, UL 9540A, UL 1741 SA, IEC 62619, IEEE 1547 Compliant to grid codes and safety standards of all major markets

COMMUNICATIONS

Protocol	Modbus TCP / DNP3 / Rest API

PART NUMBER

Megapack (all variants)	1462965-XX-Y (C00Z) (Where X is a number between 0-9, Y is a letter, and Z is a number greater than 1. Changes to these do not affect minimum product ratings and do not affect inverter ratings.)

Appendix 6C

HOMER MODEL REPORT

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Distributed Generation Proposal

PREPARED FOR:
DSRSD, San Ramon WWTP
7035 Commerce Cir, Pleasanton, CA 94588

PREPARED BY:
Christian Tasser, Associate
Carollo Engineers,

This proposal has been generated using HOMER Grid, a dynamic software engine that runs complex simulations and sensitivity analyses with your energy data. It evaluates thousands of variables to compare value streams, assess system options, and provide risk-mitigation and cost reduction strategies. Originally developed at the US Department of Energy's National Renewable Energy Laboratory, the HOMER software is a risk-mitigation tool trusted by over 200,000 project developers and financial institutions to produce informed economic feasibility studies, system design and engineering insight, as well as energy cost savings.

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Project Summary

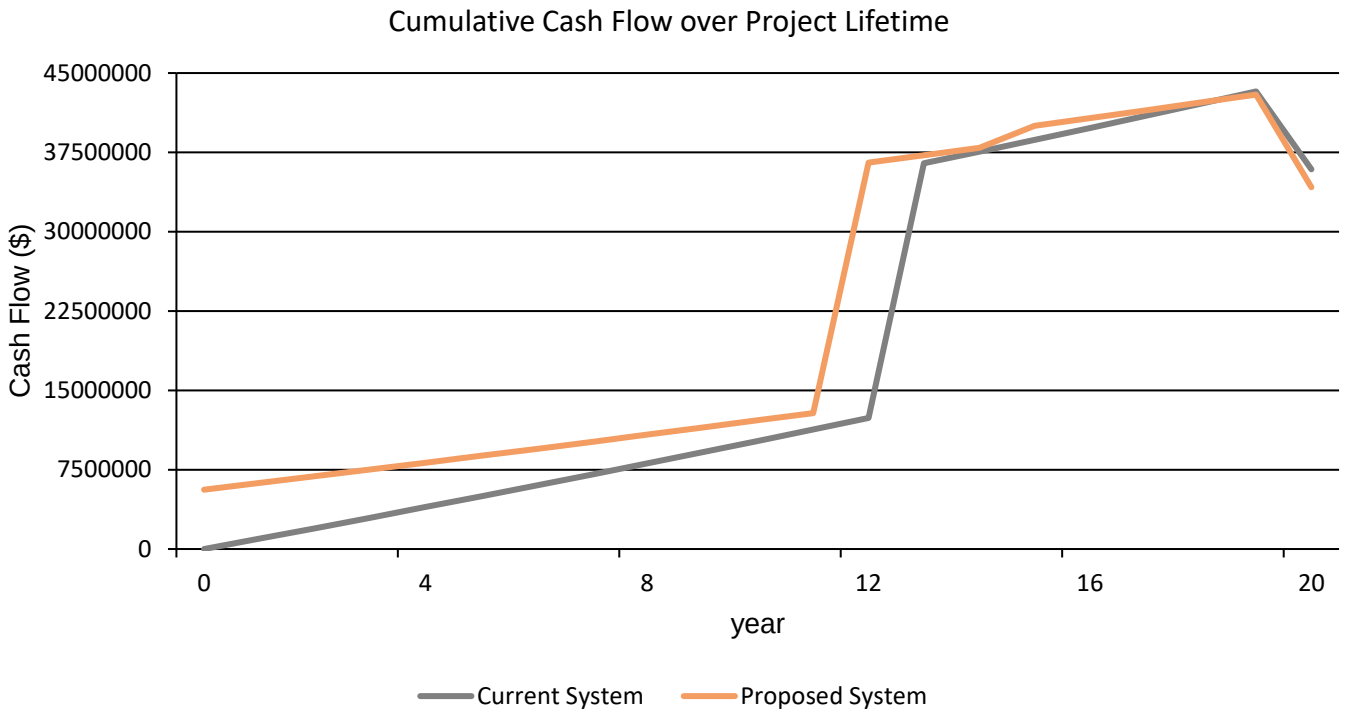
CURRENT SYSTEM

The electric needs of 7035 Commerce Cir, Pleasanton, CA 94588 are met with a grid connection and 1,400 kW of generator capacity. You currently spend $766,756 on your utility bill per year. 84% of your utility bill is demand charges.

PROPOSED SYSTEM

We propose adding 1,000 kW of PV and 1,000 kWh of battery capacity. This would reduce your annual utility bill to $435,598. Your investment has a payback of 19.18 years and an IRR of 1.14%.

Simple payback:	19.2 yr	Net Present Value:	$1.69M
Return on Investment:	0.841 %	Capital Investment (including incentives):	$5.61M
Internal Rate of Return:	1.14 %	Annualized Savings:	$329,781



PREPARED BY:
Christian Tasser,
Associate, Carollo Engineers,
,

HOMER Grid

ABOUT CAROLLO ENGINEERS

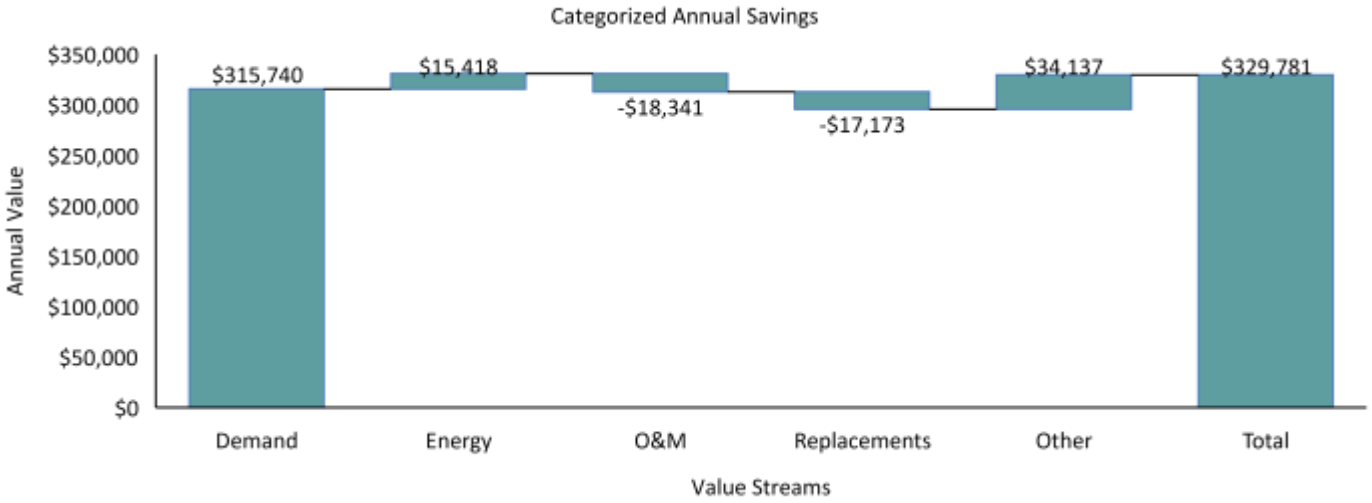
Customer Testimonials

—

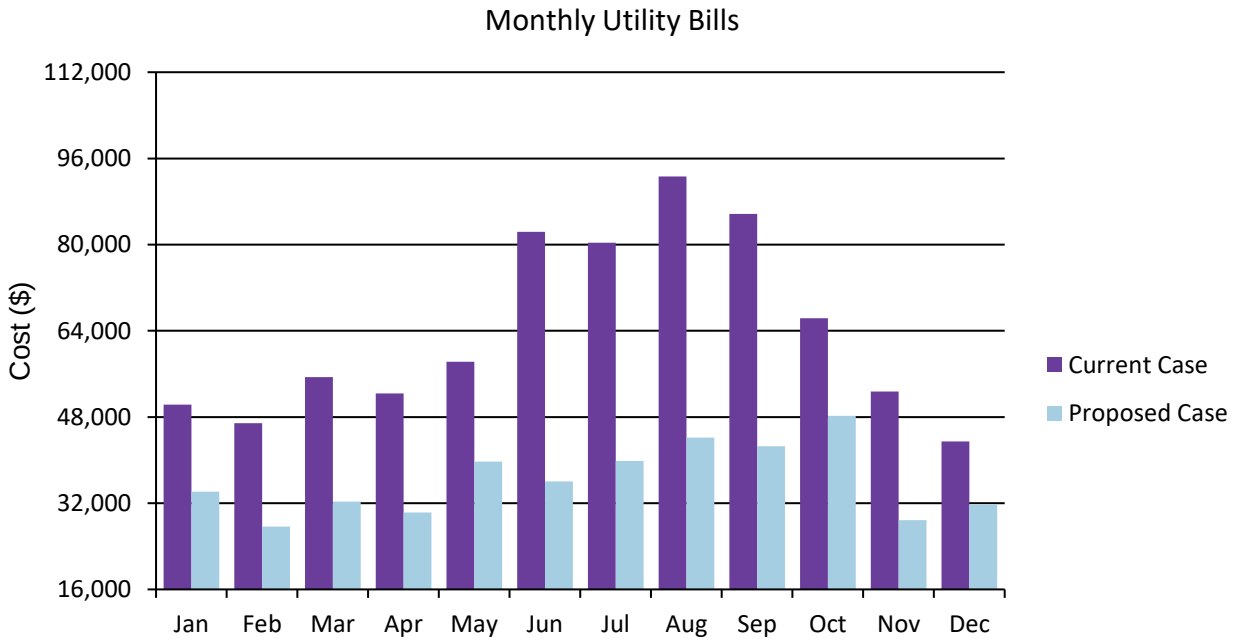
Savings Summary

The chart summarizes down your estimated annual savings in the following categories:

1. Demand: Savings from demand charge reduction
2. Energy: Consumption reduction and self-consumption
3. O&M: Operating and maintenance costs of the proposed components
4. Replacements: Cost to replace proposed system components over the project lifetime
5. Other: Cost differences not included in the other categories
6. Total: The total savings (annualized) of the proposed system



Your monthly utility bill savings by month:



Savings Details

1. Utility Bill Savings

The facility at 7035 Commerce Cir, Pleasanton, CA 94588 is served by Pacific Gas & Electric Co. The electricity tariff plan you are currently on is the Large General - Time of Use.

Your monthly electricity bill has two main parts:

1) Energy charges for the total amount of electricity you consume.

2) Demand charges—for "peak usage." If your facility tends to use a lot of power over short periods, your demand charges will comprise a larger part of your bill. If you use power at a more consistent rate throughout the month, your demand charges will generally comprise a smaller part of your bill. Demand charges make up a significant portion of commercial and industrial customers' total electricity costs: typically, between 30 and 70 %.

Your annual utility bills and savings by category:

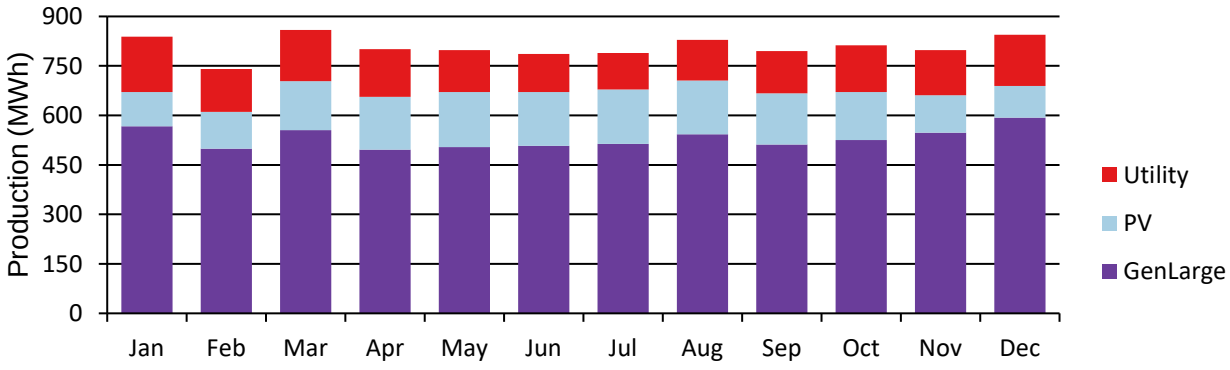
	Consumption Charge	Demand Charge	Fixed Rate	Total
Base Case	$110,920	$643,418	$12,418	$766,756
Proposed Case	$95,502	$327,679	$12,418	$435,598
Annual Savings	**$15,418**	**$315,740**	**$0.00**	**$331,158**

Current System: Grid-Connection and Generator
Proposed System: Grid-Connection, Solar, Generator, and Storage

Consumption Summary

Electric Consumption

This facility uses 26418 kWh/day and has a peak of 2470 kW. In the proposed system, the following generation sources serve the electrical load.

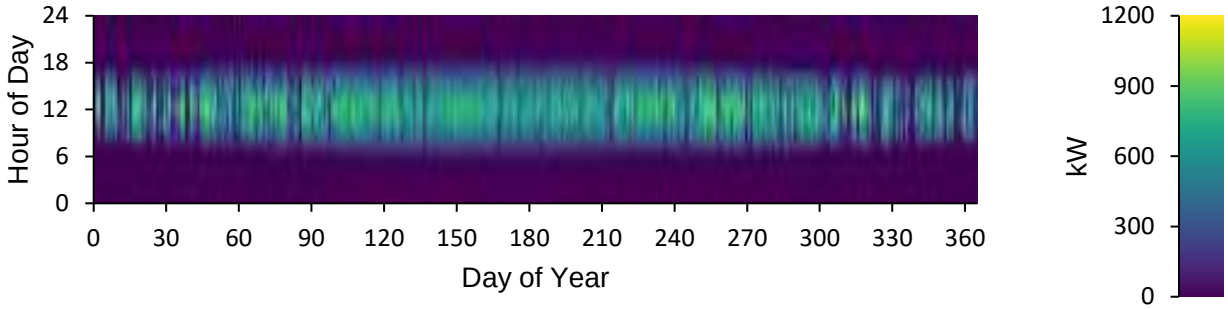


PV: Generic flat plate PV

The Generic PV system has a nominal capacity of 1,000 kW. The annual production is 1,690,232 kWh/yr.

Rated Capacity	1,000 kW
Capital Cost	$3.33M
Specific Yield	1,690 kWh/kW
PV Penetration	17.5 %

Total Production	1,690,232 kW
Maintenance Cost	8,340 $/yr
LCOE	0.0855 $/kWh

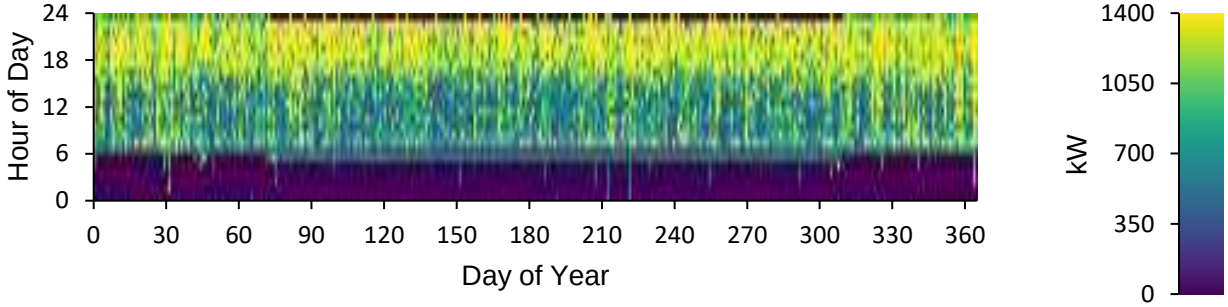


Generator: Generic Large Genset (size-your-own) (Natural Gas)

Power output from the Generic generator system, rated at 1,400 kW using Natural Gas as fuel, is 6,364,213 kWh/yr.

Capacity	1,400 kW
Operational Life	12.0 yr
Maintenance Cost	66.7 $/yr
Electrical Production	6,364,213 kWh/yr
Hours of Operation	6,670 hrs/yr
Fixed Generation Cost	258 $/hr

Generator Fuel	Natural Gas
Generator Fuel Price	0.100 $/m³
Fuel Consumption	1,683,600 m³
Thermal Production	6,156,802 kWh/yr
Marginal Generation Cost	0.0244 $/kWh

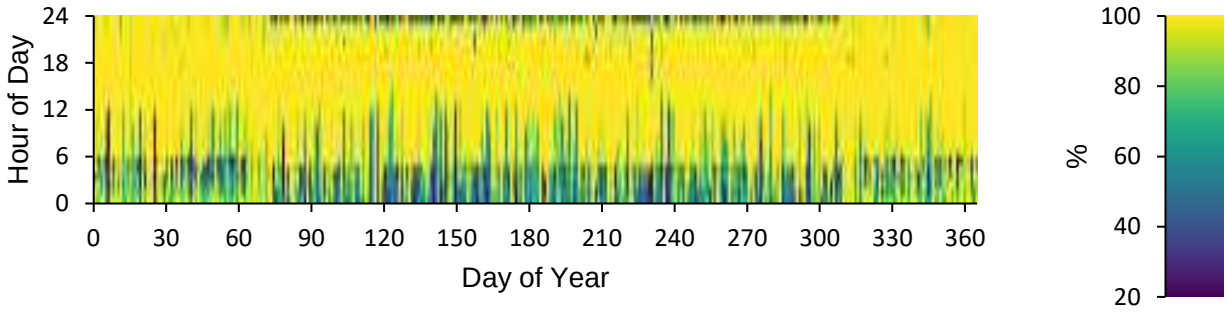


Storage: Generic 1MWh Li-Ion

The Generic storage system's nominal capacity is 1,000 kWh. The annual throughput is 180,442 kWh/yr.

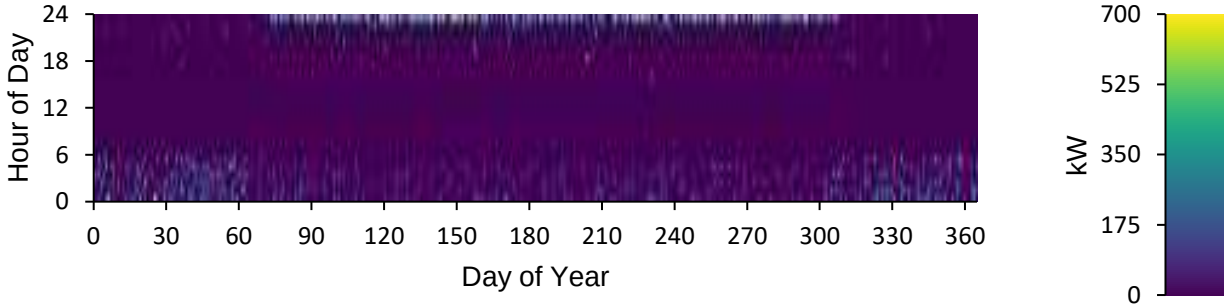
Rated Capacity	1,000 kWh	Expected Life	14.9 yr
Annual Throughput	180,442 kWh/yr	Capital Costs	$2.38M
Maintenance Cost	10,000 $/yr	Losses	18,020 kWh/yr
Autonomy	0.727 hr		

The following incentives improve the economics for Storage.



Converter: System Converter

Capacity	618 kW	Hours of Operation	1,115 hrs/yr
Mean Output	18.6 kW	Energy Out	162,623 kWh/yr
Minimum Output	0 kW	Energy In	171,183 kWh/yr
Maximum Output	618 kW	Losses	8,559 kWh/yr
Capacity Factor	3.01 %		



Cash Flows

Project Lifetime 20 years

Expected Inflation Rate 6.0%

Nominal Discount Rate 5.0%

Real Interest Rate -0.9%

Year	1	2	3	4	5	6	7	8	9	10
Generic 1MWh Li-Ion	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)
Generic flat plate PV	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)
Generic Large Genset (size-your-own)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)
Large General - Time of Use	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)
SGIP- Large Storage- Step 2- Claiming ITC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
System Converter	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Year	11	12	13	14	15	16	17	18	19	20
Generic 1MWh Li-Ion	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)
Generic flat plate PV	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)	($8,340)
Generic Large Genset (size-your-own)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)	($66.70)
Large General - Time of Use	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)	($435,598)
SGIP- Large Storage- Step 2- Claiming ITC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
System Converter	$0.00	$0.00	$0.00	$0.00	($185,300)	$0.00	$0.00	$0.00	$0.00	$123,533

Year
Generic 1MWh Li-Ion
Generic flat plate PV
Generic Large Genset (size-your-own)
Large General - Time of Use
SGIP- Large Storage- Step 2- Claiming ITC
System Converter

Utility Bill Details

Utility Monthly Summary - Current System

Month	Energy Purchased (kWh)	Energy Sold (kWh)	Net Energy Purchased (kWh)	Peak Load (kW)	Energy Charge	Demand Charge	Demand Response	Fixed Charge	Minimum Charge	Taxes	Total
January	178,156	73.7	178,082	2,336	$10,168	$39,095	$0.0	$1,055	$0.0	$0.0	$50,317
February	146,281	0	146,281	2,385	$8,356	$37,520	$0.0	$952.61	$0.0	$0.0	$46,828
March	185,420	76.6	185,344	2,362	$10,539	$43,810	$0.0	$1,055	$0.0	$0.0	$55,403
April	163,428	0	163,428	2,342	$9,389	$41,959	$0.0	$1,021	$0.0	$0.0	$52,369
May	123,363	513	122,851	2,202	$7,466	$49,743	$0.0	$1,055	$0.0	$0.0	$58,264
June	150,646	546	150,100	2,221	$9,244	$72,100	$0.0	$1,021	$0.0	$0.0	$82,364
July	144,255	450	143,804	2,221	$8,772	$70,499	$0.0	$1,055	$0.0	$0.0	$80,326
August	168,166	89.4	168,076	2,470	$10,356	$81,227	$0.0	$1,055	$0.0	$0.0	$92,638
September	152,673	135	152,538	2,277	$9,446	$75,241	$0.0	$1,021	$0.0	$0.0	$85,708
October	144,978	14.7	144,963	2,158	$8,815	$56,481	$0.0	$1,055	$0.0	$0.0	$66,351
November	153,138	21.3	153,116	2,325	$8,799	$42,933	$0.0	$1,021	$0.0	$0.0	$52,753
December	167,555	26.6	167,529	2,168	$9,570	$32,811	$0.0	$1,055	$0.0	$0.0	$43,436
Annual	1,878,059	1,947	1,876,112	2,470	$110,920	$643,418	$0.0	$12,418	$0.0	$0.0	$766,756

Utility Monthly Summary - Proposed System

Month	Energy Purchased (kWh)	Energy Sold (kWh)	Net Energy Purchased (kWh)	Peak Load (kW)	Energy Charge	Demand Charge	Demand Response	Fixed Charge	Minimum Charge	Taxes	Total
January	168,474	1,018	167,456	2,336	$9,557	$23,517	$0.0	$1,055	$0.0	$0.0	$34,128
February	130,075	617	129,458	2,385	$7,388	$19,332	$0.0	$952.61	$0.0	$0.0	$27,673
March	155,666	1,326	154,339	2,362	$8,771	$22,461	$0.0	$1,055	$0.0	$0.0	$32,287
April	144,416	356	144,060	2,342	$8,226	$21,054	$0.0	$1,021	$0.0	$0.0	$30,300
May	126,635	1,528	125,107	2,202	$7,580	$31,072	$0.0	$1,055	$0.0	$0.0	$39,706
June	115,813	1,070	114,743	2,221	$6,961	$28,086	$0.0	$1,021	$0.0	$0.0	$36,067
July	110,781	1,134	109,647	2,221	$6,690	$32,108	$0.0	$1,055	$0.0	$0.0	$39,852
August	122,542	611	121,931	2,470	$7,392	$35,755	$0.0	$1,055	$0.0	$0.0	$44,202
September	128,307	1,341	126,966	2,277	$7,708	$33,842	$0.0	$1,021	$0.0	$0.0	$42,571

Utility Bill Details

October	142,229	826	141,403	2,158	$8,572	$38,561	$0.0	$1,055	$0.0	$0.0	$48,187
November	137,029	811	136,218	2,325	$7,809	$20,016	$0.0	$1,021	$0.0	$0.0	$28,845
December	155,242	199	155,044	2,168	$8,849	$21,876	$0.0	$1,055	$0.0	$0.0	$31,780
Annual	1,637,208	10,837	1,626,372	2,470	$95,502	$327,679	$0.0	$12,418	$0.0	$0.0	$435,598

Glossary Section

Annualized Savings
The difference in annualized cost between the base case system and the proposed system. The annualized cost is the cost that, if it were to repeat in every year of the project lifetime, would give the same net present cost as the actual cash flow sequence.

Capital Investment
The capital investment is the additional installed cost of the proposed system relative to the base case system at the start of the project.

Internal rate of return
Internal rate of return (IRR) is the discount rate at which the base case and proposed system have the same net present cost. HOMER calculates the IRR by determining the discount rate that makes the present value of the difference of the two cash flow sequences equal to zero.

Net Present Cost
The total net present cost (NPC) of a system is the present value of all the costs the system incurs over its lifetime, minus the present value of all the revenue it earns over its lifetime. Costs include capital costs, replacement costs, O & M costs, fuel costs, emissions penalties, and the costs of buying power from the grid. Revenues include salvage value and grid sales revenue. HOMER calculates the total NPC by summing the total discounted cash flows in each year of the project lifetime.

Net Present Value
Net Present Value (NPV), also referred to as net present worth, is the difference between the net present costs of the base case system and the proposed system.

Return on Investment
Return on Investment (ROI) is the yearly cost savings relative to the initial investment. The ROI is the average yearly difference in nominal cash flows over the project lifetime, divided by the difference in capital cost.

Simple payback
Simple payback is the number of years at which the cumulative cash flow of the difference between the proposed system and base case system switches from negative to positive. The payback is an indication of how long it would take to recover the difference in investment costs between the proposed system and the base case system.

Total Annualized Cost
Total Annualized Cost is the annualized value of the total net present cost. The annualized cost of a component is the cost that, if it were to occur equally in every year of the project lifetime, would give the same net present cost as the actual cash flow sequence associated with that component. HOMER calculates annualized cost by first calculating the net present cost, then multiplying it by the capital recovery factor.

ABOUT HOMER ENERGY

HOMER software is used by more than 200,000 users in 193 different countries.

HOMER Energy is the world's leading microgrid modeling software company. The Hybrid Optimization of Multiple Energy Resources (HOMER) software helps engineers and project developers navigate the complexities of designing cost-effective and reliable microgrids that combine traditional and renewable generation sources.

HOMER evaluates thousands of variables to compare value streams, assess system options, and provide risk-mitigation and cost reduction strategies. The software includes hundreds of preconfigured components to offer detailed insight, while addressing the modeling requirements of all major microgrid segments.

HOMER software is utilized by over 200,000 users in 193 countries and is trusted by governments, financial institutions, military agencies, utilities, energy systems integrators, and NGOs to design hybrid power systems. In the last decade, HOMER has demonstrated its effectiveness for analyzing complex distributed energy systems, including grid-tied hybrid renewable microgrids and situations where the grid is insufficiently reliable, such as islands and remote communities.

ABOUT HOMER GRID

HOMER Grid is a powerful software solution for modeling hybrid energy systems and evaluating options to reduce electricity expenditures. It is a robust tool that combines engineering and economics information in one comprehensive model while rapidly performing complex calculations to determine the value of self-consumption, demand charge reduction, and energy arbitrage.

HOMER Grid allows users to compare multiple components and design outcomes, identify points at which different technologies become cost-competitive, and consider options for minimizing project risk and determining the most economic design. With integrated access to more than 20k tariffs in the US, Canada, and Mexico, and the ability to model any tariff, HOMER Grid simulates real-world performance to deliver informed choices for system design and optimization.

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Dublin San Ramon Services District
Water, wastewater, recycled water

Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 7
GHG REDUCTION OPPORTUNITIES AND FLEET TRANSITION TO ZERO-EMISSION VEHICLES ASSESSMENT

FINAL | June 2024

carollo

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Abbreviations

ACF	advanced clean fleets
BOD	biological oxygen demand
CARB	California Air Resources Board
Carollo	Carollo Engineers
CCA	Community Choice Aggregation
cfy	cubic feet per year
CH_4	methane
CO_2	carbon dioxide
DAFT	dissolved air flotation thickening
DC	direct current
DLD	dedicated land disposal
DSRSD	Dublin San Ramon Services District
EV	electric vehicle
FOG	fats, oils, and grease
FSL	facultative sludge lagoon
FW	food waste
hp	horsepower
HSW	high strength waste
HVAC	heating, ventilation, and air conditioning
GHG	greenhouse gas
gpy	gallons per year
GVWR	gross vehicle weight rating
ICE	internal combustion engine
kWh	kilowatt hours
kWh/yr	kilowatt hours per year
LAVWMA	Livermore Amador Valley Water Management Authority
MT CO_2e/yr	metric tons of carbon dioxide equivalents per year
MW	megawatt
MWh/yr	megawatt hours per year
N_2O	nitrous oxide
NG	natural gas
NPV	net present value
PG&E	Pacific Gas & Electric Company
POTW	publicly owned treatment works
ppy	pounds per year
RNG	renewable natural gas
SRT	solids retention time

TM	technical memorandum
WWTP	wastewater treatment plant
ZEV	zero-emission vehicles

Technical Memorandum 7

GREENHOUSE GAS REDUCTION OPPORTUNITIES AND FLEET TRANSITION TO ZERO-EMISSION VEHICLES ASSESSMENT

7.1 Introduction

This technical memorandum (TM) documents the estimated net greenhouse gas (GHG) emissions impact associated with the energy savings and efficiency opportunities described in TM 5 and the energy generation opportunities evaluated in TM 6. The GHG impact is intended to be used as a criterion in decision-making alongside cost and other non-financial considerations. In light of the recent regulations adopted by California Air Resources Board (CARB) in April 2023 for the incorporation of zero-emission vehicles (ZEV) into medium- and heavy-duty fleets within state and local government agency fleets, this TM also addresses strategies that the Dublin San Ramon Services District (DSRSD) can employ to meet those requirements.

The first step in the GHG reduction opportunities assessment was to build a GHG emissions baseline inventory to provide a basis for comparing technology options and operational changes. The GHG emissions baseline inventory is described in TM 1. The GHG emissions for the existing system were then projected to year 2035 and design year 2047 as described in TM 4. The baseline inventory and projections are summarized in Section 7.2.

Once the technology options and operational changes were evaluated, as described in TM 5 and TM 6, Carollo Engineers (Carollo) evaluated the power usage, natural gas usage, chemical usage, and other factors that influence GHG emissions in order to calculate the net reduction in GHG emissions achievable by each opportunity. The GHG impact of the energy saving and generation opportunities as well as the vehicle fleet transition to ZEV are described in detail in Section 7.3 and summarized in Section 7.4.

7.2 Baseline Greenhouse Gas Emissions Inventory and Projections

7.2.1 System Boundary

The system boundary for the GHG emissions analysis included the three GHGs that are relevant for wastewater treatment emissions: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Only emissions associated with operations were included; emissions associated with construction activities are not included. The baseline inventory included scopes 1, 2, and 3 emissions, as described below:

1. Scope 1 emission sources include process emissions, on-site stationary combustion of biogas and natural gas, as well as those from gasoline and diesel fuel consumed in DSRSD's fleet vehicles.

2. Scope 2 emissions include emissions from purchased electricity, steam, heating, or cooling. None of the DSRSD facilities purchase steam or hot water, so the Scope 2 emissions only included those associated with purchased electricity.
3. Scope 3 emissions and offsets include emission sources or sinks that are up or downstream of the treatment plant. For example, emissions associated with the production of natural gas and chemicals, as well as chemical transport. Scope 3 also includes avoided emissions, such as avoided purchased electricity through cogeneration and, where applicable, carbon sequestration and fertilizer offsets from biosolids land application.

A GHG emissions inventory was developed for baseline year 2021 and these GHG emissions were projected to 2035 and 2047. The baseline inventory, described in detail in TM 1, included all major DSRSD facilities, as well as some DSRSD – East Bay Municipal Utilities District Recycled Water Authority and Livermore Amador Valley Water Management Authority (LAVWMA) facilities. The 2034 and 2047 projections, described in detail in TM 4, only included the facilities managed and operated by DSRSD. The analysis conducted in this TM also focused exclusively on DSRSD facilities, listed below:

1. Wastewater treatment plant (WWTP) and collection system.
2. Potable water distribution system.
3. Recycled water distribution system.
4. Administrative and other buildings.
5. Vehicle fleet.

7.2.2 Baseline Greenhouse Gas Emissions Inventory and Projections Summary

The baseline GHG emissions inventory (TM 1) was based on data year 2021, which was found to be representative of historical flows and loads and electricity usage and production. These baseline GHG emissions were then projected to years 2035 and 2047 (TM 4), in most cases proportionally to increasing wastewater flows or potable water demands. Separate GHG inventories and projections were developed for each DSRSD-managed facility and the vehicle fleet to facilitate comparison to the facility-specific energy saving and energy generation opportunities described in detail in TM 5 and TM 6 and the fleet vehicle conversion to ZEV described in detail in Section 7.4.

Table 7.1 summarizes the GHG emissions baseline inventories and projections for all facilities managed and operated by DSRSD and the vehicle fleet. The majority of DSRSD's GHG emissions are contributed by the WWTP, which accounts for approximately 88 percent of the total. Of the WWTP GHG emissions, the majority are from natural gas combustion in cogeneration, which account for up to 92 percent of the WWTP GHG emissions.

Table 7.1 DSRSD GHG Emissions Baseline and Projections

Facility	GHG Emissions (MT CO_2e/yr)[1]		
	2021	2035	2047
WWTP and collection system[2]	3,914	3,624	3,419
Potable water distribution[3]	294	382	388
Recycled water distribution[4]	22	22	22
Administrative and other buildings[5]	115	115	115
Vehicle fleet[6]	89	89	89
Total	**4,434**	**4,232**	**4,033**

Notes:
MT CO_2e/yr - metric tons of carbon dioxide equivalents per year.
(1) To be conservative, the baseline and projected GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the Community Choice Aggregation (CCA) and Pacific Gas & Electric Company (PG&E) portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.
(2) The wastewater collection system and WWTP's GHG emissions were projected proportionately to the influent flow and loading projections with the following exceptions: assuming existing cogeneration capacity will remain constant, the GHG emissions associated with avoided purchased electricity through onsite electricity generation will remain the same as in 2021, and the natural gas needed in the engines will decrease relative to 2021 as the digester gas production increases.
(3) GHG emissions projections for potable water distribution were calculated in proportion to the future potable water demand.
(4) GHG emissions for recycled water distribution are assumed to stay the same over the planning period.
(5) GHG emissions are not expected to increase over the planning period for DSRSD's buildings.
(6) The baseline GHG emissions for DSRSD's fleet are not expected to increase under "business as usual" operation.

7.3 Analysis of Greenhouse Gas Reduction Opportunities

Consistent with the GHG analyses in previous TMs and summarized in Section 7.2, the energy savings and production opportunities were broken down by facility to facilitate a side-by-side comparison of alternatives. Energy saving opportunities (described in TM 5) were evaluated for the WWTP, the potable water distribution system, the administrative and other buildings, and the vehicle fleet. In addition to energy saving and efficiency opportunities, energy production and storage opportunities and energy management and advanced control opportunities (described in TM 6) were evaluated. Based on the opportunities screening described in TM 2, no opportunities were deemed promising enough to carry forward into the detailed evaluation for the recycled water distribution system. The following sections describe the GHG impacts of these energy efficiency and generation opportunities.

7.3.1 Wastewater Treatment Plant Opportunities

The WWTP accounts for the vast majority of DSRSD's GHG emissions and, as expected, also has the most opportunities for energy savings and efficiency improvements. Due to the large number of energy efficiency alternatives evaluated for the WWTP, these were grouped into liquid stream treatment process and solids stream treatment process opportunities. The following sections describe the GHG impact of these opportunities.

7.3.1.1 Liquid Stream Treatment Opportunities

The following liquid stream treatment energy efficiency opportunities were evaluated in TM 5:

- LS-5: Real Time Solids Retention Time (SRT) Control.

- LS-6: Model Predictive Aeration Control.
- LS-7: Low Dissolved Oxygen Operation.
- LS-12: More Efficient Aeration Diffusers.
- LS-13: Upgrade Aeration Blowers.
- LS-16: Upgrade Pre-Aeration Blowers.

In addition, the following liquid stream treatment energy generation opportunity was evaluated in TM 6:

- LS-3: Improve carbon diversion from primaries to digesters.

Table 7.2 summarizes the power and natural gas (NG) savings and corresponding GHG impact of the liquid stream treatment energy saving and generation opportunities.

7.3.1.2 Solids Stream Treatment Opportunities

The solids stream treatment opportunities encompass both biosolids treatment efficiency and generation opportunities and biogas utilization energy generation opportunities. Due to the large number of solids stream treatment opportunities, these were further broken down into biosolids treatment and biogas utilization opportunities.

The following biosolids treatment energy efficiency opportunity was evaluated in TM 5:

- BS-2A: Dissolved Air Flotation Thickening (DAFT) Optimization (not included in GHG analysis).

In addition, the following solids stream treatment energy generation opportunities were evaluated in TM 6:

- BS-2B: Mechanical Thickening Post-DAFT.
- BS-2C: Mechanical Thickening Instead of DAFT.
- BS-7: Recuperative Thickening.
- BS-13: Dewatering Post Digestion.
- BS-17: Drying and Pyrolysis (not included in GHG analysis).
- BS-18: Drying and Gasification (not included in GHG analysis).
- BS-22: Lystek Thermochemical Hydrolysis.
- BS-23: Co-digest Fats, Oils, and Grease (FOG).
- BS-24: Co-digest Food Waste (FW) Slurry and High-Strength Waste (HSW).

As described in TM 5, DAFT operations and equipment are already optimized and no additional energy saving technology or operational changes were recommended; thus, BS-2A was not included in this GHG analysis. As described in TM 6, drying and pyrolysis and drying and gasification are costly, complex, and do not provide significant energy savings, so they were not recommended for further evaluation as part of this master plan. For those reasons, BS-17 and BS-18 were not included in this GHG analysis.

Table 7.3 summarizes the changes in power, fuels, chemicals, and other usages that affect the GHG emissions for the other listed opportunities. Table 7.4 summarizes the corresponding GHG impacts for each of these usages.

Table 7.2 GHG Impact of WWTP – Liquid Stream Treatment Opportunities

Opportunity	Usage Inputs			GHG Emissions (MT CO_2e/yr)					% Increase or Decrease in GHG Emissions[12]
	Power Usage (kWh/yr)	NG (1,000 cfy)	Biogas (1,000 cfy)	Power Usage (Scope 2)[10]	NG Onsite Combustion (Scope 1)	NG Offsite Production (Scope 3)	Biogas Onsite Combustion (Scope 1)[11]	Total	
LS-5[3]	-43,276	0	0	-3	0	0	0	**-3**	**-0.1%**
LS-6[4]	-432,756	0	0	-32	0	0	0	**-32**	**-0.8%**
LS-7[5]	-865,513	0	0	-64	0	0	0	**-64**	**-1.6%**
LS-12[6]	-432,756	0	0	-32	0	0	0	**-32**	**-0.8%**
LS-13[7]	-173,103	0	0	-13	0	0	0	**-13**	**-0.3%**
LS-16[8]	-62,213	0	0	-5	0	0	0	**-5**	**-0.1%**
LS-3[9]	-432,756	-3,345	6,025	-32	-182	-5	1	**-218**	**-5.4%**

Notes:
cfy - cubic feet per year; kWh/yr - kilowatt hours per year.
(1) Values represent design year 2047.
(2) Reductions in power usage and GHG emissions are shown as negative values. Increases are shown as positive values.
(3) Assumes 1 percent reduction in aeration power usage.
(4) Assumes 10 percent reduction in aeration power usage.
(5) Assumes 20 percent reduction in aeration power usage based on expected range of 15 to 25 percent.
(6) Assumes 10 percent reduction in aeration power usage.
(7) Assumes 4 percent improvement in blower energy efficiency.
(8) Assumes 5 horsepower (hp) pre-aeration blower motor efficiency increases from 30 to 70 percent.
(9) Assumes 10 percent more biological oxygen demand (BOD) removal in the primary clarifiers, resulting in 10 percent reduction in aeration power usage and 5 percent increase in digester gas production. Additional biogas production is assumed to replace an equivalent amount of natural gas in cogeneration.
(10) For consistency with the projections in TM 4, the GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.
(11) Emissions from on-site combustion of biogas include CH_4 and N_2O only. CO_2 emissions are not included since they are considered biogenic.
(12) Calculated relative to 2047 total DSRSD GHG emissions of 4,033 MT CO_2e/yr.

Table 7.3 Power, Fuel, Chemical, and the Usages for WWTP – Solids Stream Treatment Opportunities

Opportunity	Power (kWh/yr)	NG (1,000 cfy)	Biogas (1,000 cfy)	Diesel for FSLs and DLDs (gpy)	Polymer (ppy)	Cake Hauling (wet ton/year)	Cake to Land App (dry ton/year)	FW Diverted from Landfill (wet ton/year)
BS-2B: Mechanical Thickening Post-DAFT(3)	71,669	0	0	0	31,667	0	0	0
BS-2C: Mechanical Thickening Instead of DAFT(3)	-1,421,037	0	0	0	31,667	0	0	0
BS-7: Recuperative Thickening(3)	773,906	0	0	0	31,667	0	0	0
BS-13: Dewatering Post Digestion(4)	13,865	0	0	-3,306	120,706	17,374	4,024	0
BS-22: Lystek Thermochemical Hydrolysis(4)	13,865	0	0	-3,306	120,706	17,374	4,024	0
BS-23: Co-digest FOG(5)	113,903	-22,214	38,012	0	0	0	0	0
BS-24: Co-digest FW Slurry and HSW(5,6)	343,442	-20,285	34,711	0	0	0	0	-5,970

Notes:
DLD - dedicated land disposal; FSL - facultative sludge lagoons; gpy - gallons per year; ppy - pounds per year.
(1) Values represent design year 2047.
(2) Reductions in power, fuel, chemical, and other usages are shown as negative values. Increases are shown as positive values.
(3) One of these thickening alternatives is needed to create additional digestion capacity for the co-digestion opportunities (BS-23 and BS-24) to be viable.
(4) The dewatering alternatives (BS-13 and BS-22) assume that the FSLs and DLDs would be decommissioned.
(5) The co-digestion opportunities need to be combined with one of the thickening alternatives (BS-2B, BS-2C, or BS-7) to create additional digestion capacity for co-digestion to be feasible.
(6) The FW co-digestion opportunity (BS-24) needs to be combined with one of the dewatering and land application alternatives (BS-13 or BS-22) to qualify as landfill diversion, per SB 1383.

Table 7.4 GHG Impact of WWTP – Solids Stream Treatment Opportunities

	GHG Emissions (MT CO_2e/yr)												
Opportunity	Power Usage (Scope 2)[3]	NG onsite Combustion (Scope 1)	NG offsite Production (Scope 3)	Biogas Onsite Combustion[4] (Scope 1)	Diesel Usage for FSLs & DLDs (Scope 1)	Polymer Usage (Scope 3)	Diesel Usage for Polymer Transport (Scope 3)	Diesel Usage for Cake Hauling (Scope 1 or 3)	Land Application (Scope 3)	Direct CH_4 Emissions from FSLs (Scope 1)	Diversion of FW from Landfill (Scope 3)	Total	% Increase or Decrease[5]
BS-2B	5	0	0	0	0	41	5	0	0	0	0	**51**	**1.3%**
BS-2C	-104	0	0	0	0	41	5	0	0	0	0	**-59**	**-1.5%**
BS-7	57	0	0	0	0	41	5	0	0	0	0	**102**	**2.5%**
BS-13	1	0	0	0	-34	155	19	180	-241	-16	0	**64**	**1.6%**
BS-22	1	0	0	0	-34	155	19	106	-241	-16	0	**-10**	**-0.3%**
BS-23	8	-1,209	-36	6	0	0	0	0	0	0	0	**-1,230**	**-30.5%**
BS-24	25	-1,104	-32	6	0	0	0	0	0	0	-2,316	**-3,423**	**-84.9%**

Notes:
(1) Values represent design year 2047.
(2) Reductions in GHG emissions are shown as negative values. Increases are shown as positive values.
(3) For consistency with the projections in TM 4, the GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.
(4) Emissions from on-site combustion of biogas include CH_4 and N_2O only. CO_2 emissions are not included since they are considered biogenic.
(5) Calculated relative to 2047 total DSRSD GHG emissions of 4,033 MT CO_2e/yr.

The following biogas utilization energy generation opportunities were evaluated in TM 6:

- BS-26: Improve Gas Conditioning System (not included in GHG analysis).
- BS-28: Increase Biogas Storage (not included in GHG analysis).
- BS-30 and 31: Replace Cogeneration with Higher Efficiency Engine Generators.
- BS-34: Upgrade Cogeneration for all WWTP Needs.
- BS-35: Increase Cogeneration Capacity for Peak Demand and Redundancy.
- BS-37: Condition Biogas for Pipeline Injection.

As described in TM 6, BS-26 and BS-28 have minimal to no impact on energy generation and GHG emissions. Thus, these were not included in the GHG analysis.

In addition, a variation of BS-30 and BS-31 was evaluated that uses purchased renewable natural gas (RNG) instead of NG to supplement the engine generators:

- BS-30 and 31 B: Replace Cogen with Higher Efficiency Engine Generators and Use RNG instead of NG.

Table 7.5 summarizes the energy savings and corresponding GHG impact of the biogas utilization energy generation opportunities.

7.3.2 Building System Operations Optimization Opportunities

The following building system operations energy efficiency opportunities were evaluated in TM 5:

- BLG-2: Adjust Lighting and Temperature Schedules.
- BLG-4: Reduce Ground Lighting at Night.
- BLG-7: Metal Buildings Insulation.
- BLG-8, BLG:9, and BLG-10: Air Handling Unit Replacement and Heating, Ventilation, and Air Conditioning (HVAC) Reduction (not included in GHG analysis).
- BLG-11: HVAC Energy Recovery (not included in GHG analysis).
- BLG-14: Refrigerant HVAC System.
- BLG-15: Economized Cooling via Fan Addition.

As described in TM 5, the energy savings of BLG-8, BLG-9, BLG-10, and BLG-11 are expected to be minimal, and thus these opportunities were not included in the GHG analysis.

In addition, the following building system operations energy generation opportunities were evaluated in TM 6:

- BLG-12: Solar Thermal Heating.
- BLG-13: Wastewater Thermal Energy Use for Heating and Cooling (not included in GHG analysis).

As described in TM 6, the WWTP already has more thermal energy than it needs and there are no additional heat users, so BLG-13 was not included in the GHG analysis.

Table 7.6 summarizes the energy savings and corresponding GHG impact of the building system operations energy efficiency opportunities.

Table 7.5 GHG Impact of WWTP – Biogas Utilization Opportunities

Opportunity	Usage Inputs		GHG Emissions (MT CO_2e/yr)					% Increase or Decrease in GHG Emissions[6]
	Power (kWh/yr)	NG (1,000 cfy)	Power Usage (Scope 2)[5]	NG Onsite Combustion (Scope 1)	NG Offsite Production (Scope 3)	NG Offset (Scope 3)	Total	
BS-30 & 31[3]	-2,499,658	0	-184	0	0	0	**-184**	**-4.6%**
BS-34[3]	-3,134,450	0	-230	0	0	0	**-230**	**-5.7%**
BS-35[3]	-3,134,450	0	-230	0	0	0	**-230**	**-5.7%**
BS-37[4]	11,401,002	-110,330	837	-2,558	-75	-3,550	**-5,346**	**-132.5%**
BS-30/31 B[3]	-2,499,658	-46,984	-184	-2,558	-75	0	**-2,817**	**-69.8%**

Notes:
(1) Values represent design year 2047.
(2) Reductions in power usage and GHG emissions are shown as negative values. Increases are shown as positive values.
(3) The cogeneration opportunities (BS-30, 31, 34, 35, and 30/31B) assume the same amount of natural gas and biogas is used in the cogeneration engines as in the baseline. 100% of biogas is assumed to go to cogeneration. The on-site power generation from cogeneration increases due to the new, higher efficiency engines.
(4) The pipeline injection opportunity (BS-37) assumes that RNG exported to the grid results in a natural gas offset. In addition, the cogeneration system is assumed to be decommissioned, and instead the power is imported from the grid. The decommissioning of cogeneration also results in additional natural gas savings.
(5) For consistency with the projections in TM 04, the GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the State goal of 100 percent zero-carbon electricity by 2045.
(6) Calculated relative to 2047 total DSRSD GHG emissions of 4,033 MT CO_2e/yr.
Abbreviations: MT CO_2e/yr – metric tons of carbon dioxide equivalents per year; kWh/yr – kilowatt hours per year; cfy – cubic feet per year; NG = natural gas.

Table 7.6 GHG Impact of Building System Operations Opportunities

Opportunity	Usage Inputs		GHG Emissions (MT CO_2e/yr)				% Increase or Decrease in GHG Emissions[11]
	Power (kWh/yr)	NG (1,000 cfy)	Power Usage (Scope 2)[10]	NG Onsite Combustion (Scope 1)	NG Offsite Production (Scope 3)	Total	
BLG-2[4]	-50,107	-390	-4	-21	-1	**-26**	**-0.6%**
BLG-4[5]	-20,043	0	-1	0	0	**-1.5**	**-0.04%**
BLG-7[6]	-240,513	-3,119	-18	-170	-5	**-192**	**-4.8%**
BLG-12[7]	-4,850	0	-0.4	0	0	**-0.4**	**-0.01%**
BLG-14[8]	-60,128	-780	-4	-42	-1	**-48**	**-1.2%**
BLG-15[9]	-210,45	0	-2	0	0	**-1.5**	**-0.04%**

Notes:
(1) Values represent design year 2047.
(2) Reductions in power usage and GHG emissions are shown as negative values. Increases are shown as positive values.
(3) Lighting and HVAC electricity use are estimated as 2 percent and 3 percent of total WWTP electricity use, respectively. Based on electricity use from 2021 since the lighting and HVAC electricity use would not increase with increasing wastewater flows.
(4) Assumes 10 percent reduction of lighting and HVAC power usage and 10 percent reduction of HVAC natural gas usage.
(5) Assumes 10 percent reduction of lighting power usage.
(6) Assumes 80 percent reduction of HVAC power and natural gas usage.
(7) Estimate from Energy Research Institute calculator.
(8) Assumes 20 percent reduction of HVAC power and natural gas usage.
(9) Assumes 7 percent reduction of HVAC power usage.
(10) For consistency with the projections in TM 4, the GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.
(11) Calculated relative to 2047 total DSRSD GHG emissions of 4,033 MT CO_2e/yr.

7.3.3 Potable Water Distribution System Opportunities

The following potable water distribution system energy efficiency opportunities were evaluated:

- PWD-2, PWD-3: Pumping Efficiency Improvements.

Several pumping efficiency improvements were identified and are described in detail in TM 5. However, energy savings were not quantified for these opportunities, so they were not included in this GHG analysis.

7.3.4 Energy Management and Advanced Control Opportunities

The following energy management and advanced control energy efficiency opportunities were evaluated. These are described in detail in TM 5.

- AC-1: Alternative Power Monitoring System (combine with AC-4).
- AC-2: Artificial Intelligence (not included in GHG analysis).
- AC-4: Alternative Energy Decision Management Tools (combine with AC-1).

As described in TM 5, there are no anticipated energy savings from AC-2, so this opportunity was not included in the GHG analysis. In addition, TM 5 recommends combining AC-1 with AC-4.

Table 7.7 summarizes the energy savings and corresponding GHG impact of the energy management and advanced control opportunities.

Table 7.7 GHG Impact of Energy Management and Advanced Control Opportunities

Opportunity	Power Usage (kWh/yr)	GHG Emissions (MT CO_2e/yr)(4)	% Increase or Decrease in GHG Emissions(5)
AC-1: Alternative Power Monitoring System + AC-4: Alternative Energy Decision Management Tools(3)	-49,000	**-4**	**-0.1%**

Notes:
(1) Values represent design year 2047.
(2) Reductions in power usage and GHG emissions are shown as negative values. Increases are shown as positive values.
(3) Assumes 0.5 percent reduction in system-wide power usage.
(4) For consistency with the projections in TM 4, the GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the State goal of 100 percent zero-carbon electricity by 2045.
(5) Calculated relative to 2047 total DSRSD GHG emissions of 4,033 MT CO2e/yr.

7.3.5 Renewable Energy Generation and Storage Opportunities

Due to the large number of renewable energy generation and storage opportunities, these were grouped into renewable energy production, energy storage, and thermal energy recovery opportunities. These energy generation opportunities are described in detail in TM 6, and the following sections describe the GHG impact of these opportunities.

7.3.5.1 Renewable Energy Production Opportunities

The following renewable energy production opportunities were evaluated in TM 6:

- RE-1: On-Site Solar Installation.
- RE-2A: Solar Installation at the Gleason Property.

- RE-2B: Solar Installation at the LAVWMA Site.
- RE-3: Solar Installation at the DLD Site.
- RE-4: Solar Power for Electric Vehicle (EV) Fleet Recharging Station.
- RE-5: On-Site or Off-Site Wind Energy (not included in GHG analysis).
- RE-7: Renewable Energy Partnerships.
- RE-8: Green Power Purchasing.

As described in TM 6, the wind energy renewable energy opportunity is not recommended because there is not enough wind speed at the DSRSD sites, so RE-5 was not included in the GHG analysis.

Table 7.8 summarizes the energy savings and corresponding GHG impact of the renewable energy production opportunities.

Table 7.8 GHG Impact of Renewable Energy Production Opportunities

Opportunity	Power Usage (kWh/yr)	GHG Emissions (MT CO_2e/yr)(8)	% Increase or Decrease in GHG Emissions(9)
RE-1: On-Site Solar Installation(3)	-98,000	**-7**	**-0.2%**
RE-2A: Solar Installation at the Gleason Property(4)	-3,700,000	**-272**	**-6.7%**
RE-2B: Solar Installation at the LAVWMA Site(5)	-3,400,000	**-250**	**-6.2%**
RE-3: Solar Installation at the DLD Site(4)	-3,700,000	**-272**	**-6.7%**
RE-4: Solar Power for EV Fleet Recharging Station(6)	-100,000	**-7**	**-0.3%**
RE-7: Renewable Energy Partnerships(4)	-3,700,000	**-272**	**-6.7%**
RE-8: Green Power Purchasing (7)	-13,526,000	**-993**	**-24.6%**

Notes:
(1) Values represent design year 2047.
(2) Reductions in power usage and GHG emissions are shown as negative values. Increases are shown as positive values.
(3) Assumes renewable power generation of 98 megawatt hours per year (MWh/yr).
(4) Assumes renewable power generation of 3,700 MWh/yr.
(5) Assumes renewable power generation of 3,400 MWh/yr.
(6) Assumes renewable power generation of 100 MWh/yr.
(7) Assumes all imported power has zero GHG emissions.
(8) For consistency with the projections in TM 4, the GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.
(9) Calculated relative to 2047 total DSRSD GHG emissions of 4,033 MT CO2e/yr.

7.3.5.2 Energy Storage Opportunities

The following energy storage opportunities were evaluated in TM 6:

- ES-1: Battery Storage and Microgrid System Installation.
- ES-2: Battery Storage for Peak Demand Charges.

Table 7.9 summarizes the energy savings and corresponding GHG impact of the energy storage opportunities.

Table 7.9 GHG Impact of Energy Storage Opportunities

Opportunity	Power Usage (kWh/yr)	GHG Emissions (MT CO_2e/yr)(5)	% Increase or Decrease in GHG Emissions(6)
ES-1: Battery Storage and Microgrid System Installation(3)	-180,000	**-13**	**-0.3%**
ES-2: Battery Storage for Peak Demand Charges(4)	-360,000	**-26**	**-0.7%**

Notes:
(1) Values represent design year 2047.
(2) Reductions in power usage and GHG emissions are shown as negative values. Increases are shown as positive values.
(3) Assumes 1 megawatt (MW) battery capacity reduces power import by 180 MWh/yr.
(4) Assumes 2 MW battery capacity reduces power import by 360 MWh/yr.
(5) For consistency with the projections in TM 4, the GHG emissions from purchased electricity were calculated using the current emission factor for imported electricity, which is based on the current renewable energy mix from the CCA and PG&E portfolios. However, this emission factor is expected to decrease over time as PG&E and other California power utilities transition to meet the state goal of 100 percent zero-carbon electricity by 2045.
(6) Calculated relative to 2047 total DSRSD GHG emissions of 4,033 MT CO2e/yr.

7.3.5.3 Thermal Energy Recovery Opportunities

The following thermal energy recovery opportunities were evaluated in TM 6:

- TH-1: Recover Thermal Energy from Influent and Effluent (not included in GHG analysis).
- TH-2: Capture Heat from Collection System for Commercial Use (not included in GHG analysis).
- TH-4: Expand Heat Loop (not included in GHG analysis).
- TH-5 and TH-7: Use Heat for Process Needs and Advanced Biosolids Processing (not included in GHG analysis).

As described in TM 6, DSRSD has more thermal energy than they are using and additional thermal energy use hinges on finding additional on-site or off-site heat users. Since there is no current or expected future use for the additional thermal energy, the thermal energy recovery opportunities are not recommended and were thus not included in the GHG analysis.

7.4 Vehicle Fleet – Energy Savings and Efficiency Opportunities

7.4.1 Regulatory Considerations

As of April 28, 2023, there are two approved CARB regulations, ***Advanced Clear Cars II*** and ***Advanced Clean Fleets*** (ACF), that will influence the timeline for DSRSD's transition to ZEV. Advanced Clean Cars II aims to rapidly scale down fossil fuel-based passenger and light-duty vehicles, defined as vehicles with a gross vehicle weight rating (GVWR) of less than 8,500 pounds, by banning the sale of internal combustion engines (ICE) incrementally starting in the year 2026 with a full ban in 2035. Figure 7.1 shows the timeline for how conventional ICE vehicles will be phased out for ZEV alternatives as outlined in the Advanced Clean Cars II regulations. This does not directly affect DSRSD's transition to a fully ZEV fleet but will limit the availability of conventional ICE light-duty and passenger vehicles in California.

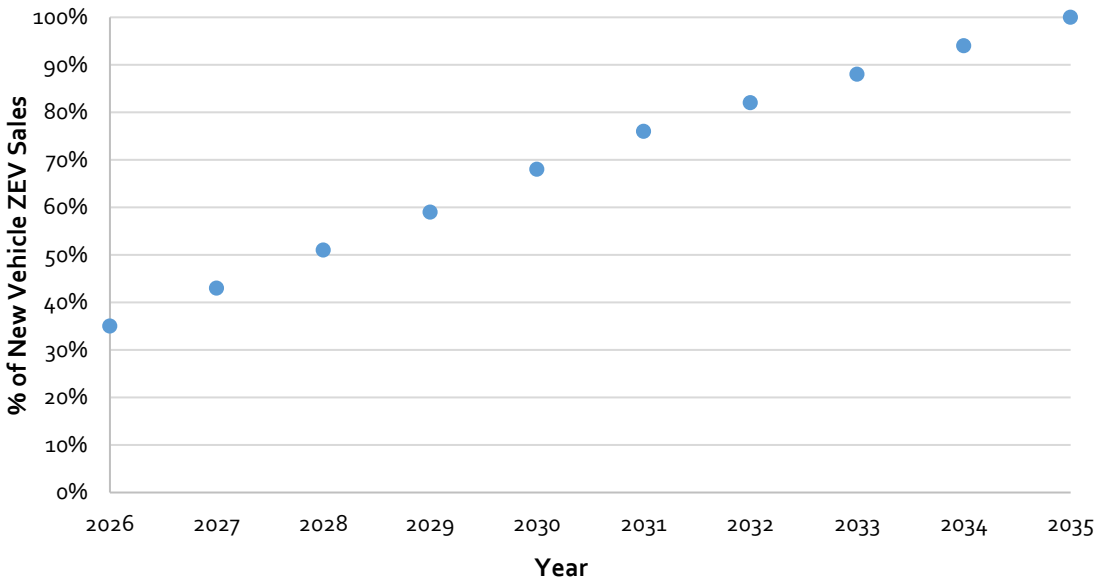

Figure 7.1 California's Clean Cars II ICE Vehicle Phaseout Schedule

However, the passing of ACF within California does directly influence near-term and future DSRSD fleet vehicle purchases. The ACF Regulations apply to fleets performing drayage operations, those owned by State, local, and federal government agencies, and high priority fleets. High priority fleets are entities that own, operate, or direct at least one vehicle in California, and that have either $50 million or more in gross annual revenues, or that own, operate, or have common ownership or control of a total of 50 or more vehicles (excluding light-duty package delivery vehicles). The regulation applies to medium- and heavy-duty on-road vehicles with a gross vehicle weight rating greater than 8,500 pounds, off-road yard tractors, and light-duty mail and package delivery vehicles.

According to the ***State and Local Government Agency Fleet Regulations,*** DSRSD will be required to transition their fleet to ZEVs with the following requirements:

1. Starting January 1, 2024, 50 percent of "total vehicle purchases" for a California fleet in each calendar year must be ZEVs.
2. Starting January 1, 2027, 100 percent of "total vehicle purchases" for a California fleet in each calendar year must be ZEVs.

It is important to note that State and Local Government Agency fleets have no requirement to end the use of existing compliant combustion vehicles and can be operated indefinitely. Additionally, per Section 2013(e), in lieu of complying with the requirements of the ***State and Local Government Agency Fleets***, it allows publicly owned treatment works (POTW) to elect to permanently opt their entire medium and heavy-duty fleet into the ZEV Milestone Option adhering to the appropriate timeline for Group 1, 2, or 3 based on vehicle type; under the ***High Priority and Federal Fleets Requirements*** (*Title 13, California Code Of Regulations, Section 2015.2*) until January 1, 2030. If choosing this option, fleet owners must comply with all the requirements applicable to ***High Priority and Federal Fleets Requirements*** specified in Section 2015. After electing to use this option, POTW fleet owners may not switch back to the ***State and Local Government Agency Fleets Requirements***.

The percentage of vehicles needed to comply with the Milestone Group must be in operation by January 1 of the Milestone year. If you know the vehicle will not be in operation in time, you must apply for an extension. Table 7.10 below presents the grouping classifications for each applicable vehicle type.

Additionally, the portion of the POTW fleet that meets the requirements of Section 2015.2(b) *Waste and Wastewater Fleet Provision* as of January 1, 2024, may qualify for opting those vehicles into Milestone Group 3. In other words, if 100 vehicles were in the fleet, and only 10 were exclusively fueled with biomethane and support implementation of SB 1383, those 10 could be included in the Milestone Group 3 while the rest of the fleet would be categorized under Group 1, 2 or 3 based on vehicle type. Fleet owners utilizing this provision must report fleet and vehicle information as specified in Sections 2015.4(c)(1)(J) and keep records as specified in Section 2015.5(m).

A timeline addressing both regulations is presented in Figure 7.2. ***High Priority and Federal Fleets Requirements*** differentiates the type of ZEVs by group, each with distinct timelines.

Final important considerations of CARB's ACF regulations include the following:

- DSRSD meets the requirements for ***High Priority and Federal Fleets*** but must legally opt into this program.
- The ***High Priority and Federal Fleets*** timeline requires that ALL medium- and heavy-duty vehicles, not just vehicle purchases, relating to a GVWR greater than 8,500 pounds must be replaced according to Figure 7.2. Because of this distinction, along with several other challenges, Carollo does not recommend opting into ***High Priority and Federal Fleets***. This allows DSRSD to preserve as much flexibility as possible for meeting their levels of service supported by appropriate vehicles.
- A "vehicle purchase" means an action wherein a fleet owner has either placed an order to acquire the legal or equitable title to a vehicle or to convert a vehicle. A vehicle purchase includes when the fleet owner has executed any one of the following:
  - Identified, committed, and encumbered funds and executed a written notice to proceed to a manufacturer, authorized dealer, or entity that converts vehicles to ZEVs to begin production of the vehicle.
  - A written purchase agreement between a fleet owner and the manufacturer or entity that converts vehicles to ZEVs specifies the date when the work to manufacture or convert the vehicle is to proceed.
  - A written purchase agreement between a fleet owner and another party for the purchase and immediate delivery of a used vehicle; or A signed written lease agreement between a fleet owner and the manufacturer or authorized dealer for a new vehicle to be placed in service in the California fleet for a contract term of one year or more.

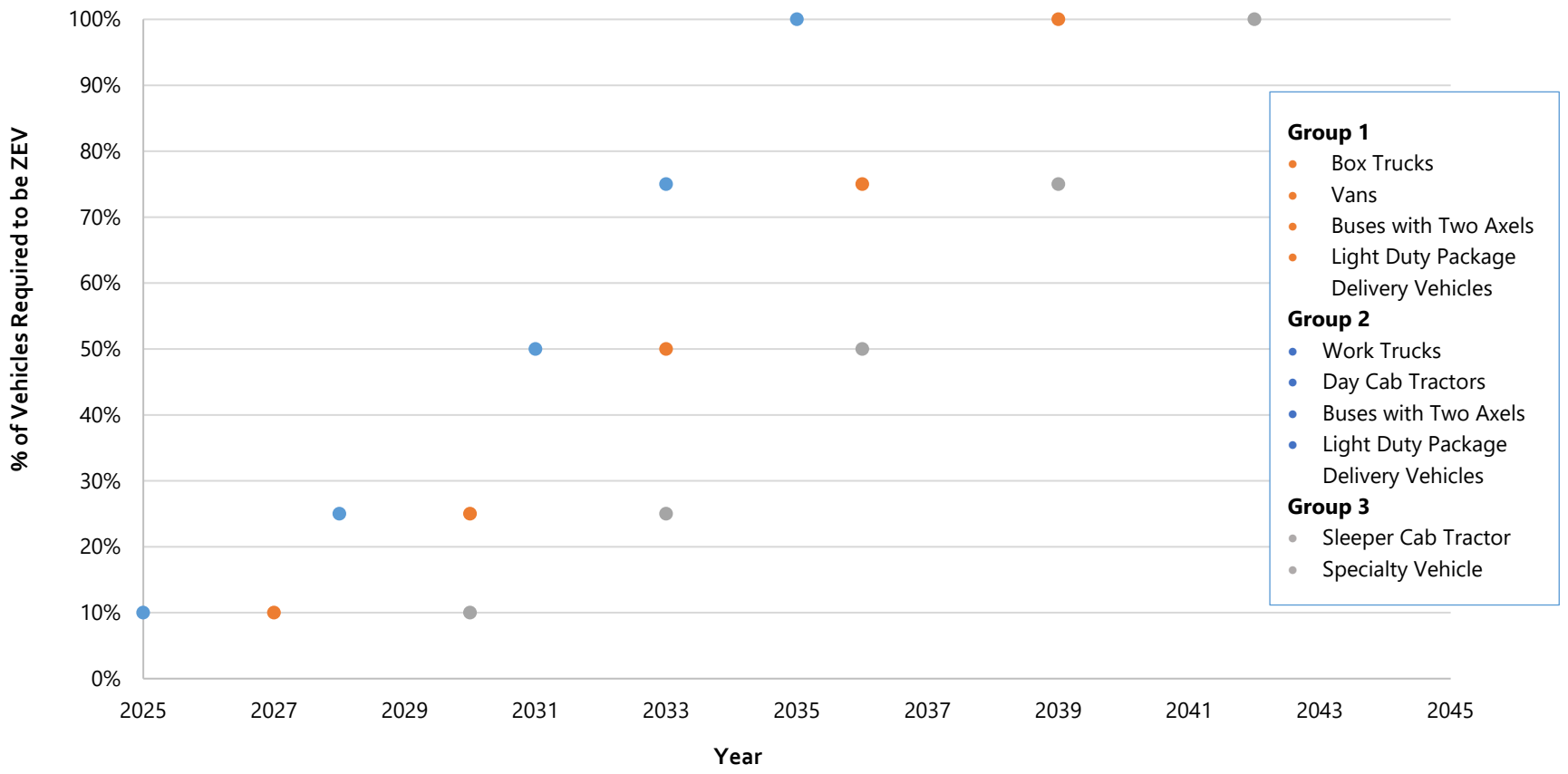

Figure 7.2 High Priority and Federal Fleets Timeline Depending on Group Classification

7.4.1.1 Flexibility Provisions

Flexibility provisions are possible exemptions available for medium- and heavy-duty vehicles of a certain age. These provisions or exemptions are listed as follows along with additional specific information for DSRSD.

- **Vehicle Delivery Delay Extension:** Allows a fleet to remain compliant if a ZEV order is delayed.
  - This extension is available to vehicles registered under the High Priority and Federal Fleets Requirements.
- **Infrastructure Delay Extension:** Extends compliance for up to five years for delays during planning and construction.
  - Carollo recommends DSRSD pursue this flexibility provision, considering DSRSD's intentions to utilize solar infrastructure to support charging.
- **ZEV Purchase Exemptions:** Can buy ICE vehicle if ZEV is not available in configuration needed.
  - Carollo recommends DSRSD pursue this flexibility provision, especially if a functionally equivalent ZEV is not available.
- **Daily Usage Exemption:** Can purchase ICE vehicle if ZEV does not meet fleet's mileage or power needs.
  - Carollo recommends DSRSD pursue this flexibility provision, especially for vehicles that are used as emergency or power-related vehicles.
- **Mutual Aid Assistance:** Reserves up to 25 percent of ICE vehicles in a fleet for use in mutual aid events.
  - Not relevant to DSRSD at this time.
- **Waste/Wastewater Fleets Extension:** Extends existing CNG trucks in waste diversion and biomethane generation.
  - Not relevant to DSRSD.
- **Non-Repairable Vehicle:** Flexibility to purchase used replacement ICE vehicle in case of an accident.
  - Carollo recommends DSRSD pursue this flexibility provision when applicable or needed.
- **Backup Vehicle Exemption:** Excludes vehicles operated less than 1,000 miles per year including mutual aid events.
    - Carollo recommends DSRSD pursue this flexibility provision for backup vehicles. Most other vehicles in DSRSD exceed 1,000 miles per year limit however.
- **Intermittent Snow Removal Vehicle:** May purchase ICE vehicles to operate as intermittent snowplow until 2030.
  - Not relevant to DSRSD.

7.4.2 Proposed Timeline of Fleet Transition to Zero-Emission Vehicles

Meeting the ***State and Local Government Agency Fleet Regulations*** is the driving factor for the proposed timeline. Other considerations, such as DSRSD's supplemental information regarding expected useful life, maintenance notes, annual usage, and availability of ZEV equivalent replacements, were included in this proposed timeline. Figure 7.3 shows the proposed timeline to meet regulatory requirements according to the ***State and Local Government Agency Fleet***

Regulations. The timeline can be reasonably updated depending on funding and application of the flexibility provisions.

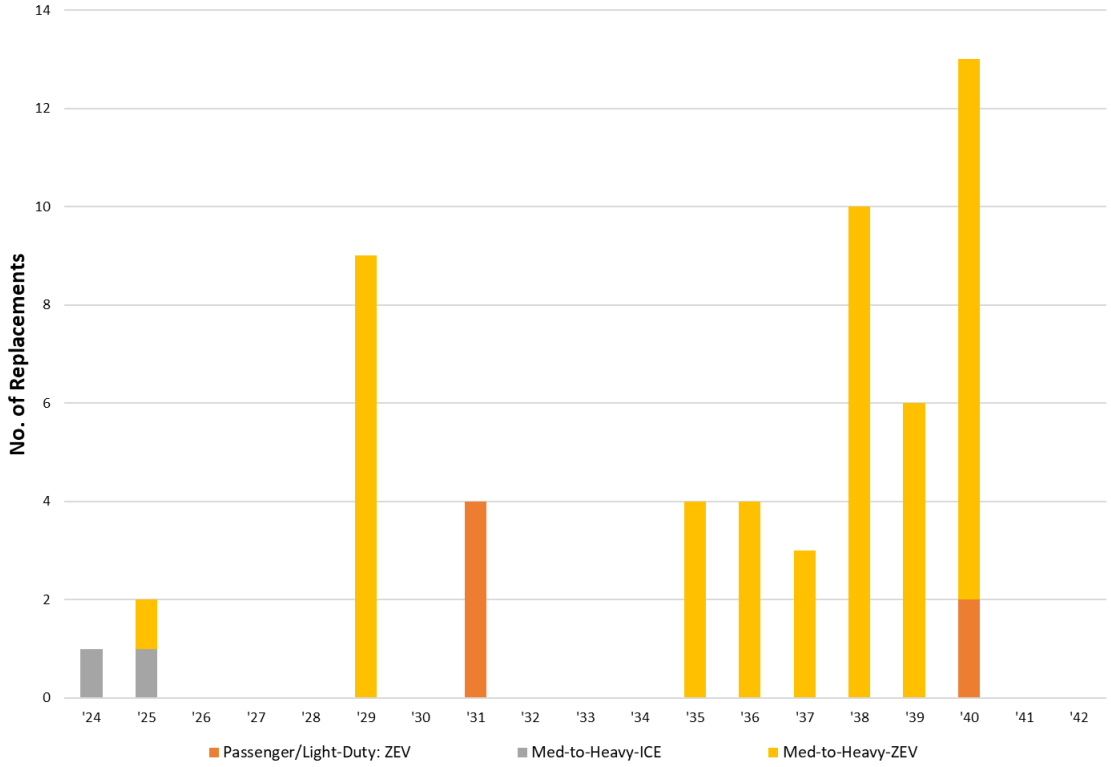

Figure 7.3 Proposed State and Local Government Timeline for Vehicle Fleet Transition to ZEVs

CARB has compiled various resources that discuss the ZEV alternatives to commonly used fleet vehicles. Light-duty and passenger vehicles have multiple options and are best left to the discretion of DSRSD. For pricing purposes, the closest model and make of a ZEV alternative was used for replacement of an existing fleet vehicle. In general, there are fewer medium- to heavy-duty options available that meet the needs of POTWs. As of the time of this analysis, manufacturers claim there are ZEV options that closely match the existing medium- and heavy-duty trucks within DSRSD. However, there are very limited options for medium-duty truck ZEV replacements (e.g., F-350 and F-450 trucks).

Carollo recommends identifying specific functions needed for each vehicle, to determine wherever possible a switch can be made to a ZEV option that can perform those functions. This may prove impossible at this time since there are no known "functionally equivalent" medium- and heavy-duty ZEV options that meet the day-to-day tasks of the existing ICE vehicles within the fleet. Potential limitations of ZEVs include but are not limited to the following:

- **Towing capacity:** Current heavy-duty truck ICE vehicles have towing capacities of well over 20,000 pounds, while existing ZEV models typically only have half that capacity.
- **Distance and time traveled:** Currently, manufacturers estimate increased battery weight will drastically reduce the length of time a heavy-duty ZEV can operate before needing to be charged.
- **Power take-off applicability:** ZEVs need to support remote power to a pump or similar equipment for emergency and response events.

The regulations, as interpreted, may allow for a flexibility provision if these daily applications and needs are not met by current ZEVs on the market. Considering this and the fact that ZEVs cost significantly more than conventional ICE vehicles, the required capital costs for a fleet transition are exceptionally high when compared to a business-as-usual approach. It is also important to understand that the volatility of the ZEV market directly impacts the validity and confidence of projected costs. Carollo recommends further discussions and analysis be held within DSRSD to better understand the fleet's specific needs and what the best approach would be to address those needs in light of the limitations of the available ZEV replacements.

Because there is no need to replace existing compliant ICE vehicles and DSRSD efforts to replace some older vehicles nearing their expected end of useful life, the number of replacements can be spread over time (assuming vehicles remain compliant). The timeline in Figure 7.3 takes into account the following driving factors and assumptions:

- All passenger/light duty vehicles needing to be replaced were considered to be a ZEV replacement regardless of the Clean Cars II ICE Vehicle Phaseout Schedule.
- All light duty trucks that are comparable to a Ford F150 Lightning (Ford F150 and Ford Ranger) were included to be a medium and heavy-duty ZEV replacement since the Ford F150 Lightning has a GVWR exceeding 8,500 pounds.
- Existing medium- and heavy-duty ICE vehicles do not need to be replaced as long they are compliant with other California regulations and are operational.
- A medium- or heavy-duty vehicle is replaced with a medium or heavy-duty ZEV when there is no requirement that this must be done and a vehicle can simply not be replaced or replaced with a light duty vehicle instead.
- Once a ZEV replacement is purchased, that replacement must then be replaced within an 18 year timeframe.
- Operator information regarding the miles driven, expected remaining years of useful life, and vehicle status was provided to Carollo to assist in forming this timeline.
  - Vehicles with a "loaner" status were not assumed to be replaced.
  - Vehicles with 0 to 2 years and 3 to 5 years of expected remaining years of useful life were given the priority for replacement.
- Other flexibility provisions may be applicable but were not assumed for this analysis.

7.4.3 Existing Vehicles and Proposed Alternatives

A full list of existing vehicles owned by DSRSD, including loaner, active, and recently purchased vehicles, and the potential ZEV alternatives is presented in Table 7.10. As previously stated, DSRSD will need to consider various functions of the vehicles (including towing capacities, feasible alternatives, costs, and timeframes for manufacturing) when identifying medium- and heavy-duty vehicles (specifically, those marked in red text in Table 7.10).

Table 7.10 List of Existing and Proposed Fleet Vehicles

Make of Existing Vehicle	Existing Class	Existing Model	Number	ZEV Replacement
Ford	Passenger Car	Escape	6	Nissan Leaf
		Explorer	1	VW ID.4
		Fusion	2	Nissan Leaf
	Light-Duty Truck	F-150	8	F-150 Lightning(1)
		Ranger	9	F-150 Lightning
	Heavy-Duty	F-250	19	No Functional Equivalent
		F-350	8	No Functional Equivalent
		F-450	4	No Functional Equivalent
		Transit T-150	1	Ford E-Transit
		Transit Connect	5	Ford E-Transit
Freightliner	Heavy-Duty	Camel: 108 SD	1	eCascadia
		Camel: 114 SD	1	eCascadia
Other	Heavy-Duty	Closed-circuit television	1	No Functional Equivalent
		Vac-Con	1	No Functional Equivalent
Total			**67**	

Notes:
(1) The F-150 Lightning could potentially exceed a GVWR of 8,500 pounds so careful attention must be made to determine the battery rating and weight for it to be considered light-duty and not mandated under ACF Regulations.

7.4.4 Zero-Emission Vehicle Charging Considerations

There are various manufacturers and types of ZEVs that are on the market or quickly emerging including EVs. Charging stations that are offered for larger EVs are more limited. For example, chargers for heavy-duty EVs would be limited to Level 2 chargers and direct current (DC) fast chargers. A Level 2 charger can fully charge a medium-duty EV in roughly 8 hours, while DC fast chargers can charge a light-duty EV in minutes and a medium-duty electric truck in an hour or less. However, it still takes nearly 100 hours to completely charge a heavy-duty EV using a level 2 charger and approximately 10 hours using a DC fast charger.

Many of these charging stations are expected to be fully constructed by the manufacturer with one station usually being able to charge two or more vehicles at a time. The low mileage requirements for DSRSD's heavy-duty vehicles may favor Level 2 charging stations for periodic or overnight charging of multiple vehicles when needed. An example Level 2 48Amp EV charger named ClipperCreek HCS-60EV Charger costs $990. Additionally, Inland Empire Utilities Agency recently purchased, installed, and tested 35 charging stations (15 dual, 5 single ports) for $258,000 with other infrastructure costs being covered by Southern California Edison. For more

information involving funding opportunities, refer to TM 8 for additional information. As mentioned in previous TM's, most notably TM 6 and TM 8, energy credits and incentives can be provided to DSRSD for renewable energy alternatives related to EV charging.

Although there are other emerging technologies, such as hydrogen-fueled or compressed natural gas alternatives, EV charging stations are currently the most practical option for DSRSD in the short-term. Carollo recommends working with charging station manufacturers as well as PG&E and other funding organizations to implement EV charging stations within DSRSD.

7.4.5 Greenhouse Gas and Energy Impacts

Key assumptions of this analysis were presented in TM 1 but more have been included as this analysis has proceeded to keep up with regulatory and market updates. The key assumptions affecting costs and GHG emissions are presented in Table 7.11. Vehicle costs for both ICE vehicles and ZEVs that are currently on the market were determined by the manufacturer's suggested retail price. An escalation price factor was used to estimate medium- and heavy-duty vehicle costs that currently do not have viable alternatives, this is shown in Table 7.11. Finally, vehicle miles traveled information given by DSRSD for select vehicles in 2021 was used to project estimated future usage of the fleet's vehicles.

Table 7.11 Fleet Analysis Assumptions

Parameter	Assumption	Notes
Gasoline Price ($/gallon)	5.84	DSRSD Confirmed
Annual Gasoline escalation (%)	1	Accounts for increase of gasoline price.
Diesel Price ($/gallon)	6.59	DSRSD Confirmed
Annual diesel escalation (%)	1	Accounts for increase of diesel price.
Electricity Price ($/kWh)	0.20	DSRSD Confirmed
ZEV electricity consumption (kWh/100 miles)	Varies for ZEV replacement.	Unique electricity requirements on a per mile basis was used to calculate energy requirements for each ZEV.
Annual electricity escalation (%)	1	Accounts for increase of electricity price.
O&M Cost Factor (Not including fuels) (ICE) ($/mile)	$0.101	publications.anl.gov/anlpubs/2021/05/167399.pdf
O&M Cost Factor (Not including electricity) (ZEV) ($/mile)	$0.061	publications.anl.gov/anlpubs/2021/05/167399.pdf
Annual decrease of GHG emissions from grid (%)	5	Accounts for California's goal of carbon neutrality by 2045.
Discount rate for NPV (%)	1	DSRSD Confirmed
Escalation rate for NPV (%)	3	DSRSD Confirmed
Price escalation of medium- and heavy-duty ZEVs (%)	250	Accounts for expected cost surplus for ZEVs that are not currently on the market.

Notes:
kWh - kilowatt hour; NPV - net present value; O&M - operations and maintenance.

Table 7.12 shows the associated GHG emissions relating to a business-as-usual approach and the proposed timelines for a ZEV fleet dictated by the regulations. Although capital costs are much higher when purchasing ZEVs, O&M costs are slightly lower due to decreased gasoline and diesel consumption. It is recommended that DSRSD does not opt into the ***High Priority Fleets Regulations***. CARB interpretations of ***State and Local Government Agency Fleets***, specifically the flexibility provisions and no driver to replace an ICE vehicle prematurely, require significantly less costs and less burden to DSRSD. Detailed calculations for each scenario is presented in Appendix 7A.

Table 7.12 GHG and Cost Impact of Fleet Transition

Scenario	NPV of Capital Cost ($)(1)	NPV of O&M Cost ($)	NPV of Total Cost ($)	GHG Emissions (MT CO_2e)
Business-as-Usual	3,719,000	1,075,000	4,794,000	1,211
State and Local Fleets	7,239,000	937,000	8,176,000	930

Notes:
(1) The vehicle costs are rapidly changing as the market evolves. This estimate is based on the current market conditions.
(2) All numbers represent either the total sum of prices or GHG emissions through 2024 to 2042.

7.5 Summary of Greenhouse Gas Reduction Opportunities and Fleet Transition to Zero-Emission Vehicles

7.5.1 Greenhouse Gas Reduction Opportunities

Table 7.13 provides a summary of the GHG emissions impact of the energy efficiency and generation opportunities evaluated. The top five opportunities with the largest potential GHG emissions reduction are listed below and bolded in Table 7.13. These opportunities have emissions reduction close to or above 1,000 MT CO_2e/yr, which is substantial relative to the total DSRSD-wide GHG emissions estimated at 4,033 MT CO_2e/yr for year 2047. As expected, the opportunities with the largest potential GHG emissions reductions are those that reduce natural gas use in cogeneration or that produce a natural gas offset by producing RNG. In addition, green power purchasing also has a large potential GHG emissions reduction. Combining several of these opportunities, it appears possible for DSRSD to achieve carbon neutrality.

- BS-23: Co-digest FOG.
- BS-24: Co-digest FW Slurry and HSW.
- BS-37: Condition Biogas for Pipeline Injection.
- BS-30/31B: Replace Cogen with Higher Efficiency Engine Generators and Use RNG instead of NG.
- RE-8: Green Power Purchasing.

The findings of this GHG analysis are not intended to be used on their own to make recommendations or decisions on the best opportunities for DSRSD to implement. Instead, these findings should be combined with the cost analysis of these opportunities (described in TM 5 and TM 6) and other considerations, such as staff preferences and funding opportunities, to make recommendations later in this Energy Facilities Master Plan.

Table 7.13 Summary of GHG Emissions Impact of Energy Efficiency and Generation Opportunities

Opp. ID	Opportunity Name	Opp. Type	Estimated Potential for Energy Savings/Generation	GHG Emissions (MT CO_2e/yr)	% Increase or Decrease	Considerations
WWTP - Liquid Stream Treatment Opportunities						
LS-3	Improve Carbon Diversion from Primaries to Digesters	Generation (TM 6)	10% aeration power savings (-433,000 kWh/yr), 5% biogas production increase resulting in NG use reduction in cogeneration.	-218	-0.1%	
LS-5	Real Time SRT Control	Efficiency (TM 5)	1% aeration power savings (-43,000 kWh/yr).	-3	-0.8%	
LS-6	Model Predictive Aeration Control	Efficiency (TM 5)	10% aeration power savings (-433,000 kWh/yr).	-32	-1.6%	
LS-7	Low Dissolved Oxygen Operation	Efficiency (TM 5)	20% aeration power savings (-866,000 kWh/yr).	-64	-0.8%	
LS-12	More Efficient Aeration Diffusers	Efficiency (TM 5)	10% aeration power savings (-433,000 kWh/yr).	-32	-0.3%	
LS-13	Upgrade Aeration Blowers	Efficiency (TM 5)	4% blower power savings (-173,000 kWh/yr).	-13	-0.1%	
LS-16	Upgrade Pre-Aeration Blowers	Efficiency (TM 5)	Blower efficiency increase from 30 to 70% (-62,000 kWh/yr).	-5	-5.4%	TM 5 recommends not pursuing further at this point.
WWTP - Solids Stream Treatment Opportunities						
BS-2A	DAFT Optimization	Efficiency (TM 5)	No anticipated energy savings.	Not quantified.	-	Not evaluated because DAFT is already optimized.
BS-2B	Mechanical Thickening Post-DAFT	Generation (TM 6)	Increases power (72,000 kWh/yr) and polymer use but provides capacity for co-digestion.	51	1.3%	Provides additional digestion capacity, which is needed after 2026, for FOG and FW co-digestion (BS-23 and BS-24).
BS-2C	Mechanical Thickening Instead of DAFT	Generation (TM 6)	Overall net reduction in power use due to decommissioning of DAFT (-1,420,000 kWh/yr). Increases polymer use but provides capacity for co-digestion.	-59	-1.5%	Provides additional digestion capacity, which is needed after 2026, for FOG and FW co-digestion (BS-23 and BS-24).
BS-7	Recuperative Thickening	Generation (TM 6)	Increases power (774,000 kWh/yr) and polymer use but provides capacity for co-digestion.	102	2.5%	Provides additional digestion capacity, which is needed after 2026, for FOG and FW co-digestion (BS-23 and BS-24).
BS-13	Dewatering Post-Digestion	Generation (TM 6)	Increase power (14,000 kWh/yr) and polymer use but eliminates FSL and DLD diesel usage and provides land application GHG benefits.	13	1.6%	Provides beneficial use of biosolids through agricultural land application, which is needed for FW-codigestion (BS-24) to qualify as landfill diversion, per SB 1383.
BS-17	Drying and Pyrolysis	Generation (TM 6)	Minimal to negative energy savings.	Not quantified.	-	Not evaluated due to high cost and complexity combined with low to negative energy and GHG reductions. TM 6 recommends not pursuing further, except if PFAS regulations require it in the future.
BS-18	Drying and Gasification	Generation (TM 6)	Minimal to negative energy savings.	Not quantified.	-	Not evaluated due to high cost and complexity combined with low to negative energy and GHG reductions. TM 6 recommends not pursuing further, except if PFAS regulations require it in the future.
BS-22	Lystek Thermo-Chemical Hydrolysis	Generation (TM 6)	Increase power (14,000 kWh/yr) and polymer use but eliminates FSL and DLD diesel usage and provides land application GHG benefits.	-61	-0.3%	Provides beneficial use of biosolids through agricultural land application, which is needed for FW-codigestion (BS-24) to qualify as landfill diversion, per SB 1383.
BS-23	**Co-digest FOG**	**Generation (TM 6)**	**Additional biogas production from co-digestion of 15,000 gallons/day of FOG reduces natural gas usage (-228,000 therms/year) in cogeneration.**	**-1,230**	**-30.5%**	**Needs to be combined with one of the mechanical thickening alternatives to provide sufficient digestion capacity after 2026.**
BS-24	**Co-digest FW Slurry and HSW**	**Generation (TM 6)**	**Additional biogas production from co-digestion of 33,000 gallons/day of FW slurry reduces natural gas usage (-208,000 therms/year) in cogeneration. Includes GHG emissions reduction from diverting FW from landfills.**	**-3,423**	**-84.9%**	**Needs to be combined with one of the mechanical thickening alternatives to provide sufficient digestion capacity after 2026. Needs to be combined with BS-13 or BS-22 for beneficial use of biosolids to qualify as landfill diversion, per SB 1383.**

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Table 7.13 Summary of GHG Emissions Impact of Energy Efficiency and Generation Opportunities (continued)

Opp. ID	Opportunity Name	Opp. Type	Estimated Potential for Energy Savings/Generation	GHG Emissions (MT CO_2e/yr)	% Increase or Decrease	Considerations
BS-26	Improve Gas Conditioning	Generation (TM 6)	No anticipated energy savings.	Not quantified.	-	Not evaluated since it does not affect energy usage or GHG emissions.
BS-28	Increase Biogas Storage	Generation (TM 6)	No anticipated energy savings.	Not quantified.	-	Not evaluated since it does not affect energy usage or GHG emissions.
BS-30/31	Replace Cogeneration with Higher Efficiency Engine Generators	Generation (TM 6)	Assumes same amount of biogas and NG to engines as baseline. Increase in energy generation (-2,500,000 kWh/yr) is from higher efficiency engines.	-184	-4.6%	
BS-34	Upgrade Cogeneration for all WWTP Needs	Generation (TM 6)	Assumes same amount of biogas and NG to engines as baseline. Increase in energy generation (-3,130,000 kWh/yr) is from higher efficiency engines.	-230	-5.7%	
BS-35	Increase Cogeneration Capacity for Peak Demand and Redundancy	Generation (TM 6)	Assumes same amount of biogas and NG to engines as baseline. Increase in energy generation (-3,130,000 kWh/yr) is from higher efficiency engines.	-230	-5.7%	
BS-37	**Condition Biogas for Pipeline Injection**	**Generation (TM 6)**	**Increase power usage substantially (11,400,000 kWh/yr) but results in GHG benefits due to NG offset.**	**-5,346**	**-132.5%**	
BS-20/31B	**Cogeneration with Purchased RNG instead of NG**	**Generation (TM 6)**	**Assumes same amount of biogas and NG to engines as baseline. Increase in energy generation (-2,500,000 kWh/yr) is from higher efficiency engines.**	**-2,817**	**-69.8%**	
WWTP – Building System Operations Opportunities						
BLG-2	Adjust Lighting and Temperature Schedules	Efficiency (TM 5)	10% savings in lighting and HVAC power (-50,000 kWh/yr) and natural gas usage.	-26	-0.6%	
BLG-4	Reduced Ground Lighting at Night	Efficiency (TM 5)	10% savings in lighting power usage (-20,000 kWh/yr).	-1	-0.04%	
BLG-7	Metal Buildings Insulation	Efficiency (TM 5)	80% savings in HVAC power (-241,000 kWh/yr) and natural gas usage.	-192	-4.8%	
BLG-8/9/10	Air Handling Unit Replacement and HVAC Reduction	Efficiency (TM 5)	Minimal energy savings.	Not quantified.	-	
BLG-11	HVAC Energy Recovery	Efficiency (TM 5)	No anticipated energy savings.	Not quantified.	-	TM 5 recommends not pursuing further at this point.
BLG-12	Solar Thermal Heating	Generation (TM 6)	Estimate of -4,850 kWh/yr power savings.	-0.4	-0.01%	
BLG-13	Wastewater Thermal Energy Use for Heating and Cooling	Generation (TM 6)	WWTP already has more thermal energy than it needs.	Not quantified.	-	TM 6 recommends not pursuing further at this point.
BLG-14	Refrigerant HVAC System	Efficiency (TM 5)	20% savings in lighting and HVAC power (-50,000 kWh/yr) and natural gas usage.	-48	-1.2%	
BLG-15	Economized Cooling via Fan Addition	Efficiency (TM 5)	7% savings in HVAC power usage (-21,000 kWh/yr).	-2	-0.04%	
Potable Water Distribution System Opportunities						
PWD-2/3	Pumping Efficiency Improvements	Efficiency (TM 5)	Not quantified.	Not quantified.	-	

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Table 7.13 Summary of GHG Emissions Impact of Energy Efficiency and Generation Opportunities (continued)

Opp. ID	Opportunity Name	Opp. Type	Estimated Potential for Energy Savings/Generation	GHG Emissions (MT CO_2e/yr)	% Increase or Decrease	Considerations
Energy Management and Advanced Control Opportunities						
AC-1	Alternative Power Monitoring System	Efficiency (TM 5)	0.5% savings in system-wide power usage (-49,000 kWh/yr).	-4	-0.1%	Needs to be combined with AC-4.
AC-2	AI	Efficiency (TM 5)	No anticipated energy savings.	Not quantified.	-	TM 5 states no CIP action needed at this time.
AC-4	Energy Decision Management Tools	Efficiency (TM 5)	Combine with AC-1.	See AC-1	See AC-1	Needs to be combined with AC-1.
Renewable Energy Generation and Storage Opportunities						
RE-1	On-Site Solar Installation		-98,000 kWh/yr	-7	-0.2%	
RE-2A	Solar Installation at the Gleason Property		-3,700,000 kWh/yr	-272	-6.7%	
RE-2B	Solar Installation at the LAVWMA Site		-3,400,000 kWh/yr	-250	-6.2%	
RE-3	Solar Installation at the DLD Site		-3,700,000 kWh/yr	-272	-6.7%	
RE-4	Solar Power for EV Fleet Charging Station		-100,000 kWh/yr	-7	-0.3%	
RE-5	On-Site or Off-Site Wind Energy		Not viable due to insufficient wind speed.	Not quantified.	-	TM 6 recommends not pursuing further at this point.
RE-7	Renewable Energy Partnerships		-3,700,000 kWh/yr	-272	-6.7%	
RE-8	**Green Power Purchasing**		**Assumes all imported power (13,526,000 kWh/yr) has zero GHG emissions.**	**-993**	**-24.6%**	
ES-1	Battery Storage and Microgrid System Installation		-180,000 kWh/yr based on 1 MW battery capacity.	-13	-0.3%	
ES-2	Battery Storage for Peak Demand Charges		-360,000 kWh/yr based on 2 MW battery capacity.	-26	-0.7%	
Vehicle Fleet Opportunities						
	Business-as-Usual	Fleet Transition	No savings with this approach.	No GHG savings with this approach.	-	Does not meet regulatory requirements.
	State and Local Fleets	Fleet Transition	Not quantified.	-15	-1.3%	Recommended to meet regulatory requirements.
	High Priority Fleets	Fleet Transition	Not quantified.	Not quantified.	Not quantified.	Not recommended. Places a large and immediate burden on DSRSD.

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7.5.2 Fleet Transition to Zero-Emission Vehicles

DSRSD shall follow the requirements of the ***State and Local Government Agency Fleet Regulations,*** to transition their fleet to ZEVs based on the following requirements:

1. Starting January 1, 2024, 50 percent of "total vehicle purchases" for a California fleet in each calendar year must be ZEVs.
2. Starting January 1, 2027, 100 percent of "total vehicle purchases" for a California fleet in each calendar year must be ZEVs.

Since the regulations allow for flexibility regarding the timing for replacement of vehicles, DSRSD shall replace vehicles based on need.

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Appendix 7A

DETAILED FLEET ANALYSIS

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Project: Energy Facilities Master Plan
Job Number: 200892
Client: Dublin San Ramon Services District

By: SJ Hall
Date: 2/26/2024

Checked:
Date:

	Total	Year 1 24	Year 2 25	Year 3 26	Year 4 27	Year 5 28	Year 6 29	Year 7 30	Year 8 31	Year 9 32	Year 10 33	Year 11 34	Year 12 35	Year 13 36	Year 14 37	Year 15 38	Year 16 39	Year 17 40	Year 18 41	Year 19 42
NPV of Capital Cost																				
Business-as-Usual	$ 3,719,000	$ 532,000	$ -	$ 614,000	$ -	$ -	$ 459,000	$ -	$ 147,000	$ -	$ -	$ -	$ 251,000	$ 253,000	$ 171,000	$ 585,000	$ 334,000	$ 373,000	$ -	$ -
State & Local Fleets	$ 7,239,000	$ 532,000	$ -	$ 689,000	$ -	$ -	$ 1,092,000	$ -	$ 140,000	$ -	$ -	$ -	$ 690,000	$ 625,000	$ 384,000	$ 1,457,000	$ 888,000	$ 742,000	$ -	$ -
NPV of O&M Cost																				
Business-as-Usual	$ 1,075,000	$ 67,000	$ 67,000	$ 59,000	$ 51,000	$ 49,000	$ 46,000	$ 47,000	$ 49,000	$ 50,000	$ 52,000	$ 53,000	$ 54,000	$ 57,000	$ 58,000	$ 59,000	$ 62,000	$ 63,000	$ 65,000	$ 67,000
State & Local Fleets	$ 937,000	$ 58,000	$ 60,000	$ 56,000	$ 57,000	$ 58,000	$ 60,000	$ 61,000	$ 63,000	$ 57,000	$ 52,000	$ 48,000	$ 48,000	$ 40,000	$ 38,000	$ 38,000	$ 22,000	$ 39,000	$ 40,000	$ 42,000
NPV of Total Cost																				
Business-as-Usual	$ 4,794,000	$ 599,000	$ 67,000	$ 673,000	$ 51,000	$ 49,000	$ 505,000	$ 47,000	$ 196,000	$ 50,000	$ 52,000	$ 53,000	$ 305,000	$ 310,000	$ 229,000	$ 644,000	$ 396,000	$ 436,000	$ 65,000	$ 67,000
State & Local Fleets	$ 8,176,000	$ 590,000	$ 60,000	$ 745,000	$ 57,000	$ 58,000	$ 1,152,000	$ 61,000	$ 203,000	$ 57,000	$ 52,000	$ 48,000	$ 738,000	$ 665,000	$ 422,000	$ 1,495,000	$ 910,000	$ 781,000	$ 40,000	$ 42,000
GHG Emissions (MT $CO_{2\,eq}$)																				
Business-as-Usual	1,211	95	84	83	58	53	90	53	67	53	53	53	62	61	58	68	60	59	53	53
State & Local Fleets	930	82	76	78	67	67	104	66	80	57	50	42	49	38	30	19	12	10	2	1
Energy Consumption (kWh)																				
Business-as-Usual	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
State & Local Fleets	453,613	5470	5470	11986	11986	11986	11986	11986	11986	13224	16596	21589	24277	29395	36126	36126	48356	48356	48356	48356
Gasoline Consumption (Gallons)																				
Business-as-Usual	108,482	9348	8726	7404	5728	5168	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151
State & Local Fleets	84,106	7576	7576	6344	6344	6344	6344	6344	6344	5882	5019	4068	3825	2698	2108	2108	0	1727	1727	1727
Diesel Consumption (Gallons)																				
Business-as-Usual	11,928	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628
State & Local Fleets	5,769	628	628	628	628	628	628	628	628	107	107	107	107	107	107	107	0	0	0	0

Project: Energy Facilities Master Plan — SJ Hall
Job Number: 200892 — 2/26/2024
Client: Dublin San Ramon Services District

ZEV Heavy Duty Cost % Increase	250%
Discount Rate =	1.0%
Escalation Rate =	3.0%

Assumptions are in red.

	Item Description	Vehicle Status: 2024	Year 1 2024	Year 2 2025	Year 3 2026	Year 4 2027	Year 5 2028	Year 6 2029	Year 7 2030	Year 8 2031	Year 9 2032	Year 10 2033	Year 11 2034	Year 12 2035	Year 13 2036	Year 14 2037	Year 15 2038	Year 16 2039	Year 17 2040	Year 18 2041	Year 19 2042
	DSRSD Vehicles in 2021										***Vehicle Capital Cost***										
1	2000 FORD RANGER: 61	Replaced/Loaner																			
2	2002 FORD F350 PICK-UP 3/4 TON: 63	Active: 6-10 years						$ 48,000.00													
3	2002 FORD F150: 33	Replaced/Loaner																			
4	2002 FORD RANGER PICK-UP 1/2 TON: 64	Replaced/Loaner																			
5	2003 FORD F250 W/UTLITY BOX: 71	Replaced/Loaner																			
6	2004 FORD F250 PICK-UP: 55	Active: 3-5 years			$ 47,000.00																
7	2004 FORD F250 W/UTILITY BOX: 74	Active: 6-10 years						$ 47,000.00													
8	2004 FORD F250 W/UTILITY BOX: 75	Replaced/Loaner																			
9	2004 FORD F250 W/UTILITY BOX: 76	Active: 6-10 years						$ 47,000.00													
10	2006 FORD E250 VAN: 45	Being Replaced																			
11	2006 FORD F250 SUPER DUTY PICK-UP: 21	Active: 6-10 years						$ 47,000.00													
12	2006 VAC-CON JETTER: 77	Active: <1000 miles per year																			
13	2008 FORD EXPLORER XLT 4X4: 95	Being Replaced																			
14	2008 FORD F150 SUPERCREW XLT: 96	Active: <1000 miles per year																			
15	2008 FORD F350 4X4 TRUCK: 86	Being Replaced																			
16	2008 FORD F350 TRUCK: 88	Being Replaced																			
17	2008 FORD F350 XL: 94	Active: 6-10 years						$ 48,000.00													
18	2014 CAMEL FREIGHTLINER: 109	Active: 0-2 years	$ 532,000.00																		
19	2014 CAMEL FREIGHTLINER: 110	Active: 3-5 years			$ 532,000.00																
20	2014 FORD F150: 111	Active: 6-10 years						$ 41,000.00													
21	2014 FORD FUSION: 106	Active: 6-10 years								$ 35,000.00											
22	2015 FORD ESCAPE: 108	Active: 6-10 years								$ 28,000.00											
23	2015 FORD F350 SUPER DUTY: 112	Active: 6-10 years						$ 48,000.00													
24	2015 FORD FUSION: 107	Active: 6-10 years								$ 35,000.00											
25	2016 FORD F350: 117	Active: 10+ years												$ 48,000.00							
26	2016 FORD F450 HEAVY DUTY: 113	Active: 10+ years												$ 58,000.00							
27	2016 FORD F450:116	Active: 10+ years												$ 58,000.00							
28	2016 FORD TRANSIT CONNECT: 114	Active: 10+ years												$ 34,000.00							
29	2017 FORD F150 SUPERCREW XL: 119	Active: 10+ years													$ 41,000.00						
30	2017 FORD F250 W/UTILITY BOX: 120	Active: 10+ years													$ 47,000.00						
31	2017 FORD F450 HEAVY DUTY: 121	Active: 10+ years													$ 58,000.00						
32	2017 FORD TRANSIT 150: 118	Active: 10+ years													$ 50,000.00						
33	2018 FORD ESCAPE SE: 126	Active: 6-10 years								$ 28,000.00											
34	2018 FORD F150 SUPER CAB 4X4: 125	Active: 10+ years														$ 41,000.00					
35	2018 FORD F150 SUPER CAB: 122	Active: 6-10 years						$ 41,000.00													
36	2018 FORD F150 SUPER CAB: 123	Active: 10+ years														$ 41,000.00					
37	2018 FORD F350 W/UTILITY BOX: 124	Active: 10+ years														$ 48,000.00					
38	2019 FORD F150: 128	Active: 6-10 years						$ 41,000.00													
39	2019 FORD F250: 127	Active: 10+ years															$ 47,000.00				
40	2020 FORD ESCAPE HYBRID SE SPORT: 130	Active: 10+ years															$ 28,000.00				
41	2020 FORD F350: 129	Active: 10+ years															$ 48,000.00				
42	2020 FORD F450: 131	Active: 10+ years															$ 58,000.00				
43	2022 FORD RANGER: 132	Active: 10+ years															$ 44,000.00				
44	2022 FORD RANGER: 133	Active: 10+ years															$ 44,000.00				
45	2022 FORD TRANSIT CONNECT: 115	Active: 10+ years															$ 29,000.00				
46	2022 FORD F250: 43	Active: 10+ years															$ 47,000.00				
47	2022 FORD RANGER: 33	Active: 10+ years															$ 44,000.00				
48	2022 FORD F250 TRUCK: 89	Active: 10+ years															$ 47,000.00				
49	2022 FORD TRANSIT CONNECT: 66	Active: 10+ years																$ 29,000.00			
50	2022 FORD F250 4X4 TRUCK: 93	Active: 10+ years																$ 47,000.00			
51	2022 FORD F250 TRUCK: 87	Active: 10+ years																$ 47,000.00			
52	2022 FORD ESCAPE HYBRID: 73	Active: 10+ years																$ 30,000.00			
53	2022 FORD RANGER: 20	Active: 10+ years																$ 44,000.00			
54	2022 FORD F250 PICK-UP: 29	Active: 10+ years																$ 47,000.00			
55	2022 FORD F250 PICK-UP: 38	Active: 10+ years																	$ 47,000.00		
56	2022 FORD TRANSIT CONNECT VAN: 45	Active: 10+ years																	$ 29,000.00		
57	2000 FORD RANGER REPLACEMENT:	Active: 10+ years																	$ 44,000.00		
58	2024 FORD ESCAPE HYBRID	Active: 10+ years																	$ 28,000.00		
59	2024 FORD ESCAPE HYBRID	Active: 10+ years																	$ 28,000.00		
60	2023 FORD RANGER	Active: 10+ years																	$ 44,000.00		
61	2024 FORD F250	Active: 10+ years																	$ 47,000.00		
62	2024 FORD F250	Active: 10+ years																	$ 47,000.00		
63	2022 FORD RANGER	Active: 10+ years																	$ 44,000.00		
64	2023 FORD F250	Active: 10+ years																	$ 47,000.00		
65	2023 FORD F250	Active: 10+ years																	$ 47,000.00		
66	2022 FORD RANGER	Active: 10+ years																	$ 44,000.00		
67	2023 FORD TRANSIT	Active: 10+ years																	$ 29,000.00		
	Unit O&M Costs Breakdown																				
	Annual gasoline unit cost ($/gal)	1%	$ 5.84	$ 5.90	$ 5.96	$ 6.02	$ 6.08	$ 6.14	$ 6.20	$ 6.26	$ 6.32	$ 6.39	$ 6.45	$ 6.52	$ 6.58	$ 6.65	$ 6.71	$ 6.78	$ 6.85	$ 6.92	$ 6.99
	Annual diesel unit cost ($/gal)	1%	$ 6.59	$ 6.66	$ 6.72	$ 6.79	$ 6.86	$ 6.93	$ 7.00	$ 7.07	$ 7.14	$ 7.21	$ 7.28	$ 7.35	$ 7.43	$ 7.50	$ 7.58	$ 7.65	$ 7.73	$ 7.80	$ 7.88
	Annual electricity unit cost ($/kWh)	1%	$ 0.20	$ 0.20	$ 0.20	$ 0.21	$ 0.21	$ 0.21	$ 0.21	$ 0.21	$ 0.22	$ 0.22	$ 0.22	$ 0.22	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.24	$ 0.24
	O&M Costs Breakdown																				
	Annual gasoline cost ($/year)	-	$ 54,595	$ 51,470	$ 44,109	$ 34,463	$ 31,404	$ 31,614	$ 31,930	$ 32,249	$ 32,572	$ 32,898	$ 33,226	$ 33,559	$ 33,894	$ 34,233	$ 34,576	$ 34,921	$ 35,271	$ 35,623	$ 35,980
	Annual diesel cost ($/year)	-	$ 4,137	$ 4,179	$ 4,220	$ 4,263	$ 4,305	$ 4,348	$ 4,392	$ 4,436	$ 4,480	$ 4,525	$ 4,570	$ 4,616	$ 4,662	$ 4,709	$ 4,756	$ 4,803	$ 4,851	$ 4,900	$ 4,949
	Annual electricity cost ($/year)	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Annual maintenance cost ($/year)	-	$ 8,101	$ 8,101	$ 7,967	$ 7,967	$ 7,967	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118	$ 5,118
	Cost Summary																				
	Capital cost	-	$ 532,000	$ -	$ 579,000	$ -	$ -	$ 408,000	$ -	$ 126,000	$ -	$ -	$ -	$ 198,000	$ 196,000	$ 130,000	$ 436,000	$ 244,000	$ 267,000	$ -	$ -
	O&M cost	-	$ 67,000	$ 64,000	$ 56,000	$ 47,000	$ 44,000	$ 41,000	$ 41,000	$ 42,000	$ 42,000	$ 43,000	$ 43,000	$ 43,000	$ 44,000	$ 44,000	$ 44,000	$ 45,000	$ 45,000	$ 46,000	$ 46,000
	Total cost	-	**$ 599,000**	**$ 64,000**	**$ 635,000**	**$ 47,000**	**$ 44,000**	**$ 449,000**	**$ 41,000**	**$ 168,000**	**$ 42,000**	**$ 43,000**	**$ 43,000**	**$ 241,000**	**$ 240,000**	**$ 174,000**	**$ 480,000**	**$ 289,000**	**$ 312,000**	**$ 46,000**	**$ 46,000**
	Net Present Value																				
	Discount rate = 1.0%	-																			
	Escalation rate = 3.0%	-																			
	Capital cost = **$ 3,719,000**	-	$ 532,000	$ -	$ 614,000	$ -	$ -	$ 459,000	$ -	$ 147,000	$ -	$ -	$ -	$ 251,000	$ 253,000	$ 171,000	$ 585,000	$ 334,000	$ 373,000	$ -	$ -
	O&M cost = **$ 1,075,000**	-	$ 67,000	$ 67,000	$ 59,000	$ 51,000	$ 49,000	$ 46,000	$ 47,000	$ 49,000	$ 50,000	$ 52,000	$ 53,000	$ 54,000	$ 57,000	$ 58,000	$ 59,000	$ 62,000	$ 63,000	$ 65,000	$ 67,000
	Total cost = **$ 4,794,000**	-	**$ 599,000**	**$ 67,000**	**$ 673,000**	**$ 51,000**	**$ 49,000**	**$ 505,000**	**$ 47,000**	**$ 196,000**	**$ 50,000**	**$ 52,000**	**$ 53,000**	**$ 305,000**	**$ 310,000**	**$ 229,000**	**$ 644,000**	**$ 396,000**	**$ 436,000**	**$ 65,000**	**$ 67,000**
	GHG Emissions																				
	Annual gasoline consumption (gal/year)	-	9348	8726	7404	5728	5168	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151
	Annual diesel consumption (gal/year)	-	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628
	Annual electricity consumption (kWh/year)	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Annual GHG emissions (MT CO_2 eq/year)	-	89	84	72	58	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	GHG footprint of vehicle manufacturing (MT CO_2 eq/vehicle)	6.00	6	0	10	0	0	38	0	14	0	0	0	10	8	5	15	7	6	0	0
	Total GHG emissions (MT CO_2 eq/year)	-	**95**	**84**	**83**	**58**	**53**	**90**	**53**	**67**	**53**	**53**	**53**	**62**	**61**	**58**	**68**	**60**	**59**	**53**	**53**

carollo

Legend:

Passenger/Light-Duty ICE	Under 8,500 GVWR - Can be either ZEV/ICE
Passenger/Light-Duty ZEV	Under 8,500 GVWR - After 2035, must be ZEV
Med-to-Heavy Duty ICE	Over 8,500 GWVR - ICE
Med-to-Heavy Duty ZEV	Over 8,500 GWVR - ZEV

Assumed higher price ZEVs prior 2035

Project: Energy Facilities Master Plan — SJ Hall
Job Number: 200892 — 2/26/2024
Client: Dublin San Ramon Services District

ZEV Heavy Duty Cost % Increase	250%
Discount Rate =	1.0%
Escalation Rate =	3.0%

Assumptions are in red.

	Item Description	Vehicle Status: 2024	Year 1 2024	Year 2 2025	Year 3 2026	Year 4 2027	Year 5 2028	Year 6 2029	Year 7 2030	Year 8 2031	Year 9 2032	Year 10 2033	Year 11 2034	Year 12 2035	Year 13 2036	Year 14 2037	Year 15 2038	Year 16 2039	Year 17 2040	Year 18 2041	Year 19 2042
	DSRSD Vehicles in 2021																				
1	2000 FORD RANGER: 61	Replaced/Loaner																			
2	2002 FORD F350 PICK-UP 3/4 TON: 63	Active: 6-10 years						$ 120,000.00													
3	2002 FORD F150: 33	Replaced/Loaner																			
4	2002 FORD RANGER PICK-UP 1/2 TON: 64	Replaced/Loaner																			
5	2003 FORD F250 W/UTLITY BOX: 71	Replaced/Loaner																			
6	2004 FORD F250 PICK-UP: 55	Active: 3-5 years			$ 117,500.00																
7	2004 FORD F250 W/UTILITY BOX: 74	Active: 6-10 years						$ 117,500.00													
8	2004 FORD F250 W/UTILITY BOX: 75	Replaced/Loaner																			
9	2004 FORD F250 W/UTILITY BOX: 76	Active: 6-10 years						$ 117,500.00													
10	2006 FORD E250 VAN: 45	Being Replaced																			
11	2006 FORD F250 SUPER DUTY PICK-UP: 21	Active: 6-10 years						$ 117,500.00													
12	2006 VAC-CON JETTER: 77	Active: <1000 miles per year																			
13	2008 FORD EXPLORER XLT 4X4: 95	Being Replaced																			
14	2008 FORD F150 SUPERCREW XLT: 96	Active: <1000 miles per year																			
15	2008 FORD F350 4X4 TRUCK: 86	Being Replaced																			
16	2008 FORD F350 TRUCK: 88	Being Replaced																			
17	2008 FORD F350 XL: 94	Active: 6-10 years						$ 120,000.00													
18	2014 CAMEL FREIGHTLINER: 109	Active: 0-2 years	$ 532,000.00																		
19	2014 CAMEL FREIGHTLINER: 110	Active: 3-5 years			$ 532,000.00																
20	2014 FORD F150: 111	Active: 6-10 years						$ 86,000.00													
21	2014 FORD FUSION: 106	Active: 6-10 years								$ 30,000.00											
22	2015 FORD ESCAPE: 108	Active: 6-10 years								$ 30,000.00											
23	2015 FORD F350 SUPER DUTY: 112	Active: 6-10 years						$ 120,000.00													
24	2015 FORD FUSION: 107	Active: 6-10 years								$ 30,000.00											
25	2016 FORD F350: 117	Active: 10+ years												$ 120,000.00							
26	2016 FORD F450 HEAVY DUTY: 113	Active: 10+ years												$ 145,000.00							
27	2016 FORD F450:116	Active: 10+ years												$ 145,000.00							
28	2016 FORD TRANSIT CONNECT: 114	Active: 10+ years												$ 135,000.00							
29	2017 FORD F150 SUPERCREW XL: 119	Active: 10+ years													$ 86,000.00						
30	2017 FORD F250 W/UTILITY BOX: 120	Active: 10+ years													$ 117,500.00						
31	2017 FORD F450 HEAVY DUTY: 121	Active: 10+ years													$ 145,000.00						
32	2017 FORD TRANSIT 150: 118	Active: 10+ years													$ 135,000.00						
33	2018 FORD ESCAPE SE: 126	Active: 6-10 years								$ 30,000.00											
34	2018 FORD F150 SUPER CAB 4X4: 125	Active: 10+ years														$ 86,000.00					
35	2018 FORD F150 SUPER CAB: 122	Active: 6-10 years						$ 86,000.00													
36	2018 FORD F150 SUPER CAB: 123	Active: 10+ years														$ 86,000.00					
37	2018 FORD F350 W/UTILITY BOX: 124	Active: 10+ years														$ 120,000.00					
38	2019 FORD F150: 128	Active: 6-10 years						$ 86,000.00													
39	2019 FORD F250: 127	Active: 10+ years															$ 117,500.00				
40	2020 FORD ESCAPE HYBRID SE SPORT: 130	Active: 10+ years															$ 75,000.00				
41	2020 FORD F350: 129	Active: 10+ years															$ 120,000.00				
42	2020 FORD F450: 131	Active: 10+ years															$ 145,000.00				
43	2022 FORD RANGER: 132	Active: 10+ years															$ 86,000.00				
44	2022 FORD RANGER: 133	Active: 10+ years															$ 86,000.00				
45	2022 FORD TRANSIT CONNECT: 115	Active: 10+ years															$ 135,000.00				
46	2022 FORD F250: 43	Active: 10+ years															$ 117,500.00				
47	2022 FORD RANGER: 33	Active: 10+ years															$ 86,000.00				
48	2022 FORD F250 TRUCK: 89	Active: 10+ years															$ 117,500.00				
49	2022 FORD TRANSIT CONNECT: 66	Active: 10+ years																$ 135,000.00			
50	2022 FORD F250 4X4 TRUCK: 93	Active: 10+ years																$ 117,500.00			
51	2022 FORD F250 TRUCK: 87	Active: 10+ years																$ 117,500.00			
52	2022 FORD ESCAPE HYBRID: 73	Active: 10+ years																$ 75,000.00			
53	2022 FORD RANGER: 20	Active: 10+ years																$ 86,000.00			
54	2022 FORD F250 PICK-UP: 29	Active: 10+ years																$ 117,500.00			
55	2022 FORD F250 PICK-UP: 38	Active: 10+ years																	$ 47,000.00		
56	2022 FORD TRANSIT CONNECT VAN: 45	Active: 10+ years																	$ 135,000.00		
57	2000 FORD RANGER REPLACEMENT:	Active: 10+ years																	$ 86,000.00		
58	2024 FORD ESCAPE HYBRID	Active: 10+ years																	$ 30,000.00		
59	2024 FORD ESCAPE HYBRID	Active: 10+ years																	$ 30,000.00		
60	2023 FORD RANGER	Active: 10+ years																	$ 86,000.00		
61	2024 FORD F250	Active: 10+ years																	$ 117,500.00		
62	2024 FORD F250	Active: 10+ years																	$ 117,500.00		
63	2022 FORD RANGER	Active: 10+ years																	$ 86,000.00		
64	2023 FORD F250	Active: 10+ years																	$ 117,500.00		
65	2023 FORD F250	Active: 10+ years																	$ 117,500.00		
66	2022 FORD RANGER	Active: 10+ years																	$ 86,000.00		
67	2023 FORD TRANSIT	Active: 10+ years																	$ 135,000.00		
	Unit O&M Costs Breakdown																				
	Annual gasoline unit cost ($/gal)	1%	$ 5.84	$ 5.90	$ 5.96	$ 6.02	$ 6.08	$ 6.14	$ 6.20	$ 6.26	$ 6.32	$ 6.39	$ 6.45	$ 6.52	$ 6.58	$ 6.65	$ 6.71	$ 6.78	$ 6.85	$ 6.92	$ 6.99
	Annual diesel unit cost ($/gal)	1%	$ 6.59	$ 6.66	$ 6.72	$ 6.79	$ 6.86	$ 6.93	$ 7.00	$ 7.07	$ 7.14	$ 7.21	$ 7.28	$ 7.35	$ 7.43	$ 7.50	$ 7.58	$ 7.65	$ 7.73	$ 7.80	$ 7.88
	Annual electricity unit cost ($/kWh)	1%	$ 0.20	$ 0.20	$ 0.20	$ 0.21	$ 0.21	$ 0.21	$ 0.21	$ 0.21	$ 0.22	$ 0.22	$ 0.22	$ 0.22	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.24	$ 0.24
	O&M Costs Breakdown																				
	Annual gasoline cost ($/year)	-	$ 44,246	$ 44,688	$ 37,791	$ 38,169	$ 38,551	$ 38,936	$ 39,326	$ 39,719	$ 37,196	$ 32,060	$ 26,245	$ 24,925	$ 17,757	$ 14,013	$ 14,153	$ -	$ 11,827	$ 11,945	$ 12,065
	Annual diesel cost ($/year)	-	$ 4,137	$ 4,179	$ 4,220	$ 4,263	$ 4,305	$ 4,348	$ 4,392	$ 4,436	$ 761	$ 768	$ 776	$ 784	$ 792	$ 800	$ 807	$ -	$ -	$ -	$ -
	Annual electricity cost ($/year)	-	$ 1,094	$ 1,105	$ 2,445	$ 2,470	$ 2,495	$ 2,520	$ 2,545	$ 2,570	$ 2,864	$ 3,630	$ 4,769	$ 5,417	$ 6,625	$ 8,223	$ 8,305	$ 11,228	$ 11,340	$ 11,454	$ 11,568
	Annual maintenance cost ($/year)	-	$ 8,101	$ 8,101	$ 8,048	$ 8,048	$ 8,048	$ 6,919	$ 6,919	$ 6,919	$ 6,919	$ 6,919	$ 6,919	$ 6,414	$ 5,984	$ 5,984	$ 5,026	$ 5,011	$ 4,966	$ 4,892	$ 4,892
	Cost Summary																				
	Capital cost	-	$ 532,000	$ -	$ 650,000	$ -	$ -	$ 971,000	$ -	$ 120,000	$ -	$ -	$ -	$ 545,000	$ 484,000	$ 292,000	$ 1,086,000	$ 649,000	$ 532,000	$ -	$ -
	O&M cost	-	$ 58,000	$ 58,000	$ 53,000	$ 53,000	$ 53,000	$ 53,000	$ 53,000	$ 54,000	$ 48,000	$ 43,000	$ 39,000	$ 38,000	$ 31,000	$ 29,000	$ 28,000	$ 16,000	$ 28,000	$ 28,000	$ 29,000
	Total cost	-	**$ 590,000**	**$ 58,000**	**$ 703,000**	**$ 53,000**	**$ 53,000**	**$ 1,024,000**	**$ 53,000**	**$ 174,000**	**$ 48,000**	**$ 43,000**	**$ 39,000**	**$ 583,000**	**$ 515,000**	**$ 321,000**	**$ 1,114,000**	**$ 665,000**	**$ 560,000**	**$ 28,000**	**$ 29,000**
	Net Present Value																				
	Discount rate = 1.0%	-																			
	Escalation rate = 3.0%	-																			
	Capital cost = $ 7,239,000	-	$ 532,000	$ -	$ 689,000	$ -	$ -	$ 1,092,000	$ -	$ 140,000	$ -	$ -	$ -	$ 690,000	$ 625,000	$ 384,000	$ 1,457,000	$ 888,000	$ 742,000	$ -	$ -
	O&M cost = $ 937,000	-	$ 58,000	$ 60,000	$ 56,000	$ 57,000	$ 58,000	$ 60,000	$ 61,000	$ 63,000	$ 57,000	$ 52,000	$ 48,000	$ 48,000	$ 40,000	$ 38,000	$ 38,000	$ 22,000	$ 39,000	$ 40,000	$ 42,000
	Total cost = $ 8,176,000	-	**$ 590,000**	**$ 60,000**	**$ 745,000**	**$ 57,000**	**$ 58,000**	**$ 1,152,000**	**$ 61,000**	**$ 203,000**	**$ 57,000**	**$ 52,000**	**$ 48,000**	**$ 738,000**	**$ 665,000**	**$ 422,000**	**$ 1,495,000**	**$ 910,000**	**$ 781,000**	**$ 40,000**	**$ 42,000**
	GHG Emissions																				
	Annual gasoline consumption (gal/year)	-	7576	7576	6344	6344	6344	6344	6344	6344	5882	5019	4068	3825	2698	2108	2108	0	1727	1727	1727
	Annual diesel consumption (gal/year)	-	628	628	628	628	628	628	628	628	107	107	107	107	107	107	107	0	0	0	0
	Annual electricity consumption (kWh/year)	-	5470	5470	11986	11986	11986	11986	11986	11986	13224	16596	21589	24277	29395	36126	36126	48356	48356	48356	48356
	Annual GHG emissions (MT CO_2 eq/year)	-	76	76	67	67	67	67	66	66	57	50	42	40	30	25	4	4	3	2	1
	GHG footprint of vehicle manufacturing (MT CO_2 eq/vehicle)	6.00	6	0	10	0	0	38	0	14	0	0	0	10	8	5	15	7	6	0	0
	Total GHG emissions (MT CO_2 eq/year)	-	**82**	**76**	**78**	**67**	**67**	**104**	**66**	**80**	**57**	**50**	**42**	**49**	**38**	**30**	**19**	**12**	**10**	**2**	**1**

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Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 8
FINANCING/PARTNERSHIPS OPPORTUNITIES ASSESSMENT

FINAL | June 2024

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Abbreviations

BAM	Build America Mutual
BioMAT	Bioenergy Market Adjusting Tariff
CARB	California Air Resources Board
Carl Moyer Program	Carl Moyer Memorial Air Quality Standards Attainment Program
CDS	congressionally directed spending
CEDA	California Design Assistance
CI	carbon intensity
CIP	capital improvement project
Cogen	cogeneration
CPF	community project funding
CPUC	California Public Utility Commission
CVRP	Clean Vehicle Rebate Project
CWSRF	Clean Water State Revolving Fund
DERA	Diesel Emissions Reduction Act
DG	digester gas
DOE	Department of Energy
DSRSD	Dublin San Ramon Services District
ECAA	Energy Conservation Assistance Act
EDA	Economic Development Administration
EECBG	Energy Efficiency and Conservation Block Grant
EIR	Energy Infrastructure Reinvestment
EPA	Environmental Protection Agency
EV	electric vehicle
FY	fiscal year
GC	government code
GFOA	Government Finance Officers Association
GHG	greenhouse gas
GO	general obligation
GVWR	gross vehicle weight rating
HVAC	heating, ventilation, and air conditioning
HVIP	Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project
IRA	Inflation Reduction Act
IRS	Internal Revenue Service
ITC	investment tax credit
JPA	joint powers authority
kW	kilowatt
kWh	kilowatt-hour

LCFS	low carbon fuel standard
LPO	loan programs office
MIP	Microgrid Incentive Program
MW	megawatt
MWh	Megawatt-hour
O&M	operations and maintenance
OBF	on-bill financing
P3	public-private partnerships
PAYGO	pay-as-you-go
PBEB	Public Bank East Bay
PG&E	Pacific Gas & Electric Company
PHEV	plug-in hybrid light-duty vehicles
PPA	power purchase agreement
PTC	production tax credit
PV	photovoltaic
RFS	renewable fuel standard
RIN	renewable identification number
RLF	revolving loan fund
RNG	renewable natural gas
RVO	renewable volume obligation
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Self-generation incentive program
TM	technical memorandum
USACE	United States Army Corps of Engineers
Wh	Watt-hour
WIFIA	Water Infrastructure Finance and Innovation Act
ZEV	zero-emission vehicles

Technical Memorandum 8

FINANCING/PARTNERSHIPS OPPORTUNITIES ASSESSMENT

8.1 Introduction

The Dublin San Ramon Services District (DSRSD), as part of this Energy Facilities Master Plan, has selected a capital improvements project (CIP) list for energy generation and energy efficiency improvements in wastewater treatment and throughout DSRSD. The CIP list is to be implemented over the next 10 to 20 years and each project carries significant capital costs. As such, a search of federal and state grant and loan financing opportunities was performed. This technical memorandum (TM) presents an overview of the federal and state financing opportunities assessed and a high-level summary of traditional funding mechanisms for DSRSD's CIP projects. It also includes a section about public private partnerships as an option for cogeneration (Cogen) system design, funding, and operations including power purchase agreements (PPA). DSRSD is seeking these additional sources of funding to reduce the financial burden on rate payers and the length of the overall payback periods associated with the projects recommended in DSRSD's CIP as they will require financial investments above its typical budget availability.

A complete list of CIP projects will be identified in TM 12 which will include projects for green energy generation, such as from digester gas (DG), as well as energy efficiency projects. Within that TM, descriptions of funding options will be summarized in a matrix of projects that relate to specific funding sources.

8.2 Funding Instruments

In general, there are two cost components associated with CIP projects:

- Capital costs required to plan, design, and construct the facilities and infrastructure elements.
- Re-occurring operational costs required to maintain, operate, and repair the infrastructure elements.

Operations and maintenance (O&M) costs are funded through user rates and other recurring annual sources of revenue. Capital costs may be funded through a variety of traditional and non-traditional sources. These mechanisms are summarized below and will be described in depth in the following sections

- **Traditional:**
  - **Rates and Pay-as-you-go (PAYGO) Financing**: Upfront collections through user rates for project costs from existing and new users for future capital improvement projects.

  - **Capacity Reserve Fees**: Charges assessed to new developments to fund the capital cost for expansion of the existing system, if required, to provide sufficient capacity to serve the new customers.
  - **Debt Financing**: Acquisition of funds through borrowing mechanisms (e.g., debt issuance such as general obligation bonds, revenue bonds, and certificates of participation etc.).
- **Non-Traditional:**
  - **Loans and Grants**: Federal, state, and local programs that provide funding at zero, low, or treasury rate interest loans, principal forgiveness, rebates or grants, for projects that meet select criteria.
  - **Other Mechanisms**: Financing through funds obtained from the Inflation Reduction Act (IRA) tax credits as a direct pay option, purchase agreements, voluntary programs, collaborations, partnerships, and trading and offset programs (e.g., credits for renewable energy generation and greenhouse gas [GHG] reduction offset).

8.2.1 Traditional: Rates and Pay-As-You-Go Financing

Depending on an agency's existing capital reserves, it can build up its financial capacity to fund expenditures. PAYGO financing involves collection of payments from existing and future customers within the utility's jurisdiction through user charges so that project costs are able to be paid upfront from the revenues received.

Typically, all or a portion of these revenues are accumulated in a capital reserve fund and are used for capital projects in future years. DSRSD apportions a certain portion of rate payer fees to fund future capital expenditures related to the rehabilitation of existing assets (this fund is referred to as the "replacement allocation").

PAYGO financing could be used to finance 100 percent or only a portion of a given project. Overall, total costs are substantially lower when employing a PAYGO financing approach due to the avoidance of interest payments incurred from bond funding, along with the associated transaction costs (e.g., legal fees, underwriters' discounts, etc.). However, it is often challenging to employ this funding approach for large new or replacement projects, due to the high amount of capital that is needed on-hand or in reserves, or from rate-based cash flow. If the program is reserve funded, the agency must already have sufficient cash-on-hand designated for such a project. If the program is rate funded, it could significantly increase the agency's rates and fees if the program represents a sizeable increase in capital needs. This funding approach does not recognize the inter-generational nature of water and wastewater utility assets which typically provide long-term benefits to multiple generations of ratepayers.

8.2.2 Traditional: Capacity Reserve Fee

Capacity reserve fees are used to fund capital projects that support projects' future growth and are not used to pay for O&M costs. These fees are specific, one-time, charges assessed to new developments to fund the capital cost for expansion of the existing system, if required, to provide sufficient capacity to serve the new customers. As these fees are collected at the time of permitting for applicable developments, annual revenues from capacity charges depend solely on the rate of growth. Consequently, funds may not be available to construct new facilities at the time they are needed.

8.2.3 Traditional: Debt financing

Acquisition of funds through borrowing mechanisms enables an agency to lessen the rate payer's upfront burden. There are multiple debt issuance options such as general obligation bonds, revenue bonds, and certificates of participation.

General obligation (GO) bonds are municipal securities secured by the issuer's pledge of its full faith, credit, and taxing power. GO bonds are backed by the general taxing authority of local governments and are often repaid using utility revenues when issued in support of a sewer or water enterprise fund. If GO bonds are issued for a project, the agency must have the necessary taxing capacity to issue the bonds.

Revenue bonds are historically the principal method of incurring long-term debt. This method of debt obligation requires specific non-tax revenues such as user charges, facility income, and other funds, pledged to guarantee repayment. There is often no legal limitation on the amount of authorized revenue bonds that may be issued, but from a practical standpoint, the size of the issue must be limited to an amount where annual interest and principal payments are well within the revenues available for debt service on the bonds. Revenue bond covenants generally include coverage provisions, which require that revenue from fees minus operating expenses be greater than debt service costs.

Certificates of participation provide long-term financing through a lease agreement that does not require voter approval. The legislative body of the issuing agency is required to approve the lease arrangement by a resolution. The lessee (city) is required to make payments, typically from revenues derived from the operation of the facilities. The amount financed may include reserves and capitalized interest for the period that facilities will be under construction. Within the State of California, most municipal water utility bonds are issued in the form of certificates of participation rather than traditional revenue bonds.

As this is a general overview of debt financing, specific options are described in detail under Section 8.3.

8.2.4 Non-Traditional: Loans and Grants

Federal, state, and local loan and grant funding sources are available for the planning, design and construction of water, wastewater, and public infrastructure projects. Loans may have low or no interest or principal forgiveness incentives. Rebate or voucher programs can also be viewed as grant-like dollars. These programs have become more competitive due to an overall increased interest in alternate funding options and federal/state budget constraints, coupled with a Nation-wide, consistent increase in construction costs. Most programs require a public entity to be the applicant or serve as a conduit for funding to private entities. Many programs have challenging qualification processes, specific timeframes in which funds can be used, and have eligibility restrictions. For example, funding sources often exclude standard maintenance projects from being eligible in order to focus on improvement projects. Additionally, programs may prioritize projects with innovation in the technical approach, demonstrate community engagement and benefits, and clearly show local funding needs (serving disadvantage communities, etc.). Available federal, state, and local funding sources should be considered as potential funding mechanisms to help reduce the overall costs of the projects for DSRSD and its rate payers. However, it is important to note that the majority of these programs do not pay for O&M costs.

Examples of federal and state agencies that provide funding opportunities include the Environmental Protection Agency (EPA), Economic Development Administration (EDA), United States Bureau of Reclamation, United States Army Corps of Engineers (USACE), United States Department of Agriculture, Department of Housing and Urban Development, Department of Energy (DOE), Federal Emergency Management Agency, the State of California's Clean Water State Revolving Fund (CWSRF), and Congress, among others.

State of California's CWSRF and EPA's Water Infrastructure Finance and Innovation Act (WIFIA) programs provide some of the best avenues for securing a larger source of loan funding. Programs under the EPA, EDA, USACE and others can provide sources of grant funding and have the obvious advantage over loans in that they do not require repayment. However, these programs also typically require matching funds for the grant allocation and are more competitive to secure. Because of the constraints of federal and state grant and loan programs, some agencies secure low interest loan financing for the entire project while simultaneously pursuing grants where the entity will be competitive. Smaller grants can also be pursued as they are helpful in building relationships with funding agencies and reducing the overall financial burden.

There are numerous factors that should be considered in the pursuit of external low interest loan and grant funding, including:

- **Specific Project Priorities:** Most low interest loan and grant programs target a specific type of project or have clear purposes, priorities, and goals for their funds to be awarded and therefore a project needs to be aligned with these to be competitive. Some examples of program goals that a project should align with are shown below:
  - Builds regional partnerships.
  - Incorporates integrated project benefits.
  - Enhances water conservation or efficiency.
  - Protects groundwater resources.
  - Provides renewable energy improvements or energy efficiency.
  - Addresses risk and resiliency.
  - Demonstrates consistency with the state and regional policies and objectives.
  - Demonstrates regional cooperation and partnerships with partners and stakeholders.
  - Serves a disadvantaged community.
  - Helps create both construction and post-construction related employment.
- **Does Not Cover Full Project Cost:** Most grant programs do not cover the full cost of the project, requiring the sponsoring agency to provide a minimum cost share ranging from 25 to 75 percent (in-kind donations are applicable matches).
- **Demonstration of Ability to Pay for Project:** Funding agencies typically require the proposed grant applicant to demonstrate the ability to construct, operate, and maintain the project without external funding.
- **Funding Restrictions:** Few programs allow for the retroactive funding of design and construction work, and some programs will only fund activities that are conducted post selection for award or even require entering into an agreement prior to starting work activities.
- **Application Timelines:** Application timing is critical for most grant and loan programs. Typically, grant programs release funding announcements once per year with a 45- to 60-day window to apply, and availability varies year to year pending Congressional

appropriations. Low interest loan programs typically accept applications on a rolling basis (e.g., WIFIA, CWSRF); however, they may require submission of pre-application materials by a prescribed date.

- **Award Timing:** With the increased interest in external funding and limited funding agency staff availability, the review, selection, and execution of a funding agreement can take an average of 12 months (sometimes longer). In general, agencies should plan on submitting a loan application 6 to 12 months in advance of when funding will be needed and prior to construction start.
- **Project and Documentation Readiness:** Applications may require multiple documents (e.g., engineering, environmental, and financial) to show the readiness level of the project. Assessing project document readiness early on is important to ensure the appropriate level of documentation is available to support the funding application.
- **Grant Reimbursement:** Most grants are reimbursements, not upfront cash. This may require that a separate source of funding (i.e., bridge loan) be available as an entity awaits reimbursement of submitted payment receipts if they do not have the cash flow to support the project. Grant reimbursements are subject to annual budget and appropriations processes and thus disbursement of grant funds on schedule is not guaranteed.
- **Federal Compliance Requirements:** Federal funding sources require compliance with federal requirements including, but not limited to, American Iron and Steel; Davis Bacon Wage Determinations; anti-lobbying; Disadvantaged Business Enterprise; Build America, Buy America; Williams-Steiger Occupational Safety and Health Act; and environmental, archeological, procurement, and reporting requirements. These conditions may add to the project's overall cost, influence project schedules, and increase the administrative burden on the borrower.

As this is a general overview of federal, state, and local loans and grants potential funding programs to evaluate further for DSRSD's wastewater infrastructure improvements are summarized in TM 6 as well as in Section 8.4, Section 8.5, and Table 8.3 of this TM. In addition to summarizing specific funding program information, Table 8.3 includes the most applicable programs for DSRSD's CIP as well as a likelihood of obtaining these funding opportunities considering project eligibility and competitiveness. Programs with a "high" and/or "medium" priority are those recommended for further consideration.

8.2.5 Non-Traditional: Other Mechanisms

In addition to the mechanisms mentioned previously, there are also funding opportunities through other nontraditional mechanisms such as purchase agreements, third-party private funding offerings, tax credits, collaborations, partnerships, voluntary programs, credits, offsets, and public-private partnerships (P3) which are long term agreements between the private and public sector which are consistently becoming more common in the utility sector. Tax credits are a mechanism that, while they have been traditional for private entities, are newer for public entities. The IRA of 2022 legislation permitted and directed the Internal Revenue Service (IRS) to create avenues for public entities to receive relevant energy tax credits with direct pay. Pacific Gas & Electric Company (PG&E) has many specific offerings for those in their service area as well, which is one example of a third-party entity providing non-traditional funding. As this is a general overview of these non-traditional options programs that are relevant to DSRSD under this category are summarized in Section 8.6.

8.3 Potential Sources of Traditional Debt Financing

This section discusses many programs and sources of traditional debt financing and how they related to DSRSD's projects.

8.3.1 Loans from national and regional banks or public banks

Conventional loans are available from national and regional retail banks. In addition, in Northern California special purpose public banks are being established. A public bank is owned and controlled by the people of the city, state, or region it serves. Public Bank East Bay (PBEB) is in Oakland and will take revenue deposits from the governments in the region (and can take deposits from semi-governmental organizations such as East Bay Municipal Utility District or Bay Area Rapid Transit). Because it is a public entity, rather than a completely profit-driven corporation, it is expected to be in a position to both save money and make money for its depositors and — much more important — for the people who live in the cities, states, and regions using PBEB.

PBEB is expected to work with local community banks and credit unions to make more favorable loans and purchase some of the cities' and counties' debt creating an additional source of funds for new bond issuing. Over time, and as a public bank grows its assets, it can start underwriting and issuing the municipalities' bonds itself, reducing the costs.

Timing: Ongoing.

Link: https://www.publicbankeastbay.org/pbeb-lending-priorities

Contact: **PublicBankEastBay@gmail.com**

Recommendation: Pursue loan programs from retail or public banks once they become available.

8.3.2 Bonds and Green Bonds

The municipal bonds or green bonds with a focus on green projects would be a solution to pay for the conversion from a fossil fuel-based economy and infrastructure to cleaner, greener, and more sustainable energy alternatives.

The California Treasury has gathered the experienced parties in the green bond marketplace to develop actionable strategies to stimulate a robust green market in the United States and elsewhere.

Link: https://www.treasurer.ca.gov/greenbonds/index.asp

The first green municipal bond was issued nearly a decade ago, but the public finance industry — and California in particular — have been working to further develop this instrument.

A committee formed by the California treasurer's office has developed investor-driven guidelines for disclosure on green bond issuance. The thrust of the guidelines, created by the California Green Bond Market Development Committee, was to help issuers provide more uniform disclosure. It deals with the International Capital Market Association's guidelines but provides information more specific to municipal bond issuers. Though the effort was launched in California, the guidelines, released Monday, are intended to be a resource for issuers across the country interested in issuing green bonds.

The Government Finance Officers Association (GFOA) has been working on a similar effort. The GFOA released the first of three best practices focusing on disclosure of ESG risk factors in October 2022.

Link: https://www.bondbuyer.com/news/california-green-bond-committee-could-issue-guidance-next-year

One potential service provider is Build America Mutual (BAM) for the green bond certification. BAM claims that it does not necessarily cause higher costs or compliance reporting. Many school districts have used these bonds for energy conservation projects and the link below shows water agencies in California.

Link: https://buildamerica.com/credit-profiles/?tab=green

Recommendation: Based on projects in Northern California the green bonds have been successfully applied for green power projects and should be pursued.

8.3.3 Water and Wastewater Rate Reduction Bond Program

The California Pollution Control Financing Authority reviews the issuance of certain rate reduction bonds to finance and/or refinance water and wastewater utility projects that are approved by joint powers authorities (JPA). These issuances allow local agencies that own and operate water and wastewater utilities to access low-cost financing through rate reduction bonds. The rate reduction bonds issued by JPAs to local agencies to finance or refinance a water or wastewater utility project are to be secured by utility project property and repaid through a separate utility project charge imposed on the utility ratepayers' bills.

The following criteria are requirements to be considered eligible under the program:

- Qualification as water or wastewater utility project furnishing water or wastewater service to greater than 25,000 customers.
- Utility project property (treatment plant considered as equity) and the utility project charge are sources of payment to cover utility project costs and financing costs. In other words, the project's value is used as equity when constructed by the JPA and will be paid for by rate payers of the member agencies to cover the bond and funding costs.
- The rates of the publicly owned utility plus the utility project charge are expected to be lower than the rates if the project was financed by revenue bonds, or other substantial benefits to the public utility if the utility has more than 500,000 retail customers.

Timing: Ongoing.

Link: https://www.treasurer.ca.gov/cpcfa/reduction/index.asp

Contact: cpcfabond@treasurer.ca.gov

Recommendation: Recommend pursuing if the eligibility criteria can be met.

8.3.4 Tax-Exempt Bond Financing Program

The Tax-Exempt Bond Financing Program facilitates low-cost capital through private activity, tax-exempt bonds. The securities pay for acquisition, construction, or installation of qualified pollution control, water furnishing, waste disposal, waste recovery facilities and equipment. Tax-exempt bond financing assists qualified borrowers in receiving lower interest rates than through conventional loans.

Eligible projects and facilities under this program include but not limited to:

- Wastewater treatment facilities.
- Waste-to-energy facilities.
- Qualified solid waste or hazardous waste disposal projects.
- Waste recovery facilities.
- Purchase of collection vehicles and residential waste containers.
- Water furnishing facilities.

Examples of recently accepted projects include financing for construction and operation of anaerobic digesters, recycling of used oil, conversion of waste to clean burning fuel, electric vehicles (EV) for waste hauling companies, and more. Prospective borrowers should contact a bond counsel to help determine if a proposed project qualifies under federal law. The bond counsel must be listed on the State Treasurer's Office list of approved firms.

Timing: Ongoing.

Link: https://www.treasurer.ca.gov/cpcfa/tax_exempt.asp

Contact: cpcfabond@treasurer.ca.gov

Recommendation: Recommend pursuing these bonds as eligible projects include the construction and operation of anaerobic digesters, waste to biogas/hydrogen and funding of EVs.

8.4 Potential Sources of Loan Funding

This section discusses many programs and sources of low interest loan financing and how they relate to DSRSD's projects.

8.4.1 Water Infrastructure and Innovation Act - Loan

Under WIFIA, loans are available on a rolling basis. Applicants can submit a Letter of Intent to get pre-qualified. If approved (engineering feasibility, etc.) the full application process will start.

- The costs include:
  - $100,000 application fee.
  - A percentage of the loan amount will be charged as a loan processing fee.

This loan requires that the applicants have engineers' report and contracts in place.

Under WIFIA, funding opportunities for a large range of water, wastewater, stormwater, green infrastructure, energy efficiency projects, alternative water supply, aquifer recharge, drought reduction or mitigation projects, and a combination of these projects are secured by a common security thread which provides low interest rate financing for large dollar-value water and wastewater projects. Projects that can be completed within a 5 to 6 year window, serve a similar purpose and will be repaid from the same revenue stream can be packaged as a group of projects under one loan. Because DSRSD has over 25,000 customers, projects must cost no less than $20 million. Projects can be combined and submitted as a group of projects with the maximum amount of the loan not exceeding 49 percent of the project costs. Maximum loan term is 35 years, which includes a 5-year repayment deferment period. Interest rate of WIFIA loans are equal to the United States Treasury rate of a similar maturity. Funds can be used to cover planning, retroactive design, and construction activities. Application fees apply to be considered for these loans and average between $200,000 and $300,000 pending reviews and legal

negotiations. Current Fiscal Year (FY) 2024 lending capacity is $7.5 billion and is currently accepting applications on a rolling basis.

Link: https://www.epa.gov/wifia

Contact: WIFIA@epa.gov

Info session schedule: https://www.epa.gov/wifia/wifia-webinars

Recommendation: Pursue this funding for green infrastructure (Cogen), energy efficiency projects (standby power, solar photovoltaic [PV] carports, etc.) as an additional funding to the grants which typically does not cover the entire project costs.

8.4.2 California Clean Water State Revolving Fund

The CWSRF program provides low-interest loans to eligible entities for a wide range of wastewater and stormwater projects that protect surface water and groundwater resources. The program offers low-cost financing for a wide variety of water quality projects and is capable of financing projects from <$1 million to >$100 million. The following includes program eligibility requirements but is not meant to be an exhaustive list:

- Reducing energy consumption.
- Publicly owned wastewater treatment construction, repair, or replacement.
- Implementation of a non-point source management plan.
- Decentralized systems treating municipal or domestic sewage.
- Reducing, treating, or managing stormwater.
- Reducing demand for publicly owned works through conservation.
- Watershed projects.
- Projects for reusing or recycling wastewater or stormwater.
- Increasing security at publicly owned treatment works.

The loan rate is half the most recent State General Obligation Bond Rate at the time of approval. Terms are up to 30 years. Principal Forgiveness may be available to disadvantaged borrowers or borrowers that incorporate sustainability into projects. Projects are evaluated and ranked based on the level of water quality protection achieved and are scored and prioritized based in part on the project's readiness to being constructed. If plans are greater than 49 percent complete on December 31, then the project will receive 1 "construction readiness point." If greater than 89 percent complete on December 31, then 2 points are given. If less than 50 percent, no points are given. Applications are accepted year-round via their portal (FAAST), email, or hard copy.

Contact: CleanWaterSRF@waterboards.ca.gov or (916) 327-9978

Link: https://www.waterboards.ca.gov/water_issues/programs/grants_loans/srf/

Energy audit funds are available for projects, facilities, or activities that would be eligible for CWSRF financing. Agencies may hire consultants to perform the audit or perform the work with their own staff. Principal forgiveness may be awarded for 100 percent of the audit costs, up to a maximum of $35,000.

Application instructions link:
https://www.waterboards.ca.gov/water_issues/programs/grants_loans/srf/docs/forms/water_energy_audit_application_instructions.pdf

Contact: CleanWaterSRF@waterboards.ca.gov or 916-327-9978

Recommendation: Pursue this funding option for energy efficiency projects, for cogeneration engine replacement project to purchase the engine and exhaust treatment systems.

8.4.3 Innovative Clean Energy Loan Guarantees

Under these Clean Energy Loans, approximately $2.5 billion in loan guarantees for energy projects that utilize "innovative" technology to reduce, avoid, or sequester GHG emissions. Projects must use new or significantly improved technology as compared to commercial technology. Eligible projects include renewable energy, efficient electrical generation, pollution control, fuel-efficient vehicles, pollution control, and energy storage.

The proposed technology needs to be more efficient and more "innovative" than commercial technology, which leads to GHG reduction. According to *Title 17 Innovative Clean Energy*, "innovation" must constitute one or more meaningful and important improvements in productivity or value that is not considered "Commercial Technology." Commercial Technology is defined as technology that has been installed in and is being used in three or more commercial projects within the United States in the same general application. One of the potential energy savings and applicable demand reduction projects would be an innovative energy storage such as hydrogen storage to reduce GHG from grid power beyond the battery storage duration of 4 to 8 hours to reduce the demand and peak power.

It is possible to get funding for up to 80 percent of the total eligible project cost. Interest rates currently range between 0.375 percent for AAA project credit rating to 2 percent for B-. Costs include a facility fee, which is 1 percent for a portion of the principal amount of the Guaranteed Obligation, less than or equal to $150 million and 0.6 percent for any portion of the amount over $150 million. Additional fees involve a consulting fee for consultants needed by the Loan Programs Office (LPO) and monitoring fee based on size and complexity of project up to $500,000 per year. This is a loan program (no grant forgiveness offered) that accepts application year-round. Contact LPO to schedule a pre-application consultation.

DOE can serve as sole lender or as a co-lender. If this funding is for a novel technology, the prediction of the life cycle costs and revenues is complicated and requires additional third-party bankability studies. The loans can be managed through a bank which specializes in working with DOE to streamline the application process. Therefore, it is often used by private energy project developers or public private partnerships such as digester and renewable natural gas (RNG) projects.

> **Link**: https://www.energy.gov/lpo/innovative-clean-energy-loan-guarantees and https://www.energy.gov/sites/default/files/2022-06/DOE-LPO_T17_Lending_Reference_Guide_June2022.pdf
>
> **Contact:** lgprogram@hq.doe.gov
>
> (Source Page #5 of the following document: https://www.energy.gov/lpo/articles/t17-downloadable-handout-overview?nrg_redirect=473100

Project Eligibility Requirements

Significant projects, with an approximate cost of $10 to $20 million, can be funded by the Loan Guarantee Process but must meet the following eligibility requirements:

1. Project needs to be located in the United States at one general location (exceptions may apply). (Unless the proposed multiple locations satisfy the requirements of clause (1) of the definition of "Eligible Project" in Section 609.2 of the 1703 Regulations.)
2. Project employs new or significantly improved technologies as compared to Commercial Technologies in service in the United States at the time the guarantee is issued including projects that employ elements of Commercial Technologies in combination with New or Significantly Improved Technologies.
3. Project avoids, reduces, utilizes, or sequesters air pollutants or anthropogenic GHG emissions.
4. Project relates to any of the categories in the following list:
    a. Renewable energy systems.
    b. Hydrogen fuel cell technology for residential, industrial, or transportation applications.
    c. Carbon capture, utilization, and sequestration practices and technologies including agricultural and forestry practices that store and sequester carbon and synthetic technologies to remove carbon from the air and oceans.
    d. Efficient electrical generation, transmission, and distribution technologies.
    e. Efficient end-use energy technologies.
    f. Production facilities for the manufacture of fuel-efficient vehicles or parts of those vehicles, including electric drive vehicles and advanced diesel vehicles.
    g. Pollution control equipment.
    h. Energy storage technologies for residential, industrial, transportation, and power generation applications.
    i. Technologies or processes for reducing greenhouse gas emissions from industrial applications, including iron, steel, cement, and ammonia production, hydrogen production, and the generation of high-temperature heat.

Recommendation: Request a no-cost Pre application consultation for a novel energy storage technology project (https://www.energy.gov/lpo/request-pre-application-consultation). An example for such a project would be a novel energy storage technology as an alternative to lithium-ion batteries: iron flow batteries, or hydrogen with fuel cells for long duration energy storage. The relevant eligibility criteria for such projects are described below:

Distributed Energy Projects

Projects that are comprised of installations of systems, facilities, equipment, or technologies at multiple sites (Distributed Energy Projects) must: (i) satisfy the requirements under the definition of an Eligible Project under this Solicitation; and (ii) deploy a technology or a defined suite of technologies concerned with the production, consumption, or transportation of energy (Distributed Technologies) pursuant to an integrated and comprehensive business plan.

"Commercial Technology" means a technology in general use in the commercial marketplace in the United States at the time the Term Sheet is offered by DOE. A technology is in general use if it is being used in three or more facilities that are in commercial operation in the United States for the same general purpose as the proposed project and has been used in each such facility for

a period of at least five years. The five-year period for each facility shall start on the in-service date of the facility employing that particular technology or, in the case of a retrofit of a facility to employ a particular technology, the date the facility resumes commercial operation following completion and

8.4.4 Energy Infrastructure Reinvestment (EIR) Program

The IRA of 2022 created this new loan program to finance projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations, or enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants or GHG emissions. IRA appropriates $5 billion through September 30, 2026, to carry out EIR, with a total cap on loans of up to $250 billion.

Potential projects could include repurposing shuttered fossil energy facilities for clean energy production, retooling infrastructure from power plants that have ceased operations for new clean energy uses, or updating operating energy infrastructure with emissions control technologies, including carbon capture, utilization, and storage. While the loan program does not have the same restrictions as the Innovative Clean Energy loan guarantees with respect to projects utilizing innovative technology and reducing, avoiding, utilizing, or sequestering GHG emissions, EIR does require that eligible projects replacing energy infrastructure that has ceased operations and that involve electricity generation through the use of fossil fuels will be required to have controls or technologies to avoid, reduce, utilize, or sequester air pollutants and GHG emissions.

Link: https://www.energy.gov/lpo/energy-infrastructure-reinvestment

Contact: lpo@hq.doe.gov

Recommendation: Funding is available up until 2026 for 'innovative, new or significantly improved technology'. For the upgrade of the cogeneration plant and replacement of the NG fuel with DG in the future could be eligible for the EIR loan. Request a no-cost Pre application consultation for a novel energy storage technology project (https://www.energy.gov/lpo/request-pre-application-consultation).

8.4.5 Energy Conservation Assistance Act (ECAA) Loans

The ECAA is the basis of a revolving loan program that provides 1 percent interest loans up to $3 million to cities, counties, special districts, and other public entities for energy efficiency and clean energy generation projects. Projects with proven energy or demand cost savings or both are eligible. Loans finance energy efficiency and energy generation projects, energy storage systems, and electric vehicle charging infrastructure.

The loan must be repaid from energy savings (including principal and interest) within a maximum of 20 years. Loans are made on a reimbursement basis. Only approved project-related costs with invoices dated within the executed term of the loan are eligible to be reimbursed from loan funds. Partial funding can be provided for projects that exceed the simple payback, which is calculated by dividing the loan amount by the estimated first-year energy cost savings. A promissory note and a loan agreement between the applicant and the Energy Commission are all that are required to secure the loan.

The repayment schedule is based on the estimated annual energy cost savings from the aggregated projects, using energy costs and operating schedules at the time of loan approval.

Loans will be amortized on the estimated annual energy cost savings achieved by the loan-funded project. Applicants will be billed twice a year, in June and December, after the projects are completed. Applications are accepted on a first-come, first-served basis. Funding is currently available.

Link: https://www.energy.ca.gov/programs-and-topics/programs/energy-conservation-assistance-act/low-interest-loans

Link: https://www.energy.ca.gov/solicitations/2023-01/pon-22-002-energy-conservation-assistance-act-ecaa-low-interest-loan-program

Contact: pubprog@energy.ca.gov or ECAA@energy.ca.gov

(https://www.energy.ca.gov/sites/default/files/2023-04/ECAA_FactSheet_2023_ada.pdf)

Recommendation: Loan amount might be too small for the cogeneration project but consider pursuing the California Energy Commission loan programs for smaller projects such as pump and aeration blower replacement projects.

8.4.6 Climate Tech Finance Loans

Climate Tech Finance supports emerging technologies that reduce GHG emissions. This is offered through a unique partnership between IBank and the Bay Area Air District. Climate Tech Finance offers loan guarantees of up to $5 million on loans of up to $20 million, with up to a seven-year term (the loan term can be longer). Emerging technologies include technologies that have been successfully demonstrated at the pilot, demonstration, or early commercial scale, but have not reached full commercial scale.

Examples of eligible technologies include:

- Fuel cell or battery systems for on-site energy storage.
- Waste-to-energy systems at wastewater treatment or solid waste facilities.
- Carbon-sequestering cement substitutes.
- In-vessel composting systems.

Timing: Application accepted on an ongoing basis.

Link: https://ctf.baaqmd.gov/

Contact: ctf@baaqmd.gov

Recommendation: Pursue this option in addition or in combination with other loans in case the Public Bank Eastbay is not ready to accept applications yet for the biogas engine upgrades or other larger projects.

8.4.7 IBank Infrastructure State Revolving Fund Program Loans

IBank provides loans for public entities ranging from $1 million to $65 million, with up to 30-year terms. Projects should generally be construction ready by the time the applicant is ready to receive the loan. IBank interest rates for public entities are set based on a combination of an Interest Rate Benchmark and Interest Rate Adjustments, which are dependent upon the repayment source. The Interest Rate Benchmark will be based on Thompson's Municipal Market

Data Index. Interest Rate Adjustments may cause the interest rate on financing to be below the Interest Rate Benchmark.

Timing: Application accepted on an ongoing basis.

Link: https://ibank.ca.gov/loans/infrastructure-loans/

Contact: infrastructureloans@ibank.ca.gov

Recommendation: Pursue this option in addition or in combination with other loans in case the Public Bank Eastbay is not ready to accept applications yet for the biogas engine upgrades or other larger projects.

8.4.8 Greenhouse Gas Reduction Loan Program

Loans to fund construction, renovation, or expansion of facilities for pre-processing, digesting, or composting organics, or the pre-processing or manufacturing of value-added finished products using recycled fiber, plastic, or glass. Eligible projects do not qualify for a loan unless they are past the design phase of the project and are prepared for construction. Applicants must complete all California Environmental Quality Act requirements.

Projects eligible for funding consist of the following:

- Construction, renovation, or expansion of facilities to increase in-state infrastructure for one of the following:
  - The digestion or composting of organics into compost, soil amendments, biofuels, or bioenergy (e.g., DG and RNG).
  - The manufacturing of value-added finished products using California derived recycled content fiber, plastic, or glass.
- Purchase of equipment and machinery.
- Real estate improvements associated with the installation of equipment and machinery.

The maximum loan amount is the lesser of $2 million or 75 percent of total project cost. Borrowers may take out multiple loans for a total maximum of $5 million per entity.

The following is the Schedule of Fees and Costs for the program:

- Loan Application Fee: $300, due at the time of loan application submittal.
- Loan Closing Points: 0.50 percent, due when loan funds are paid into escrow.
- Loan Interest Rate: 4 percent, fixed on a simple interest basis.
- Prepayment Penalty: None.

Timing: Ongoing.

Link: https://calrecycle.ca.gov/funding/GHGLoans/

Contact: loans@calrecycle.ca.gov

Recommendation: Pursue a GHG loan for cogeneration engine replacement project to purchase the engine and exhaust treatment systems.

8.5 Potential Sources of Grant Funding

This section discusses many programs and potential sources of grant funding and how they relate to DSRSD's projects.

8.5.1 Congressionally Directed Spending (CDS) and Community Project Funding (CPF)

Also known as "earmarks", CPF and CDS appropriations are a mechanism by which members of Congress can request funding for specific projects in their home states. Projects must directly serve the public and have been submitted by state and local government entities and nonprofits to their respective congressmember.

FY25 requests have closed and FY26 request deadlines are expected in spring of 2025. Members may request funding for up to 15 projects in their community, although only a handful may be funded. Projects with demonstrated community support are typically considered. CDS is limited to no more than 1 percent of discretionary spending of the federal budget. State/local match may be required.

The average funding congressionally awarded in FY 2024 for water and wastewater projects ranged from $1 to 5 million but could be higher. Projects are ultimately selected by the House and Senate with funding, if approved, distributed as part of the federal appropriations process the next FY (October through September). Funds must be spent within 1 year.

Timing: Congressmembers open applications periods every spring.

Link: https://www.appropriations.senate.gov/

Link: https://appropriations.house.gov/

Recommendation: Connect with state senators and your congressional district representative and discuss options and opportunities for them to support projects through funding via CPF/CDS.

8.5.2 Emerging Renewable Program Grants

Emerging Renewable Programs provides grants in California for emerging renewable projects, for a name plate capacity of less than 50 kilowatt (kW), and could be used for a carport or roof-top PV system.

The California Energy Commission has specific requests for proposals to advance the innovation and reduce electrical rates using technologies and companies based in California. These are only available at specific times and durations and might be better managed by the technology provider if there is a specific request and a match with the needs of the DSRSD.

8.5.3 Organics Grant Program

The Department of Resources Recycling and Recovery administers the Organics Grant Program pursuant to Public Resource Code section 42999. The purpose of this competitive grant program is to lower overall greenhouse gas emissions by expanding existing capacity or establishing new facilities in California to reduce the amount of California-generated green materials, food materials, and/or alternative daily cover being sent to landfills.

The diversion of food waste from landfills is funded with grants up to $10 million. These annual grant applications are typically due by May of each year (the last submission was due May 2, 2023) however, the program did not receive an allotment of funding for FY 2025-2026.

Equipment for food waste processing, digestion and composting and related construction costs can be funded, while engineering and project administration costs need to be covered by the applicant.

Timing: Each year proposals are accepted by April/May.

Link: https://calrecycle.ca.gov/funding/organics/

Recommendation: Pursue this grant if the program receives funding in FY 2026-2027. If DSRSD decides to co-digester food waste for future food waste receiving stations, future digester upgrades or retrofits and digester gas treatment.

8.5.4 Diesel Emissions Reduction Act (DERA)

This program provides various grants to support projects aimed at reducing emissions from the nation's existing fleet of older diesel engines. Eligible diesel emissions reduction solutions include verified retrofit technologies such as exhaust after-treatment technologies, engine upgrades, cleaner fuels or additives, verified idle reduction technologies, verified aerodynamic technologies, verified low rolling resistance tires, certified engine replacements and conversions, and certified vehicle or equipment replacement.

Eligible entities include regional, state, or local agencies; tribal governments (or intertribal consortia) and native villages; or port authorities, which have jurisdiction over transportation or air quality, and nonprofit organizations or institutions that:

1. Represent or provide pollution education or educational services to diesel fleets.
2. Have, as their principal purpose, the promotion of transportation or air quality.

Public and private fleets can work with eligible recipients to receive DERA funding. In 2021, $46 million in DERA funding was announced and two to eight awards were given per EPA region. $4 million was available for Region 9, which includes California. Currently, no announcement is pending, but this is a longstanding program that should be continuously monitored for potential funding opportunities if DSRSD wants to collaborate with an eligible entity.

Link: https://www.epa.gov/dera

Contact: 1-877-623-2322 or dera@epa.gov

Recommendation: For equipment and vehicles which are difficult to convert to EV consider a clean diesel (e-fuel) vehicle in collaboration with other water agencies and California Association of Sanitation Agencies.

8.5.5 Clean Vehicle Rebate Project (CVRP) for Fleets

CVRP for fleets offers up to $7,000 for the purchase or lease of new, eligible zero-emission vehicles (ZEV) and plug-in hybrid light-duty vehicles (PHEV) for public agencies — up to 30 rebates a year. Rebate funds can be reserved up to 18 months prior to vehicle purchase and up to 3 months after purchase. The vehicles must be registered in the state of California, new at the time of lease or purchase, and owned, operated, and registered in the state for a minimum of 30 months. Original lease terms must be for a minimum of 30 months. Vehicles must be on a list of eligible vehicles to qualify for rebates.

Public fleets must submit annual vehicle usage reports to the CVRP administrator for all rebated vehicles 12, 24, and 30 months following the date of asset delivery. Required data may include,

but is not limited to, mileage reporting, annual fuel use by fuel type, and percentage of operation within underserved communities. Some fleets may qualify for increased incentives if the location of the facility is within a California disadvantaged community census tract.

Timing: Ongoing.

Link: https://cleanvehiclerebate.org/en/fleet

Contact: cvrp@energycenter.org

Recommendation: Pursue this rebate program for the purchase of EVs.

8.5.6 Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP)

HVIP provides point-of-purchase cost reductions through a voucher system for medium and heavy-duty vehicles. Vouchers range from $20,000 to $240,000, depending on the vehicle purchased. Each fleet purchaser is limited to a maximum of 30 voucher requests per calendar year. Participating vehicle dealers work with the HVIP program, and purchasers pay the dealer for the vehicle minus the rebate cost. Dealers submit paperwork to HVIP. Funding is available on a first-come, first-served basis until funds are depleted. HVIP re-opened to voucher requests on April 27, 2023, with nearly $29.7 million available in this round of funding across standard HVIP and set-aside funds for public transit buses, class 8 tractors performing drayage operations, refuse collection trucks and school buses. No funding for light duty trucks and pick-up trucks.

Link: https://californiahvip.org/

https://californiahvip.org/vehicle-category/heavy-duty/

Contact: 1-888-457-HVIP

Recommendation: Do not pursue. The current fleet and type of vehicles at DSRSD is not eligible for this funding.

8.5.7 Carl Moyer Memorial Air Quality Standards Attainment Program (Carl Moyer Program)

The Carl Moyer Program (provides grant funding for cleaner-than-required engines, equipment, and other sources of air pollution. The Carl Moyer Program is implemented as a partnership between California Air Resources Board (CARB) and California's 35 local air districts. Up to $100 million has been made available to the Bay Area Air Quality Management District. Eligible project types include but not limited to the following:

- **Vehicle Replacement:** Replace heavy-duty trucks, transit buses, solid waste vehicles, utility trucks, emergency vehicles, and other vehicles in compliant fleets with the cleanest-emissions vehicles available, including ZEVs.
- **Fleet Expansion**: Expand existing fleet with new zero-emission vehicles. There is limited funding for this project type, which is geared towards larger fleets such as refuse collection.
- **Infrastructure projects:** Install, convert, or expand new or existing battery-charging or hydrogen-fueling stations.

The following criteria are required to be eligible for funding through this program:

- Public and private entities are eligible.
- The vehicles to be replaced and the new vehicles must have a gross vehicle weight rating (GVWR) greater than 14,000 pounds.
- Vehicles to be replaced and applicants must comply with all Air District and CARB regulations.
- Funding cannot be used for upgrades or equipment purchases that are already required by an existing regulation, local ordinance, or contract.
- Applicants must submit an application, be awarded, and enter into a funding agreement with the Air District prior to starting their projects. Projects or purchases that have started prior to the funding agreement being signed by all parties will be disqualified.
- Applicants applying for funding must document current fleet compliance.
- Complete applications will be evaluated on a first-come, first-served basis until all funds have been awarded.

For fleets with ten or fewer vehicles over 14,000 pounds GVWR, the state funding amount cannot exceed 80 percent of the vehicle cost (excluding taxes and fees). For fleets with more than ten vehicles, the funding amount cannot exceed 50 percent of the vehicle cost (excluding taxes and fees). Funding limit per vehicle is $60,000 to $30,000 depending on vehicle size.

Link: https://www.baaqmd.gov/en/funding-and-incentives/funding-sources/carl-moyer-program

Link: https://www.baaqmd.gov/en/funding-and-incentives/apply-for-funding

Contact: 415-749-4994 or grants@baaqmd.gov

Recommendation: Watch opportunities through Bay Area Air Quality Management District for fleet replacement, expansion, or charging.

8.5.8 Solid Waste Infrastructure for Recycling Grant Program

The Solid Waste Infrastructure for Recycling Grant Program is a new grant program authorized by the Save Our Seas 2.0 Act and initially funded through the Bipartisan Infrastructure Law. $275 million has been allocated with $55 million per year from FY22 to FY26 to remain available until expended. EPA was provided an additional $2.5 million in FY22 funding to implement the program.

The Solid Waste Infrastructure for Recycling program provides grants to implement a strategy to improve post-consumer materials management and infrastructure; support improvements to local post-consumer materials management and recycling programs; and assist local waste management authorities in making improvements to local waste management systems.

The entities eligible to apply for Solid Waste Infrastructure for Recycling grants include United States states and political subdivisions of states. EPA considers counties, cities, towns, and similar units of governments that have executive and legislative functions to be political subdivisions of states and territories.

Timing: Round two closed December 2024. No further application rounds have been announced at this time.

Link: https://www.epa.gov/rcra/solid-waste-infrastructure-recycling-grant-program

Contact: SWIFR@epa.gov

Recommendation: This EPA grant program could be applied if future rounds are provided to support regional food waste and on-site co-digestion (if DSRSD considers accepting and processing bioslurry).

8.5.9 Energy Efficiency Revolving Loan Fund (RLF) Capitalization Grant Program

The Infrastructure Investment and Jobs Act has appropriated $250 million to DOE to make funds available to states to implement energy efficiency revolving loan fund capitalization grant programs. These capitalization grants will enable states to establish RLFs to provide loans and grants for commercial and residential energy audits, energy upgrades, and retrofits among other activities. 40 percent of capitalization grants will be allocated by formula to states eligible for funding under the State Energy Program. The remaining 60 percent will be allocated to the 15 states with highest per-capita residential and commercial sector energy consumption or the highest annual per capita energy-related carbon emissions, which California does not meet this requirement.

A state that receives a capitalization grant may use up to 25 percent of funds to provide grants or technical assistance to eligible entities. Eligible entities include businesses with fewer than 500 employees and low-income owners of residential buildings.

Timing: Applications were due by the states in April 2023. States will be able to set up funds afterwards. This program will be recurring in future years.

Link: https://www.energy.gov/bil/energy-efficiency-revolving-loan-fund-capitalization-grant-program

Contact: stateandlocal@hq.doe.gov

Recommendation: We do not recommend pursuing this program.

8.5.10 Energy Efficiency and Conservation Block Grant (EECBG)

The EECBG Program provides federal grants to states and units of local government to assist eligible entities in implementing strategies to reduce fossil fuel emissions, to reduce total energy use, and to improve energy efficiency. Approximately $550 million has been allocated through the Bipartisan Infrastructure Law; the breakdown of those funds are as follows:

- 8 percent of the funds will be set aside for grant awards to cities and counties.
- 28 percent of the funds will be awarded to states. States must then give 60 percent to cities and counties that do not receive funding directly from DOE.
- 2 percent will be set aside for tribes.
- 2 percent will be set aside for competitive grants to local governments that are not eligible based on population or to a consortium of local governments.

Cities, towns, and villages with a population of at least 35,000 are eligible to apply to and receive grants directly from the DOE. Funding can be used for a broad range of energy-savings projects, including:

- Developing and implementing an energy efficiency and conservation strategy.
- Conducting residential and commercial building energy audits.
- Developing and implementing energy efficiency and conservation programs for buildings and facilities.
- Purchasing and implementing technologies to reduce and capture methane and other GHGs generated by landfills or similar sources.
- Developing, implementing, and installing renewable energy technology on or in any government building, such as solar, wind, fuel cells, and biomass.
- Financing energy efficiency, renewable energy, and zero-emission transportation (and associated infrastructure), capital investments, projects and programs for leveraging of additional public and private sector funds.

Timing: Date of funding opportunity has not yet been announced. Program currently inactive as under federal review.

Link: https://www.energy.gov/scep/office-state-and-community-energy-programs?nrg_redirect=467338

Contact: Adam Guzzo at (202) 287-1585 and eecbg@hq.doe.gov

Recommendation: Consider this program to fund the solar carport or onsite solar PV projects if program is reactivated.

8.6 Other Non-Traditional Sources of Funding

This section discusses many programs and potential sources of non-traditional funding.

8.6.1 Third-party Private Funding and Public Private Partnerships.

Energy efficiency projects are well suited for third-party private funding sources or P3s. These options often have a tax component, which are historically accessible for tax obligated entities and can be traded to large banks as tax equity. Third-party private funding based on equity and debt are suitable for larger projects, where financing companies provide administrative support and access to funding sources and the technology vendors (microturbine or biogas engine vendors) or operations companies (Energy as a Service Company) provide the design, construction and operations services. Third-party private entities, like PG&E, may also provide various funding programs within their regions. P3s are long term agreement between a public agency and a private entity to design, build, finance, operate and maintain (or a combination thereof) infrastructure projects.

Recommendation: Recommend pursuing third-party private funding or P3s. Projects for DSRSD *that may be well suited for these non-traditional options include:*

- *Aeration blower upgrades to turbo blowers and install better controls for dissolved oxygen.*
- *Retrofits of aeration systems with more efficient diffusers reducing power demand.*
- *Upgrade cogeneration project for on-site power and heat generation*

- *Reduce maintenance and issues causing electrical inefficiencies using new pumps and piping, etc.*
- *Recover food waste (divert from landfill) for co-digestion and treatment in a digester to produce biogas and Cogen power to compensate for the predicted future power demand increases.*

8.6.1.1 California's Government Code (GC) 4217

Performance contracting is defined in the California GC 4217 and could be used for energy efficiency retrofits including aeration blowers; aeration systems; heating, ventilation, and air conditioning (HVAC); etc. for larger project funding and PPA, etc.

This code is not a program or a grant fund but rather is a procurement code that allows public agencies to enter into purchase agreements that can address a wide range of infrastructure needs. For example, for the upgrade of the district wide HVAC equipment and to replace the roofs that the equipment sits on GC 4217 can be used to fund that. For the replacement of windows, repair of central plant, and installation of solar photovoltaics and a battery storage system GC 4217 could be helpful with the procurement.

Link: https://southlandind.com/article/getting-it-all-done-how-gc-4217-can-address-multiple-infrastructure-needs-all-once

Recommendation: For information purposes only - private parties would take advantage of this code for P3 projects.

8.6.2 Energy Partnership Program Technical Assistance

The program offers services to help identify the most cost-effective, energy-saving opportunities for buildings and new construction. Energy audits and feasibility studies are included in the services provided. The program provides technical assistance services up to $20,000 of a consultant's costs. If the cost of the study exceeds $20,000, the applicant may opt to share in the cost or reduce the scope of the project. The Energy Commission contracts with experienced engineering and architectural consultants who provide technical assistance. An application and governing board resolution are required along with other documents such as 12 months of gas and electric bills, past energy studies, plans, etc. Applications are accepted on a first-come, first-served basis.

Timing: The program is not accepting applications at this time and it is unknown if it will be available in the future.

Link: https://www.energy.ca.gov/programs-and-topics/programs/energy-partnership-program

Contact: pubprog@energy.ca.gov or 855-380-8722

Recommendation: Do not recommend pursuing due to the limited funding amounts available.

8.6.3 Bioenergy Market Adjusting Tariff (BioMAT) (Senate Bill 1122)

The power export incentive under the BioMAT program is an option for PG&E customers. This program offers feed-in tariff PPAs for eligible bioenergy projects. The BioMAT program is an adjustable tariff for biogas derived green power. Utilities are required to procure a certain amount of biopower from wastewater plants. The PG&E program allocation is 30.5 megawatts (MW) for wastewater plants. At the commencement of the BioMAT program, the available

Contract Price for each of the four Fuel Resource Pricing Categories was set at $127.72/megawatt-hour (MWh). Thereafter, the contract price for each category adjusts independently for each bi-monthly program period based on market acceptance.

Timing: Ongoing.

Link: https://www.pge.com/en/about/doing-business-with-pge/wholesale-electric-power-procurement/bioenergy-market-adjusting-tariff.html

Contact: 877-660-6789

Recommendation: Do not recommend pursuing. Only projects involving the export of power are eligible for this program. Because DSRSD consumes all generated power on-premises, DSRSD *would not be eligible to receive any benefits offered through this program.*

8.6.4 Low Carbon Fuel Standard (LCFS)

The LCFS is designed to encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce GHG emissions and decrease petroleum dependence in the transportation sector. LCFS sets annual carbon intensity (CI) standards, or benchmarks, which reduce over time, for gasoline, diesel, and the fuels that replace them.

All transportation fuels need a carbon intensity score to participate in the LCFS, and the fuel type dictates which process is used to determine that CI. Providers of low carbon fuels used in California transportation generate credits by obtaining a certified CI and reporting transaction quantities on a quarterly basis. Credits are calculated relative to the annual CI benchmark and will undergo verification post credit generation. Biomethane from wastewater sludge used as vehicle fuel (e.g., RNG fueling vehicles onsite or for pipeline injection) or green power exported to EV charging stations (eLCFS credits) are eligible pathways; after project registration credits from biomethane can be monetized as a source of additional revenue.

Timing: Ongoing.

Contact: https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-contacts

Link: https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard

Recommendation: Since biogas cogeneration does not allow for pipeline injection and sale of the RNG this option does not apply.

8.6.5 California Clean Fuel Reward

The California Clean Fuel Reward offers up to $750 on the purchase or lease of an eligible new Battery Electric or PHEV with a battery capacity greater than 5 kilowatt-hour (kWh) from a participating automotive retailer. The customer must register the vehicle in California and the customer must reside in California. This instant EV reward is offered on a sliding scale, depending on vehicle battery size. Participating retailers will include the reward in the sales transaction when purchasing the new vehicle.

Timing: Ongoing, but program is currently depleted and inactive. More funds may become available.

Link: https://cleanfuelreward.com/

Contact: 1-800-880-0320 or info@cleanfuelreward.com

Recommendation: Track and determine eligibility and interest if more funds become available.

8.6.6 Pacific Gas & Electric Company Opportunities

PG&E offers and administers various funding options for EV charging infrastructure for the customer's fleet, fleet funding, and energy focused assistance. The programs are described in the following sections.

8.6.6.1 Fleet Partner Program

Under this program, PG&E will plan and build the appropriate charging infrastructure for the customer's fleet. Through the Fleet Partner Plan, PG&E offers feasibility assessments, charging analysis, and more for no cost to the consumer and no obligation to proceed with further construction or design. Through the Fleet Partner Build, PG&E will provide final design and construction of make-ready infrastructure and a custom incentive based on forecasted energy use of the chargers, up to $750,000. To be eligible for funding, the following program requirements must be met:

- Charging site(s) must be in PG&E service territory.
- DSRSD must pay for any make-ready costs not covered by the custom cost incentive.
- Add a minimum of 70 kW of new load (usually equivalent to 10 Level 2 ports or 1-2 DC fast chargers).
- Purchase and install PG&E-approved, networked, Level 2 or DC Fast Chargers.
- Keep chargers operational and share charging data with PG&E for 10 years.
- Commit to forecasted energy use of the chargers.
- Sign an easement covering PG&E-owned infrastructure.
- DSRSD must sign the Participation Agreement before construction can begin.
- Applications are accepted throughout the year.

Timing: Applications accepted year-round.

Link: https://portlandgeneral.com/fleet-partner

Contact: fleetpartner@pgn.com

Recommendation: As of January 3, 2023, all funds for final design and construction have been fully reserved. Recommend pursuing the free Fleet Partner Plan to gain more insight on preliminary design and be included for future funding opportunities involving EV charging stations.

8.6.6.2 Electric Vehicle Fleet Program

PG&E's EV Fleet Program offers competitive incentives to facilitate the installation of EV supply equipment for medium and heavy-duty vehicle fleets. PG&E offers dedicated electrical infrastructure design and construction services and reduced costs for electrical infrastructure work. Sites located in disadvantaged communities may be eligible to receive a rebate for the purchase of the EVSE. Rebates up to $42,000 per charger or $9,000 per vehicle are available via the program.

Applicant eligibility hinges on the applicant acquiring and deploying a minimum of two medium or heavy-duty EVs by 2024. Rebates for vehicles are available for transit buses, class 8 vehicles, school buses, local delivery trucks, and other medium- and heavy-duty vehicles. Sectors that can participate in this program include utilities and municipalities that meet the eligibility criteria.

Timing: Ongoing.

Link: https://www.pge.com/en_US/large-business/solar-and-vehicles/clean-vehicles/ev-fleet-program/ev-fleet-program.page

Contact: Submit information at https://energyinsight.secure.force.com/EVCustomerInterestFormPage?_ga=2.27724287.2100077583.1666047423-945043623.1665584069 to have representative reach out

Recommendation: With medium- and heavy-duty vehicles being included in this list, DSRSD should submit applications for potential rebates. Purchasing two medium or heavy-duty EVs may not be feasible and/or desired before 2024, DSRSD should continue to monitor program for renewal.

8.6.6.3 Business Electric Vehicle Charging Pilot Program

PG&E non-residential customers who install qualifying Level 2 EV chargers may receive a rebate of $1,000 per port. Qualified chargers must be on an approved list and be kept operational and with a cost-of-service rate for 10 years. Rebates are capped at $50,000 per location. Applications are accepted until funding is depleted. Rebate applications require supplemental information, such as a W-9 form, invoice of chargers, photo of installation, and photo of charger nameplate with serial number. As further discussed in TM 7, EV chargers are needed soon to comply to the Advanced Clean Fleets Regulations.

Timing: Ongoing.

Link: https://portlandgeneral.com/energy-choices/electric-vehicles-charging/business-charging-fleets/ev-charging-pilot-program-business

Contact: evrebate@pgn.com

Recommendation: DSRSD should pursue various EV charging incentive programs to assist in the near-term installations of associated infrastructure needed to support zero emission vehicles. Currently, installation of EV charging stations is not included in the CIP due to their low capital costs, especially when compared to other major CIP projects listed.

8.6.6.4 On-Bill Financing (OBF) for Energy Efficiency Through Pacific Gas & Electric Company

With OBF, PG&E offers zero percent interest loans for replacing old and obsolete equipment with more energy-OBF efficient models. PG&E will set a loan repayment amount that is in line with the monthly energy savings from the upgrade so that the energy bill shouldn't increase due to the equipment investment. Once the loan is paid off, the client will see savings on the bill.

Loans range between $5,000 and $4 million per premise, with loan periods of up to 120 months. Tier 1A is an alternative qualification pathway for OBF customers seeking an OBF loan between $5,000 and $100,000 with loan periods of up to 72 months. Only a select list of simple, like-for-like replacement measures are eligible for this tier. The energy savings quality control will be automated through the Tier 1A application workbook template.

Eligible energy efficiency financing project costs that may be covered under the loan are those associated with the required components of the energy efficiency project for the life of the loan. Eligible projects costs include:

- Implementation costs, such as material costs, labor, lift rentals, etc.
- Project developer fees.
- Costs associated with building code compliance.
- Initial and ongoing measurement and verification expenses, only if paid upfront under the loan disbursement.
- O&M activities, including costs for customer O&M training, if paid upfront under the loan disbursement.
- Quality assurance provider costs.
- An energy efficiency project performance guarantee.

The PG&E handbook for OBF describes the application procedures and provides the following table.

Table 8.1 Loan Amounts and Interest Rates for Various Project Types Funded through PG&E

	OBF	OBF With Incentives	Tier 1A
Interest	0%	0%	0%
Minimum Loan Amount	$5,000	$5,000	$5,000
Maximum Loan Amount	$250,000 ($4,000,000 per premises by exception)(1)	$250,000	$100,000
Maximum Loan Term, not to exceed the expected useful life of the measures	120 months	120 months	72 months

Notes:
(1) Customers may take multiple loans to support their projects. The maximum load per premises is $4,000,000.

Timing: Ongoing.

Link: *https://www.pge.com/en/save-energy-and-money/energy-saving-programs/energy-efficiency-programs-for-businesses/energy-efficiency-financing.html#accordion-eccbfd4615-item-4626c9f689*

Contact: businesscustomerhelp@pge.com

Recommendation: It does not appear that any of the alternatives under evaluation would qualify for this program.

8.6.6.5 California Energy Design Assistance (CEDA)

In 2021, the CEDA program replaced the Savings by Design program to further new construction energy efficiency. The program provides complimentary energy design assistance for new construction and major alterations for commercial, public, multifamily (four stories and taller), industrial and agricultural projects. Organization may use own design team and still be eligible for incentives under specific conditions. Fixed incentives rates are given for each kWh, peak kW, and therms saved. Incentives are capped in a variety of ways including, the lesser of 100 percent

of incremental costs or 50 percent full measure costs, buildings with onsite generation exceeding usage on an hourly basis, or a total amount of $1 million.

To be eligible for funding, projects must meet the following criteria:

- Project(s) must be in the early design phase(s).
- Located in a PG&E or similar service territory with an eligible rate structure.
- Project team interest and committed to evaluating energy efficiency options.
- Project must consist of new construction or a major alteration to an existing facility.

There are two types of categories that design projects may be placed into:

- All-electric:
  - Higher cash incentives to promote electric design are provided.
  - Encourage facilities that can integrate renewable energy generation, EV charging, and/or battery storage.
- Mixed fuel:
  - Optimize gas and process heating systems to reduce carbon and other GHG emissions.
  - Optimize electric systems to maximize energy efficiency and reduce lifecycle operating costs.

Timing: Ongoing. DSRSD must fill out initial application.

Link: https://ceda.willdan.com/

Contact: 855-502-3914 or CEDA@willdan.com

Recommendation: It does not appear that any of the alternatives under evaluation would qualify for this program.

8.6.6.6 State of California Microgrid Program (MIP) administered by PG&E

The State of California and the California Public Utility Commission (CPUC) have initiated new legislation and programs that could have a positive impact on DSRSD's future cogeneration projects.

For in front of the meter assets, the state launched the new MIP which is a $200 million statewide program intended to fund clean energy microgrids to support the critical needs of vulnerable populations and water infrastructure impacted by a grid outage. The MIP was approved in concept in January 2021 but still requires a Commission vote on implementation details to become operational. The Commission voted to approve a decision for the next phase of these proceedings on April 6, 2023. The decision adopted implementation rules for the Microgrid Incentive Program. Also, on this date the Commission approved rules for the MIP for PG&E, Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). It allocated $79.2 million for PG&E, $83.3 million for SCE, and $17.5 million for SDG&E. Projects selected under the MIP can receive up to $15 million in award funding.

The most important changes by CPUC related to resilience and microgrids are summarized as follows:

- Under the Net Energy Metering it is now allowed to install larger energy storage sizes.
- CPUC is creating one central approval agency for future Microgrids.

- Incentives will be available for resilience in disadvantaged communities.
- Utilities have requested to procure a local area distribution controller.
- PG&E is to revise its Rule 19, to allow local government microgrids to service critical customers on adjacent parcels. Some utilities will create a renewable microgrid tariff that prevents cost shifting for their territories.
- Other utilities will develop a statewide MIP with a $200 million budget to fund clean energy microgrids to support the critical needs of vulnerable communities impacted by grid outages and to test new technologies.

Timing for PG&E's program: Initial consultation request form due May 30, 2025.

Link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/resiliency-and-microgrids

Link to PG&Es program: https://www.pge.com/en/save-energy-and-money/rebates-and-incentives/community-microgrids.html?vnt=mip

Recommendation: Submit initial consultation request to PG&E if interested in initiating a microgrid effort.

8.6.6.7 State of California Self-Generation Incentive Program (SGIP) Administered by PG&E

The SGIP State Rebate Program provides incentives to local government, nonprofit, state government, federal government, institutional customers who generate electricity from fuel cells or wind turbines or use energy storage to reduce grid power demand. The payments range from $1 to $4.50 per Watt while the new system can range from 30 kW to 5 MW. For Cogen systems on biogas the base rate is $2 per Watt and a resiliency adder would provide incentive of an additional $2.5 per Watt. The legislation which put this program in place is the Cal Pub Util Code § 379.6 and SB 412.

Through the SGIP program, the on-site generation of green power is incentivized based on performance. The first 50 percent of the grant is paid out after completion of the installation. The remaining 50 percent of the grant is performance based; the electrical generation is metered and reported by an independent third party. Energy management from renewable sources and electrical battery storage as part of a microgrid qualifies for energy grants and incentives. The SGIP would be paid out to the operating entity. Under a PPA, these grants would be paid to the private operator.

Various incentives to fund energy storage systems are also available. Table 8.2 shows the energy storage incentives for resilience systems under the SGIP. The incentives are reduced as the duration of the energy storage (Watt-hours [Wh]) increases in relation to the rated capacity. A four-hour system with a 100-kW discharge rating storing 400,000 Wh at $0.4 per Wh would receive $160,000 in incentives. The incentives are reduced to $0.2 per Wh for greater than 4 to 6 hours of storage.

Table 8.2 SGIP Incentives Based on Discharge Duration

Discharge Duration (hours)	Percent Base Incentive
0 to 2 hours	100
Greater than 2 to 4 hours	100
Greater than 4 to 6 hours	50
Greater than 6 hours	0

Timing: Ongoing.

Link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program

Contact: PG&E Program Administrator Contact Information Phone: 415-973-6436

Email: selfgen@pge.com

Program Metrics Link: https://www.selfgenca.com/home/program_metrics/

Recommendation: We recommend pursuing this program and preparing a reservation request through PG&E for the cogeneration project for the replacement of the biogas engines and battery energy storage.

8.6.7 Biogas Tax Credit Opportunities

With IRA funding and legislative actions, projects being completed to comply with California's SB 1383 are now able to receive federal funding via tax credits through the IRS. Biogas properties and projects, defined as facilities that effectively eliminate any use of coal or oil in the generation of energy, are further defined below:

- A qualified property is a system that is for cleaning, gas conditioning, or converting biogas that:
  - Consists of not less than 52 percent methane by volume.
  - Concentrated by system into a gas not less than 52 percent methane.
  - Captured gas is for sale or productive use and not disposal.
- Property that begins construction after 12/31/2024 is excluded as a defined qualified property:
  - No double benefits if the project is credited under section 48 of the Internal Revenue Code.
- Other important takeaways that are described in the tax credit program (*Subtitle D – Energy Security, Part 1-Clean Electricity, and Reducing Carbon Emissions*) are listed below:
  - Increased amount of tax credit is determined by the following criteria:
    - Credit is equal to the amount multiplied by 5.
    - Energy projects receiving increased credit is defined as a project consisting of one or more properties that are a part of a single project provided the following criteria are met:
      - Net output of less than 1 MW of electrical or thermal energy.
      - Project construction begins before the date that is 60 days after Treasury issues guidance related to prevailing wage and apprenticeship mandates.
      - Project complies with prevailing wage and apprenticeship mandates.
        - Prevailing Wage mandate required for any project construction and for alternation or repair during the five-year period after placed in service date:
        - Penalties may apply.
        - If violation of mandate occurs, Treasury can recapture benefits from increased credit awarded.
          - Apprenticeship to Journeyman mandate for employment ratio applies:
            - 10 percent for construction beginning **before** 1/1/2023.

  - 12.5 percent for construction **after** 12/31/2022 **but before** 1/1/2024.
  - 15 percent for construction beginning **after** 12/31/2023.
  - Penalties for failure to comply may apply.
- Domestic content bonus credit (amount of 10 percent) would be determined if a project meets compliance with United States produced iron, steel, and manufactured products.
  - For manufactured products compliance would be deemed met if the total costs of all manufactured products in the project are not less than 40 percent.
  - If a project elects a credit, the credit would be applied to the tax year elected.
    - Value of credit would be phased out by value of credit multiplied by applicable percentage of 2 percent for a project that does not comply with domestic content.
    - Value of bonus credit would be set to 10 percent if project complies with domestic content.
    - Value of bonus credit would be boosted an additional 10 percent if project located in an energy community (if a project does not comply with Domestic Content, credit is only 2 percent).

Several guidelines were being developed in 2024 accompanied by a strict schedule (e.g., start construction in 2024). The scheduling factors, and other requirements would not allow DSRSD to take advantage of the full tax credits.

Recommendation: Further discuss tax credits with a tax professional and consider applying for the IRA tax credits funding for the cogeneration system upgrades if available when project design begins for options that do not have the strict scheduling if such parameters have not been met.

8.6.7.1 Business Energy Investment Tax Credit (ITC)

Energy tax credits are a variety of indirect federal subsidies to finance the investment and production of renewable energy. The energy tax credit was first enacted in the Energy Tax Act of 1978 (P.L. 95-618), which created a temporary 10 percent tax credit for business energy property and equipment using energy resources other than oil or natural gas. Currently, the program provides up to a 30 percent credit for qualified expenditures. Bonus credits are given under some circumstances. Eligible projects are:

- Solar technologies.
- Fuel cells.
- Wind turbines.
- Geothermal systems.
- Microturbines.
- Combined heat and power.
- Offshore wind.
- Waste energy recovery.
  - Qualified waste energy recovery property is defined by a property that generates electricity solely from heat from buildings or equipment if the primary purpose of such building or equipment is not the generation of electricity. The term "waste energy recovery property" does not include any property that has a capacity in excess of 50 MW.

- Energy storage systems (both paired with generation 0r installed as a stand-alone system).
- Thermal energy storage systems.
- Qualified biogas property.
- Microgrid controllers.
- Interconnection Property associated with the installation of energy property with a maximum net output of not greater than 5 MW-AC to provide for the transmission or distribution of the electricity produced or stored by such property, and which are properly chargeable to the capital account of the taxpayer.

The program has undergone several changes over the years. The IRA of 2022 (H.R. 5376) made several significant alterations such as creation of the similar Clean Electricity ITC to cover the Business Energy Investment Tax credit, and establishing procedures for non-tax paying entities to directly monetize tax credits. The provision applies to nonprofits, a state or political subdivisions, or any corporation operating on a cooperative basis which is engaged in furnishing electric energy to persons in rural areas for tax years beginning after December 31, 2022, and before January 1, 2033. These entities can elect to be treated as having made a tax payment equal to the value of the tax credit they would otherwise be eligible to claim. The entity can then claim a refund for the excess taxes they are deemed to have paid. The option effectively makes this tax credit refundable for these entities.

The act also allows eligible taxpayers to transfer all or a portion of their eligible tax credits to an unrelated taxpayer. Transfers must be reported to IRS and only one transfer is permitted. Must be elected no later than the due date for tax filing for the tax year the tax credit is claimed. This program is being phased out and replaced by the Clean Electricity Investment Tax Credit for systems placed in service on or after January 1, 2025.

Link: https://programs.dsireusa.org/system/program/detail/658 and https://www.irs.gov/businesses/small-businesses-self-employed/business-tax-credits

8.6.7.2 Renewable Electricity Production Tax Credit (PTC)

PTC is an inflation-adjusted per-kWh tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service. Wage and apprenticeship requirements are mandatory for a larger system to qualify for the full value of the tax credit. In late-2022 or 2023, the Treasury Secretary will issue guidance for these new labor provisions. Rates for available tax credits under the PTC are as follows:

- 2.6 cents per kWh:
  - Wind.
  - Closed-loop biomass facilities.
  - Geothermal energy.
- 1.3 cents per kWh:
  - Open-loop biomass facilities.
  - Small irrigation power facilities.
  - Landfill gas and trash facilities.

The IRA of 2022 made several significant alterations to PTC, establishing procedures for non-tax paying entities to directly monetize tax credits. The provision applies to nonprofits, a state or

political subdivisions, or any corporation operating on a cooperative basis which is engaged in furnishing electric energy to persons in rural areas for tax years beginning after December 31, 2022, and before January 1, 2033. These entities can elect to be treated as having made a tax payment equal to the value of the tax credit they would otherwise be eligible to claim. The entity can then claim a refund for the excess taxes they are deemed to have paid. The option effectively makes this tax credit refundable for these entities (Figure 8.1).

The act also allows eligible taxpayers to transfer all or a portion of their eligible tax credits to an unrelated taxpayer. Transfers must be reported to IRS and only one transfer is permitted. Must be elected no later than the due date for tax filing for the tax year the tax credit is claimed. This program is being phased out and replaced by the Clean Electricity Investment Tax Credit for systems placed in service on or after January 1, 2025.

Link: https://www.irs.gov/forms-pubs/about-form-8835

8.6.7.3 Clean Electricity Investment Tax Credit and Production Tax Credit

As described the IRA initiated various new options and adjustments to energy tax credits. The image below shows a visual representation of these. With the column of 2023-2033 being reflective of the adjustments finalized into tax code on January 5, 2025.

Summary of Investment Tax Credit (ITC) and Production Tax Credit (PTC) Values Over Time

			Start of Construction						
			2006 to 2019	2020 to 2021	2022	2023 to 2033	The later of 2034 (or two years after applicable year[a])	The later of 2035 (or three years after applicable year[a])	The later of 2036 (or four years after applicable year[a])
ITC	Full rate (if project meets labor requirements[b])	Base Credit	30%	26%	30%	30%	22.5%	15%	0%
		Domestic Content Bonus				10%	7.5%	5%	0%
		Energy Community Bonus				10%	7.5%	5%	0%
	Base rate (if project does not meet labor requirements[b])	Base Credit	30%	26%	6%	6%	4.5%	3%	0%
		Domestic Content Bonus				2%	1.5%	1%	0%
		Energy Community Bonus				2%	1.5%	1%	0%
	Low-income bonus (1.8 GW/yr cap)	<5 MW projects in LMI communities or Indian land				10%	10%	10%	10%
		Qualified low-income residential building project / Qualified low-income economic benefit project				20%	20%	20%	20%
PTC for 10 years ($2022)	Full rate (if project meets labor requirements[b])	Base Credit			2.75 ¢	2.75 ¢	2.0 ¢	1.3 ¢	0.0 ¢
		Domestic Content Bonus				0.3 ¢	0.2 ¢	0.1 ¢	0.0 ¢
		Energy Community Bonus				0.3 ¢	0.2 ¢	0.1 ¢	0.0 ¢
	Base rate (if project does not meet labor requirements[b])	Base Credit			0.55 ¢	0.55 ¢	0.4 ¢	0.3 ¢	0.0 ¢
		Domestic Content Bonus				0.1 ¢	0.0 ¢	0.0 ¢	0.0 ¢
		Energy Community Bonus				0.1 ¢	0.0 ¢	0.1 ¢	0.0 ¢

a "Applicable year" is defined as the later of (i) 2032 or (ii) the year the Treasury Secretary determines that there has been a 75% or more reduction in annual greenhouse gas emissions from the production of electricity in the United States as compared to the calendar year 2022.

b "Labor requirements" entail certain prevailing wage and apprenticeship conditions being met.

Figure 8.1 Summary of Tax Credits Under IRA

The updated ITC and PTC tax credit programs will replace the Business Energy ITC and Renewable Electricity PTC for systems placed in service on or after January 1, 2025.

Unlike the long standing ITC or the PTC, these are not technology specific. It applies to all generation facilities and energy storage systems that have an anticipated GHG emissions rate of zero. The credit amount is generally calculated in the same manner as the Business Energy ITC, but it will be phased out as the United States meets GHG emission reduction targets. The tax credit will be reduced annually from initially 100 percent to 75 percent and to 50 percent in the third year, until it is phased out as soon as the United States are meeting the GHG emission targets.

It is important to note that these tax credits have been finalized into law and are published in the Federal Registrar. It would take only an act of congress to adjust them moving forward.

Link: https://programs.dsireusa.org/system/program/detail/658

Link to IRS site: https://www.irs.gov/credits-and-deductions-under-the-inflation-reduction-act-of-2022

Link to Federal Registrar Code: Federal Register :: Section 45Y Clean Electricity Production Credit and Section 48E Clean Electricity Investment Credit

8.6.8 Environmental Protection Agency Renewable Fuel Standard (RFS) Program

The RFS program is a national policy that requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil, or jet fuel. The four renewable fuel categories under RFS are:

- Biomass-based diesel.
- Cellulosic biofuel.
- Advanced biofuel.
- Total renewable fuel.

For a fuel to qualify as a renewable fuel under the RFS program, EPA must determine that the fuel qualifies under the statute and regulations. Among other requirements, fuels must achieve a reduction in GHG emissions as compared to a 2005 petroleum baseline. Obligated parties under the RFS program are refiners and importers of gasoline or diesel fuel. Compliance is achieved by blending renewable fuels into fossil fuel-based transportation fuel, or by obtaining credits called "Renewable Identification Numbers" (RIN) to meet an EPA-specified Renewable Volume Obligation (RVO). EPA calculates and establishes RVOs every year through rulemaking, based on the Clean Air Act volume requirements and projections of gasoline and diesel production for the coming year. Facilities receive RINs that can be sold to other refiners. RINs are tied to each gallon of biofuel produced. The standards are converted into a percentage and obligated parties must demonstrate compliance annually. Since 2016, wastewater treatment plants have been eligible for projects such as compressed natural gas from facility digester gas.

The eRIN certificates under EPA's RFS will also provide green power certificates for biogas cogeneration. For projects of 1 MW or larger the eRIN brokers would sell the green power attributes (eRIN) to the EV manufacturing companies while the actual power can still be used onsite. EPA is working on the eRIN pathway certification, but has not released the details for this eRIN program yet.

The total value of the eRIN credits could be 22 cents per kWh; the EV manufacturing company generating the credits is expected to keep 60 percent of that value and the generator of biogas power would retain 8 to 9 cents per kWh. The higher value of the eRIN is a factor of the higher efficiency of the electric motor compared to RNG used in combustion engines.

Timing: Program is ongoing.

Link: https://www.epa.gov/renewable-fuel-standard-program

Link to final rule: https://www.epa.gov/renewable-fuel-standard-program/final-renewable-fuels-standards-rule-2023-2024-and-2025

Contact: FuelsProgramSupport@epa.gov or 1-800-385-6164

Recommendation: The RFS program is expected to implement the eRIN certificates by the end of 2023 and then we recommend pursuing the registration of the existing (and future) biogas cogeneration project. Consider further if regional food waste and on-site co-digestion program is implemented.

8.6.9 Qualified Commercial Clean Vehicle Tax Credit

The IRA of 2022 established a tax credit for qualified commercial clean vehicles purchased on or after January 1, 2023, and up to December 31, 2032. The vehicle must have a gross vehicle weight rating of less than 14,000 pounds and have a battery rating of not less than 7 kWh to qualify. Mobile machinery (including vehicles that are not designed to perform the function of transporting a load over the public highways) can exceed the 14,000-pound weight limit but must have a battery capacity of not less than 15 kWh. The tax credit is worth 30 percent of the cost of the vehicle or equipment, up to $7,500 for vehicles less than 14,000 pounds., or $40,000 for mobile machinery.

The direct pay option allows non-taxable entities to directly monetize these tax credits. The provision applies to nonprofits, a state or political subdivisions, or any corporation operating on a cooperative basis which is engaged in furnishing electric energy to persons in rural areas for tax years beginning after December 31, 2022, and before January 1, 2033. These entities can elect to be treated as having made a tax payment equal to the value of the tax credit they would otherwise be eligible to claim. The entity can then claim a refund for the excess taxes they are deemed to have paid. The option effectively makes this tax credit refundable for these entities.

The act also allows eligible taxpayers to transfer all or a portion of their eligible tax credits to an unrelated taxpayer. Transfers must be reported to IRS and only one transfer is permitted. Must be elected no later than the due date for tax filing for the tax year the tax credit is claimed.

Link: https://www.irs.gov/credits-deductions/commercial-clean-vehicle-credit

Recommendation: Pursue if there are appropriate vehicles with the applicable ratings.

8.7 Next Steps and Recommendations

With such a large number of incentives and funding programs to apply for, Carollo Engineers recommends the following for the best balance between financial support and effort in meeting your specific projects and funding requirements.

- The IRA provides funding for new cogeneration engines and associated project costs, including digester upgrades, mixing, etc.
- The WIFIA program provides loans for very large projects within the 20-year CIP (plant expansions, new cogeneration, etc.).
- The SGIP from PG&E provides funding for battery storage and better for long duration hydrogen storage to reduce PG&E's demand charges.
- In addition, PG&E offers on-bill financing or loans for energy efficiency projects including new aeration blowers and systems, HVAC systems, variable frequency drive additions, etc.

Table 8.3 describes grants, loans and incentives for the recommended CIP at DSRSD. The "Likelihood of successful funding" column ratings are based on the program requirements, the specific energy projects and their competitiveness. Programs with a "high" and/or "medium" priority are those recommended for further consideration. As DSRSD evaluates these options, one strategy to consider is grouping similar CIP projects into specific packages or phases based on timing, purpose, location and other factors when submitting applications. When looking at the columns "Types of projects" and "Specific DSRSD projects" potential groupings and eligible projects emerge. Some external funding programs accept such packages of projects assuming the projects each meet the defined priorities of the program. Where feasible, packaging multiple projects into one application will reduce the workload on DSRSD staff and potentially award higher amounts of funding at one time. Timelines of packaged projects would need to align with DSRSD budgeting to ensure debt payments match up with available funds.

Table 8.3 Summary of Recommended Grants and Project Types

Type of Grant/Loan/Rebate	Types of Projects	Specific DSRSD Projects	Application costs	Due date	Likelihood of successful funding
PG&E - OBF	Energy efficiency	Aeration (LS-13) and pre-aeration blowers (LS-16) or adjusting lighting (BLG-2)	N/A	Ongoing	High
PG&E - loan	Large capital projects	Cogen projects (BS-30, BS-31, etc.)	N/A	Ongoing	High
IRA – Energy project tax incentives	Biogas related energy projects, digester upgrades, etc.	Cogen project (BS-30, BS-31, etc.)	Tax lawyer or consultants	2024 to 2026	Very high, but incentive decreasing over time
EPA loans - WIFIA	Large capital projects water and wastewater infrastructure energy efficiency	New treatment facilities?	$100,0000 and percentage fee	Ongoing	High, with project pre-qualification
PG&E - SGIP	Battery and hydrogen storage	Lithium-ion battery storage in case of a solar project (ES-1) Hydrogen energy system for back-up and energy storage (ES-2)	N/A	Annual due date	Very competitive / funding is mostly used for battery energy storage
PG&E - Fleet Partner Program	EV charging stations	EV charging stations	N/A	Ongoing	High
PG&E – EV Fleet Program	EV purchases	Compliance with Advanced Clean Fleets Regulations	N/A	1/1/2024	Low given the tight timeline for application. Recommend potential renewal of the program later.
CVRP for Fleets	EV purchases	Compliance with Advanced Clean Fleets Regulation	N/A	Ongoing	High

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Technical Memorandum 9
EVALUATION OF SEPARATE RECYCLED WATER TREATMENT PLANT POWER SUPPLY

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Abbreviations

DERWA	Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority
DSRSD	Dublin San Ramon Services District
kcmil	thousands of circular mills
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
MCC	motor control center
PG&E	Pacific Gas & Electric Company
PSR1	Pump Station R1
RWTP	recycled water treatment plant
TM	technical memorandum
UV	ultraviolet
V	volt
WWTP	wastewater treatment plant

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Technical Memorandum 9

EVALUATION OF SEPARATE RECYCLED WATER TREATMENT PLANT POWER SUPPLY

9.1 Introduction

This technical memorandum (TM) evaluates the feasibility and planning level cost of providing a separate power supply and metering for the recycled water treatment plant (RWTP). The RWTP currently is supplied from the same power supply as the wastewater treatment plant (WWTP).

The TM also includes an estimation of the impact of separate power supplies for the WWTP and RWTP on WWTP energy costs by estimating the utility peak power demand and usage costs for the WWTP if it the RWTP had a separate Pacific Gas & Electric Company (PG&E) power supply.

9.2 Separate Recycled Water Treatment Plant Power Supply and Metering

A separate power supply and metering for the RWTP would need to power switchgear DPN and motor control centers (MCC) M1 and M3. This section outlines electrical infrastructure needed for separating the utility power supply to the RWTP from the WWTP, including a planning level cost estimate.

9.2.1 New Service Switchgear

A new 25 kilovolt (kV) rated service switchgear would be required to receive and meter incoming power from PG&E. The new service switchgear would be rated to receive PG&E service voltage at 20.8 kV voltage level as shown below in Figure 9.1.

As depicted in Figure 9.1, main-tie-tie-main type, 25 kV service switchgear would be recommended to allow maintenance and testing of the switchgear with complete isolation of either side A or side B for staff safety and protection.

The new service switchgear would be used to supply power to existing power transformer XFMR-7, which feeds switchboard XFMR-7-SWBD, which feeds existing switchgear DPN. Switchgear DPN supplies power to Pump Station R1 (PSR1) and recycled water ultraviolet (UV) disinfection system.

9.2.2 Switchgear DPN

As described above, switchgear DPN supplies power to PSR1 and UV systems depicted in Figures 9.2 and 9.3. This switchgear would be served from the new service switchgear and under separate PG&E electric service and metering as described above and shown in Figure 9.1.

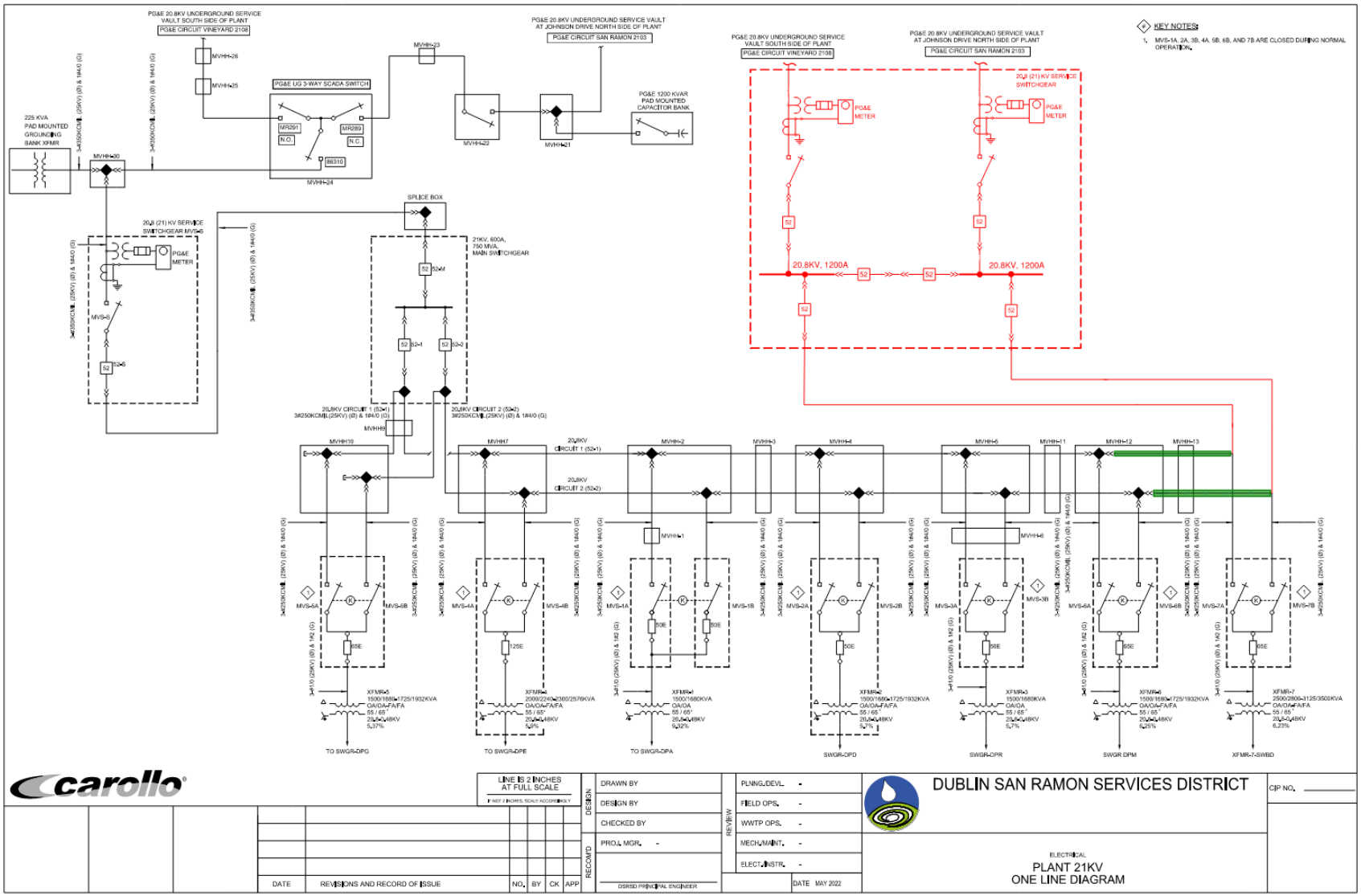

Figure 9.1 Plant 21 kV One-Line Diagram

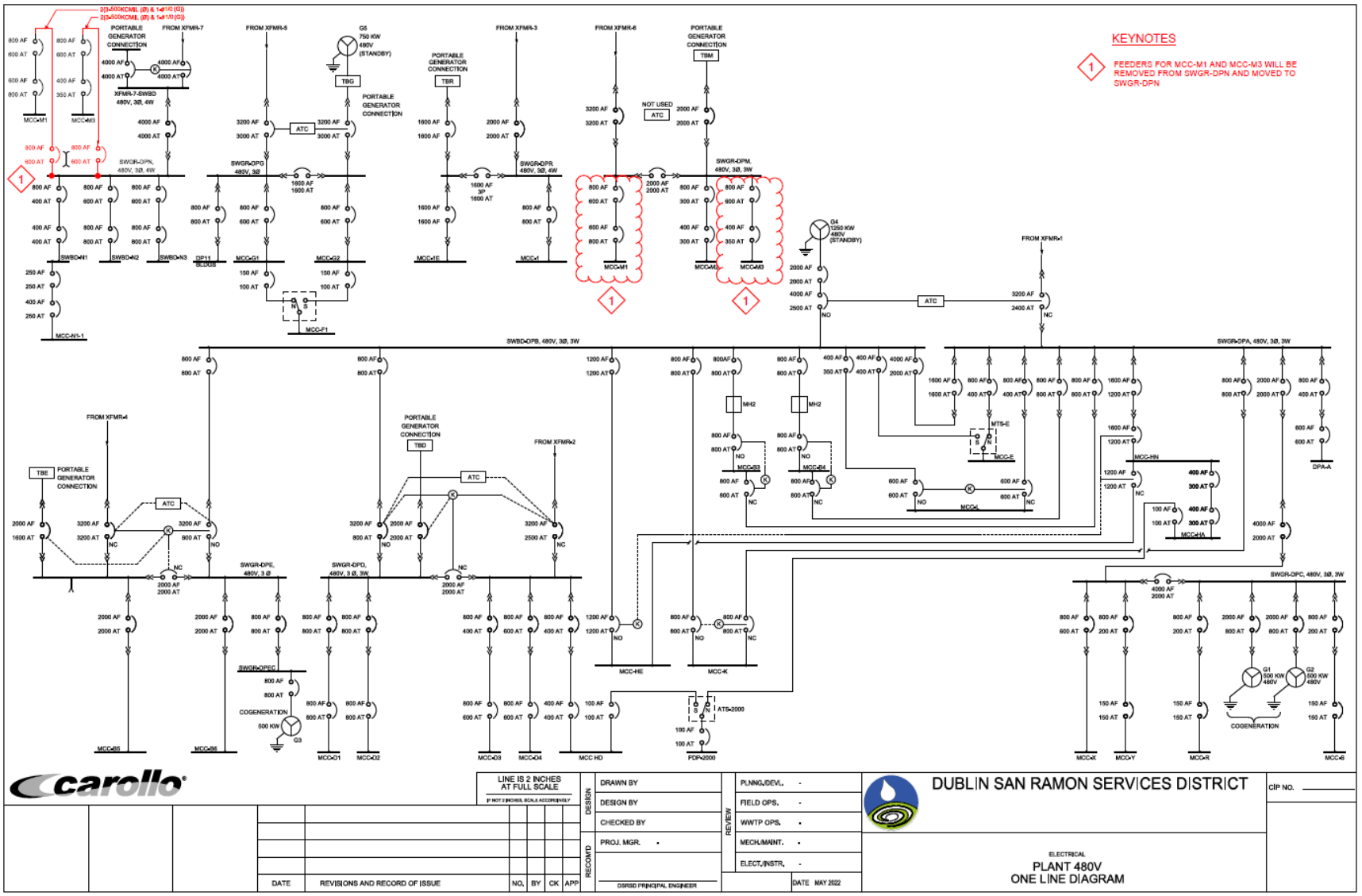

Figure 9.2 Plant 480 Volt (V) One-Line Diagram

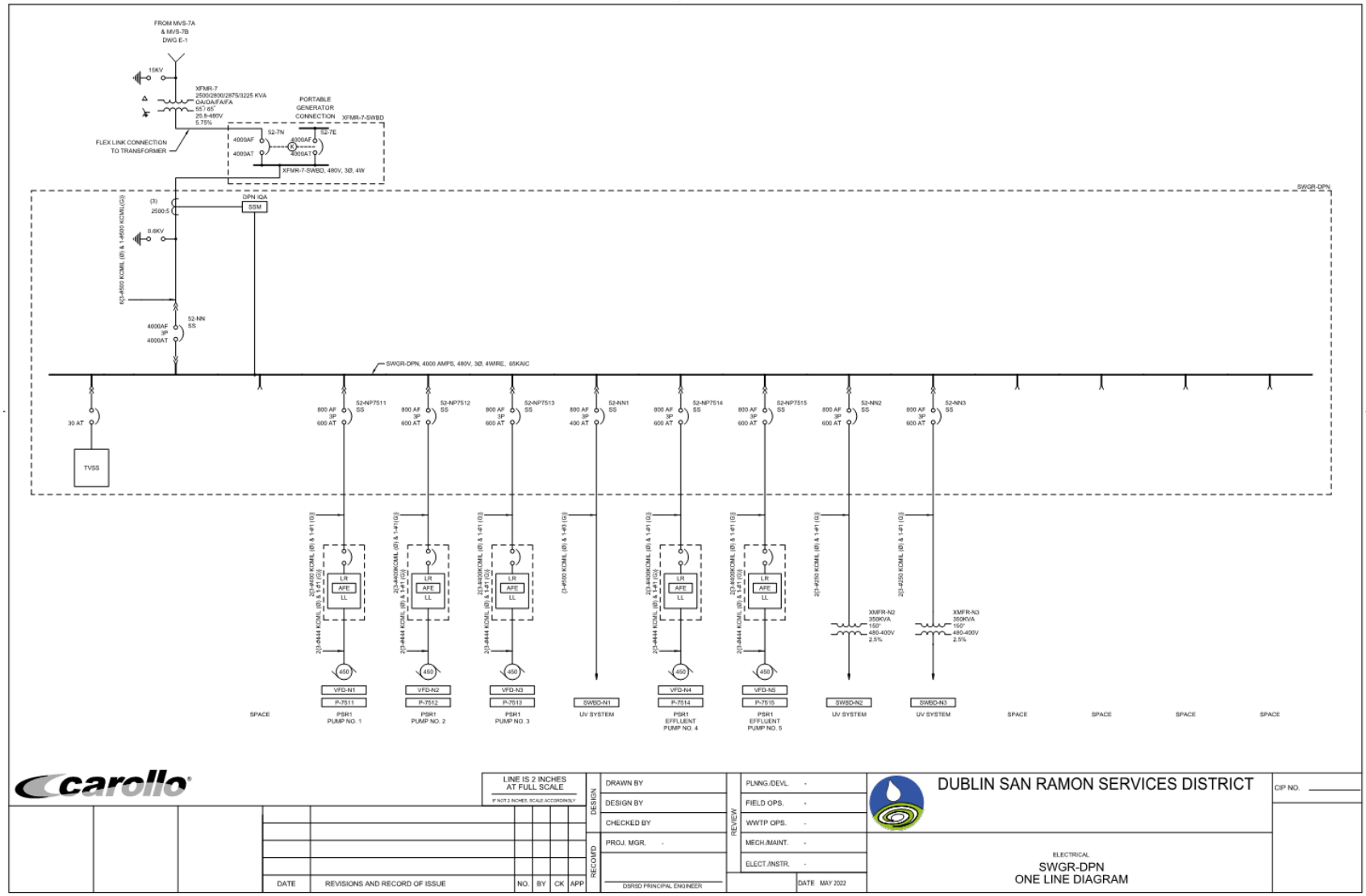

Figure 9.3 SWGR-DPN One-Line Diagram

Supplying power from new PG&E services would not require modifications to SWGR-DPN, its power transformer XFMR-7, or 25 kV switches MVS-7A/7B that feed XFMR-7. However, the 25 kV switches MVS-7A/7B would need to be disconnected from the existing 21 kV power distribution system and connected to the new service switchgear as shown in Figure 9.1.

For a level 5 cost estimate for this modification, it is assumed that the new service switchgear can be located within 250 feet of the existing 25 kV switches MVS-7A/7B.

9.2.3 Motor Control Centers M1 and M3

MCCs M1 and M3 supply power to the existing RWTP loads not supplied by DPN and would need to be transferred to the new PG&E service. The most cost-effective approach would be to disconnect MCCs M1 and M3 from the existing switchgear SWGR-DPM and reconnect them to switchgear SWGR-DPN, which would be connected to the new PG&E services to RWTP.

The required MCC modifications described above would be feasible if SWGR-DPN has adequate physical and electrical capacity. Front elevation photo of SWGR-DPN shown in Figure 9.4 indicates there are six blank or empty spaces available tin SWGR-DPN for addition of new breakers. Therefore, two feeder breakers could be installed in any of the six available spaces to supply power to MCCs M1 and M3.

Figure 9.4 SWGR-DPN Front Elevation Photo

Based on WWTP's SKM Power Tools electrical study, Switchgear DPN appears to have adequate electrical capacity as indicated in Table 9.1. The electrical study was prepared to provide arc flash labels for electrical equipment in WWTP. As a result, the study may not represent the actual

demand and operating loads on the switchgear. A more detailed load study would need to be performed to examine the available electrical capacity of SWGR-DPN if separate power meter and service for RWTP is desired in future.

Table 9.1 SWGR-DPN Electrical Capacity

Equipment	Rating (Amps)	Connected Load (Amps)	% Loaded
SWGR-DPN (Exist)	4,000	3,011	75
MCC-M1	600	478	80
MCC-M3	600	208	35
SWGR-DPN (Modified with M1 and M3)	4,000	3,697	92

For a level 5 cost estimate for this modification, it is assumed that MCCs M1 and M3 are located approximately 500 feet from SWGR-DPN.

9.2.4 Separate Power Supply and Metering Cost Estimate

A planning level cost estimate for the required modifications for separate power supply to RWTP is shown in Table 9.2. The design and construction cost of the separate power supply is estimated at $5,300,000.

Table 9.2 Separate Power Supply Cost Estimate

Equipment	Quantity	Material/ Labor	Overhead/ Profit	Total
New 21 kV Service Switchgear	1	$1.650M	$280,000	$1.930M
21 kV Conduits (Two 4-inch Conduits)	250 feet(1)	$70,000	$22,000	$92,000
21 kV Conductors (Two sets of 250 kcmil Cables)	250 feet(1)	$65,000	$21,000	$86,000
21 kV Ductbank	450 feet(1)(2)	$200,000	$25,000	$225,000
480 V SWGR-DPN Breakers	2	$140,000	$10,000	$150,000
480 V Cables for MCC-M1 (Two sets of 500 kcmil Cables)	500 feet(3)	$110,000	$10,000	$120,000
480 V Cables for MCC-M3 (Two sets of 500 kcmil Cables)	500 feet(3)	$110,000	$10,000	$120,000
480 V Ductbank (Four 3-inch Conduits)	500 feet(3)	$200,000	$50,000	$250,000
Subs and Miscellaneous	1	-	-	$60,000
Demolition	1	-	-	$50,000
PG&E Service Cost	1	-	-	$100,000(4)
Labor and Material Total(5)	-	-	-	$3.183M
Engineering (20%)	1	-	-	$637,000
Contingency (40%)	1	-	-	$1.528M
Total	-	-	-	$5.3M

Notes:
kcmil - thousands of circular mils.
(1) Assumes 250 feet between the service switchgear and MVS-7A & MVS-7B.
(2) Assumes 100 feet between the service switchgear and each PG&E Vaults.
(3) Assumes 500 feet between MCCs M1 & M3 and SWGR-DPN.
(4) Assumes $100K for PG&E's service costs.
(5) Labor and Materials total includes 40 percent labor escalation.

9.3 Impact of Separate Recycled Water Treatment Plant Power Supply on Wastewater Treatment Plant Energy Costs

This section provides an estimation of the impact of separate power supplies for the WWTP and RWTP on WWTP PG&E energy costs. The estimation is based on WWTP and RWTP energy costs from March 2021 through February 2022. This period was chosen in consultation with District staff since PG&E transitioned from the E-20 rate schedule to the B-20 rate schedule in March 2021.

9.3.1 Wastewater Treatment Plant Pacific Gas & Electric Company Power Cost With Combined versus Separate Metering

Utility power charges include energy usage charges per kilowatt-hour (kWh) of electricity used for each energy time of use period (peak, partial-peak, and off-peak in the summer, and peak, off-peak, and super off-peak in the winter) and power demand charges based on peak 15-minute kilowatt (kW) power demands for each demand time of use period (max peak, max partial-peak, and maximum in the summer, and maximum peak, and maximum in the winter) for the billing period.

Dublin San Ramon Services District (DSRSD) calculates the electricity usage charge for the RWTP by adding the metered usage for DPN, MMC-M1 and MCC-M3 for each PG&E energy time of use period, and calculates the demand charges for the RWTP by adding the power demand of DPN, MMC-M1 and MCC-M3 in 15-minute increments, and determining the peak 15-minute demand for each PG&E demand time of use period for the month.

DSRSD provided monthly data for March 2021 through February 2022 for the kWh of electricity and kW of peak demand for the WWTP and RWTP for each time of use period. The peak demand data included peak demands at the time of the PG&E peak demands, peak demands at the time of the RWTP peak demands and peak demands at the time of the WWTP peak demands, since the peaks typically did not occur at the same time. This data was used in conjunction with the PG&E rate per kWh and kW for each month and season to calculate a total PG&E electricity and demand cost for each month. The RWTP monthly electricity and demand cost was then subtracted from the total PG&E cost to calculate the WWTP PG&E for each month for the current combined PG&E service. These costs are summarized in Table 9.3.

The table also summarizes the estimated monthly energy and demand charges for the WWTP if the RWTP had a separate PG&E power supply. The energy use for this scenario was calculated by subtracting the RWTP energy use for each time of use period from the total PG&E energy use for each period. It was assumed that any cogeneration energy produced in excess of WWTP demand was credited to DSRSD at PG&E rates. The peak demands for this scenario were calculated by subtracting the demand met by the cogeneration facilities at the time of the WWTP maximum demand (rather than at the time of the peak WWTP + RWTP demand) for each demand time of use period from the WWTP peak demand at the time of the WWTP maximum demand for each demand time of use period.

Table 9.3 Estimated WWTP PG&E Usage and Demand Charges

Month	PG&E Season	Calculated Total PG&E Usage and Demand Charges (WWTP + RWTP)	RWTP Usage and Demand Charges Calculated by DSRSD	DSRSD PG&E Cost With Current Combined PG&E Service (Total PG&E - RWTP)	DSRSD WWTP PG&E Cost With Separate DERWA PG&E Service
March-21	Winter	$42,232	$33,318	$8,914	$16,318
April-21	Winter	$74,779	$63,649	$11,129	$9,083
May-21	Winter	$89,256	$87,581	$1,675	-$236
June-21	Summer	$144,605	$144,994	-$389	$32,080
July-21	Summer	$148,384	$157,784	-$9,399	$9,630
August-21	Summer	$160,947	$152,729	$8,218	$32,860
September-21	Summer	$135,074	$133,046	$2,028	$14,708
October-21	Winter	$101,109	$68,370	$32,739	$44,751
November-21	Winter	$0	$37,140	-$37,140	$11,988
December-21	Winter	$57,813	$30,066	$27,747	$13,558
January-22	Winter	$37,103	$31,256	$5,846	$7,033
February-22	Winter	$49,986	$47,316	$2,670	$7,586
	Total	**$1,041,289**	**$987,250**	**$54,039**	**$198,461**

Notes:
DERWA - Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority.

9.3.2 Conclusions

The results indicate that the annual WWTP PG&E energy and demand cost would be approximately four times higher if the RWTP had a separate PG&E power supply compared to the existing combined service, with the cost increasing for the March 2021 through February 2022 period from approximately $54,000 to $207,000. The difference would be even larger if it was not assumed that cogeneration energy produced in excess of WWTP demand was credited to DSRSD at PG&E rates.

The combined service reduces the WWTP PG&E costs compared to separate services primarily because (1) peak WWTP and RWTP demands do not usually occur at the same time, thereby reducing the monthly demand charges compared to separate services, and (2) DSRSD charges DERWA based on the RWTP peak demands at the time of the DERWA peak demands rather than at the time of the PG&E peak demands.

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Technical Memorandum 10 BACKUP POWER SYSTEM OPTIMIZATION EVALUATION/ ASSESSMENT

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Abbreviations

ATC	automatic transfer controller
CIP	capital improvement program
DERWA	Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority
DSLC	digital synchronizer and load control
DSRSD	Dublin San Ramon Services District
kV	kilovolt
kW	kilowatt
MSLC	master synchronizer and load controller
OOS	out of service
PG&E	Pacific Gas & Electric Company
PLC	programmable logic controller
PSR1	Pump Station R1
PV	photovoltaic
RTS	return to service
SCADA	supervisory control and data acquisition
SFUV	sand filtration ultraviolet
TM	technical memorandum
V	volt
WWTP	wastewater treatment plant

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Technical Memorandum 10

BACKUP POWER SYSTEM OPTIMIZATION EVALUATION/ASSESSMENT

10.1 Introduction

This technical memorandum (TM) reviews the current state of the generator systems at the Dublin San Ramon Services District's (DSRSD) wastewater treatment plant (WWTP) and evaluates methods to improve WWTP operations when Pacific Gas & Electric Company (PG&E) power is unavailable. Refer Appendix 10A for explanation of concepts and terms used in this TM.

10.2 Background

The DSRSD WWTP presently has two types of engine-driven generators. Three generators use gaseous-fuel spark-ignited engines which operate in cogeneration, or combined heat and power where the waste heat is recovered for use in digesters and other WWTP facilities, herein referred to as "Cogen." These generators operate continuously to produce the required heat and reduce energy purchased from PG&E. The other two generators have diesel engines and operate only as standby power to enable WWTP operation while PG&E power is unavailable. The diesel generator sets each power separate WWTP areas. There are also provisions to connect temporary generators in several locations.

Table 10.1 Engine Generators

Generator	Rated Capacity	Actual Capacity	Fuel	Manufacturer	Model	Date
G1	500 kW	450 kW	Digester gas/ natural gas blend	Waukesha	F3521GSID	1982
G2	500 kW	400 kW	Digester gas	Waukesha	F3521GLD	1995
G3	500 kW	500 kW	Natural gas	Waukesha	F2895GSI	2008
G4	1250 kW	1250 kW	Diesel	Cummins	KTA50-G9	2004
G5	750 kW	750 kW	Diesel	Cummins	KTA2300G	1979

Notes:
kW – kilowatt.

There are two 20.8 kilovolt (kV) (approximated to 21 kV for the purpose of this TM) PG&E power service supplies available at the plant via two separate underground service feed vaults located at the south and north sides of the plant. The two 20.8kV PG&E power supplies terminate at a single underground, supervisory control and data acquisition (SCADA) controlled, 3-way PG&E transfer switch before entering the plant's service switchgear MVS-S, which feeds plant's 21 kV main switchgear. Normal source is through the north service vault from PG&E's San Ramon circuit 2103 and alternate source is through the south service vault from PG&E's Vineyard circuit 2108. Power is distributed within the WWTP at 21 kV and stepped down to 480 volts (V) for

utilization as shown in Figure 10.1. PG&E revenue metering is on the utility side of circuit breaker 52-S. While both breakers 52-M and 52-S can isolate power to the entire WWTP, it appears that the primary intent of 52-S is to isolate the WWTP in the event of a fault within the WWTP while 52-M is used to separate the WWTP from PG&E in the event of a PG&E power outage to prevent Cogen from energizing the PG&E system in accordance with Rule 21 requirements from PG&E and the state of California. Rule 21 contains requirements to improve the safety of utility workers by ensuring that utility power lines are not energized by others when the electrical utility experiences a power outage. Details of the rule are described in Appendix 10A.

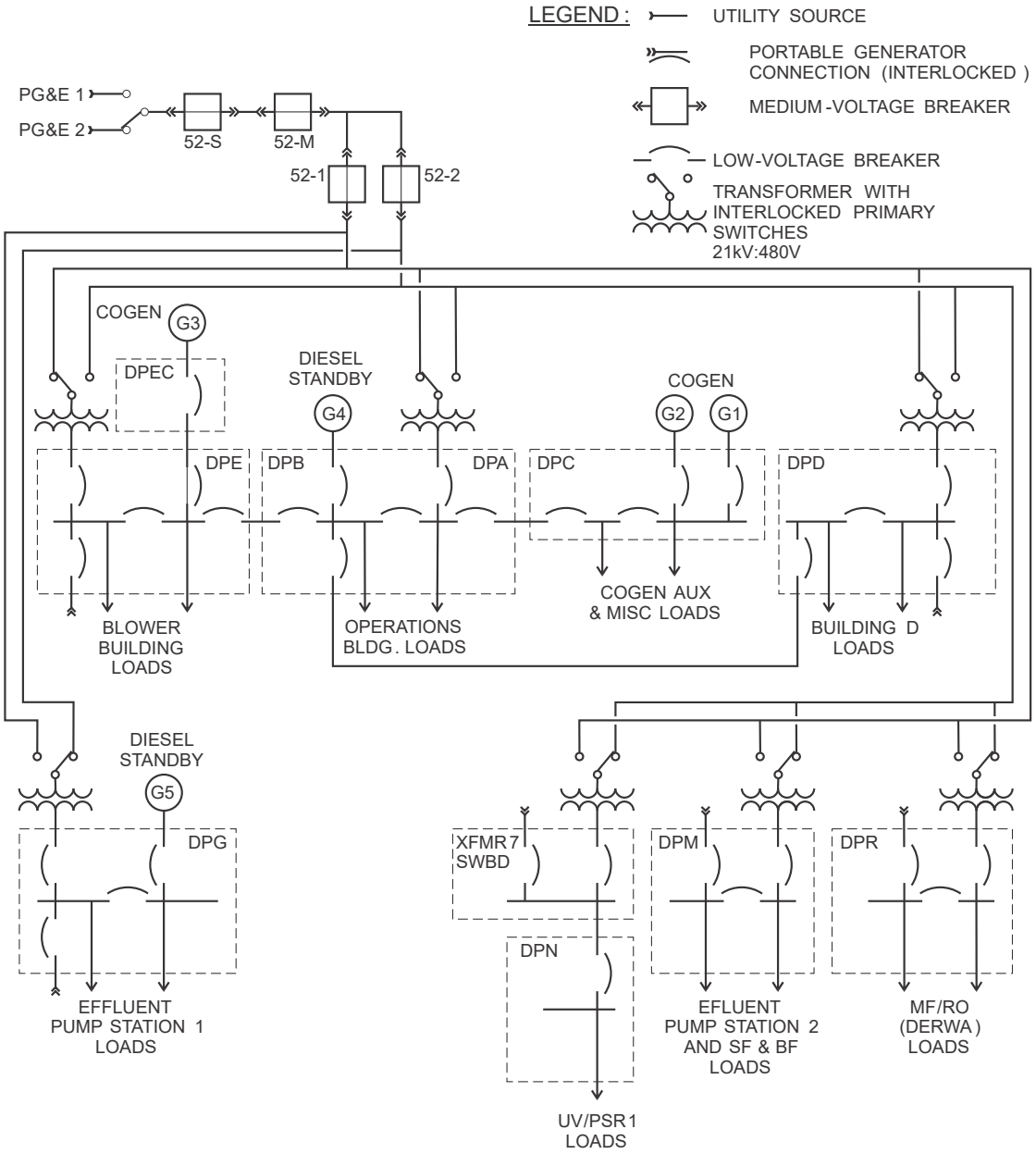

Figure 10.1 Simplified DSRSD WWTP One-Line Diagram

Eaton IQ Transfer model ATC-900 automatic transfer controllers (ATC) call for standby generators to run on loss of the PG&E source, transfer certain loads to standby generator power,

and perform closed-transition return to PG&E using passive synchronization once utility power has been restored.

Under normal operating conditions, both diesel generators are offline and the desired Cogen units are operating at their pre-determined maximum output as shown in Figure 10.2. When total WWTP load is more than Cogen output, the additional power is provided by PG&E. When Cogen output exceeds WWTP load, the surplus is exported to PG&E.

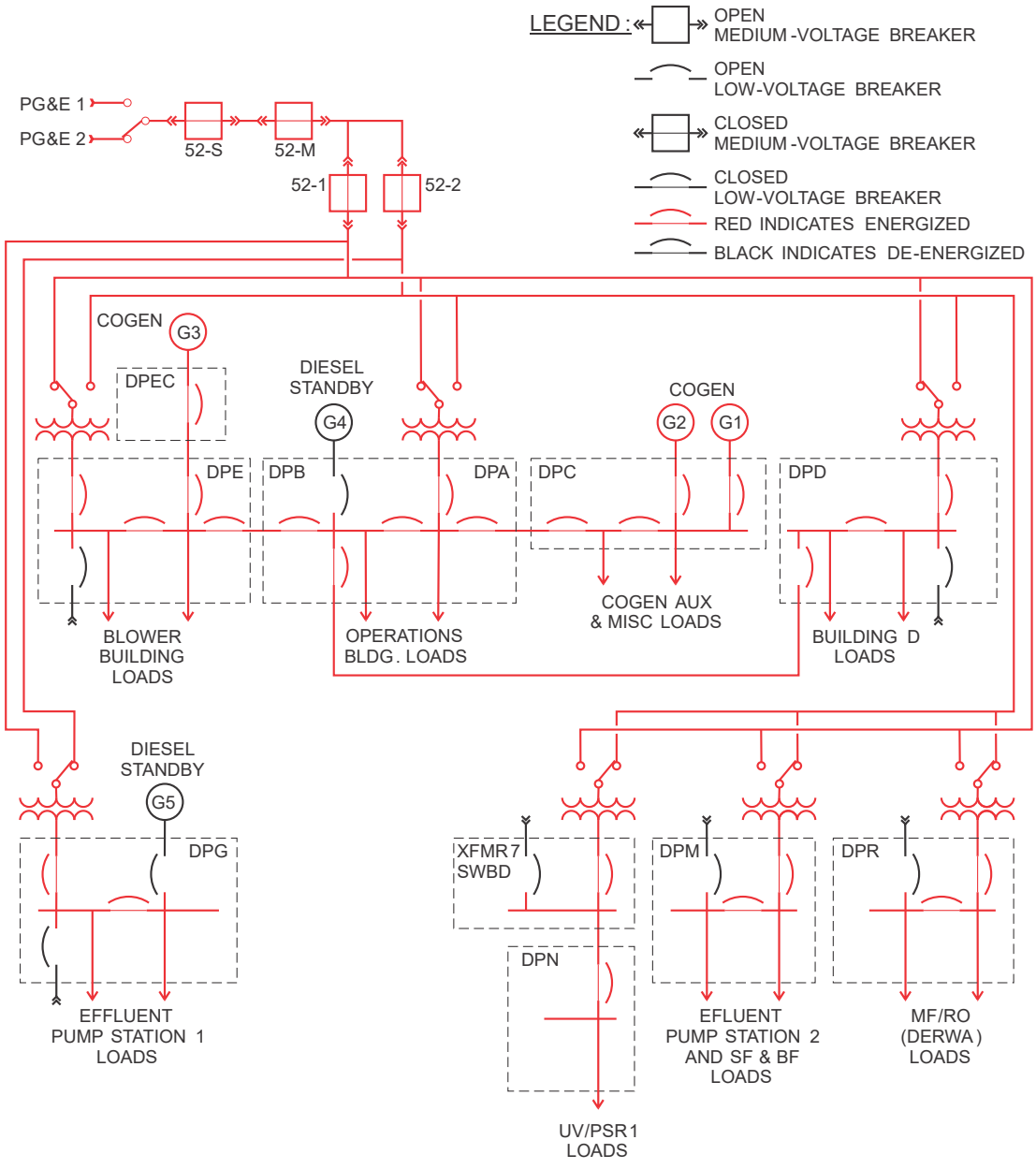

Figure 10.2 Simplified One-Line: Normal Configuration With PG&E Available

10.2.1 Generation Systems

10.2.1.1 Cogeneration

The existing cogeneration system consists of three Waukesha spark-ignited gaseous fuel engine driven generators. Each operates on different fuel based on its capabilities and historical operating experience. Details on each engine are described above in Table 10.1.

Operating both G1 and G2 enables the digester gas to be fully utilized. All three Cogen units produce heat for digesters and other heating needs and the generators are manually operated based on power and heat demands.

10.2.1.2 Diesel Generator Systems

Two diesel standby generators are presently installed. Details of these are shown in Table 10.1.

Diesel standby generator G4 is a 1,250 kW Cummins generator. Its Cummins PowerCommand® PCC3100 controller was recently replaced with a DynaGen TG410 engine controller with Basler SR Retrofit model voltage regulator similar to that on G5, both of which include isochronous governor control and a voltage regulator for constant voltage control. They do not appear to have any provisions to actively synchronize, nor do they appear to have any droop function or other real or reactive load sharing capabilities for parallel operation with other generators when islanded from PG&E. It backs up DPA/DPB (Operations Building), DPD (Building D) and DPE (Blower Building). Its recent maintenance history consists of:

- 5/9/22 out of service (OOS) for water leak and controller replacement return to service (RTS) 5/22/22.

Diesel standby generator G5 is a 750 kW Cummins generator. It has recently had its engine controller replaced with a DynaGen TG410 engine controller with Basler SR Retrofit model voltage regulator. The DynaGen controller does not appear to have any droop function or other real or reactive load sharing capabilities for parallel with other generators when islanded from PG&E. It backs up DPG (Effluent Pump Station No. 1). This generator is extremely underloaded when these effluent pumps are not in use. Operating with insufficient load can result in wet stacking due to insufficient manifold and exhaust temperature which allows steam in the exhaust to condense on internal surfaces, and can result in corrosion and premature failure of the engine.

- 4/9/2020 OOS for alternator rebuild and oil leak repair RTS 7/27/2020.
- 6/30/2022 OOS controller failure RTS 9/25/2022.
- 9/8/2022 replace governor RTS 9/25/2022.

Portable generator connections available for DPM (Effluent Pump Station No. 2), DPN (sand filtration ultraviolet [SFUV] disinfection/Pump Station R1 [PSR1]), and DPR (microfiltration/reverse osmosis – Dublin San Ramon Services District – East Bay Municipal Utilities District Recycled Water Authority [DERWA]) as shown in Figure 10.1. There is also a portable generator connection provision at DPG to use if generator G5 is not available. These connections use key-interlocked breakers to ensure that the portable generators do not operate in parallel with PG&E or other WWTP generation. Each of these buses is de-energized during a PG&E outage unless a portable generator is connected. Portable generator connections at DPD and DPE allow those to be powered by portable generators if G4 is unavailable or additional capacity is needed.

10.2.2 Transfer Controls

Reliable operation of the WWTP requires electrical power to be always available. Provisions are in place to transfer key WWTP areas to local diesel generator power on loss of the PG&E source. These include automatic transfer controllers that switch to diesel generator power, and more complex controls that were added in 2012 but not fully implemented which allow the Cogen system to continue to power the WWTP during PG&E outages to avoid any interruption in WWTP operation.

10.2.2.1 Transfer Scheme – As Presently Implemented

The primary source for standby power consists of two diesel engine-generator units and provisions for temporary connections. When PG&E power is lost, the entire WWTP becomes deenergized. Breaker 52-M is tripped and locked out by the Rule 21 interconnection relays. Cogeneration units trip offline although it may be possible for them to continue to run, idling with no load. The loss of voltage on the WWTP system is sensed by an ATC at switchgear DPA/DPB, which sends a command to start generator G4. At the same time, an ATC at switchgear DPG senses the loss and commands G5 to start. Figure 10.3 shows the configuration at this point.

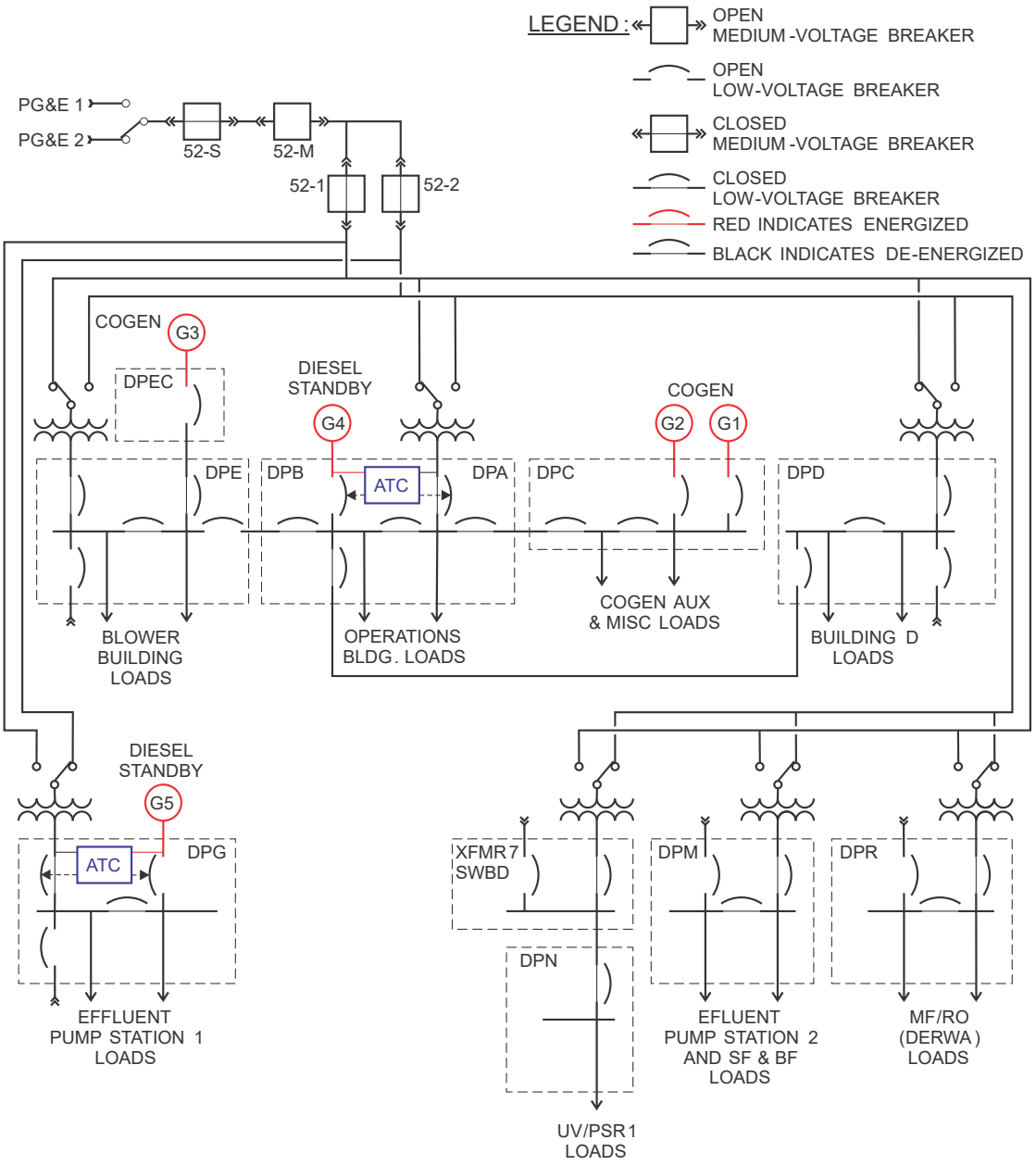

Figure 10.3 Simplified One-Line: Loss of PG&E – Standby Diesel Generators Start

Once each of these generators is running at rated voltage and frequency, each ATC trips the local main breaker and closes the generator breaker, providing generator power to DPA/DPB, DPC, and DPG, as shown on Figure 10.4.

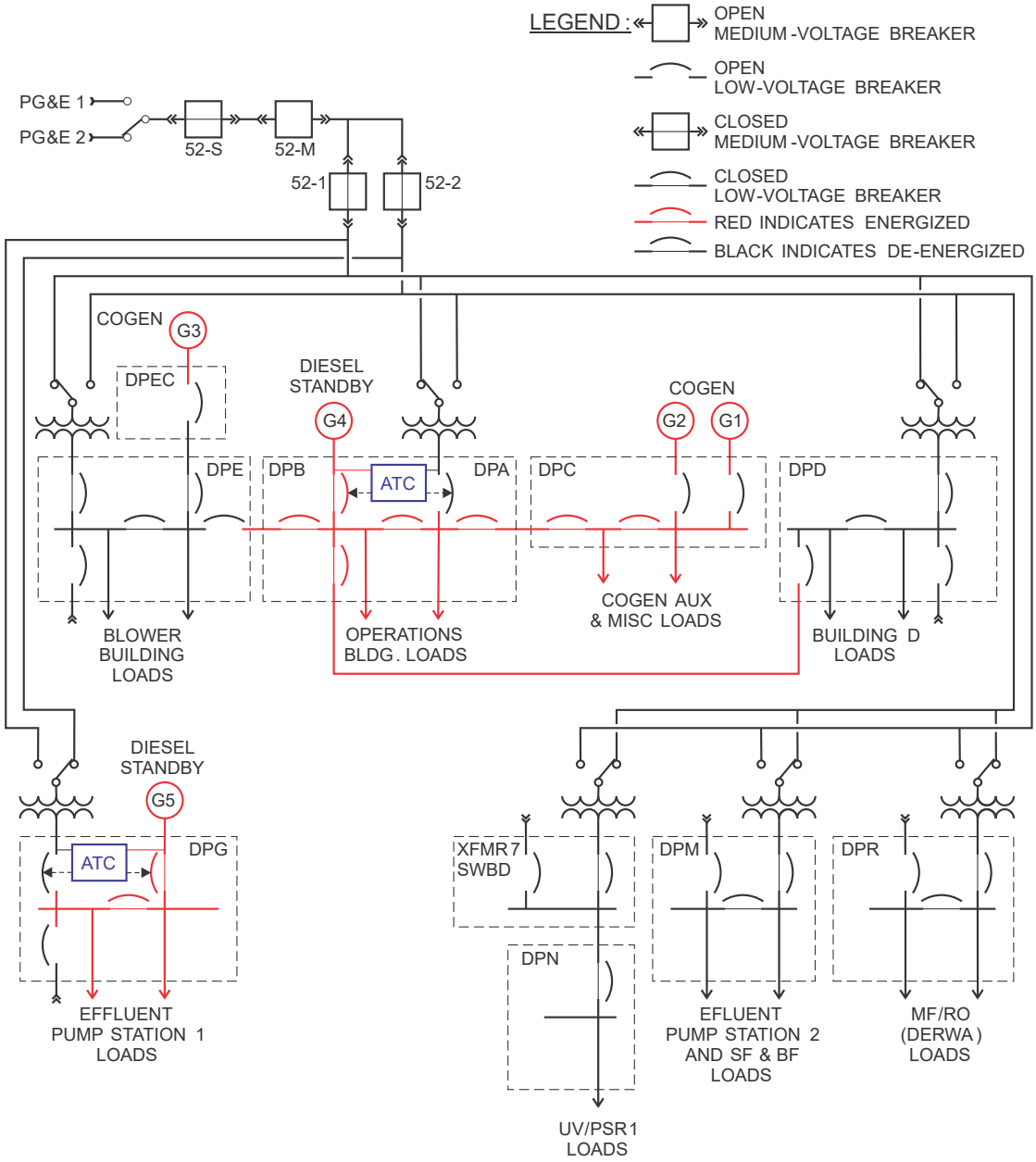

Figure 10.4 Simplified One-Line: Loss of PG&E – Initial Energization

Once DPB is energized from generator G4, power is sensed at DPD and DPE by their ATC units, which then connect by opening their respective main breakers and closing the emergency tie breakers, as shown in Figure 10.5.

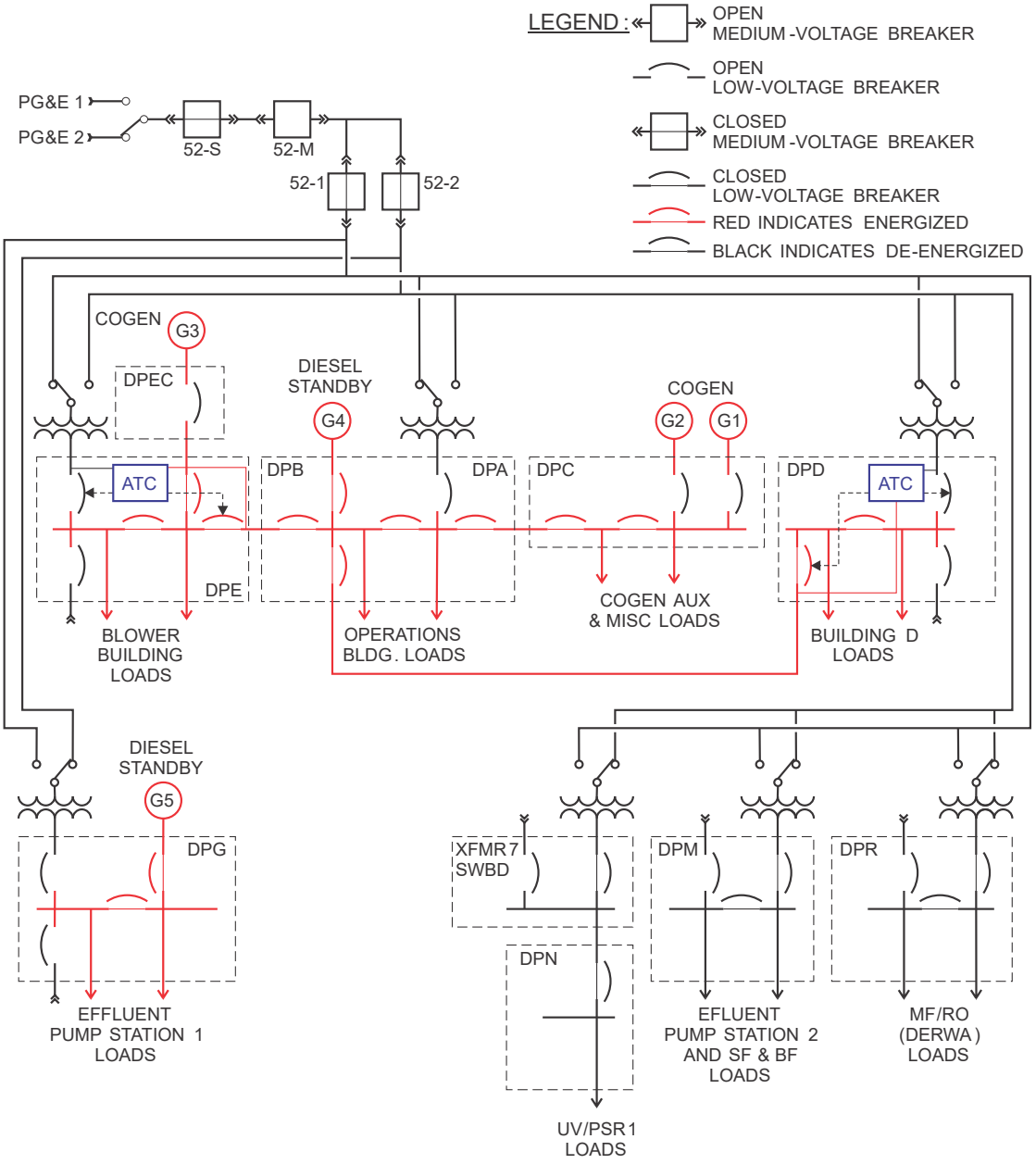

Figure 10.5 Simplified One-Line: Loss of PG&E – Energization of DPD and DPE

This restores power to all process areas except DPR (DERWA), DPM (Effluent Pump Station 2) and DPN (SFUV/PSR1). If those areas are required to operate during an extended outage, portable generators must be connected.

On restoration of PG&E power, an operator manually resets the lockout relay at WWTP main breaker 52-M and closes that breaker. Then, each ATC will sense normal voltage on its main circuit breaker and will perform a passive closed transition return by closing the main breaker (when synchronization criteria are met) and immediately opening the generator breaker (DPB and DPG) or emergency tie breaker (DPD and DPE).

Advantages of this system:

- **Simplicity:** It uses standby diesel generators for their intended purpose without complicated paralleling controls.
- **Reliability:** Diesel generators are very robust, and can handle sudden changes is load.
- **Cost:** This system is already in place – no new work is required.

Disadvantages of this system:

- Generator G4 does not have sufficient capacity to carry full load on all connected buses under all WWTP operating scenarios:
  - During high flows, there may not be sufficient generator capacity to run a third or fourth influent pump.
  - There may not be sufficient generator capacity to run two blowers, and one blower may not provide sufficient aeration under certain conditions.
- Generator G4 has limited reactive power capability for starting motors – it may not be able to start large motors even if it has sufficient capacity to run them:
  - Two of the blowers are on soft starters, which results in reactive inrush current. Generator G4 is apparently able to start these blowers, but it's likely to experience a significant transient voltage dip by doing so.
  - The third blower is on an across the line starter, which has significantly more reactive inrush current. It's likely that G4 will be unable to start this blower, and the resulting voltage dip is likely to impact other operating loads, possibly causing them to trip offline.
- The WWTP will experience a brief loss of power at the beginning of a PG&E outage, requiring restarting of many WWTP processes.

There are procedures in place for adding a Cogen unit in parallel to the G4 to allow additional loads to be started. The Cogen unit would operate at a set point power (typically its maximum output) and power factor or reactive power. This adds additional real power capability to allow more loads to run. It will also improve motor starting capability due to motor inrush current. When adding a Cogen unit it's imperative that the initial load set point power is significantly less than the load on generator G4, and that load on the G4 is regularly monitored. If total load on the system ever drops below the Cogen output, the excess Cogen power will cause the generator on G4 to operate as motor, which will trip it offline shutting down most of the WWTP and could cause damage.

10.2.2.2 Transfer Scheme – 2012 Upgrades

The upgrade project added components to theoretically allow the plant to ride through a utility power outage without any interruption using the Cogen system. On loss of PG&E, breaker 52-M trips isolating the WWTP from PG&E. Cogen engine generators continue to operate and pick up most of the WWTP load. The intended configuration immediately after PG&E power is lost is shown in Figure 10.6. It was planned to have provisions for G5 to power bus DPG and for G4 to supplement Cogen power, but it does not appear that those capabilities were implemented. The entire control strategy would need to be carefully evaluated, and the issues listed previously would need to be evaluated and addressed.

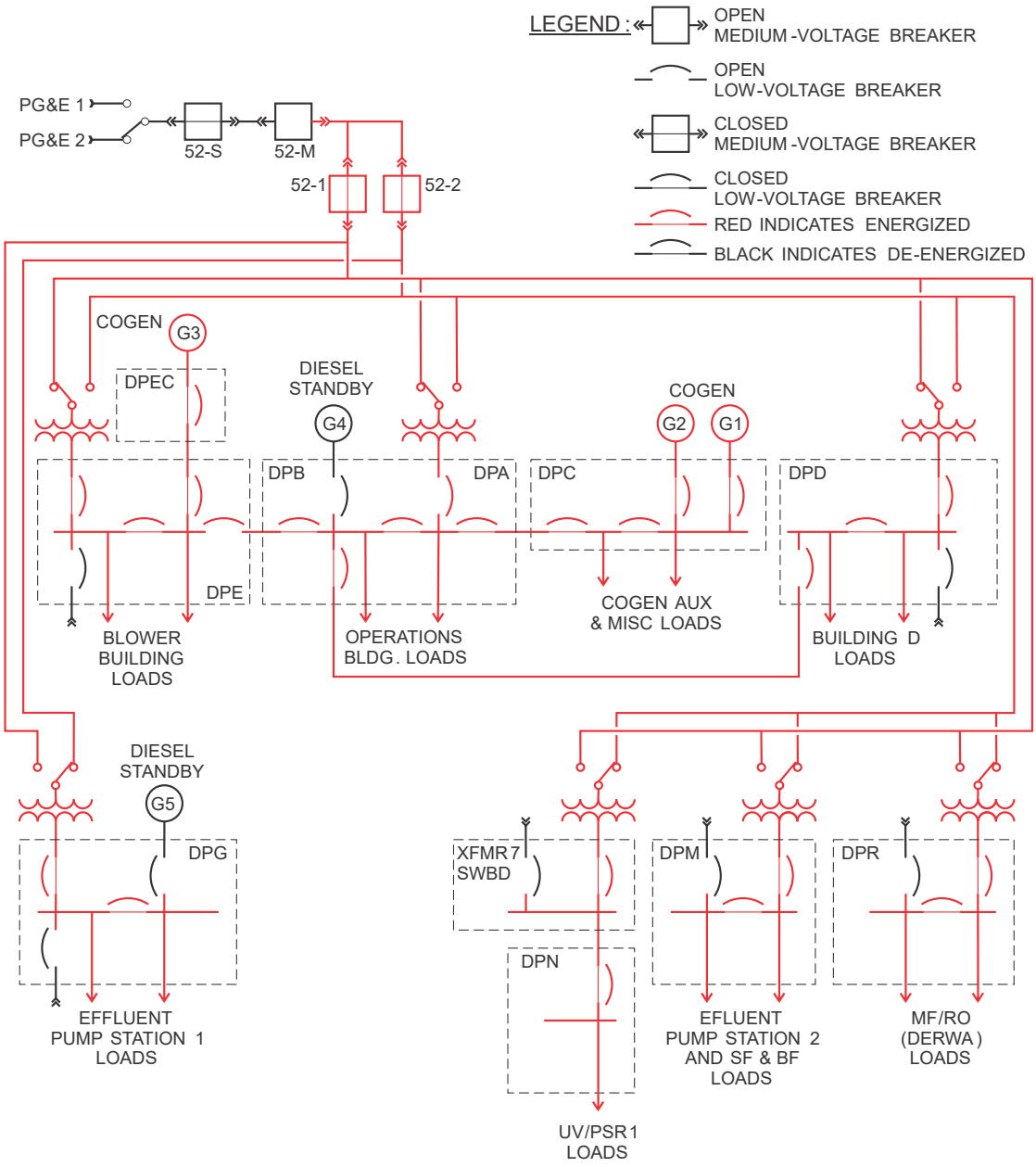

Figure 10.6 Simplified One-Line: Loss of PG&E – Ride-Through with Cogen

The new components include Woodward Digital Synchronizer and Load Control (DSLC)-2 controllers at each Cogen unit and a Woodward Master Synchronizer and Load Controller (MSLC), which are all networked together. The DSLC-2 units are DSLCs, which adjust engine and generator output to synchronize them to the bus and regulate load, including load sharing between Cogen units when islanded from PG&E, by sending speed bias signals to the Woodward 723 Plus governor and engine controller and voltage bias signals to the Basler DECS-200 voltage regulator at each Cogen unit. Whether operating in parallel with PG&E or as an isochronous system, these bias signals work with the droop curves in the governor and voltage regulator to make changes in real power and reactive power produced by each Cogen unit. The MSLC monitors PG&E power on the utility side of breaker 52-M and WWTP conditions on the WWTP side of 52-M when the WWTP is ready to be re-connected to PG&E, and instructs each DSLC-2 as required to synchronize the Cogen system to PG&E for a bumpless return to utility power.

These modifications were intended to provide several capabilities, but these were not fully tested and implemented. They include:

- **Import/Export Control:** A set point import or export power can be entered, and load on Cogen engines will be automatically adjusted to maintain the desired import from PG&E or export to PG&E.
- Bumpless transfer from PG&E to onsite generators on a PG&E outage.
- **Operation of Standby Diesel G4:** Diesel unit G4 automatically starts and synchronizes with the bus at switchgear DPB once the WWTP is isolated due to a PG&E outage. Once connected, it operates in parallel with Cogen units. Generator G4 maintains system conditions while Cogen units operate at fixed set points.
- **Operation of Standby Diesel G5:** Diesel unit G5 automatically starts and takes on switchgear DPG loads through a closed-transition transfer from Cogen. On restoration of PG&E, DPG automatically transfers back to the 21 kV system through another closed-transition transfer.
- **Bumpless transfer to PG&E:** On restoration of PG&E power, or when retransfer is selected and PG&E is available, the MSLC synchronizes Cogen with PG&E and closes 52-M and returns to normal operation (base load or import/export set point).

10.2.2.3 Upgraded Control System Issues

The details of the intended operation of the 2012 upgrades are described in the Cogeneration Improvements and Electrical Service Relocation Projects Revised Standard Operating Procedure in Appendix 10B. These details are in many cases inconsistent with the implemented system and its capabilities, and with capabilities of the Cogen system and diesel transfer controls. Among the apparent issues are:

- No work was included for standby generators G4 and G5. As a result, they would see continued presence of voltage from Cogen as an indication that PG&E power was available and would not transfer unless Cogen failed to take on WWTP load.
- The closed-transition transfer controls for diesel generator G4 prevents the generator G4 breaker from remaining closed when the DPA main breaker is closed. This ensures that paralleling of G4 and PG&E is very short in duration, which allows such operation without including G4 in the interconnection agreement that allows the Cogen units to operate in parallel with PG&E and without meeting many of the Rule 21 requirements for extended parallel operation. For G4 to parallel with the Cogen units when they are

energizing the 21 kV system through the main breaker in DPA, this control would need to be revised to allow both breakers to remain closed for an extended time. This would require additional complex interlocks between the main 21 kV switchgear, Cogen system controls, and the G4 breaker controls to prevent the possibility of extended parallel operation of G4 and PG&E while maintaining the ability for the closed-transition transfer from the G4 back to PG&E if Cogen fails to operate throughout the PG&E outage. These changes could also require a new interconnection application with PG&E incorporating G4 and the updated controls, and possible additional Rule 21 relaying at DPB.

- Status indicating that G4 is connected, and monitoring of its load, do not appear to have been included. These are needed to determine whether Cogen units should be operated to maintain system conditions (isochronous and constant voltage with real and reactive sharing) or at a fixed set point (to allow G4 to control the system) and how much load Cogen can provide while still allowing G4 to have enough load to provide stable control of the power system.
- Load shedding or addition may be required to maintain stable operation, which was not provided with the upgraded Cogen controls. Operating load may be greater than Cogen capacity, and gas-fired engines can become unstable with significant changes in load, whether increase or decrease, which would occur when there is an appreciable net import or export of power prior to the utility outage. Any of these situations would likely result in Cogen tripping offline.
- The existing Cogen units have a very limited range of load that they can effectively support, so operating at lower loads to maintain the import/export set point may result in instability or their emissions being out of compliance with air permits.
- Back-feeding the 21 kV system when 52-M is open creates an ungrounded 21 kV system because the transformers have delta windings on the 21 kV primary and the ground bank installed with the Cogen upgrade project is on the PG&E side of 52-S (and therefore the PG&E side of 52-M and not connected to the WWTP during a PG&E outage). A ground fault on one phase of the 21 kV system would not result in any appreciable fault current when the system ungrounded, so no overcurrent device will detect it, but it will result in phase-to-ground overvoltage on the two ungrounded phases. Phase to ground voltage is nominally 12 kV, while a single phase to ground fault with the system otherwise ungrounded will result in a phase to ground voltage of 20.8 kV on the other two phases. Some of the equipment may be capable of sustaining this voltage, but this will exceed the maximum continuous operating voltage of the surge protectors, which is likely to cause them to fail. While a ground fault during a PG&E outage is unlikely, the potential for serious damage is real and provisions should be included to protect the equipment from this situation.
- The specified operating sequence states that breakers 52-1 and 52-2 would be tripped so that only those parts of the system connected to the circuit fed from 52-1 would be energized, and the intent appears to have been that all loads except DERWA would be on that circuit. Breakers 52-1 and 52-2 could be manually closed to power all facilities provided that there was sufficient generator capacity. The as-built drawings do not appear to include any control for breakers 52-1 or 52-2, and relaying shown on original drawings do not show any functions that would trip on a utility power loss. The present connection for DPG does not match this intent from the previous design.

10.3 Options to Enhance Generator Operations at DSRSD

Five options are shown to improve the resiliency of the power system during PG&E outages. Options 1, 4, and 5 offer different degrees of modification to the overall control system, so only one of these can be implemented. The other three are independent enhancements that can be implemented individually.

Table 10.2 Summary of Options

No.	Option	Recommendation	Relative Cost	Notes
1	Facilitate adding base-loaded Cogen units	Consider	$1,370,000(1)	Primary benefit is ability to start and run more loads during PG&E outage. If Cogen replacement is expected in 5 years or less, delay implementation and incorporate desired functionality into that project.
2	Automate return on restoration of PG&E power	Implement	$53,000	Most of the changes could be utilized even after Cogen units are replaced.
3	Add load bank to DPG	Implement	$100,000	Improves maintenance and life expectancy of generator G5.
4	Implement existing upgraded master Cogen control plus load shedding - without diesel	Do not implement	*(2)	Cogen is not sufficiently resilient to be used as a primary standby power supply without complex load management. If the potential to ride through PG&E outages justifies the effort and risks, consider incorporating when Cogen is replaced.
5	Implement existing upgraded master Cogen control with diesel	Do not implement	*(2)	Same notes as Option 4 plus more complex controls and difficult to tune operation of diesels and Cogen for stable parallel operation.

Notes:
(1) Note that even if this is pursued, it may be difficult to find a contractor capable of making it successful, and the work is not likely to be compatible with any Cogen replacement project.
(2) Option was determined to be not feasible due to complexities, suitability of existing engines, and near-term plans to replace them, so no cost estimate was prepared.

10.3.1 Facilitate Adding Base-Loaded Cogen Units

This option would entail modifying the controls to improve performance of a Cogen unit when operating in parallel with diesel G4 to allow more loads to run, facilitate starting of large blower motors, and provide heat for digesters. The Cogen unit could be selected and connected manually or automatically based on plant loading, and multiple Cogen units could be added if

needed. Provisions could be included to prevent starting of large loads unless adequate Cogen units are online.

The existing Cogen synchronizing and load control systems could be utilized, but parameters in the engine controllers, voltage regulators, and DSLC-2 load controllers should be evaluated and tuned to optimize performance when operating in parallel with G4. Proper tuning of droop in the Cogen engine controllers and voltage regulators and of real and reactive power control loops in the DSLC-2 units should minimize the risk of instability.

Provisions would be required to ensure that G4 always has adequate load. The real and reactive load on G4 should be constantly monitored, similar to how the Cogen master controls monitor net load into or out of the WWTP. When load on G4 drops below a predetermined set point, automatic responses can include reducing the power set point for Cogen, taking Cogen units offline, or incorporating an automatic load bank configured to keep G4 above a pre-determined minimum load. Modifications to process controls should also be implemented to coordinate loads with generation during normal operation. Failure to manage loads could result in Cogen units producing more power than is consumed by the connected loads, which would cause G4 to operate as a motor, which could cause damage to the engine and would likely result in G4 tripping offline, which in turn would likely cause Cogen to trip, de-energizing most of the WWTP.

Even with the system being expertly tuned it is possible that the load control of Cogen and speed control of G4 could create an instability. Also, with G4 being considerably weaker than the PG&E grid, voltage and frequency will change more as WWTP loads fluctuate than they would when connected to PG&E. Protective relaying at Cogen should be coordinated with G4 protection to trip Cogen units offline before G4 trips. This is likely to require broader trip settings than would be used for strict utility parallel operation. Rule 21 protection is handled by relaying at main breaker 52-M, so expanding the settings at the individual Cogen breakers will not compromise the PG&E interconnection requirements.

The existing standard operating procedure calls for the Cogen unit to be manually taken offline before re-connecting to PG&E. This may not be necessary as the Cogen would simply change from operating in parallel with G4 to operating in parallel with PG&E. To allow bumpless return to PG&E with Cogen operating, the timing parameters in the Eaton IQ Transfer units should be adjusted so that the one in DPA/DPB transfers before those at DPD and DPE to ensure that load on Cogen units stays constant until G4 is disconnected. If the existing procedure to remove Cogen before returning to PG&E is retained, loads must be within the capabilities of G4 prior to taking the Cogen unit offline, so the logic would be added to reduce or shut off loads as required to accomplish this.

Advantages of this option:

- Ability to operate more loads during a PG&E outage.
- Ability to start blowers more easily, and possibly to start the across-the-line blower.
- Production of heat from Cogen during PG&E outage.

Disadvantages of this option:

- Requires evaluation of Cogen load control tuning parameters.
- Even with proper tuning, there may be control loop stability issues due to Cogen load control and G4 speed control both impacting and responding to system frequency.

10.3.2 Automate Return on Restoration of Pacific Gas & Electric Company Power

As presently configured, a loss of PG&E power results in isolating the plant by tripping the lockout relay (also known as the "86 relay") at breaker 52-M. This requires an operator to manually reset the lockout before the plant can return to PG&E power. An 86 relay is often incorporated into breaker controls to ensure that personnel are aware that a fault has occurred so that the cause can be investigated before allowing the breaker to be re-closed. Trips due to phase or ground overcurrent, differential current, and arc flash detection are indicative of a failure within the WWTP, and the condition is cleared as soon as the breaker trips, and therefore it is logical for those to trip the 86 relay. Interconnection trip functions, which are based on primarily on voltage and frequency, do not indicate any internal failures, and the relay will continue to sense these conditions even after the breaker trips to prevent re-closing until the conditions return to normal, so tripping the lockout on these functions is not required. Limiting lockout trips to actual fault conditions also ensures that power system operators are aware that a fault has occurred, and won't simply reset the relay and close 52-M into a fault assuming that the trip was due to a PG&E outage.

Revising the relay configuration and breaker control wiring so that these functions trip the breaker and inhibit re-closing rather than locking out would enable the WWTP to automatically return to PG&E power once it has returned to normal. Or, if operator intervention is desired, to allow this to be done remotely such as from a SCADA workstation.

Depending on how the main transfer system is operated, the procedures for restoring the plant to PG&E power could be handled in several ways:

- If the existing system is retained, base-loaded Cogen units are allowed to be added, or any other situation where the 21 kV system is de-energized during standby operation, 52-M can be reclosed as soon as PG&E power returns (after a brief proving delay), re-energizing the 21 kV system. The existing IQ Transfer ATCs would then sense this and restore PG&E power as they do now.
- If the system is configured to allow Cogen to back-feed the 21 kV system, then the DSLC would be used to synchronize the Cogen units to PG&E once its power returns to normal.

If automatic return is implemented, a Normal After Close contact from the 52-M breaker control switch, or addition of an AUTO/MANUAL mode switch should be incorporated into the breaker controls to prevent automatic closure when breaker has been manually tripped for other reasons.

Advantages of this option:

- Ability to automatically return to PG&E after outage or streamline a manually initiated return.
- Separation of interconnection trip functions (indicating PG&E outage) from fault trips so that that when the lockout relay trips, operators will know that a fault has occurred and needs to be investigated before resetting.

Disadvantages of this option:

- Cost to modify relay configuration and breaker control wiring.

10.3.3 Add Load Bank to DPG

Generator G5 is sized based on pumping requirements at Effluent Pump Station No. 1. When those pumps are not in use, the capacity of G5 far exceeds the demand, which could impact its maintenance requirements and service life. Adding an automatic load bank to DPG would allow sufficient load on G5 whenever it's running, whether due to a PG&E outage or routine exercising of the generator.

To accomplish this, a 400 kW automatic load bank would be installed outdoors near DPG. A current transformer on one lead from generator G5 would be connected to the controller in the load bank to control how many load elements are connected. When G5 is off, no elements would be connected. When G5 is producing power, sufficient elements would be added to maintain a minimum preset load on G5.

Advantages of this option:

- Prolong life of G5 and reduce maintenance and potential repair costs.
- Enable generator G5 exercising under load when insufficient pump loads are available on DPG.

Disadvantages of this option:

- Cost to add load bank.

10.3.4 Implement Existing Upgraded Master Cogen Control Plus Load Shedding – Without Diesel

When protective relaying at 52-M detects a PG&E outage, that breaker will trip to isolate the plant, just as it does with the present procedures. Breakers 52-1 and 52-2 would not be tripped so that the entire facility would remain energized from Cogen. The existing Cogen unit trips would be eliminated by programming changes and adjustments to protective relay settings, allowing them to remain online powering the entire WWTP, and leaving the facility configured as shown in Figure 10.6. As soon as 52-M opens, the Cogen operating mode would switch from base load with power factor control to isochronous with voltage control.

Energizing the 21 kV system from Cogen would create an ungrounded condition, so means should be added to isolate the 21 kV system from a ground fault. The existing 21 kV ground fault sensing relies on the upstream ground bank ahead of 52-S and the PG&E system grounds even further upstream, all of which will be isolated from the plant. To protect the system, protection from ground faults on the 21 kV system with the WWTP should trip and lock out the breakers that can connect the generators to the 21 kV, which are the main breakers in DPA, DPD, and DPE. It may be possible to incorporate this protection into the SEL 351-7 relays at 52-M (using the potential transformers on the WWTP bus), provided that breaker 52-1 is kept closed during a PG&E outage, or by adding grounded-wye to broken delta potential transformers with a load resistor and ground overvoltage (American National Standards Institute function 59G) relay to the existing potential transformers at the WWTP side of breaker 52-1. For either of these, a new lockout relay would be added at the main switchgear, with trip contacts wired to the three low-voltage breakers.

The Cogen controls must determine whether Cogen is to be base loaded or operate as an isochronous system based on whether the Cogen units are connected to PG&E. When connected (i.e., 52-S, 52-M, 52-1, and the DPA main breaker all closed), operation should be base loaded

with power factor or reactive power control at each generator (same as existing Cogen operation). When not connected (any one of those breakers is open), operation should immediately switch to isochronous speed and constant voltage control. These changes are not described in the existing operating sequence but have likely been implemented. This should be verified as part of implementing this option.

The Cogen improvements narrative states that generator G4 would start up and parallel with the Cogen system, and G5 would start up and take loads at DPG, isolating them from the rest of the plant, but the as-built drawings do not show any interface to signal the transfer controllers to allow this.

For the Cogen system to be able to take on plant load without becoming unstable and tripping off, the load immediately after isolating from PG&E must be similar to the load prior to the utility power loss. This would require continuously monitoring net import/export (which is presently monitored by the Cogen master controls), subtracting any loads that would be isolated (e.g., DERWA if breakers 52-1 and 52-2 are to be tripped), and using that data in a load shed system to quickly adjust load to minimize the step change in load on loss of PG&E. Once the plant is isolated from PG&E, additional Cogen can be brought online as required and loads can be restarted as required, within the starting and running limitations of the operating generators.

Load shedding can be implemented in several ways:

- Direct process control – Existing automatic controls in the programmable logic controllers (PLC) are revised to maintain a list of loads to be shut off in a PG&E outage occurs. The determination would be based on a combination of the importance of the load to the WWTP process and the amount of power it requires. When the interconnection relays sense an outage, those loads are immediately stopped by removing their call to run. This provides the best match of load to generation when an outage occurs, but the time required for the loss of PG&E to be identified by the PLC and for it to process the logic could result in instability in the generators.
- Separate load shed controls – Hard-wired interlocks would be added to some of the large plant loads which cause the loads to be immediately de-energized when the load shed contact opens. A load shed relay would be energized whenever PG&E power is normal or the generators are operating within their capabilities. When the interconnection relays detect a PG&E outage, this relay would be immediately de-energized. Load shed controls in the PLCs (or a new load shed PLC) will determine which loads are running and which of those will need to be shed. An output from the PLC for each load that is running and will not be shed would bypass the load shed relay contact for that load. This produces a faster response which increases the likelihood that Cogen will keep the WWTP operating, but requires control modifications to many loads, and significant field wiring from the load shed controls to each large load.
- Breaker tripping – The most common method for load shedding is tripping of selected circuit breakers on loss of utility power. This provides a fast response and requires less wiring and control modifications than separate load shed controls but will trip whole process areas (or a few specific large loads whether they are operating or not) rather than individual loads and may not match the running load to the generator output as well as the other methods.

If it is likely that Cogen output could exceed plant load prior to loss of PG&E power, a load bank may be added. The Cogen controls would be modified to constantly determine the appropriate load surplus, and which load bank elements would be needed to add that load. Once the plant is isolated from PG&E, this additional load would be removed in small steps, allowing the system to stabilize between steps.

Return to utility power would be managed by the MSLC-2 at 52-M, which will actively synchronize the Cogen engines to the PG&E source, close 52-M when conditions are met, and return Cogen units to their normal base load operation.

Advantages of this option:

- Ability to ride through a PG&E outage with minimal impact to WWTP operation.
- Ability to power all WWTP areas during a PG&E outage.

Disadvantages of this option:

- Requires significant modifications to protect against ground faults on the 21 kV system.
- Requires thorough evaluation of existing logic and controls, and implementation of additional logic to accommodate limitations in Cogen loading.
- Requires load shedding logic and controls, and potentially load addition via new load bank.
- Even with load shedding and addition provisions, there may stability issues due to inability of Cogen engines to respond to changes in loads, whether due to the initial loss of PG&E power or starting and stopping of loads due to normal WWTP operation, which could cause Cogen units to trip offline and de-energizing the plant until diesels come on.
- Available Cogen capacity may not be sufficient for required WWTP operation.

10.3.5 Implement Existing Upgraded Master Cogen Control With Diesel

Initial transfer to Cogen would be the same as described in the previous option. The diesel generators do not have provisions to share load, so they must be isolated from each other. Each would be transferred as described below. The system could also be configured to remove all Cogen units once both diesels are online, providing standby operation similar to the present procedures, but without the initial loss of power at backed-up facilities.

10.3.5.1 Generator G5

The Cogen controls would be modified to send a signal to the ATC at DPG telling it to go to its emergency source. This would cause G5 to start, and for its ATC to transfer DPG loads to G5.

10.3.5.2 Generator G4

The ATC at DPA/DPB can also be instructed to go to its emergency source, which would be similar to starting G4 for exercising. Once G3 was connected, though, the ATC would immediately trip the main breaker in DPA, which would isolate G3 from G1 and G2 (if G3 was running), which would likely cause instability and possible overload in G3, or simply de-energize the 21 kV circuit and deenergize the rest of the WWTP (if G3 was not running). To prevent this, the ATCs at DPD and DPE would be instructed to transfer to the emergency source first (concurrently with DPG) as shown in Figure 10.7. Then, once both were connected to the emergency ties to DPB, the ATC at DPA/DPB would be given the command to transfer to emergency. That would result in an operating condition similar to the existing standby power procedures, except that Cogen can be used to supplement G4. The 21 kV system will be

deenergized as soon as the ATC at DPA/DPB trips the DPA main breaker, deenergizing DPR, DPM, and DPN loads for the remainder of the PG&E outage and allowing the commands for the ATCs to go to emergency would be removed because their normal source would be deenergized.

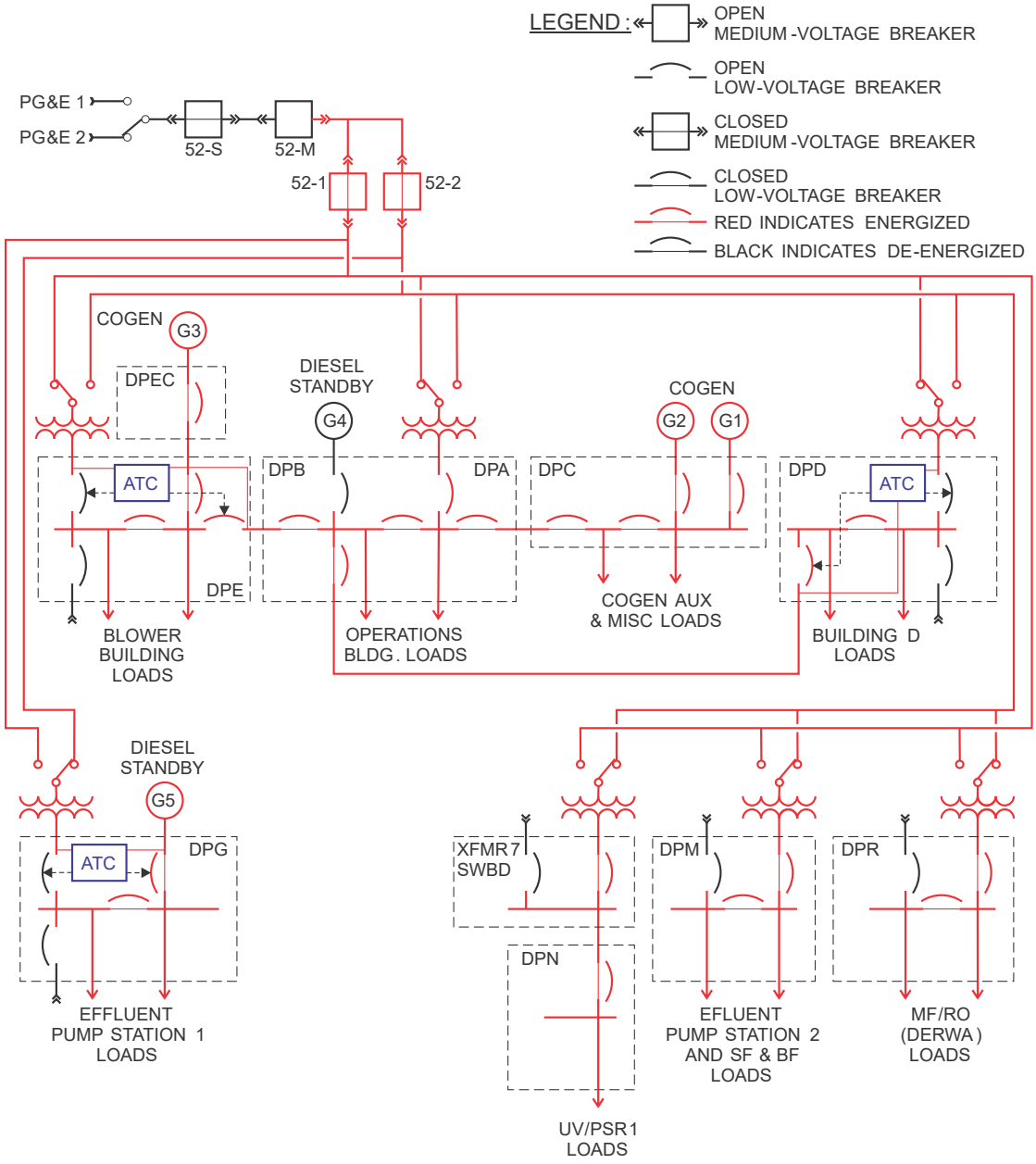

Figure 10.7 Simplified One-Line: Loss of PG&E – Preparation to Add Diesels

Once the DPA main breaker is open, the controls would remove Cogen units or adjust their load set points as required to ensure that G4 carries sufficient load, and the WWTP will be configured as shown in Figure 10.8.

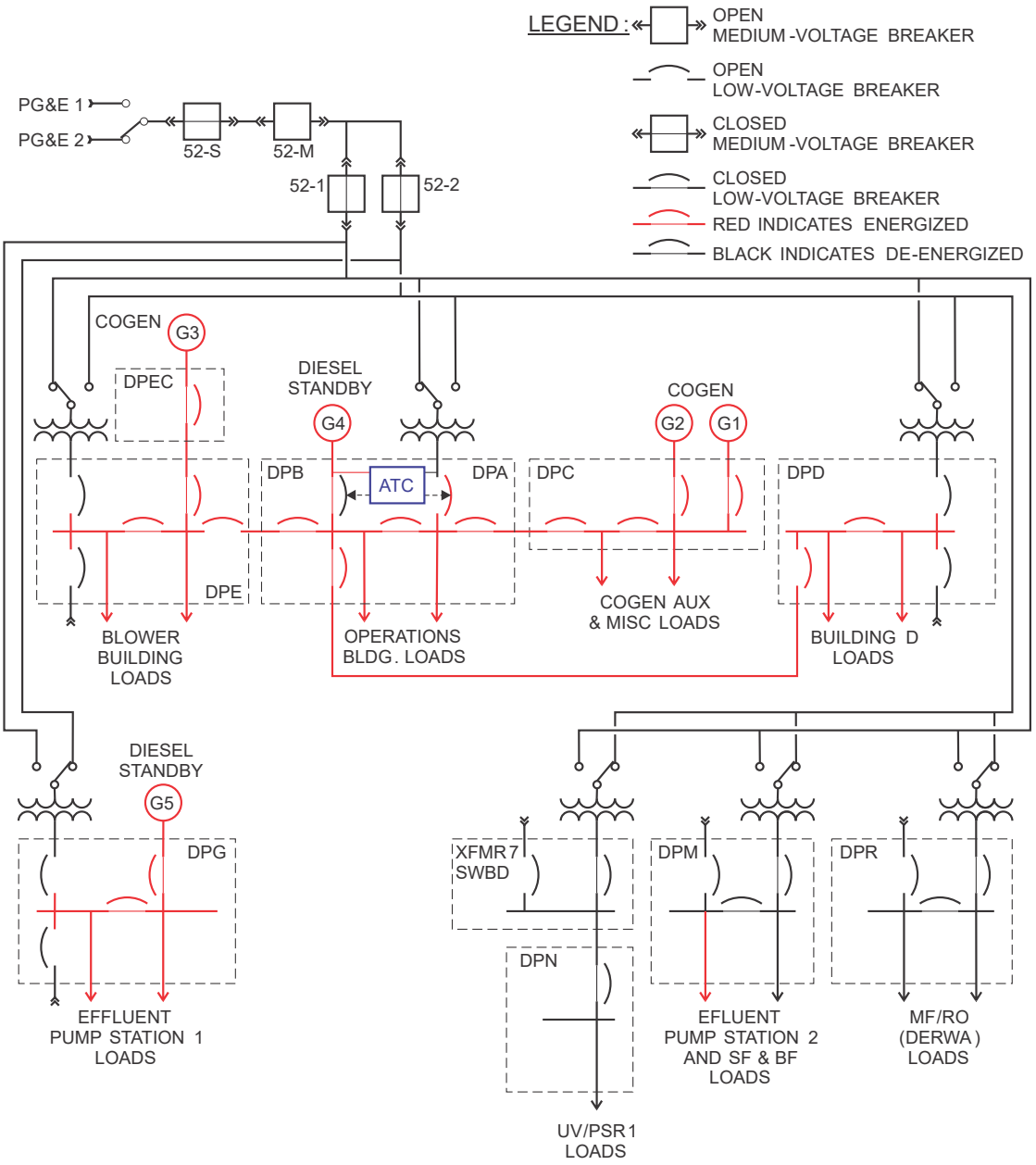

Figure 10.8 Simplified One-Line: Loss of PG&E – Cogen and Diesel Generators Operating

10.3.5.3 Return to PG&E

Return to PG&E would be similar to the present procedures where each ATC will sense return of utility power and transfer back through fast closed transition switching.

Advantages of this option:

- Ability to ride through a PG&E outage with minimal impact to WWTP operation.
- Less risk of damage from 21 kV ground fault than with previous option.

Disadvantages of this option:

- Requires significant modifications to protect against ground faults on the 21 kV system.
- Requires thorough evaluation of existing logic and controls, and implementation of additional logic to accommodate limitations in Cogen loading.
- Requires load shedding logic and controls, and potentially load addition via new load bank.
- Even with load shedding and addition provisions, there may stability issues due to inability of Cogen engines to respond to changes in loads until diesels are online and taking load.

10.4 Implications of New Generation Systems

As described above, care must be taken when connecting multiple power sources together when isolated from the utility grid to ensure that the system frequency and voltage can be reliably controlled.

10.4.1 Replacement of Cogen system

A new Cogen system would utilize modern low-emission, high-efficiency generators. The control systems that are packaged with these generators include the functions of the existing DSLC-2 controls, and compatible master controllers can be incorporated which provide the functions of the existing MSLC. The capabilities of these systems as well as the methods for interfacing them with other systems (e.g., the diesel generators) will vary by manufacturer. It is unlikely that the existing Cogen control system would be compatible with new Cogen units. Therefore, if the Cogen system is to be replaced, any upgrades to the existing standby power system to incorporate Cogen power would only be useful until the Cogen system replacement occurs.

While this tightly integrated control complicates combining Cogen and diesels for standby operation, it is likely to allow a wider range or output from each Cogen unit making import/export control more feasible. It would also enhance their ability to be used as primary standby power source, enabling the plant to ride through PG&E outages without even a brief power loss, but the generators would still lack the ability to handle sudden load changes as well as the diesel generators can, so load shedding and load management controls would be critical to making them a viable standby source.

It may be possible to operate one or both diesel generators in parallel with new Cogen for standby power operation, but this is likely to be complicated to configure and tune for stable operation. Details of how it will be accomplished should be determined as part of the selection process for the new Cogen system. If any parallel operation of Cogen and diesels is desired, the Cogen generators should be specified to have 2/3 winding pitches to match the diesels.

10.4.2 Additional Renewables

Power sources whose power output isn't controllable, such as most photovoltaics (PV), may overproduce on standby, preventing standby generators from controlling system frequency and therefore causing them to trip offline. Most PV systems are designed to be grid-interactive, in that they simply match the system voltage and frequency and produce power based on the amount of sunlight reaching their surface. If size is large enough that the standby generators cannot be sufficiently loaded to maintain system stability, provisions should be included to

prevent operation in parallel with standby power, such as by location in the system (on buses not backed up) or controls that prevent operation when on standby power.

10.4.3 Standby Generator for DPD

The current DSRSD capital improvement program (CIP) includes a project to install a 900 kW generator at distribution center DPD. This will allow DPD to operate separately from diesel generator G4, allowing more of the capacity of G4 to be available for other areas. If integrating Cogen units into the standby power system is implemented, then this additional capacity may not provide significant benefit. Otherwise it will allow more load to be backed up during PG&E outages and should be retained in the CIP.

10.5 Recommendations

Provisions to allow the plant to ride through would enhance plant operations when a PG&E power outage occurs, but the added complexity of the required controls will be difficult to tune and balance, and operations staff may get frustrated with it and return to simpler controls (as evidenced by the failure to implement the complex elements of controls installed in 2012). In addition, the work required to implement some options would not be applicable to new Cogen units. Therefore, we make the following recommendations for implementing the enhancements:

1. Facilitate adding base-loaded Cogen units: Postpone decision until Cogen replacement project, and if desired, implement with new Cogen system.
2. Automate return on restoration of PG&E power: Implement.
3. Provision for temporary generator to DPA/DPB: Implement.
4. Add load bank to DPG: Implement.
5. Implement existing upgraded master Cogen control without diesel: Do not implement. If functionality is desired, include in Cogen replacement project.
6. Implement existing upgraded master Cogen control with diesel: Do not implement. If functionality is desired, include in Cogen replacement project.

Appendix 10A

GENERATOR SYSTEM BASICS

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Generator System Basics

Generating units consist of several key elements: A prime mover, such as an engine, to convert the fuel or other energy source into rotational motion; an alternator to convert rotational motion to electrical power; and various control elements to be able to produce stable power. This appendix is intended to give some background on these elements as they apply to the descriptions of systems and options in this technical memorandum. Any operation that includes parallel operation of generators with different control systems, different fuel types, or other differences in characteristics requires careful evaluation, is likely to be difficult to properly tune, and may result in unexpected issues in operation.

Prime Movers

The prime movers for the generating systems at the WWTP are engines which convert fuel to mechanical power.

Engine Controls

A governor is the primary element in the engine controls. The engine must operate at a constant speed to maintain the required power system frequency. Total real power produced by the generator matches the load it's powering. As load increases, a governor senses that the engine is slowing and opens the throttle to maintain speed. As load decreases, the governor closes the throttle as required. This balances the power produced to the power required by the loads.

When one generator is operating alone, isolated from other power sources, the governor simply maintains frequency. This is called "isochronous" control, meaning constant speed. This is how typical standby generators operate and is the present control of diesel generators G4 and G5 a the WWTP. When in isochronous control, any change to the speed set point changes the speed of the generator and therefore the frequency of the power system.

When two or more similar generators are operating in parallel, calibration of the speed controls is not perfect, so if operating isochronously, each governor will try to maintain a slightly different speed, resulting in one generator taking on all load and then forcing power into the other (also known as motoring) until both generators trip offline. Similarly, when a generator is connecting to the utility grid, any slight error in speed setting relative to the grid frequency will cause the governor to either continue to open its engine's throttle until it overloads or close it until it trips due to motoring. To prevent this, some means are needed to allow the generators to share the load.

The simplest way to share loads is through droop, which is a response curve where the speed set point decreases as load increases. With droop, the generators will reach an equilibrium where a slight error in speed calibration becomes a small difference in power production. The drawback to using droop is that the frequency is lower at higher loads. Droop can also be used to control the amount of power produced, particularly when the generator is in parallel with other generators or the electric utility. Increasing the speed set point will cause the generator to take on more load. The impact of changing the speed set point when connected to the utility is that it changes the power produced. This is a grid-interactive mode of operation. Changing the speed set point when connected to other generators will have some impact on speed and some impact

on load. The droop function is presently used to control power produced by the Cogen generators.

Other types of load sharing are called isochronous load sharing because they are able to maintain frequency while sharing load. These include an analog load sharing bus and digital communications between load controllers. These both use a small amount of droop for stability but compensate for it with active controls. With the analog load sharing bus, each governor can sense whether its generator is overproducing or underproducing compared to the average of all generators and adjusts its frequency set point slightly to compensate. With digital communications, the load controllers communicate their loads to each other, and send small adjustments, or bias signals, to the governors to balance the load between generators while maintaining system frequency. The upgraded Cogen controls use digital communications between the DSLC-2 load controllers, which then send a speed set point bias to the Cogen governors, to control load sharing.

The various load sharing methods are not generally compatible with each other, and there are different manufacturer-specific ways to implement each that are not mutually compatible. There are hybrid configurations that are possible, but in general all generators should operate on a single load sharing system. It's also possible for frequency to be controlled by one generator (or a group of generators with isochronous load sharing) while other generators operate in droop, but this requires that the speed set points (and therefore power produced) on the generators operating in droop is set or controlled to prevent them from taking too much load from the isochronous generator system. It is also important for any changes to the set points for the droop generators to be done gradually to prevent them from impacting the stability of the speed control of the isochronous generator.

When a generator is connected to the utility grid the governor operates in a grid-interconnected mode, which means its operating in droop and typically has a load controller adjusting the speed set point to maintain a constant power output. One or more generators operating isolated from the utility grid is called an island. When a single generator operates as an island, it operates in an isochronous mode with the governor maintaining speed. When a group of generators operate as an island, they generally operate in isochronous load sharing, also sometimes called island mode, although some generators may operate in their grid-interconnected mode as described above relying on others to maintain power system parameters. In order for the system to be stable, changes in operating mode must occur immediately when the grid connection changes, so auxiliary contacts on circuit breakers must be used to signal the required operating mode to each governor or load controller.

Engine Types

Gaseous Fuel Spark-Ignited (e.g. Cogen)

The Cogen systems use gaseous fuel containing primarily methane. This is in the form of biogas from the digesters, natural gas, or a blend of the two. They are spark-ignited engines similar to those in a typical automobile.

This type of engine is relatively unstable on sudden large change in load. When a sudden change, or step load, occurs, the frequency changes rapidly and the governor responds to correct it. When the load step is too large, the governor will overcorrect and result in tripping on high or low speed. They also have limited operation range, typically being optimized for producing their

maximum output. Operating at lower loads can reduce stability or increase emissions beyond what their permits allow. These engines are typically used for grid-interconnected operation where their load is based on a speed set point and droop rather than responding to varying loads.

Diesel Engine

This type of engine is very stable and can typically handle its full rated load being applied or removed in a single step. Large load changes will impact frequency, but the changes are within acceptable parameters, and the governors are able to quickly restore operation to the rated speed. These engines are the most common type used for standby operation. They are also used for prime power applications, but generally require extensive emission controls to be allowed to operate other than as a standby source.

Alternators

The dynamo on a generator set is often referred to as the generator, but because that term also applies to the whole generator set, including the engine, the term alternator will be used in this document. The alternator converts the mechanical power from the prime mover to real electrical power (measured in kilowatts or kW) for the loads. It also provides the reactive power (in kilovolt-amperes reactive or kVARs). This reactive power does not produce work or require fuel, but the reactive power produced much match that consumed to maintain system voltage just as the real power produced must match that consumed to maintain system speed or frequency.

Alternator Construction

There are many types of alternators, but those used on standby and Cogen generator sets are nearly always brushless synchronous alternators, meaning that they have a rotating exciter with a rotating armature and stationary field connected to a main alternator with rotating field and stationary armature. Rectifiers on the shaft convert the AC from the exciter to DC current for the main alternator field windings. These are called "brushless" because they do not require commutators to produce DC from the exciter or slip rings to power the main alternator field, both of which require brushes to transfer current between rotating and stationary components, which require frequent inspection and periodic replacement.

Alternators can have various winding pitches. The winding pitch is the ratio of the number of armature slots spanned by the magnetic poles of the field to the number of slots spanned by the one loop in the armature winding. The most common winding pitch for generators is 2/3, but 5/6 pitch is also common. Each available pitch has different harmonic characteristic in its output voltage. Paralleling alternators with different winding pitches on a common bus causes a mismatch in these harmonics, resulting in harmonic currents circulating between the alternator neutrals. In addition to the increased heating caused by these circulating currents, a number of unexplained failures have been attributed to mis-matched winding pitches. This isn't an issue when paralleling with PG&E because the delta-connected primary winding on the WWTP power transformers blocks these harmonic currents from flowing. Available data indicates that all Cogen and diesel generator units a the WWTP have the same 2/3 pitch, so parallel operations should be possible.

Alternator Controls

The alternator must provide a constant AC voltage to the power system. This is controlled by a voltage regulator, which provides alternator control similar to the engine control from the

governor. The voltage regulator senses system voltage and adjusts the DC current to the exciter field to obtain the required voltage.

As generator output current increases, the voltage will drop. The voltage regulator will sense this and raise the exciter field current to return to the correct voltage. This increase in exciter field current creates a higher exciter output voltage, which in turn increases main alternator field current, and therefore main alternator terminal voltage. Inductance in each winding prevents this correction from happening quickly, so a significant dip in output voltage when the reactive current demand suddenly changes, such as when a large motor starts.

When one generator is operating alone, isolated from other power sources, the voltage regulator simply maintains voltage. This is called voltage control. This is how typical standby generators operate and is the present control of diesel generators G4 and G5 a the WWTP. When in voltage control, any change to the voltage set point changes the voltage of the power system.

When two or more similar generators are operating in parallel, calibration of the voltage controls is not perfect, so if operating in voltage control, each generator will try to maintain a slightly different voltage, resulting in one generator taking on all reactive load and then forcing reactive power into the other until both generators trip offline. Similarly, when a generator is connecting to the utility grid, any slight error in voltage setting relative to the grid frequency will cause the voltage regulator to either continue to increase exciter field current until it trips on excess current or reduce it until it trips due to loss of field. To prevent this, some means are needed to allow the generators to share the reactive load.

The simplest way to control the reactive load is through reactive droop, which is similar concept to droop in the governor. It has response curve where the voltage set point decreases as alternator current increases. With reactive droop, the generators will reach an equilibrium where a slight error in voltage calibration becomes a small difference in reactive power production. The drawback to using reactive droop is that the voltage is lower at higher loads. Reactive droop can also be used to control the amount of reactive power produced and therefore the power factor, particularly when the generator is in parallel with other generators or the electric utility. Increasing the voltage set point will cause the generator to take on more reactive load. The impact of changing the voltage set point when connected to the utility is that it changes the reactive power produced. A separate controller will typically monitor the reactive power or power factor output of the alternator and adjust the voltage set point to achieve a desired reactive power or power factor (PF) to ensure that the generator produces an appropriate amount of reactive power. Producing excessive reactive power will add to generator losses and can overload the alternator field while not producing sufficient reactive power can overburden the utility source, including portions within the WWTP, and can lead to instability in the generator. This is a VAR/PF mode of operation. Changing the voltage set point when connected to other generators will have some impact on voltage and some impact on reactive power.

Other types of reactive load sharing include cross-current compensation, which is similar to an analog bus for real power sharing, and digital communications between load controllers. These both use a small amount of droop for stability but compensate for it with active controls. With the cross-current compensation, each voltage regulator can sense whether its generator is producing more or less current compared to the average of all generators, and adjusts its voltage set point slightly to compensate. With digital communications, the load controllers communicate their reactive loads to each other, and send small adjustments, or bias signals, to

the voltage regulators to balance the reactive load between generators while maintaining system voltage. The upgraded Cogen controls use digital communications between the same DSLC-2 load controllers that are used to share real power.

As with real power load sharing, reactive load sharing systems are not generally compatible with each other, so all generators need to use the same system, or the isochronous generators need to also share reactive power while the generators running in droop speed control use reactive droop with a VAR/PF controller.

When a generator is connected to the utility grid its voltage regulator operates in a VAR/PF mode, which means its operating in reactive droop and typically has a controller adjusting the voltage set point to maintain a constant power factor or reactive power output. When a single generator operates as an island, it operates in a voltage control mode. When a group of generators operate as an island, they must have appropriate reactive load sharing enabled. In order for the system to be stable, changes in voltage regulator operating mode must occur immediately when the grid connection changes, at the same time that the governor mode is changed.

Transitions

A transition occurs when the primary power source changes, such as when utility power is lost and the WWTP transfers to generator power, or when the WWTP reconnects to PG&E after an outage or separation for testing. These can be open transitions, where the loads are not connected to both sources at the same time or closed transitions where both sources are connected together for a period of time. Closed transition transfers are often referred to as "bumpless" because there is no loss of power to create a bump in operation.

Delayed Open Transition

The simplest and most common transition type is an open transition with a time delay to allow motor fields to decay. Failure to allow a sufficient delay results in the power frequency and phase angle differing from the residual magnetic field in motor field windings (typically induced fields in induction motors). This difference results in a large amount of torque to pull the rotor into phase with the power source, resulting on high current and stress on mechanical components. A delayed open transition is the only available method when transferring to generators that are not already operating in parallel with the utility source. When it is also used for return to utility power, it results in a second brief loss of power, requiring many systems to restart.

Fast Open Transition

A fast open transition requires the sources to by synchronized to each other, meaning that the voltages and frequencies are similar, and that the phase angle of both power sources are nearly the same. This allows the new source to be connected a fraction of a second after the old source is disconnected without introducing significant torque to make the phase angle of the motors match the new source. While there is still a period of time where neither source is connected, this time is small – a fraction of a second – minimizing the impacts on the power system.

Extended Closed Transition

A closed transition requires the sources to be synchronized and involves connecting the new source before disconnecting the previous source. An extended closed transition keeps the two sources in parallel for a period of time to either allow the generator source to gradually add or

remove load, which reduces stress on the generators and further smooths the transfer, or allows the generators to continue operation, such as allowing the Cogen system to return to normal base-loaded operation. This extended time with generators connected to PG&E requires protection to prevent the generators from having negative impacts on PG&E or energizing PG&E facilities that should not be energized. This operation is governed by PG&E and the State of California's Rule 21 and requires an interconnection agreement between DSRSD and PG&E.

Fast Closed Transition

In a fast closed transition, the amount of time that both sources are connected is very short – typically less than ½ second. Rule 21 allows fast closed transitions, with some restrictions, without the need for additional protective relaying or an interconnection agreement. The IQ Transfer ATC-800 Automatic Transfer Controllers on Switchboards DPA/DPB, DPD, DPE, and DPG use this method to return to PG&E.

Synchronizing

Synchronization is required whenever two power sources are connected to ensure that the frequency, phase angle, and voltages all match within prescribed limits before making the connection. This occurs when a generator is connected to an energized system, such as when a Cogen unit is brought online when the WWTP is on PG&E power. It also occurs when an islanded power system re-connects to the utility, whether a single generator such as G4 or G5 under the present operations or a group of generators such as under the upgraded Cogen control system. The two types of synchronization are active and passive. Either one can also allow dead bus operation, where a prescribed combination of live and dead bus conditions will allow the breaker to close, such as to energize the WWTP 21 kV system on return of PG&E when the generators are powering islands that are isolated from the 21 kV system.

Active Synchronization

In active synchronization, a synchronizer monitors voltage, frequency, and phase angle on both sides of a circuit breaker. It adjusts both the governor and voltage regulator to match the generator to the power system. The speed is usually controlled to be slightly faster so that the generator picks up load on the initial connection. Once the voltage and speed are properly matched, it then monitors the phase angle, and calls for the breaker to close when the generator system is almost in phase with the system, which allows for the slight delay in breaker closing time, and then calls for the breaker to close. When a group of generators are operating in a load sharing mode, then a master synchronizer is used to match the generator bus to the utility bus by communicating to each synchronizer. The existing Cogen controls use the DSLC-2 controllers as the synchronizers on the individual generators, and the MSLC as the master synchronizer (which isn't currently in use).

Passive Synchronization

Active synchronization requires that the governor and voltage regulator have bias inputs to allow the synchronizer to make the necessary adjustments to speed and voltage. Where this isn't available, passive synchronization is used. In order to passively synchronize, the generator voltage and speed need to be close enough to the system conditions that the connection may take place without excessive real or reactive power swings due to the mismatch. A controller monitors conditions on both systems, and when speed and voltage are within acceptable limits of each other, waits for the phase angle to be correct, then closes the interconnecting breaker.

This is usually part of a fast closed-transition transfer system, where the controller trips the breaker to the previous source as soon as the new source is connected. This is the method used by the existing IQ-Transfer devices at the WWTP.

If voltage or frequency are not close enough on the two sources for the closed-transition transfer to occur within a predefined time limit, the transfer controller will default to an open transition transfer. This can be a fast in-synch transfer where the controller waits for the phase angles to be correct, then trips the first source breaker and then immediately closes the new source breaker. If the controller is not capable or configured for a fast open transition transfer, or if the voltage and frequency are not matched sufficiently, then a delayed transition is required.

Load banks

Generating system may include load banks. These banks of resistors with cooling fans add real power load to a system. The most common application of load banks is for generator exercising. This ensures that adequate load is placed on the engine to bring it up to full operating temperature. Failure of the exhaust system to reach normal operating temperatures allows condensation from the fuel combustion to condense before leaving the exhaust. It can then trickle down into the engine and cause corrosion. This increases engine maintenance requirements and reduces service life.

Load banks are often connected just for testing and exercising, but then can be permanently connected to add load when operating system loads are not sufficient whether during exercising or standby operation due to a utility power outage. In this application, the load bank monitors the generator output and adds load elements as required to maintain the required minimum generator load.

They can also be used as part of a load control system with less-stable generator systems to compensate for a sudden loss of load, such as when utility power is lost while generators are exporting, or when a large load must be rapidly started or stopped. Load elements matching the amount of load being lost can be quickly switched on to prevent large step changes in load.

Interconnection Requirements

Any generating system that can operate in parallel with the electrical utility must meet interconnection requirements to prevent the system from energizing an otherwise isolated line and to ensure safety of utility personnel working on those lines. In California, this is governed by California Public Utilities Commission Electric Rule 21. and variations of this rule are used by all electrical utilities in the state.

When a utility power loss occurs, the lines will be energized and back-fed from customer generator, so sensing devices at the customer service will still detect voltage. If the customer generating system is running in an interconnected mode, the governor will be controlling power, not frequency, and the voltage regulator will be in a VAR/PF mode, not directly controlling voltage. As a result, the frequency and voltage will start to shift as loads change, and these changes will be detected by protective relays which isolate the generators from the electrical grid. Rule 21 dictates requirements for these relays and their settings to ensure quick isolation from the grid.

While the primary intent of Rule 21 is to quickly isolate generators that are not under the control of the electric utility, there are competing requirements from the Federal Energy Regulatory

Commission (FERC) through regional reliability councils which require all generating systems to remain online briefly to support momentary conditions to ensure overall power grid reliability. California is part of the Western Electricity Coordinating Council (WECC). Rule 21 incorporates minimum trip times to meet these reliability requirements in additional to the maximum trip times to ensure safety on local power lines.

Interconnected generators in California operate under interconnection agreements between the generating facilities and the electrical utility, which require an application process followed by extensive review to ensure that the Rule 21 requirements are met, the power system can handle the additional generators, and that operation of the generators do not impede the electric utility's protection systems' abilities to detect power line faults.

Appendix 10B

UPGRADED COGEN CONTROL NARRATIVE

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Dublin San Ramon Services District (DSRSD)
Wastewater Treatment Plant (WWTP)
Cogeneration Improvements and Electrical Service Relocation Projects

Revised Standard Operating Procedure
Revised February 2010

The purpose of this Standard Operating Procedure (SOP) is to provide a preliminary description of the operating procedures for the cogeneration units (referred to as G1, G2, and G3). The goal is to provide an operational description of internal generation in general and cogeneration systems in particular at the DSRSD WWTP. This SOP is addresses the operational descriptions of the internal generation sources without including details of WWTP operations or specifics of internal plant functions.

On site generation at the WWTP include the sources shown on the following Table A-1. Refer also to Contract Drawings for single line diagrams of the system configuration and the fo0llowing related Specification Sections:

16420	-	480 Volt Generator Switchgear
16491	-	Gas Engine Generator System Rehabilitation and Controls
16621	-	Engine Monitoring System
16900	-	Control Systems and Control Panels

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07/07/10

TABLE A-1
DSRSD WWTP INTERNAL PLANT GENERATION SOURCES

Source	Nameplate Rating/ Emergency Rating (Note 1)	Bus Connection Location/ Synchronization Breaker	Fuel	Duty/Standby Parallel/Isolated	Comments
Cogeneration Unit 1 (G1 or S13)	500 kW/550 kW	DPC/52-CG1	Digester Gas/ Natural Gas	Duty/Parallel	Existing unit, reconnected under this Project
Cogeneration Unit 2 (G2 or S22)	500 kW/550 kW	DPC/52-CG2	Digester Gas/ Natural Gas	Duty/Parallel	Existing unit, reconnected under this Project
Cogeneration Unit 3 (G3 or S29)	400 kW/500 kW	DPE/52-ECG3	Digester Gas/ Natural Gas	Duty/Parallel	Existing unit, installed under this project
Standby Generator G4	1250 kW	DPB/52-B1	Diesel	Standby/Parallel	Parallel during bumpless transition on return to PG&E only
Standby Generator G5	750 kW	DPG	Diesel	Standby/Isolated	
Fuel Cells	2 @ 300 kW	DPE/52-EFC	Digester Gas/ Natural Gas	Duty/Parallel	
Photovoltaic System	7kW	Maintenance Bldg	Solar	Duty/Parallel	
Portable Connection	N/A	DPD/NA	Diesel	Isolated	Portable generator: not immediately available following an outage
Portable Connection	N/A	DPM/NA	Diesel	Isolated	Portable generator: not immediately available following an outage

Table A-1 Notes:

1. Emergency rating is based on fuel type (digester gas or natural gas) and weather conditions.
2. Planned future 600kW battery system at DPE not shown.

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I. Paralleling and Synchronization

Normal Operation

During normal operation with PG&E on line, the District intent is to operate with up to three cogeneration units and the fuel cells in operation. From the units (identified as "Duty" on Table A-1) the total available capacity while synchronized to PG&E totals 2MW at nameplate ratings. During these periods units G1, G2, G3, and the fuel cells shall be synchronized to their local buses and in turn synchronized to the PG&E incoming service at the 21 kV switchgear (See Sheet E-2).

Presently, while connected to PG&E the co-generation units operate to maintain a net 100kW import from PG&E to the plant for system stability and reliability. However, ability to export all excess generator power to PG&E during peak rate periods shall be included as a standard operating mode for the system being installed under this Contract. Net power is measured across the plant main breaker (52-M) and includes all power to the Plant and DERWA Facilities.

Table A-2 summarizes cogeneration operating modes when connected to PG&E.

PG&E Outage / Island Mode

During a utility outage, the plant main breaker (52-M) and feeder breakers (52-1 and 52-2) shall all open to isolate the plant from the PG&E system at the 21 kV level. All operating generation systems shall continue to operate in parallel and synchronized to each other at their respective local busses. In addition, standby generator G4 (Not in Contract) shall be called to start automatically using existing startup and unit control logic. Once up to speed and voltage, the unit is synchronized automatically to bus DPB and breaker 52-B1 closes allowing G4 to be connected to the system. All G4 logic for startup and control is existing and presently part of the DSRSD operational scheme and not part of this Contract.

Generator set G5 shall also start automatically but is electrically interlocked so that the unit runs independently to serve only those loads on the local bus DPG. Portable units on busses DPD and DPM (if available) require manual switching via a mechanical interlock and manual starting. Neither G5 nor the portable units are synchronized with the system. All G5 logic for startup and control is existing and presently part of the DSRSD operational scheme and not part of this Contract.

During periods when PG&E is unavailable, the District generation systems shall continue to operate automatically with the additional existing diesel standby generators added as noted. Depending on specific conditions at the time of the outage (e.g. availability of fuel cells, amount of power imported from PG&E), loads may also be shed based on current internal Plant operating conditions. A load shed scheme is not part of this Contract.

Output of the on-line cogeneration system units shall be automatically controlled based on District criteria for power provided to the plant's internal to the 21 kV system based on rating limits on busses, feeders, or transformers.

Note that under normal operating scenarios, opening feeder breakers 52-1 and 52-2 effectively isolates the DERWA facility from the internal generator capacity. However, synchronizing devices are included across both feeder breakers to allow feeders to be reclosed under manual supervision should excess internal generation capacity be available for serving the DERWA facility.

Table A-3 summarizes cogeneration unit operating modes when in Island Mode (PG&E Outage).

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TABLE A2
DSRSD COGENERATION UNIT OPERATING MODES – PG&E ON LINE

COGENERATION MASTER MODE	FUEL CELLS	PHOTOVOLTAIC	PG&E	COGENERATION
MANUAL	100% (Note 2)	100% (Note 2)	Variable - Import or Export (Note 1 and Note 5)	All unit are started and stopped manually with kW and kVAR output fixed by Operator at Master Panel
AUTOMATIC: DIFFERENTIAL (TIE-LINE) MODE	100% (Note 2)	100% (Note 2)	Fixed at Operator adjustable set point – import or export (Note 1)	Load Following: designated Swing (Lead) unit – Note 3
AUTOMATIC: FULL EXPORT MODE	100% (Note 2)	100% (Note 2)	PG&E receives maximum export kW (Note 1 and Note 5)	All units operate at maximum rated output
POWER FACTOR MODE	100% (Note 2)	100% (Note 2)	Variable - Import or Export (Note 1 and Note 5)	Selected unit operates to maintain operator set system power factor (VAR) output.
AUTOMATIC: HEAT MODE	100% (Note 2 and Note 4)	100% (Note 2 and Note 4)	Variable - Import or Export (Note 1 and Note 5)	Two units as req'd for process heat remain on line at all times operating at user adjustable output kW (Note 4)
OFF	100% (Note 2)	100% (Note 2)	Variable - Import or Export (Note 1 and Note 5)	No Cogeneration units operating

TABLE A2 NOTES

1. PG&E export level shall be maximum amount of internal generation capacity available as per the District-PG&E Interconnection Agreement.
2. Fuel Cell and PV system output are not adjustable. 100% output defined as full capacity available from the system at any given time based on equipment and fuel availability.
3. Cogeneration units set in an operator designated LEAD/LAG/2'nd LAG scheme. Selection of LEAD, LAG, and 2'nd LAG selectable from the MCCP HMI. LEAD unit modulates (swing bus) to meet operator designated PG&E import/export level. On increasing loads, if LEAD unit reaches a unit specific operator adjustable maximum output level, the selected LAG unit is automatically started, synched, and connected to the system bus. LAG unit operates at an operator adjustable load carrying output level. 2'nd LAG unit operates similarly if loads continue to increase. On decreasing loads, if LEAD unit reaches a unit specific minimum value, 2'nd LAG unit is automatically removed from service; subsequently LAG unit is removed from service if loads continue to decrease.
4. All setpoints adjustable from cogeneration master controller HMI; LEAD/LAG/2'nd LAG selection made at HMI and only applies to units set in REMOTE at the respective engine control panel. Units in HAND mode are operated locally and shall not be controllable from the master controller.
5. During G3 interim mode while Units G1 and G2 are unavailable, G3 shall be operating at all times to provide process heat for the facility. Switchgear G3 shall include all controls for Mode selection and operation when running as a single unit during this period. Refer to operating constraints described in Section 01010.

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TABLE A-3

DSRSD COGENERATION UNIT OPERATING MODES – PG&E UNAVAILABLE

COGENERATION MASTER MODE	FUEL CELLS	PHOTOVOLTAIC	G4 (1250 kW)	COGENERATION
MANUAL	100% (Note 2)	100% (Note 2)	Variable - Follows Load	All unit are started and stopped manually with kW and kVAR output fixed by Operator at Master Panel
AUTOMATIC: ISLAND MODE (Note 1)	100% (Note 2)	100% (Note 2)	Variable - Follows Load	All unit kW and kVAR output fixed by Operator at Master Panel (Note 3)
OFF	100% (Note 2)	100% (Note 2)	Variable - Import or Export (Note 1 and Note 5)	No Cogeneration units operating

TABLE A-3 NOTES

1. Master cogeneration controller HMI automatically switches to Island Mode after separation from PG&E if set in any Automatic position; upon return of PG&E transfer back to utility shall be done manually. Master Controller HMI automatically switches to Load Sharing Mode upon switchback to PG&E if in Automatic Island Mode position
2. Fuel Cell and PV system output cannot be adjusted. 100% output defined as full capacity available from the system at any given time based on equipment and fuel availability.
3. Cogeneration master controller monitors output of Unit G4. When unit nears minimum level established by an Operator adjustable setpoint, lowest priority (LAG or 2'nd LAG) cogeneration unit is taken off-line. When G4 nears maximum level established by an Operator adjustable setpoint, next available (LAG or 2'nd LAG) cogeneration unit is brought on-line. (At minimum levels, operators may choose to remove PV and/or fuel cells from service to assure adequate process heat is available.
4. All setpoints adjustable from cogeneration master controller HMI; LEAD/LAG/2'nd LAG selection made at HMI and only applies to unit set in REMOTE at the respective engine control panel. Units in HAND mode are operated locally and shall not be controllable from the master controller.

PG&E Restoration

Following restoration of utility power the system shall wait for a manual command to transfer back to utility connection. Restoration shall occur by automatically synchronizing across the Plant feeder breakers (52-1 and 52-2) using the existing synchronization check relays, then a final synchronization back to PG&E across the main breaker (52-M) new automatic synchronization relay provided under this Contract. After sensing synchronized reconnection with PG&E, standby generator G4 immediately disconnected from the DPB bus and begin its unloaded cool down sequence (not in Contract).

Generator G5 automatically disconnected from the DPG bus in a "make-before-break"/closed transition sequence to ensure that the transfer of the DPG loads is bumpless. Any portable generators that are online continue to operate until physically stopped and disconnected from the load bus. Busses served from portable units must be de-energized, the portable disconnected and the bus re-energized under normal power. As a result, bus transfer back to normal power will not be bumpless for these facilities.

All controls and requirements of the existing diesel standby generators are existing and not included in this Contract.

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After transfer and synchronization back to utility power, the system shall revert to the normal operation of the cogeneration sources to allow operation in the control mode as determined by operator selection.

II. Island Mode (disconnected from PG&E)

Operation in island mode shall require the facility to be disconnected from PG&E. Only District Plant and (potentially) DERWA loads shall be served from the facilities internal generation sources during an outage. The island condition shall continue until the system is manually directed to be reconnected to PG&E as described previously. Separation from PG&E may be due to loss of the PG&E source (undervoltage relay) or triggered by other system upsets.

Following restoration of PG&E power, 21kV Distribution Switchgear 52-M shall remain open. Service Switchgear breaker 52-S shall be closed first ensuring a synchronized transfer back to parallel operation with PG&E across breaker 52-M. A hardwired interlock shall be provided between 52-M and 52-S to inhibit closing of 52-S should 52-M also be closed. The purpose of this interlock is to prohibit closing of 52-S between unsynchronized sources.

III. Power Exporting Capability

While normal operation of the District internal generation sources is to be a net importer of 100 kW of power from PG&E, the system shall include the provision to export power to PG&E. It is anticipated that the power export agreement with PG&E will allow full export of all excess power from the plant's internal sources without limitation.

IV. Protective Relaying – Refer to Single Line Diagrams

V. Project Phasing

The project shall be phased to facilitate operations for both electrical power and heat needs as defined in Section 01010. The following summarizes the additional duty and standby capacity during the various project phases. Additional portable generator capacity serving isolated plant loads are not included. Units are shown at their normal (nameplate) rating.

Initial conditions - preconstruction:

Duty:
- G1 @ 500 kW
- G2 @ 500 kW
- Fuel Cells @ 600 kW

Total Duty Capacity = 1,600 kW

Standby (not connected to PG&E):
- G4 @ 1250 kW
- G5 @ 750 kW

Total Standby Capacity = 2,000 kW

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Phase 1 – Generator G3 on-line at interim location; prior to demolition of DPC

Duty:
- G1 @ 500 kW
- G2 @ 500 kW
- G3 @ 400 kW
- Fuel Cells @ 600 kW

Total Duty Capacity = 2,000 kW

Standby (not connected to PG&E):
- G4 @ 1250 kW
- G5 @ 750 kW

Total Standby Capacity = 2,000 kW

Phase 2 – Generator G3 on-line at interim location; existing DPC demolished

Duty:
- G3 @ 400 kW
- Fuel Cells @ 600 kW

Total Duty Capacity = 1,000 kW

Standby (not connected to PG&E):
- G4 @ 1250 kW
- G5 @ 750 kW

Total Standby Capacity = 2,000 kW

Phase 3 – Generator G3 on-line at interim location; new DPC commissioned

Duty:
- G1 @ 500 kW
- G2 @ 500 kW
- G3 @ 400 kW
- Fuel Cells @ 600 kW

Total Duty Capacity = 2,000 kW

Standby (not connected to PG&E):
- G4 @ 1250 kW
- G5 @ 750 kW

Total Standby Capacity = 2,000 kW

Phase 4 – Generator G3 off-line while connection point relocated to DPC Room

Duty:
- G1 @ 500 kW
- G2 @ 500 kW
- Fuel Cells @ 600 kW

Total Duty Capacity = 1,600 kW

Standby (not connected to PG&E):
- G4 @ 1250 kW
- G5 @ 750 kW

Total Standby Capacity = 2,000 kW

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Phase 5 – Generator G3 on-line in permanent location in DPC Room

Duty:
- G1 @ 500 kW
- G2 @ 500 kW
- G3 @ 400 kW
- Fuel Cells @ 600 kW

Total Duty Capacity = 2,000 kW

Standby (not connected to PG&E):
- G4 @ 1250 kW
- G5 @ 750 kW

Total Standby Capacity = 2,000 kW

VI. Generation Capacity and Plant Operations

Under Load Following Mode, cogeneration capacity shall follow plant loading closely. Initial operating intent is to maintain a constant import of 100 kW (adjustable to be selected by the operator) from PG&E under all scenarios. Cogeneration units shall be started, stopped, and unit output controlled to achieve the desired PG&E import value.

When plant operations are such that the facility is a net power exporter, cogeneration export capacity is negatively correlated with plant loads. That is, as plant treatment requirements increase, power available for export shall decrease as more power is consumed in process treatment. Therefore, power exported to the PG&E system will vary over time as plant process loads change.

VII. Base case conditions with maximum and minimum expected demand loads.

The plant had the following peak and minimum values:

Plant Peak: 2950 kW July 2008

Plant Minimum: 100 kW (estimated)

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LOCATION	BREAKER	TABLE A-4: BREAKER OPERATING MODES CONDITIONS NORMAL	NOTES	A) PG&E OUTAGE B) 21kV NETWORK USED FOR EXPORT	NOTES	A) PG&E OUTAGE B) 21kV NETWORK BLACK	NOTES	COMMENTS
DPA	52-AM	CLOSED		CLOSED	Allows export via ckt to T1	OPEN	Isolate from 21kV system to allows 480V island conditions	
	52-AC	CLOSED	Provides synch source to DPC and G1 and G2	CLOSED	Provides synch source to DPC and G1 and G2	CLOSED	Provides synch source to DPC and G1 and G2	Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
	52-AB	CLOSED		CLOSED	Provides synch source to DPB and G4 on PG&E failure	CLOSED	Provides synch source to DPB and G4 on PG&E failure	Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
DPB	52-BG-4	OPEN		CLOSED	G4 on line	CLOSED	G4 on line	
	52-BE	CLOSED		CLOSED	Provides backup source to DPE	CLOSED	Provides backup source to DPE	Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
	52-BD	CLOSED		CLOSED	Limited export capability via T2 via DPD feeder with limited ampacity	CLOSED		Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
	52-BA	CLOSED	Provides synch source for G4	CLOSED	Allows means for G4 power export via T1	CLOSED		Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
DPC	52-CG1	CLOSED	G1 on-line	CLOSED		CLOSED		Controlled by Synch logic
	52-CG2	CLOSED	G2 on-line	CLOSED		CLOSED		Controlled by Synch logic
	52-CT	CLOSED		CLOSED		CLOSED		Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
	52-CA	CLOSED		CLOSED		CLOSED		Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
DPD	52-DS	OPEN		OPEN	Local energization of T2 inhibits Auto Xfer	CLOSED	Allows DPD feed from DPB if 21 kV network black	Add UV or Under Freq protection to isolate from 21 KV and cause Xfer to DPB should 480V generation be unable to serve load demand Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
	52-DT	CLOSED		CLOSED		CLOSED		Open only for maintenance functions
	52-DP	OPEN		OPEN		OPEN		Emergency portable generator only
	52-DN	CLOSED		CLOSED		OPEN		

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LOCATION	BREAKER	TABLE A-4: BREAKER OPERATING MODES CONDITIONS NORMAL	NOTES	A) PG&E OUTAGE B) 21kV NETWORK USED FOR EXPORT	NOTES	A) PG&E OUTAGE B) 21kV NETWORK BLACK	NOTES	COMMENTS
DPE	52-EN	CLOSED		CLOSED	Local sources energizing ckt to T4 and inhibits Auto Xfer	G3 on-line: OPEN - DO NOT Xfer - synch problem between DPE and DPB busses G3-off line: CLOSED - Auto Xfer works as usual	Auto Xfer scheme should remain unchanged: If G3 on line, will see local source and not switch	Add UV or Under Freq protection to isolate from 21 KV and cause Xfer to DPB should DPE generation be unable to serve load demand Provide operational placard warning against closing: "WARNING: DO NOT CLOSE UNDER LOAD"
	52-EEC	CLOSED	G3 on-line	CLOSED	G3 online for local synch source	CLOSED	Provides synch voltage back to DPEC if G3 brought on line. Condition allows G3 to synch to DPB (G1, G2, and G4)	Provide operational placard: "WARNING: IF BREAKER OPEN DO NOT CLOSE UNLESS DPEC BUS IS DE-ENERGIZED"
	52-ET	CLOSED		CLOSED		CLOSED		Open only for maintenance functions
	52-EFC	CLOSED		CLOSED	Fuel cells assumed on-line from G3 source	CLOSED	Fuel cells assumed on-line from G3 or DPB source	
	52-ES	OPEN		OPEN	Local sources energizing ckt to T4 and inhibits Auto Xfer	G3 on-line: OPEN - DO NOT Xfer - synch problem between DPE and DPB busses. G3-off line: CLOSED - Auto Xfer works as usual	Auto Xfer scheme should remain unchanged: If G3 on line, will see local source and not switch	Provide operational placard for new G3 source: "WARNING: DO NOT CLOSE UNDER LOAD"
DPEC	52-ECG3	CLOSED	G3 on-line	CLOSED		CLOSED		Controlled by Synch logic

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Multi-Generator Co-Generation Control System

Operational Narration

Valley Power Systems Inc.

Dublin San Ramon Services District WWTP

TT Customer Order No. C-039177

TT Work Order No. W-066339-W-066343

September 01, 2010

REV 0

Generator Control Switchgear [GCS] DPC	W-066339
Generator Control Switchgear [GCS] DPEC	W-066340
Generator Control Switchgear [GCS] ECP	W-066341
Generator Control Switchgear [GCS] MCCP	W-066342
24V DC Station Service	W-066343

The system consists of three 500kW, 480V dual fuel gas generators (2 Waukesha VHP 3521 and 1 Waukesha VHP 2895).

The generator control switchgear (GCS) DPC contains the DSLC synchronizer power generation controllers, generator synchronizing circuit breakers, feeder breakers and incoming utility breaker (DPA). The seven-section GCS is 3-phase, 3-wire, 480V solidly grounded.

Refer to SLD drawing W-066339-03A and 03B.

The bus is split into two via a tie breaker between the two generators and the incoming utility feeder breaker. The normal operating mode is with the tie breaker closed.

Automatic closing of the tie breaker is performed by the master control panel PLC.

Each generator is equipped with an engine control PLC based auto start engine controls located in the ECP engine control & monitoring panels. The engine control PLC will handle engine start/stop and protection.

Each generator breaker is equipped with a Basler BE1-11g protection relay for primary electrical protection. The DSLC synchronizer power generation controller interfaces with engine control PLC to oversee the genset operation. The DSLC controller provides automatic synchronizing and load control.

The incoming feeder 52-CA and generators are equipped with Cutler Hammer IQ 6600 advanced digital multimeters.

A Schweitzer SEL-587Z bus differential protection relay provides utility, generator, feeder breakers 52-CX, 52-CY, 52-CR and 52-CS differential.

The generator control switchgear (GCS) DPEC contains the DSLC synchronizer power generation controller, generator synchronizing circuit breaker. The single section GCS is 3-phase, 3-wire, 480V solidly grounded.

Refer to SLD drawing W-066340-03A.

The generator is equipped with an engine control PLC based auto start engine controls located in the ECP engine control & monitoring panel. The engine control PLC will handle engine start/stop and protection.

The generator breaker is equipped with a Basler BE1-11g protection relay for primary electrical protection. The DSLC synchronizer power generation controller interfaces with engine control PLC to oversee the genset operation. The DSLC controller provides automatic synchronizing and load control.

The generators are equipped with a Cutler Hammer IQ 6600 advanced digital multimeter.

A Schweitzer SEL-587Z bus differential protection relay provides differential overcurrent protection on generator 3 and the bus at switchgear DPEC.

The IQ 6600 meters and breaker trip units are all connected to a Modbus network and then to the Control Logix PLC.

All breakers are protected by Cutler Hammer Magnum DS drawout electrically operated LSIG Digitrip 1150 trip units. Breaker trip units are IMPACC Powernet compatible.

The master control MCCP and DPEC displays are an Allen Bradley Versa View Industrial PC's operating on Windows XP with a 12" LCD color touch screens. Communications with the PLC's is via Ethernet TCP/IP.

The HMI display runs on GE Fanuc iFIX embedded software.

An Ethernet TCP/IP and ModbusTCP connection is provided for customer use. Data may be accessed at this port; this information will include operating modes, breaker position, generator status (modes, alarms) and metering parameters. OPC protocols supported per spec.

The master control & monitoring MCCP and DPEC PLC's are Allen Bradley ControlLogix using the 1756-L62 processors. Communications are with Ethernet module model 1756-ENBT.

The three gas generators, G1, G2, and G3 will be synchronized to their local buses and in turn synchronized to the PG&E incoming service at the 21 kV switchgear as demanded by the system controls.

The generator control system provides automatic co-generation control, standby operation complete with closed transition soft load transfer control.

The system is designed to export all excess generator power to the PG&E utility supply during peak rate periods.

Hardwired control switches are provided to allow an operator to manually operate the system in the event automatic operation fails or manual control is desired. The breaker trip/close switches are policed by their respective protection relay and dead bus logic to ensure safe operation.

The control system is designed to be fail safe ensuring operator and equipment protection.

A 24V DC station service supply is provided. It consists of one 24V DC battery charger, Ni-Cad batteries and a mounting rack.

A common alarm contact from the charger will be monitored by the PLC. As well, the feeds to each control panel and switchgear will be monitored by the PLC to alert the operator to a problem.

The following set of hardwired controls are available on the switchgear and control panels.

Generator Control Switchgear [GCS] DPC W-066339

Breaker Control Switch (SW1):

Each breaker is equipped with a breaker trip/close pistol grip switch.

Moving the switch to the TRIP position will immediately trip open the breaker.

Moving the switch to the CLOSE position will close the breaker, as allowed by the protection relay synchronism check.

86 Lockout (LOR):

The generator lockout relays are tripped via the Emergency Stop pushbutton PB1, Generator Protection Relay BE1-11g, and/or the Current Differential Relay 587Z. The breaker is immediately opened and locked out, and the engine start signal will be relinquished.

RESET - The system is ready to assume normal operation.

TRIP - The breaker will be locked out from closing and the generator will be shutdown.

Emergency Stop (PB1): Immediately trips the breaker and stops the engine. The emergency stop button is a push-pull type. To reset the emergency stop, first pull the button out to the reset position, switch the controller to **OFF** and press the **RESET** button.

Voltage Raise/Lower (SW2):

The voltage adjust switch is used to raise or lower the voltage.

During normal operation the voltage should not require adjusting.

Normally these settings are adjusted during initial startup and re-adjustment is only required if something has affected the dynamics of one or more of the generators (i.e. engine rebuild, etc).

Improper adjustment may impair the ability of the system to automatically synchronize the generator to the bus and will limit the system's ability to service the load. The system nominal voltage is 480V.

Speed Raise/Lower (SW3):

The speed adjust switch is used to raise or lower the speed.

During normal operation the speed should not require adjusting.

Normally these settings are adjusted during initial startup and re-adjustment is only required if something has affected the dynamics of one or more of the generators (i.e. engine rebuild, governor linkage adjusted, etc).

Improper adjustment may impair the ability of the system to automatically synchronize the generator to the bus and will limit the system's ability to service the load. The system nominal speed is 60Hz.

Generator Control Switchgear [GCS] DPEC W-066340

Breaker control Switch (SW1):

Each breaker is equipped with a breaker trip/close pistol grip switch.

Moving the switch to the TRIP position will immediately trip open the breaker.

Moving the switch to the CLOSE position will close the breaker, as allowed by the protection relay synchronism check.

86 Lockout (LOR):

The generator lockout relays are tripped via the Emergency Stop pushbutton ES, Generator Protection Relay BE1-11g, and/or the Current Differential Relay 587Z. The breaker is immediately opened and locked out, and the engine start signal will be relinquished.

RESET - The system is ready to assume normal operation.

TRIP - The breaker will be locked out from closing and the generator will be shutdown.

Emergency Stop (PB1): Immediately trips the breaker and stops the engine. The emergency stop button is a push-pull type. To reset the emergency stop, first pull the button out to the reset position, switch the controller to **OFF** and press the **RESET** button.

Voltage Raise/Lower (SW2):

The voltage adjust switch is used to raise or lower the voltage.

During normal operation the voltage should not require adjusting.

Normally these settings are adjusted during initial startup and re-adjustment is only required if something has affected the dynamics of one or more of the generators (i.e. engine rebuild, etc).

Improper adjustment may impair the ability of the system to automatically synchronize the generator to the bus and will limit the system's ability to service the load. The system nominal voltage is 480V.

Speed Raise/Lower (SW3):

The speed adjust switch is used to raise or lower the speed.

During normal operation the speed should not require adjusting.

Normally these settings are adjusted during initial startup and re-adjustment is only required if something has affected the dynamics of one or more of the generators (i.e. engine rebuild, governor linkage adjusted, etc).

Improper adjustment may impair the ability of the system to automatically synchronize the generator to the bus and will limit the system's ability to service the load. The system nominal speed is 60Hz.

Alarm Reset (PB2): Latching alarms may be reset at anytime by pressing the reset button. To reset shutdowns the controller must first be selected to **OFF** and the generator at a complete stop.

Generator Control Switchgear [GCS] ECP W-066341

Local/Remote (SW1):

REMOTE - In this mode, control is from the HMI display screen. The system is always considered to be in AUTO in this mode.

LOCAL - Disables control from the HMI display screen. All control except individual generator base load mode is accomplished using the selector switches on the switchgear.

Engine Mode Switch (SW3):

OFF – The engine is stopped if running and does not start on a remote start command.

MANUAL RUN – The engine is started if not running. Not further action is taken. The generator is available to connect to the bus if called for from the master PLC provided the system control switch (43AM) is in Auto.

AUTO – The generator is available to operate based on system requirements.

Emergency Stop (PB3): Immediately trips the breaker and stops the engine. The emergency stop button is a push-pull type. To reset the emergency stop, first pull the button out to the reset position, switch the controller to **OFF** and press the **RESET** button.

Speed Raise/Lower (SW5):

The speed adjust switch is used to raise or lower the speed.

During normal operation the speed should not require adjusting.

Normally these settings are adjusted during initial startup and re-adjustment is only required if something has affected the dynamics of one or more of the generators (i.e. engine rebuild, governor linkage adjusted, etc).

Improper adjustment may impair the ability of the system to automatically synchronize the generator to the bus and will limit the system's ability to service the load. The system nominal speed is 60Hz.

Voltage Raise/Lower (SW4):

The voltage adjust switch is used to raise or lower the voltage.

During normal operation the voltage should not require adjusting.

Normally these settings are adjusted during initial startup and re-adjustment is only required if something has affected the dynamics of one or more of the generators (i.e. engine rebuild, etc).

Improper adjustment may impair the ability of the system to automatically synchronize the generator to the bus and will limit the system's ability to service the load. The system nominal voltage is 480V.

Reset/Horn Silence (PB2): Latching alarms may be reset at anytime by pressing the reset button. To reset shutdowns the controller must first be selected to **OFF** and the generator at a complete stop.

Generator Control Switchgear [GCS] MCCP W-066342

System Control (SW1):

In **AUTO** the system PLC is enabled and will automatically control the generators.

In **MANUAL** the operator can control the system manually without interference from the automatic controls.

When switching from **AUTO** to **MANUAL** the system will remain in its last state (e.g. connected generators will continue to run to serve the load).

Emergency Stop (PB1, 2, 3): Immediately trips the breaker and stops the engine. The emergency stop button is a push-pull type. To reset the emergency stop, first pull the button out to the reset position, switch the controller to **OFF** and press the **RESET** button.

Reset/Horn Silence (PB4): Latching alarms may be reset at anytime by pressing the reset button. To reset shutdowns the controller must first be selected to **OFF** and the generator at a complete stop.

Master Control (HMI Touch Screen Display)

The HMI display is an IBM compatible computer with built-in Color Touch Screen 12" LCD monitor, running on the Windows XP Professional OS platform. It is mounted on the front door of the MCCP control panel and is used to interface with the GE Fanuc iFIX embedded software and the master PLC controller software.

Three functions are provided - control, parameter adjustment and status. Control and parameter adjustment allows the operator to make changes to set points and operating modes.

The HMI display has security levels to control user login and control.

View Only **(Limited access)**	This is the default level. No user name or password is required for this security level. When pressing the Logoff button the HMI will default to this security level.
Operator **(Full access)**	User Name: op Password: 123
Control and Setpoints	User Name: admin Password: admin

To change security levels, press the "Change" button in the top right corner of the screen. On the Password screen, press the button of the desired new security level. You will be prompted for a password. If successful, the security level will change. If the password is incorrect, the security level will remain the same. Changing to the Read Only security level requires no password.

The main screen is the singleline screen. This is the start-up screen and gives all necessary information on system operation. It provides brief metering data, generator and utility states of operation, and breaker status.

The Utility Setup Screen provides all necessary parameters for utility.

Parameter settings for co-generation, import, export levels and modes are included. Setting are also included for utility failure action.

Generator setup screens are provided to configure necessary parameter settings. (Start delays, warm-up time, ramp rates, failure action, etc.)

The system setup screen is used to configure the system for load demand, load shed action, co-generator lead – lag selection (priority of start stop), etc.

The test setup screen provided configuration of the system control when co-generator testing is desired.

There are screens for alarm history, events and action.

OPERATIONAL NARRATION:

The following modes of operation are selected via the master HMI displays. For the following operational description, the hardwired controls are assumed to be in the following position:

System Control **SW1** (MCCP, DPEC): AUTO

Local/Remote **SW1** (ECPG1, 2, 3): REMOTE

Engine Control **SW3** (ECPG1, 2, 3): AUTO

During normal operation with PG&E utility on line, the co-generation plant will operate with up to three cogeneration units online.

Breaker 52-M is closed.

Breakers 52-G1,2,3 closed based on system co-generation requirements.

Feeder breakers are closed and remain so during all operation.

Loading of the generators shall be initiated manually based on the operator selected control mode. Unit loading will be done automatically based on status and availability.

The generators G1 or G2 at switchgear DPC will, when called to start and the unit is up to operating temperature, be connected to the bus within 10 seconds.

The second generator (if at temperature) shall then be synchronized, paralleled, and shall be controlled to the load based on the control mode selected as displayed on the Master HMI.

Generator G3 at switchgear DPEC will, when called to start and the unit is up to operating temperature be connected to the bus within 10 seconds.

G3 shall be controlled to the load based on the control mode as selected as displayed on the DPEC HMI.

PARALLEL CO-GENERATION OPERATION:

In this mode the generators operate in parallel with utility to support the load.

The DPC tie breaker (52-CT) closes energizing the DPC bus with system voltage for generator synchronization.

The generators start. The first generator synchronizes to the bus followed by the second and third generators synchronizing to the generator bus, the generators soft load according to the selected mode:

Base Load – the generators will output a specific kW level as a group.

Import – the generators will output power in order to maintain the utility kW import at a specific level

Export – the generators will output power in order to support the load plus an additional specified kW level.

When parallel generation mode is cancelled the generators soft unload. Once the load across the generator main output falls below 50kw (adjustable), the generator breakers then trip open and the generators will continue to run for a cooldown period.

Note: Should the utility fail during parallel generation operation, the PLC will immediately trip the utility, generator and distribution breakers. The system will then proceed as outlined in Utility Power Failure section.

Note: If a generator fails to synchronize upon initiation of Parallel generation, a generator fail to sync alarm is annunciated. To restart parallel generation of the failed unit, reset the fail to sync alarm on the single line screen.

Note: Should a transient fault be detected by the utility feeder protection relay during co-generation operation, the PLC will if possible continue to keep the generators online.

Utility Failure

Loss of Utility Sequence:

During a utility outage, the plant main breaker (52-M) and feeder breakers (52-1 and 52-2) shall all open to isolate the plant from the PG&E system at the 21 kV level. If possible, all operating generation systems shall continue to operate in parallel and synchronized to each other at their respective local buses.

If the transient fault on the utility causes the generators to trip off line, the system will initiate the standby mode of operation. The system load shed logic will be employed and all available generators will be scramble started and brought online.

At this time the system will operate in load demand mode maintaining the required generator capacity to satisfy the configuration settings.

Restoration of Utility Sequence:

Upon restoration of utility supply voltage, the generators will continue to run and the generator breakers shall remain closed. The main switchgear utility breaker shall remain open and the operator shall be notified of the availability of utility power. Retransfer back to the utility source shall be accomplished by manually operating the key interlocked utility main and two feeders to the WWTP Main 21 kV Switchgear with auto synchronization.

Restoration shall occur by automatically synchronizing across the Plant feeder breakers (52-1 and 52-2) using the existing synchronization check relays, then a final synchronization back to PG&E across the main breaker (52-M).

After transfer and synchronization back to utility power, the system shall revert to the normal operation of the cogeneration sources to allow operation in the control mode as determined by operator selection.

ISLAND POWER OPERATION:

In this mode the generators take over the plant load.

The generators start. The first generator synchronizes to the bus followed by the second and third generators synchronizing to the generator bus, the generators soft load. Once the load across the utility breaker 52-M falls below 50kw (adjustable), the breaker is tripped. Generators are now supporting the load.

When island power mode is cancelled, the generators synchronize across breaker 52-M. The system will revert back to plant co-generation mod as selected on the HMI.

If the operator selects the generators to terminate co-generation mode the generators are commanded to unload.

The generators soft unload. Once the load across the generator output breakers falls below 50kw (adjustable), the generator breakers trip open and the generators will continue to run for a cooldown period.

Master Control "DPC NO LOAD TEST-NORMAL" and "DPEC NO LOAD TEST – NORMAL"

When the switch is placed in the "DPC NO LOAD TEST" position, automatic start of any available generator (i.e. G1 and/or G2 in AUTO and with all operating permissives met) shall occur and all automatic synchronizing functions completed, except the DPC tie breaker 52-CT shall remain open and plant loads shall remain connected to the normal source. However, should the normal power source fail during the test procedure, system shall wait until startup of G4 then automatically synchronize across 52-CT to begin load pickup in Island Mode.

Returning the switch to the "NORMAL" position shall initiate the shutdown of the engine generators, and restore all equipment all equipment to normal operation.

The test mode functionality for DPEC and unit G3 is the same as for generator 1 and 2.

Note: The system will manage the starting, synchronizing and breaker closing in the test modes ensuring safe operation and preventing simultaneous breaker operation.

CONFIGURATION:

The following features can be enabled to be active during all automatic modes of operation.

LOAD DEMAND – The number of online generators are optimized to support the current load. Generator priorities can be manually adjusted, or automatically adjusted to equalize engine runtime or engine starts.

LOAD SHED / ADD – Three (3) levels of load shed / add are provided to control downstream loads when load is supported exclusively by generators. Loads will be shed based on bus underfrequency, overload or during a dead bus event. Loads will be added based on assigned priority and when online generation capacity exceeds assigned load levels.

MANUAL OPERATION:

In the AUTO mode the HMI is used to choose the operating modes. The generators automatically start and synchronize as required.

In the MANUAL mode the generators are controlled via the hardwired start/stop pushbuttons, sync and close pushbutton and/or trip-close switches.

The Breaker trip/close switches provided for the main and tie breakers are policed via their respective protection relays and interlocking is provided to only allow closure in dead bus or sync check permissive.

Auto/Off/Run and Reset pushbuttons are provided for each generator so they may be manually started and stopped. The generator breaker trip/close switches are provided to allow manual control of the generator breakers. Additionally, a sync and close pushbutton is provided to allow an operator to manually initiate the automatic synchronizing and closing of the generator breaker without having to manually adjust speed or voltage.

Remote Monitoring

An Ethernet port will be provided on the master PLC. This data will be read only and may be accessed via the customer's plant control system over the ModbusTCP protocol. The data will include all alarms, breaker positions, and a subset of metering data from PQM and engine alarms and parameters from the ECP panels.

Refer to the communications block diagram W-066342-03B.

Dublin San Ramon Services District
Water, wastewater, recycled water

Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 11
ALTERNATIVES ANALYSIS

FINAL | June 2024

carollo

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Abbreviations

AC	advanced control
AHU	air handling unit
BLG	building
BPI	Blue Plan-it®
BS	biosolids
CAPEX	capital expenses
CIP	capital improvement program
cogen	cogeneration
DAFT	dissolved air flotation thickener
DERWA	Dublin San Ramon Services District - East Bay Municipal Utility District Recycled Water Authority
DO	dissolved oxygen
DSRSD	Dublin San Ramon Services District
ES	energy storage
EV	electric vehicle
FOG	fats, oils, and grease
FW	food waste
GHG	greenhouse gas
HSW	high strength waste
HVAC	heating, ventilation, and air conditioning
IRA	Inflation Reduction Act
k	thousand
kWh	kilowatt hour
LAVWMA	Livermore-Amador Valley Water Management Agency
LS	liquid stream
M	million
NG	natural gas
OPEX	operating expenses
PPA	power purchase agreement
PG&E	Pacific Gas & Electric Company
PWD	potable water distribution
RE	renewable energy
SGIP	Self-Generation Incentive Program
SRT	solids retention time
TM	technical memorandum
WWTP	wastewater treatment plant
ZEV	zero-emission vehicle

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Technical Memorandum 11

ALTERNATIVES ANALYSIS

11.1 Background

This technical memorandum (TM) documents the criteria and methodology for evaluating and reducing the 67 alternatives identified in Phase 1 to the 17 energy project recommendations (14 capital improvement program [CIP] projects and 3 non-CIP projects) for implementation. Figure 11.1 provides an overview of the evaluation process for reducing the 108 preliminary alternatives into the final proposed energy projects recommended to be included in Dublin San Ramon Services District's (DSRSD) CIP.

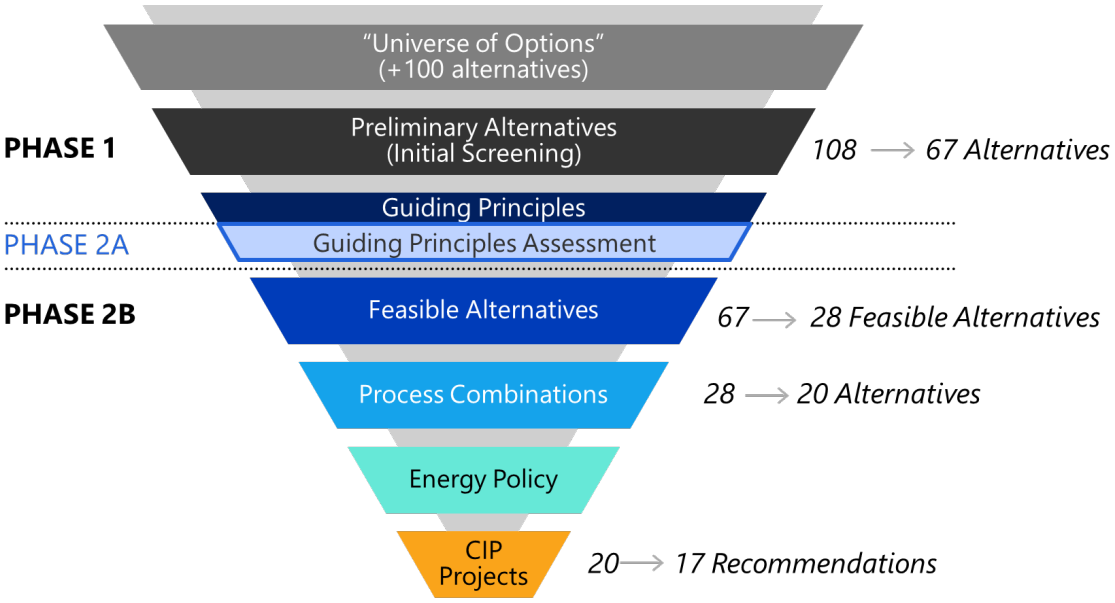

Figure 11.1 Energy Opportunities Evaluation Process Overview

11.1.1 Preliminary Alternatives Analysis/Initial Screening

During Phase 1 of the evaluation process, a comprehensive list of 108 energy- and greenhouse gas (GHG)-related opportunities were identified and an initial screening phase resulted in 67 preliminary alternatives selected for further evaluation. The initial screening methodology and results are described within TM 2.

11.2 Feasibility Alternatives Assessment

In Phase 2B, the 67 alternatives from the initial screening were assessed for their feasibility and effectiveness in implementation. This involved a more detailed analysis that looked at conforming to the guiding principles, implementation feasibility, technology reliability and track-record. The evaluations considered the cost of implementation, operations and maintenance, as well as impacts on DSRSD staffing, Finally, it considered the anticipated

impacts of the projects on energy use, renewable energy generation and power resilience, and greenhouse gas reduction. The methodology and results from this feasibility assessment are described in TM 5, TM 6, and TM 7.

The feasibility study identified, a total of 28 feasible alternatives were selected for further evaluation. Table 11.1 summarizes the 28 alternatives.

Table 11.1 Feasible Alternatives Identified

Alternative Count	Opportunity ID	Opportunity Name
LS Treatment Efficiency Opportunities		
1	LS-5	Real Time SRT Control
2	LS-6	Model Predictive Aeration Control
3	LS-7	Low DO Operation
4	LS-12	Replace Aeration Diffusers
5	LS-13	Upgrade Aeration Blowers
BS Treatment Efficiency Opportunities		
6	BS-2C	Mechanical Thickening instead of DAFT
7	BS-13	Dewatering Post Digestion
8	BS-23	Co-digest FOG
9	BS-24	Co-digest Food Waste Slurry and HSW
10	BS-31B [(1)]	Replace Cogen with Higher Efficiency Engine Generators
11	BS-35	Increase Cogen Capacity for Peak Demand and Redundancy
BLG System Operations Optimization		
12	BLG-7	Metal Building Insulation
13	BLG-8	Screen Room Air Handling Unit Replacement
14	BLG-9	Building A and C Air Handling Unit Replacement
15	BLG-10	Bar Screen Building Exhaust Fan Motor
PWD System Opportunities		
16	PWD-2	Assess Pump Condition
17	PWD-3	Assess Pump Design Point
RE Generation and Storage Opportunities		
18	RE-1	On-Site Solar Installation (RE-1A: Administration Building/RE-1B: Field Operations Facility
19	RE-2	Off-Site Solar Installation (RE-2A: Gleason Property/RE-2B and RE-2C LAVWMA Property)
20	RE-4	Solar Power for EV Fleet Recharging Stations
21	RE-7	Renewable Energy Generation Partnerships
22	RE-8	Green Power Purchasing
ES Opportunities		
23	ES-1	ES in Microgrid Systems
24	ES-2	Battery Storage for Peak Demand Charges

Alternative Count	Opportunity ID	Opportunity Name
Energy Management and AC Opportunities		
25	AC-1	Alternative Power Monitoring
26	AC-4	Energy Decision Management Tools and Staff Focus on Energy Management
ER Opportunities		
27	ER-5	Install Load Bank
28	ER-6	Reconfigure Switchgear for Power Outages

Notes:
AC - advanced control; BLG - building; BS - biosolids; cogen - cogeneration; DAFT - dissolved air flotation thickening; DO - dissolved oxygen; ER - energy reliability; ES - energy storage; EV - electric vehicle; FOG - fats, oils, and grease; HSW - high strength waste; LAVWMA - Livermore-Amador Valley Water Management Agency; LS - liquid stream; PWD - potable water distribution; RE - renewable energy; SRT - solids retention time.
(1) *Replace Cogeneration with Higher Efficiency Engine Generators* (BS-31): Although further evaluation is recommended, BS-31B represents the most accurate costs to be included DSRSD's CIP with a minimum of two cogen engines.

Additionally, the asset review conducted in Phase 1 and documented in TM 3 identified several aging electrical infrastructure assets at the wastewater treatment plant (WWTP) in need of replacement. Further analysis performed as part of TM 14 identified electrical infrastructure reliability issues and prioritized these for two phases of replacement. These projects are identified as WWTP Electrical Improvements Phase 1 and Phase 2 for a total of 30 projects.

11.3 Process Combinations

As part of Phase 2 of the EFMP, projects were grouped into "combinations" to provide increased construction efficiency or link connected alternatives into a single "project". For example, *LS-12: Replace Aeration Diffusers* was grouped with *LS-13: Upgrade Aeration Blowers* since both are linked to upgrades within the aeration system with similar recommended implementation timing. Sixteen feasible alternatives were combined into six project combinations, reducing the number of feasible alternatives from 30 to 20. Table 11.2 lists the six process combinations, the alternatives included with each process combination and the justification for including each alternative in a respective project combination.

Table 11.2 Process Combinations Identified

Project	Alternatives Included Within Project	Implementation Timing	Reason for Combining
Combination 1: Aeration System Upgrades	Model Predictive Aeration Control (LS-6)	2030 - 2033	All aeration related improvements. Diffuser and blower equipment have similar estimated remaining useful life. Upgrading blowers can allow for flexibility in upgrades to diffusers and aeration controls.
	Low DO Operation (LS-7)		
	Upgrade Aeration Diffusers (LS-12)		
	Upgrade Aeration Blowers (LS-13)		
Combination 2: Mechanical Thickening instead of DAFT	Mechanical Thickening instead of DAFT (BS-2C)	2036 - 2039	SRT control is tied with DAFT replacement since mechanical thickening allows for improved ability to control SRT. Timing is based on remaining useful service life of existing DAFT facilities.
	Real time SRT control (LS-5)		
Combination 3: HVAC Improvements	Screen Room AHU (BLG-8)	2024-2025	All HVAC replacements with similar timing can be implemented as one project.
	Building A and C AHUs (BLG-9)		
	Bar Screen Building Exhaust Fan Motor (BLG-10)		
Combination 4: Potable Water Distribution System Improvements	PWD-2 - Assess Pump Condition	2024-2025	Related improvements to be further investigated as part of the Water System Master Planning effort.
	PWD-3 - Assess Pump Design Point		
Combination 5: Energy Management Improvements	Renewable Energy Generation Partnerships (RE-7)	2025	All of these opportunities fall under energy management, where DSRSD takes an active role in managing its energy use and resources.
	Additional Power Monitoring (AC-1)		
	Energy Decision Management Tools (AC-4)		
Combination 6: On-Site Solar Projects	On-Site Solar Installation (RE-1A Admin Building and RE-1B Field Ops Building)	2025 or as soon as a PPA can be secured to maximize incentives and align with EV fleet replacements.	Solar with EV charging needed at both sites. To be implemented soon to coincide with EV fleet vehicle replacement requirements. Possibility of PPA funding is available for this project.
	Solar Power for EV Fleet Recharging Stations (RE-4)		

Notes:
HVAC - heating, ventilation, and air conditioning; PPA - power purchase agreement.

11.4 Alternatives Analysis

Carollo Engineers performed an alternative evaluation of the 20 feasible projects using the advanced Portfolio Manager module of the Blue Plan-it® (Blue Plan-it) Decision Support System One Water Suite, referred to as the BPI energy model hereafter. Further information on the BPI energy model can be found in Appendix 11A, including how it operates, what estimates and inputs were utilized, and what information was concluded as a result of this analysis. Also included, Appendix 11B shows the dashboards and overview of the BPI Energy Model.

Each of the 20 potential alternatives were evaluated within the BPI energy model across three criteria related to the implementability of the opportunity for DSRSD and four criteria related to the impact the opportunity would have on DSRSD's energy and GHG management. The implementability and impact criteria were as follows:

- Implementability:
  - Capital cost.
  - Operations and maintenance costs.
  - Payback period.
  - Impact on staffing resources.
- Impact:
  - Operational or regulatory reliability or flexibility.
  - Infrastructure resilience or ability to address aging or capacity-limited infrastructure.
  - Energy demand or GHG emissions.
  - Energy independence and the generation and use of renewable energy.

To better understand the impacts and implementability of combinations of selected alternatives, the BPI energy model allows for the creation of "portfolios" to select variations of project combinations to compare. Based on feedback from DSRSD staff, seven project portfolios were developed for comparison.

- **Baseline Portfolio:** Business as usual scenario, no energy projects selected.
- **Portfolio 1 – Guiding Principles:** Only projects that align with the Guiding Principles.
- **Portfolio 2 – Energy Independence:** Only projects that provide independence from utility power.
- **Portfolio 3 – Prioritized Energy Efficiency:** All projects that increase efficiency.
- **Portfolio 4 – All Renewable Energy:** All projects that increase renewable energy.
- **Portfolio 5 – GHG Neutrality:** All projects that reduce GHG emissions.
- **Portfolio 6 – Favorable Payback:** Only projects that have a less than 15-year payback.
- **Portfolio 7 – Current CIP:** Only projects already in the DSRSD CIP.

The seven recommended portfolios are included in Appendix 11A within Table 11A.6 along with a variety of figures that present comparisons of each recommended portfolio on electricity consumption, natural gas consumption, and GHG emissions.

As a result of this analysis, the following three alternatives were eliminated from further consideration at this time. The reason for elimination of the alternative is also provided below:

- BLG-7 – Metal Building Insulation – Cost versus benefit of insulating this small building did not pencil out. The payback for insulating the building was over 30 years due to the infrequent need for heating and cooling this space.

- RE-8 – Green Power Purchasing – This option is currently not available in the area. It could be considered at a future date if Pacific Gas & Electric Company (PG&E), Ava Energy, or others offer this in the future. DSRSD is looking to produce its own green power through cogeneration and solar project implementation in the near term which will greatly reduce its demand for electricity from the grid.
- ES-1 – Energy Storage in Microgrid Systems – The cost versus benefit of this alternative does not pencil out for DSRSD at this time due to the fact that most of the power generated by the cogeneration engines is used by the WWTP facility or Dublin San Ramon Services District - East Bay Municipal Utility District Recycled Water Authority (DERWA). There is currently little need for microgrid storage.

11.5 Proposed Energy Projects

Table 11.3 summarizes the 14 projects that are recommended for inclusion in the District's Capital Improvement Program. Project descriptions, estimated capital costs, estimated operational savings (or costs), proposed implementation timing, and justifications for the recommendation are provided. The recommended projects include one regulatory driven project, four asset replacement driven projects, three positive payback driven projects, three energy generation projects, and four reliability driven projects. All energy generation and payback driven projects have a return on investment of 20 years or less.

Table 11.4 includes three additional recommendations from the Energy Master Plan that do not qualify as capital projects but should be pursued by DSRSD for energy related benefits. Project 15 is not considered a CIP project as the FOG facility has already been constructed and only requires activation once the necessary permits are obtained. Project 16 will likely be limited to pump replacement which is covered under maintenance and not the CIP.

Table 11.3 Overview of Proposed Energy Projects to be Included Within the Future CIP

Project	Alternatives Included Within Project	CAPEX ($)	OPEX ($/Year)	Implementation Timing	Comments	Justification
Regulatory Driven Projects						
Project 1: Fleet Assets Program	Transition to ZEV fleet.	5.05M	See TM 7	2024-2042		Compliance with California Air Resources Board regulations.
Asset Replacement Projects						
Project 2: Cogeneration Engine Replacement	Replace Cogen with Higher Efficiency Engine Generators (BS-31)	44.4M	-560k	2026-2030	Recommend additional planning and design before implementing project. Planning effort should evaluate coordination with Project 6, Project 8 and Project 11, and assess feasibility of islanding mode. May be a candidate for SGIP funding. PPA funding may also be available and could be considered as an alternative funding mechanism.	Near the end of useful life (5 years remaining) and newer engines have improved efficiency. Potential 16-year payback with SGIP funding incentives. Due to higher efficiency, new engine expected to produce approximately 20% more power; additional power will offset future energy demands associated with new customers.
Project 3: Aeration System Upgrades	Model Predictive Aeration Control (LS-6)	100k	-95k	2030-2033		Near the end of useful life (10 years remaining) and newer engines have improved efficiency.
	Low DO Operation (LS-7)	100k	-190k			
	Upgrade Aeration Diffusers (LS-12)	1.0M	-95k			
	Upgrade Aeration Blowers (LS-13)	7.6M	-38k			
Project 4: DAFT Replacement with Mechanical Thickening	Mechanical Thickening instead of DAFT (BS-2C)	26.6M	-630k	2036-2039	SRT control is tied with DAFT replacement since thickening leads to higher hydraulic capacity of codigestion.	DAFT structure and equipment nearing the end of its useful life (15 to 20 years remaining) and a significant improvement in energy efficiency is expected.
	Real time SRT control (LS-5)	50k	-10k			
Project 5: WWTP HVAC Improvements	Screen Room AHU (BLG-8) Building A and C AHUs (BLG-9) Bar Screen Building Exhaust Fan Motor (BLG-10)	2.9M	Not evaluated	2024-2025	-	Units are near the end of their useful life (5 years remaining) and newer models have improved efficiency.
Positive Payback Projects						
Project 6: Off-site Solar Power	Off-Site Solar Installation (RE-2C LAVWMA Property)	9.1M	-311k	2025-2026	May be a candidate for IRA funding (~30% reimbursement).PPA funding may also be available and could be considered as an alternative funding mechanism.	Estimated 14-year payback with IRA incentives. Increased energy independence and increased diversity of renewable energy are also beneficial outcomes of these projects.
Project 7: Battery Storage	Battery Storage for Peak Demand Charges (ES-2)	4.8M	-$480k	2026-2027	Considerations relating to sharing the associated costs with DERWA is a possibility that should be discussed. May be a candidate for IRA and SGIP funding (~30% reimbursement).	Estimated 7- to 8-year payback. Offsets peak demand charges and improves energy independence.

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Table 11.3 Overview of Proposed Energy Projects to be Included Within the Future CIP (continued)

Project	Alternatives Included Within Project	CAPEX ($)	OPEX ($/Year)	Implementation Timing	Comments	Justification
Energy Generation Projects						
Project 8: On-site Solar Power, Battery Storage, and EV Charging	On-Site Solar Installation (RE-1A/RE-1B) Solar Power for EV Fleet Recharging Stations (RE-4)	9.3M	-191k	2025 - 2026	Recommend solar arrays for the District Office Administration Building, Field Office Facility and WWTP. May be a candidate for IRA funding (~30% reimbursement).PPA funding may also be available and could considered as an alternative funding mechanism.	Estimated 20-year payback with IRA incentives. Increased energy independence and increased diversity of renewable energy.
Project 9: Codigestion of FW and other HSW	Co-digest Food Waste Slurry and HSW (BS-24)	3.9M	Not evaluated	2026 - 2028	Project aligns with one of the action items specified in the District's strategic goals: "Build relationships and actively participate in local partnerships, regional groups, coalitions, and associations to advance common goals." Significant reduction in NG consumption and associated GHG emissions.	Gas production associated with these facilities will offset future energy demands associated with new customers.
Project 10: Additional Cogeneration Engine	Increase Cogen Capacity for Peak Demand and Redundancy (BS-35)	9.6M	Not evaluated	2037 - 2038	Would provide approximately 600,000 kWh/year in renewable energy production if FOG receiving and FW codigestion are implemented. PPA funding may be available for this project and could be considered as a potential funding mechanism. The funding mechanism for Project 1 will likely dictate funding mechanism.	Provides redundancy if an engine is out of service and allows for meeting peak demands.
Reliability Driven Projects						
Project 11: Install Load Bank for DP-G	Install load bank to protect Standby Generator G5 and provide reliable operation (AC-5).	300	Not evaluated	2027	Generator G5 is sized based on pumping requirements at Effluent Pump Station No. 1. When those pumps are not in use, the capacity of G5 far exceeds the demand, which impact its maintenance requirements and service life.	Adding an automatic load bank to DPG would allow sufficient load on G5 whenever it's running, whether due to a PG&E outage or routine exercising of the generator.
Project 12: Reconfigure Switchgear for Power Outages	Reconfigure the switchgear at the WWTP to allow for automatic restoration of power after a PG&E power outage.	100k	Not evaluated	2027	Project is contingent on the findings of a preliminary engineering study (e.g., Project 1), however for planning purposes, project is tentatively scheduled for 2027.	Improves performance and provides reliability of existing assets.
Project 13: WWTP Electrical Improvements Phase 1	Upgrade WWTP's electrical equipment with inadequate short circuit ratings.	2.1M	Not evaluated	2025 - 2026	It is recommended that this project be implemented as soon as possible due to the criticality of this equipment.	Improves performance and provides reliability of existing assets.
Project 14: WWTP Electrical Improvements Phase 2	Upgrade WWTP's electrical equipment with marginal or overloaded performance.	4M	Not evaluated	2025, 2034-2035	It is recommended that an investigation using power monitoring should be completed in 2025 with replacement occurring in 2035.	Improves performance and provides reliability of existing assets.

Notes:
AHU - air handling unit; CAPEX - capital expenses; IRA - Inflation Reduction Act; k - thousand; kWh - kilowatt hour; M - million; NG - natural gas; OPEX - operating expenses; SGIP - Self-Generation Incentive Program.

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Table 11.4 Non-CIP Project Recommendations – Enterprise Fund

Project	Alternatives Included within Project	Justification
Project 15: FOG Facility Activation	Co-digest FOG (BS-23)	Reduction of 1,230 metric tons in carbon dioxide equivalents for a slight increase in operating costs ($300k).
Project 16: PWD System Improvements	Conduct hydraulic evaluation of PS20B	Poor efficiency under typical hydraulic conditions.
	Revise reservoir level pump control points for PS1A, PS4A, and PS200A.	Improve pump efficiency, investigate further as part of Water System Master Plan.
	Inspect specific components as preventative maintenance items.	At several pump stations (PS1A, PS2A, PS2B, PS3C, andPS300C) hydraulic analysis indicated potential impeller damage and/or stuck valves.
Project 17: Energy Management Improvements	Renewable Energy Generation Partnerships (RE-7)	DSRSD shall seek opportunities to expand renewable energy portfolio where possible.
	Additional Power Monitoring (AC-1)	Allows for better energy management decisions by understanding where power is consumed.
	Energy Decision Management Tools (AC-4)	
	Staff focus on Energy Management	DSRSD focus on energy management, understanding overall efficiency, look for funding and partnership opportunities, and help achieve energy goals and targets. Duties could be distributed among current staff or assigned to new staff.

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Appendix 11A

BPI ENERGY MODEL SUMMARY

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BPI Energy Model Summary

Planning Basis

The following is a summary of the Blue Plan-it® (BPI) energy model including assumptions and inputs that assisted with the BPI energy model analysis; all information can be updated in the future as needed:

- Table 11A.1 includes relevant assumptions and information for each of the feasible alternatives.
- Table 11A.3 presents the annual funding availability for Funds 210, 220, 310, 320, 610, and 620, which covers both water and wastewater, both expansion and replacement.
- The following assumptions were made for funding allocation based on inputs from the District:
  - **Projects LS5, LS13, BSC, BS3, ES1, and ES2:** 20 percent from Fund 320 (Expansion) and 80 percent from Fund 310 (Replacement).
  - **Projects LS6, LS7, LS12, BLG7, BLG8, BLG10, RE1, RE2, AC1, AC4, and AC5:** 100 percent from Fund 310 (Replacement).
  - **Projects BS24 and BS35:** 100 percent from Fund 320 (Expansion).
  - **Project BS31:** 5 percent from Fund 320 (Expansion), 95 percent from Fund 310 (Replacement).
  - **Project PWD2**: 100 percent from Fund 610 (Replacement).
  - **Project RE4:** 50 percent from Fund 610 (Water Replacement), 20 percent from Fund 210 (Collection System Replacement), and 30 percent from Fund 310 (Replacement).

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Table 11A.1 Shortlisted Energy Capital Improvement Program (CIP) Projects

Categories	ID	Projects	CIP Funding Year	Duration of Project Implementation	Capital Costs (K$)	O&M Costs (K$)	Simply Payback Check (Capital/ O&M Saving)	Power Impact (kWh/year)	Natural Gas Consumption (scf/year)	2047 GHG Impact (MT CO_{2e})
WW Liquid Stream	LS5	Real time SRT control	2025	1	$50	-$10	5	-43,276	0	-3
WW Liquid Stream	LS6	Model predictive aeration control	2025	1	$100	-$95	1	-432,756	0	-32
WW Liquid Stream	LS7	Low DO operation	2025	1	$100	-$190	1	-865,513	0	-64
WW Liquid Stream	LS12	Change to more energy efficient diffusers	2032	4	$1,000	-$95	11	-432,756	0	-32
WW Liquid Stream	LS13	Upgrade to more efficient blowers	2032	4	$7,600	-$38	200	-173,000	0	-13
Biosolids	BS2C	Mechanical thickening instead of DAFT	2035	4	$7,300	-$630	12	-1,440,000	-101,835,000	-59
Biosolids	BS13	Implement dewatering post digestion	2025	5	$21,600	$3,820	-6	14,000	0	13
Biosolids	BS23	Co-digest FOG	2025	1	$0	$301	0	113,903	-32,316,000	-1,230
Biosolids	BS24	Co-digest food waste slurry/HSW	2026	4	$2,209	$365	-6	343,442	-24,592,000	-3,423
Biosolids	BS31	Replace cogen with new higher efficiency engine generators	2028	4	$22,800	-$557	41	-2,500,000	0	-184
Biosolids	BS35	Increase cogen capacity and number of units to avoid peak demand charges during downtime, and for unit redundancy	2031	3	$5,300	$0	NA	-634,450	0	-46
Potable Water Distribution	PWD2	Assess pump condition for distribution system and DSRSD recycled water distribution system	2025	1	$50	$0	NA	150,000	0	0
Potable Water Distribution	PWD3	Assess pump design point for distribution system and DSRSD recycled water distribution system	2025	1	$0	$0	10	0	0	0
Building HVAC Lighting	BLG7	Metal building insulation	2025	2	$70	-$5	14	-240,513	-3,119	-192
Building/HVAC Lighting	BLG8	Screen room air handling unit replacement	2028	1	$20	$0	NA	-250	0	0
Building/HVAC Lighting	BLG9	Building A and C air handling unit replacement	2032	1	$20	$0	NA	-250	0	0
Building/HVAC Lighting	BLG10	Bar screen building exhaust fan motor	2032	1	$20	$0	NA	-250	0	0
Renewable Energy	RE1	Solar installation on site at WWTP	2030	3	$335	-$394	1	-55,000	0	-7
Renewable Energy	RE2	Solar field off site for Gleanson Property and LAVWMA Basins	2030	3	$0	$0	NA	-7,500,000	0	-572
Renewable Energy	RE4	Electric vehicle fleet recharged using solar power	2024	1	$436	-$31	NA	-191,000	0	-7
Renewable Energy	RE7	Renewable generation partnerships	2028	1	$0	-$222	14	-3,700,000	0	-282
Renewable Energy	RE8	Green power purchasing					0			
Renewable Energy	ES1	Battery storage and microgrid	2030	3	$1,500	-$330	5	-180,000	0	-13
Renewable Energy	ES2	Battery storage for equipment/processes driving peak demand charges	2030	3	$2,400	$427	-6	-360,000	0	-26
District-Wide	AC1	Additional power monitoring	2024	3	$300	$0	NA	-49,000	0	-4
District-Wide	AC4	Energy decision management tools	2024	3	$100	$100	-1	0	0	0
District-Wide	AC5	Load bank	2025	1	$200	$0	NA	0	0	0

Notes:
cogen - cogeneration; DAFT - dissolved air flotation thickener; DO - dissolved oxygen; DSRSD - Dublin San Ramon Services District; FOG - fats, oils, grease; GHG - greenhouse gas; HSW - high strength waste; HVAC - heating, ventilation, and air conditioning; k$ - thousands of dollars; kWh - kilowatt-hour; LAVWMA - Livermore-Amador Valley Water Management Agency; MT CO_{2e} - metric tons of carbon dioxide equivalents; O&M - operations and maintenance; O&M - operations and maintenance; scf - standard cubic feet; SRT - solids retention time; WW - wastewater; WWTP - wastewater treatment plant.

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Multi-Criteria Decision Making (MCDM)

The BPI energy model integrates the widely used MCDM analysis to prioritize, rank or choose from a variety of different alternatives based on multiple criteria. What is advanced about the methodology used by BPI Portfolio Manager is that the MCDM is conducted in two integrated tiers, the individual alternative level and the portfolio level, to prioritize individual projects, support portfolio making, and rank alternative portfolios.

For both tiers of MCDM, the same seven criteria grouped in two categories are used to rank individual projects and portfolios. These criteria are presented in Table 11A.2. The total score for each category represents an implementation score and an impact score for each alternative or portfolio being ranked. A higher implementation score means lower costs. A higher impact score means more benefits (e.g., high energy reduction or GHG reduction).

Table 11A.2 Categories and Criteria Used for Multi-Tier MCDM

Categories	Criteria
Implementation	1. Capital Costs.
	2. Operational Costs.
	3. Impact on Staffing Resources.
Impact	1. Operational Reliability or Flexibility.
	2. Infrastructure Resilience.
	3. Energy Demand Reduction or Increase Generation, Independence, and Use of Renewable Energy.
	4. GHG Reduction.

Figures 11A.1 and 11A.2 present screenshots of the BPI energy model Project Ranking Dashboard and Portfolio Ranking Dashboard, respectively. To calculate implementation and impact scores for an individual project, follow these steps:

- Each project is scored on a 1 to 5 scale (5 equals best) based on each criterion:
  - Scores were originally developed in Technical Memorandum (TM) 2 as fixed values on a 1 to 5 scale entered by the user.
  - In the BPI energy model, scores for the Criteria "Capital Costs," "Operational Costs," and "Energy Demand Reduction or Increase Generation, Independence and Use of Renewable Energy," and "GHG Reduction" were calculated from the numerical model outputs (costs in million dollars, energy consumption in kWh, GHG emission in MT CO_{2e}, etc.). The scores were processed using a reversed normalization method, so that the maximum costs, energy consumption, or GHG emission would result in the lowest score of 1 and the minimum would result in the highest score of 5.
- A weighting factor (expressed in percentage) developed in TM 2 is used for each criterion.
- The total weighted average score for each project is normalized onto the 1 to 5 scale and used for project ranking, as shown in bar charts on the Project Ranking Dashboard (Figure 11A.1).

Calculated impact and implementation scores were also normalized onto a -1 to 1 scale and used in the quadrant charts on the Project Ranking Dashboard (Figure 11A.1).

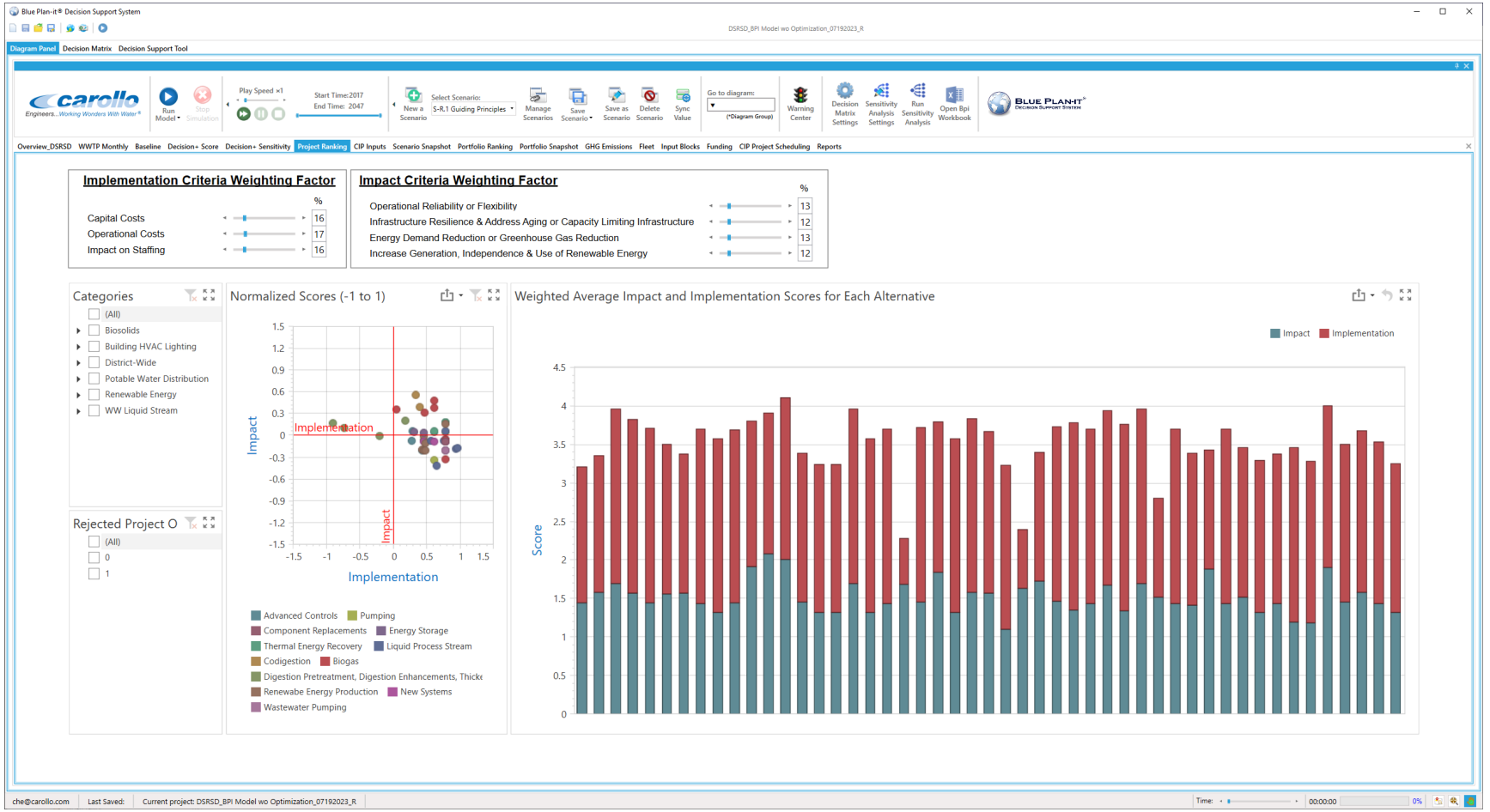

Figure 11A.1 BPI Model Project Ranking Dashboard

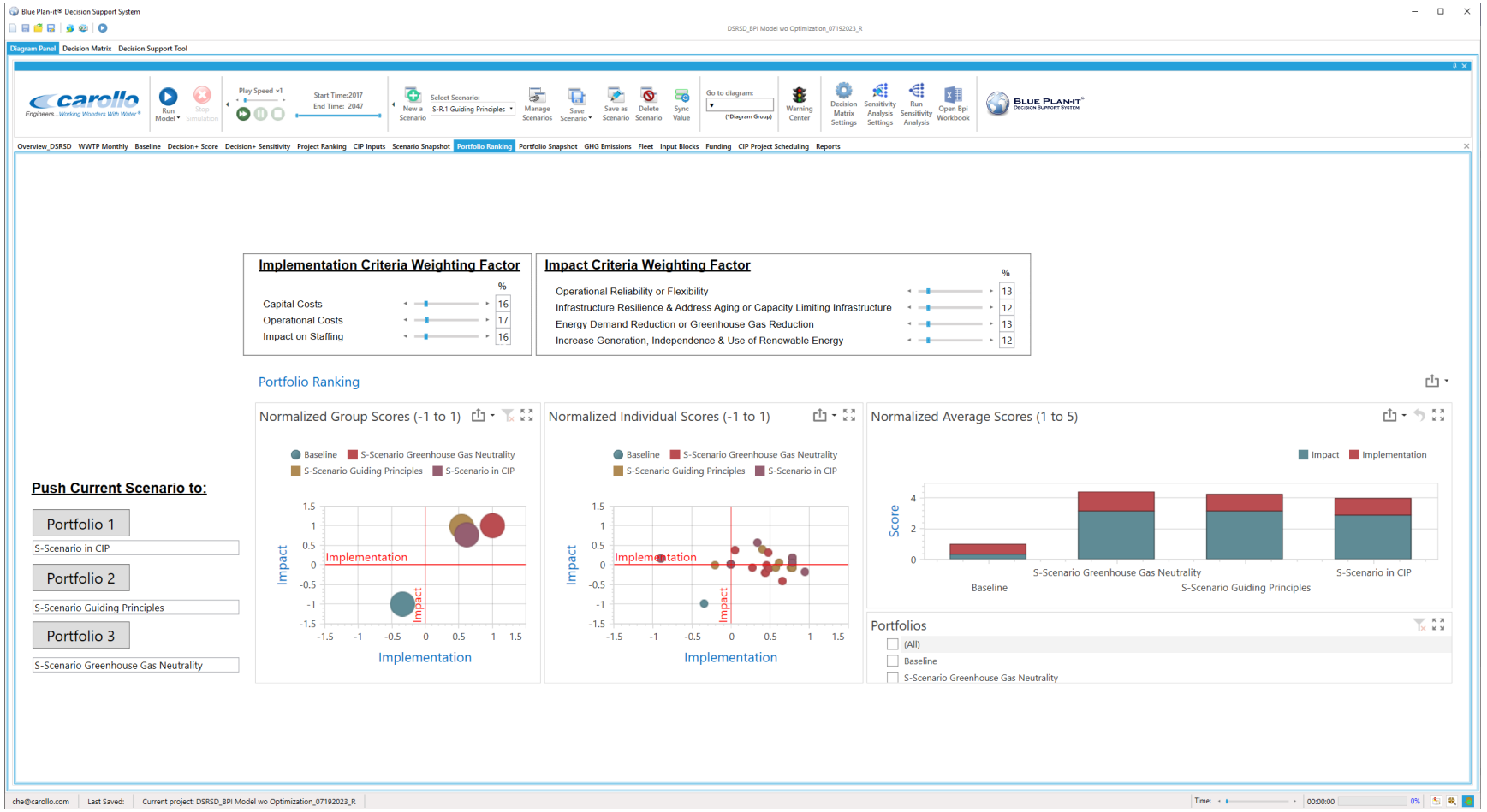

Figure 11A.2 BPI Model Portfolio Ranking Dashboard

To calculate implementation and impact scores for a portfolio, follow these steps:

- Select a list of energy CIP projects to build a scenario.
- Select three scenarios and make them Portfolios 1, 2, and 3.
- Compare three portfolios with baseline "Do Nothing" at the same time.
- Calculate the "group" overall score by averaging scores of each project in that portfolio for a given criterion and then normalize the average score onto the 1 to 5 scale. The baseline "Do Nothing" portfolio would have the best implementation score (5) but the worst impact score (1). The portfolio that contains all energy CIP projects has the best impact score (5) but the lowest implementation score (1). See the bar charts on the Portfolio Ranking Dashboard (Figure 11A.2).
- Calculated impact and implementation scores for each portfolio were also normalized onto a -1 to 1 scale and used in the quadrant charts on the Portfolio Ranking Dashboard (Figure 11A.2). The baseline "Do Nothing" portfolio would have the best implementation score (1) but the worst impact score (-1). The portfolio that contains all energy CIP projects has the best impact score (1) but the lowest implementation score (-1).

Refer to Appendix 11B for a step-by-step quick guide on how to use the BPI energy model to perform alternative project ranking and alternative portfolio evaluation.

Alternative Summary

To create alternative portfolios for further evaluation using the BPI energy model, inputs from DSRSD staff were collected through an email survey. These alternatives were reviewed at the alternative evaluation workshop. Consensus was built and seven recommended alternatives (see Table 11A.3) were developed shortly after the workshop, including the following:

- Baseline Portfolio.
- Portfolio 1: Guiding Principles.
- Portfolio 2: Energy Independence.
- Portfolio 3: Prioritized Energy Efficiency.
- Portfolio 4: All Renewable Energy.
- Portfolio 5: GHG Neutrality.
- Portfolio 6: Favorable Payback (less than 15 years).
- Portfolio 7: Current CIP.

Figures 11A.3 through 11A.5 present a comparison of each recommended portfolio on electricity consumption, natural gas consumption, and GHG emissions.

Table 11A.3 Seven Recommended Portfolios

Categories	ID	Projects	Guiding Principles	Energy Independence	Prioritize Energy Efficiency	All Renewable Energy	GHG Neutrality	Favorable Payback (less than 15 years)	Current CIP
WW Liquid Stream	LS5	Real time SRT control			x			x	x
WW Liquid Stream	LS6	Model predictive aeration control	x		x			x	
WW Liquid Stream	LS7	Low DO operation for activated sludge process			x			x	
WW Liquid Stream	LS12	Change to more energy efficient diffusers in aeration basins	x		x				
WW Liquid Stream	LS13	Upgrade to more efficient blowers	x	x	x	x	x	x	
Biosolids	BS2C	Mechanical thickening instead of DAFT	x		x	x	x	x	
Biosolids	BS13	Implement dewatering post digestion				x	x		x
Biosolids	BS23	Co-digest FOG	x	x	x	x	x	x	
Biosolids	BS24	Co-digest food waste slurry/HSW				x	x		x
Biosolids	BS31	Replace cogen with new higher efficiency engine generators	x	x	x	x	x	x	x
Biosolids	BS35	Redundant cogen engine		x			x		x
Potable Water Distribution	PWD2	Assess pump condition for distribution system and DSRSD recycled water distribution system	x						x
Potable Water Distribution	PWD3	Assess pump design point for distribution system and DSRSD recycled water distribution system	x		x			x	x
Building HVAC Lighting	BLG7	Metal building insulation	x		x			x	
Building/HVAC Lighting	BLG8	Screen room air handling unit replacement	x	x	x	x	x	x	
Building/HVAC Lighting	BLG9	Building A and C air handling unit replacement	x	x	x	x	x	x	
Building/HVAC Lighting	BLG10	Bar screen building exhaust fan motor	x	x	x	x	x	x	
Renewable Energy	RE1	Solar installation on site at WWTP	x	x		x			
Renewable Energy	RE2	Solar field off site Gleason property and LAVWMA Basins		x		x	x	x	
Renewable Energy	RE4	Electric vehicle fleet recharged using solar power	x	x		x		x	
Renewable Energy	RE7	Renewable generation partnerships		x		x			
Renewable Energy	ES1	Battery storage and microgrid		x					
Renewable Energy	ES2	Battery storage for equipment/processes driving peak demand charges		x		x		x	
District-Wide	AC1	Additional power monitoring	x	x	x	x			
District-Wide	AC4	Energy decision management tools	x		x	x			
District-Wide	AC5	Install load bank	x	x					

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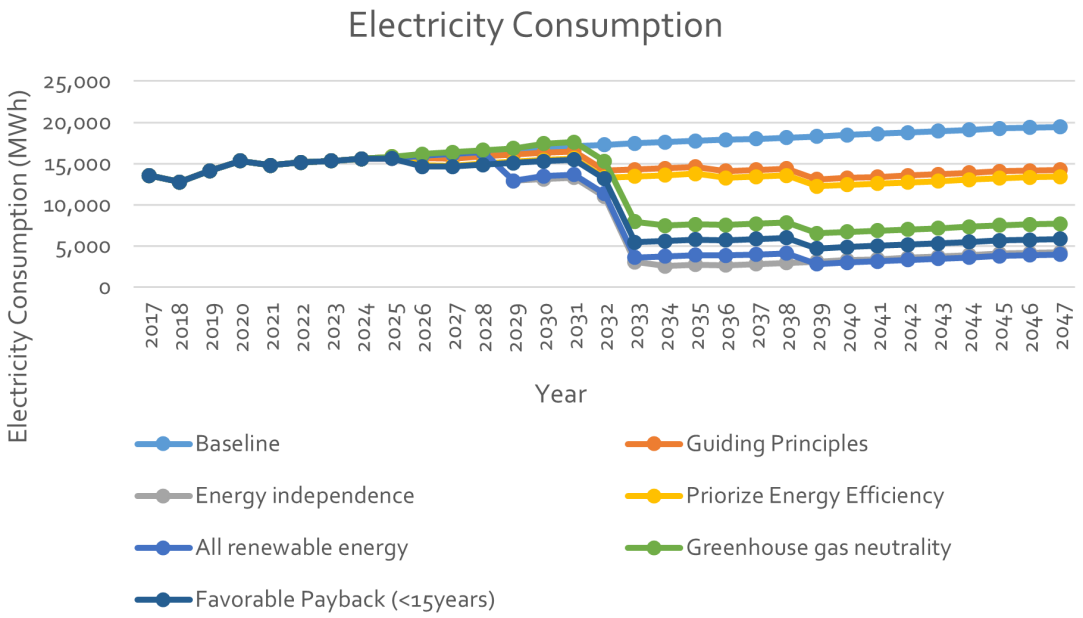

Figure 11A.3 Portfolio Comparison – Electricity Consumption

Year	Baseline	Guiding Principles	Energy independence	Prioritize Energy Efficiency	All renewable energy	Greenhouse gas neutrality	Favorable Payback (<15years)
2017	13,538	13,538	13,538	13,538	13,538	13,538	13,538
2018	12,738	12,738	12,738	12,738	12,738	12,738	12,738
2019	14,108	14,108	14,108	14,108	14,108	14,108	14,108
2020	15,305	15,305	15,305	15,305	15,305	15,305	15,305
2021	14,531	14,531	14,531	14,531	14,531	14,531	14,531
2022	15,130	15,130	15,130	15,130	15,130	15,130	15,130
2023	15,333	15,333	15,333	15,333	15,333	15,333	15,333
2024	15,556	15,559	15,559	15,559	15,559	15,559	15,559
2025	15,806	15,620	15,620	15,811	15,620	15,811	15,620
2026	16,029	15,676	15,958	14,808	15,958	16,149	14,617
2027	16,265	15,623	16,146	14,755	16,146	16,386	14,613
2028	16,494	15,853	16,376	14,985	16,376	16,616	14,843
2029	16,712	16,072	12,895	15,204	12,895	16,835	15,062
2030	16,933	16,308	13,118	15,426	13,475	17,415	15,284
2031	17,106	16,483	13,293	15,602	13,650	17,590	15,460
2032	17,282	14,159	10,969	13,277	11,326	15,266	13,135
2033	17,444	14,270	3,040	13,444	3,577	7,932	5,442
2034	17,596	14,422	2,556	13,595	3,728	7,449	5,593
2035	17,756	14,583	2,718	13,757	3,890	7,611	5,755
2036	17,876	14,098	2,666	13,271	3,838	7,558	5,702
2037	18,011	14,234	2,802	13,408	3,974	7,694	5,838

Year	Baseline	**Guiding Principles**	**Energy independence**	**Prioritize Energy Efficiency**	**All renewable energy**	**Greenhouse gas neutrality**	**Favorable Payback (<15years)**
2038	18,149	14,372	2,940	13,545	4,111	7,832	5,976
2039	18,291	13,075	3,082	12,248	2,814	6,535	4,679
2040	18,460	13,247	3,255	12,421	2,987	6,707	4,851
2041	18,599	13,386	3,394	12,559	3,125	6,846	4,990
2042	18,765	13,552	3,559	12,725	3,291	7,012	5,156
2043	18,935	13,698	3,706	12,871	3,438	7,158	5,302
2044	19,103	13,866	3,874	13,040	3,606	7,326	5,470
2045	19,280	14,043	4,050	13,216	3,782	7,503	5,647
2046	19,386	14,149	4,157	13,323	3,889	7,609	5,753
2047	19,464	14,227	4,234	13,400	3,966	7,687	5,831

Note: Baseline electricity consumption includes WWTP, PWD, RWD, Field Operations Facility, District Buildings, etc.

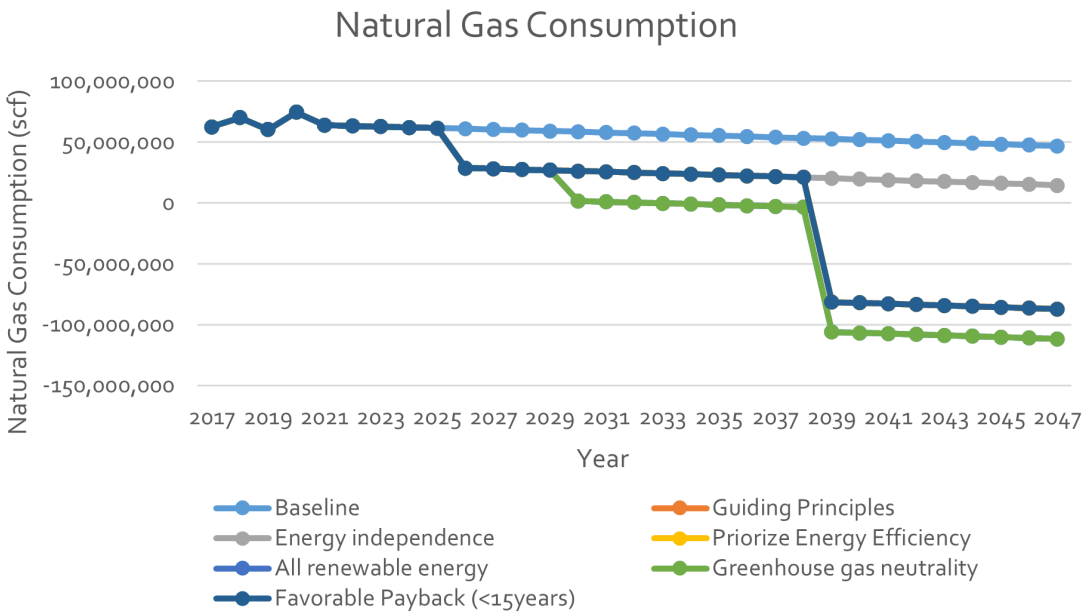

Figure 11A.4 Portfolio Comparison – Natural Gas Consumption

Year	Baseline	Guiding Principles	Energy independence	Prioritize Energy Efficiency	All renewable energy	Greenhouse gas neutrality	Favorable Payback (<15years)
2017	62,569,325	62,569,325	62,569,325	62,569,325	62,569,325	62,569,325	62,569,325
2018	70,041,130	70,041,130	70,041,130	70,041,130	70,041,130	70,041,130	70,041,130
2019	60,357,120	60,357,120	60,357,120	60,357,120	60,357,120	60,357,120	60,357,120
2020	74,612,765	74,612,765	74,612,765	74,612,765	74,612,765	74,612,765	74,612,765
2021	64,084,241	64,084,241	64,084,241	64,084,241	64,084,241	64,084,241	64,084,241
2022	63,318,956	63,318,956	63,318,956	63,318,956	63,318,956	63,318,956	63,318,956
2023	62,746,940	62,746,940	62,746,940	62,746,940	62,746,940	62,746,940	62,746,940
2024	62,168,289	62,168,289	62,168,289	62,168,289	62,168,289	62,168,289	62,168,289
2025	61,582,925	61,582,925	61,582,925	61,582,925	61,582,925	61,582,925	61,582,925
2026	60,990,771	28,674,771	28,674,771	28,674,771	28,674,771	28,674,771	28,674,771
2027	60,391,748	28,072,629	28,075,748	28,072,629	28,075,748	28,075,748	28,072,629
2028	59,785,776	27,466,657	27,469,776	27,466,657	27,469,776	27,469,776	27,466,657
2029	59,172,775	26,853,656	26,856,775	26,853,656	26,856,775	26,856,775	26,853,656
2030	58,552,663	26,233,544	26,236,663	26,233,544	1,644,663	1,644,663	26,233,544
2031	57,925,358	25,606,239	25,609,358	25,606,239	1,017,358	1,017,358	25,606,239
2032	57,290,777	24,971,658	24,974,777	24,971,658	382,777	382,777	24,971,658
2033	56,648,834	24,329,715	24,332,834	24,329,715	-259,166	-259,166	24,329,715
2034	55,999,444	23,680,325	23,683,444	23,680,325	-908,556	-908,556	23,680,325
2035	55,342,522	23,023,403	23,026,522	23,023,403	-1,565,478	-1,565,478	23,023,403
2036	54,677,979	22,358,860	22,361,979	22,358,860	-2,230,021	-2,230,021	22,358,860

Year	Baseline	**Guiding Principles**	**Energy independence**	**Prioritize Energy Efficiency**	**All renewable energy**	**Greenhouse gas neutrality**	**Favorable Payback (<15years)**
2037	54,005,728	21,686,609	21,689,728	21,686,609	-2,902,272	-2,902,272	21,686,609
2038	53,325,678	21,006,559	21,009,678	21,006,559	-3,582,322	-3,582,322	21,006,559
2039	52,637,740	-81,516,379	20,321,740	-81,516,379	-106,105,260	-106,105,260	-81,516,379
2040	51,941,822	-82,212,297	19,625,822	-82,212,297	-106,801,178	-106,801,178	-82,212,297
2041	51,237,832	-82,916,287	18,921,832	-82,916,287	-107,505,168	-107,505,168	-82,916,287
2042	50,525,674	-83,628,445	18,209,674	-83,628,445	-108,217,326	-108,217,326	-83,628,445
2043	49,805,256	-84,348,863	17,489,256	-84,348,863	-108,937,744	-108,937,744	-84,348,863
2044	49,076,481	-85,077,638	16,760,481	-85,077,638	-109,666,519	-109,666,519	-85,077,638
2045	48,339,253	-85,814,866	16,023,253	-85,814,866	-110,403,747	-110,403,747	-85,814,866
2046	47,593,472	-86,560,647	15,277,472	-86,560,647	-111,149,528	-111,149,528	-86,560,647
2047	46,839,040	-87,315,079	14,523,040	-87,315,079	-111,903,960	-111,903,960	-87,315,079

Note: Baseline NG consumption includes Cogen, Field Operations Facility, and Buildings etc.

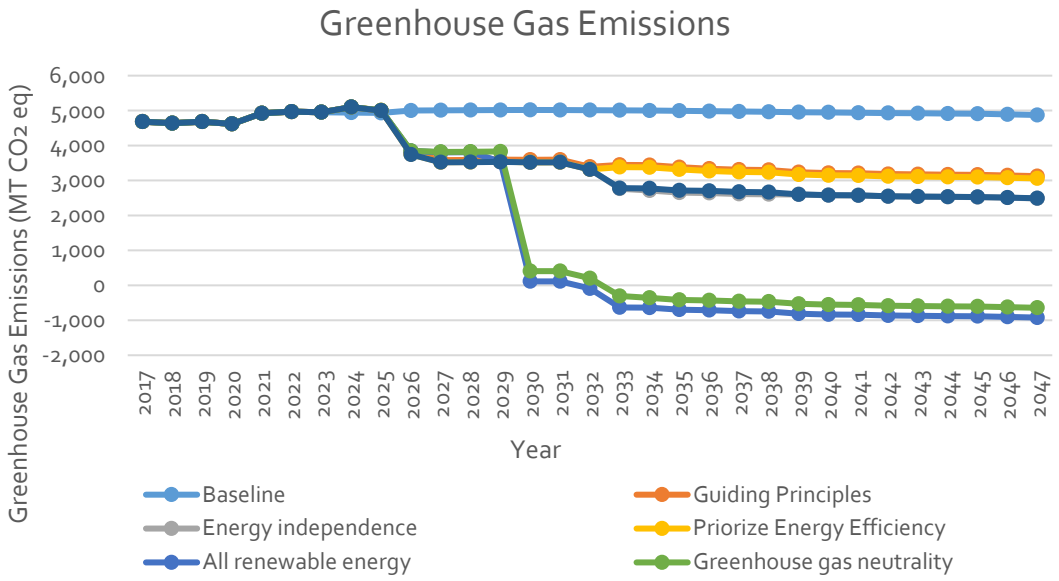

Figure 11A.5 Portfolio Comparison – Greenhouse Gas Emissions

Year	Baseline	Guiding Principles	Energy independence	Prioritize Energy Efficiency	All renewable energy	Greenhouse gas neutrality	Favorable Payback (<15years)
2017	4,682	4,682	4,682	4,682	4,682	4,682	4,682
2018	4,640	4,640	4,640	4,640	4,640	4,640	4,640
2019	4,682	4,682	4,682	4,682	4,682	4,682	4,682
2020	4,619	4,619	4,619	4,619	4,619	4,619	4,619
2021	4,923	4,923	4,923	4,923	4,923	4,923	4,923
2022	4,967	4,967	4,967	4,967	4,967	4,967	4,967
2023	4,953	4,953	4,953	4,953	4,953	4,953	4,953
2024	4,941	5,099	5,099	5,099	5,099	5,099	5,099
2025	4,932	4,998	4,998	5,005	4,998	5,005	4,998
2026	5,002	3,809	3,841	3,749	3,841	3,848	3,742
2027	5,008	3,582	3,806	3,522	3,806	3,817	3,519
2028	5,012	3,587	3,811	3,527	3,811	3,822	3,524
2029	5,015	3,595	3,537	3,535	3,537	3,830	3,532
2030	5,018	3,594	3,523	3,521	113	406	3,518
2031	5,015	3,597	3,526	3,524	116	409	3,521
2032	5,012	3,392	3,321	3,319	-89	204	3,316
2033	5,007	3,448	2,766	3,382	-631	-305	2,781
2034	5,000	3,441	2,713	3,375	-638	-358	2,774
2035	4,995	3,382	2,654	3,316	-697	-417	2,715
2036	4,983	3,337	2,641	3,271	-710	-430	2,702

Year	Baseline	**Guiding Principles**	**Energy independence**	**Prioritize Energy Efficiency**	**All renewable energy**	**Greenhouse gas neutrality**	**Favorable Payback (<15years)**
2037	4,974	3,310	2,614	3,244	-737	-457	2,675
2038	4,964	3,300	2,604	3,234	-747	-467	2,665
2039	4,955	3,238	2,601	3,172	-809	-529	2,603
2040	4,949	3,214	2,577	3,148	-833	-553	2,579
2041	4,938	3,209	2,572	3,143	-838	-558	2,574
2042	4,931	3,184	2,547	3,118	-863	-583	2,549
2043	4,924	3,177	2,540	3,111	-870	-590	2,542
2044	4,916	3,169	2,532	3,103	-878	-598	2,534
2045	4,909	3,162	2,525	3,096	-885	-605	2,527
2046	4,893	3,146	2,509	3,080	-901	-621	2,511
2047	4,873	3,126	2,489	3,060	-921	-641	2,491

Note: Baseline electricity consumption includes WWTP, PWD, RWD, Field Operations Facility, District Buildings, etc.

Year	Baseline	Guiding Principles	Energy independence	Prioritize Energy Efficiency	All renewable energy	Greenhouse gas neutrality	Favorable Payback (<15years)
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	1,043	4,043	3,963	3,363	3,973	3,323	3,933
2025	2,545	3,274	3,075	2,894	4,965	4,685	3,094
2026	3,952	16,076	15,907	15,836	18,187	17,467	15,596
2027	9,142	16,841	16,841	13,961	25,481	22,601	16,841
2028	12,510	265	265	265	8,905	8,905	265
2029	12,532	287	287	287	8,927	8,927	287
2030	13,810	1,024	8,494	990	1,144	8,531	890
2031	14,400	1,084	1,134	1,050	1,204	1,171	950
2032	530	5,590	6,790	5,188	6,315	5,913	4,588
2033	7,213	6,013	5,413	6,013	6,738	6,738	5,413
2034	1,634	1,634	1,634	1,634	1,634	1,634	1,634
2035	343	1,073	343	1,143	1,073	1,073	1,143
2036	1,937	2,667	1,937	2,667	2,667	2,667	2,667
2037	342	4,722	342	4,722	4,722	4,722	4,722
2038	322	4,702	322	4,702	4,702	4,702	4,702
2039	349	349	349	349	349	349	349
2040	158	158	158	158	158	158	158
2041	231	231	231	231	231	231	231
2042	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0

Note: Baseline capital cost is equal to the Capital cost for the current CIP lists.

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Appendix 11B

BPI ENERGY MODEL QUICK GUIDE

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11B

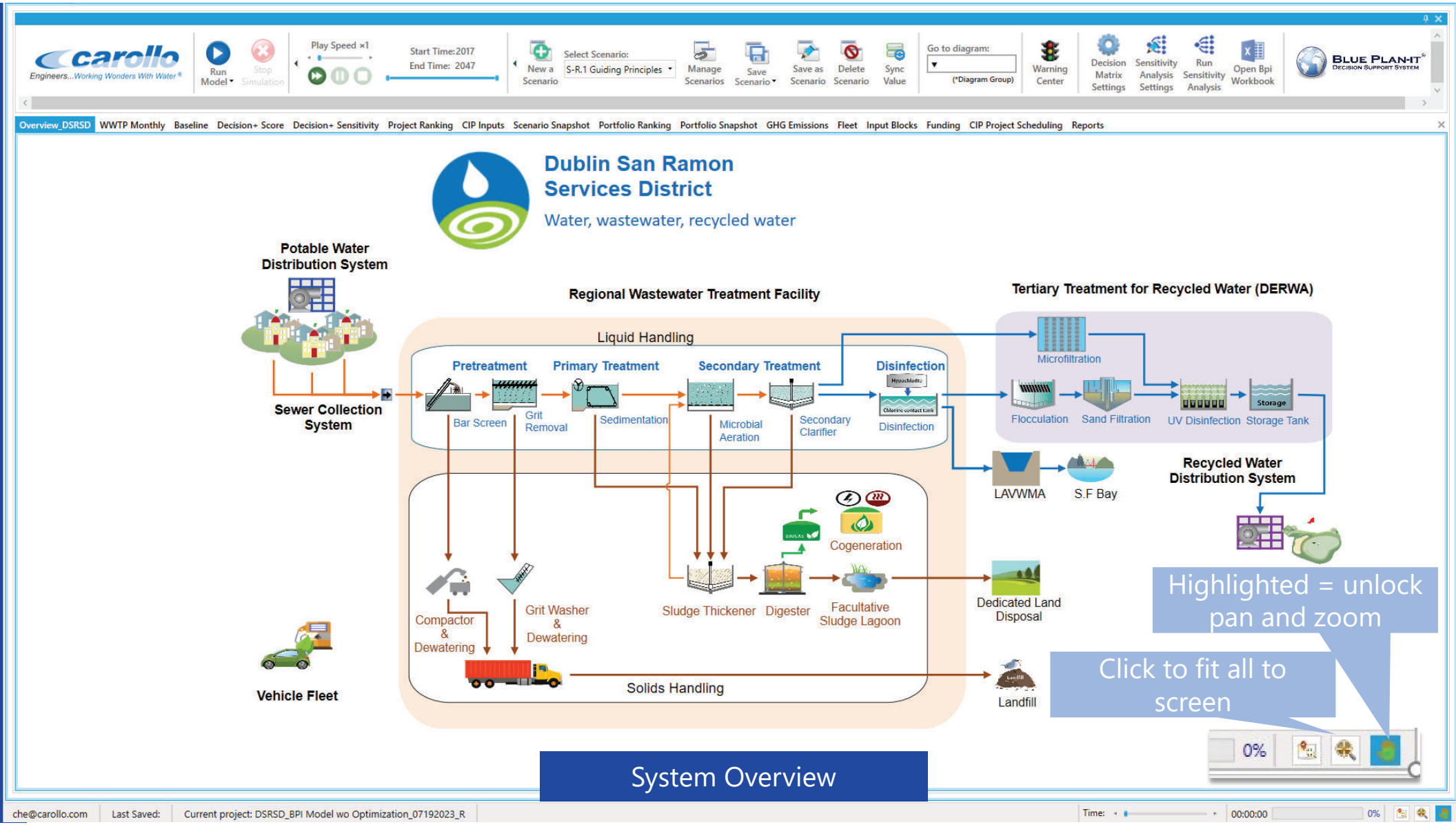
Appendix 11B: Blue Plan-it® Energy Model Quick Guide

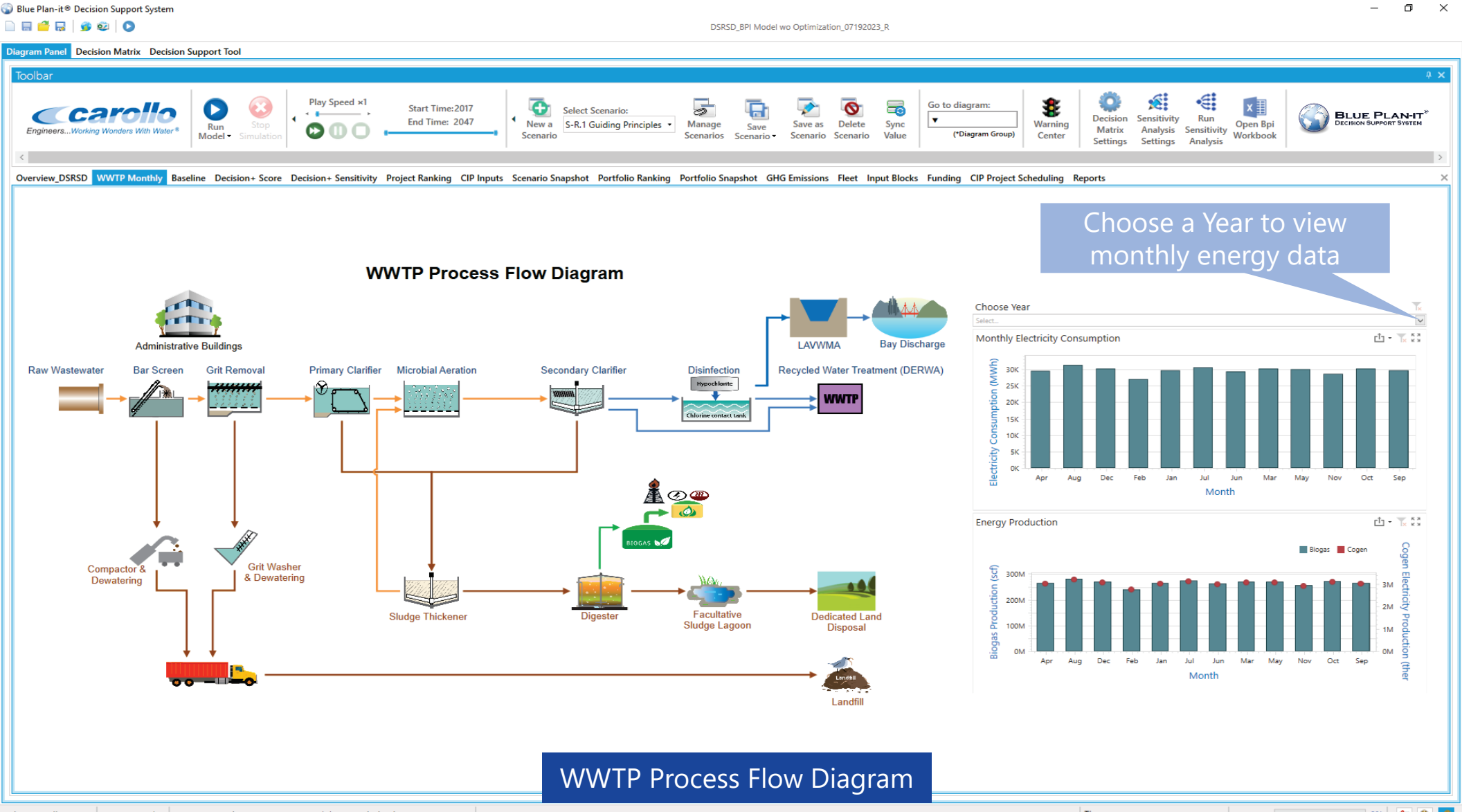
TM 11 Alternative Evaluation

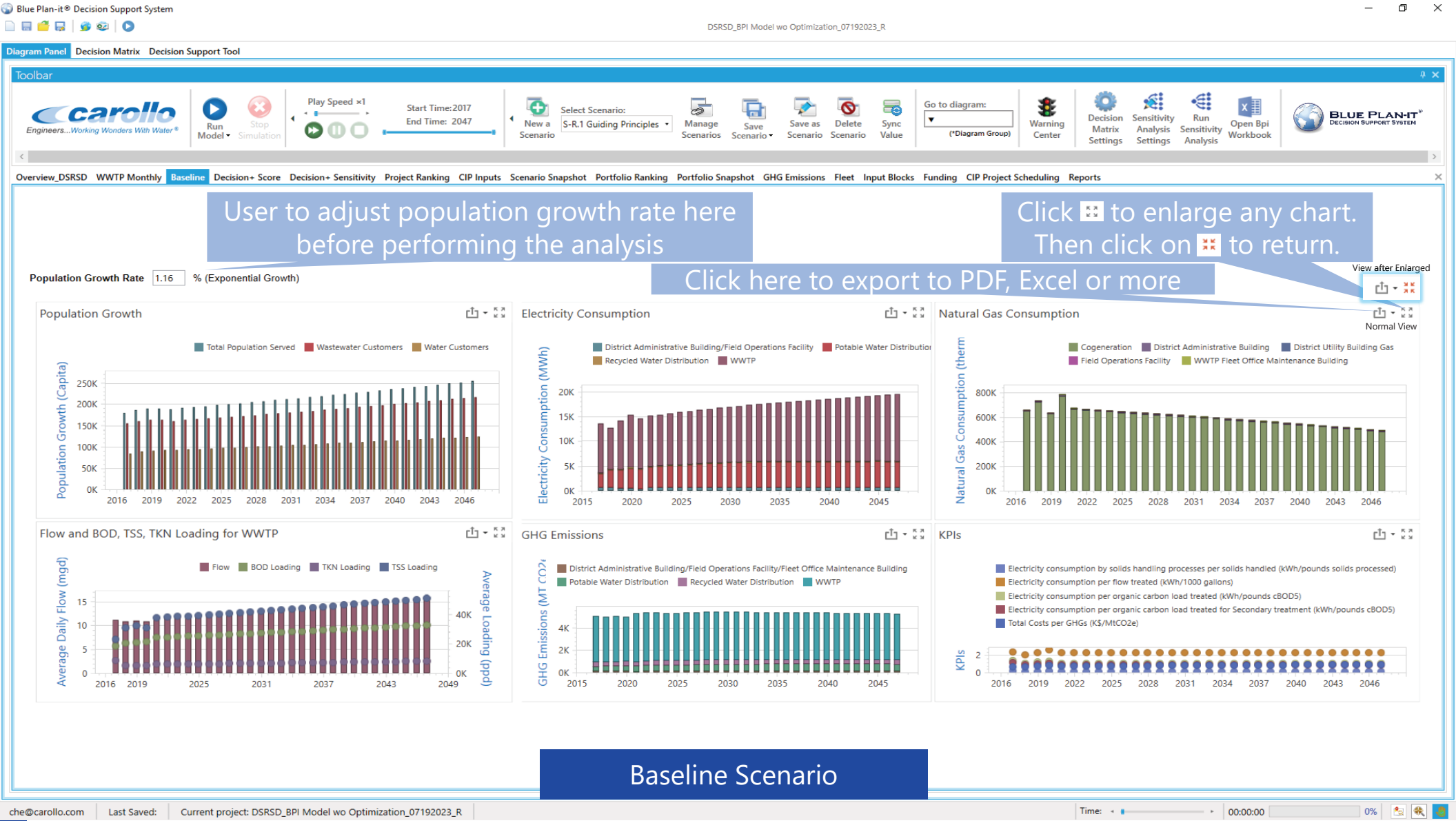
BLUE PLAN-IT®
DECISION SUPPORT SYSTEM

carollo

90 YEARS


carollo
Engineers...Working Wonders With Water
Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
Save Scenario
Save as Scenario
Delete Scenario
Sync Value
Go to diagram:
(*Diagram Group)
Warning Center
Decision Matrix Settings
Sensitivity Analysis Settings
Run Sensitivity Analysis
Open Bpi Workbook
BLUE PLAN-IT
DECISION SUPPORT SYSTEM
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
Dublin San Ramon Services District
Water, wastewater, recycled water
Potable Water Distribution System
Sewer Collection System
Regional Wastewater Treatment Facility
Liquid Handling
Pretreatment
Primary Treatment
Secondary Treatment
Disinfection
Bar Screen
Grit Removal
Sedimentation
Microbial Aeration
Secondary Clarifier
Disinfection
Tertiary Treatment for Recycled Water (DERWA)
Microfiltration
Flocculation
Sand Filtration
UV Disinfection
Storage Tank
LAVWMA
S.F Bay
Recycled Water Distribution System
Cogeneration
Compactor & Dewatering
Grit Washer & Dewatering
Sludge Thickener
Digester
Facultative Sludge Lagoon
Dedicated Land Disposal
Solids Handling
Landfill
Vehicle Fleet
Highlighted = unlock pan and zoom
Click to fit all to screen
System Overview
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time:
00:00:00
0%


Blue Plan-it® Decision Support System
DSRSD_BPI Model wo Optimization_07192023_R
Diagram Panel
Decision Matrix
Decision Support Tool
Toolbar
carollo
Engineers...Working Wonders With Water®
Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
Save Scenario
Save as Scenario
Delete Scenario
Sync Value
Go to diagram:
(*Diagram Group)
Warning Center
Decision Matrix Settings
Sensitivity Analysis Settings
Run Sensitivity Analysis
Open Bpi Workbook
BLUE PLAN-IT
DECISION SUPPORT SYSTEM
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
WWTP Process Flow Diagram
Administrative Buildings
Raw Wastewater
Bar Screen
Grit Removal
Primary Clarifier
Microbial Aeration
Secondary Clarifier
Disinfection
Hypochlorite
Chlorine contact tank
LAVWMA
Bay Discharge
Recycled Water Treatment (DERWA)
WWTP
Compactor & Dewatering
Grit Washer & Dewatering
BIOGAS
Sludge Thickener
Digester
Facultative Sludge Lagoon
Dedicated Land Disposal
Landfill
Choose a Year to view monthly energy data
Choose Year
Select...
Monthly Electricity Consumption
Electricity Consumption (MWh)
30K
25K
20K
15K
10K
5K
0K
Apr Aug Dec Feb Jan Jul Jun Mar May Nov Oct Sep
Month
Energy Production
Biogas
Cogen
Biogas Production (scf)
300M
200M
100M
0M
Cogen Electricity Production (ther
3M
2M
1M
0M
Apr Aug Dec Feb Jan Jul Jun Mar May Nov Oct Sep
Month
WWTP Process Flow Diagram
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time:
00:00:00
0%


Blue Plan-it® Decision Support System
DSRSD_BPI Model wo Optimization_07192023_R
Diagram Panel
Decision Matrix
Decision Support Tool
Toolbar
carollo
Engineers...Working Wonders With Water®
Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
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Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
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Save as Scenario
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Sensitivity Analysis Settings
Run Sensitivity Analysis
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DECISION SUPPORT SYSTEM
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
User to adjust population growth rate here before performing the analysis
Click to enlarge any chart. Then click on to return.
Click here to export to PDF, Excel or more
View after Enlarged
Normal View
Population Growth Rate
1.16
% (Exponential Growth)
Population Growth
Total Population Served
Wastewater Customers
Water Customers
Population Growth (Capita)
Electricity Consumption
District Administrative Building/Field Operations Facility
Potable Water Distributio
Recycled Water Distribution
WWTP
Electricity Consumption (MWh)
Natural Gas Consumption
Cogeneration
District Administrative Building
District Utility Building Gas
Field Operations Facility
WWTP Fleet Office Maintenance Building
Natural Gas Consumption (therm
Flow and BOD, TSS, TKN Loading for WWTP
Flow
BOD Loading
TKN Loading
TSS Loading
Average Daily Flow (mgd)
Average Loading (ppd)
GHG Emissions
District Administrative Building/Field Operations Facility/Fleet Office Maintenance Building
Potable Water Distribution
Recycled Water Distribution
WWTP
GHG Emissions (MT CO2
KPIs
Electricity consumption by solids handling processes per solids handled (kWh/pounds solids processed)
Electricity consumption per flow treated (kWh/1000 gallons)
Electricity consumption per organic carbon load treated (kWh/pounds cBOD5)
Electricity consumption per organic carbon load treated for Secondary treatment (kWh/pounds cBOD5)
Total Costs per GHGs (K$/MtCO2e)
Baseline Scenario
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time:
00:00:00
0%

Blue Plan-it® Decision Support System

DSRSD_BPI Model wo Optimization_07192023_R

Diagram Panel | Decision Matrix | Decision Support Tool

Toolbar

carollo Engineers...Working Wonders With Water®

Run Model | Stop Simulation | Play Speed ×1 | Start Time:2017 End Time: 2047

New a Scenario | Select Scenario: S-R.1 Guiding Principles | Manage Scenarios | Save Scenario | Save as Scenario | Delete Scenario | Sync Value

Go to diagram: (*Diagram Group)

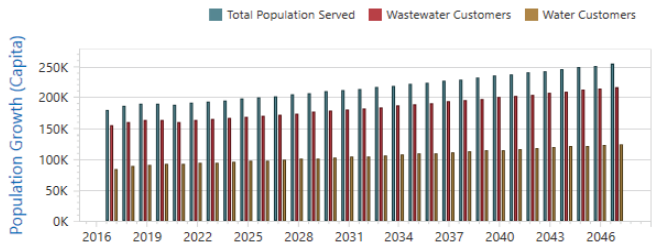
Warning Center | Decision Matrix Settings | Sensitivity Analysis Settings | Run Sensitivity Analysis | Open Bpi Workbook

BLUE PLAN-IT® DECISION SUPPORT SYSTEM

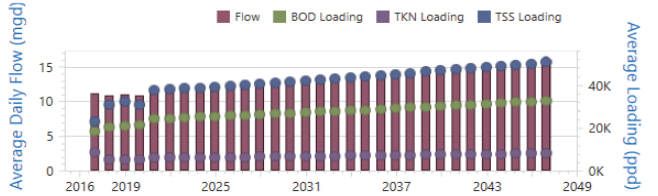
Overview_DSRSD | WWTP Monthly | Baseline | Decision+ Score | Decision+ Sensitivity | Project Ranking | CIP Inputs | Scenario Snapshot | Portfolio Ranking | Portfolio Snapshot | GHG Emissions | Fleet | Input Blocks | Funding | CIP Project Scheduling | Reports

Population Growth Rate 1.16 % (Exponential Growth)

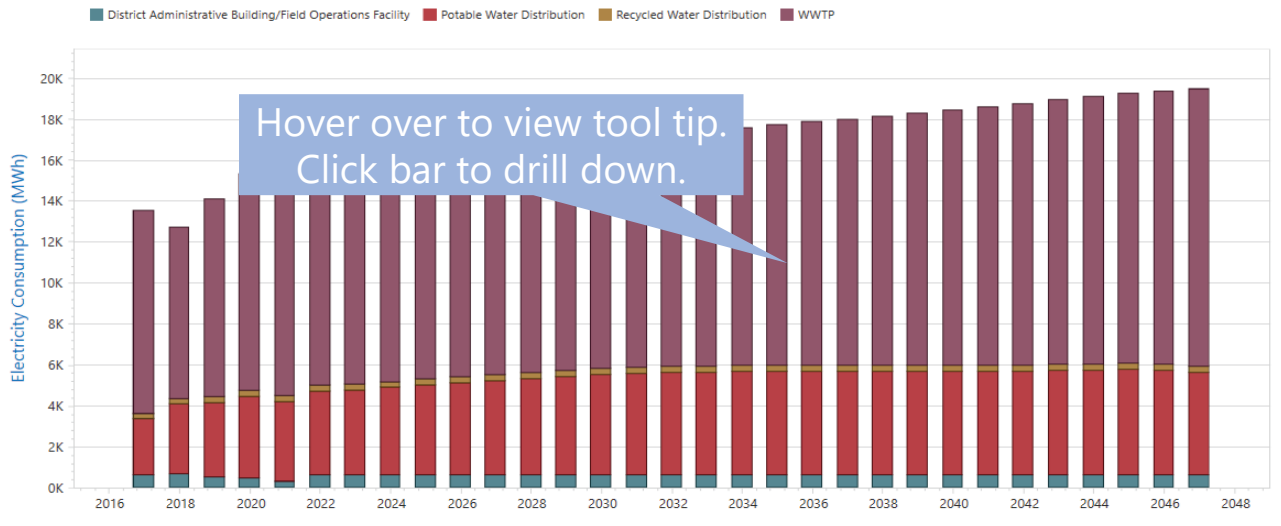
Population Growth



Flow and BOD, TSS, TKN Loading for WWTP



Electricity Consumption



che@carollo.com | Last Saved: | Current project: DSRSD_BPI Model wo Optimization_07192023_R | Time: 00:00:00 0%

Blue Plan-it® Decision Support System

DSRSD_BPI Model wo Optimization_07192023_R

Diagram Panel | Decision Matrix | Decision Support Tool

Toolbar

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Run Model | Stop Simulation | Play Speed ×1 | Start Time:2017 End Time: 2047 | New a Scenario | Select Scenario: S-R.1 Guiding Principles | Manage Scenarios | Save Scenario | Save as Scenario | Delete Scenario | Sync Value | Go to diagram: (*Diagram Group) | Warning Center | Decision Matrix Settings | Sensitivity Analysis Settings | Run Sensitivity Analysis | Open Bpi Workbook | BLUE PLAN-IT® DECISION SUPPORT SYSTEM

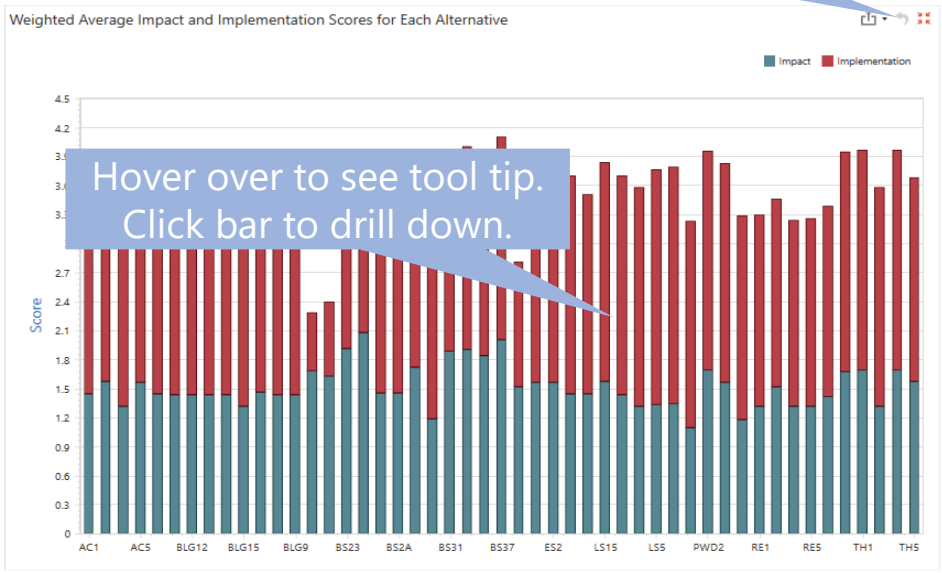
Overview_DSRSD | WWTP Monthly | Baseline | Decision+ Score | Decision+ Sensitivity | Project Ranking | CIP Inputs | Scenario Snapshot | Portfolio Ranking | Portfolio Snapshot | GHG Emissions | Fleet | Input Blocks | Funding | CIP Project Scheduling | Reports

Blue numbers are users inputs.

ID	Strategies	Alternatives	Weight						
			Implementation				Impact		
			16	17	1		12	13	12
			Capital Costs	Operational Costs	Impact on Staffing Resources	[illegible]	Infrastructure Resiliency / Address Aging Infrastructure	Energy Demand Reduction or Increase Generation & Use of Renewable Energy	Greenhouse Gas Reduction
BS37	Biosolids	Condition biogas for pipeline injection	5	5	3	5	5	1	5
BS28	Biosolids	Increase biogas storage	5	5	4	5	2	3	1
BS35	Biosolids	Increase cogen capacity and number of units to avoid peak demand charges during downtime, and for unit redundancy	4	5	3	5	5	3	2
BS31	Biosolids	Replace cogen with new higher efficiency engine generators	1	5	3	5	5	3	2
BS30	Biosolids	Status Quo operation with replacement of aging equipment	5	5	4	3	2	3	1
BS34	Biosolids	Upgrade cogeneration to handle all WWTP electricity needs (microgrid)	5	5	3	5	5	3	2
BS23	Biosolids	Co-digest fats, oils, grease (FOG)	5	4	2	5	5	3	2
BS24	Biosolids	Co-digest food waste slurry/HSW	5	4	2	5	5	3	4
BS2A	Biosolids	DAFT Optimization / Replacement with Mechanical Thickening	5	5	2	3	4	3	1
BS13	Biosolids	Implement dewatering post digestion	1	1	1	4	5	3	1

Note: 1. Please enter the scores in blue on 1 to 5 scale (5 = Best) 2. Values in black are calculated based on costs, energy saving, GHG reduction.

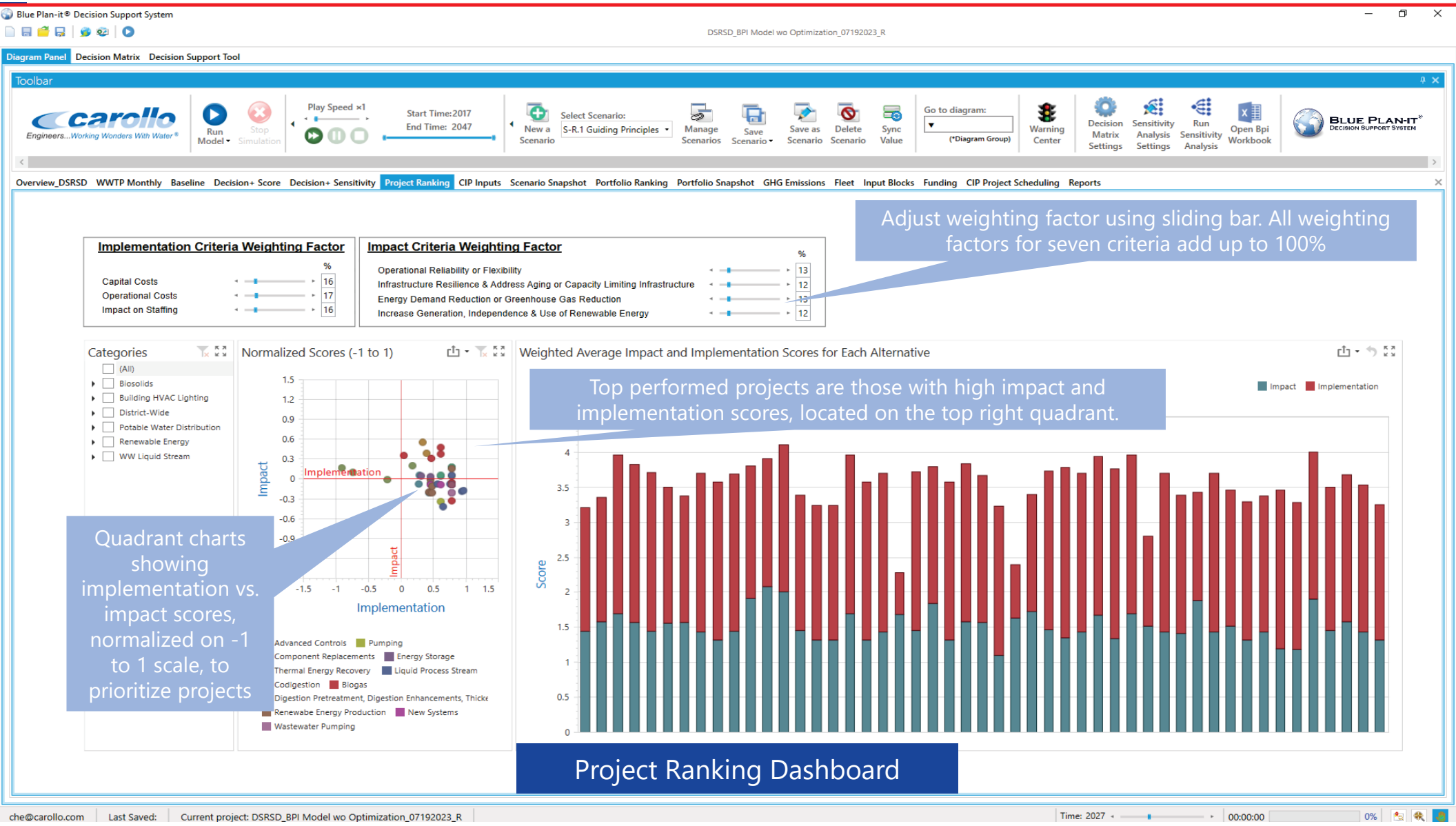
Click arrow to drill up



Hover over to see tool tip.
Click bar to drill down.

Decision Matrix Input Dashboard

che@carollo.com | Last Saved: | Current project: DSRSD_BPI Model wo Optimization_07192023_R | Time: 00:00:00 0%


Blue Plan-it® Decision Support System
DSRSD_BPI Model wo Optimization_07192023_R
Diagram Panel
Decision Matrix
Decision Support Tool
Toolbar
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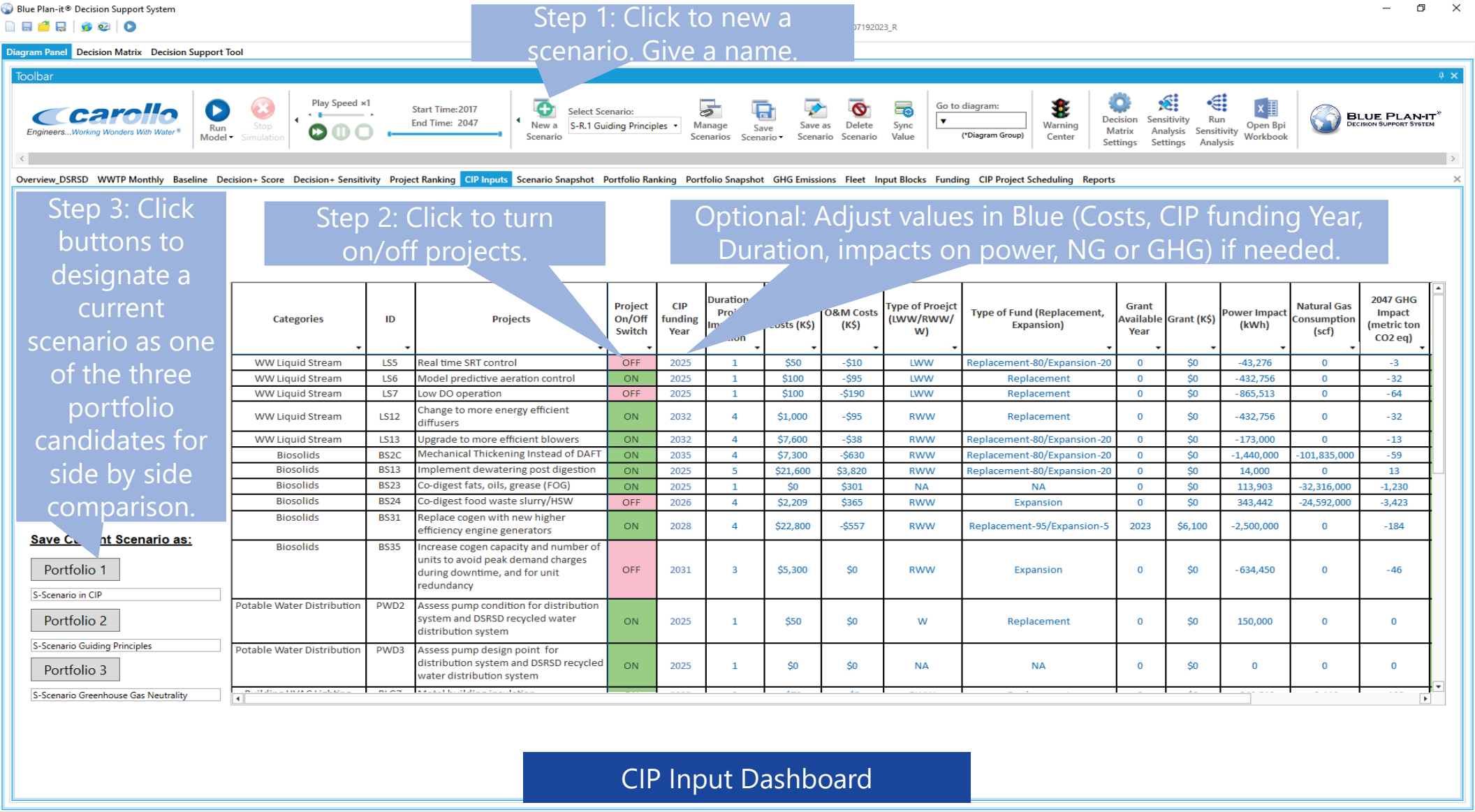
Engineers...Working Wonders With Water®
Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
Save Scenario
Save as Scenario
Delete Scenario
Sync Value
Go to diagram:
(*Diagram Group)
Warning Center
Decision Matrix Settings
Sensitivity Analysis Settings
Run Sensitivity Analysis
Open Bpi Workbook
BLUE PLAN-IT
DECISION SUPPORT SYSTEM
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
Implementation Criteria Weighting Factor
%
Capital Costs 16
Operational Costs 17
Impact on Staffing 16
Impact Criteria Weighting Factor
%
Operational Reliability or Flexibility 13
Infrastructure Resilience & Address Aging or Capacity Limiting Infrastructure 12
Energy Demand Reduction or Greenhouse Gas Reduction 13
Increase Generation, Independence & Use of Renewable Energy 12
Adjust weighting factor using sliding bar. All weighting factors for seven criteria add up to 100%
Categories
(All)
Biosolids
Building HVAC Lighting
District-Wide
Potable Water Distribution
Renewable Energy
WW Liquid Stream
Normalized Scores (-1 to 1)
Impact
Implementation
Advanced Controls
Pumping
Component Replacements
Energy Storage
Thermal Energy Recovery
Liquid Process Stream
Codigestion
Biogas
Digestion Pretreatment, Digestion Enhancements, Thicke
Renewabe Energy Production
New Systems
Wastewater Pumping
Weighted Average Impact and Implementation Scores for Each Alternative
Impact
Implementation
Score
Top performed projects are those with high impact and implementation scores, located on the top right quadrant.
Quadrant charts showing implementation vs. impact scores, normalized on -1 to 1 scale, to prioritize projects
Project Ranking Dashboard
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
00:00:00
0%


Blue Plan-it® Decision Support System
Step 1: Click to new a scenario. Give a name.
Diagram Panel
Decision Matrix
Decision Support Tool
Toolbar
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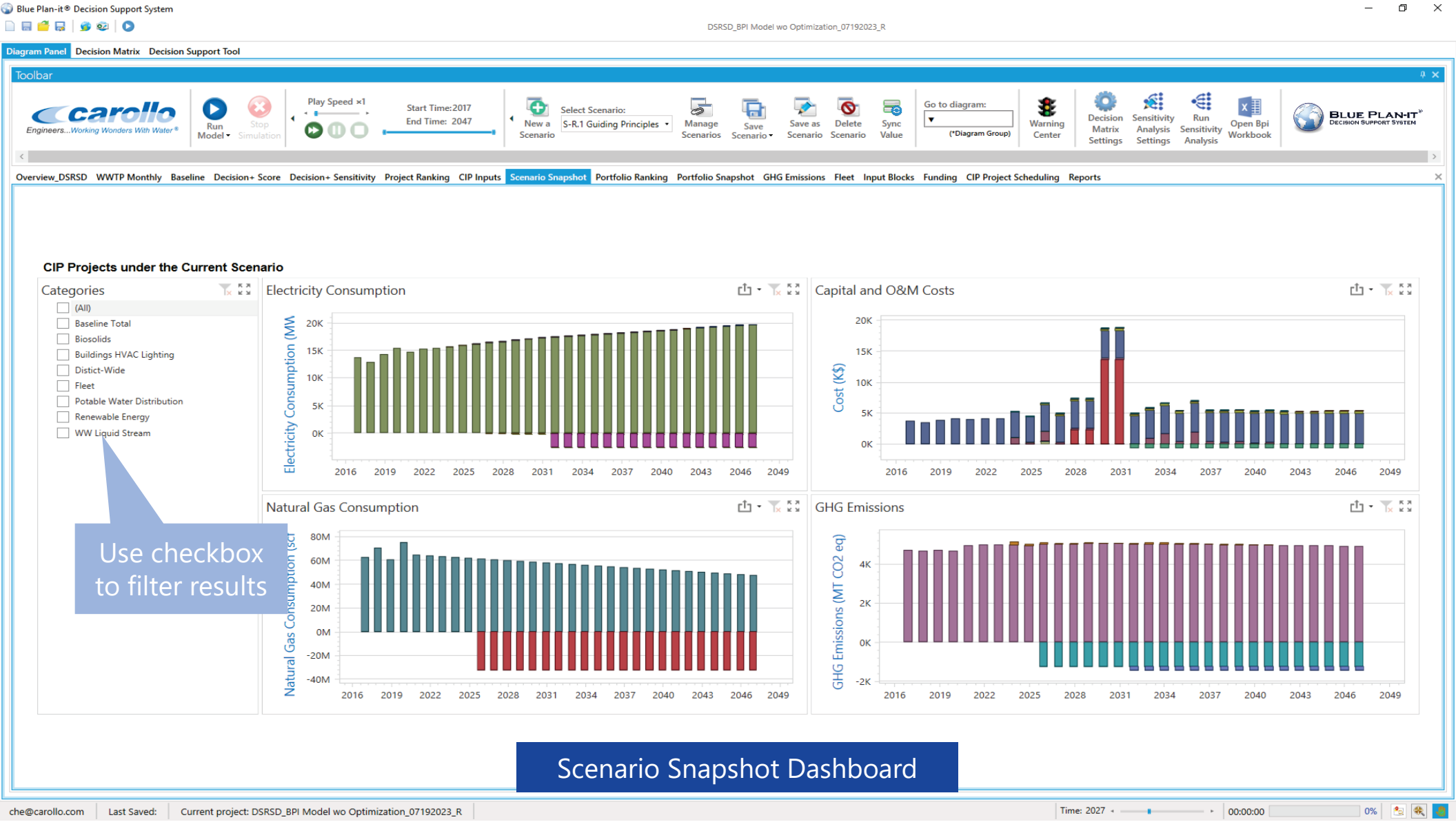
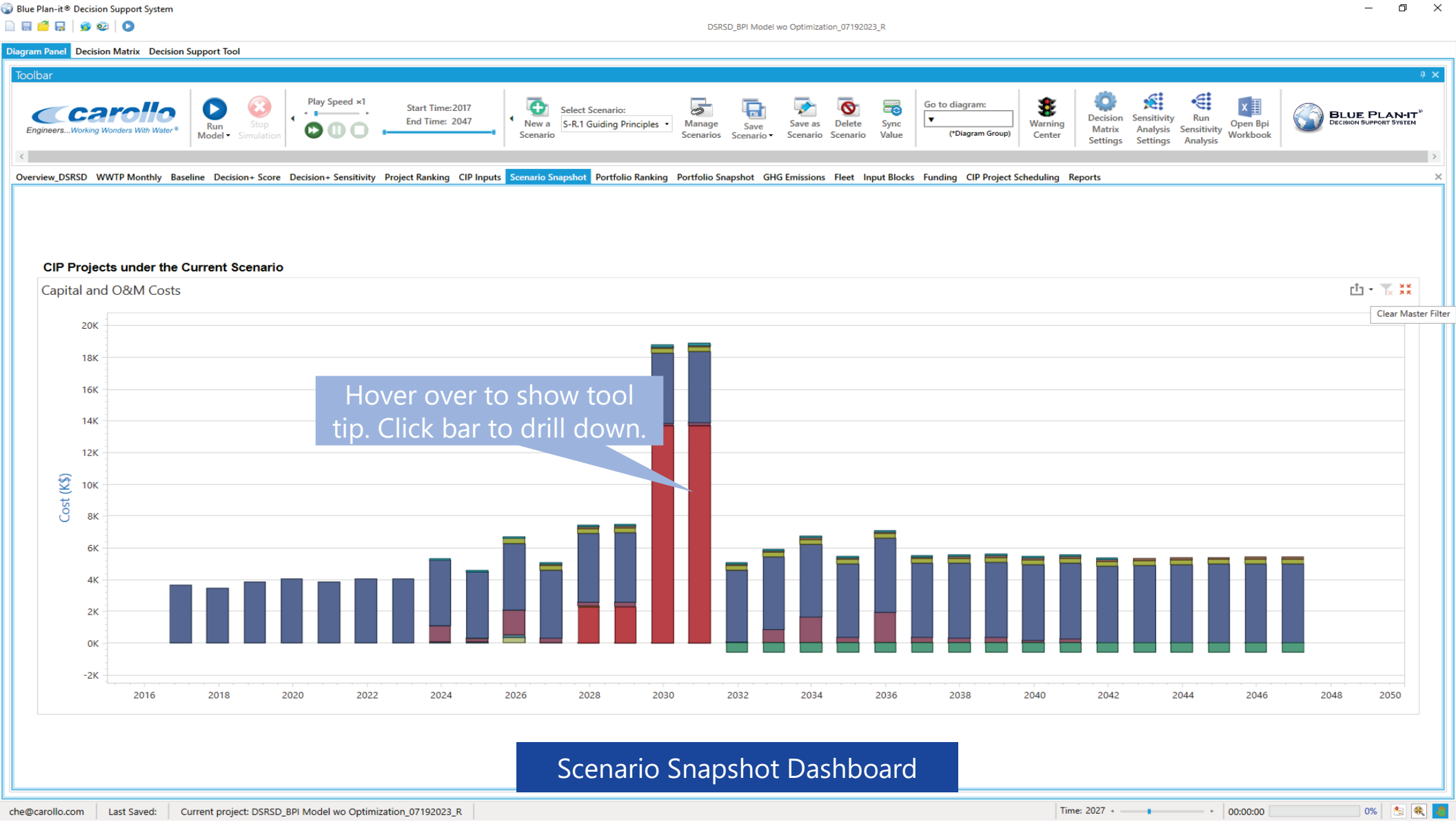
Engineers...Working Wonders With Water®
Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
Save Scenario
Save as Scenario
Delete Scenario
Sync Value
Go to diagram:
(*Diagram Group)
Warning Center
Decision Matrix Settings
Sensitivity Analysis Settings
Run Sensitivity Analysis
Open Bpi Workbook
BLUE PLAN-IT
DECISION SUPPORT SYSTEM
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
Step 3: Click buttons to designate a current scenario as one of the three portfolio candidates for side by side comparison.
Step 2: Click to turn on/off projects.
Optional: Adjust values in Blue (Costs, CIP funding Year, Duration, impacts on power, NG or GHG) if needed.
Save Current Scenario as:
Portfolio 1
S-Scenario in CIP
Portfolio 2
S-Scenario Guiding Principles
Portfolio 3
S-Scenario Greenhouse Gas Neutrality
Categories
ID
Projects
Project On/Off Switch
CIP funding Year
Duration
Costs (K$)
O&M Costs (K$)
Type of Proejct (LWW/RWW/W)
Type of Fund (Replacement, Expansion)
Grant Available Year
Grant (K$)
Power Impact (kWh)
Natural Gas Consumption (scf)
2047 GHG Impact (metric ton CO2 eq)
WW Liquid Stream LS5 Real time SRT control OFF 2025 1 $50 -$10 LWW Replacement-80/Expansion-20 0 $0 -43,276 0 -3
WW Liquid Stream LS6 Model predictive aeration control ON 2025 1 $100 -$95 LWW Replacement 0 $0 -432,756 0 -32
WW Liquid Stream LS7 Low DO operation OFF 2025 1 $100 -$190 LWW Replacement 0 $0 -865,513 0 -64
WW Liquid Stream LS12 Change to more energy efficient diffusers ON 2032 4 $1,000 -$95 RWW Replacement 0 $0 -432,756 0 -32
WW Liquid Stream LS13 Upgrade to more efficient blowers ON 2032 4 $7,600 -$38 RWW Replacement-80/Expansion-20 0 $0 -173,000 0 -13
Biosolids BS2C Mechanical Thickening Instead of DAFT ON 2035 4 $7,300 -$630 RWW Replacement-80/Expansion-20 0 $0 -1,440,000 -101,835,000 -59
Biosolids BS13 Implement dewatering post digestion ON 2025 5 $21,600 $3,820 RWW Replacement-80/Expansion-20 0 $0 14,000 0 13
Biosolids BS23 Co-digest fats, oils, grease (FOG) ON 2025 1 $0 $301 NA NA 0 $0 113,903 -32,316,000 -1,230
Biosolids BS24 Co-digest food waste slurry/HSW OFF 2026 4 $2,209 $365 RWW Expansion 0 $0 343,442 -24,592,000 -3,423
Biosolids BS31 Replace cogen with new higher efficiency engine generators ON 2028 4 $22,800 -$557 RWW Replacement-95/Expansion-5 2023 $6,100 -2,500,000 0 -184
Biosolids BS35 Increase cogen capacity and number of units to avoid peak demand charges during downtime, and for unit redundancy OFF 2031 3 $5,300 $0 RWW Expansion 0 $0 -634,450 0 -46
Potable Water Distribution PWD2 Assess pump condition for distribution system and DSRSD recycled water distribution system ON 2025 1 $50 $0 W Replacement 0 $0 150,000 0 0
Potable Water Distribution PWD3 Assess pump design point for distribution system and DSRSD recycled water distribution system ON 2025 1 $0 $0 NA NA 0 $0 0 0 0
CIP Input Dashboard
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
00:00:00
0%


Blue Plan-it® Decision Support System
DSRSD_BPI Model wo Optimization_07192023_R
Diagram Panel
Decision Matrix
Decision Support Tool
Toolbar
carollo
Engineers...Working Wonders With Water®
Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
Save Scenario
Save as Scenario
Delete Scenario
Sync Value
Go to diagram:
(*Diagram Group)
Warning Center
Decision Matrix Settings
Sensitivity Analysis Settings
Run Sensitivity Analysis
Open Bpi Workbook
BLUE PLAN-IT
DECISION SUPPORT SYSTEM
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
CIP Projects under the Current Scenario
Categories
(All)
Baseline Total
Biosolids
Buildings HVAC Lighting
Distict-Wide
Fleet
Potable Water Distribution
Renewable Energy
WW Liquid Stream
Use checkbox to filter results
Electricity Consumption
Electricity Consumption (MW
20K
15K
10K
5K
0K
2016 2019 2022 2025 2028 2031 2034 2037 2040 2043 2046 2049
Capital and O&M Costs
Cost (K$)
20K
15K
10K
5K
0K
2016 2019 2022 2025 2028 2031 2034 2037 2040 2043 2046 2049
Natural Gas Consumption
Natural Gas Consumption (scf
80M
60M
40M
20M
0M
-20M
-40M
2016 2019 2022 2025 2028 2031 2034 2037 2040 2043 2046 2049
GHG Emissions
GHG Emissions (MT CO2 eq)
4K
2K
0K
-2K
2016 2019 2022 2025 2028 2031 2034 2037 2040 2043 2046 2049
Scenario Snapshot Dashboard
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
00:00:00
0%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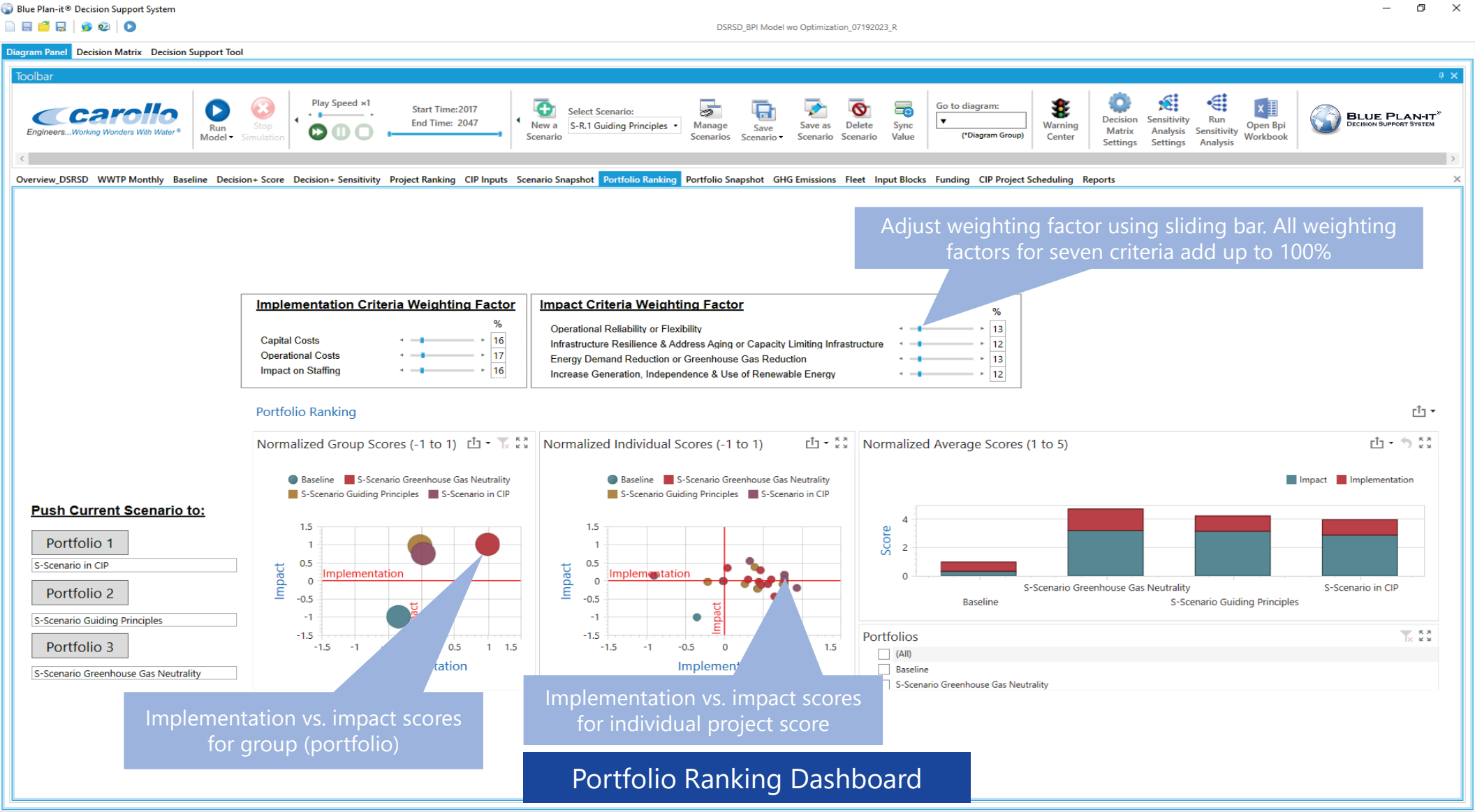
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
CIP Projects under the Current Scenario
Capital and O&M Costs
Clear Master Filter
Hover over to show tool tip. Click bar to drill down.
Cost (K$)
20K
18K
16K
14K
12K
10K
8K
6K
4K
2K
0K
-2K
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
Scenario Snapshot Dashboard
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
00:00:00
0%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carollo
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CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
Adjust weighting factor using sliding bar. All weighting factors for seven criteria add up to 100%
Implementation Criteria Weighting Factor
%
Capital Costs 16
Operational Costs 17
Impact on Staffing 16
Impact Criteria Weighting Factor
%
Operational Reliability or Flexibility 13
Infrastructure Resilience & Address Aging or Capacity Limiting Infrastructure 12
Energy Demand Reduction or Greenhouse Gas Reduction 13
Increase Generation, Independence & Use of Renewable Energy 12
Portfolio Ranking
Normalized Group Scores (-1 to 1)
Normalized Individual Scores (-1 to 1)
Normalized Average Scores (1 to 5)
Baseline
S-Scenario Greenhouse Gas Neutrality
S-Scenario Guiding Principles
S-Scenario in CIP
Impact
Implementation
Score
Push Current Scenario to:
Portfolio 1
S-Scenario in CIP
Portfolio 2
S-Scenario Guiding Principles
Portfolio 3
S-Scenario Greenhouse Gas Neutrality
Portfolios
(All)
Baseline
S-Scenario Greenhouse Gas Neutrality
Implementation vs. impact scores for group (portfolio)
Implementation vs. impact scores for individual project score
Portfolio Ranking Dashboard
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
00:00:00
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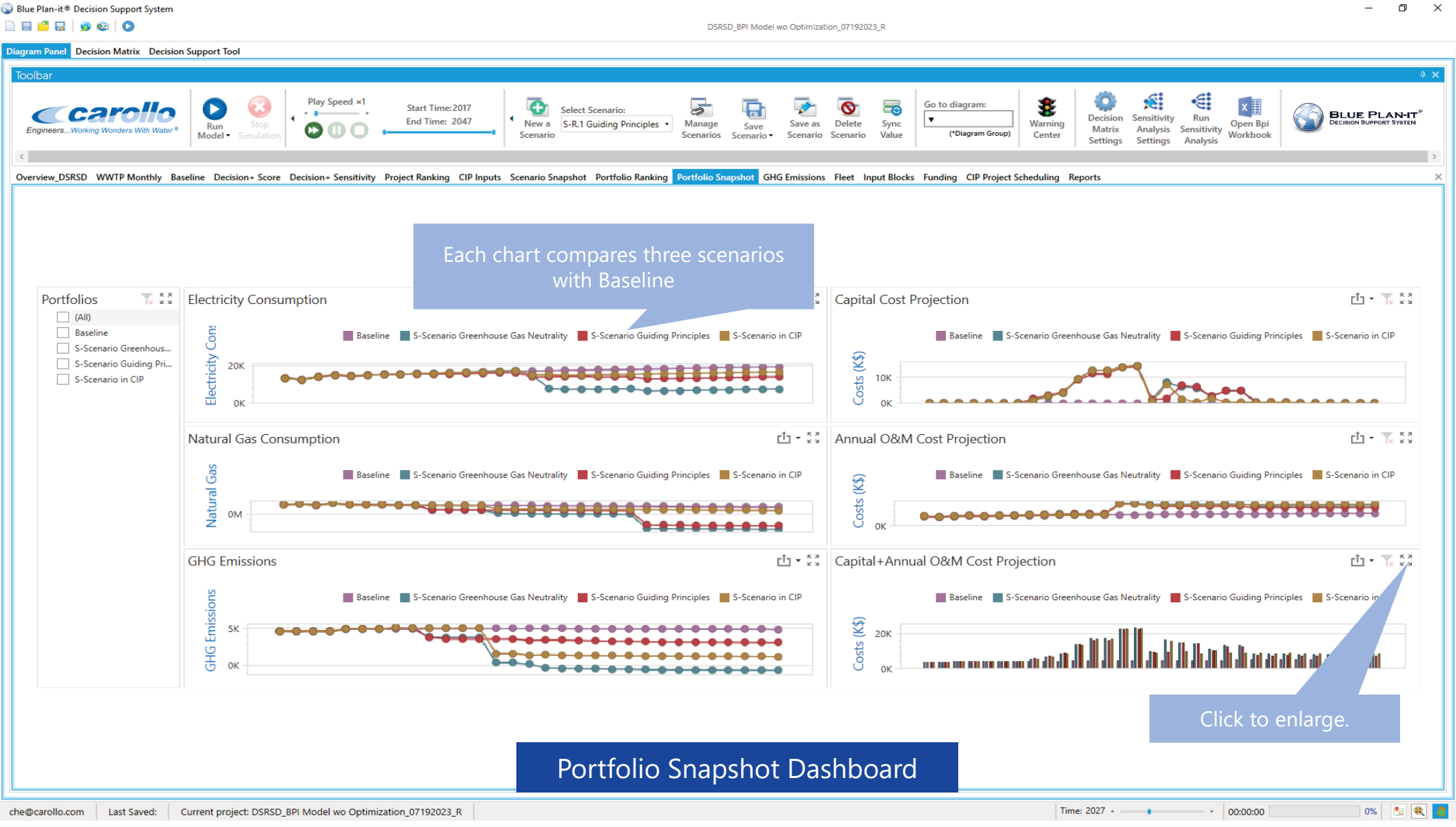
Blue Plan-it® Decision Support System
DSRSD_BPI Model wo Optimization_07192023_R
Diagram Panel
Decision Matrix
Decision Support Tool
Toolbar
carollo
Engineers...Working Wonders With Water®
Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
Save Scenario
Save as Scenario
Delete Scenario
Sync Value
Go to diagram:
(*Diagram Group)
Warning Center
Decision Matrix Settings
Sensitivity Analysis Settings
Run Sensitivity Analysis
Open Bpi Workbook
BLUE PLAN-IT
DECISION SUPPORT SYSTEM
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
Each chart compares three scenarios with Baseline
Portfolios
(All)
Baseline
S-Scenario Greenhous...
S-Scenario Guiding Pri...
S-Scenario in CIP
Electricity Consumption
Electricity Cons
20K
0K
Capital Cost Projection
Costs (K$)
10K
0K
Natural Gas Consumption
Natural Gas
0M
Annual O&M Cost Projection
Costs (K$)
0K
GHG Emissions
GHG Emissions
5K
0K
Capital+Annual O&M Cost Projection
Costs (K$)
20K
0K
Baseline
S-Scenario Greenhouse Gas Neutrality
S-Scenario Guiding Principles
S-Scenario in CIP
Click to enlarge.
Portfolio Snapshot Dashboard
che@carollo.com
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Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
00:00:00
0%

Blue Plan-it® Decision Support System

DSRSD_BPI Model wo Optimization_07192023_R

Diagram Panel | Decision Matrix | Decision Support Tool

Toolbar

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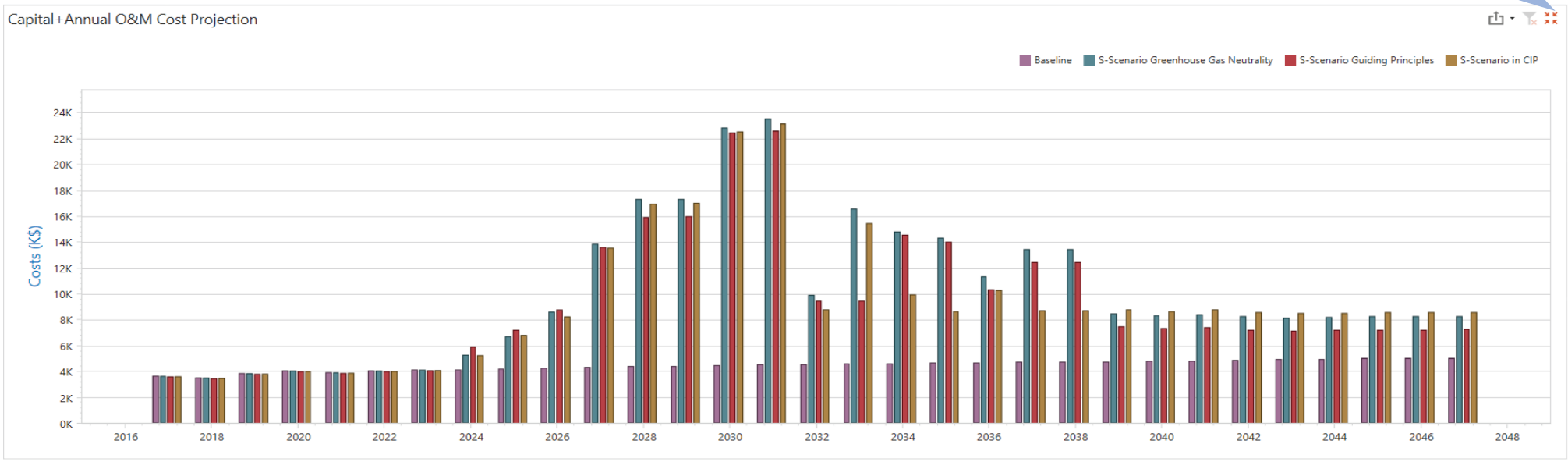
Run Model | Stop Simulation | Play Speed ×1 | Start Time:2017 End Time: 2047 | New a Scenario | Select Scenario: S-R.1 Guiding Principles | Manage Scenarios | Save Scenario | Save as Scenario | Delete Scenario | Sync Value | Go to diagram: (*Diagram Group) | Warning Center | Decision Matrix Settings | Sensitivity Analysis Settings | Run Sensitivity Analysis | Open Bpi Workbook | BLUE PLAN-IT® DECISION SUPPORT SYSTEM

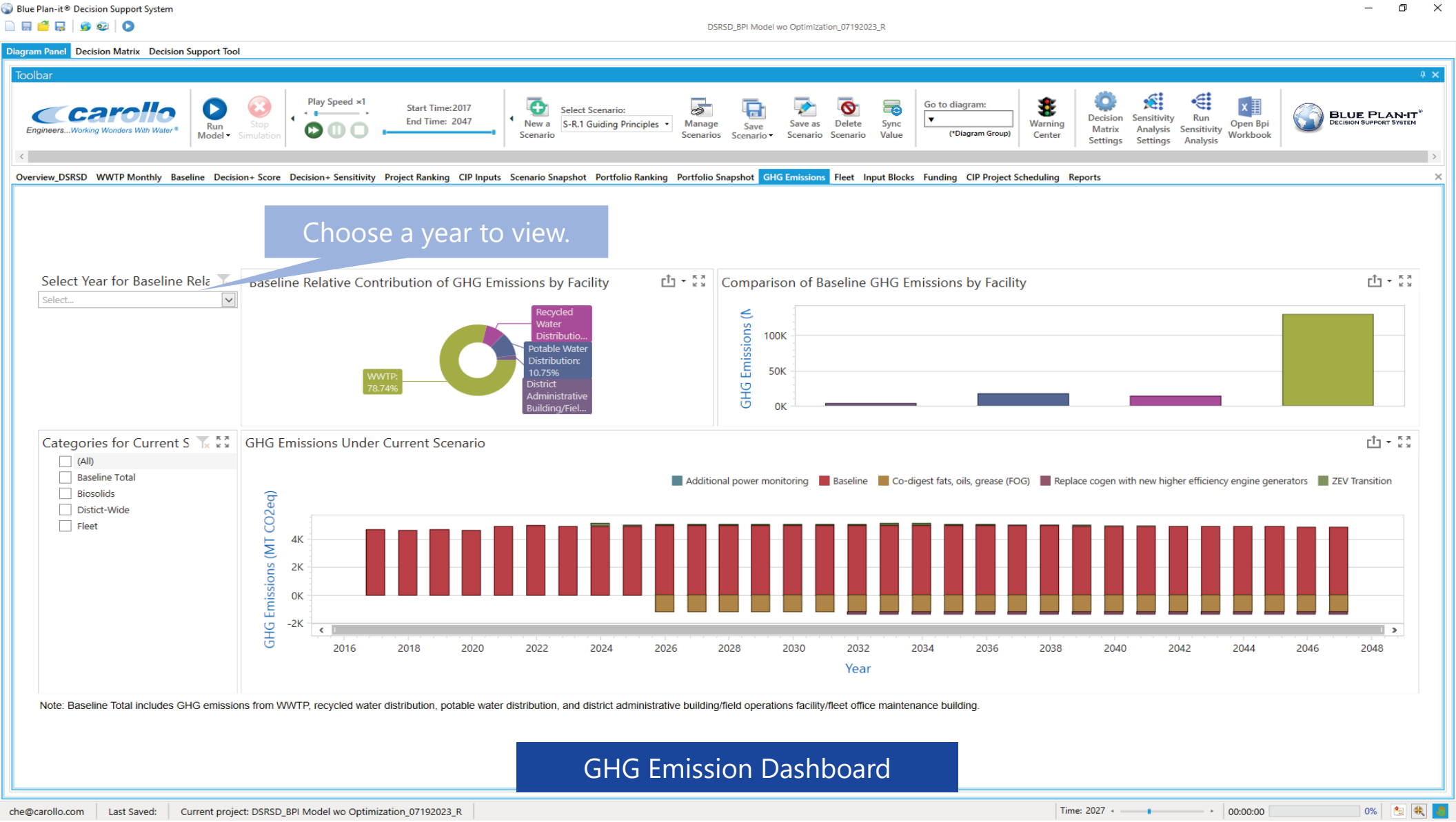
Overview_DSRSD | WWTP Monthly | Baseline | Decision+ Score | Decision+ Sensitivity | Project Ranking | CIP Inputs | Scenario Snapshot | Portfolio Ranking | Portfolio Snapshot | GHG Emissions | Fleet | Input Blocks | Funding | CIP Project Scheduling | Reports

Click to return.



Portfolio Snapshot Dashboard

che@carollo.com | Last Saved: | Current project: DSRSD_BPI Model wo Optimization_07192023_R | Time: 2027 | 00:00:00 | 0%


Blue Plan-it® Decision Support System
DSRSD_BPI Model wo Optimization_07192023_R
Diagram Panel
Decision Matrix
Decision Support Tool
Toolbar
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Run Model
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Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
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Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Input Blocks
Funding
CIP Project Scheduling
Reports
Choose a year to view.
Select Year for Baseline Rela
Select...
Baseline Relative Contribution of GHG Emissions by Facility
Recycled Water Distributio...
Potable Water Distribution: 10.75%
District Administrative Building/Fiel...
WWTP: 78.74%
Comparison of Baseline GHG Emissions by Facility
GHG Emissions (M
100K
50K
0K
Categories for Current S
(All)
Baseline Total
Biosolids
Distict-Wide
Fleet
GHG Emissions Under Current Scenario
Additional power monitoring
Baseline
Co-digest fats, oils, grease (FOG)
Replace cogen with new higher efficiency engine generators
ZEV Transition
GHG Emissions (MT CO2eq)
4K
2K
0K
-2K
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
Year
Note: Baseline Total includes GHG emissions from WWTP, recycled water distribution, potable water distribution, and district administrative building/field operations facility/fleet office maintenance building.
GHG Emission Dashboard
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
00:00:00
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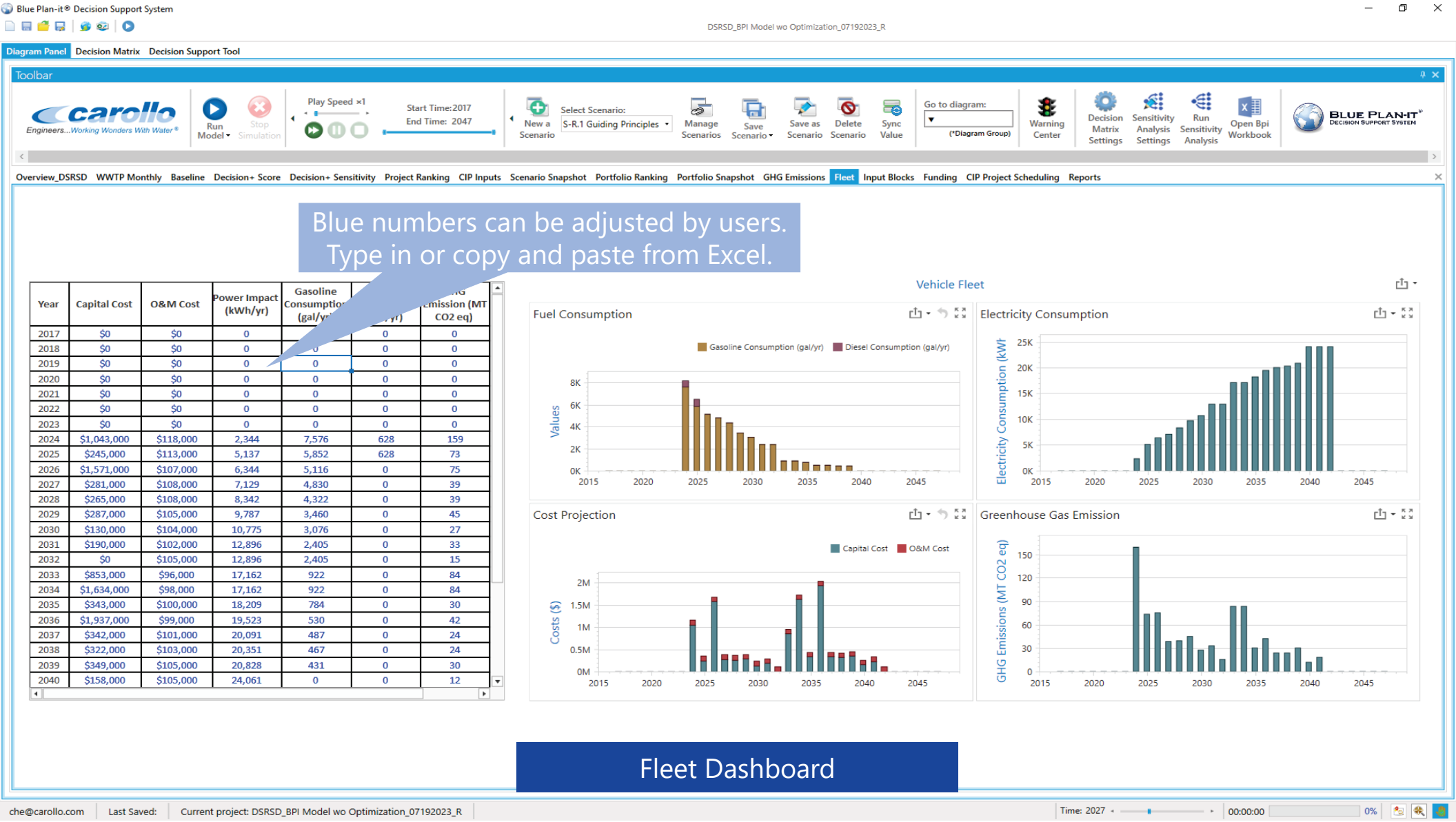
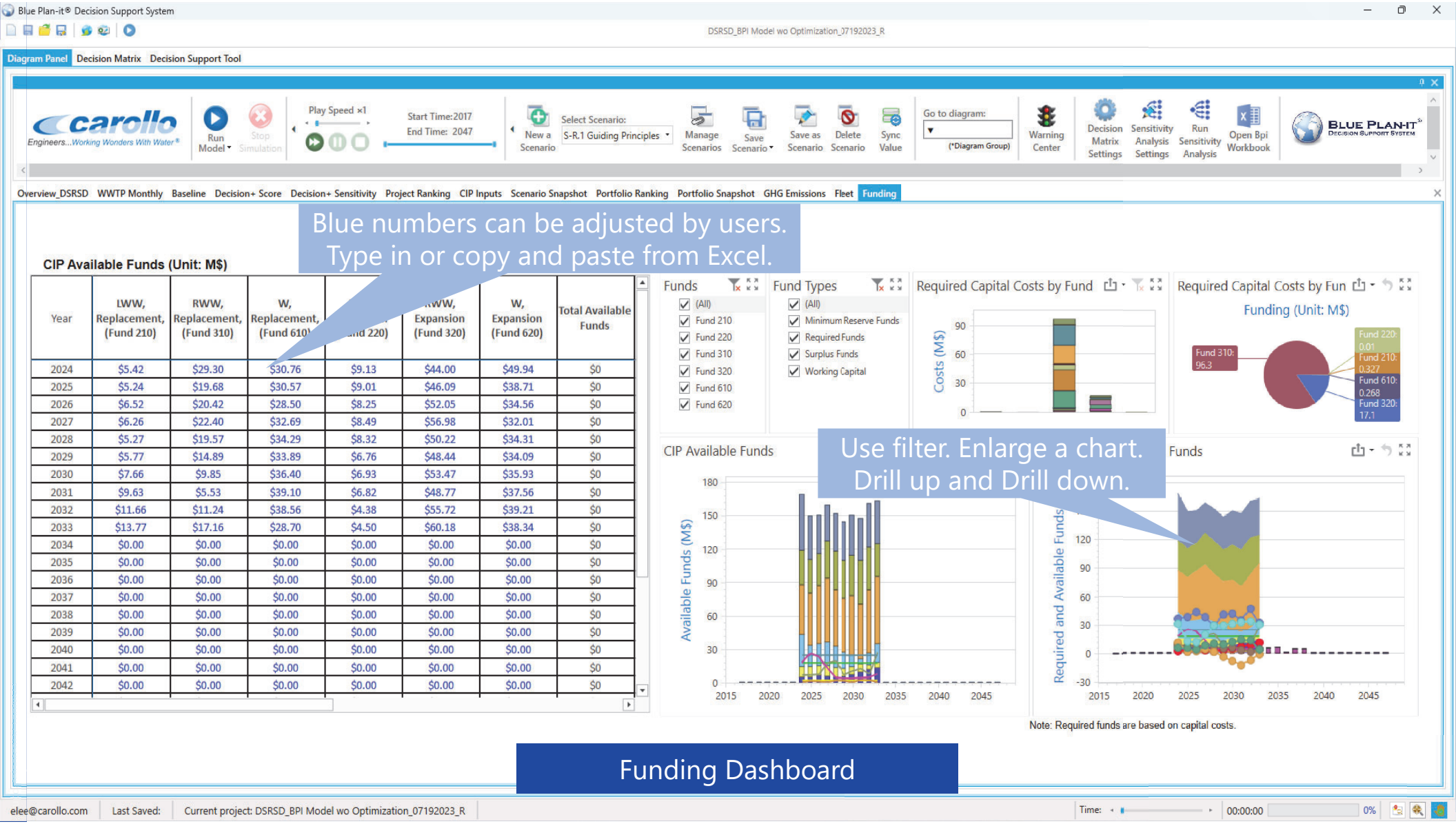


Year	Capital Cost	O&M Cost	Power Impact (kWh/yr)	Gasoline Consumption (gal/yr)	Diesel Consumption (gal/yr)	GHG Emission (MT CO2 eq)
2017	$0	$0	0	0	0	0
2018	$0	$0	0	0	0	0
2019	$0	$0	0	0	0	0
2020	$0	$0	0	0	0	0
2021	$0	$0	0	0	0	0
2022	$0	$0	0	0	0	0
2023	$0	$0	0	0	0	0
2024	$1,043,000	$118,000	2,344	7,576	628	159
2025	$245,000	$113,000	5,137	5,852	628	73
2026	$1,571,000	$107,000	6,344	5,116	0	75
2027	$281,000	$108,000	7,129	4,830	0	39
2028	$265,000	$108,000	8,342	4,322	0	39
2029	$287,000	$105,000	9,787	3,460	0	45
2030	$130,000	$104,000	10,775	3,076	0	27
2031	$190,000	$102,000	12,896	2,405	0	33
2032	$0	$105,000	12,896	2,405	0	15
2033	$853,000	$96,000	17,162	922	0	84
2034	$1,634,000	$98,000	17,162	922	0	84
2035	$343,000	$100,000	18,209	784	0	30
2036	$1,937,000	$99,000	19,523	530	0	42
2037	$342,000	$101,000	20,091	487	0	24
2038	$322,000	$103,000	20,351	467	0	24
2039	$349,000	$105,000	20,828	431	0	30
2040	$158,000	$105,000	24,061	0	0	12


Blue Plan-it® Decision Support System
DSRSD_BPI Model wo Optimization_07192023_R
Diagram Panel
Decision Matrix
Decision Support Tool
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Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
Save Scenario
Save as Scenario
Delete Scenario
Sync Value
Go to diagram:
(*Diagram Group)
Warning Center
Decision Matrix Settings
Sensitivity Analysis Settings
Run Sensitivity Analysis
Open Bpi Workbook
BLUE PLAN-IT
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Funding
Blue numbers can be adjusted by users.
Type in or copy and paste from Excel.
CIP Available Funds (Unit: M$)
Year
LWW, Replacement, (Fund 210)
RWW, Replacement, (Fund 310)
W, Replacement, (Fund 610)
Expansion (Fund 320)
W, Expansion (Fund 620)
Total Available Funds
2024 $5.42 $29.30 $30.76 $9.13 $44.00 $49.94 $0
2025 $5.24 $19.68 $30.57 $9.01 $46.09 $38.71 $0
2026 $6.52 $20.42 $28.50 $8.25 $52.05 $34.56 $0
2027 $6.26 $22.40 $32.69 $8.49 $56.98 $32.01 $0
2028 $5.27 $19.57 $34.29 $8.32 $50.22 $34.31 $0
2029 $5.77 $14.89 $33.89 $6.76 $48.44 $34.09 $0
2030 $7.66 $9.85 $36.40 $6.93 $53.47 $35.93 $0
2031 $9.63 $5.53 $39.10 $6.82 $48.77 $37.56 $0
2032 $11.66 $11.24 $38.56 $4.38 $55.72 $39.21 $0
2033 $13.77 $17.16 $28.70 $4.50 $60.18 $38.34 $0
2034 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2035 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2036 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2037 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2038 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2039 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2040 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2041 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2042 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
Funds
(All)
Fund 210
Fund 220
Fund 310
Fund 320
Fund 610
Fund 620
Fund Types
(All)
Minimum Reserve Funds
Required Funds
Surplus Funds
Working Capital
Required Capital Costs by Fund
Costs (M$)
Required Capital Costs by Fun
Funding (Unit: M$)
Fund 310: 96.3
Fund 220: 0.01
Fund 210: 0.327
Fund 610: 0.268
Fund 320: 17.1
Use filter. Enlarge a chart.
Drill up and Drill down.
CIP Available Funds
Available Funds (M$)
Funds
Required and Available Funds
Note: Required funds are based on capital costs.
Funding Dashboard
elee@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time:
00:00:00
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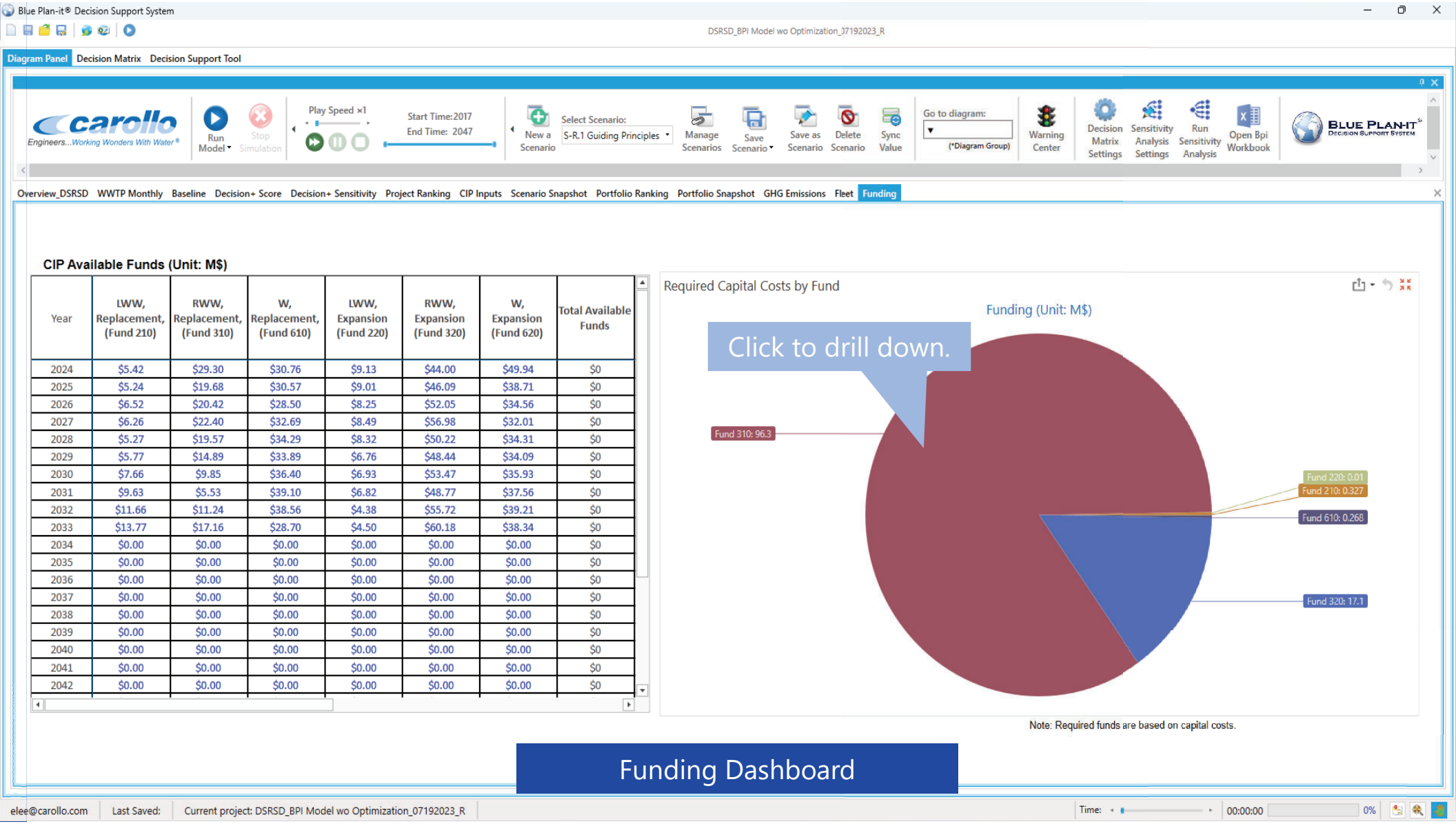
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Decision Matrix
Decision Support Tool
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Run Model
Stop Simulation
Play Speed ×1
Start Time:2017
End Time: 2047
New a Scenario
Select Scenario:
S-R.1 Guiding Principles
Manage Scenarios
Save Scenario
Save as Scenario
Delete Scenario
Sync Value
Go to diagram:
(*Diagram Group)
Warning Center
Decision Matrix Settings
Sensitivity Analysis Settings
Run Sensitivity Analysis
Open Bpi Workbook
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DECISION SUPPORT SYSTEM
Overview_DSRSD
WWTP Monthly
Baseline
Decision+ Score
Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ranking
Portfolio Snapshot
GHG Emissions
Fleet
Funding
CIP Available Funds (Unit: M$)
Year
LWW, Replacement, (Fund 210)
RWW, Replacement, (Fund 310)
W, Replacement, (Fund 610)
LWW, Expansion (Fund 220)
RWW, Expansion (Fund 320)
W, Expansion (Fund 620)
Total Available Funds
2024 $5.42 $29.30 $30.76 $9.13 $44.00 $49.94 $0
2025 $5.24 $19.68 $30.57 $9.01 $46.09 $38.71 $0
2026 $6.52 $20.42 $28.50 $8.25 $52.05 $34.56 $0
2027 $6.26 $22.40 $32.69 $8.49 $56.98 $32.01 $0
2028 $5.27 $19.57 $34.29 $8.32 $50.22 $34.31 $0
2029 $5.77 $14.89 $33.89 $6.76 $48.44 $34.09 $0
2030 $7.66 $9.85 $36.40 $6.93 $53.47 $35.93 $0
2031 $9.63 $5.53 $39.10 $6.82 $48.77 $37.56 $0
2032 $11.66 $11.24 $38.56 $4.38 $55.72 $39.21 $0
2033 $13.77 $17.16 $28.70 $4.50 $60.18 $38.34 $0
2034 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2035 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2036 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2037 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2038 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2039 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2040 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2041 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
2042 $0.00 $0.00 $0.00 $0.00 $0.00 $0.00 $0
Required Capital Costs by Fund
Funding (Unit: M$)
Click to drill down.
Fund 310: 96.3
Fund 220: 0.01
Fund 210: 0.327
Fund 610: 0.268
Fund 320: 17.1
Note: Required funds are based on capital costs.
Funding Dashboard
elee@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time:
00:00:00
0%

Blue Plan-it® Decision Support System

DSRSD_BPI Model wo Optimization_07192023_R

Diagram Panel | Decision Matrix | Decision Support Tool

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Run Model | Stop Simulation | Play Speed ×1 | Start Time:2017 End Time: 2047 | New a Scenario | Select Scenario: S-R.1 Guiding Principles | Manage Scenarios | Save Scenario | Save as Scenario | Delete Scenario | Sync Value | Go to diagram: (*Diagram Group) | Warning Center | Decision Matrix Settings | Sensitivity Analysis Settings | Run Sensitivity Analysis | Open Bpi Workbook | BLUE PLAN-IT® DECISION SUPPORT SYSTEM

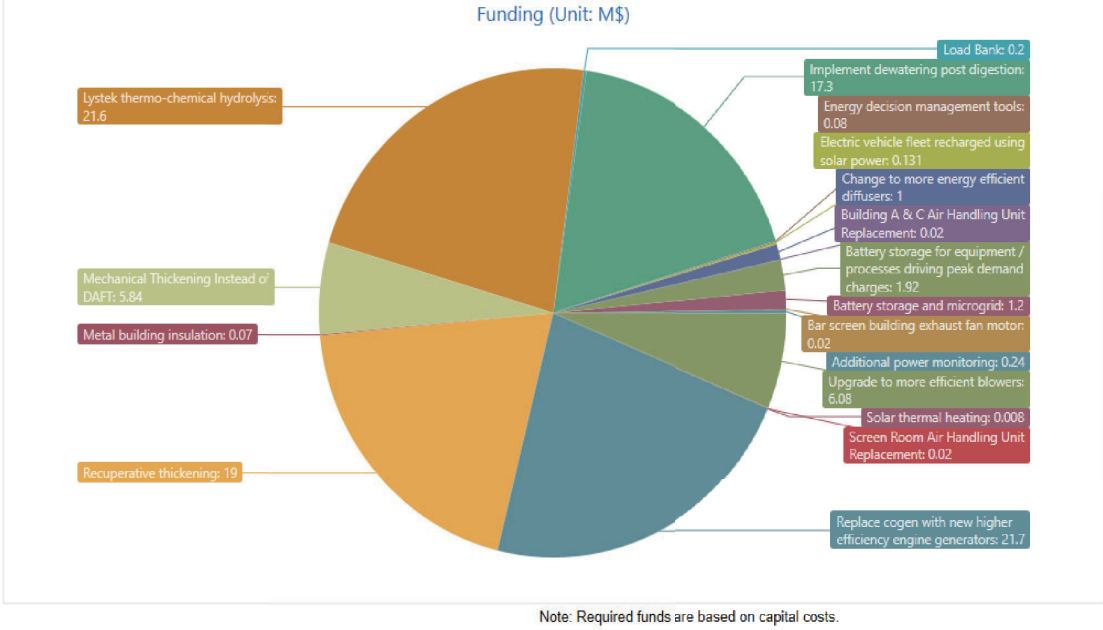
Overview_DSRSD | WWTP Monthly | Baseline | Decision+ Score | Decision+ Sensitivity | Project Ranking | CIP Inputs | Scenario Snapshot | Portfolio Ranking | Portfolio Snapshot | GHG Emissions | Fleet | Funding

Click to drill up

CIP Available Funds (Unit: M$)

Year	LWW, Replacement, (Fund 210)	RWW, Replacement, (Fund 310)	W, Replacement, (Fund 610)	LWW, Expansion (Fund 220)	RWW, Expansion (Fund 320)	W, Expansion (Fund 620)	Total Available Funds
2024	$5.42	$29.30	$30.76	$9.13	$44.00	$49.94	$0
2025	$5.24	$19.68	$30.57	$9.01	$46.09	$38.71	$0
2026	$6.52	$20.42	$28.50	$8.25	$52.05	$34.56	$0
2027	$6.26	$22.40	$32.69	$8.49	$56.98	$32.01	$0
2028	$5.27	$19.57	$34.29	$8.32	$50.22	$34.31	$0
2029	$5.77	$14.89	$33.89	$6.76	$48.44	$34.09	$0
2030	$7.66	$9.85	$36.40	$6.93	$53.47	$35.93	$0
2031	$9.63	$5.53	$39.10	$6.82	$48.77	$37.56	$0
2032	$11.66	$11.24	$38.56	$4.38	$55.72	$39.21	$0
2033	$13.77	$17.16	$28.70	$4.50	$60.18	$38.34	$0
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
2041	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
2042	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0

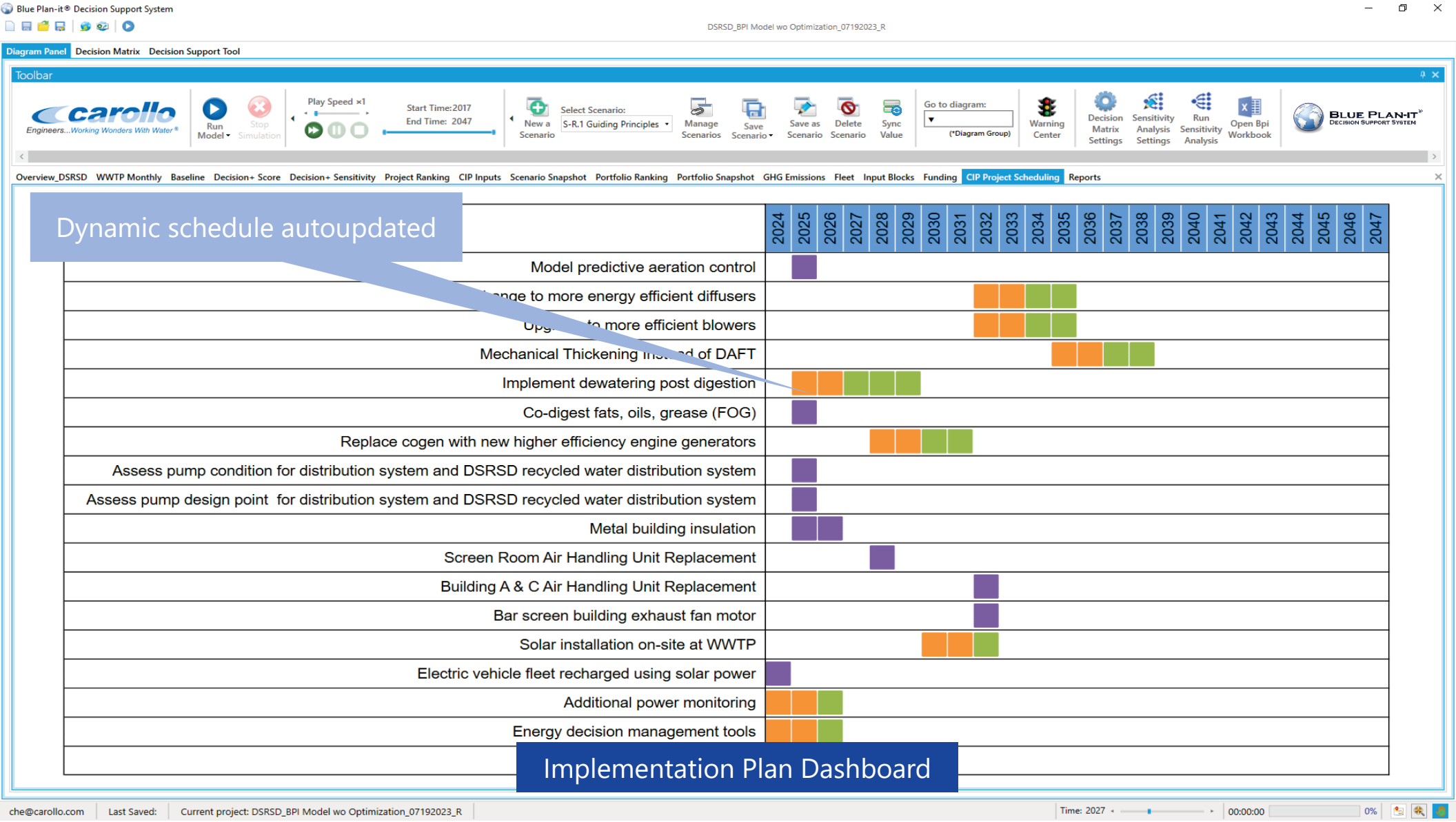
Required Capital Costs by Fund - Fund 310



Note: Required funds are based on capital costs.

Funding Dashboard

elee@carollo.com | Last Saved: | Current project: DSRSD_BPI Model wo Optimization_07192023_R | Time: 00:00:00 0%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Input Blocks
Funding
CIP Project Scheduling
Reports
Dynamic schedule autoupdated
2024
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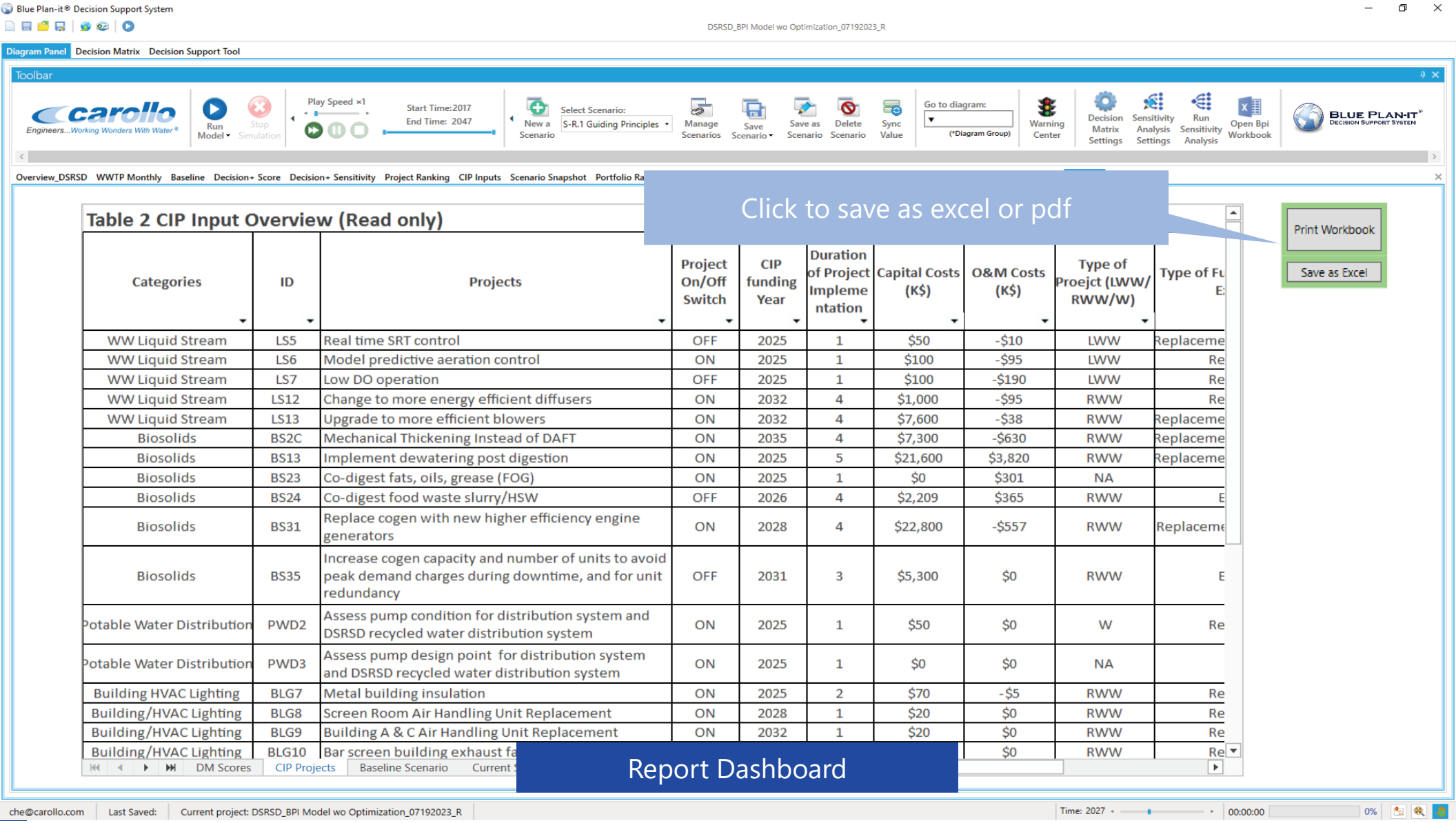
2047
Model predictive aeration control
nge to more energy efficient diffusers
to more efficient blowers
Mechanical Thickening
of DAFT
Implement dewatering post digestion
Co-digest fats, oils, grease (FOG)
Replace cogen with new higher efficiency engine generators
Assess pump condition for distribution system and DSRSD recycled water distribution system
Assess pump design point for distribution system and DSRSD recycled water distribution system
Metal building insulation
Screen Room Air Handling Unit Replacement
Building A & C Air Handling Unit Replacement
Bar screen building exhaust fan motor
Solar installation on-site at WWTP
Electric vehicle fleet recharged using solar power
Additional power monitoring
Energy decision management tools
Implementation Plan Dashboard
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
00:00:00
0%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Decision+ Sensitivity
Project Ranking
CIP Inputs
Scenario Snapshot
Portfolio Ra
Click to save as excel or pdf
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Save as Excel
Table 2 CIP Input Overview (Read only)
Categories
ID
Projects
Project On/Off Switch
CIP funding Year
Duration of Project Implementation
Capital Costs (K$)
O&M Costs (K$)
Type of Proejct (LWW/ RWW/W)
Type of Fu
WW Liquid Stream LS5 Real time SRT control OFF 2025 1 $50 -$10 LWW Replaceme
WW Liquid Stream LS6 Model predictive aeration control ON 2025 1 $100 -$95 LWW Re
WW Liquid Stream LS7 Low DO operation OFF 2025 1 $100 -$190 LWW Re
WW Liquid Stream LS12 Change to more energy efficient diffusers ON 2032 4 $1,000 -$95 RWW Re
WW Liquid Stream LS13 Upgrade to more efficient blowers ON 2032 4 $7,600 -$38 RWW Replaceme
Biosolids BS2C Mechanical Thickening Instead of DAFT ON 2035 4 $7,300 -$630 RWW Replaceme
Biosolids BS13 Implement dewatering post digestion ON 2025 5 $21,600 $3,820 RWW Replaceme
Biosolids BS23 Co-digest fats, oils, grease (FOG) ON 2025 1 $0 $301 NA
Biosolids BS24 Co-digest food waste slurry/HSW OFF 2026 4 $2,209 $365 RWW E
Biosolids BS31 Replace cogen with new higher efficiency engine generators ON 2028 4 $22,800 -$557 RWW Replaceme
Biosolids BS35 Increase cogen capacity and number of units to avoid peak demand charges during downtime, and for unit redundancy OFF 2031 3 $5,300 $0 RWW E
Potable Water Distribution PWD2 Assess pump condition for distribution system and DSRSD recycled water distribution system ON 2025 1 $50 $0 W Re
Potable Water Distribution PWD3 Assess pump design point for distribution system and DSRSD recycled water distribution system ON 2025 1 $0 $0 NA
Building HVAC Lighting BLG7 Metal building insulation ON 2025 2 $70 -$5 RWW Re
Building/HVAC Lighting BLG8 Screen Room Air Handling Unit Replacement ON 2028 1 $20 $0 RWW Re
Building/HVAC Lighting BLG9 Building A & C Air Handling Unit Replacement ON 2032 1 $20 $0 RWW Re
Building/HVAC Lighting BLG10 Bar screen building exhaust fa $0 RWW Re
DM Scores
CIP Projects
Baseline Scenario
Current
Report Dashboard
che@carollo.com
Last Saved:
Current project: DSRSD_BPI Model wo Optimization_07192023_R
Time: 2027
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Dublin San Ramon Services District
Water, wastewater, recycled water

Dublin San Ramon Services District
Energy Facilities Master Plan

Technical Memorandum 12
RECOMMENDED CAPITAL IMPROVEMENT PROGRAM

FINAL | June 2024

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Abbreviations

AHU	air handling unit
AIC	ampere interrupting current
BAAQMD	Bay Area Air Quality Management District
CEQA	California Environmental Quality Act
CIP	capital improvement program
DAFT	dissolved air flotation thickener
DSRSD	Dublin San Ramon Services District
EV	electric vehicle
FOF	field operations facility
FOG	fats, oils and grease
FW	food waste
FYE	fiscal year ending
GHG	greenhouse gas
HSW	high strength waste
HVAC	heating, ventilation, and air conditioning
IRA	Inflation Reduction Act
kWh	kilowatt-hour
kWh/yr	kilowatt-hour per year
LAVWMA	Livermore-Amador Valley Water Management Agency
MCC	motor control center
MT CO_2e	metric tons of carbon dioxide equivalents
MWh	megawatt-hours
MWh/yr	megawatt-hours per year
PG&E	Pacific Gas and Electric Company
PPA	power purchase agreement
scf/yr	standard cubic feet per year
SGIP	self-generation incentive program
SWGR	switchgear
TM	technical memorandum
WWTP	wastewater treatment plant
ZEV	zero-emission vehicle

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Technical Memorandum 12

RECOMMENDED CAPITAL IMPROVEMENT PROGRAM

12.1 Introduction

The Energy Facilities Master Plan includes 17 recommendations for capital improvement program (CIP) projects and programs, and non-CIP actions. Fourteen CIP projects and programs are recommended over the 25-year planning horizon of the Energy Facilities Master Plan, including 11 near term projects over the next 10 years (fiscal year ending [FYE] 2024 through FYE 2033) and three future projects in the 10 to 25-year planning horizon. In addition, there are three additional non-CIP actions described in this technical memorandum (TM).

The total budget for the projects recommended in the Energy Facilities Master Plan is $133.3 million. Of this budget, approximately $88.3 million is planned over the next 10 years (i.e., FYE 2024-2033) and an additional $45.0 million is planned over the 10- to 25-year planning horizon (FYE 2034-2048).

12.2 Summary of Recommendations

12.2.1 Energy Related Capital Improvement Program Projects

This section provides a summary of the recommended energy-related CIP projects and programs. Based on the alternatives analysis recommendations described in TM 11, the following energy-related CIP projects are recommended.

In total, 10 energy-related CIP projects and programs are recommended over the 25-year planning horizon. Of these 10 energy-related projects, seven projects are recommended in the near term (i.e., FYE 2024-2033), and two projects are recommended for implementation in the 10- to 25-year planning horizon. The Fleet Assets Program spans both periods. Projects and programs already included in Dublin San Ramon Services District's (DSRSD) adopted CIP Ten-Year Plan and Two-Year Budget for Fiscal Years 2024 and 2025 are listed with its CIP number, if applicable.

Near term projects (FYE 2024-2033):

1. Fleet Assets PROGRAM (CIP No. A004).
2. Wastewater Treatment Plant (WWTP) Heating, Ventilation, and Air Conditioning (HVAC) Replacements (CIP No.22-P010).
3. Cogeneration Replacement (CIP No. T18-15).
4. Aeration System Upgrades (NEW).
5. Off-site Solar Power (NEW).
6. Battery Storage (NEW).
7. On-site Solar Power, Battery Storage and Electric Vehicle (EV) Charging (NEW).
8. Codigestion of Food Waste (FW) and Other High Strength Waste (HSW) (NEW).

Future projects (FYE 2034-2048):

1. Fleet Assets PROGRAM (CIP No. A004) (spans both near term and future).
2. Additional Cogeneration Engine (CIP No. 20-P010).
3. Dissolved Air Flotation Thickener (DAFT) Replacement with Mechanical Thickening (NEW).

The total budget for all energy-related projects and programs is $126.8 million. Approximately $52.2 million is already programmed into DSRSD's adopted CIP Ten-Year Plan and Two-Year Budget for Fiscal Years 2024 and 2025. Therefore, energy-related projects and programs recommended from this Energy Facilities Master Plan will add an additional $74.6 million over the 25-year planning horizon (FYE 2024-2048); approximately $85.7 million is planned over the next 10 years (i.e. FYE 2024-2033) and an additional $41.1 million is planned over the 10- to 25-year planning horizon (FYE 2034-2048).

12.2.2 Wastewater Treatment Plant Electrical Reliability Capital Improvement Program Projects

One of the tasks of the Energy Facilities Master Plan was to evaluate the existing electrical distribution system and infrastructure at the WWTP considering distribution topology, flexibility, redundancy, and safety. The findings of this analysis are provided in TM 14. Four projects are recommended for inclusion in the CIP based on the findings to provide for reliability of the WWTP's electrical infrastructure as follows:

Near term projects (FYE 2024-2033):

1. Install Load Bank for DP-G (NEW).
2. Reconfigure Switchgear for Power Outages (NEW).
3. WWTP Electrical Improvements Phase 1 (CIP No. T16-11).
4. WWTP Electrical Improvements Phase 2 (NEW) – Study Only.

Future projects (FYE 2034-2049):

1. WWTP Electrical Improvements Phase 2 (NEW).

The total budget for WWTP electrical reliability-related projects is $6.5 million. Approximately $2.1 million is already programmed into DSRSD's adopted CIP Ten-Year Plan and Two-Year Budget for FYE 2024 and 2025. Therefore, WWTP electrical reliability-related projects recommended from this Energy Facilities Master Plan will add an additional $4.4 million over the 20-year planning horizon (FYE 2024-2043); approximately $2.6 million is planned over the next 10 years (i.e. FYE 2024-2033) and an additional $3.9 million is planned over the 10- to 25-year planning horizon (FYE 2034-2048).

12.2.3 Master Plan Capital Improvement Program Budget

The total budget for all projects and programs recommended in the Energy Facilities Master Plan is $133.3 million. Of this budget, approximately $88.3 million is planned over the next 10 years (i.e., FYE 2024-2033) and an additional $45.0 million is planned over the 10- to 25-year planning horizon (FYE 2034-2048).

Figure 12.1 summarizes the Energy Facilities Master Plan CIP projects and programs. The orange bars in the figure indicate planning and design efforts while the green bars indicate construction implementation periods. The projects are organized based on the primary drivers for implementing the project including regulatory, asset replacement, renewable energy generation or energy diversification, and resiliency.

12.2.4 Non-Capital Improvement Program Recommendations

In addition to the 14 CIP recommendations, the Energy Facilities Master Plan also includes three non-CIP recommendations as follows:

1. **Fats, Oil, and Grease (FOG) Facility Activation:** This is not a CIP project as the FOG facility has already been constructed and is awaiting activation pending permit approvals from the Bay Area Air Quality Management District (BAAQMD). Activation of the FOG facility is anticipated to reduce DSRSD's greenhouse gas (GHG) footprint by approximately 1,230 metric tons of carbon dioxide equivalents (MT CO_2e) per year based on offsetting natural gas usage by the cogeneration engines. Operating costs for this facility are anticipated to be approximately $300,000 per year. Additional details regarding this analysis are provided in TM 7, Section 7.3.1.2.
2. **Potable Water Distribution System Improvements:** The analysis included in this Energy Facilities Master Plan (TM 5, Section 5.4) evaluated the energy efficiency of all 16 potable water pump stations currently in operation. The majority of the pump stations operate at acceptable energy efficiency ranges and did not show signs of damage. Several pump stations, however, were identified with low efficiency under specific operating conditions and/or potential pump damage resulting in low efficiency. Specific recommendations for follow up action are included for each of these pump stations, including:
    a. Conduct a hydraulic evaluation of PS20B as part of the upcoming Water Master Plan Update.
    b. Inspect specific components of PS1A, PS2B, PS3C, PS300C as preventive maintenance items.
    c. Revise reservoir level pump control points for PS1A, PS4A, and PS200A to improve pump efficiency; investigate as part of the Water System Master Plan and Operations Plan Update (CIP No. 20-W017), and currently expected to commence in FYE 2024.
3. **Energy Management Improvements:** As documented in this Energy Facilities Master Plan (TM 5, Section 5.5), there are opportunities for DSRSD to improve its energy management through better tools and decision-making processes. The recommendations include staff focus on energy management, by assigning specific energy management related tasks to current or new DSRSD staff. This focus, along with additional power monitoring and improved energy decision management tools, will assist DSRSD staff in better understanding where improvements in energy efficiency and cost savings can be realized and track its achievements as the energy CIP is implemented. Additionally, this staff focus can assist DSRSD in seeking out opportunities to expand its renewable energy portfolio through energy generation partnerships and grant funding opportunities.

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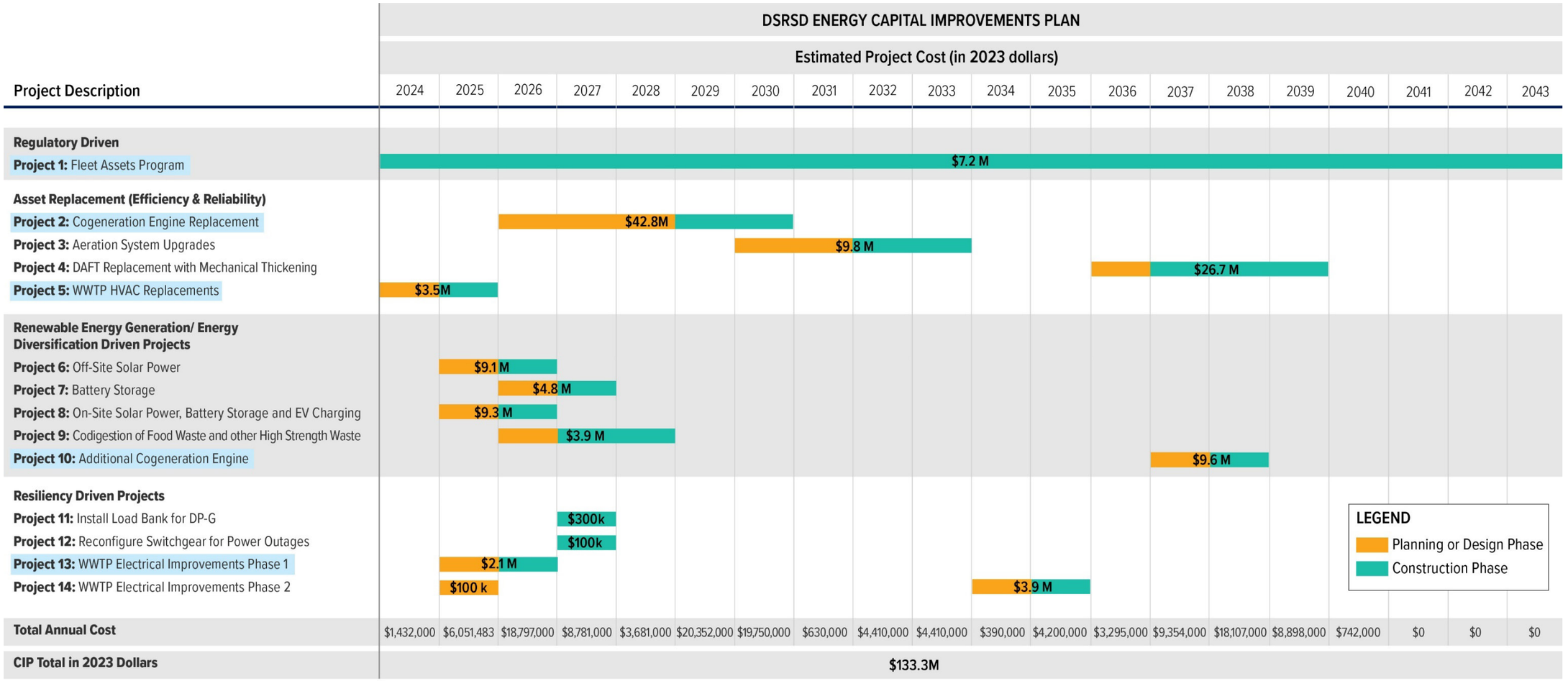

Project Description	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Total Annual Cost	$1,432,000	$6,051,483	$18,797,000	$8,781,000	$3,681,000	$20,352,000	$19,750,000	$630,000	$4,410,000	$4,410,000	$390,000	$4,200,000	$3,295,000	$9,354,000	$18,107,000	$8,898,000	$742,000	$0	$0	$0
CIP Total in 2023 Dollars	$133.3M																			

Notes: All or portions of the projects highlighted in blue are included in the current approved CIP.

Figure 12.1 Energy Facilities Master Plan CIP

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12.3 Impacts of Proposed Capital Improvement Program

12.3.1 Electrical Energy Impacts – All Facilities

Projects proposed in the Energy Facilities Master Plan CIP include both energy efficiency projects and energy generation projects.

Energy efficiency projects include:

- WWTP HVAC replacements.
- Aeration system upgrades.
- DAFT replacement with mechanical thickening.

These projects will reduce energy use at DSRSD's facilities by approximately 825 megawatt-hours per year (MWh/yr) or 5 percent by 2030 and by nearly 2,000 MWh/yr or 10 percent by 2047 when compared to the baseline scenario.

Energy generation projects include:

- Cogeneration engine replacement.
- Additional cogeneration engine.
- Offsite solar power.
- Battery storage (although not energy generation, it will be used to optimize the use of DSRSD's power generation projects and therefore included in this list).
- Onsite solar power, battery storage, and EV charging.
- Codigestion of FW and other HSW (increases renewable fuel available for cogeneration).

These projects are expected to generate an additional 3,200 MWh/yr or 20 percent by 2030, and by 8,000 MWh/yr or 40 percent by 2047 when compared to the baseline scenario.

Figure 12.2 illustrates DSRSD's electricity consumption over time associated with the proposed CIP compared with the baseline scenario (2021). Based on future growth projections (blue line in Figure 12.2), by 2047, DSRSD is expected to purchase approximately 20,000 megawatt-hours (MWh) to operate all its facilities, which equates to an increase of approximately 5,000 MWh compared to the baseline scenario (2021). The black line accounts for the impacts of the proposed energy projects; electricity purchased from Pacific Gas and Electric Company (PG&E) will decrease by approximately 4,000 MWh/yr or 25 percent by 2030 and by nearly 10,000 MWh/yr or 50 percent by 2047.

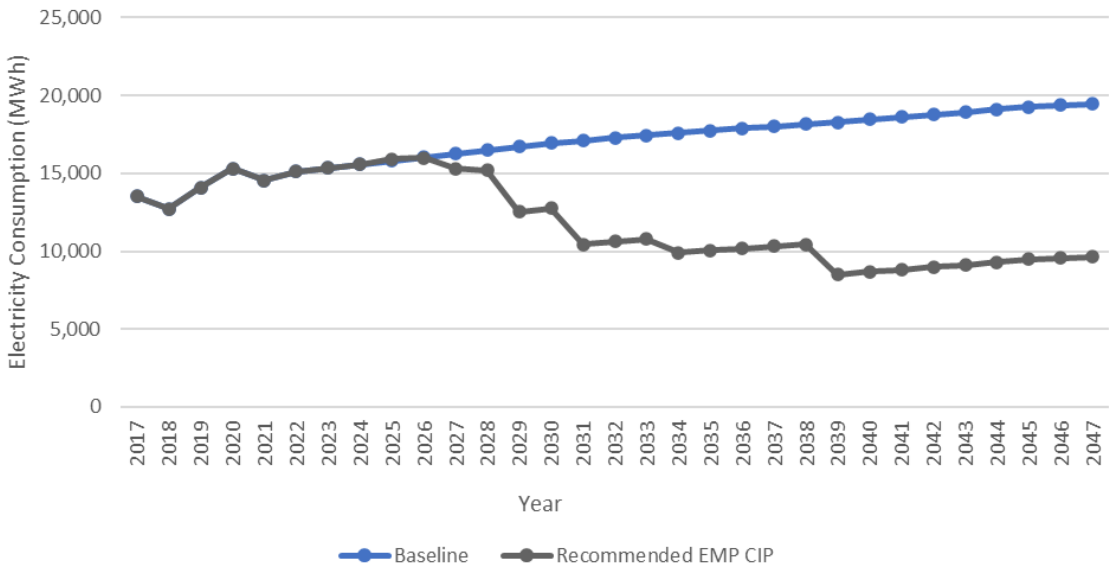

Figure 12.2 Electricity Consumption Impacts of the Recommended CIP – All Facilities

12.3.2 Electrical Energy Impacts – Wastewater Treatment Plant Facilities

Energy efficiency projects at the WWTP include:

- WWTP HVAC replacements.
- Aeration system upgrades.
- DAFT replacement with mechanical thickening.

These projects will reduce energy use at DSRSD's facilities by approximately 825 MWh/yr or 5 percent by 2030 and by nearly 2,000 MWh/yr or 10 percent by 2047 when compared to the baseline scenario.

Energy generation projects at the WWTP include:

- Cogeneration engine replacement.
- Additional cogeneration engine.
- Onsite solar power, battery storage, and EV charging at the WWTP.
- Codigestion of FW and other HSW (increases renewable fuel available for cogeneration).

These projects are expected to generate an additional 3,700 MWh/yr or 33 percent by 2030, and 4,400 MWh/yr or 33 percent by 2047 when compared to the baseline scenario (2021).

Figure 12.3 illustrates DSRSD's WWTP electricity consumption over time associated with the proposed CIP compared with the baseline scenario. Based on future growth projections (blue line in Figure 12.3), by 2047, DSRSD is expected to purchase 13,500 MWh/yr to operate the WWTP, which equates to an increase of approximately 3,600 MWh compared to the baseline scenario (2021). The black line accounts for the impacts of the proposed energy projects at the WWTP; electricity purchased from PG&E will decrease by approximately 800 MWh/yr or 7 percent by 2030 and by 6,500 MWh/yr or 48 percent by 2047 when compared to the baseline scenario.

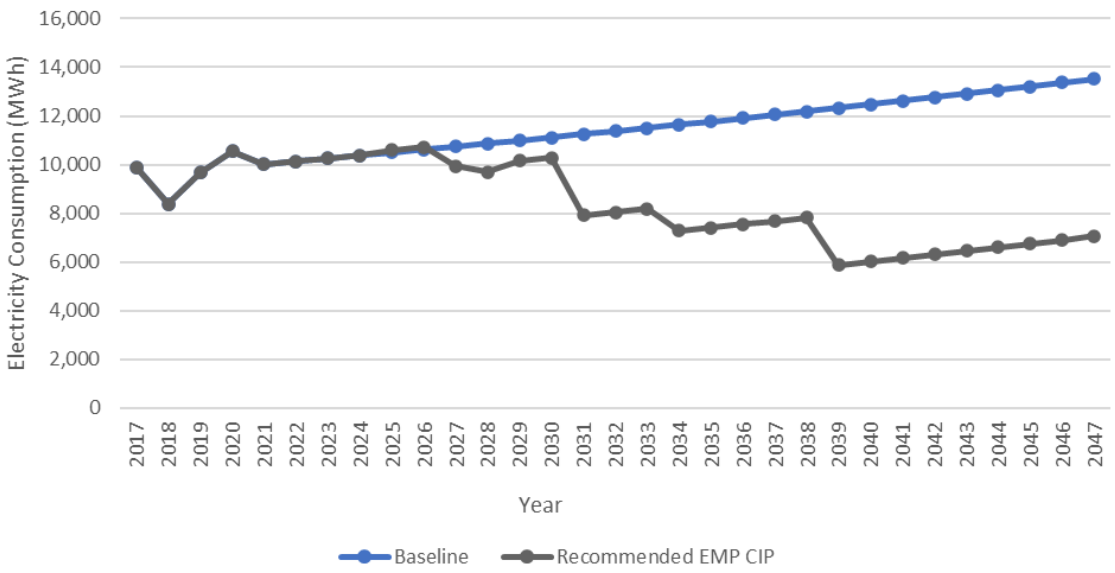

Figure 12.3 Electricity Consumption Impacts of the Recommended CIP – WWTP Facilities

12.3.3 Natural Gas Consumption Impacts – All Facilities

Figure 12.4 illustrates DSRSD facilities' natural gas usage over time associated with the proposed CIP compared with the baseline scenario. All natural gas use is currently at DSRSD's WWTP facilities so these numbers also reflect the reduction at the WWTP facilities. Based on future growth projections (blue line in Figure 12.4), by 2047, DSRSD is expected to purchase approximately 47 million standard cubic feet per year (scf/yr), which equates to a decrease of approximately 16 million scf/yr compared to the baseline scenario (2021). The amount of natural gas used under the baseline scenario is anticipated to decrease as loads to the WWTP increase, thereby increasing digester gas production and offsetting natural gas use by the cogeneration engines. The black line accounts for the impacts of the proposed energy projects; natural gas purchased from PG&E will decrease by an additional 40 or 66 percent by 2030 and by 45 million scf/yr or 80 percent by 2047 when compared to the baseline scenario. The significant decrease in natural gas use under this scenario is based on the increased digester gas production associated with the codigestion of FW and FOG which will offset natural gas use by the cogeneration engines.

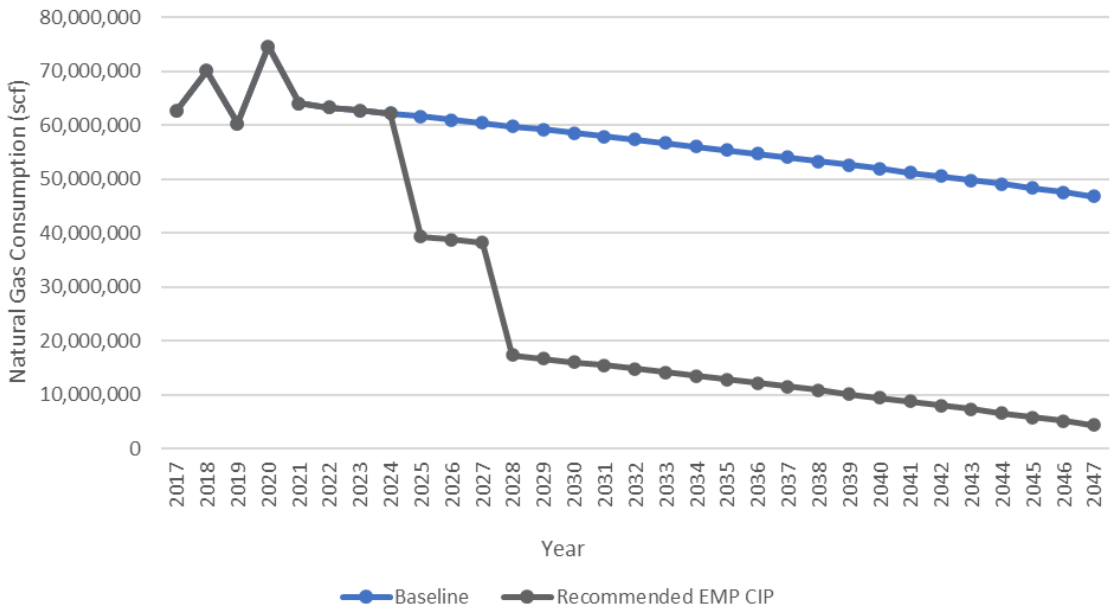

Figure 12.4 Natural Gas Consumption Impacts of the Recommended CIP

12.3.4 Greenhouse Gas Reduction Impacts – All Facilities

The most significant contributor to DSRSD's GHG footprint is associated with its use of natural gas for energy production within the cogeneration engines at the WWTP. Because the Energy Facilities Master Plan CIP includes a number of projects that will generate additional renewable energy, DSRSD will become less dependent on purchasing natural gas to supplement energy production through the cogeneration engines and instead utilize the additional gas produced at the facility through codigestion of FW and FOG receiving at the facility. Figure 12.5 illustrates the GHG emissions reductions over time associated with the proposed CIP compared with the baseline scenario. Based on future growth projections (blue line in Figure 12.5), DSRSD's total GHG emissions is expected to remain relatively constant through 2047 (i.e., 4,900 MT CO_2e). The black line accounts for the impacts of the proposed energy projects; total GHG emissions is expected to decrease by approximately 2,800 MT CO_2e or 57 percent by 2030 and by 3,200 MT CO_2e or 66 percent by 2047.

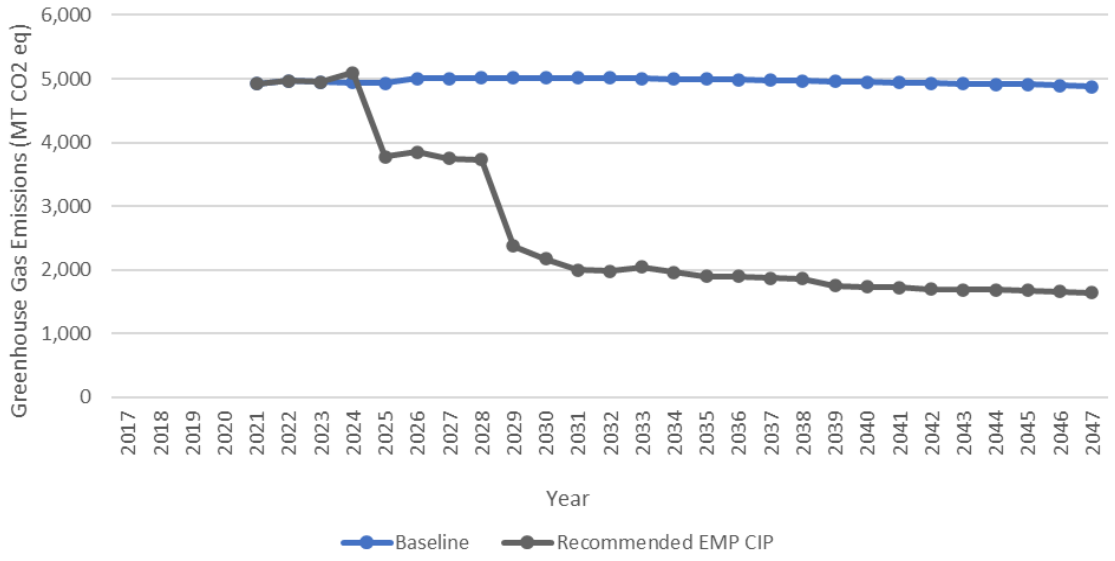

Figure 12.5 GHG Emissions Impacts of the Recommended CIP – All Facilities

12.3.5 Greenhouse Gas Reduction Impacts – Wastewater Treatment Plant Facilities

Figure 12.6 illustrates the GHG emissions reductions over time associated with the proposed CIP compared with the baseline scenario. Based on future growth projections (blue line in Figure 12.6), by 2047, total GHG emissions associated with operation of the WWTP is expected to be approximately 4,400 MT CO_2e, which equates to an increase of approximately 500 MT CO_2e compared to the baseline scenario (2021). The black line accounts for the impacts of the proposed energy projects; total GHG emissions for the WWTP is expected to decrease by approximately 2,500 MT CO_2e or 62 percent by 2030 and by 3,000 MT CO_2e or 67 percent by 2047.

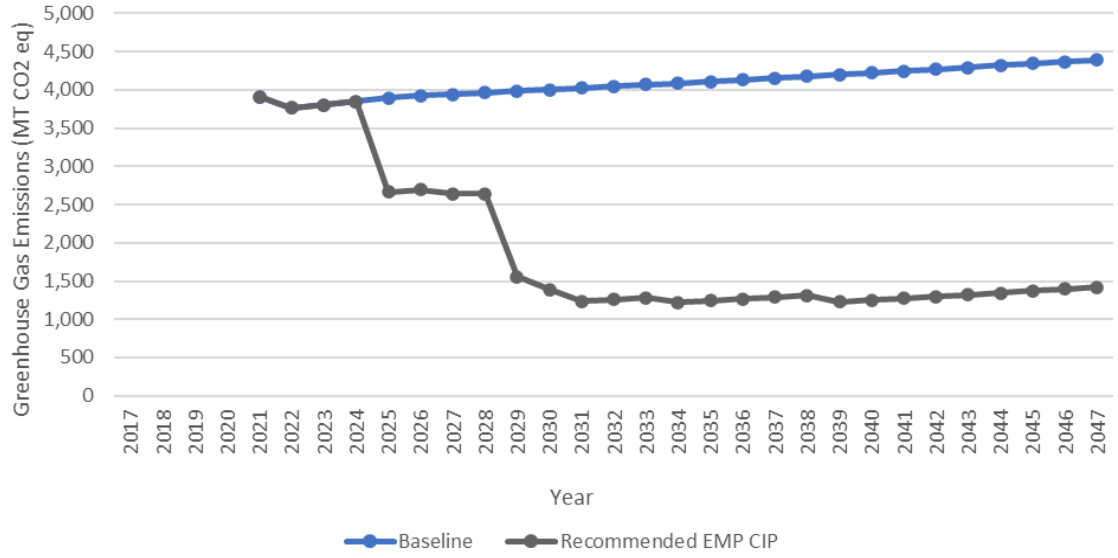

Figure 12.6 GHG Emissions Impacts of the Recommended CIP – WWTP Facilities

12.4 Capital Improvement Program Project Worksheets

This section provides project worksheets for each individual CIP project or program. Included is a summary description of each project, funding allocation justification, anticipated California Environmental Quality Act (CEQA) requirements, the 10-year cash flow and estimated project costs, and any potential grant funding opportunities that may be available for each project.

CIP No.00-A004 Fleet Assets Program			
Funding Allocation:	20% 210	30% 310	50% 610

Project Summary:

As of April 28, 2023, there are two approved California Air Resources Board regulations, Advanced Clear Cars II and Advanced Clean Fleets, that will dictate the timeline for DSRSD's transition to zero-emission vehicles (ZEV). The recommendations in this Energy Facilities Master Plan are for DSRSD to opt into the ZEV Milestones Option Flexibility under the High Priority and Federal Fleets Requirements (Title 13, California Code of Regulations Section 2015.2). This approach allows for a longer timeline for transition to ZEVs which is beneficial given that there are currently limited replacement options for much of DSRSD's current fleet. The regulations also allow for DSRSD to utilize vehicles for up to 18 years prior to replacement. The costs included herein assume an 18-year replacement cycle for DSRSD fleet vehicles and compliance with the High Priority and Federal Fleets Requirements. Figure 12.7 shows the number of vehicle replacements per year based on vehicle types due for replacement and whether replacement vehicles are internal combustion engine type or ZEVs.

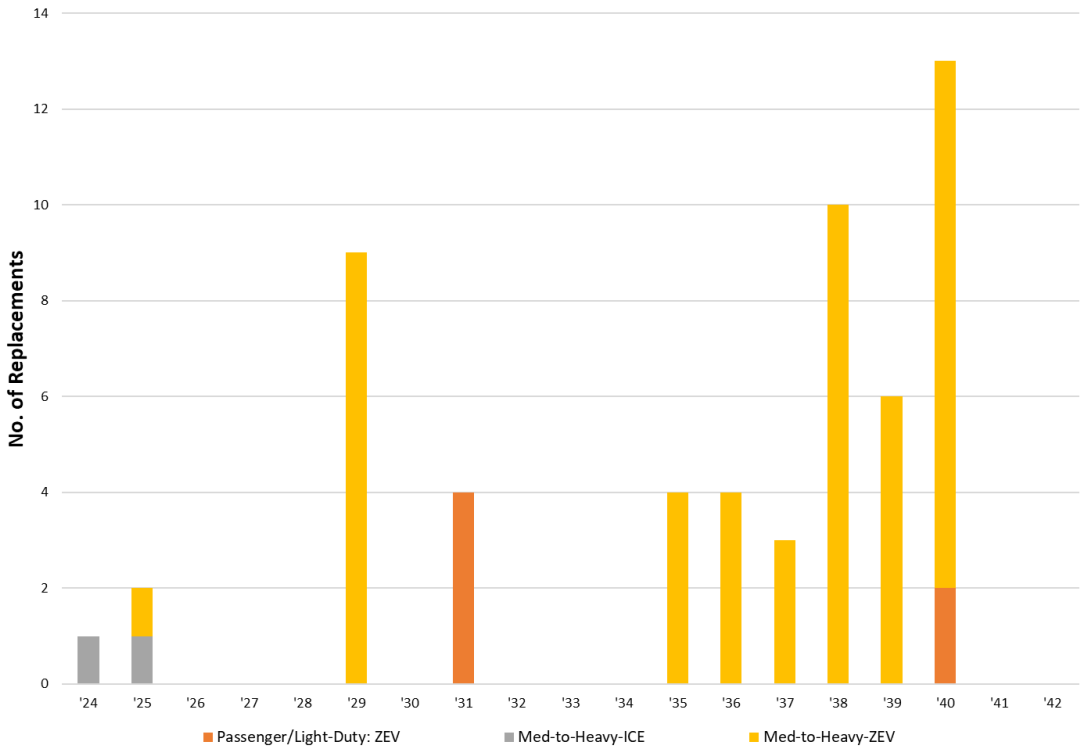

Figure 12.7 Fleet Vehicle Replacement Schedule

Funding Allocation Justification: Ratio based on department/function associated with each vehicle.

Anticipated CEQA: Not a project under CEQA (CEQA Guideline 15378).

10-Year Cash Flow and Estimated Project Cost (Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
532	0	689	0	0	1,092	0	140	0	0	4,786

Total Estimated Project Cost: $7,239,000.

Current Adopted Budget: $5,420,000.

Increase/(Decrease): $1,891,000.

Energy Impacts: Provides for compliance with state regulations. Reduces gasoline consumption by over 10,000 gallons and diesel consumption by 6,000 gallons over the next 20 years. Reduces GHG emissions by 1,059 MT CO_2e over the next 20 years.

Potential Grant or Financing Opportunities: None identified. EV charging facilities budgeted for elsewhere in this Energy Facilities Master Plan CIP may be eligible for Inflation Reduction Act (IRA) funding.

CIP No. 22-P010 WWTP HVAC Replacements

Funding Allocation: 100% 310

Project Summary:

This project involves making HVAC improvements including replacing the Screen Room Air Handling Unit (AHU), replacing the Building A and C AHUs, and replacing the Bar Screen Building exhaust fan motor. The justification for this project is that these units were all identified as being near the end of their useful life (five years remaining) and newer models have improved efficiency.

Funding Allocation Justification:

Asset replacement of existing equipment.

Anticipated CEQA:

Categorical Exemption (CEQA Guideline 15302).

10-Year Cash Flow and Estimated Project Cost(Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
2,852										

Total Estimated Project Cost: $2,852,467.

Current Adopted Budget: $2,852,467.

Increase/(Decrease): $0.

Energy Impacts: Reduces energy use by approximately 250 kilowatt-hour per year (kWh/yr) due to more efficient equipment.

Potential Grant or Financing Opportunities:

PG&E on-bill financing for efficiency improvements.

Current CIP No. T18-15 Cogeneration Engine Replacement

Funding Allocation: 80% 310 20% 320

Project Summary:

This project involves replacing the existing cogeneration engines with similar capacity engines. It is likely the newer engines will be higher efficiency engines based on current available technologies but additional analysis is required during the design phase to determine the appropriate engine type, sizing, and configuration. The justification for this project is that the existing cogeneration engines are near the end of their useful service life. The engines are considered critical WWTP infrastructure as their failure could result in significant costs incurred due to PG&E demand standby charges. Based on the age of the existing engines, reliability concerns, and difficulty obtaining replacement parts, it is recommended that the preliminary design phase of this project start in FYE 2026. Preliminary engineering studies should also consider battery storage options, islanding operational modes, and automatic restoration of power after a PG&E power outage.

Costs assume the new cogeneration engines will be located within a new building constructed at the location of the former fuel cell pad, between Secondary Clarifiers Nos. 1 and 2.

Funding Allocation Justification:

The replacement cogeneration engines will have a higher efficiency and are therefore anticipated to generate approximately 20 percent more power than the existing engines. The additional power generated through the higher efficiency engines will be used to offset the additional energy demands needed due to future growth.

Reference:

Energy Facilities Master Plan, TM 6.

Anticipated CEQA:

It is likely that this project will be a Categorical Exemption under CEQA (CEQA Guideline 15302). Permitting through the BAAQMD will also be required.

10-Year Cash Flow and Estimated Project Cost (Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
		428	1,926	1,926	19.260	19.260				

Total Estimated Project Cost: $42,800,000.

Current Adopted Budget: $33,460,000.

Increase/(Decrease): $9,340,000.

Energy Impacts: Additional renewable energy production of 2,210,000 kWh/yr and maintains current renewable energy production.

Potential Grant or Financing Opportunities:

IRA and Self-Generation Incentive Program (SGIP) funding opportunities may be available. Power Purchase Agreement (PPA) financing is also an option.

CIP No.EMP001 Aeration System Upgrades

Funding Allocation: 75% 310 25% 320

Project Summary:

This project involves upgrading the aeration blowers, implementing model predictive aeration control, and upgrading the aeration diffusers. The justification for this project is that the existing aeration blowers and diffuser are near the end of their useful life (10 years remaining) and new high-efficiency blowers and diffusers along with model predictive aeration control is expected to substantially increase the energy efficiency of the aeration system. It is recommended that DSRSD commence the planning/preliminary engineering phase of an "Aeration System Upgrade" CIP project in FYE 2030.

Funding Allocation Justification:

Based on ratio of current influent flow (2021) to projected influent flows (2047).

Reference:

Energy Facilities Master Plan, TM 4 – Section 4.4.

Anticipated CEQA: Categorical Exemption (CEQA Guideline 15302).

10-Year Cash Flow and Estimated Project Cost(Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
						490	490	4,410	4,410	

Total Estimated Project Cost: $9,800,000.

Current Adopted Budget: $0.

Increase/(Decrease): $9,800,000.

Energy Impacts: Approximately 1,000,000 kWh/yr in energy savings from operational efficiencies. Reduces GHG emissions by approximately 76 MT CO_2e over the next 20 years.

Potential Grant or Financing Opportunities:

PG&E on-bill financing for energy improvement projects.

CIP No.EMP002 Off-site Solar Power

Funding Allocation: 1% 210 38% 310 61% 610

Project Summary:

This project involves building new solar power facilities around the Livermore-Amador Valley Water Management Agency (LAVWMA) effluent storage basins. The justification for this project is the relatively fast payback periods (if financed through a PPA), and increased diversity of DSRSD's renewable energy portfolio. The budget assumes the layout provided below in Figure 12.8 which comprises canopy mounted solar facilities around the perimeter of the basins. The facility would have a total energy production output of 3.2 million kWh/yr. It is recommended that these projects be implemented in FYE 2025 to maximize the likelihood of obtaining financial incentives currently available. The solar power project could be funded through a PPA if available.

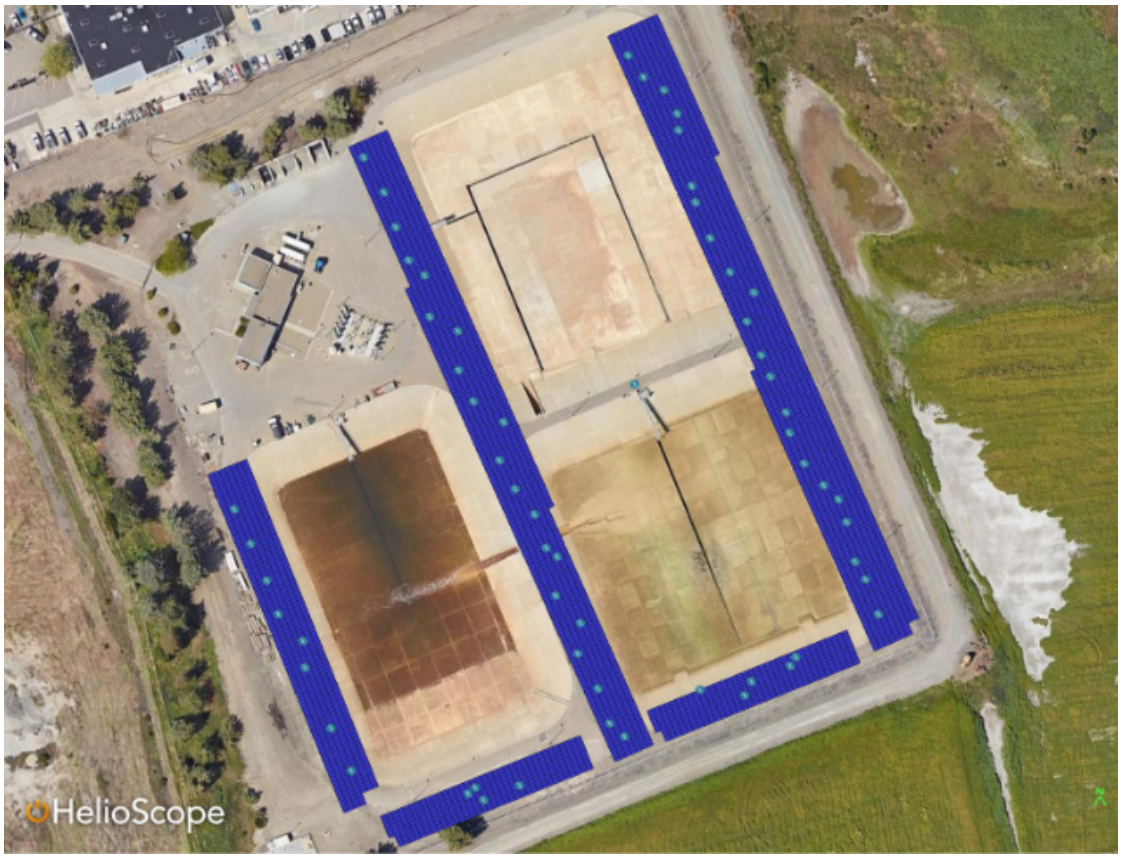

Figure 12.8 Off-site Solar Facility Layout at LAVWMA Basins

Funding Allocation Justification:

Implementation of this project will offset existing energy demands. Fund split is based on the 2021 electrical demands for 210 (10,400 kilowatt-hour [kWh]) – 1 percent; 310 (4788 MWh) – 38 percent, and 610 (7746 MWh) – 61 percent.

Reference:

Energy Facilities Master Plan, TM 6.

Anticipated CEQA: Initial Study/Mitigated Negative Declaration.

10-Year Cash Flow and Estimated Project Cost (Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
	100	9,000								

Total Estimated Project Cost: $9,100,000.

Current Adopted Budget: $0.

Increase/(Decrease): $9,100,000.

Energy Impacts: Renewable power generation of approximately 3,200,000 kWh/yr. GHG reduction of approximately 282 MT CO_2e over the next 20 years.

Potential Grant or Financing Opportunities:

IRA funding and PPA financing potential.

CIP No.EMP003 Battery Storage

Funding Allocation: 75% 310 25% 320

Project Summary:

This project involves installing a new 1 megawatt battery storage system to store power generated at the WWTP by the cogeneration engines and future solar facilities to be used for offsetting peak demand charges rather than exporting the power to the grid. The justification for this project is its relatively fast payback period through reduction of peak demand charges and increased energy resiliency. To confirm battery storage will be compatible with DSRSD's energy objectives, preliminary engineering for battery storage should be conducted in conjunction with preliminary engineering studies for the replacement of the cogeneration engines (estimated in FYE 2026). In order to maximize the likelihood of obtaining financial incentives and to align with the solar power project at the WWTP, this project is tentatively recommended for implementation starting in FYE 2027

Funding Allocation Justification:

The project will benefit both new and existing customers with increased energy resiliency and lower power costs. Allocation is based on ratio of current influent flow (2021) to projected influent flows (2047).

Reference:

Energy Facilities Master Plan, TM 4 – Section 4.4

Anticipated CEQA: Initial Study/Mitigated Negative Declaration.

10-Year Cash Flow and Estimated Project Cost (Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
		100	4,700							

Total Estimated Project Cost: $4,800,000.

Current Adopted Budget: $0.

Increase/(Decrease): $4,800,000.

Energy Impacts: DSRSD currently spends about $1.7 million per year on utility bills with about 70 percent of the bill associated with demand charges. The project is estimated to reduce the annual utility bill by approximately $800,000 per year with potentially greater savings as utility rates increase.

Potential Grant or Financing Opportunities:

IRA and SGIP funding opportunities may be available.

CIP No.EMP004 On-site Solar Power, Battery Storage, and EV Charging

Funding Allocation: 8% 210 36% 310 24% 320 32% 610

Project Summary:

This project involves installation of new solar power facilities at the WWTP, Field Operations Facility (FOF) Building, and at the DSRSDAdministration Building. The proposed locations for these facilities are shown in Figure 12.9. The project also includes installation of EV charging stations, 10 per facility location, and battery storage at the FOF Building and Administration Building for storing excess power generated during the day for use with EV charging overnight. The justification for this project is its relatively fast payback period, increased energy independence, increased diversity of renewable energy, and regulatory requirements for electrification of the vehicle fleet which will require charging. It is recommended that this project be implemented in FYE 2025 to maximize the likelihood of obtaining financial incentives and to align with EV fleet vehicle replacements.

Figure 12.9 Onsite Solar and EV Charging Facility Locations at the WWTP, Administration Building, and FOF Building

Funding Allocation Justification:

Implementation of this project will offset both existing and future electrical demands. Electrical generation through solar arrays on the DSRSD Office and Field Office Facility will offset future electrical demands. Solar arrays installed at the WWTP will offset future electrical demands induced by future growth. .

Reference:

Energy Facilities Master Plan, TM 6.

Anticipated CEQA: Initial Study/Mitigated Negative Declaration.

10-Year Cash Flow and Estimated Project Cost (Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
	3,000	6,300								

Total Estimated Project Cost: $9,300,000.

Current Adopted Budget: $0.

Increase/(Decrease): $9,300,000.

Energy Impacts: Reduces utility power use by approximately 870,000 kWh/yr.

Potential Grant or Financing Opportunities:

IRA funding and PPA financing opportunities may be available.

CIP No. 20-P010 Additional Cogeneration Engine

Funding Allocation: 0% 310 100% 320

Project Summary:

This project will permit and install additional cogeneration capacity at the WWTP. This additional capacity would serve two purposes. The first would be redundancy for when other cogeneration engines are out of service for maintenance. The second is with the proposed increases in biogas generation from the FOG receiving facility and future CIP project EMP007 codigestion of FW, the payback for this additional engine would be less than 10 years. Costs for this project assume the new Cogeneration Building budgeted for under CIP No.T18-15 will include sufficient space for housing this additional engine. Based on the forecasted biogas production rates, it is recommended that this project be implemented starting in FYE 2037.

It is estimated that the project will require two years for planning, design and construction; funding should be allocated from FYE 2037 and FYE 2038. Proposed funding includes $2.9M and $6.7M for FYE 2037 and FYE 2038, respectively.

Funding Allocation Justification:

Energy production associated with these facilities will offset future energy demands associated with new customers.

Anticipated CEQA: Initial Study/Mitigated Negative Declaration. Air permitting will be required.

10-Year Cash Flow and Estimated Project Cost(Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
										9,600

Total Estimated Project Cost: $9,600,000.

Current Adopted Budget: $10,500,000.

Increase/(Decrease): ($900,000).

Energy Impacts: Would provide approximately 600,000 kWh/yr in renewable energy production if FOG receiving and FW codigestion are implemented. GHG reduction of approximately 46 MT CO_2e over the next 20 years.

Potential Grant or Financing Opportunities:

IRA and SGIP funding opportunities may be available. PPA financing is also an option.

CIP No.EMP005 DAFT Replacement With Mechanical Thickening

Funding Allocation: 75% 310 25% 320

Project Summary:

This project involves replacing the existing DAFT system with mechanical thickening and implementing real time solids retention time control. The justification for this project is that the existing DAFT structure and equipment are nearing the end of their useful service life (15 to 20 years remaining) and this thickening technology is more energy-intensive than alternative mechanical thickening technologies. In addition, mechanical thickening combined with waste activated sludge wasting from the return activated sludge line rather than the aeration basins can result in higher solids concentration going into the anaerobic digesters, increasing the anaerobic digestion capacity. A capacity analysis of the anerobic digesters identified that they would become capacity-limited by 2046, with no additional co-digestion loads. Costs for this facility assume a new building for housing the new mechanical thickeners (rotary drum thickeners are assumed), and demolition of the existing DAFT facility once construction of the new facility is complete. Based on the estimated remaining useful life of the existing DAFT structure and equipment, it is recommended that DSRSD implement this project in FYE 2036. It is estimated that the project will require four years for planning, design and construction; funding should be allocated from FYE 2035 through FYE 2038. Proposed funding includes $2.7M, $8M, $8M, and $8M for FYE 2035, FYE 2036, FYE 2037, and FYE 2038, respectively.

Funding Allocation Justification:

Allocation is based on ratio of current influent flow (2021) to projected influent flows (2047).

Reference:

Energy Facilities Master Plan, TM 4 – Section 4.4.

Anticipated CEQA: This project is likely to require an Initial Study and Mitigated Negative Declaration (MND) under CEQA.

10-Year Cash Flow and Estimated Project Cost(Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
										26,700

Total Estimated Project Cost: $26,700,000.

Current Adopted Budget: $0.

Increase/(Decrease): $26,700,000.

Energy Impacts: Improved energy efficiency reducing energy use by approximately 1,400,000 kWh/yr. GHG reduction of approximately 59 MT CO_2e over the next 20 years.

Potential Grant or Financing Opportunities:

PG&E on-bill financing for energy improvement projects.

CIP No.EMP006 Food Waste Receiving Facility

Funding Allocation: 0% 310 100% 320

Project Summary:

This project includes the construction and permitting of a FW and other HSW receiving facility to increase biogas production within the WWTP digesters and offset future energy demands for the WWTP. The facility would include a new strain press, holding tank, blending tank, rock trap/macerator, and three transfer pumps, as well as odor control for the FW receiving facility. The FW receiving facility would be constructed on a concrete pad located near the existing digesters, similar to the recently constructed FOG facility. With the implementation of Senate Bill 1383, diversion of FW from landfills will be a priority, increasing the demand for this service. It is recommended that DSRSD implement this project once the existing FOG facility has become operational and allow operations staff time to adjust to this new operation. Studies and design should begin in FYE 2026.

Funding Allocation Justification:

The additional power generated from this facility will offset the need to purchase energy required to serve new customers. Increase in biogas production through FW gas digestion is anticipated to generate approximately 760,000 kWh. By 2047, energy demand for the WWTP is expected to increase by approximately 3,500 MWh. Energy generated from this facility will be used offset these future energy demands.

Reference:

Energy Facilities Master Plan, TM 7.

Anticipated CEQA: Categorical Exemption (CEQA Guideline 15302).

10-Year Cash Flow and Estimated Project Cost(Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
		390	1,755	1,755						

Total Estimated Project Cost: $3,900,000.

Current Adopted Budget: $0.

Increase/(Decrease): $3,900,000.

Energy Impacts:

Energy generation using biogas as a fuel source (vs fossil fuels used for electrical purchases from the grid) is also estimated to results GHG reduction of approximately 3,423 MT CO_2e over the next 20 years.

Potential Grant or Financing Opportunities:

IRA funding is currently available but may not be available when this project is implemented.

CIP No.EMP007 Load Bank for DP-G

Funding Allocation: 100% 310 0% 320

Project Summary:

This project involves the installation of a new load bank at DP-G mounted on a concrete foundation. Generator G5 is sized based on pumping requirements at Effluent Pump Station No. 1. When those pumps are not in use, the capacity of G5 far exceeds the demand, which could impact its maintenance requirements and service life. Adding an automatic load bank to DP-G would allow sufficient load on G5 whenever it's running, whether due to a PG&E outage or routine exercising of the generator. To accomplish this, a 400 kilowatt automatic load bank would be installed outdoors near DP-G. A current transformer on one lead from generator G5 would be connected to the controller in the load bank to control how many load elements are connected. When G5 is off, no elements would be connected. When G5 is producing power, sufficient elements would be added to maintain a minimum preset load on G5.

This project is recommended for implementation in FYE 2027 to prolong life of G5 and reduce maintenance and potential repair costs. It will also enable generator G5 exercising under load when insufficient pump loads are available on DP-G.

Funding Allocation Justification:

Improves performance and provides reliability of existing assets.

Anticipated CEQA: Categorical Exemption (CEQA Guideline 15302).

10-Year Cash Flow and Estimated Project Cost(Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
			300							

Total Estimated Project Cost: $300,000.

Current Adopted Budget: $0.

Increase/(Decrease): $300,000.

Energy Impacts: Improves standby power reliability at the WWTP.

Potential Grant or Financing Opportunities:

None identified.

CIP No.EMP008 Reconfigure Switchgear for Power Outages

Funding Allocation: 100% 310 0% 320

Project Summary:

This project consists of reconfiguring the switchgear at the WWTP to allow for automatic restoration of power after a PG&E power outage. As presently configured, a loss of PG&E power results in isolating the plant by tripping the lockout relay (also known as the "86 relay") at breaker 52-M. This requires an operator to manually reset the lockout before the plant can return to PG&E power. To implement this feature, a Normal After Close contact from the 52-M breaker control switch, or addition of an AUTO/MANUAL mode switch should be incorporated into the breaker controls to prevent automatic closure when breaker has been manually tripped for other reasons.

The benefits of this project include:

- Ability to automatically return to PG&E after outage or streamline a manually initiated return.
- Separation of interconnection trip functions (indicating PG&E outage) from fault trips so that that when the lockout relay trips, operators will know that a fault has occurred and needs to be investigated before resetting.

Preliminary engineering for this project should be conducted in conjunction with preliminary engineering studies for the replacement of the cogeneration engines. This project is contingent on the findings of the preliminary engineering study; however, for planning purposes, this project is tentatively recommended for implementation in FYE 2027.

Funding Allocation Justification:

Improves performance and provides reliability of existing assets.

Anticipated CEQA: Categorical Exemption (CEQA Guideline 15302).

10-Year Cash Flow and Estimated Project Cost (Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
			100							

Total Estimated Project Cost: $100,000.

Current Adopted Budget: $0.

Increase/(Decrease): $100,000.

Energy Impacts: Improves reliability of electrical system at the WWTP.

Potential Grant or Financing Opportunities:

None identified.

CIP No.T16-11 WWTP Electrical Improvement Phase 1

Funding Allocation: 100% 310 0% 320

Project Summary:

The electrical master plan conducted as part of the Energy Facilities Master Plan effort identified several electrical components with inadequate short circuit ratings. This project will upgrade the WWTP's motor control center (MCC) MCC-E, and individual breakers in other MCCs, and switchgear (SWGR) listed in Table 12.1 to recommended short circuit current rating or ampere interrupting current (AIC) rating indicated in the table. It is recommended that this project be implemented as soon as possible due to the criticality of this equipment.

Table 12.1 Equipment With Inadequate Short Circuit Current Rating

Equipment	Description
MCC-E	Equipment has 25,000 AIC rating, which is inadequate based on the most recent short circuit study. Replace equipment with 65,000 AIC rated equipment. In addition, MCC has a probability of failure of 4 in condition assessment.
Breakers CB-K-TFRIPP2, CB-K-TFRV, and CB-K-WR5801 in MCC-K	Breakers have 14,000 ampere AIC rating, which is inadequate based on the most recent short circuit study. Replace breakers with 65,000 AIC rated breakers.
Breakers CB-DPC-MCC-R, CB-R-CRN1020, and CB-R-TFR-R1 in MCC-R	Breakers have 14,000 ampere AIC rating, which is inadequate based on the most recent short circuit study. Replace breakers with >=42,000 AIC rated breakers.
Breakers CB-DPC-MCC-S, CB-S-MME-1010, and CB-S-XFMRS1 in MCC-S	Breakers have 14,000 ampere AIC rating, which is inadequate based on the most recent short circuit study. Replace breakers with >=42,000 AIC rated breakers.
Breakers CB-X-XFMR-X1, MCP-X-AHU1310, MCP-X-F1082, and MCP-X-P1101 in MCC-X	Breakers have 14,000 and 30,000 ampere AIC rating, which is inadequate based on the most recent short circuit study. Replace breakers with >=42,000 AIC rated breakers.
Breaker CB-Y-TFR-Y1 in MCC-Y	Breakers have 14,000 ampere AIC rating, which is inadequate based on the most recent short circuit study. Replace breakers with >=42,000 AIC rated breakers.
SWGR-DPA	Some breakers in the switchgear have 30,000 ampere AIC rating, which is inadequate based on the most recent short circuit study. Replace breakers with 65,000 AIC rated breakers. Also, switchgear has a probability of failure of 4 in condition assessment, see Table 14.2. In addition, switchgear was identified as 90% loaded in load study, see Table 14.3.

Funding Allocation Justification:

Improves performance and provides reliability of existing assets.

Anticipated CEQA: Categorical Exemption (CEQA Guideline 15302).

10-Year Cash Flow and Estimated Project Cost (Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
	210	1,890								

Total Estimated Project Cost: $2,100,000.

Current Adopted Budget: $2,069,000.

Increase/(Decrease): $31,000.

Energy Impacts: Improves reliability of electrical system at the WWTP.

Potential Grant or Financing Opportunities:

None identified.

CIP No.EMP009 WWTP Electrical Improvements Phase 2

Funding Allocation: 100% 310 0% 320

Project Summary:

The electrical master plan conducted as part of the Energy Facilities Master Plan effort identified several electrical components as marginal or overloaded based on electrical load studies. This includes switchgear, transformers, MCCs, and fuses. Additional investigation using power monitoring is required to confirm whether or not this equipment should be replaced. This study is recommended for implementation in FYE 2025.

The costs included herein assumes replacement of switchgear SWGR-DPN, transformer XFMR-7 switchboard, and MCC-F1, MCC-R, MCC-S, MCC-X, and MCC-Y, all of which showed overloaded or marginal performance in the load study. This project is recommended for implementation in FYE 2034. It is estimated that the project will require two years for planning, design and construction; funding should be allocated in FYE 2034 and FYE 2035. Proposed funding includes $390,000 and $3.5M in FYE 2034 and FYE 2035, respectively.

Funding Allocation Justification:

Improves performance and provides reliability of existing assets.

Anticipated CEQA: Categorical Exemption (CEQA Guideline 15302).

10-Year Cash Flow and Estimated Project Cost (Cost in $1000):

FYE24	FYE25	FYE26	FYE27	FYE28	FYE29	FYE30	FYE31	FYE32	FYE33	Future
	100									3,900

Total Estimated Project Cost: $4,000,000.

Current Adopted Budget: $0.

Increase/(Decrease): $4,000,000.

Energy Impacts: Improves reliability of the electrical system at the WWTP.

Potential Grant or Financing Opportunities:

None identified.

Appendix 12A

CAPITAL IMPROVEMENT PROGRAM PROJECT COST ESTIMATES

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Project: Energy Facilities Master Plan
Job Number: 200892
Client: Dublin San Ramon Services District

By: SJ Hall
Date: 2/26/2024

Checked: S. Deslauriers
Date: 2/28/2024

		Total	Year 1 24	Year 2 25	Year 3 26	Year 4 27	Year 5 28	Year 6 29	Year 7 30	Year 8 31	Year 9 32	Year 10 33	Year 11 34	Year 12 35	Year 13 36	Year 14 37	Year 15 38	Year 16 39	Year 17 40	Year 18 41	Year 19 42
NPV of Capital Cost																					
	Business-as-Usual	$ 3,719,000	$ 532,000	$ -	$ 614,000	$ -	$ -	$ 459,000	$ -	$ 147,000	$ -	$ -	$ -	$ 251,000	$ 253,000	$ 171,000	$ 585,000	$ 334,000	$ 373,000	$ -	$ -
	State & Local Fleets	$ 7,239,000	$ 532,000	$ -	$ 689,000	$ -	$ -	$ 1,092,000	$ -	$ 140,000	$ -	$ -	$ -	$ 690,000	$ 625,000	$ 384,000	$ 1,457,000	$ 888,000	$ 742,000	$ -	$ -
NPV of O&M Cost																					
	Business-as-Usual	$ 1,075,000	$ 67,000	$ 67,000	$ 59,000	$ 51,000	$ 49,000	$ 46,000	$ 47,000	$ 49,000	$ 50,000	$ 52,000	$ 53,000	$ 54,000	$ 57,000	$ 58,000	$ 59,000	$ 62,000	$ 63,000	$ 65,000	$ 67,000
	State & Local Fleets	$ 937,000	$ 58,000	$ 60,000	$ 56,000	$ 57,000	$ 58,000	$ 60,000	$ 61,000	$ 63,000	$ 57,000	$ 52,000	$ 48,000	$ 48,000	$ 40,000	$ 38,000	$ 38,000	$ 22,000	$ 39,000	$ 40,000	$ 42,000
NPV of Total Cost																					
	Business-as-Usual	$ 4,794,000	$ 599,000	$ 67,000	$ 673,000	$ 51,000	$ 49,000	$ 505,000	$ 47,000	$ 196,000	$ 50,000	$ 52,000	$ 53,000	$ 305,000	$ 310,000	$ 229,000	$ 644,000	$ 396,000	$ 436,000	$ 65,000	$ 67,000
	State & Local Fleets	$ 8,176,000	$ 590,000	$ 60,000	$ 745,000	$ 57,000	$ 58,000	$ 1,152,000	$ 61,000	$ 203,000	$ 57,000	$ 52,000	$ 48,000	$ 738,000	$ 665,000	$ 422,000	$ 1,495,000	$ 910,000	$ 781,000	$ 40,000	$ 42,000
GHG Emissions (MT $CO_{2\,eq}$)																					
	Business-as-Usual	1,211	95	84	83	58	53	90	53	67	53	53	53	62	61	58	68	60	59	53	53
	State & Local Fleets	930	82	76	78	67	67	104	66	80	57	50	42	49	38	30	19	12	10	2	1
Energy Consumption (kWh)																					
	Business-as-Usual	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	State & Local Fleets	453,613	5470	5470	11986	11986	11986	11986	11986	11986	13224	16596	21589	24277	29395	36126	36126	48356	48356	48356	48356
Gasoline Consumption (Gallons)																					
	Business-as-Usual	108,482	9348	8726	7404	5728	5168	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151	5151
	State & Local Fleets	84,106	7576	7576	6344	6344	6344	6344	6344	6344	5882	5019	4068	3825	2698	2108	2108	0	1727	1727	1727
Diesel Consumption (Gallons)																					
	Business-as-Usual	11,928	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628	628
	State & Local Fleets	5,769	628	628	628	628	628	628	628	628	107	107	107	107	107	107	107	0	0	0	0

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CLIENT:	Dublin San Ramon Services District (DSRSD)		
PROJECT:	Energy Facilities Master Plan	**ESTIMATE CLASS:**	5
JOB # :	200892	**ESTIMATE PREPARATION DATE :**	1/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Renewable Energy Generation	**REVIEW DATE :**	9/30/2023
PROJECT ID:	22-P010	**REVIEWED BY :**	RLG
DESCRIPTION:	WWTP HVAC Replacements		

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
2	**Equipment**					
	HVAC System Components Replacement and Ductwork Cleaning in Buildings A and T	1	LS	$750,000	$750,000	
	HVAC Replacement in Building C	1	LS	$200,000	$200,000	
	Total					$950,000
	SUBTOTAL					**$950,000**
3	**Allowances**					
	EIC Allowance	30	%		$285,000	
	Total					$285,000
	SUBTOTAL					**$1,235,000**
	Estimating Contingency	30	%			$371,000
	SUBTOTAL					**$1,606,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$69,000
	SUBTOTAL					**$1,675,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$503,000
	SUBTOTAL					**$2,178,000**
	CONSTRUCTION COST SUBTOTAL					**$2,178,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$654,000
	PROJECT COST					**$2,800,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Renewable Energy Generation
PROJECT ID: T18-15
DESCRIPTION: New Cogen Engines 2x700 kW (40% DG and 60% NG)

ESTIMATE CLASS: 5
ESTIMATE PREPARATION DATE : 2/28/2024
PREPARED BY : CT
REVIEW DATE : 3/1/2024
REVIEWED BY : RLG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Concrete pad for conditioning system	1000	SF	$100	$100,000	
	New Cogen Building	5400	SF	$900	$4,860,000	
	Total					$4,960,000
2	**Equipment**					
	700 kW Engine/Generator Cogeneration System (Jenbacher 4 series) with Heat Recovery Unit. and SCR	2	EA	$1,300,000	$2,600,000	
	Misc. Mechanical Equipment	2	LS	$250,000	$500,000	
	Misc. pumps, valves, piping	2	LS	$250,000	$500,000	
	Testing Allowance	2	LS	$75,000	$150,000	
	HVAC	2	LS	$100,000	$200,000	
	Fuel Conditioning system (siloxane, H2S removal)	1	EA	$2,500,000	$2,500,000	
	Equipment installation	10%	%		$645,000	
	Total					$7,095,000
	SUBTOTAL					**$12,055,000**
3	**Allowances**					
	Process Mechanical Allowance	10	%		$1,206,000	
	Yard Piping & Site Civil Allowance	10	%		$1,206,000	
	EIC Allowance	30	%		$3,617,000	
	Coating/Painting Allowance	5	%		$603,000	
	Total					$6,632,000
	SUBTOTAL					**$18,687,000**
	Estimating Contingency	30	%			$5,606,000
	SUBTOTAL					**$24,293,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$1,040,000
	SUBTOTAL					**$25,333,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$7,600,000
	SUBTOTAL					**$32,933,000**
	CONSTRUCTION COST SUBTOTAL					**$32,933,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$9,880,000
	PROJECT COST					**$42,800,000**

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CLIENT:	Dublin San Ramon Services District (DSRSD)		
PROJECT:	Energy Facilities Master Plan	**ESTIMATE CLASS:**	5
JOB # :	200892	**ESTIMATE PREPARATION DATE :**	10/2/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	CT
PROCESS:	Power Generation	**REVIEW DATE :**	10/3/2023
PROJECT ID:	20-P010	**REVIEWED BY :**	RLG
DESCRIPTION:	Additional Cogen Engine 700 kW (40% DG and 60% NG)		

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Concrete pad for conditioning system	600	SF	$100	$60,000	
	Allowance for cogen building retrofit	1	LS	$300,000	$300,000	
	Total					$360,000
2	**Equipment**					
	700 kW Engine/Generator Cogeneration System (Jenbacher 3 series) with Heat Recovery Unit. and SCR	1	EA	$1,300,000	$1,300,000	
	Misc. Mechanical Equipment	1	LS	$250,000	$250,000	
	Misc. pumps, valves, piping	1	LS	$250,000	$250,000	
	Testing Allowance	1	LS	$75,000	$75,000	
	HVAC	1	LS	$100,000	$100,000	
	Fuel Conditioning system (siloxane, H2S removal)	0	EA	$2,000,000	$0	
	Equipment installation	10%	%		$197,500	
	Total					$2,173,000
	SUBTOTAL					**$2,533,000**
3	**Allowances**					
	Process Mechanical Allowance	20	%		$507,000	
	Yard Piping & Site Civil Allowance	10	%		$253,000	
	EIC Allowance	30	%		$760,000	
	Coating/Painting Allowance	5	%		$127,000	
	Total					$1,647,000
	SUBTOTAL					**$4,180,000**
	Estimating Contingency	30	%			$1,254,000
	SUBTOTAL					**$5,434,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$233,000
	SUBTOTAL					**$5,667,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$1,700,000
	SUBTOTAL					**$7,367,000**
	CONSTRUCTION COST SUBTOTAL					**$7,367,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$2,211,000
	PROJECT COST					**$9,600,000**

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CLIENT:	Dublin San Ramon Services District (DSRSD)		
PROJECT:	Energy Facilities Master Plan		
JOB # :	200892	**ESTIMATE CLASS:**	5
LOCATION :	San Ramon, CA	**ESTIMATE PREPARATION DATE :**	2/8/2023
PROCESS:	Secondary Treatment	**PREPARED BY :**	RLG
PROJECT ID:	EMP001	**REVIEW DATE :**	9/30/2023
DESCRIPTION:	Aeration System Upgrades	**REVIEWED BY :**	PF

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Allowance for blower building retrofit	1	LS	$100,000	$100,000	
	Total					$100,000
2	**Equipment**					
	High Speed Turbo NX600 Blower	2	EA	$575,000	$1,150,000	
	Blower MCP	1	LS	$115,000	$115,000	
	Misc. pumps, valves, piping	1	LS	$250,000	$250,000	
	Testing Allowance	1	LS	$75,000	$75,000	
	Aeration Diffusers	1	LS	$400,000	$400,000	
	Equipment installation	25%	%		$497,500	
	Total					$2,488,000
	SUBTOTAL					**$2,588,000**
3	**Allowances**					
	Process Mechanical Allowance	10	%		$259,000	
	Electrical Allowance	20	%		$518,000	
	Coating/Painting Allowance	5	%		$129,000	
	Total					$1,682,000
	SUBTOTAL					**$4,270,000**
	Estimating Contingency	30	%			$1,281,000
	SUBTOTAL					**$5,551,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$238,000
	SUBTOTAL					**$5,789,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$1,737,000
	SUBTOTAL					**$7,526,000**
	CONSTRUCTION COST SUBTOTAL					**$7,526,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$2,258,000
	PROJECT COST					**$9,800,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Renewable Energy Generation
PROJECT ID: EMP002
DESCRIPTION: Off-Site Solar (at LAVWMA site, 2.2 MW)

ESTIMATE CLASS: 5
ESTIMATE PREPARATION DATE : 10/19/2023
PREPARED BY : CT
REVIEW DATE : 10/22/2023
REVIEWED BY : RLG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Included in equipment costs	0	SF	$0	$0	
	Total					$0
2	**Equipment**					
	Solar panels	2,170,000	watt	$2.5	$5,425,000	
	Energy monitoring Package	1	LS	$20,000	$20,000	
	Switchgear interconnection installation allowance (10%)	1	LS	$542,500	$542,500	
	Total					$5,988,000
	SUBTOTAL					**$5,988,000**
3	**Allowances**					
	Yard Elec & Site Civil Allowance	10	%		$599,000	
	Total					**$599,000**
	SUBTOTAL					**$6,587,000**
	Estimating Contingency	10	%			$659,000
	SUBTOTAL					**$7,246,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$310,000
	SUBTOTAL					**$7,556,000**
	General Conditions, Contractor Overhead, & Profit	10	%			$756,000
	SUBTOTAL					**$8,312,000**
	CONSTRUCTION COST SUBTOTAL					**$8,312,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	10	%			$832,000
	PROJECT COST					**$9,100,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Backup Power System
PROJECT ID: EMP003
DESCRIPTION: Battery Storage (1MW)

ESTIMATE CLASS: 5
ESTIMATE PREPARATION DATE : 10/19/2023
PREPARED BY : CT
REVIEW DATE : 10/22/2023
REVIEWED BY : RLG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Concrete pad for Battery	200	SF	$100	$20,000	
	Total					$20,000
2	**Equipment**					
	1 MW Battery	1	LS	$2,387,000	$2,387,000	
	Installation Allowance (30%)	1	LS	$716,100	$716,100	
	Total					$3,103,000
	SUBTOTAL					**$3,123,000**
3	**Allowances**					
	Yard Elec & Site Civil Allowance	10	%		$312,000	
	Total					**$312,000**
	SUBTOTAL					**$3,435,000**
	Estimating Contingency	10	%			$344,000
	SUBTOTAL					**$3,779,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$162,000
	SUBTOTAL					**$3,941,000**
	General Conditions, Contractor Overhead, & Profit	10	%			$394,000
	SUBTOTAL					**$4,335,000**
	CONSTRUCTION COST SUBTOTAL					**$4,335,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	10	%			$434,000
	PROJECT COST					**$4,800,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Renewable Energy Generation
PROJECT ID: EMP004
DESCRIPTION: On-Site Solar Power, Battery Storage, and EV Charging (at Admin Bldg, FOF, and WWTP)

ESTIMATE CLASS: 5
ESTIMATE PREPARATION DATE : 10/19/2023
PREPARED BY : CT
REVIEW DATE : 10/22/2023
REVIEWED BY : RLG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Included in equipment costs	0	SF	$0	$0	
	Total					$0
2	**Equipment**					
	Solar panels @ FOF	70,000	watt	$2.5	$175,000	
	Fleet Vehicle Charging @ FOF	10	EA	$3,500	$35,000	
	Battery Storage (4 MWh) @ FOF	1	LS	$2,000,000	$2,000,000	
	Energy monitoring Package @ FOF	1	LS	$20,000	$20,000	
	Solar panels @ Admin Bldg	350,000	watt	$2.5	$875,000	
	Fleet Vehicle Charging @ Admin Bldg	10	EA	$3,500	$35,000	
	Battery Storage (4 MWh) @ Admin Bldg	1	LS	$2,000,000	$2,000,000	
	Energy monitoring Package @ Admin Bldg	1	LS	$20,000	$20,000	
	Solar panels @ WWTP	120,000	watt	$2.5	$300,000	
	Fleet Vehicle Charging @ WWTP	10	EA	$3,500	$35,000	
	Energy monitoring Package @ WWTP	1	LS	$20,000	$20,000	
	Switchgear interconnection installation allowance (10%)	1	LS	$552,000	$552,000	
	Total					$6,067,000
	SUBTOTAL					**$6,067,000**
3	**Allowances**					
	Yard Elec & Site Civil Allowance	10	%		$607,000	
	Total					**$607,000**
	SUBTOTAL					**$6,674,000**
	Estimating Contingency	10	%			$667,000
	SUBTOTAL					**$7,341,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$314,000
	SUBTOTAL					**$7,655,000**
	General Conditions, Contractor Overhead, & Profit	10	%			$766,000
	SUBTOTAL					**$8,421,000**
	CONSTRUCTION COST SUBTOTAL					**$8,421,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	10	%			$843,000
	PROJECT COST					**$9,300,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Solids Handling
PROJECT ID: EMP005
DESCRIPTION DAFT Replacement with Mechanical Thickening (RDT's)

ESTIMATE CLASS: 5
PREPARED BY: CP
DATE PREPARED: 6/2/2023
REVIEWED BY: RLG
DATE REVIEWED: 6/5/2023

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
3	**CONCRETE/STRUCTURES**					
	Thickener Building	5000	SF	$ 900	$ 4,500,000	
	Filtrate Wet Well Allowance	1	LS	$ 500,000	$ 500,000	
	Total					$ 5,000,000
11	**EQUIPMENT**					
	Thickening RDTs	3	EA	$ 204,757	$ 614,270	
	Polymer Feed System	1	LS	$ 150,000	$ 150,000	
	Thickening Feed Pumps	2	EA	$ 50,000	$ 100,000	
	Digester Feed Pumps	2	EA	$ 50,000	$ 100,000	
	HVAC/Odor Control System	1	LS	$ 500,000	$ 500,000	
	Installation Allowance	30%			$ 289,281	
	Total					$ 1,754,000
	SUBTOTAL					**$ 6,754,000**
	Sitework & Yard Piping Allowance for RAS Wasting	20	%		$ 1,351,000	
	DAFT Demolition Allowance	1	LS		$ 500,000	
	Process Mechanical Allowance	15	%		$ 1,013,000	
	Electrical, Instrumentation & Control Allowance	30	%		$ 2,026,000	
	Total					$ 4,890,000
	DIRECT COST SUBTOTAL					**$ 11,644,000**
	Estimating Contingency	30	%			$ 3,493,000
	SUBTOTAL					**$ 15,137,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$ 648,000
	SUBTOTAL					**$ 15,785,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$ 4,736,000
	SUBTOTAL					**$ 20,521,000**
	TOTAL CONSTRUCTION COST					**$ 20,500,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$6,150,000
	TOTAL PROJECT COST					**$26,700,000**

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CLIENT: Dublin San Ramon Services District (DSRD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Solids Handling, Energy Generation
PROJECT ID: EMP006
DESCRIPTION CoDigestion of Food Waste and other HSW

ESTIMATE CLASS: 5
PREPARED BY: CP
DATE PREPARED: 3/21/2023
REVIEWED BY: RLG
DATE REVIEWED: 6/5/2023

DIVISION	DESCRIPTION	QUAN	UNIT	UNIT COST	SUBTOTAL	TOTAL
3	**CONCRETE**					
	FW Receiving Slab	150	CY	$675	$101,250	
	Total					$101,000
11	**EQUIPMENT**					
	FW Receiving Equipment					
	Huber Strainpress	1	EA	$205,000	$205,000	
	Holding Tanks	55,500	GAL	$4	$222,000	
	Blending Tank	1	EA	$37,000	$37,000	
	Rock Trap/Macerator	1	EA	$15,000	$15,000	
	Transfer Pump	3	EA	$19,000	$57,000	
	Odor Control Equipment (Scrubber)					
	FRP Ductwork	1	EA	$45,000	$45,000	
	Odor Control Scrubber	1	EA	$101,250	$101,250	
	Installation Allowance	30%			$204,675	
	Total					$887,000
	SUBTOTAL					**$988,000**
	Sitework & Yard Piping Allowance	20%	%		$198,000	
	Process Mechanical Allowance	20%	%		$198,000	
	Electrical, Instrumentation & Control Allowance	30%	%		$296,000	
	Total					$692,000
	DIRECT COSTS SUBTOTAL					**$1,680,000**
	Estimating Contingency	30%				$504,000
	SUBTOTAL					**$2,184,000**
	Sales Tax on 50% of Subtotal Above	8.56%				$93,000
	SUBTOTAL					**$2,277,000**
	General Conditions, Contractor Overhead, & Profit	30%				$683,000
	SUBTOTAL					**$2,960,000**
	CONSTRUCTION COST					**$3,000,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30%				$900,000
	TOTAL PROJECT COST					**$3,900,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Backup Power System
PROJECT ID: EMP007
DESCRIPTION: Load Bank for DP-G

ESTIMATE CLASS: 5
ESTIMATE PREPARATION DATE : 10/19/2023
PREPARED BY : AM
REVIEW DATE : 10/22/2023
REVIEWED BY : RLG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
1	**Structures**					
	Concrete pad for Load Bank	100	SF	$100	$10,000	
	Total					$10,000
2	**Equipment**					
	400 kW Load Bank	1	EA	$42,000	$42,000	
	Conduit & Wire parrallel runs 2[(3#250 &#2 Gnd)]	100	LF	$340	$34,000	
	Current Transformer 500 amp	1	EA	$2,000	$2,000	
	Total					$78,000
	SUBTOTAL					**$88,000**
3	**Allowances**					
	Yard Elec & Site Civil Allowance	10	%		$9,000	
	EIC Allowance	30	%		$26,000	
	Total					**$35,000**
	SUBTOTAL					**$123,000**
	Estimating Contingency	30	%			$37,000
	SUBTOTAL					**$160,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$7,000
	SUBTOTAL					**$167,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$50,000
	SUBTOTAL					**$217,000**
	CONSTRUCTION COST SUBTOTAL					**$217,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$66,000
	PROJECT COST					**$300,000**

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CLIENT:	Dublin San Ramon Services District (DSRSD)		
PROJECT:	Energy Facilities Master Plan	**ESTIMATE CLASS:**	5
JOB # :	200892	**ESTIMATE PREPARATION DATE :**	10/19/2023
LOCATION :	San Ramon, CA	**PREPARED BY :**	AM
PROCESS:	Backup Power System	**REVIEW DATE :**	10/22/2023
PROJECT ID:	EMP008	**REVIEWED BY :**	RLG
DESCRIPTION:	Reconfigure Switchgear for Power Outages		

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
2	**Equipment**					
	PLC Programming including Main SWGR Controls	1	LS	$34,000	$34,000	
	Breaker Control Switch	1	EA	$1,700	$1,700	
	Conduit and Wire	100	LF	$52	$5,200	
	Total					$41,000
	SUBTOTAL					**$41,000**
	Estimating Contingency	30	%			$12,000
	SUBTOTAL					**$53,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$2,000
	SUBTOTAL					**$55,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$17,000
	SUBTOTAL					**$72,000**
	CONSTRUCTION COST SUBTOTAL					**$72,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$22,000
	PROJECT COST					**$100,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Electrical Facilities
PROJECT ID: T16-11
DESCRIPTION: WWTP Electrical Improvements Phase 1

ESTIMATE CLASS: 5
ESTIMATE PREPARATION DATE : 10/19/2023
PREPARED BY : JD
REVIEW DATE : 10/22/2023
REVIEWED BY : RLG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
2	**Equipment**					
	MCC-E	1	LS	$60,000	$60,000	
	Breaker Control Switch	1	LS	$12,000	$12,000	
	Breakers CB-K-TFRIPP2, CB-K-TFRV, and CB-K-WR5801 in MCC-K	1	LS	$12,000	$12,000	
	Breakers CB-DPC-MCC-R, CB-R-CRN1020, and CB-R-TFR-R1 in MCC-R	1	LS	$12,000	$12,000	
	Breakers CB-X-XFMR-X1, MCP-X-AHU1310, MCP-X-F1082, and MCP-X-P1101 in MCC-X	1	LS	$16,000	$16,000	
	Breaker CB-Y-TFR-Y1 in MCC-Y	1	LS	$4,000	$4,000	
	SWGR-DPA	1	LS	$600,000	$600,000	
	Total					$716,000
	Installation Allowance	25	%			$179,000
	SUBTOTAL					**$895,000**
	Estimating Contingency	30	%			$269,000
	SUBTOTAL					**$1,164,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$50,000
	SUBTOTAL					**$1,214,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$364,000
	SUBTOTAL					**$1,578,000**
	CONSTRUCTION COST SUBTOTAL					**$1,578,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$474,000
	PROJECT COST					**$2,100,000**

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CLIENT: Dublin San Ramon Services District (DSRSD)
PROJECT: Energy Facilities Master Plan
JOB # : 200892
LOCATION : San Ramon, CA
PROCESS: Electrical Facilities
PROJECT ID: EMP009
DESCRIPTION: WWTP Electrical Improvements Phase 2

ESTIMATE CLASS: 5
ESTIMATE PREPARATION DATE : 10/19/2023
PREPARED BY : JD
REVIEW DATE : 10/22/2023
REVIEWED BY : RLG

ITEM NO.	DESCRIPTION	QTY	UNIT	UNIT COST	SUBTOTAL	TOTAL
2	**Equipment**					
	SWGR-DPN	1	LS	$750,000	$750,000	
	XFMR-7 SWBD	1	LS	$250,000	$250,000	
	MCC-F1	1	LS	$40,000	$40,000	
	MCC-R	1	LS	$80,000	$80,000	
	MCC-S	1	LS	$80,000	$80,000	
	MCC-X	1	LS	$100,000	$100,000	
	MCC-Y	1	LS	$100,000	$100,000	
	Total					$1,400,000
	Installation Allowance	25	%			$350,000
	SUBTOTAL					**$1,750,000**
	Estimating Contingency	30	%			$525,000
	SUBTOTAL					**$2,275,000**
	Sales Tax on 50% of Subtotal Above	8.56	%			$97,000
	SUBTOTAL					**$2,372,000**
	General Conditions, Contractor Overhead, & Profit	30	%			$712,000
	SUBTOTAL					**$3,084,000**
	CONSTRUCTION COST SUBTOTAL					**$3,084,000**
	Engineering, Const. Mgmt., Eng. Support During Const.	30	%			$926,000
	PROJECT COST					**$4,000,000**