Appendix 5-4. Future Gas Utilization

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APPENDIX 5-3 – FUTURE GAS UTILIZATION

1.1 FUTURE GAS UTILIZATION

Future digester gas production was predicted using the BioWin solids loading projections and making assumptions based on historic plant performance. Methane gas is produced when bioavailable solids are consumed by methanogenic bacteria. While it is difficult to calculate the bioavailability of a waste stream, the reduction of volatile solids within a digester identifies the quantity of digested solids and can be used to predict future digester performance. The digesters at Blue Lake WWTP have consistently provided a 53% reduction in volatile solids, and the assumption has been made that this performance will continue through 2050.

The volatile solids projections along with the digester performance provide an estimate of solids digested. Historically, the rate of gas generation has ranged from 15 to 18 scf per pound of volatile solids consumed. Typical digester performance is 15 scf/lb VS, and as the heavily bioavailable waste stream from Northern Star Co. will be significantly reduced in 2020, using the rate of gas generation of a typical municipal wastewater digester is appropriate.

The methane content of digester gas has reliably been between 57 and 58%, which is at the low end of a normal range for wastewater treatment plant digesters. The lower average of 57.1% has been assumed for projections out to 2050. The lower heating value (LHV) of methane is used when gas is combusted to reflect that heat lost to vaporization of water formed during combustion is not recoverable. The LHV of methane is 910 btu/scf of methane, as reflected in Table 1-1.

Table 1-1: Digester Gas Projections

PARAMETER	CURRENT	2020 - LOW	2020 - HIGH	2030 - LOW	2030 - HIGH	2050 - LOW	2050 - HIGH
VS, lb/d	28,654	21,987	25,663	23,851	29,999	27,273	36,761
Flow[1,2], scfm	334	258	301	280	352	320	432
Methane, %	57.1%	57.1%	57.1%	57.1%	57.1%	57.1%	57.1%
HHV[3], btu/scf	578	587	587	587	587	587	587
LHV[3], btu/scf	520	528	528	528	528	528	528
LHV, MMbtu/d	**250**	**196**	**229**	**213**	**268**	**243**	**328**

Notes:

Based on current average VSR of 53%.

Assumes a gas production rate of 15 scfm/VS lb.

The Higher Heating Value (HHV) and Lower Heating Value (LHV) are assumed to be 1012 and 910 btu/scf of methane respectively.

Digester gas utilization systems should be sized to take advantage of the highest projected gas production. Alternative analysis needs to consider the low range of gas production when evaluating the economics of gas utilization. The organic loading by Northern Star Co. is highly bioavailable, and their planned reduction in solids contributions through IPIP are project to significantly reduce digester gas production. The projected rate of digester gas production is shown in Figure 1-1, and includes the historic gas generation from 2013 to 2019.

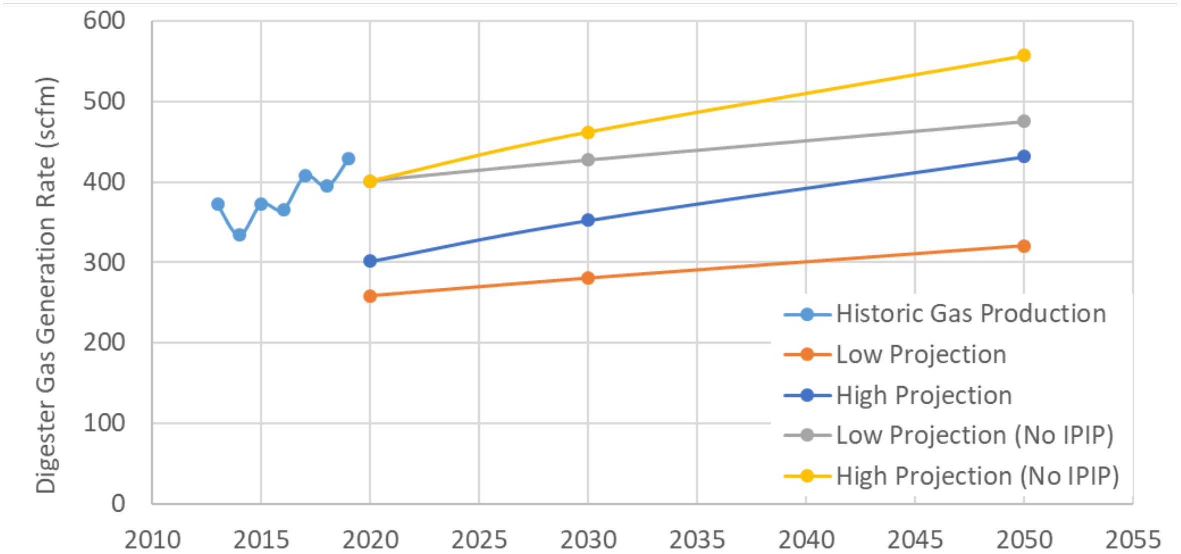

Figure 1-1: Digester Gas Production Projections

1.1.1 Modification of Current Use of Digester Gas

Using digester gas in the dryers would continue to be a beneficial use of the digester gas but the value of the gas is only as an offset to purchased natural gas. In recent years digester gas use in the dryers was limited by the condition of the RTO. This recent history also illustrates that without an alternative to drying as an end use for the gas, most of the digester gas must be wasted. To provide a 20-year planning horizon, the high IPIP projection of gas production in 2030 (500,635 cuft/d) was used as a mid-point for evaluating the gas utilization alternatives. Because of the anticipated reduction in loading, the projected gas production is lower than in recent years. The digesters have capacity for additional organic loading if high strength waste were added for co-digestion the additional digester gas would provide more offset or revenue.

Two alternative end uses for digester gas are combined heat and power (CHP) using engine generators and upgrading of the digester gas to renewable natural gas (RNG).

1.1.2 CHP

CHP involves the generation of electricity and heat by combusting digester gas in engine generators. Electricity generated by the engine's offsets Blue Lake WWTP's demand from the utility, and the heat generated can be recycled by heating the digester feed or meeting building heating needs. In order to implement CHP at Blue Lake, the existing digester gas treatment system would require siloxane removal to protect equipment, as well as a 1,500 kW engine generator.

The vast majority of savings provided by CHP comes from offsetting electrical demands (85%). Although the Blue Lake WWTP has sufficient electrical demand to utilize electricity generated by CHP, the value of offsetting purchased electricity varies depending on the time of day. Electricity is provided by Xcel Energy, which charges based on a two tier rate structure. Xcel has noted that in the near future, the plant will be subjected to a three tier rate structure, which could significantly impact the electrical costs offset by generating electricity at the plant. Cost benefit analysis was performed using both the two tier and hypothetical three tier rate structures, and is explained in detail in Appendix Y.

The operation of a CHP system is fairly complicated and maintenance intensive. The engine generator requires frequent cleaning due to the combustion of digester gas, and the siloxane removal system has a high operating cost. In addition, timing the generator to operate during peak hours and switching electrical sources is complex, especially if digester gas is additionally utilized by the dryers during non-peak hours. The current rate structure doesn't make CHP look as attractive as using the digester gas directly in the dryers, and future changes to the rate structure only reduce the potential revenue and increase the complications. Given the additional complexity and reduced savings potential, CHP is not an attractive option for the Blue Lake WWTP.

CHP uses digester gas to fuel engine generators, producing electricity and heat. Because the CHP system can operate continuously independent of the dryers the dryers can be configured to use digester gas during engine downtime. Waste heat from the engine can supply digester and building heating needs. The digesters may not be able to use all waste heat from the engines if dryer scrubber water heat recovery continues. Gas treatment for moisture and siloxanes is recommended. The existing moisture removal system can continue to be used with the addition of siloxane removal. The concentration of hydrogen sulfide (H_2S) in the digester gas is approximately 300 ppmv, which is acceptable for engines designed for biogas. Therefore, H_2S removal is not required. The system evaluated is one engine generator sized to use all the digester gas. Using gas storage, the engine operates at higher output during on-peak hours. Currently there are two rate periods. On peak hours are Monday through Friday, 8:00 am to 8:00 pm. Off-peak hours are all other hours. Table 1-2 and Table 1-3 reflect the current usage and demand charges.

Table 1-2: Current Energy Charge Rates

TYPE OF USAGE CHARGE	$/KWH
On-Peak Energy	0.0486
Off-Peak Energy	0.0234
Fuel Cost Charge (on-peak)	0.0326
Fuel Cost Charge (off-peak)	0.0213
Sales True Up (all hours)	0.0017
Resource Adjustment (all hours)	0.0051
Overall On-Peak Energy Costs	**0.0879**
Overall Off-Peak Energy Costs	**0.0515**

Table 1-3: Current Demand Charge Rates

TYPE OF DEMAND CHARGE	$/KW	CURRENT KW DEMAND
Firm On-Peak Demand - Summer	14.79	1,500
Firm On-Peak Demand - Winter	10.49	1,500
Control On-Peak Demand	6.56	Variable

A proposed change to the rate structure would create a three-tier system which includes mid-peak hours. Peak hours are expected to be 3:00 pm to 8:00 pm, Monday through Friday. Mid-peak hours would be 6:00 am to 3:00 pm and 8:00 pm to 12:00 pm. All other hours would be considered off-peak. The proposed future rate structure reduces the benefit of the electricity offset provided by the CHP system. The future rate structure is anticipated to take effect starting in 2023. The anticipated rates are summarized in Table 1-4 and Table 1-5.

Table 1-4: Projected Usage Charge Rates

TYPE OF USAGE CHARGE	$/KWH	NOTES
On-Peak Energy	0.0892	3:00pm - 8:00pm
Mid-Peak Energy	0.0616	6:00am - 3:00pm, 8:00pm - 12:00am
Off-Peak Energy	0.0285	12:00am - 6:00am

Table 1-5: Projected Demand Charge Rates

TYPE OF DEMAND CHARGE	$/KW	NOTES
Firm On-Peak Demand - Summer	7.50	May-Sept
Firm Mid-peak Demand - Summer	6.40	May-Sept
Firm On-Peak Demand - Winter	4.75	Oct-Apr
Firm Mid-peak Demand - Summer	5.03	Oct-Apr
Firm Off-peak Demand	2.00	Year Round
Controllable On-Peak Demand	6.35	Year-round

To take advantage of all the digester gas produced and using the available storage a generator sized for 1,500 kW output would be able to use all of the gas projected in the year 2040. However, using the 2030 gas production for the economic analysis the engine would operate at 1,500 kW during on-peak hours in either scenario and at reduced output during mid-peak and off-peak hours depending upon availability of digester gas. Table 1-6 and Table 1-7 provide summaries the gas utilization for CHP given the present and future rate structures.

Table 1-6: CHP summary with current rate structure

CATEGORY	QTY	UNITS
Generator Capacity	1,500	kW
Average Daily Gas Production	500,635	cuft
Gas Storage Capacity	166,000	cuft
Gas Storage Capacity	8	hours
On-Peak annual hours	3,120	hours
Off-Peak annual hours	5,640	hours
Gas Remaining	-	cuft/day

Table 1-7: CHP summary with future rate structure

CATEGORY	QTY	UNITS
Generator Capacity	1,500	kW
Average Daily Gas Production	500,635	Cuft
Gas Storage Capacity	166,000	Cuft
Gas Storage Capacity	8	Hours
On-Peak annual hours	1,300	hours
Mid-Peak annual hours	5,252	hours
Off-Peak annual hours	2,208	hours
Gas Remaining	-	cuft/day

1.1.3 RNG

An RNG system would upgrade all digester gas to RNG suitable for injection into the gas utility pipeline. In this alternative the existing moisture removal system would continue to be used but both H_2S removal and siloxane removal would be required. The second stage would remove carbon dioxide (CO_2) to create the RNG which is nearly pure methane. Costs are included for piping gas to the injection point and for interconnection charges at the pipeline.

The operation of the gas treatment system is straightforward, and the process equipment is proven and reliable. But working with the gas utility and marketing the gas to off-takers and managing the renewable energy incentives requires specialists and may mean more management time for MCES staff. Although the value of RINs is near historic lows, there continues to be growth in RNG. In the analysis for Blue Lake RNG remains the economic choice based on potential revenue. The future market for RNG may not be RINs and vehicle fuel. It appears that RNG will have demand for its inherent carbon offsets compared to fossil fuels and these renewable attributes will continue to have value in the future.

1.1.4 Recommended Solution

Table 1-8 includes the 20-year NPV for five separate gas utilization alternatives: No Utilization (100% Flare), Current Use (34% Flare), Alternative 1 (100% Dryer), Alternative 2 (CHP) and Alternative 3 (RNG). Currently, approximately 50% of the digester gas produced is flared, and the remainder is utilized by either they dryer or the boiler. If the capacity of the RTO is increased, it is anticipated that the dryer fuel source will no longer be limited, and it can operate exclusively on digester gas.

Two NPV analysis have been done, one given the current electrical rate structure and one using the future rate structure. Table 1-8 below summarizes the costs associated with each of the 5 options given the two rate structures.

Table 1-8: Alternative Cost Comparison

ALTERNATIVE	CAPITAL COST	ANNUAL O&M COST	PRESENT WORTH OF ANNUAL O&M	PRESENT WORTH
Flare All Gas	$0	$468,000	$6,960,000	$6,960,000
Current Use (34% Flare)	$744,000	$198,000	$2,950,000	$3,694,000
100% Digester Gas in Dryer	$744,000	$76,000	$1,140,000	$1,884,000
CHP Current Rate	$5,777,000	($267,000)	($3,980,000)	$1,886,000
CHP Future Rate	$5,777,000	($227,000)	($3,380,000)	$2,486,000
RNG	$9,629,000	($674,000)	($10,202,000)	($390,000)

The recommend solution is based on the high digester gas production projections with loss of industrial loading. Digester gas alternatives are sensitive to energy pricing. The cost analysis does not include any escalation of either natural gas or electricity prices. However, based on the current cost structure the CHP and dryer alternatives are essentially equivalent on a present worth basis. Since the dryer alternative requires a lower capital investment and no change in operations it is the more favorable alternative.

RNG is economically attractive but has significant uncertainties that may affect future economics and requires the largest capital investment.

The disadvantage to continuing with the dryers as the single end use that can utilize all of the digester gas is that gas is wasted when the dryer(s) are not available. However, alternative end uses can be re-evaluated and added in the future should there be a change in the economics or plant operations.

The recommended project is the use digester gas in the dryers, with the installation of new RTOs that will allow the dryer to fully utilize the available digester gas.