Biogas Cogeneration System Sizing and Payback Based on Weekly Patterns of Anaerobic Digestion and Biosolids Dryer Operation

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Pinellas County Utilities (PCU) operates the South Cross Bayou Water Reclamation Facility (SCBWRF), rated at 33 mgd. The biogas produced at SCBWRF is used in the on-site biosolids drying/pelletizing process and reduces the quantity of natural gas (NG) that otherwise would be required. The PCU is presently trucking belt filter press dewatered biosolids at about 18-19 percent solids concentration from its 9-mgd William E. Dunn Water Reclamation Facility (WEDWRF) to the SCBWRF and processing it directly in the drying/pelletizing facilities. The option of converting the anaerobic digestion operation to a three-phase mode of digestion operation (acid mesophilic / methane thermophilic / non-heated storage), including the codigestion of five feedstocks: SCBWRF thickened solids; WEDWRF cake; fats, oil, and grease (FOG) dewatered by the PCU using polymer; and lime-dewatered FOG from a private hauler, has been evaluated (Kabouris et al, 2008). The PCU proceeded with the design of digestion upgrades and the conceptual design of heat and power cogeneration, with the objective of utilizing the energy from biogas available when the dryer is not operating.

The cogeneration analysis is complicated by the many interactions among the various considered system components (digestion, dryer, cogeneration, boiler, flares) as depicted in Figure 1, and by the time-varying availability of digester gas. Most of the gas production is expected to occur on weekdays, when the FOG will be accepted and fed to the digesters. The dryer will also operate mostly on weekdays, so less biogas will likely be available for cogeneration during the week. Therefore, to produce realistic projections, a mass and energy balance approach for the digesters, dryer, and cogeneration system was constructed for both weekday and weekend conditions. The mass balance incorporated the results of laboratory scale batch and semi-continuous digestion for the various feedstock combinations, as described (Kabouris et al, 2008).

The process by which the biogas cogeneration system selection was justified based on projections of financial payback under a range of operating scenarios and variable digester gas production and availability is described. It includes sensitivity analysis results on the payback periods based on the price of purchased electricity and natural gas, and quantifies the effects of operating the cogeneration on biogas with and without natural gas supplementation.

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Estimation of Biogas Available for Cogeneration

The supplemental digestion feedstocks (polymer FOG, lime FOG, and WEDWRF cake) are expected to be fed to the digestion process only on weekdays. As a result, the gas production from the egg-shaped digesters (ESDs) is expected to be higher during the week than on weekends. In addition, the SCBWRF pelletizer typically also operates only on weekdays. It is therefore important to estimate the distribution of biogas production on weekdays versus weekends, as well as the associated biogas consumption in the pelletizer. In this manner, the cogeneration engines can be sized with sufficient peak and turndown capacity to optimize the storage and utilization of biogas on both weekdays and weekends, to minimize the likelihood of biogas wastage through flaring.

A conceptual model for the weekly pattern of biogas generation was developed to facilitate the analysis and decision making. Based on insight from the laboratory-scale acid-methane digestion testing of SCBWRF sludge and polymer FOG (Kabouris et al, 2008), a stepwise biogas production profile was implemented, with a reduction of about 17 percent between weekday and weekend biogas production. The pelletizer typically oper-

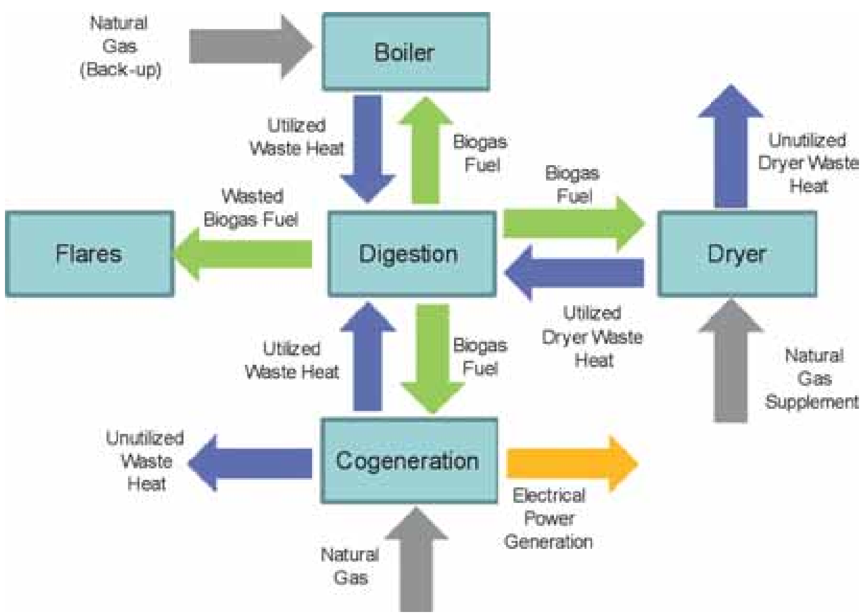

Figure 1. Evaluated South Cross Bayou Water Reclamation Facility System

ates an average of approximately five days per week, but this period may be longer or shorter depending on the weekly biosolids load to the dryer. To further simplify the analysis, it was also assumed that the high biogas production period would coincide with the dryer's operation period, because both dryer operation and FOG deliveries typically occur five days per week. This conceptual modeling approach was considered sufficient for the purposes of cogeneration feasibility analysis and preliminary system sizing. The actual biogas production will vary on a daily basis because of variability in the amounts of SCBWRF sludge, WEDWRF cake, and FOG quantities fed, as well as variability in operating conditions.

A mass and energy balance approach, similar to the approach used to derive the expected biogas quantities in the digestion upgrades PCU project (Kabouris et al, 2008), was used to estimate the biogas quantities that could become available for cogeneration following the digestion upgrades. All calculations were performed based on the selected future operational scenario of three-phase digestion. The projected gas production is strongly related to the amount of FOG that will be available for digestion because of the very high biogas generation potential associated with the digestion of FOG. Due to digestion capacity and future availability uncertainty, the number of 15,000 wet-pound truckloads of lime FOG delivered each weekday and processed in the SCBWRF digestion facilities following their upgrades is also uncertain. Accordingly, the analysis considered the sensitivity of the projected benefits based on one, two, or three such truckloads of lime FOG each weekday.

In addition to the uncertainties in the biogas production and methane content, uncertainty also exists regarding the rate of biogas consumption by the dryer. According to information obtained from Andritz (the SCBWRF rotary dryer's manufacturer), up to 90 percent of the combined natural gas and biogas fuel blend for the dryer can be biogas. This assumption has been used in the analysis and design of the digestion upgrades (Kabouris et al, 2009) and was considered as one possible scenario. This assumption of high biogas utilization in the dryer results in low surplus biogas available for cogeneration, but is an unproven operational condition, and PCU staff felt that there are constraints in the dryer's design parameters that could prevent it from having such a high biogas content in the dryer's fuel. To cover the full range of possibly available biogas for cogeneration, a second scenario was therefore considered, based on the historically low biogas utilization by the dryer. Under that scenario, it was assumed that only 35 percent of the combined natural gas and biogas fuel blend could be biogas, which is also the biogas percentage originally used by Andritz in the SCBWRF dryer design calculations. As a result of the low biogas consumption in the dryer, this scenario is associated with the availability of a large amount of surplus biogas and methane gas for beneficial utilization in cogeneration.

Table 1. Projected Annual Average and Average Weekly Pattern of Biogas

Case	A1	A2	A3	A4 (Target)	A5	B1	B2	B3
Case Definition								
Percent of combined natural gas and biogas dryer fuel blend being biogas	35	35	35	35	35	90	90	85.4
TWAS Ultimate VSR, percent	45	45	45	45	23	45	45	23
Number of 15,000 wet lb lime FOG truckloads per weekday	1	1	2	3	1	1	3	1
WEDWRF Cake Addition Point[(1)]	D	P	D	D	D	D	D	D
Digesters FOG VS load, percent of total VS load	14	16	21	26	14	14	26	14
Methane phase (ESD) biogas produced[(2)], scfm	316	291	368	421	239	316	421	239
Dryer in operation (weekdays), scfm	337	306	391	444	253	337	444	253
Dryer not in operation (weekends), scfm	281	255	326	370	211	281	370	211
Percent methane of biogas	72.6	72.4	72.8	73.1	72.6	72.6	73.1	72.6
Days per week dryer operation	4.3	5.0	4.6	4.8	4.6	4.3	4.8	4.6
Biogas used in dryer, scfm	55	63	57	60	167	169	184	167
Dryer in operation, scfm	88	88	88	88	253	272	270	253
Dryer not in operation, scfm	0	0	0	0	0	0	0	0
Excess biogas available for cogeneration[(3)], scfm	261	228	311	361	181	147	236	72
Dryer in operation, scfm	249	218	303	356	165	65	174	0
Dryer not in operation, scfm	281	255	326	370	211	281	370	211

[1] D: digesters; P: pelletizer.
[2] Only methane phase biogas to be utilized, the low quality acid phase biogas to be flared.
[3] Can be converted to heat, power, plus heat losses. Power is typically about 33-40 percent of the total.

Finally, the possibility of target and low digestibility for the thickened waste activated sludge (TWAS) was also considered, based on ultimate volatile solids reduction (VSR) values of 45 and 23 percent, respectively. The low digestibility TWAS was considered in conjunction with one lime FOG truckload per day, to estimate a minimum rate of biogas production.

The projected annual average and average weekly pattern of biogas balances for eight considered cases are presented in Table 1. It can be observed that in most of the cases, the dryer operation is expected to be within the range of 4.5-5 days, justifying the simplifying assumption that the available sludge and gas storage will be utilized so that the high biogas production period will be identical to the dryer operation period.

The biogas balance results indicate that the amount of excess gas available for cogeneration is highly variable, depending on each scenario for FOG loading and biogas utilization in the dryer. For target scenario A4, an average of 361 scfm of excess biogas is projected to be available for cogeneration after the pelletizer biogas demand is met. In particular, 356 scfm would be available during pelletizer operation periods and 370 scfm would be available when the pelletizer would not be in operation. In the less likely lowest biogas production case (B3), there is not enough biogas generated to cover the energy requirements of both the pelletizer and cogeneration during days of pelletizer operation. For this case, there is no biogas available for cogeneration during weekdays, and there are 211 scfm when the pelletizer is not in operation, for an average of 72 scfm.

Selection of Cogeneration Technology

The following alternatives for cogeneration were evaluated for SCBWRF: internal combustion engines (ICE), Stirling engines, fuel cells, gas turbines, and microturbines. A preliminary analysis of the considered cogeneration technologies included the examination of their advantages and disadvantages and es-

Continued on page 42

Continued from page 41

timation of payback period and life cycle financial benefit analyses.

The financial evaluations for the cogeneration technologies were based on the target scenario (Case A4). The Water Environment Research Foundation's (WERF) Life Cycle Assessment Manager for Energy Recovery (LCAMER) tool was used for the financial evaluation of the various technologies. The LCAMER model inputs for the ICE alternative were adjusted so that its predicted biogas quantities were in general agreement with the independently-determined biogas quantities for Case A4. The LCAMER tool, calibrated to SCBWRF conditions, was then applied to evaluate the remaining cogeneration technologies of Stirling engines, gas turbines, microturbines, and fuel cells.

The financial comparison of the five cogeneration alternatives is presented in more detail (Surti et al, 2011) and is summarized in Table 2. The ICE technology's life cycle financial benefit at about $5.5 million was estimated to be more than twice the financial benefit from the second-best technology for SCBWRF, which is the gas turbine technology, at about $2.4 million. In addition, ICE had the lowest total initial installation capital cost among all technologies. Based on this evaluation, the most suitable and promising cogeneration alternative for SCBWRF was determined to be ICE alternative, and this one was further analyzed in more detail.

Table 2. Comparison of the Cogeneration Alternatives Using LCAMER

	ICE	Stirling	Gas Turbine	Micro-turbine	Fuel Cell
Cogeneration system considered	GE Jenbacher J420	Stirling Biopower	Solar Saturn 20	Ingersoll-Rand MT250	Fuel Cell Energy DFC1500
Number of cogen. units	1	30	1	5	1
Net electrical capacity per unit, KW	1,335	40	1,037	225	1,000
Avg. net capacity, KW	1,335	980	1,037	1,125	1,000
Electrical efficiency, percent	39.3	26	24	27	44
Total initial installation cost, $	$5,215,000	$5,608,000	$5,796,000	$5,675,000	$7,956,000
Cogeneration service life, years	20	15	20	9.5	10
Annual benefits from power generation, $/year	$1,076,000	$787,000	$835,400	$907,000	$805,700
Total annual O&M cost, $/year	$357,000	$157,000	$285,000	$294,000	$413,000
Net benefit, $/year	$718,700	$630,000	$550,568	$611,900	$393,000
20-yr life cycle net benefit(1), $/year	$5,480,000	$636,000	$2,400,000	$347,000	($7,400,000)
Payback period(2), years	7.3	13	11	14	34

1 Cost of Electricity: $0.092/kWh; Cost of Natural Gas: $0.0093/scf; Discount Rate (percent): 3 percent; Capital and O&M cost includes the cost of biogas treatment for each cogeneration technology.
2 Including replacement capital cost.

Table 3. Basic Data for the 1,059 kW and 1,426 kW ICE Cogeneration Sets

	JMS320	JMS420
Gross output rated capacity, kW	1,059	1,426
Parasitic load(1), kW	30	35
Total recovered heat available to heat the digesters, MBTU/hr	4.3	5.2
Electrical efficiency at full load(2), percent	37.9	39.3
Thermal energy efficiency at capacity, percent	46.4	43.1
Net power plus thermal efficiency, percent	84.3	82.4

1 Load consumed by the ICE generator set.
2 Ratio of net electrical energy output at capacity to lower heat value (LHV) of input fuel.

Table 4. Conceptual Level Cogeneration Project Cost Estimates

Item	JMS420 – 1,426 kW	JMS320 Plus JMS 420 – 2,485 kW
Total equipment cost	$1,900,000	$3,000,000
Total project cost	$5,200,000	$7,950,000

Detailed Evaluation of ICE Alternatives

There are several engine manufacturers of state-of-the-art high electrical efficiency lean-burn engines, including Caterpillar, Cummins, GE Jenbacher, and Waukesha. These manufacturers produce ICE systems at manufacturer-specific power generation capacities, necessitating the evaluation to be performed for a specific manufacturer. The manufacturer selected for this evaluation was GE Jenbacher, which produces two ICE models that were considered suitable for implementation at SCBWRF.

The evaluated ICE alternatives were (1) installation of a JMS420 ICE (1,426 kW rated capacity) and (2) installation of a JMS320 plus a JMS 420 (2,485 kW combined rated capacity). Basic data for these two models are included in Table 3. In both cases, the ICEs are assumed to be operating at their rated capacity by supplementing the biogas with natural gas when needed. This would maximize the utilization of the installed capacity and allow the ICEs to operate at their maximum electrical efficiency.

Conceptual level project cost estimates were generated and are summarized in Table 4. The biogas system considered is based on a design capacity of 370 scfm, which is the projected available biogas for Case A4 during weekends. Conceptual level O&M cost estimates were generated. The implemented cost factors and assumptions are presented in Tables 5 and 6, respectively.

The payback period and life cycle financial benefits comparison of the two considered ICE alternatives (one versus two ICEs) is summarized in Table 7 for the target case on available biogas (Case A4) and for the projected energy cost during the first year of cogeneration, as well as for a scenario anticipating a 25 percent escalation on the cost of energy.

There is a trade off in the risk associated with the future cost of power and natural gas for the cases with one versus two ICE systems. By operating solely on biogas, the one ICE system eliminates the dependency of the cogeneration on natural gas and the risk of its price fluctuations in the future. However, it generates less power and thus it results in a higher amount of purchased electrical energy for SCBWRF. Only about 40 percent of the total energy is generated by one ICE, compared to about 70 percent of the SCBWRF energy consumption generated by the two ICE alternatives.

For the baseline unit cost of energy (9.2 cents/kWh and $0.9/therm), by operating solely on the biogas energy and thus not incurring any cost of purchasing natural gas for cogeneration, the alternative with one ICE is about 40 percent lower compared to the two ICE case (7.3 versus 12 years). The payback period and life cycle benefits of the alternatives with two ICEs are less attractive, due to the significant cost of supplemental natural gas (about $600,000 per year). Similar results are obtained if the unit cost of energy increases by 25 percent (9.2 cents/kWh and $0.9/therm), only in this case the payback period for the one ICE case is about 35 percent lower compared to the two ICE case (5.4 versus 8.3 years). The reason for the lower percentage reduction in the payback period at the higher unit cost of energy is that the benefits for both cases increase significantly and reduce the importance of the cost to buy supplemental natural gas to use for cogeneration. The 20-year life cycle benefits are significant in all four cases, ranging from $1.9 to $6.3 million. As a result of this analysis, and considering the uncertainty on the biogas quantity, PCU staff decided to implement the alternative with one ICE, with an installed rating in the order of 1,400 kW, with provisions for the potential installation of a second ICE sometime in the future. As a result, the remaining analysis focuses on the single ICE alternative.

The life cycle benefits and payback periods were evaluated for the eight available biogas cases for the 1,426 kW ICE with a 370 scfm biogas treatment system and are summarized in Table 8. The purpose of the analysis is to estimate the risk in the payback period and life cycle benefit if biogas is significantly reduced in the future; for example, due to a reduction in the available FOG quantities. The payback period and life cycle benefit of the lower biogas cases are therefore penalized by the unutilized excess biogas treatment capacity and by the use of natural gas supplementation in the ICU so that it operates at its 1,426 kW capacity to fully utilize it. Cases A are considered more likely than Cases B, because Cases A are consistent with the SCBWRF design specifications. Among the A Cases, the ones with high TWAS digestibility have attractive payback periods and offer significant life cycle net benefits ($3.2 million to $5.4 million). The payback and life cycle benefit of the lower biogas cases would approach those of Case A4 if each case

Continued on page 44

Table 7. Comparison of Installing One or Two ICE Generation Sets

Case	Baseline Electrical Energy Unit Cost		25 Percent Higher Electrical Energy Unit Cost	
	JMS 420	JMS 320 JMS 420	JMS 420	JMS 320 JMS 420
ICE installed				
Available biogas case	A4	A4	A4	A4
Electrical cost, cents/kWh	9.2	9.2	11.5	11.5
Natural gas cost, $/therm	0.9	0.9	1.13	1.13
Power rating, kW(1)	1,426	2,485	1,426	2,485
Avg. biogas available for cogeneration, scfm	361	361	361	361
Avg. biogas used for cogeneration, scfm	297	361	297	361
Percentage of available for cogeneration biogas(2)	82	100	82	100
Energy NG supplement in cogen, percent of total energy input to cogen(2)	0	34	0	34
Generated electrical energy, kWh/year	11,698,000	20,351,000	11,698,000	20,351,000
Percentage of the existing consumption at SCBWRF	39	68	39	68
Annual value of produced electrical energy	$1,076,000	$1,872,000	$1,345,000	$2,340,000
Annual cost of NG supplement for cogeneration to operate at capacity	-	$611,000	-	$764,000
Annual cogeneration O&M cost	$277,000	$501,000	$278,000	$502,000
Annual gas treatment O&M cost	$86,000	$99,000	$99,000	$113,000
Annual net benefit from cogeneration	$713,000	$661,000	$968,000	$960,000
Present worth of 20-year net benefits(3)	$10,614,000	$9,838,000	$14,403,000	$14,282,000
Construction cost	$5,215,000	$7,937,000	$5,215,000	$7,937,000
Payback period, years	7.3	12.0	5.4	8.3
20-year life cycle benefits(3)	$5,400,000	$1,900,000	$9,190,000	$6,350,000

1 Engines considered operating at capacity with supplemental NG when needed.
2 The single JMS420 ICE case is sized at a fraction of the average available biogas to eliminate ICE operational dependency on NG throughout the year.
3 Based on discount rate (above inflation) of 3 percent.

Table 5. Operation and Maintenance Cost Factors for ICE Cogeneration Sets

	JMS320 – 1,059 kW	JMS 420 – 1,426 kW
PCU daily oversight (based on continuous operation), FTE equivalent	0.2	0.2
Genset system O&M expense – Standard maintenance (oil changes) performed by plant personnel and major events and overhauls performed by contractor, $/hr	19	23.5
Genset system O&M expense for consumables (e.g. oil and coolant), $/hr	6	7

Table 6. Additional Operation and Maintenance Assumptions

Item	Value	Comments
ICE availability, percent	96	Considered an upper limit with good maintenance and gas treatment.
Power consumption for gas treatment, kW	75	Includes blower and chiller power. For 370 scfm system, scaled down linearly for lower scfm.
Power consumption for the heat loop pump, kW	8	
Hydrogen sulfide removal annual O&M cost	$5,000	Based on biological system.
Siloxane removal non-regenerative annual O&M cost	$30,000	For biogas silicon being 5-10 ppmv. For 370 scfm system, scaled down linearly for lower scfm.

Continued from page 43

is sized with its optimal (lower) biogas treatment and ICE capacities instead of the system being sized based on Case A4.The only exception corresponds to the lowest biogas case (Case B3), for which there no biogas surplus when the pelletizer is in operation, as shown in Table 1. The associated use of natural gas to run the ICE during such periods would therefore preclude the payback of case A4 from approaching that of Case A4.

The target biogas case (A4), with three lime-FOG truckloads per day, and alternative A3, with two lime-FOG truckloads per day, have identical life cycle benefits ($5.4 million) and payback period (7.3 years). This is because, in both these scenarios, there is excess biogas available beyond the ICE fuel demand. As shown is Table 7, the 1,426 kW ICE is sized conservatively to utilize only about 82 percent of the available cogeneration biogas on average, in order to minimize the probability of significant amount of supplemental NG needed in the future, given the long-term uncertainty in the amount of available FOG and the NG price. A heat balance in the system was used to calculate the recovered heat from the 1,426 kW ICE and compare it to the average heat demand of the digesters. The average heat recovered during the operation of the 1,426 kW ICE is projected to be sufficient to cover the average heat demand of the digesters in all considered cases. As a result, the boiler will serve primarily as a backup heat source.

The payback period and life cycle benefits analysis was repeated for various scenarios of 25 percent unit price escalation for electrical power and/or natural gas. The sensitivity of the financial benefits and payback period to the incremental addition of one, two, and three truckloads of lime FOG each weekday is highlighted in the charts included in Figure 2. From these, it becomes apparent that a 25 percent escalation in the price of electricity, without an associated escalation in the price of natural gas, would make the use of natural gas supplementation to the ICE significantly more attractive and make the benefits of Case A1 approach the benefits of Cases A3 and A4.

Conversely, a 25 percent escalation in the price of natural gas without an associated escalation in the price of electrical power would make the use of natural gas supplementation to the ICE significantly less attractive and reduce the life cycle benefits of case A1 to roughly 50 percent of the benefits from cases A3 and A4. As a result, the lack of significant lime FOG quantities in the future is expected to reduce financial benefits by a large percentage only if there is a very large increase in the cost of natural gas relative to the cost of electricity. This could occur sporadically but is an unlikely long-term event, since natural gas prices influence electrical power costs.

The effect of JMS420 1,426 kW ICE availability on payback and life cycle benefits was investigated. The target ICE availability of 96 percent was compared to a reduced availability of 93 percent. This reduction in ICE utilization results in a small increase of the payback period, from 7.3 to 7.5 years.

Continued on page 46

Table 8. Life Cycle Benefit and Payback Sensitivity Analysis on the Cost of Energy for the 1,426 kW(1) ICE

Case	A1	A2	A3	A4 (Target)	A5	B1	B2	B3
Biogas in dryer fuel, percent	35(2)	35(2)	35(2)	35(2)	35(2)	90(3)	90(3)	85.4(3)
TWAS Ultimate VSR, percent	45	45	45	45	23	45	45	23
Number of 15,000 wet lb lime FOG truckloads per weekday	1	1	2	3	1	1	3	1
WEDWRF cake addition	Digesters	Pelletizer	Digesters	Digesters	Digesters	Digesters	Digesters	Digesters
Annual value of produced electrical energy	$1,076,000	$1,076,000	$1,076,000	$1,076,200	$1,076,000	$1,076,000	$1,076,000	$1,076,000
Annual cost of NG supplement to run cogen at capacity	$159,000	$267,000	-	-	$422,000	$533,000	$240,000	$780,000
Annual value of not needing NG in boiler to heat ESDs	-	-	-	-	-	-	-	$74,000
Annual cogeneration O&M cost	$277,000	$277,000	$277,000	$277,000	$277,000	$277,000	$277,000	$277,000
Annual gas treatment O&M cost	$74,000	$66,000	$86,000	$86,000	$54,000	$46,000	$68,000	$28,000
Annual net benefit from cogeneration	$566,000	$466,000	$713,000	$713,000	$323,000	$220,000	$491,000	$74,000
Present worth of 20-year net benefits(4)	$8,420,000	$6,939,000	$10,614,000	$10,614,000	$4,808,000	$3,272,000	$7,310,000	$1,098,000
Construction cost	$5,215,000	$5,215,000	$5,215,000	$5,215,000	$5,215,000	$5,215,000	$5,215,000	$5,215,000
Payback period, years	9.2	11.2	7.3	7.3	16.1	23.7	10.6	70.6
20-year life cycle net benefit(4)	$3,210,000	$1,720,000	$5,400,000	$5,400,000	$(410,000)	$(1,940,000)	$2,090,000	$(4,120,000)

1 Covers roughly 40 percent of the present electrical demand of SCBWRF.
2 Scenarios A meet the dryer's design criteria.
3 Scenarios B are less likely to occur.
4 Based on discount rate (net interest rate above inflation) of 3 percent.

Continued from page 44

Conclusions

The main conclusions are as follows:

- Based on the expected high biogas production due to the codigestion of FOG, and also due to a limit in the biogas utilization by the SCBWRF dryer/pelletizer, significant biogas quantities are expected to remain available after the pelletizer's biogas needs are met.
- When considering cogeneration, coupled with the operation of a dryer, it is important to analyze separate periods when the dryer is or is not in operation to obtain a realistic estimate of the available biogas for cogeneration, since during dryer operation periods there may not be available biogas for cogeneration.
- ICE-based cogeneration provided the maximum life cycle benefit when compared to alternative technologies (Stirling engine, gas turbine, microturbine, or fuel cell technologies).
- The extreme case was considered, namely when there was no excess biogas projected to be available for cogeneration during dryer operation (Case B3), and involved the operation of the dryer on 85 percent biogas, with low TWAS digestibility (22.5 percent VSR), and low FOG quantities (14 percent of the total digesters VS load due to FOG).
- The selected ICE capacity was 1,426 kW rated electrical capacity, which allowed for operating on biogas and thus eliminating the dependency on the price of natural gas.
- Based on the target biogas scenario A4 (44 percent TWAS VSR and 26 percent of the total digesters VS load due to FOG), at \$0.09/kWh, the payback period of a 1,400 kW (electrical) ICE cogeneration system and associated biogas treatment was estimated to be 7.3 years, with a projected 20-year life cycle benefit of \$5.4 million.
- At an electrical power cost of \$0.115/kWh and NG cost of \$0.9/therm, a cogeneration scheme that is sized conservatively to handle the maximum available biogas case would have a low payback period (5.4 to 9.8 years) for all available biogas cases.
- There is a trade off in the risk associated with the future cost of power and natural gas for the cases with one versus two ICE systems. The one-ICE system eliminates the dependency of the cogeneration on the risk of natural gas price fluctuations, but generates less power and thus it results in a higher amount of purchased electrical energy for SCBWRF, increasing the risk from future electrical price uncertainty.

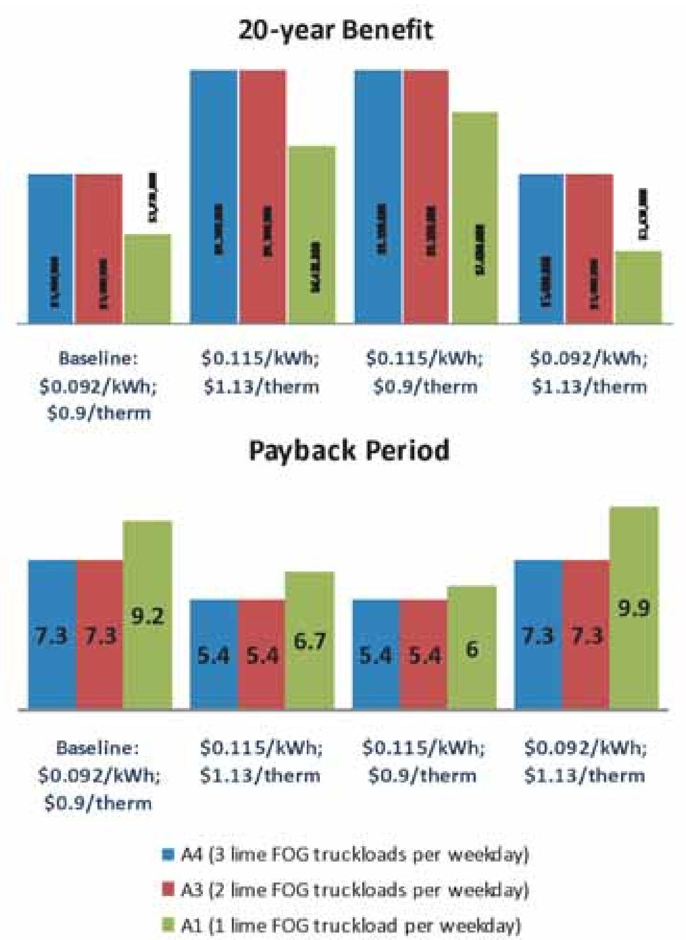

Figure 2. Life Cycle Benefits and Payback Period Sensitivity Analysis

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