Don't Pass on the Gas: More Bang for Your Biogas Buck

Matthew Munz and Bruce Petrik

In June 2013 the City of Tampa retained MWH to evaluate the production and utilization of biogas at the City's Howard F. Curren Advanced Wastewater Treatment Plant (AWTP). Its study included a detailed analysis of current biogas quantity and quality, a condition assessment of the current biogas handling facilities, an investigation of environmental regulations affecting the biogas cogeneration at the facility, and an economic analysis comparing various biogas utilization alternatives.

The AWTP is permitted for 96 mil gal per day (mgd), with current flows averaging between 50 and 60 mgd. The biosolids handling facilities include gravity thickening of the waste activated sludge (WAS), anaerobic digestion, dewatering using belt filter presses, and sludge drying facilities for the Class AA end product. The digester gas from the anaerobic digestion process is used for mixing the digesters, cogeneration, and firing boilers for the digestion heating process during the winter months. The hot water from the engine's cooling system is used as the primary heating source for the digestion system. The biosolids dryer facility consists of two rotary drum dryers that use natural gas as fuel. Currently, the drying system is not operational and the dewatered sludge cake is hauled from the site for land application.

Objectives

The objectives of the study were to develop a business case for the continued utilization of biogas, provide operational enhancement recommendations, and present the potential cost savings associated with the recommendations. In order to meet these objectives, several tasks were completed, including:

- Analysis of current biosolids and biogas production
- Condition assessment of existing biogas handling system
- Evaluation of energy production and requirements
- Evaluation of environmental regulations
- Development of biogas utilization alternatives
- Economic analysis of preferred alternatives

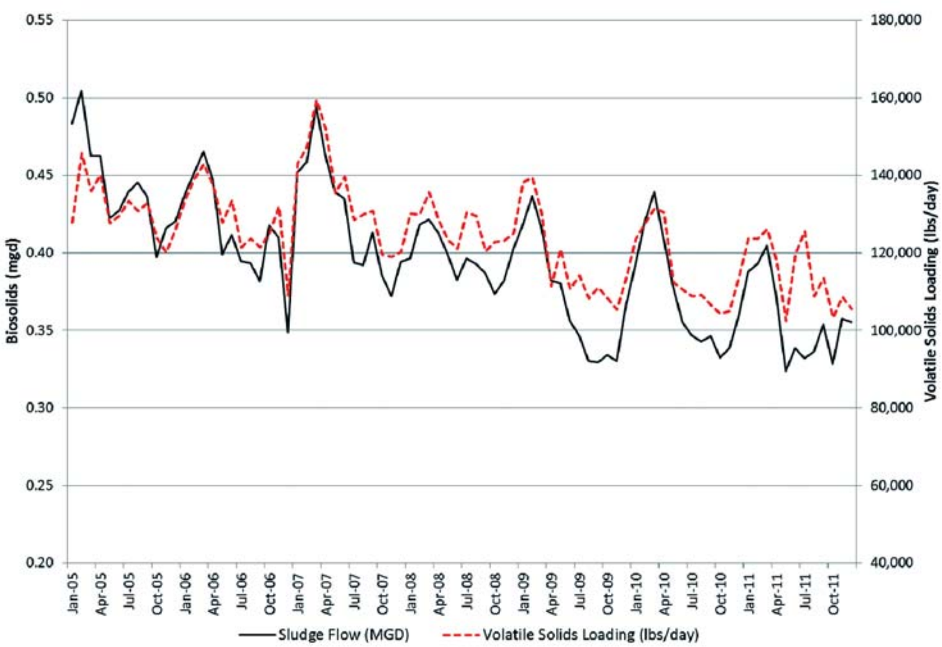

Figure 1. Digester Loading, 2005-2011

Matthew Munz, E.I., is an associate civil engineer and Bruce Petrik, P.E., is principal wastewater leader with MWH Global in Tampa.

Current Biosolids and Biogas Production

The AWTP currently operates as a high-purity oxygen (HPO) facility with primary sedimentation, carbonaceous reactors, nitrification reactors, denitrification filters, and disinfection facilities. The current biosolids handling facilities include a thickening step for WAS, mesophilic anaerobic digestion for sludge stabilization, dewatering facilities, and a sludge drying facility.

The WAS comes from carbonaceous reactors and is pumped from the plant pump station to two gravity thickeners for sludge thickening. Thickened WAS and primary sludge are pumped to a common wet well before being introduced to the anaerobic digesters for Class B sludge stabilization. The digested (stabilized) sludge is dewatered and then either hauled off site for land application or dried to produce a Class AA biosolid product.

Plant data from January 2005 to December 2011 was reviewed in an attempt to better understand the facility's overall treatment process and the biosolids produced. The liquid treatment process, and the sludge produced from those processes, affects the quality and quantity of the biosolids produced and must be considered when determining potential biosolids project alternatives utilizing gas production. Historical sludge flow quantities, as well as volatile solids (VS) loadings to the anaerobic digesters, are shown in Figure 1.The average VS loading rate is approximately 125,000 lbs/day and the average sludge flow is roughly 396,000 gal per day (gpd).

A slight downward trend in production is noted from 2005-2011 and equates to an approximately 34 percent reduction over that time frame. Based on conversations with the

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City, this trend is not expected to continue and sludge production will stabilize, and may increase, based on wastewater flow projections due to population growth.

Figure 2 shows the reported quantity of total monthly biogas produced from 2005 to 2011.

The graph shows a downward trend (30 percent drop) in biogas production over the last seven years. The average value dropped from 27.8 mil cu feet (mcf) per month to 21.9 mcf. It is important to note that even though there are three gas meters at the engine building, none of these meters are used to measure biogas flow. The City indicated that the biogas production is calculated based on the engine runtime. Each engine has a known fuel (biogas) consumption rate. This value is multiplied by the total runtime during the day to estimate the biogas produced per day.

The reported downward trend in biogas production has two main contributors, with one being that the downward trend correlates with the reduced sludge loading, as shown in Figure 1. In addition, there is a leak in the engine jacket water piping that requires the City to run the biogas-fueled hot water boilers to make up the hot water that has leaked. This would have diverted biogas from the engines and caused a decrease in the reported biogas production, as biogas production is calculated based on engine runtime. The City is currently replacing the leaking engine jacket water pipe.

In order to establish the quality of the biogas produced, samples were taken of the gas and tested for major gas constituents, gross heating value, siloxanes, sulfur compounds, and volatile organic compounds. Samples were taken from the biogas system both upstream and downstream of the existing filter units in order to provide the City with information on how well the current biogas conditioning system operates. Table 1 presents a summary of testing results that were used to determine biogas quality and potential treatment options when utilizing biogas in cogeneration engines.

The concentrations shown in Table 1 for the biogas upstream of the existing filters at the AWTP are very typical of anaerobically digested wastewater sludge. The methane concentration of 54.4 percent is slightly lower than the typical 60 percent. The lower methane content leads to a slightly lower heating value as well; the 550 British Thermal Unit (BTU)/ft^3 value reported is under the industry standard of 600 BTU/ft^3.

Table 1 shows that hydrogen sulfide and siloxane concentrations are higher downstream of the biogas filter units; this increase in concentration is caused by what is called the "rollover" effect. The filter units purge sulfur compounds (hydrogen sulfide) and siloxanes, which have smaller molecular weights as they fill with the siloxanes that have high molecular weights. This purging creates higher concentrations of siloxanes and hydrogen sulfide downstream of the existing filter units.

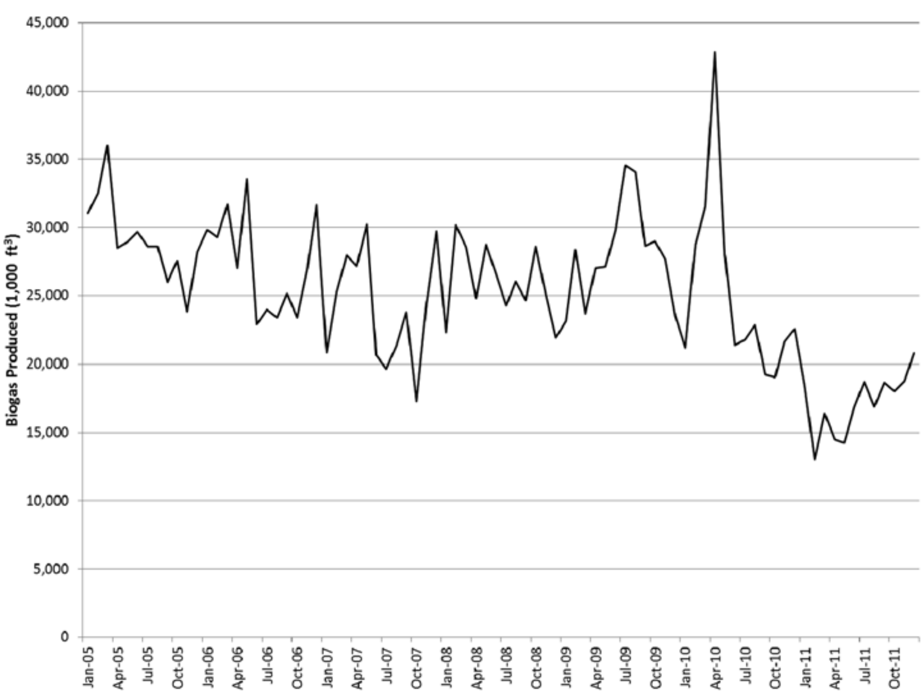

Figure 2. Biogas Production, 2005-2011

Table 1. Biogas Testing Results

Parameter	Units	Upstream of Filters	Downstream of Filters
Carbon Dioxide	percent	36.3	35.9
Methane	percent	54.4	52.0
Nitrogen	percent	7.64	8.90
Oxygen	percent	1.60	3.21
Gross Heating Value	BTU/ft^3	550	525
Total Siloxanes	ppbv	1,270.1	1,614.6
Hydrogen Sulfide	ppbv	68,900	135,000

Current Biogas Handling and Utilization

Inspections were conducted of all of the biogas handling equipment, including storage, conveyance, treatment/conditioning, and cogeneration.

The biogas produced is stored in the floating, gas-holder-type covers on digester Nos. 1 through 4. This limited storage capacity is used to build biogas reserves during nonpeak hours so that the maximum electricity production is done during peak hours, when electricity is more valuable.

The biogas is conveyed through sediment traps for moisture removal and then flows through biogas conditioning filters. After passing through the conditioning filters, biogas is pressurized by rotary positive displacement compressors where it is discharged through a common header to the cogeneration engines.

Table 2. Existing Cogeneration Engine Specifications

	Size	Manufactured	Location
Engine 1	500 kW	1984	Raw Sewage Pumping Station
Engine 2		1984	
Engine 3		1984	Generator Building
Engine 4		1984	
Engine 5		1987	

Table 3. Biogas Energy Calculations

Parameter	Value
Average volatile suspended solids (VSS) loading (lbs/day)	124,000
Average VSS destroyed (lbs/day)	66,409
Volume of biogas per pound of VSS destroyed (ft^3/lb VSS)	15
Volume of biogas (ft^3)	996,136
One Mil British Thermal Units (MBTU)/hr biogas	22.8

Note: • Average VSS destruction is 53 percent
• Average biogas heating value is 550 MBTU/ft^3

Table 4. Heat Energy Demands

Parameter	Units	Summer Months	Winter Months
Temperature of residuals	degrees F	83	75
Desired sludge temperature	degrees F	98	
Sludge flow	mgd	0.45	
Heat required to raise residual temperature to desired temperature	BTU/hr	2,720,925	4,222,125
Total heat required (including all local losses)	BTU/hr	4,274,987	7,981,952

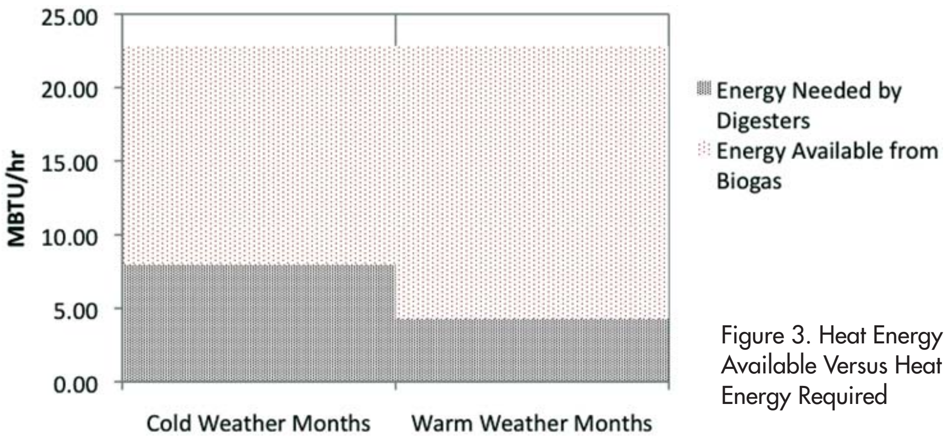

Figure 3. Heat Energy Available Versus Heat Energy Required

The AWTP currently has five cogeneration engines. Table 2 lists the specifications for each of the engines.

Waste heat is recovered from the engines and used to provide heat to the anaerobic digestion system. Mounted on each of the five engines are heat exchangers to transfer the waste heat from the engine to the jacket water loop to provide heat to the digesters. In the event that additional heat is needed for the digestion system, there are four biogas-fueled water boilers integrated into the heating loop.

Primary concerns with the current biogas handling facilities are centered on the biogas treatment system and the aging cogeneration engines. The current biogas conditioning system is highly inefficient, as supported by the biogas testing results. Operations staff has complained about the quality of the biogas used to fuel the engines; excessive moisture, white deposits on the engine pistons (siloxanes), and corrosion have been observed on the engine system. It was recommended that a new biogas conditioning system targeting hydrogen sulfide, moisture, and siloxanes be installed.

The biogas-fueled engines are old and in need of repair and/or replacement. Engine No. 1 is out of service and in need of major repairs and the City indicated that the estimated repair costs for this engine is $100,000. Engine Nos. 2, 3, 4, and 5 are currently in operation. Engine operators have indicated that the maintenance of these biogas-fueled engines is very labor intensive and time-consuming due to the poor condition of the engines. Engine operators have reported that the engines require oil replacement every 500 hours; as a comparison, the engine operations manual indicates that the oil should be replaced every 1,500 hours.

Additionally, the sludge drying facilities are unoperational and it is unclear if the City will be making the necessary investment to repair sludge drying facilities as the hauling of Class B solids is a suitable disposal method at this time.

Energy Production and Requirements

Using the biogas testing results, the amount of energy available in the biogas created was calculated. These calculations are shown in Table 3.

The primary demand of energy associated with the anaerobic digestion process comes from the heat required to maintain digester temperatures. The heat energy demands for the anaerobic digestion system are summarized in Table 4. The total energy required to maintain and operate the digestion system is approximately 7,981,952 and 4,274,987 BTU/hr during the winter and summer months, respectively.

Figure 3 shows the biogas heat energy available versus the seasonal digester operational heating/energy demands.

Environmental Regulations

The AWTP currently has a Title V air operation permit (Permit No. 0570373-018-AV) granted by the Environmental Protection Commission (EPC) of Hillsborough County. The Title V permit will expire on Nov. 1, 2016. The City was concerned that language in its current air permit would require that the existing cogeneration engines be replaced in order to operate in compliance with its permit past October 2013.

The current air permit states that the existing engines must comply with the emissions standards of 40 Code of Federal Regulations (CFR) Subpart ZZZZ by Oct. 19, 2013. The consultant spoke with air-permitting staff at the Florida Department of Environmental Protection (FDEP) and determined that there are no emissions standards in Subpart ZZZZ that would apply to the City's existing biogas-fueled engines. Subpart ZZZZ only outlines maintenance requirements for existing, nonemergency, digester-gas-fueled engines and the City is already in compliance with these requirements.

This means that under current regulations, the City's existing engines can be run indefinitely. This would also apply to any future renewals of the air permit as long as current regulations remain in effect. There is currently no regulatory need to update the cogeneration system.

Development of Biogas Utilization Alternatives

As indicated in Figure 3, there is heat energy available in the biogas produced at the

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AWTP. The City is currently utilizing some of this energy to produce electricity; however, concerns about the operational costs of the engines, new regulations, and the age of the existing equipment have led the City to evaluate alternatives for the utilization of the biogas. Alternative methods of biogas utilization were presented to the City based on the following considerations:

- Financial benefits (business case)
- Beneficial use of existing equipment
- Amount of energy provided
- Site constraints
- Technical viability
- Operational issues

Six alternatives were developed and presented to the City in an initial screening workshop.

Alternative 1 - Replace the five existing biogas engines with three new 1000-kilowatt (kW) combined heat and power (CHP) engines located in the existing generator building. Heating needs in the anaerobic digesters would be met by heat recovered from the three new CHP engines.

Alternative 2 – Similar to Alternative 1, with the addition of absorption chillers to provide heating and cooling to the facility's buildings.

Alternative 3 - Replace the five existing 500-kW engines with three new 1000-kW CHP engines located in an existing building adjacent to the dryer facility, allowing for engine exhaust to be used to supplement natural gas requirements in the dryer facility. Heating needs in the anaerobic digester would be met by hot water recovered from the dryer facility.

Alternative 4 - Replace the five existing biogas engines with three new 1000-kW CHP engines located in the existing generator building and construct a new dryer facility located near the digesters. This would allow waste heat from the cogeneration engines to be used in the new dryer facility.

Alternative 5 - Eliminate the five existing 500-kW engines and route all of the biogas to the existing dryer facility. Heating needs in the anaerobic digesters would be met by hot water recovered from the dryer facility.

Alternative 6 – Similar to Alternative 5, this would eliminate the existing cogeneration engines, but also require the construction of a new dryer facility near the digesters to allow for easier conveyance of the biogas to the new dryer facility. Heating needs in the anaerobic digesters would be met by hot water recovered from the dryer facility.

During the initial screening workshop, it was determined that Alternatives 1, 3, and 5 would be further evaluated in an economic analysis. In addition to these three alternatives, the City requested that two additional alternatives be included in the economic analysis for comparison purposes:

Alternative 5a - Eliminate the five existing 500-kW engines and use biogas to meet the heating needs of the anaerobic digesters. Any excess biogas would be routed to the existing dryer facility to offset natural gas use.

Alternative 7 - Eliminate the five existing 500-kW engines and fuel the digester boilers with biogas and flare the excess biogas.

A number of other biogas processing and utilization options are available in the marketplace, but were not considered feasible. Some of these alternatives are:

- *Fueling fleet vehicles* - Some municipalities have constructed gas stations for their municipal fleet using biogas as fuel. Although this alternative is an environmentally conscious alternative, the capital expenses, the complex logistics, and difficulty in operations represent a challenge to the City. In addition, the biogas needs to be treated and cleaned to very stringent fuel characteristics; biogas is high in carbon dioxide and hydrogen sulfide, which must be removed before the gas is burned in vehicle engines.
- *Exporting biogas to other Tampa port users* - Although the AWTP is located near the port in Tampa, with easy access to trains and freight carriers, no other port user has been identified with the need for biogas. Researching other biogas users within the area was out of the scope of this study. However, it is important to note that the AWTP has a need for use of the biogas generated, as illustrated in this section. It makes more sense to the City to utilize the biogas in its facility prior to considering selling it to other outside users.
- *Microturbines* - Microturbine manufacturers were consulted to determine the feasibility of using their equipment. The largest

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Table 5. Economic Analysis Parameters

Item		Notes
Capital Amortization Period	20 years	Specified by the City
Interest Rate	5 percent	Specified by the City
Inflation Rate	2.5 percent	
Natural Gas Cost	$4.50/ MMBTU	Based on current natural gas prices
Electricity Costs	$0.09/kWh	From utility bills provided by the City

Table 6. Economic Analysis Summary (Dryer Facility Inoperable)

Alternative	Annualized Capital Costs	Annualized O&M Cost	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue	Annualized Net Benefit
Alternative 1	($691,930)	($618,993)	$1,910,738	$236,861	$836,676
Alternative 3	($948,485)	($624,608)	$1,910,738	$236,861	$574,506
Alternative 5	($361,603)	($95,453)	$0	$236,861	($220,195)
Alternative 5a	($117,716)	($95,453)	$0	$236,861	$23,693
Alternative 7	$0	($78,785)	$0	$258,902	$179,116
Current System	$0	($985,103)	$1,137,859	$258,902	$411,657

Note: Values shown in red are a cost to the City; values in black are a net benefit to the City.

Table 7. Economic Analysis Summary (Dryer Facility Repaired)

Alternative	Annualized Capital Costs	Annualized O&M Cost	Annualized Electricity Revenue	Annualized Natural Gas Offset Revenue	Annualized Net Benefit
Alternative 1	($691,930)	($618,993)	$1,910,738	$236,861	$836,676
Alternative 3	($948,485)	($624,608)	$1,910,738	$236,861	$574,506
Alternative 5	($361,603)	($95,453)	$0	$236,861	($220,195)
Alternative 5a	($117,716)	($95,453)	$0	$236,861	$23,693
Alternative 7	$0	($78,785)	$0	$258,902	$179,116
Current System	$0	($985,103)	$1,137,859	$258,902	$411,657

Note: Values shown in red are a cost to the City; values in black are a net benefit to the City.

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microturbine engine available in the market is 250 kW. Based on current evaluation assumptions, microturbines would not be cost-effective to install because of the large amount of units needed. In addition, microturbines require more stringent fuel characteristics; the cost for cleaning the biogas to microturbine fuel characteristics is more expensive than cleaning it to engine characteristics.

- *Fuel cells* - The fuel cell technology, although very promising, has not been fully developed. At this time, it's uncertain if this new technology is adequate for the City. In addition, implementing this new technology will mean training, or possibly adding, new skilled operators dedicated to this type of system.

Economic Analysis

To further evaluate the five preferred alternatives, an economic analysis that included capital and operational and maintenance costs was conducted. This analysis allows for the five alternatives to be compared in order to determine the most economically beneficial alternative. Parameters for conducting the economic analysis are outlined in Table 5.

At the request of the City, two scenarios were evaluated for each of the alternatives; Scenario 1 assumed that the dryer facilities remain offline, while Scenario 2 assumed that the dryer facilities were repaired and operational.

The economic analysis conducted presents annualized costs and benefits for each of the preferred alternatives. These annualized values allow for inflation and the time value of money to be considered. In order to calculate the annualized values, costs and revenues for each alternative were estimated for fiscal year 2012 and then increased by the specified inflation rate of 2.5 percent over 20 years to coincide with the capital-cost amortization period. These annual costs were then equated to a net present worth, which was annualized over the same 20-year period using a 5 percent interest rate.

Table 6 presents a summary of the economic analysis considering that the dryer facilities are not repaired and Table 7 summarizes the economic analysis considering that the dryer facilities are operational.

Conclusions

As shown by the results of this study, there is a very realistic business case to be made for the continued utilization of biogas at the AWTP. While the economic benefits of biogas utilization are reduced due to the age of the biogas facilities and equipment, they are still present and should not be overlooked. The conclusions reached as a result of this study include the following:

- Alternative 1 provides the greatest net benefit if the dryer is out of operation, largely because of the revenue generated from increased electricity production.
- Alternative 3 has the greatest net benefit if the dryer is operational because it produces the same amount of electricity as Alternative 1, as well as offsets natural gas use in the dryer.
- Regardless of the operational status of the dryer, Alternative 1 provides a $425,019 increase in net benefit over the current system.
- Alternatives 5, 5a, and 7 have the lowest net benefit in both dryer operational scenarios, and are considered impractical for the following reasons:
  - o Flaring provides the lowest annual net benefit as there is no electricity production and natural gas offset is minimal.
  - o Flaring does not utilize all of the stored energy in the biogas, a readily available resource at the plant.
  - o Producing electricity is more advantageous and economical than offsetting or supplementing natural gas based on current energy prices.
- The current biogas filter units are not providing any benefit to the City and may actually degrade the quality of the biogas produced at the plant. This has greatly increased the required maintenance costs to operate the existing cogeneration engines.

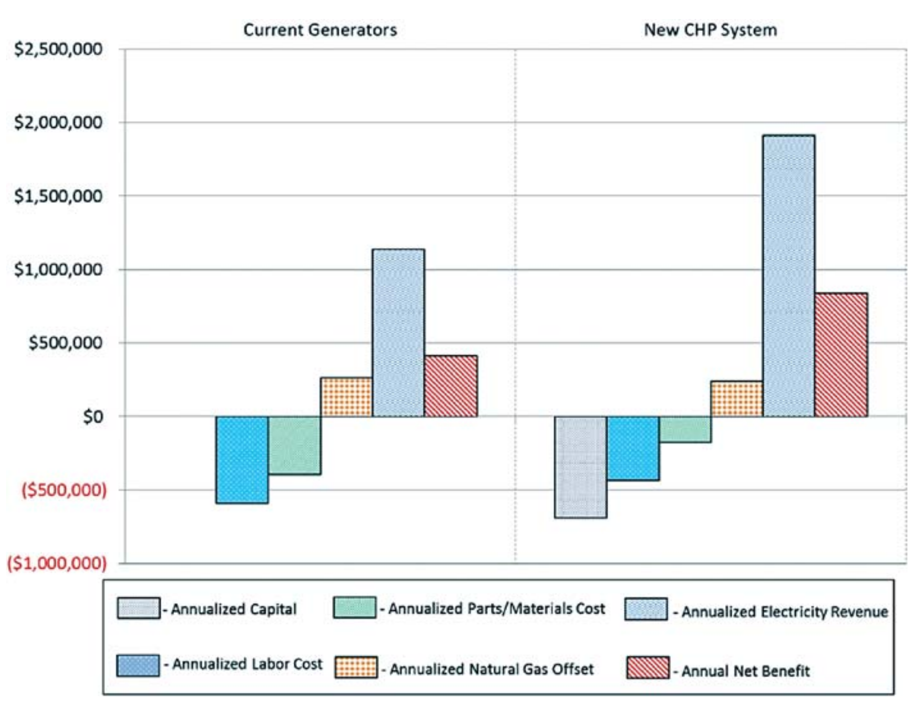

Figure 4. Comparison of Recommended Project and Current System

Recommendations

It was recommended that the City replace its current biogas conditioning system in the next one to two years. As was discussed, the current filter units are not providing any benefit to the City and may actually degrade the quality of the biogas produced. The costs of a new biogas treatment system have been included in the capital cost estimate of this recommendation.

It was also recommended that the City replace its five existing biogas-fueled engines with three new 1,000-kW engines. New engines will reduce maintenance costs and will increase revenues due to greater efficiencies in engine design. Alternative 1 is the most cost-effective, feasible alternative for the City. These improvements can be phased in over the next 20 years.

In order to demonstrate the financial benefit of this capital investment, the recommended alternative was compared to the current engine operation. Figure 4 shows the capital cost, labor cost, materials cost, revenues, and net benefit for both Alternative 1 and the current system annualized over the 20-year capital amortization period.