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Technical Memorandum

Prepared for: City of Eugene, Oregon

Project Title: Digester Heating System Evaluation

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Technical Memorandum

Subject: Evaluation of Existing Systems and Alternatives Analysis (Final)

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Limitations:

This is a draft memorandum and is not intended to be a final representation of the work done or recommendations made by Brown and Caldwell. It should not be relied upon; consult the final report.

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Background

The Metropolitan Wastewater Management Commission (MWMC) operates a water pollution control facility (WPCF, plant) located on the north bank of the Willamette River in Eugene, Oregon. The WPCF is jointly owned by the City of Eugene and City of Springfield. The solids treatment process is comprised of four anaerobic digesters, one boiler, one engine generator (EG), two sludge holding tanks, two candlestick flares, and a renewable natural gas (RNG) upgrading facility. The four anaerobic digesters produce biogas (methane, carbon dioxide, and trace gasses) which is collected and utilized in the plants' RNG upgrading facility. When the RNG upgrading facility is offline, biogas is utilized onsite in the plants' EG or boiler to provide heat for the plant processes. Excess biogas is combusted in one of the two candlestick flares.

The City of Eugene contracted Brown and Caldwell (BC) to evaluate the WPCF's existing digester heating system, which is currently experiencing operational challenges. The challenges investigated as part of this evaluation include the following:

1. The EG is unable to provide enough heat for the plant during the peak heat demand, which occurs during the coldest days of the year.
2. While the boiler is running in tandem with the EG, the EG will occasionally waste heat to its radiator.
3. The system will occasionally flare biogas while the boiler is operating on natural gas.
4. Biogas pressure drops at the EG when the boiler is started on biogas, resulting in shutdown of the EG.
5. Condensation issues inside the boiler.
6. Occasional insufficient building heat.
7. Boiler and EG three-way control valves not having sufficient control (i.e. due to improperly tuned PID control parameters or valve malfunction, resulting in too little or too much heat transfer).

This TM is separated into three sections. Section 1 summarizes BC's evaluation of the plant's heating system and includes recommended operational improvements to address the above challenges. Section 2 is an alternatives analysis which compares net present cost of three potential alternatives to provide redundancy in the plants heating system. Section 3 summarizes near term and long-term recommendations for the plant based on findings from this study.

Section 1: Evaluation of Existing Systems

1.1 Biogas System Overview

The biogas system is comprised of a boiler, EG, two candlestick flares, and an RNG upgrading system. Interconnecting piping between the four anaerobic digesters and two sludge holding tanks routes the biogas to the various uses. Figure below shows a schematic of the biogas system.

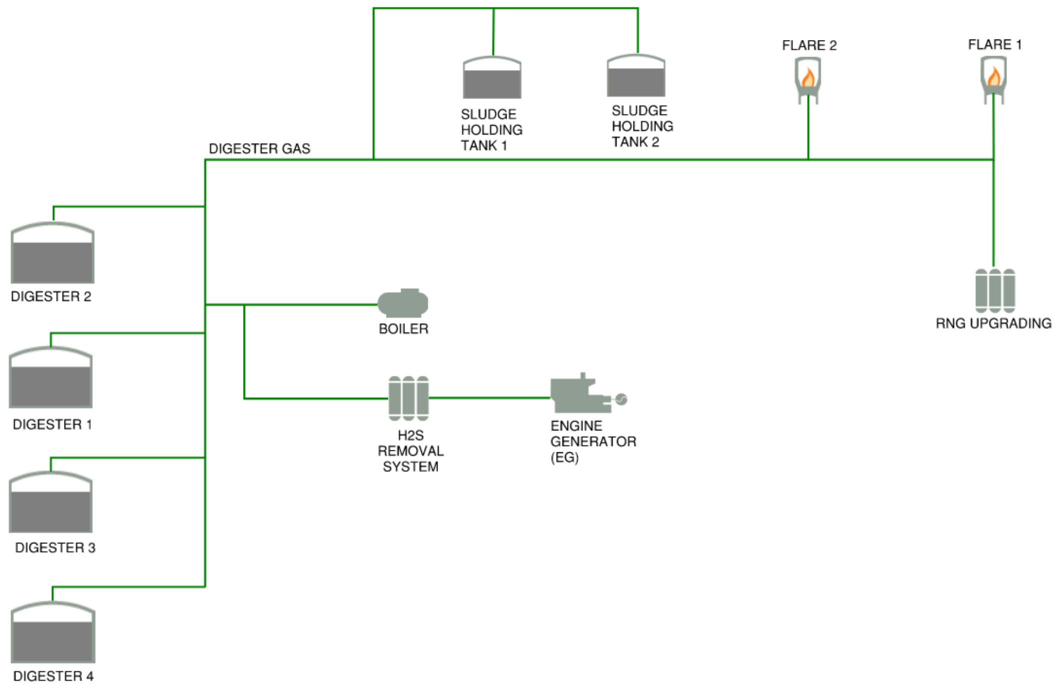

Figure 1: Biogas system overview

In 1997, a Jenbacher J316 engine (Figure 2 below) was installed at the WPCF and connected to a Kato Engineering generator. A hydrogen sulfide (H_2S) removal system was installed upstream of the EG in 2004. This EG assembly has been continually maintained according to the manufacturer's recommendations, including an engine block replacement in 2018 and a top-end rebuild circa 2020/2021. In 2019, a fourth digester and a new 200hp Hurst firetube boiler (Figure 3 below) were installed as part of the Increase Digestion Capacity Project No. P80084. The RNG upgrading system was commissioned in 2021 and has been the primary biogas use since that time.

Figure 2 Existing Jenbacher J316 Engine and Kato generator

Figure 3: Existing 200hp Hurst Firetube Boiler

1.2 Heat Loop Overview

Heat is transferred from the boiler and EG to the digesters and buildings via a primary-secondary heat loop. The four anaerobic digesters, the solids handling building, administration building, maintenance building, and environmental services/laboratory building are all connected to the primary heat loop. The boiler, EG, each digester, and the buildings all have secondary heat loops which receive hot water from the primary heat loop. Each secondary heat loop has a three-way control valve which modulates flow between the loops.

The primary heat loop water is circulated at 600gpm through an 8-inch pipe via two constant speed pumps PMP36-01 and PMP36-02. The primary heat loop return temperature (the coldest point in the loop) is monitored at the outlet of the pumps via a temperature indicating transmitter (TIT36-01). The first tie-in to the primary heat loop after the circulation pumps is the EG heat loop. Flow from the primary heat loop to the EG heat loop is pumped via the Digester Engine Heating Water Circulation Pump (PMP33-02) and is modulated via three-way valve TCV33-01. Flow within the EG heat loop is first pre-cooled by the Cogen Waste Heat Exchanger (HEX33-10), which cools the inlet water to the EG to a setpoint of 154 degrees F. Water is then heated by the engines' lube oil heat exchanger, an intercooler heat exchanger, the jacket water heat exchanger, and finally with an exhaust gas heat exchanger before either being recirculated through the EG heat loop or being sent back to the primary heat loop (depending on the position of three-way valve TCV33-01). When TCV33-01 is closed, hot water circulates within the EG heat loop. When the primary heat loop temperature at the supply side drops to a set point of 185 degrees F, three-way valve TCV33-01 opens, mixing hot water from the EG heat loop into the primary heat loop. The initial setpoint for TCV33-01 was 190 degrees F as of December 2016.

The next tie-in to the primary heat loop after the EG heat loop is the boiler heat loop. Flow from the primary heat loop to the boiler secondary heat loop is pumped via the Digester Boiler Return Water Circulation Pumps #1 and #2 (PMP29-01 and PMP29-02), and flow is modulated via three-way valve TCV28-01, which operates in the same manner as TCV33-01 (described above). Water flows through the boiler and is then recirculated through the boiler heat loop or sent to the primary heat loop (depending on the position of the three-way valve TCV28-01). Three-way control valve TCV28-01 begins to open once the primary heating loop supply temperature reaches a setpoint of 185 degrees F. The initial setpoint for TCV28-01 was 220 degrees F as of December 2016. When the boiler is off, the circulation pumps run on a set interval and three-way valve TCV28-01 modulates to 5 percent open to maintain temperature within the boiler heating loop. This works to prevent condensation and minimizes system shock upon startup.

The next tie-ins to the primary heat loop are the secondary heat loops for each of the digesters. Digesters 1, 2 and 3 each have a tie-in to the primary heat loop and each have a dedicated heat exchanger (M8-21-1, M8-21-2, M8-21-3). Flow is controlled between the primary heating loop and each digester heating loop via three-way valves TCV25-01, TCV25-02, and TCV25-03, respectively. Digester 4 uses four heat exchangers (08HEX04-01, 08HEX04-02, 08HEX04-03, and 08HEX04-04), which are integral to digesters' draft tube mixers. There are two tie ins to the primary heating loop for Digester 4, with flow being modulated via three-way valves TCV25-04 and TCV25-05. When the digester secondary heat loop three-way valves are closed, water recirculates through each respective digester heat loop. The five three-way control valves modulate flow from the primary heat loop to each respective digester heat loop in proportion to the digester heat exchanger sludge inlet temperature. These five valves are all set to maintain the sludge temperature in each digester at approximately 100 degrees F.

Following the Digester 4 heat loop tie in, there are three tie ins to provide hot water to the Solids Handling Building, the Administration Building, the Environmental Services Building, and the Maintenance Building.

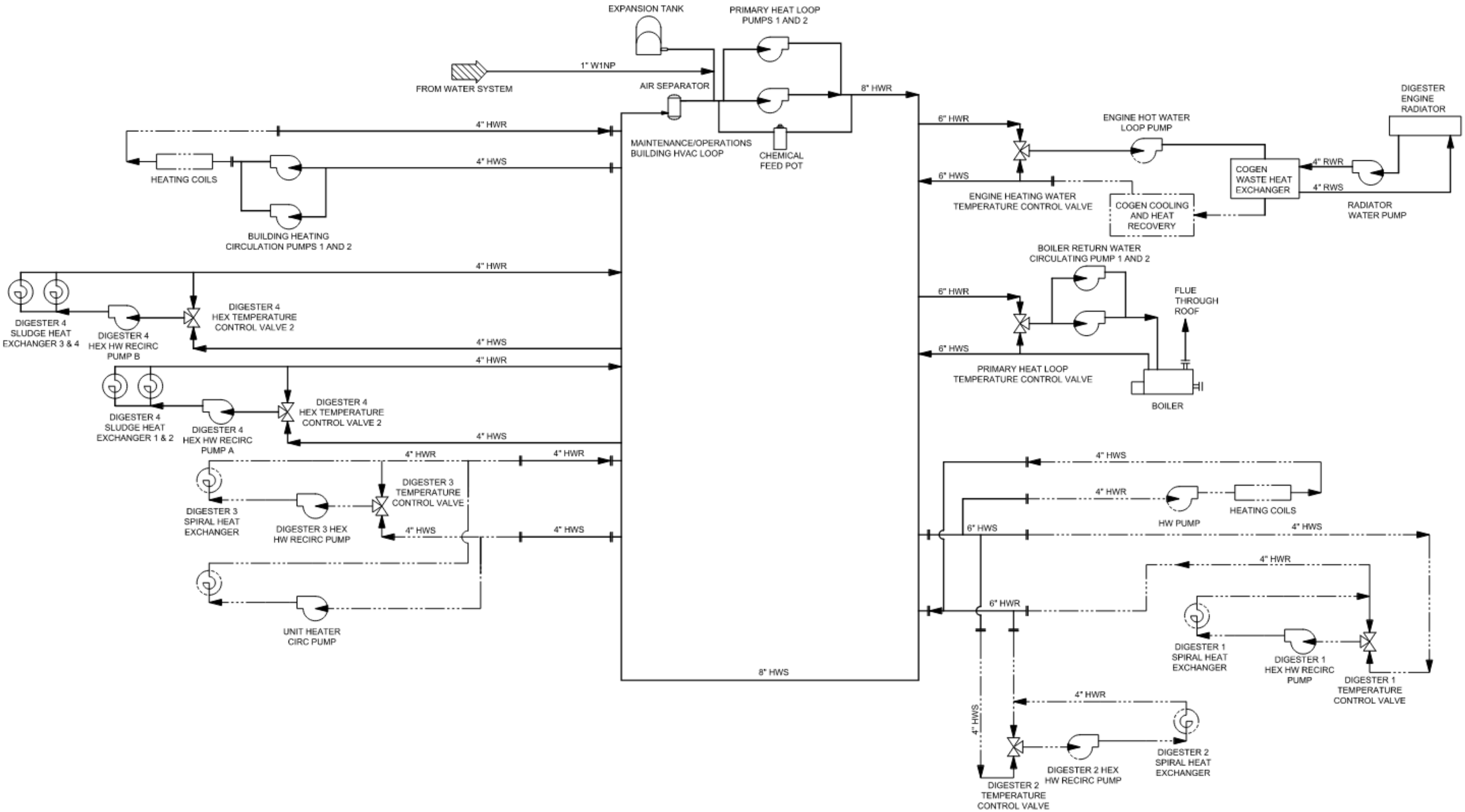

Figure 4: Existing Heating Loop Diagram (From 2019 Digestion Expansion Project)

1.3 Heat Loop Evaluation

Table 1 outlines known flow rates, setpoints, and data related to the heating system. BC received 5-minute interval temperature data of the primary heat loop supply temperature (TIT36-02) and the boiler heat loop temperature (TIT28-01) between 05/13/24 and 6/6/24. During BC's site visit on 8/1/24, screenshots were taken of the SCADA DCS system to obtain the primary heat loop return temperature (TIT36-01) and various other temperatures between 7/12/24 to 8/1/24.

Table 1. Heat Loop Design Parameters

Parameter	Value	Unit
Primary Heat Loop Flow Rate	600	gpm
Min Primary Heat Loop Supply Temp (TIT36-02) (5/13/24 thru 6/6/24)	177.3	F
Max Primary Heat Loop Supply Temp (TIT36-02) (5/13/24 thru 6/6/24)	189.6	F
Avg Primary Heat Loop Supply Temp (TIT36-02) (5/13/24 thru 6/6/24)	183.0	F
Primary Heat Loop Return Temp (TIT36-01) (7/12/24 thru 8/1/24)	164-189	F
EG Heat Loop Flow Rate	190	gpm
EG Heat Loop Three-Way Valve Setpoint	185	F
EG Radiator Flow Rate	257	gpm
EG Radiator Loop Setpoint	154	F
Boiler Heat Loop Flow Rate	500	gpm
Boiler Heat Loop Three-Way Valve Setpoint	185	F
Min Boiler Output Temp (TIT 28-01) (5/13/24 thru 6/6/24)	179.7	F
Max Boiler Output Temp (TIT 28-01) (5/13/24 thru 6/6/24)	192.3	F
Avg Boiler Output Temp (TIT 28-01) (5/13/24 thru 6/6/24)	185.6	F
Boiler Efficiency Process Value	32.8	%
Digesters 1, 2, 3 Heat Loop Flow Rate	310	gpm
Digester 4 Heat Loop Flow Rate	168	gpm

Abbreviations:

F = degrees Fahrenheit

gpm = gallons per minute

This information gives insight into the general operation of the plants heating loop, however, the given data does not encompass all available temperature gauges and does not include a range long enough to see seasonal trends. Per discussion with plant operators, the DCS system is not properly configured to log long term data for all temperature indicating transmitters, which limits the plants' ability to track and account for heat transfer within the heating loops.

To verify existing data and further investigate the EG operation, data was collected by plant operators for six days between 10/4/2024 and 10/12/2024 while the EG was running on natural gas and the boiler was offline. The data collected includes supply and return temperatures for the primary heat loop, the EG radiator heat exchanger, the boiler, the digester heat exchangers, and the building heat exchangers. Data was collected from visual gauges. The positions of the three-way control valves on the EG and boiler heat loops were also recorded. Although this data only provides a small snapshot of information, it gives a few insights into plant operations.

Table 2. Additional Engine Generator Data

Parameter	10/4/24	10/5/24	10/9/24	10/10/24	10/11/24	10/12/24	Unit
Ambient Temperature	54	46	63	48	70	47	F
Primary Heat Loop Supply Temp	166.6	164.4	168	167	166	161	F
Primary Heat Loop Return Temp	157	153.6	159	157	155	149	F
Plant Heat Demand	2.56	2.88	2.40	2.67	2.94	3.20	MMBTU/hr
EG Waste Heat Radiator HEX In	154	No data	155	151	151	128	F
EG Waste Heat Radiator HEX Out	148	No data	147	151	148	118	F
EG Heat Loop Temp (After Waste Heat Exchanger)	154	144	154	154	155	149	F
Wasted Heat	0.69	No data	1.65	0.00	0.62	0.00	MMBTU/hr

Abbreviations:

F = degrees Fahrenheit

During the six days of data collection, the plants' heat demand ranged between 2.40 and 3.21 MMBTU/hr. This range aligns with previous understanding of the plants' heat demand given the time of year this data was collected. During this time period the primary heat loop is operating with an average temperature differential of approximately 8 degrees F. There are a few outliers in the data, one being that the day with the highest ambient temperature of this dataset (10/11/24) showed a relatively high heat demand, which is unusual. It is possible that measurement inconsistency (which is common when collecting data from visual gauges), could be the cause of this outlier. Another possibility cause is variation in digester feed rate.

Additionally, the EG primary heat loop three-way control valve was recorded as fully open during all six days. This indicates that the EG is not circulating water within its heat loop and therefore all heat generated by the EG is being sent to the primary heat loop.

The EG waste heat radiator will turn on when the temperature in the radiator loop reaches the setpoint of 154 degrees F. The EG heat exchanger showed a temperature differential on four of the six days, indicating that the EG radiator was running and wasting heat. The data points show a range of between 0.62 and 1.65 MMBTU/hr wasted by the EG waste heat radiator while it's running. On 10/12/24, the waste heat radiator loop showed a lowered temperature, indicating the radiator was not running and no heat was wasted. The primary heat loop return temperature averaged 155 degrees F during this period, which likely heated the radiator loop past its setpoint and caused the radiator to turn on intermittently, as described by MWMC as an operational challenge.

A period of the provided boiler output temperature data and primary heat loop supply temperature data was plotted and is shown in Figure 5. The plot shows the water temperature of the boiler output, and primary heat loop temperature directly after the boiler tie in.

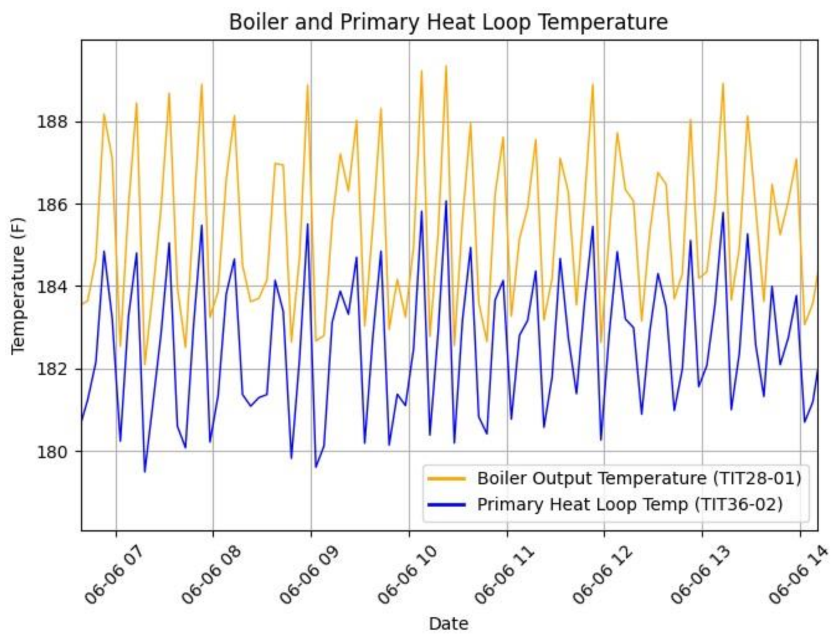

Figure 5: Boiler and Primary Heat Loop Temperature

Figure 5 shows rapid and extreme fluctuations in temperature for both the boiler heat loop and the primary heat loop. The data represented is a period of 7 hours, however these fluctuations were observed for the entire month of data received. BC observed during a site visit that the boiler cycles approximately once per hour, whereas these temperature fluctuations are occurring roughly three times per hour. Therefore, it's unlikely that boiler operation is the cause. Rather, these fluctuations may indicate improperly tuned proportional, integral, derivate (PID) setpoints for the boiler three-way valves. It was noted during a site visit that the PID values for the boiler three-way control valve (TCV28-01) are set at 100, 20, and 0, respectively. 100 and 20 are unusually high values for proportional and integral values which could be causing the valve to operate in an open/close manner rather than a modulating manner, which could explain the temperature fluctuations. Additionally, the EG loop PID setpoints were noted to be set at 100, 35, and 0, respectively. Therefore, it is likely that similar control issues are occurring on the EG three-way control valve (TCV33-01) as well.

1.4 Heat Demand and Equipment Capacity

Table 3 below provides a summary of the peak and average heating demand for the digesters and the buildings, as well as the max rated output of the EG and the boiler.

Table 3. Plant Heating Demands and Equipment Capacities[a]

Parameter	Value	Unit[b]
Digesters 1-4 Heating Demand (Average)	3.259	MMBTU/hr
Digesters 1-4 Heating Demand (Peak, Total, 2035 Estimate)	6.198	MMBTU/hr
Building Heating Demand (Average)	0.183	MMBTU/hr
Building Heating Demand (Peak, 2035 Estimate)	0.283	MMBTU/hr

Table 3. Plant Heating Demands and Equipment Capacities[a]		
Parameter	Value	Unit[b]
Total Plant Heating Demand (Average)	3.44	MMBTU/hr
Total Plant Heating Demand (Peak, Current estimate)	5.84	MMBTU/hr
Total Plant Heating Demand (Peak, 2035 Estimate)	6.48	MMBTU/hr
Boiler Rated Heat Output at Max Output	6.70	MMBTU/hr
EG Rated Heat Output at Rated Max Output (800kW)	3.40	MMBTU/hr
EG Rated Heat Output at Current Max Output (700kW)	2.87	MMBTU/hr

a. Data from BC Effluent Thermal Load Reduction TM (2022) and BC Increase Digester Capacity Project (2019)

b. MMBTU: 1 Million British Thermal Units

Based on the data in Table 3, the boiler is adequately sized to meet the plants' peak heat demand. The max rated heat output of the EG is lower than the average and peak heat demand, which explains the observation that the EG is unable to heat the plant during colder days of the year. Furthermore, the EG is operated at slightly reduced capacity (approximately 700kW) compared to its rated capacity of 800kW, which may reduce the heat output. Per an interview with the operators, the EG is run at this reduced capacity to allow for switching between natural gas and biogas.

The fourth digester was installed more recently as part of a capacity upgrading project. Digesters 3 and 4 have a lower volume resulting in a slightly lower heating demand. As a result, average and peak digestion system heating demands may vary depending on which digesters are online.

Table 4 below summarizes an estimated peak digester heating demand calculation. This calculation assumes a minimum sludge inlet temperature of 53.6 degrees F, a maximum digester temperature of 100.4 degrees F, a hydraulic retention time of 17 days, and a digester wall loss of 20%. Digester heat demands vary because the volume of digesters 1 and 2 is 1.2 MG and the volume of digesters 3 and 4 is 1.1 MG.

Table 4. Calculated Digester Heating Demands		
Parameter	Value	Unit
Calculated Digester 1 Heat Demand	1.36	MMBTU/hr
Calculated Digester 2 Heat Demand	1.36	MMBTU/hr
Calculated Digester 3 Heat Demand	1.24	MMBTU/hr
Calculated Digester 4 Heat Demand	1.24	MMBTU/hr
Calculated Total Digester Peak Heating Demand	5.20	MMBTU/hr

a. Estimated digester heating demands per designed heat loop flow rates and temperatures

The estimated peak heating demand of 5.20 MMBTU/hr generally aligns with the previously reported value of 5.84 MMBTU/hr. However, it suggests that there is either higher than normal heat loss on the digesters, or the reported value of 5.84 MMBTU/hr could be a slight overestimation.

The existing administration building is currently heated via the primary heat loop, however, there is a future plan to replace this building and heat it independently, which will slightly reduce the plants' heat demand.

The maintenance, solids handling, and environmental services/laboratory buildings will still be connected to the primary heat loop.

1.5 Fuel Demand

The boiler and EG fuel trains and combustion systems are designed to operate on either natural gas or biogas and cannot support fuel blending. Biogas undergoes H_2S, moisture, and siloxane removal before it is sent to the EG, and the boiler is fed with raw biogas. Using the plant heating demands and capacities from Table 3, BC calculated the associated fuel demands for the boiler and the EG as shown in Table 5.

Table 5. Heating Equipment Fuel Demands

Parameter	Heat Output (MMBTU/hr.)	Biogas Fuel Demand (scfm)	Natural Gas Fuel Demand (scfm)	Unit
Boiler at 100% Rated Capacity	6.70	254	145	scfm
Boiler Meeting Peak Plant Heat Demand (Current)	5.84	221	127	scfm
Boiler Meeting Peak Plant Heat Demand (2035 Estimate)	6.48	246	141	scfm
Boiler Meeting Average Plant Heat Demand (Current)	3.44	115	75	scfm
EG at Current Max Capacity (700kW)	2.87	187	107	scfm
EG at Rated Max Capacity (800kW)	3.40	222	127	scfm
Upsized EG to Meet Peak Heat Demand (Current)	5.84	381	219	scfm
Upsized EG to Meet Peak Heat Demand (2035 Estimate)	6.48	423	243	scfm
Upsized EG Meeting Average Plant Heat Demand (Current)	3.44	225	129	scfm

Abbreviations:

hr = hour

MMBTU = millions of British thermal units

scfm = standard cubic feet per minute

For comparison to the existing equipment, BC calculated the approximate fuel demand for each fuel type for an example upsized EG. This shows what the fuel demand would be for an EG that can meet the plants' peak heat demand. The upsized EG example assumes the same thermal efficiency as the existing EG.

1.6 Biogas Production

Biogas is produced from the four anerobic digesters and production varies depending on which digesters are operating and the time of year. Figure 6 below summarizes digester gas production from January 2021 to July 2024. The raw flow rate data rapidly fluctuates, so a 30-day rolling average (as shown as a dashed line) has been applied to show the overall trend. The gas production data may show these fluctuations due to unsteady gas production in the digesters or a mis-calibrated gas flow meter, both of which are common.

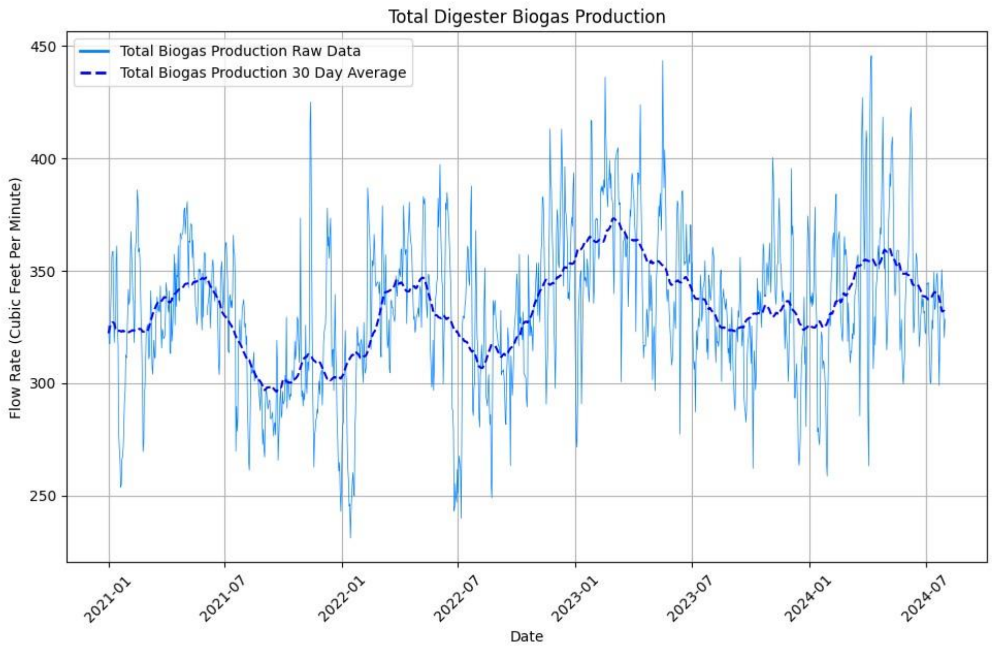

Figure 6: Total Digester Biogas Production Plot

a. Data from "08-02-24B&CDataDump"

Figure 6 above indicates the plant generates 332 scfm of digester gas on average, with occasional drops below 300 scfm and spikes above 400 scfm. Table 6 summarizes the equivalent heating energy from the plants' current biogas production.

Table 6. Heating Energy From Gas Production

Parameter	Gas Flow	Unit	Heat Energy	Unit
Minimum Gas Production	231	scfm	8.6	MMBTU/hr
Average Gas Production	332	scfm	12.4	MMBTU/hr
Maximum Gas Production	445	scfm	16.6	MMBTU/hr

Abbreviations:

hr = hour

MMBTU = millions of British thermal units

scfm = standard cubic feet per minute

Table 6 indicates that the plant produces more than enough digester gas to meet the plant's peak heat demand with the existing boiler, which requires 246 scfm (as shown in Table 5). At times when RNG upgrading is offline, plant staff have observed the boiler having sufficient capacity to meet all current existing demands. Based on the simplified assumptions for an upsized EG in Table 5, the plant does not produce enough digester gas to reliably meet the peak heat demand with an EG (requiring 423 scfm). To do so, blending natural gas with available biogas would be required.

1.7 Value of Biogas Use

MWMC requested BC approximate the value of the plants' biogas to support future decision making on plant heating capacity redundancy. The biogas value was calculated relative to cost of operating the boiler and EG on natural gas. The overall boiler cost considers the cost of natural gas and maintenance cost. The overall EG cost considers the cost of natural gas, the electric bill offset from electricity generation with a 6%

parasitic load from the EG, the maintenance cost, and the media cost for gas conditioning (assuming 0.02 $/kWh).

Operations staff noted the EG has to be rebuilt every four years, costing approximately $165,000 in parts. It was also mentioned that approximately every 2 years, the boiler needs to be retubed which costs approximately $1,500 in parts. An additional $110,000 per year is estimated for the EG maintenance labor, and $4,000 a year for the boiler maintenance labor. The values indicated in Table 7 describe an estimated dollar amount for each million BTU of heat provided to the plant. Table 7 below compares the cost of heating the plant with the EG versus the boiler when they are fueled entirely with natural gas.

Table 7. Existing Equipment Operating Costs

Parameter	Value	Unit
Natural Gas Price	8.557	$/MMBTU
Electricity Price	0.0711	$/kWh
RNG Uptime	85	%
EG Uptime	90	%
Boiler Efficiency	80	%
EG Rebuild Cost and Frequency (From Operator Interview)	165,000	$/4 years
Boiler Maintenance Cost (From Operator Interview)	1,500	$/2 years
EG General Maintenance Cost	110,000	$/year
Boiler General Maintenance Cost	4,000	$/year
Boiler Cost to Heat with Natural Gas	10.70	$/MMBTU
Boiler Estimated Maintenance Cost vs. Heat Provided	0.16	$/MMBTU
Boiler Net Cost to Heat with Natural Gas	10.85	$/MMBTU
Boiler Total Estimated Annual Cost Fueled with Natural Gas	328,000	$/year
Boiler Estimated Annual Cost Fueled with Biogas When RNG Offline	279,000	$/year
EG Parasitic Electricity Load	6	%
EG Electricity Generation vs. Heat Provided	221	kWh/MMBTU
EG Cost to Heat with Natural Gas	18.44	$/MMBTU
EG Estimated Maintenance Cost vs. Heat Provided	5.02	$/MMBTU
EG Gas Conditioning Media Cost	0.60	$/MMBTU
EG Cost to Heat with Natural Gas	23.46	$/MMBTU
EG Energy Savings vs. Heat Provided	-15.70	$/MMBTU
EG Net Cost to Heat with Natural Gas	7.75	$/MMBTU
EG Estimated Annual Cost Fueled with Natural Gas	234,000	$/year
EG Estimated Annual Cost Fueled with Biogas When RNG Offline	169,000	$/year

a. Units of heat refer to usable heat.

Table 7 indicates that the EG is a more cost-effective use of natural gas than the boiler. The boiler requires less fuel per MMBTU of heat generated and has a significantly lower maintenance cost. However, the EG offsets a significant portion of the electric bill through electricity generation, making up for its higher fuel, maintenance, and gas conditioning media cost.

Table 8 below estimates the potential annual net revenue from sale of RNG. At the time of this report, the D3 RIN price is $2.99. Since this price is subject to market fluctuations, a conservative value of $2.50 was used. Other assumptions used to calculate the revenue include 85 percent system uptime and a maintenance cost of $1,000 per scfm per year.

Table 8. Estimated RNG Value

Parameter	Value	Unit
D3 RNG RIN Price	2.50	$/RIN
Heat Energy per RIN	77,000	BTU/RIN
Gas Upgrading System Uptime	85	%
Gas Upgrading System Maintenance Cost	1,000	$/scfm-yr
RNG Sale Price, per foot	0.031	$/scf
RNG System Max Capacity	470	scfm
Average Digester Gas Production	332	scfm
Average Digester Gas Production + 30%	423	scfm
Average Potential RNG Production	195	scfm
Average Potential RNG Production + 30%	254	scfm
Estimated Net Revenue from RNG	2,442,000	$/year
Estimated Net Revenue from RNG + 30%	3,175,000	$/year

BC estimates that MWMC has the potential to generate up to $2,442,000 dollars a year in revenue from sale of their digester gas with RINs. If digester gas production increased by 30 percent, the gas upgrading system (with a max processing capacity of 470 scfm) would be capable of processing all the gas (except for occasional spikes in gas production) for up to $3,175,000 dollars per year in revenue. These values are estimates and are based on an assumed 85 percent uptime of the RNG system and do not account for parasitic loads. The values provided are meant for comparative purposes only.

1.8 Natural Gas Line Capacity

Plant staff noted that the boiler and EG cannot both operate on natural gas simultaneously. Both are supplied from a common natural gas pipe by an approximately 700ft long, 2-inch diameter pipe which ties into the natural gas utility company (NWNatural). To determine if the existing natural gas pipe is too small for both equipment to operate simultaneously, BC calculated the pressure drop and maximum flow rate. Table 9 summarizes the results.

Table 9. Natural Gas Line Capacity		
Parameter	**Value**	**Unit**
Natural Gas Supply Pressure	5.0	Psig
Maximum Allowable Pressure Drop	3.5	Psig
Natural Gas Supply Line Diameter	2	Inch
Maximum Flow Rate	153	scfm

As indicated in Table 9, the existing 2-inch pipe has a maximum flow capacity of 153 scfm of natural gas. Based on values in Table 5, this flow capacity is only sufficient for boiler firing to meet peak heating demands. Due to the lower thermal efficiency of the EG, the existing pipe does not have capacity for EG to operate at 100% capacity and for boiler to provide secondary heating to meet total demand. If the EG is to be utilized as a redundant heating option, the 2-inch pipe will need to be upsized in coordination with NWNatural to provide a higher flow rate.

1.9 Gas System Setpoints

The following table shows the pressure setpoints for the WGBs, boiler, and EG.

Table 10. Gas System Setpoints		
Parameter	**Value**	**Unit**
Primary Waste Gas Burner (Digester Gas) Start Setpoint	13.4	Inch W.C.
Primary Waste Gas Burner (Digester Gas) Stop Setpoint	11.5	Inch W.C.
Secondary Waste Gas Burner (RNG Off Spec Gas) Start Setpoint	13.0	Inch W.C.
Secondary Waste Gas Burner (RNG Off Spec Gas) Stop Setpoint	11.5	Inch W.C.
Boiler Start Setpoint	11.1	Inch W.C.
EG Start Setpoint	11.1	Inch W.C.
Digester Gas Header Pressure Range (8/1/2024)	11.5 – 13	Inch W.C.
Average Digester Gas Header Pressure (PIT15-01) (12/22 – 4/23)	22.5	Inch W.C.

The waste gas burners are located on the main biogas header between digesters and the RNG upgrading facility. The primary waste gas burner is configured to burn digester gas and has a start setpoint of 13.4 in W.C. The secondary waste gas burner is configured to burn off spec gas from the RNG system and has a start setpoint of 13.0 in W.C. Normal operating pressure of the biogas header should be approximately 11.2 in W.C. Pressure data provided from pressure indicating transmitter PIT15-01 shows an average header pressure of 22.5 inch W.C. over a one and a half year time span between December 2022 and April 2023. During the site visit on August 1st, 2024, digester gas header pressure was shown ranging between 11.5 in W.C. and 13 in W.C. The unusually high pressure measured from PIT15-01 indicates that PIT15-01 may be mis-calibrated.

1.10 Operational Challenges

The following table outlines the operational challenges as described by MWMC staff and summarizes related findings as detailed in this report. The final column provides BC's recommended approach for addressing the operational challenges.

Table 11. Operational Challenges

Operational Challenge Description	Findings	Recommendation
While the boiler is running in tandem with the EG, the EG will occasionally waste heat to its radiator.	• The EG waste radiator loop has a setpoint of 154 degrees F. • Per Table 2, the primary heat loop return temperature has been frequently observed above this setpoint (even without boiler running), resulting in the EG waste heat radiator running. • Average primary heat loop temperature differential was 8 degrees F during data collection in October. • The primary heat loop supply setpoint is 185 degrees F. • Per discussion with a Jenbacher representative, the maximum recommended inlet temperature of the EG heat loop is 165F to maintain oil temperature below 180F. • Consistent rapid fluctuations in primary heat loop supply temperature have been observed as shown in Figure 5. Improperly tuned PID setpoints for three-way control valves (TCV33-01 and TCV28-01) are the suspected cause.	1. Retune the PID setpoints for the three-way control valves on the EG and boiler heat loops (TCV33-01 and TCV28-01) in attempt to better regulate the primary heat loop supply temperature. 2. Check if the EG is still wasting heat to its radiator with and without the boiler operating. 3. If retuning the three-way control valve setpoints does not fix the issue, BC recommends investigating methods to lower primary heat loop return temperature below the EG waste heat loop setpoint of 154 degrees F. Potential methods include: a. Lowering the primary heat loop supply temperature setpoint below its current setpoint of 185 degrees F. The plant can experiment with lowering the primary heat loop supply temperature while observing digester and building temperatures to ensure the primary loop is still supplying adequate heat. The plant may be able to lower the supply temperature enough to bring the return temperature below the EG radiator loop setpoint while still meeting heat demand. During data collection in October, the average primary heat loop temperature differential was 8 degrees F. The primary heat loop should be able to tolerate a temperature differential up to 25 to 30 degrees F if necessary. Boilers can generally tolerate a temperature differential of 40 degrees F. b. Slowing the primary heat loop flow rate, which will allow more heat transfer to digesters/buildings, therefore lowering the primary heat loop return temperature. Implementing this option would require installing VFDs on the primary heat loop pumps.

Table 11. Operational Challenges		
Operational Challenge Description	**Findings**	**Recommendation**
		4. Continue operating as-is. Since the EG waste heat radiator running is not detrimental to heat loop function, the plant can continue operating as-is if the above recommendations are not effective.
The system will occasionally flare biogas while the boiler is operating on natural gas.	• Primary Waste Gas Burner Start Setpoint is 13.4 inches W.C. • Primary Waste Gas Burner Stop Setpoint is 11.5 inches W.C. • Boiler Start Setpoint is 11.1 inches W.C.	It is possible the primary waste gas burner pressure regulating valve sees the high biogas pressure before the boiler in the event of an RNG quality shut-in or other RNG upgrading system shutdown, resulting in the waste gas burner starting before the boiler controls are able to react. If a lag in pressure along the LSG line is the cause for this operational challenge, a recommended correction is to adjust the control strategy to automatically start the boiler if the WGB begins flaring biogas.
Biogas pressure drops at the EG when the boiler is started on biogas, resulting in shutdown of the EG.	• The EG consumes an estimated 222scfm of biogas at 100% capacity. • The boiler consumes an estimated 115scfm of biogas while meeting the average plant heat demand. • Lower end of biogas production is 250 scfm. • Average biogas production is 332 scfm.	While the EG is running at full capacity it consumes approximately 222scfm of biogas. If the boiler is then started, the additional biogas consumption from the boiler can easily raise the total biogas consumption to surpass the lower end of biogas production of approximately 250scfm and likely surpass the average biogas production of approximately 332scfm. Boilers typically have a spike in gas consumption during startup, which is likely a contributing factor to this problem. It may be possible to lower this gas consumption spike via control tuning, depending on the burner type. BC's recommendation is to avoid operating both the boiler and EG on biogas simultaneously.
Condensation issues inside the boiler.	Condensation can occur within a boiler when temperatures within drop too rapidly. There are a few suspected reasons for why this may be occurring. 1. Improper tuning of the three-way control valve on the boiler secondary heat loop (TCV28-01) may be dropping the temperature in the boiler too rapidly. If the PID control values for the valve causes rapid/extreme cycles between high and low temperatures, as shown in Figure 5, this could cause the boiler secondary heat loop to frequently drop near its minimum design temperature, resulting in condensation. 2. The biogas fueling the boiler is fully saturated. In the past, BC has observed biogas with high moisture content resulting in temperature drops within a boiler, causing condensation.	After retuning the three-way control valves, BC recommends testing the boiler biogas composition, primarily for H_2S content. The maximum preferrable H_2S content for this type of boiler is 400ppm.

Table 11. Operational Challenges		
Operational Challenge Description	Findings	Recommendation
	3. BC has also observed biogas with high H_2S causing condensation in boilers. When burned, H_2S primarily produces sulfur dioxide (SO_2) and water (H_2O), but can also produce sulfur trioxide (SO_3). Sulfur Trioxide is hydrophilic and binds with water in the exhaust to create sulfuric acid (H_2SO_4), resulting in condensation. If the plant is observing boiler condensation issues only while operating and biogas and the biogas has high H_2S content, this may be the cause of the condensation issue in the boiler.	
Occasional insufficient building heat.	• Existing EG is tuned down to 700kW, lowering heat output • Existing EG Heat Output at max current capacity (700kW) is 2.87 MMBTU/hr • Existing EG Heat Output at max rated capacity (800kW) is 3.40 MMBTU/hr • Plant peak heat demand is 5.84 MMBTU/hr • Plant peak heat demand (2035 estimate) is 6.48 MMBTU/hr	Given the plants peak heat demand is 5.84 MMBTU/hr and the existing EG current max output of 2.87 MMBTU/hr, it is clear the EG is undersized to meet the plants peak heat demand. During the coldest days of the year, it is expected the EG will not be able to heat all plant processes on its own. Near term, BC recommends running the boiler during times of peak heat demand. Alternatives for incorporating heating redundancy are discussed in Section 2 and 3.
Boiler and EG three-way control valves not having sufficient control.	• As shown in Figure 5, the primary and boiler secondary heat loop are undergoing constant rapid fluctuations in temperature. This is likely due to improperly tuned PID values which is causing the three-way control valves to act in an open/close manner.	BC recommends retuning the three-way control valve PID setpoints to address this problem. BC has automation specialists capable of performing this work at MWMCs' request.

Section 2: Alternatives Analysis

2.1 Alternatives Descriptions

As discussed in Section 1, the EG is undersized to meet both the plants current peak heating demand of 5.84 MMBTU/hr as well as the projected 2035 peak heat demand of 6.48 MMBTU/hr. Therefore if the boiler experiences a failure during winter months, the plants' treatment process may be interrupted and various buildings could be without heat. The Oregon Department of Environmental Quality (DEQ) requires redundancy for critical processes at wastewater treatment plants. To incorporate redundancy in the plants heating system, an additional heating system capable of meeting the peak heat demand must be installed such that either of the two heating systems can be taken offline for maintenance. A second boiler or upsizing the EG system are two options for a secondary redundant heating system.

2.1.1 Alternative 1: Install a 200 BHP Boiler to replace the EG

Two options for a new boiler were considered: 1) installing an additional boiler the same size as the existing boiler (in place of the EG), and 2) installing a smaller boiler to supplement the EG. The existing 200 BHP boiler has a peak heat output of 6.70 MMBTU/hr which is enough to meet both the current peak heat demand of 5.84 MMBTU/hr and the projected 2035 peak heat demand of 6.48 MMBTU/hr. Installing a secondary 200 BHP boiler to replace the existing EG is a straightforward approach to achieve heating redundancy. This option would allow the two boilers to act as redundant heating systems. Benefits of Alternative 1 are the following:

- Simplified controls due to less variety in equipment types.
- Simplified maintenance due to shared spare parts and maintenance routines.
- New boiler can be installed where the existing EG is located, thus saving space and not requiring an additional building. Alternatives 2 and 3 would require an additional building.

2.1.2 Alternative 2: Install a 125 BHP Boiler to supplement the EG

The second alternative is to install a smaller boiler to supplement the EGs' heat output. In terms of redundancy, this option would designate the EG combined with the smaller supplemental boiler as the primary heating system, and the existing boiler as the secondary heating system. The existing EG underwent a complete engine block replacement in 2018 and a top end rebuild in 2019/2020, so it is expected to have several years of service remaining. The existing 800kW Jenbacher EG is rated to provide a maximum of 3.40 MMBTU/hr. However, it is tuned down to 700kW and therefore is only able to provide approximately 2.87 MMBTU/hr of heat. The estimated 2035 peak plant heat demand of the plant is 6.48 MMBTU/hr, so the smaller boiler should be sized to provide at least 3.61 MMBTU/hr of heat. This corresponds to approximately 108 BHP, so a 125 BHP model would be an appropriate size for the smaller boiler. This alternative would require an additional building to house the supplemental boiler. BC has assumed the addition of a roughly 1,200 square foot building for the smaller boiler.

2.1.3 Alternative 3: Upsize the EG system

The existing 800kW Jenbacher EG (currently tuned down to 700kW) can provide a maximum of 2.87 MMBTU/hr, which is unable to meet the plants current peak heat demand of 5.84 MMBTU/hr and the estimated 2035 peak plant heat of 6.48 MMBTU/hr. Upsizing the EG system is another viable option to provide redundancy in the heating system. Upsizing the EG system would require installing an upsized gas conditioning system, so this cost has been included in the evaluation. Figure 7 below shows the maximum heat output of various EG models vs. the future peak and current average heating demands. The heat output of a single EG is shown in dark blue, and the light blue bar indicates the total heat output if two EGs are installed.

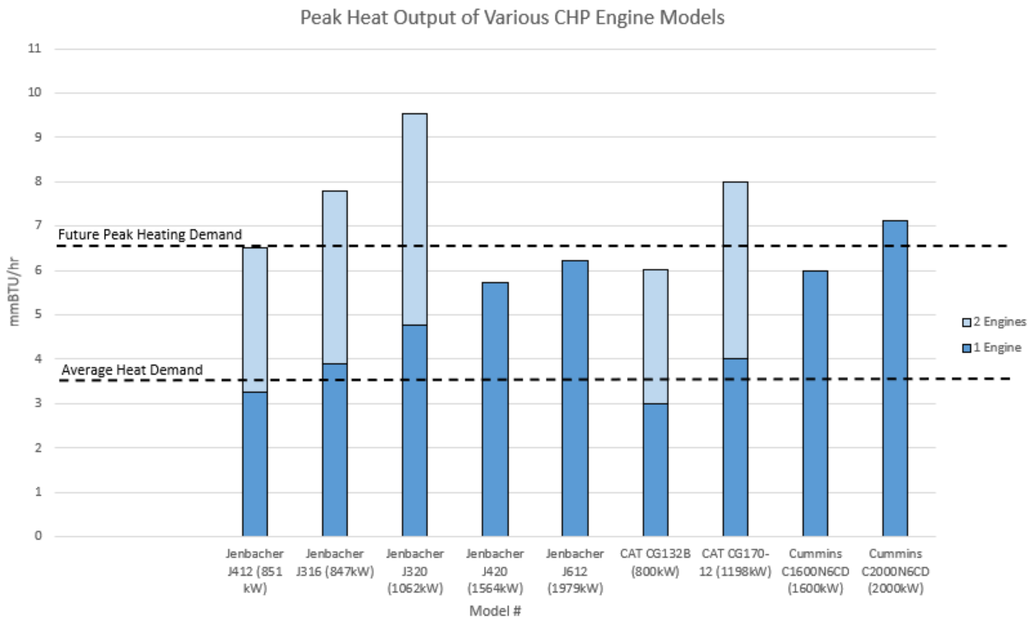

Figure 7: EG Heat Output vs. Heat Demand

2.1.3.1 Single EG Sizing

An EG can typically turn down to only 75-50% of its max operating capacity. Because EG turndown lowers efficiency and increases wear on EG components, it is not recommended to size an EG much larger than the average demand. This creates a design challenge because the peak heating demand of the plant is nearly twice the average heating demand. Because of this, a single larger EG capable of meeting the plants peak heating demand will need to either operate at roughly half its capacity or waste a significant amount of heat for the majority of its operation. Since this is unpractical, BC does not recommend installing a single larger EG, such as the Cummins C2000N6CD (heat output shown in Figure 7).

2.1.3.2 Two EG Sizing

A solution to the EG turndown challenge is to install two smaller EGs. These EGs would be sized to meet the plants average heating demand with one EG running, and the plants' peak heating demand with two EGs running. Based on Figure 6 above, the 847kw Jenbacher J316 (same model as the existing EG), and the 1198kW CAT CG170-12 are well sized (based on heat output) for a dual-EG setup. Per information from a CAT representative, the CG170-12 is typically tuned down to a capacity of approximately 1000kW and has a differing heat loop setup than the Jenbacher (hence the gap in rating between the two EGs).

The existing 800kW Jenbacher is still operational but is at the end of its service life. A singular smaller EG could be installed to run alongside the existing EG, but regardless, the existing EG will need to be either rebuilt or replaced. Thus, Alternative 3 considers an installation of two new Jenbacher J316 EGs (Alternative 3a) and an installation of two new CAT CG170-12 EGs (Alternative 3b). This alternative would require an additional building to house the EGs. BC has assumed the addition of a roughly 3,000 square foot building for the two EGs.

2.2 Business Case Evaluation

A business case evaluation of these three alternatives was performed and is summarized below. For Alternative 3 (upsizing the EG system) – the two best suited EG models (the Jenbacher J316 and the CAT CG2710) were considered as Alternative 3a and Alternative 3b, respectively. Quotes were gathered from equipment suppliers and a business case evaluation was conducted.

2.2.1 Capital Costs

Table 12 below summarizes the capital costs for both alternatives. When calculating overall capital cost, a markup factor of 4.24 was applied, which takes construction cost, taxes, contingency, engineering, and allied costs into account (Table 13). The upsized EG system will require a new, upsized gas conditioning system, which is included in Alternative 3a and 3b.

Table 12. Equipment Capital Costs

Alternative	Equipment Cost	Capital Cost
Alternative 1: New 200 BHP Boiler	$340,000[a]	$1,020,000
Alternative 2: New 125 BHP Boiler	$320,000[b]	$960,000
Alternative 3a: New 800kW Jenbacher EGs	$1,360,000[c]	$5,240,000
Alternative 3b: New 1200kW CAT EGs	$2,700,000[d]	$10,420,000
New Gas Conditioning System	$2,290,000[e]	$8,820,000
New Building for Small Boiler Alternative	$450,000[f]	$1,740,000
New Building for EG Alternatives	$1,125,000[f]	$4,340,000

[a] *Proctor Sales Quote for 200BHP Hurst S5-GG-200-30W Boiler (8/26/24)*
[b] *Proctor Sales Quote for 125BHP Hurst SG-GG-125-30W Boiler (2/28/25)*
[c] *Jenbacher Quote for 800kW J316 EG (8/29/24)*
[d] *CAT Quote for 1200kW CG170-12 EG (9/4/24)*
[e] *Varec/Unison Quotes (7/24/23 and 8/1/23, respectively)*
[f] *Based on $375/sqft single story building cost*

Table 13. Equipment Cost Markups to Estimate Capital Costs		
	EG	Boiler
Project markups	70%	55%
Mechanical allowance	25%	15%
Electrical allowance	25%	15%
Installation	20%	25%
Contractor overhead	10%	10%
Contractor profit	15%	15%
Sales tax	0%	0%
Contingency	30%	20%
Allied costs	38%	28%
Legal	2%	2%
Administrative	5%	5%
Permitting and scope	3%	3%
Preliminary Engineering	5%	5%
Final Engineering	15%	10%
Construction Engineering	8%	5%
Net markup	385%	305%

It is important to note that the capital costs provided in Table 13 are intended to provide a gross estimate of the capital costs for a fair comparison of the alternatives. These values cannot be used for budget planning purposes. Upon selecting a preferred alternative, a Class 5 cost estimate should be obtained to provide an opinion of probable cost for budgeting purposes.

2.2.2 Operating Costs

Table 14 summarizes the operating costs for the equipment associated with each alternative. Operating costs consist of the respective cost of natural gas and maintenance for each alternative. Per their natural gas bills, MWMC pays an average of $8.557/MMBTU ($0.86/therm) for their natural gas. Maintenance costs are from vendor quotes from each equipment supplier. This BCE assumed the engines are run to meet the plants average heat demand throughout the year. An engine uptime of 90% and an RNG uptime of 85% was assumed for this BCE. While RNG is down, it was assumed biogas will be sent to the EG. Alternative 2 (New 125 BHP Supplemental Boiler) assumes that the existing EG runs constantly and the supplemental boiler turns on when the heat demand exceeds the capacity of the EG.

Table 14. Equipment Operating Costs			
Alternative	Natural Gas Cost	Maintenance Cost	Gas Treatment Maintenance Cost
Alternative 1: New 200 BHP Redundant Boiler	$273,000/year	$4,000/year	$0/year
Alternative 2: New 125 BHP Supplemental Boiler	$391,000/year	$114,000/year	$15,000/year
Alternative 3a: New 800kW Jenbacher EGs	$414,000/year	$110,000/year	$18,000/year
Alternative 3b: New 1200kW CAT EGs	$432,000/year	$170,000/year	$19,000/year

2.2.3 Benefits

Table 15 below describes the cost benefits for each alternative. Cost benefits considered include the cost offset from electricity generation from the EGs. An electricity cost of 0.0711 $/kWh was used (averaged from plants' electricity bills). Note that Alternative 2 assumes the existing EG will continue to run.

Table 15. Cost Benefits

Alternative	Cost Benefit
Alternative 1: New 200 BHP Boiler	$0/year
Alternative 2: New 125 BHP Boiler	$351,000/year
Alternative 3a: New 800kW Jenbacher EGs	$421,000/year
Alternative 3b: New 1200kW CAT EGs	$452,000/year

2.2.4 Repair and Replacement Costs

Table 16 summarizes the repair and replacement (R&R) costs for the equipment associated with each alternative. Repair and replacement costs are estimated at 2% of the equipment's capital cost. Note that Alternative 2 includes R&R costs for both the new 125 BHP boiler and the existing EG.

Table 16. Equipment Repair and Replacement Costs

Alternative	Repair/Replacement Cost
Alternative 1: New 200 BHP Boiler	$7,000/year
Alternative 2: New 125 BHP Boiler	$20,000/year
Alternative 3a: New 800kW Jenbacher EGs	$28,000/year
Alternative 3b: New 1200kW CAT EGs	$54,000/year

2.2.5 Net Present Costs

Table 17 summarizes the net present costs, which consider the capital costs, operating costs, benefits, and repair and replacement costs for each alternative over a 20-year time period. An escalation rate of 2.20% and a discount rate of 4.40% was used for this analysis.

Table 17. Summary of Costs in Terms of Net Present Costs

Alternative	Net Present Cost
Alternative 1: New 200 BHP Boiler	$5,336,000
Alternative 2: New 125 BHP Boiler	$5,440,000
Alternative 3a: New 800kW Jenbacher EGs	$19,548,000
Alternative 3b: New 1200kW CAT EGs	$25,562,000

Section 3: Conclusion

3.1 Recommended Near Term Improvements

BC Recommends the following near-term actions to optimize the heating system at the plant:

- *Reconfigure DCS system/historian to log temperature data at both the supply and return point of the primary heat loop (TIT36-02 and TIT36-01 respectively) so that the plants heat demand can be logged over time.*

This study revealed the limitations on the data collection for the WPCFs' heat loop. As it stands, the plant does not have enough long term data points to quantify the heating demand. To achieve this, temperature data can be logged from both the temperature indicating transmitter (TIT) at the primary heat loop return point (TIT36-01) and at the supply point (TIT36-02). Currently, data is logged for the supply point, but not the return point. At a minimum, it is highly recommended to configure the plant historian to collect long term data from both TIT36-01 and TIT36-02 so that seasonal trends in total heat demand can be quantified.

Additionally, data from TIT28-01 (boiler heat loop temperature) is currently collected by the historian, but temperature data from TIT33-01 (EG heat loop temperature) is not. It is recommended to configure the plant historian to collect long term data from both TIT28-01 and TIT33-01 so that heat loop operation can be better understood.

- *Optional: Install additional temperature sensors and flow meters for better monitoring/evaluation of the heating loops.*

The plant may benefit from installing an additional TIT between the EG and the boiler. This would allow the plant to collect long term heat supply data from the EG and boiler separately.

- *Retune three-way control valves on the boiler and EG secondary heat loops.*

Given the temperature fluctuations observed in the boiler heat loop and primary heat loop supply temperature, it is likely that the PID values for three-way control valves TCV28-01 (boiler heat loop control valve) and TCV33-01 (EG heat loop control valve) are not set for ideal operation. BC recommends retuning the PID setpoints in attempt to lessen the fluctuations and maintain steady temperature, leading to more efficient gas use. At MWMC's request, BC can schedule an automation control specialist to visit the plant to perform the retuning.

- *Recalibrate pressure indicating transmitter PIT15-01*

Section 1.9 shows that PIT15-01 is showing a pressure rating that exceeds realistic pressure in the digester gas header. BC recommends recalibrating PIT15-01 so it reads the digester gas header pressure accurately.

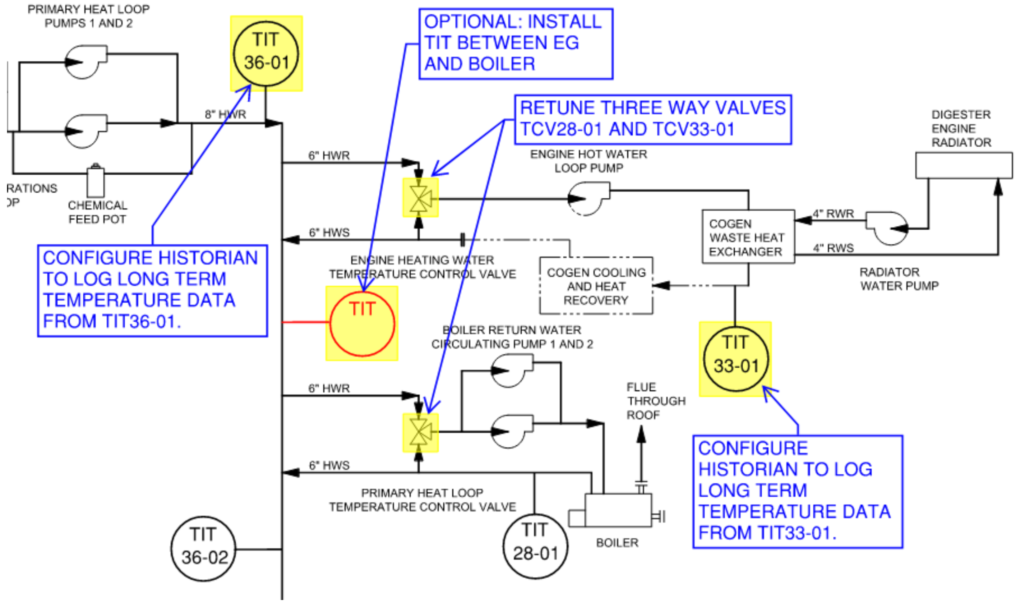

Figure 8: Summary of near-term recommendations show on heat loop PFD

3.2 Long Term Recommendations

BC conducted a business case evaluation (BCE) for three alternatives for redundancy in the plants heating system (i.e. such that there are two independent systems capable of meeting the peak heat demand in the case that one system must be taken down for maintenance). Of the three alternatives considered, the BCE determined that Alternative 1 (installing a 200 BHP boiler in place of the existing EG) and Alternative 2 (installing a 125 BHP boiler to supplement the existing EG) have comparable net present costs over a 20-year period. Despite Alternative 2 having a higher capital cost due to a new boiler building, the benefit of continued onsite electricity generation offsets the capitol cost difference when comparing Alternative 2 to Alternative 1 net present cost. The advantage of Alternative 1 is that duplicating the existing boiler model (Hurst) will simplify the controls and maintenance of the heating system. Alternatives 1 and 2 assume installation of the same boiler technology as the existing. Evaluation of other boiler technologies could impact the net present cost and relative ranking of these two boiler alternatives.

Alternative 3 (installing an upsized EG system) is estimated to have lower operating costs than Alternatives 1 and 2 due to the electricity generation offset. However, Alternative 3 has higher capital cost due to higher equipment costs, including a new gas conditioning system and an additional EG building or container. The BCE determined that over a 20-year period, the lower operating cost of the EG alternative does not completely offset the higher capital cost. EGs are most cost effective when run on biogas from the digesters, but the RNG upgrading system is the primary biogas utilization.

This BCE has determined that installing a new boiler is the most cost-effective long-term approach for achieving heating redundancy. BC recommends Alternative 1 due to the advantages of lower space requirements, simplified controls, and similar maintenance. However, Alternative 2 may be preferrable if there is a strong desire to retain the existing EG. Further analysis is recommended to determine whether the existing EG H_2S scrubbing vessels or the front end of the RNG upgrading system should be utilized for the boiler fuel.