Pleasant Hills Sewage Treatment Plant Project
On
Alternative Energy Generation

I. DISCLAIMERS

II. ACKNOWLEDGEMENTS

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1.0 EXECUTIVE SUMMARY

The National Energy Technology Laboratory (NETL) is implementing a Regional Development Program, with a goal of addressing regional energy and environmental problems. One of the emphasis areas is to determine the viability of potential technologies for the utilization of waste gases as a source of fuel. These technologies would be required to convert these waste fuels into electricity, for use at the generator facilities and preferably incorporate heat-recovery systems that could be used to offset other site-wide energy requirements.

A target market was identified as the utilization of digester biogas from sewage treatment plants. The Pleasant Hills Sewage Treatment Plant (PHSTP), adjacent to the Pittsburgh site of the National Energy Technology Laboratory (NETL), continuously generates a significant volume of "biogas," a foul-smelling, corrosive mixture of methane, carbon dioxide and hydrogen sulfide as part of their anaerobic waste treatment process. Although it has a substantial heating value (600 Btu/CF), the plant currently flares the biogas because of its corrosive effect on equipment. In June 1999, NETL recognized this situation as an opportunity to apply NETL expertise and technology to harness an energy resource that was currently being wasted while simultaneously reducing harmful environmental emissions. This concept, which had the potential for nationwide replication, was endorsed by NETL's Regional Development Program managers, Art Baldwin and Curt Nakaishi, and championed by NETL Associate Directors Fred Brown and Jim Ekmann. The balance of 1999 was spent organizing a partnership of regional entities that were potential project stakeholders. This multidisciplinary partnership was formed to develop a project that could yield economic and environmental benefits for the region with the potential for nationwide replication. The partnership, which was coordinated by NETL, included: Pleasant Hills Authority, Pennsylvania Department of Environmental Protection, Business Development Group, Gannett Fleming, Inc., Advanced Technology Systems, Inc. (ATS), Carnegie Mellon University, Allegheny Power, Equitable Gas and Columbia Gas.

During 2000, the formed task group, consisting of these potential stakeholders, completed a detailed study that determined the technical and economic feasibility of several biogas project options at PHSTP. This feasibility study included the following elements.

- Plant Characterization: The team characterized PHSTP's operating procedures, including a detailed analysis of their electricity and natural gas usage. ATS was contracted to sample the biogas and determine its composition and flow rate.
- Design Requirements: The team determined the basic design requirements for a biogas utilization project at PHSTP, including space availability, location, electrical interface, thermal interface and gas cleanup requirements.
- Technology Survey: Three technologies were surveyed for their applicability to the PHSTP project: fuel cells, reciprocating engines and microturbines. After documenting the pros and cons of each technology, the microturbine was selected for a detailed life cycle cost analysis.
- Life Cycle Cost Analysis: Four different biogas utilization project options were modeled to determine their technical and economic performance, three of which featured a 30-kilowatt microturbine. A life cycle cost analysis (including a sensitivity analysis of key variables) determined each option's net present value.
- Environmental Analysis: The potential impact on greenhouse gas and criteria pollutant emissions was determined for each of the four biogas utilization scenarios. An environmental valuation was performed to provide an economic metric to determine the environmental benefit of each option.

In October 2000, NETL presented the results of this study to the Pleasant Hills Authority, which oversees PHSTP. Consequently, the Authority decided to install the microturbine cogeneration system and authorized their engineering firm, Gannett Fleming, to proceed with the detailed design. Although NETL hopes to have an R&D role (e.g., gas cleanup & carbon dioxide sequestration) once the project is installed, NETL's regional project development goals were successfully achieved with the Authority's decision to proceed with the project.

2.0 INTRODUCTION

The current energy crisis facing the United States, exemplified by skyrocketing natural gas prices and electricity rolling blackouts in California, is spurring efforts to identify and deploy alternative sources of energy. Such efforts include energy generation from waste fuels and biomass, electricity generation from windmills and solar energy as well as distributed energy generation with fuel cells and microturbines. In light of these energy availability challenges, the United States Department of Energy's (DOE) National Energy Technology Laboratory (NETL) is exploring the development and/or implementation of technologies that utilize waste gases (landfill gas, biogas, abandoned mine methane gas etc.) as fuel. These technologies would be required to convert these fuels into electricity at site and preferably incorporate heat-recovery systems that could be used to offset energy requirements at the host facilities.

NETL identified sewage treatment plants as potential target facilities for evaluating this concept since they produce waste biogas as a result of the anaerobic digestion of the sewage sludge. An added caveat was the close proximity of the Cochrans Mill Road sewage treatment facility (PHSTP), which is operated by the Pleasant Hills Sewage Authority (PHA) of Pleasant Hills, PA. The plant processes waste from the approximately 20,000 users located in several surrounding communities. It is located in the Peters Creek watershed and processes on average 4.0 Million Gallons per Day (MGD) of wastewater that eventually flows into the Monongahela River, in the Southwestern corner of Pennsylvania. The plant operates an anaerobic digester that produces on average of 18,000 cubic feet per day of methane-containing gas (~65% methane, ~34% carbon dioxide, ~1% other). This biogas waste product has historically been used at this plant in gas burning internal combustion engines/ generator sets that supply back-up power in times of electricity outages. Most recently this biogas has been directed to a flare and back-up natural gas has been employed as a fuel source. Maintenance and operating (M&O) costs associated with the internal combustion engines made the past practice of burning this corrosive biogas prohibitive at this time. This usage change created an opportunity for NETL to evalauate technologies that would have the potential to use this biogas in an economic, efficient and environmentally sound manner. Additionally, there was a need to mitigate the malodorous emissions from that plant, since they have unpleasant impacts on the neighbors, which includes the NETL complex.

In an effort to achieve its project goals, NETL assembled a task group consisting of industrial specialists to help develop a prototype approach to the capture and utilization of this digester biogas, in cooperation with the PHA at its Cochrans Mill Road sewage treatment facility. .

2.1 The Opportunity

NETL has developed a Regional Development Program, with a goal of addressing the regional energy and environmental problems that impact each of the associated states in the region (PA, WV, OH, MD and OK). Establishing partnerships with state and local governments, other federal government agencies, industry and universities to develop and create opportunities that can lead to favorable outcomes for all of the participants, is deemed essential to the success of this program effort. The areas that NETL has the strongest interest in are those that have one or more of the following: energy, environment, and economics as critical components. The development and/or implementation of technologies that address or are applicable to these areas are preferred as is the mitigation and/or reuse of greenhouse gases.

An opportunity to work with the PHA to develop a plan to use the biogas produced at the PHSTP became a reality after a presentation to and a discussion with the Authority members. From these initial meetings, a decision was made to establish a team that included participants from a local university, several power utilities, local industry and state agencies. The plan called for partnering with all of these interested parties to come up with a technically viable economic alternative to the present practice of flaring the biogas. NETL has for many years partnered with many industry participants through cost sharing on major projects. This experience and these long time relationships with industry and universities would be a corner stone for partnering on projects developed at the regional level.

2.2 The Partnership

The NETL Regional Development Program is constantly involved in numerous local and regional activities and these efforts bring NETL in contact with numerous community leaders from both government and industry. NETL has used these relationships to form partnerships to take on problems and develop opportunities, a concept that is being applied to this PHSTP project.

Partnering began by contacting those who had the most to gain in participating on this type of project. NETL held meetings to explain its goals and gain an understanding of what the participants would like to see accomplished. The final project team as assembled indeed reflected a diverse pool of stakeholders, who represented organizations that could stand to benefit directly or indirectly from the team’s findings and output.

The following organizations were represented on the project team:

The Pleasant Hills Authority, Gannett Fleming, Advanced Technology Systems, Inc., The Business Development Group, Columbia Gas of Pennsylvania, Equitable Gas, Allegheny Energy Solutions, Pennsylvania Department of Environmental Protection, Carnegie Mellon University and The National Energy Technology Laboratory.

The participants developed a Phase I project plan that called for a feasibility study to determine a technically viable economic alternative for the beneficial use of the waste biogas at the facility. It was necessary to determine which technology would be a "good fit", when evaluated for energy, environmental and economic concerns. These factors were deemed critical and were established as early requirements for the project. To assure a stronger sense of partnership, a Memorandum of Agreement (MOA) was developed and signed by all participants. The MOA spelled out the Phase I objectives and provided guidelines for the following: establishing decision making process, identifying tasks, roles and responsibilities and resource identification, data collection and analysis, economic analysis, policy analysis, identification of key resources for Phase II activity (most importantly participant provided resources), preparation of conceptual design and finally the formulation of the format and content of the presentation of the group's findings to the Pleasant Hills Authority.

2.3 Phase I Study

The primary objective of the Phase I Study was to perform a background information survey that would be used to evaluate the application of alternative technologies for the capture and use of digester biogas as a fuel source. The components of this case study could then be evaluated and potentially developed at a scale compatible with other community sewage treatment facilities. While economic viability was of critical importance, there were many technical and site-related issues that had to be considered as well such as the quality and quantity of the biogas as produced at the plant.

3.0 CHARACTERIZATION OF BIOGAS

3.1 Biogas Composition and Flow Rate

In order to determine the best alternative technology to utilize the waste biogas, background data needed to be acquired on the quality and quantity of the produced gas. The sampling plan below was designed to achieve that objective.

Sampling and Analysis Plan for Waste Gas at the PHSTP

The purpose for sampling and analysis was to determine the quality and quantity of the methane-containing gas (Btu values) as well as determine the causative agents for the offensive odor.

Sampling Plan

The appropriate place to perform the gas sampling was on the by-pass valve to the flare feed pipe located in the basement of the Digester- Bldg. # 6. The valve piping is a 1/2" female pipe from which a 1/4" pipe connection was made to facilitate sampling into evacuated Tedlar™ bags.

The sampling frequency and duration was as follows:

One sample each at 8:00 am and 8:00 pm was acquired on the sampling days. This represented a total of six samples. An additional six samples were acquired on different days for QA/QC purposes.

Analysis Plan

The acquired samples were analyzed for: methane, ethane, other C_2 - C_6 hydrocarbons, hydrogen sulfide, mercaptans, carbonyl sulfide, sulfur dioxide, oxygen, hydrogen, carbon monoxide, carbon dioxide, nitrogen and nitrous oxide.

Gas Quantity Measurements

The team performed gas meter readings twice a day to coincide with the gas sampling episodes. This information was used to estimate the quantity of the gas that is produced and captured at the plant.

Biogas Composition

The results from the analysis of the acquired samples are shown in Table 3.1 below. This data indicates the presence of ~65% methane, ~30% carbon dioxide, ~ 0.5% hydrogen sulfide and a balance of contaminant air. The digester biogas flow was determined to average 18,000 cfd and the heat value was calculated to be an average of 600 BTU/cf.

Table 3.1 - Current Digester Biogas Composition.

Compound	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Average
O_2	0.92	1.24	1.02	0.88	0.91	0.81	0.96
N_2	2.80	3.8	2.96	2.85	2.82	2.46	2.95
CH_4	65.94	63.88	64.95	65.94	66.57	64.38	65.28
CO_2	29.90	30.63	30.63	29.91	29.24	31.84	30.36
H_2S	0.45	0.45	0.44	0.42	0.45	0.51	0.45

3.2 Current Disposition of Biogas

Since the spring of 2000, all of the biogas has been flared in the waste gas burner. Prior to this time, the plant had occasionally utilized the gas by combusting it in either the fire-tube boiler or the reciprocating engines. Unfortunately, these uses were discontinued because the hydrogen sulfide (H_2S) in the gas led to various corrosion/deposition problems that required extensive maintenance to correct. These problems included white powder formation in the boiler and the gumming of pressure reduction valves. It is expected that installing a system that removes H_2S from the biogas could eliminate these corrosion problems.

4.0 DESIGN REQUIREMENTS FOR BIOGAS UTILIZATION AT THE PHSTP

The following list of important issues was involved in evaluating the Pleasant Hills Sewage Treatment Plant for the potential use of the biogas as a fuel.

4.1 Energy Utilization

The best site applications utilize as close to 100% as possible of the thermal and electrical output of the biogas as a fuel. The more site energy that is displaced by the biogas, the higher the energy savings and the shorter the pay back period will be for the selected technology.

4.2 Space Availability

Several of the possible technology choices require enclosures and/or special operation environments. These spacing requirements will dictate how large an area is required for each of the evaluated technologies.

4.3 Location

The objective is to minimize piping and wiring runs to reduce costs and energy losses. Proximity to the mechanical room is generally the best location, but is not always available. Since the electrical and thermal building interfaces are not always next to each other, in this instance it may be more important to locate the equipment nearest the thermal/heat recovery operation

4.4 Electrical Interface

In the evaluation of equipment it should be possible for the electrical interface to be either tied directly to a dedicated electrical circuit or paralleled with the electric utility. Electrical transmission from the technologies being considered should be evaluated for electrical output going into the grid if this will be an issue for this installation.

4.5 Thermal/Heat Recovery Interface

The application of the thermal/heat recovery interface can be the most involved requirement of this installation. The temperature of the site application needed to be considered. Ideally, the heat recovered would augment the gas-fired sludge-heating boiler. A temperature of 95^{o} F is considered optimum.

4.6 Gas Cleanup/Sequestration

The application of emerging gas clean-up and gas sequestration/reuse technologies and the requirements for the their use at this site should be developed. The economic viability of these can be examined and evaluated for this scale of operation.

5.0 SURVEY OF POWER GENERATION TECHNOLOGIES

The unintended outcome of energy deregulation has been higher commodity prices and in some cases energy shortages have resulted. The unpredictability associated with the centrally generated electricity for example is calling for different outlooks and philosophies as to how energy is produced and distributed. Thus the concept of distributed resources (DR) is becoming widely accepted and the potential to demonstrate real benefits in terms of assuring individual site energy supply and security. The idea behind DR is that, in addition to obtaining energy from the central power plant or high voltage transmission and distribution (TD) systems, a facility will generate its own auxiliary power that is paralleled with that of the electric utility. Continuous development and improvements in these DR-technologies have created new markets/users with numerous niche applications. Technology options include proven gas turbines and reciprocating engines as well as emerging technologies such as fuel cells and hybrid fuel cell/microturbine cogeneration systems. These technologies can provide a multitude of service options/benefits including standby generation, peak shaving, quality power, cogeneration and base-load supply.

The emerging market for DR appears to be in deregulated states. Customers who depend on reliable power for manufacturing, banking and food service are driving the demand for DR. Developers and supporters of DR believe it will become more popular and affordable as technology manufacturers standardize processes, pay off development costs and design more efficient equipment.

Every technology option has its advantages and disadvantages and DR technologies are no exception. High-capital cost, high-production cost, somewhat lower thermal efficiencies, long-term maintenance issues, and potentially costly interconnect standards all are issues that have to be wrestled with when evaluating these alternative energy technologies. The benefits of course include low TD losses, lower peak loads, enhanced site reliability, improved power quality and the flexibility to react to energy/ electric rate increases.

The goal for this project was to determine the economic and technological feasibility of using biogas for on-site power and process heat. The quantity of the biogas can also be increased by improving the efficiency of production of the by the gas by the anaerobic digesters at the sewage plant. This can also improve the economics of implementing the alternative energy option and provide a means to control some portion of the plants' operating expenses. This gas, utilized properly in a DR technology, becomes a value-added by-product of the digestion.

In selecting an alternative technology, the pros and cons of each option have to be determined and the economics of the best performer quantified.

5.1 Technology Options

The technologies listed below were evaluated as potential DR candidates for the PHSTP. Three technology options and a base case (status quo) were studied:

- Reciprocating Engine
- Fuel Cell
- Microturbine

Evaluation criteria were established to meet the specific needs of the plant. These included the ability to utilize all the energy produced by the alternative energy option, space availability, siting constraints, capability for electrical interfacing with the existing utility grid, coupling for thermal/heat recovery and the amenability to couple gas clean-up/sequestration options.

Reciprocating Engines

Reciprocating engines have dominated the DR market for many years. Successful applications include hospitals, industry, remote-military facilities and rural housing. This technology is readily available and accepted throughout industry. It boasts electrical efficiencies near 40% and has seen improvement in noise and emissions reduction. Retooling resulting in fewer moving parts has led to claims of reduced routine maintenance and the associated expense. The vast majority of the engines are designed for liquid fuels though many models are available for use with natural gas. Needless to say the scale of these engines (some of the smaller capacities are in the 300kw range) is too large for this project (<30/kw of gas available). An engine this size would replace approximately 80%-90% of the power presently supplied to he entire facility on a daily basis. A cost of $360,000 or $120.00/kW for a 300/kW unit would be expected for this technology at this scale.

The initial cost and the operational and maintenance costs would be acceptable if the gas supply was available to support the demand**.** There may be smaller scale (<300/kW) natural gas (NG) engines than the ones we have evaluated, but at this time we were unable to find sufficient information to include them in this evaluation. Also, PHSTP’s experience with currently installed reciprocating engines has not been favorable given the high operational and maintenance (O&M) costs that the plant personnel have encountered.

The advantages and disadvantages of reciprocating engines can be summarized as follows:

Pros

- Potential to provide 80%-90% of PHSTP daily power needs
- Cost: $360,000 or $120.00/kW for a 300/kW unit
- Electrical efficiency near 40%

Cons

- Operation and maintenance (O&M) costs for existing units are very high
- Most gas engines (>300kW range) are too large for this project (<30kW of gas available)

Fuel Cells

Fuel cells are a rapidly developing DR technology option, but acceptance has been tempered by high initial cost. Cost as high as $3000/kw is being reported. Recent design and manufacturing improvements have helped trim this cost. Large-scale commercialization of the larger units (>250/kw) has been slow to meet market expectations. Government support of these technologies is also credited with cost reductions.

A drawback for our selection of this technology was the unavailability of a unit for our scale of operation at a manageable cost. At present all the major manufacturers of fuel cells are operating at capacity or are retooling for production of new models. A few companies are moving into residential units with a 7-10/kW range and a capital cost of $8,000 to $12,000. These units would supply electricity and hot water to an average size home. However, they are not expected to be commercially available until late in 2001. This area of technology development is constantly making improvements and as the market for these products increases, cost will certainly fall and become more competitive with other alternative energy products.

These size units could meet the energy and heating needs of the PHSTP. A "stack " of two or three fuel cells could utilize all the digester gas produced and supply approximately 30/kW of electricity. A difficulty is that a relatively clean supply of methane is required to produce the hydrogen used in the reaction to produce electricity. Sewage digester gas is fairly contaminated with other chemical components (H_2S, CO_2, etc.) that can damage the fuel processing stage equipment. Sulfur is particularly harsh on fuel cells. To utilize the digester gas in any of the current generation of fuel cells, some form of gas cleanup process would be required. This requirement for a clean stream of hydrogen would make this technology choice costly at this time. A commercial fuel cell in the range of 30/kW would cost $90,000 at present pricing. A gas cleanup stage would add an additional $20,000 to $30,000 to the initial cost and add around $10,000 annually in annual maintenance.

At this particular time, fuel cell availability for this size (30kW) is very low. Fuel cell technology is somewhat expensive even though there are several buy down programs sponsored by the Federal Government to help defray this cost.

The advantages and disadvantages of fuel cells can be summarized as follows:

Pros

- Increased future availability
- Industry is developing smaller fuel cells
- residential: 7-10 kW
- defense, space: portable
- large-scale utility (>1 MW)

Cons

- Current cost of 30 kW fuel cell is high: $90,000 at present pricing
- Limited Availability: 30 kW fuel cells are not widely available
- Biogas is not clean and can damage fuel cell
- Clean-up costs: $40,000 - $60,000 equipment cost
- $10,000 annual maintenance cost

Microturbines

Gas turbines (combustion turbines) are available in various sizes from the microturbine (~30/kW) range to much larger commercial/utility scale (>1MW) units. Microturbines are a resent development in the DR arena. The technology has been used in other industries such as transportation. Examples are found as turbo chargers on larger truck engines and as auxiliary power units (APU) on airplanes and also in small military jet engines. Microturbines have been demonstrated to operate on various fuels and to produce low emissions. Efficiencies of 25%-30% have been reported. This efficiency can be increased with exhaust-heat recovery to produce area space heating, process heat or even process steam.

Recent results of microturbine performance are very promising. A manufacturer of microturbines has reported 10,000 hours of operation with only routine shut downs for scheduled maintenance. The microturbine features only one moving part. It is air cooled, and it is designed with an air bearing that is reported to eliminate the need for lubricants and coolants thereby requiring very little routine maintenance.

In a similar application, the Los Angles County Sanitation District has installed a 30kW microturbine at a district landfill to generate essentially free electricity while reducing greenhouse gases. Recent tests have proven reduced hydrocarbon emissions and more importantly a reduction of NO_x emissions to 1.9 ppm. LA County has a serious problem with NO_x emissions, which are a precursor for ground-level ozone. This particular turbine has operated on untreated gas mixture (~50% CH_4, ~50% CO_2) for more than 1300 hours with very few complaints reported. Testing of the flare emissions reported NO_x levels of about 30 ppm. Therefore, a very significant NO_x reduction was achieved using the gas in the microturbine. Results like this are generally associated with fuel cells.

Microturbines are presently becoming the leading technology choice if size, cost and emissions are the leading selection criteria. With costs around $1000/kW and low NOx emission levels (9-ppm), this technology is acceptable for most applications.

At the PHSTP, an evaluation of the gas quality and quantity has been carried out. This study has indicated that the gas composition has averaged around 65% CH_4 and 30% CO_2 with the remainder being contaminant air and less than 0.5% H_2S. The quantity of gas produced will be sufficient to operate a 30/kW unit for a period of at least 12 hours a day. This gas mixture will operate well in a microturbine and can be expected to meet or exceed the emissions data reported for similar fuels (landfill gases and gas produced in oil-well drilling). The H_2S component of the gas can cause corrosion of most metal surfaces. However, a microturbine manufacturer has addressed this concern with a design that can handle up to 7.0% H_2S, which would be 14 times the H_2S level present in the PHSTP digester gas.

The choice of a 30/kW unit will use all of the digester gas produced. The small size of these packaged units will allow for installation almost anywhere. Plant personnel have expressed that installation at a location close to the existing flare would be desirable. This can easily be done. A small concrete pad and maybe a shed are all that is needed for this area. The exhaust from the turbine can be re-routed to augment the heating capabilities of the existing sludge heating boiler. This location will be ideal for this application, since it is less than 50 feet from the sludge-heating boiler.

In summary, microturbines offer the following favorable attributes:

- Can burn untreated biogas
- Low emissions
- Efficiency: 25%-30%
- Expected lifetime: 10 years with routine maintenance

- Low maintenance - one moving part
- Air-cooled - little need for lubricants and coolant
- Compact design allows for easy installation
- Exhaust may be routed to heat sludge

Consequently, the microturbine appears to be a good fit for the PHSTP and meets most of the established requirements. The small size of the units, the potential to utilize all available biogas concomitant with the associated low emissions and the potential for heat recovery, make this option the most attractive for implementation at PHSTP.

6.0 OPTIONS FOR BIOGAS UTILIZATION

Four options for utilizing digester biogas at the PHSTP were selected for more detailed analysis. A "status quo" case was also defined so that the four options could be compared with a "do nothing" alternative. These options are described individually in Sections 6.1 to 6.5. Section 6.6 summarizes and compares the technical performance of each option and Section 7 contains a life cycle cost analysis of the options.

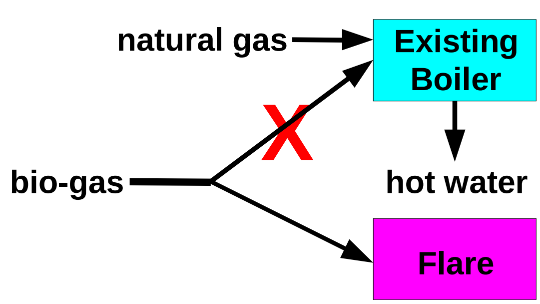
The analysis of each option involves two pieces of equipment that are currently being used in the PHSTP: the fire-tube boiler and the waste gas flare. The fire-tube boiler is used to heat process water to approximately 160 °F. The hot water then passes through an external heat exchanger to heat sewage sludge. In the winter, the hot water is also used to heat the plant's buildings. The waste gas flare is used to dispose of unwanted biogas.

The following design parameters are assumed for the analysis of each option:

- Average digester biogas flow rate is 18,000 CF/day
- Average digester biogas heating value is 600 Btu/CF (LHV)
- Average boiler efficiency, when operating on natural gas, is 80%
- Average boiler efficiency, when operating on biogas is 75%

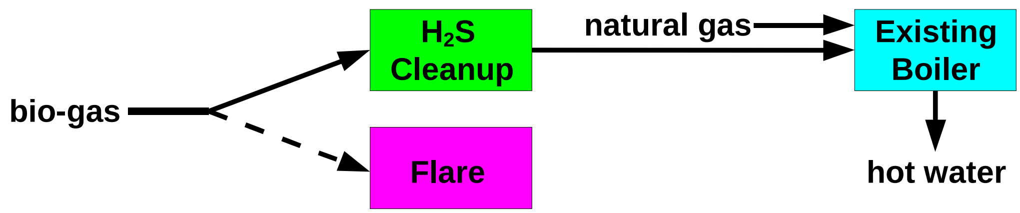
6.1 Option 0 -- Status Quo Operation

Option 0, shown in the figure below, would preserve the current operating procedure. To avoid corrosion problems and the associated maintenance costs, no biogas would be combusted in the boiler. Instead, all the biogas would be flared and the boiler would be fueled exclusively with natural gas.



6.2 Option 1 -- H_2S Removal / Combustion in Boiler

Option 1, shown in the figure below, would install equipment to remove H_2S from the raw digester biogas. The cleaned gas could then be combusted in the boiler without any corrosion problems. Some natural gas would still be required to meet the boiler's fuel demand. The waste gas flare would be retained, but not normally used.



Natural gas bills for the period February 1999 to March 2000 are shown in Attachment 1. These bills indicate the monthly variation of natural gas consumption by the boiler. During September, the boiler used the least amount of natural gas, consuming an average of 11.3 MMBtu/day.

At design conditions, 10.8 MMBtu/day of biogas fuel energy would be available. Since this is less than the boiler's minimum monthly consumption of 11.3 MMBtu/day, it is assumed that all of the biogas could be utilized in the boiler throughout the year[a].

The availability[b] of the H_2S removal equipment is assumed to be 0.98. Any biogas produced when the H_2S removal equipment is unavailable would be flared. Table 6.1 contains the projected capital and maintenance costs for Option 1.

Table 6.1: Option 1 Capital and Maintenance Costs

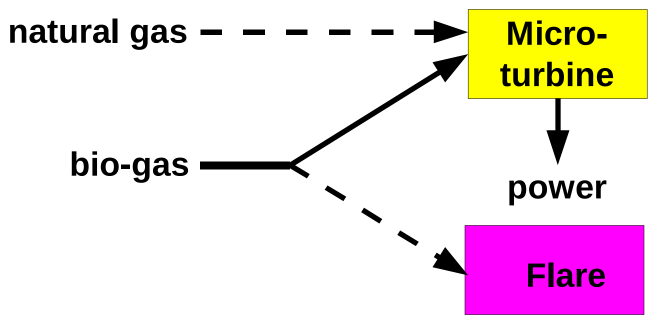
H_2S removal system installed cost	$60,000
H_2S removal system annual maintenance/refurbishment	$9,000

a Although biogas production is steady-state, the sludge heating process is not. Raw sewage is pumped into the digester twice a day and must be heated from around 50 °F to around 98 °F. Each pumping lasts for about 20 minutes. The rest of the time, hot sludge is simply being recirculated through the heat exchanger to maintain the digester temperature. It is assumed, however, that the biogas could be fully utilized in a steady-state fashion since the digester tank itself can "store" a significant amount of heat (without an objectionable variation in sludge temperature).

b.Availability is the fraction of time that equipment is available for normal operation. For example, the H2S removal system is projected to be available for 8322 of the 8760 hours in a year (8322 / 8760 = 0.95).

6.3 Option 2a -- Combustion in Microturbine

Option 2a, shown in the figure below, would install a microturbine system to generate 25 kilowatts (net) of electric power by combusting 15,290 CF/day of raw biogas. At design conditions, 2,710 CF/day of excess biogas would be produced and flared. If biogas production dipped below 15,290 CF/day, natural gas would be used to make-up the fuel deficit and keep the microturbine operating at full load. The status quo operation of the existing boiler would be unaffected by Option 2a; it would continue to be fueled solely with natural gas.



The microturbine system that was assumed for this analysis includes the following key components:

- a Model 330 Capstone microturbine, specially designed to operate on digester biogas,
- a Copeland compressor to compress the biogas to the required 50 psig microturbine inlet pressure, and
- a dessicant system to remove moisture from the biogas, aiding corrosion control.

The key design performance parameters assumed for the microturbine system are listed in Table 6.2. More information can be found in Attachment 3, which contains equipment specification sheets provided by Capstone Turbine Corporation.

The Copeland compressor is projected to consume 3 kW of the microturbine's gross 28 kW output, leaving a net system output of 25 kW.

At design conditions, the microturbine would be operated continuously at full load, even if natural gas were occasionally required to supplement the flow of biogas. Nevertheless, it is assumed that the microturbine would experience limited operation at part load as well as some scheduled and unscheduled outages. Recognizing this, the capacity factor of the microturbine system is assumed to be 0.95. Any biogas that is not utilized by the microturbine would be flared.

Table 6.2: Microturbine System Key Performance Parameters

Gross Electrical Capacity	28 kW
Net Electrical Capacity (Less Compressor Parasitic Power)	25 kW
Capacity Factor[c]	0.95
Gross Electrical Efficiency, LHV	0.25

An analysis of PHA's electricity usage concluded that the PHSTP could use all of the electricity generated by the microturbine. The analysis, contained in Attachment 2, was based on monthly utility bills and an electronic record of instantaneous demand[d]. Table A2.1 and Figure A2.1 in Attachment 2 contain a summary of PHA's electricity bills for the period January 1999 to February 2000. During this period, the average electricity demand was 350 kW –substantially higher than the 25-kW net output of the microturbine. Figures A2.2 and A2.3 display the electronic demand data for portions of the winter and spring seasons of 2000, respectively. These Figures confirm that the instantaneous electricity demand of the PHSTP never dropped below 200 kW.

The installed capital cost of the microturbine system is projected to be $61,410. This cost is broken down by component in Table 6.3, which also contains the maintenance costs assumed for the microturbine system.

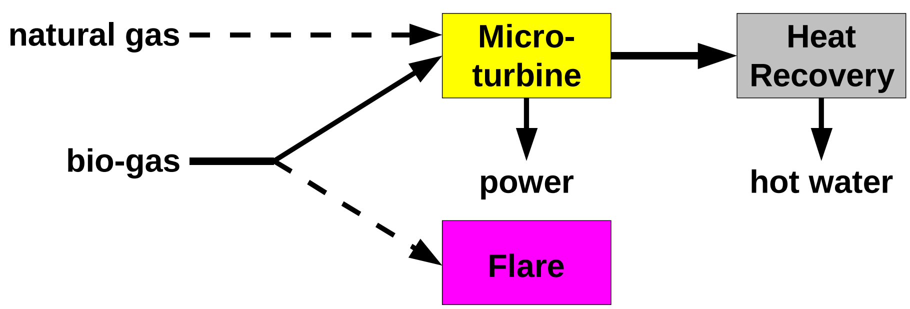
Table 6.3: Option 2a Capital and Maintenance Costs

Base Capstone Microturbine Model 330	$28,740
Enclosure	$750
Fuel Kit (Filter, Regulator)	$525
Remote Monitoring Software, With Modem	$1,125
Copeland Compressor	$6,500
Dessicant System	$3,300
Subtotal Of Equipment Cost	$40,940
Installation Cost (Estimated At 50% Of Equipment Cost)	$20,470
Total Installed Cost Of Option 2a	$61,410
Annual Routine Maintenance (For All Components)	0.010 $/kWh
Microturbine Refurbishment (Every 5 Years)	$9,500
Compressor Refurbishment (Every 3 Years)	$3,000

[c] Capacity factor takes into account those periods that the microturbine must operate at partial load or be taken off-line. It is a projection of how much electrical energy the microturbine will generate, expressed as a fraction of the maximum amount of electrical energy it is possible to generate. If the microturbine operated continuously at full load for an entire year, it would generate 219,000 kWh (net). Assuming a capacity factor of 0.95, the microturbine would generate (0.95)(219,000 kWh) = 208,050 kWh.
[d] PHA's instantaneous power demand (kW) was provided at 15-minute intervals.

6.4 Option 2b -- Combustion in Microturbine

Option 2b, shown in the figure below, is identical to option 2a except that a heat recovery system would also be installed to heat the plant's process water stream with the microturbine's waste heat. This would greatly reduce the amount of natural gas that is required by the boiler.



At design conditions, waste heat recovered from the microturbine would be transferred to the process water at a rate of 4.8 MMBtu/day. This analysis was based on the Micogen MG1-C1 heat recovery system, which was assumed to have an "efficiency[e]" of 0.7. More information can be found in Attachment 2, which contains equipment specification sheets provided by Capstone Turbine Corporation.

Natural gas bills for the period February 1999 to March 2000 are shown in Attachment 1. These bills indicate the monthly consumption of natural gas by the boiler. During September, the boiler used the least amount of natural gas, consuming an average of 11.3 MMBtu/day. Factoring in the boiler efficiency, this means that a minimum transfer rate of 9.04 MMBtu/day is required to heat the process water. Since this is greater than microturbine's waste heat recovery rate of 4.8 MMBtu/day, it is assumed that all of the waste heat recovered from the microturbine could be utilized throughout the year[f].

[e] The heat recovery "efficiency" is defined as the fraction of the microturbine's waste energy that is transferred to the plant's hot process water.

[f] Although waste heat recovery would be steady-state, the sludge heating process is not. Raw sewage is pumped into the digester twice a day and must be heated from around 50 °F to around 98 °F. Each pumping lasts for about 20 minutes. The rest of the time, hot sludge is simply being recirculated through the heat exchanger to maintain the digester temperature. It is assumed, however, that exchanger to maintain the digester temperature. It is assumed, however, that the waste heat could be fully utilized in a steady-state fashion since the digester tank itself can "store" a significant amount of heat (without an objectionable variation in sludge temperature).

As shown by Table 6.4, the heat recovery system is estimated to add $12,642 to the installed capital cost of the microturbine system while increasing maintenance costs by $0.001/kWh.

Table 6.4: Option 2b Capital and Maintenance Costs

Micogen MG1-C1 Heat Recovery System Equipment Cost	$7,224
Heat Recovery System Installation Cost (Estimated At 75% Of Equipment Cost)	$5,418
Heat Recovery System Installed Cost	$12,642
Microturbine System Installed Cost (From Table 6.2)	$61,410
Total Installed Cost Of Option 2b	$74,052
Microturbine Annual Routine Maintenance	0.010 $/kWh
Heat Recovery System Annual Routine Maintenance	0.001 $/kWh
Microturbine Refurbishment (Every 5 Years)	$9,500
Compressor Refurbishment (Every 3 Years)	$3,000

6.5 Option 3 -- H_2S Removal / Combustion in Microturbine and Boiler

Option 3, shown in the figure below, would install both an H_2S removal system and a microturbine system with heat recovery. The operation of this option is equivalent to that of Option 2b except that it would allow excess biogas to be utilized by the boiler instead of being flared. At design conditions, 15,290 CF/day of raw biogas would be cleaned and combusted in the microturbine; 2,710 CF/day of excess raw biogas would be cleaned and combusted in the boiler.

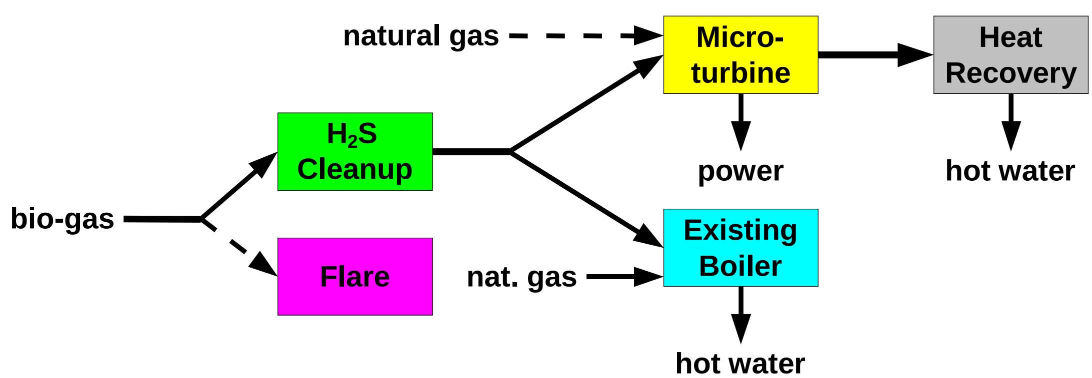


Table 6.5 contains the projected capital and maintenance costs for Option 3.

Table 6.5: Option 3 Capital and Maintenance Costs

Microturbine System Installed Cost (From Table 6.2)	$61,410
Heat Recovery System Installed Cost	$12,642
H_2S Removal System Installed Cost	$60,000
Total Installed Cost Of Option 2b	$134,052
H_2S Removal System, Annual Maintenance/Refurbishment	$9,000
Microturbine Annual Routine Maintenance	0.010 $/kWh
Heat Recovery System Annual Routine Maintenance	0.001 $/kWh
Microturbine Refurbishment (Every 5 Years)	$9,500
Compressor Refurbishment (Every 3 Years)	$3,000

6.6 Projected Technical Performance

Table 6.6 summarizes, on an annual basis, the technical performance of each proposed biogas utilization project option. The first section of Table 6.6 breaks down how each project would distribute the annual flow of biogas among various pieces of end-use equipment. The second section of Table 6.6 contains an annual energy balance for each project option. Finally, the bottom of Table 6.6 lists the overall cogeneration efficiency projected to be achieved by each project option. Although Options 1 and 3 would be the most energy efficient alternatives, the life cycle cost analysis contained in Section 7 is necessary to determine which option would have the greatest economic value.

Table 6.6: Projected Technical Performance

Option	0	1	2a	2b	3
Annual Disposition of Biogas					
Combusted in Boiler, MCF	0	6,439	0	0	1,137
Combusted in Microturbine, MCF	n/a	n/a	5,302	5,302	5,302
Combusted in Flare, MCF	6570	131	1,268	1,268	131
Total Biogas Available Annually, MCF	6,570	6,570	6,570	6,570	6,570
Annual Microturbine System Performance					
Net Electrical Energy Output, kWh	n/a	n/a	208,050	208,050	208,050
Waste Heat Recovered, MMBtu	n/a	n/a	0	1,670	1,670
Energy Balance, MMBtu/year					
Total Biogas Energy Available	3942	3942	3942	3942	3942
Boiler Heat Transferred to Hot Water	n/a	-2897	n/a	n/a	-512
Boiler Heat Rejected to Atmosphere	n/a	-966	n/a	n/a	-170
Turbine Electrical Energy Output (net)	n/a	n/a	-710	-710	-710
Electrical Energy to Compressor	n/a	n/a	-85	-85	-85
Turbine Heat Transferred to Hot Water	n/a	n/a	n/a	-1670	-1670
Turbine Heat Rejected to Atmosphere	n/a	n/a	-2386	-716	-716
Flare Energy Rejected to Atmosphere	-3942	-79	-761	-761	-79
Energy Balance Total	0	0	0	0	0
Total Energy Usefully Converted	0	2897	710	2380	2892
Total Energy Rejected to Atmosphere	3942	1045	3232	1562	1050
Overall Cogeneration Efficiency[g]	**0.0%**	**73.5%**	**18.0%**	**60.4%**	**73.4%**

[g] The overall cogeneration efficiency is the percentage of available biogas energy available that is either converted to electric power (net) or transferred to the plant's hot process water.

7.0 LIFE CYCLE COST ANALYSIS OF BIOGAS UTILIZATION OPTIONS

In the previous section, four investment alternatives (Options 1, 2a, 2b and 3) were proposed for utilizing biogas at the PHA wastewater treatment plant. Each alternative has a different capital cost and results in different types and amounts of energy cost savings. Furthermore, the magnitude and timing of maintenance and operating costs varies for each alternative. So, which of the four investments is expected to provide the greatest return? And how does this return compare to that of other investments available to PHA? This section presents a life cycle cost (LCC) analysis that helps to answer these questions by estimating the net present value (NPV) of each investment alternative.

Various cash flows, such as capital costs, maintenance costs and avoided energy costs, occur at different points throughout a project's life. For each of the four-biogas utilization project alternatives, the timing and magnitude of these cash flows were estimated. The cash flows were then discounted to their present values and summed to yield a single, net present value life cycle cost estimate for each project.

7.1 Economic Values Assumed for LCC Analysis

The method of LCC analysis chosen for this study estimated future costs and savings in current dollars and discounted them using a nominal discount rate, i.e. a discount rate that includes both the general inflation rate (the change in a dollar's purchasing power) and the time-value of money (a dollar's earning power). Table 7.1 lists the various economic values that were assumed for the LCC analysis, which set the economic life of each project option equal to ten years. Note that Section 7.4 contains a sensitivity analysis that discusses the effect of varying several key variables, including the general inflation rate, discount rate and energy price escalation rates.

Table 7.1: Economic Values Assumed for LCC Analysis

Annual No minal Discount Rate	8.0%
Annual General Inflation Rate	4.0%
First-Year Marginal Energy Utility Rates	
Natural Gas, $/MMBtu	7.58
Electrical Demand, $/kW-month	4.690
Electrical Energy, $/kWh	0.03728
Average Annual Nominal Escalation Rates for Delivered Energy Costs	
Natural Gas	4.0%
Electricity	3.3%

The annual rate of general inflation was assumed to be 4.0%. Historically, the escalation rate for construction and maintenance costs has not deviated substantially from the general inflation rate. Therefore, maintenance costs were assumed to escalate at the general inflation rate. On the other hand, history has also shown that energy prices, which are much more volatile, have deviated substantially from the general inflation rate[h] Therefore, the escalation rates for the prices of natural gas and electricity were considered separately.

As shown in Table A2.1 in Attachment 2, PHA's current marginal cost of electricity has the following two components.

- Electrical Demand: The utility measures, in kW, PHA's peak demand for electricity during a given billing month. Currently, the monthly marginal demand charge is $4.69 for each kW of peak demand.

- Electrical Energy: The utility measures, in kWh, how much electrical energy PHA consumes during a given billing month. Currently, the marginal energy charge is $0.03728 for each kWh of electrical energy consumed.

For the period 1998 to 2020, DOE's Energy Information Administration[i] projects that electricity prices for the industrial sector will decline, in real terms, at an average annual rate of –0.7%. Assuming a general inflation rate of 4.0%, this corresponds to a nominal annual escalation rate of 3.3%, which was applied in this analysis to both components of PHA's marginal electricity cost.

As shown in Attachment 1, PHA's current marginal cost of natural gas was calculated to be $7.58/MMBtu. In real terms, this cost was assumed to stay the same for the entire analysis period. Assuming a general inflation rate of 4.0%, this corresponds to a nominal annual escalation rate of 4.0%.

Table 7.2 lists the marginal rates for electricity and natural gas that were calculated for each year of the LCC analysis period.

[h] One advantage of using the current dollar method of LCC analysis was that it allowed energy prices to be escalated at rates different from the general rate of inflation.
[i] See Table A3 of the *Annual Energy Outlook 2000*. December 1999. DOE/EIA 0383.

Table 7.2: Utility Rates used for LCC Analysis

Year	Marginal Natural Gas Price, $/MCF	Marginal Electricity Prices	
		Demand, $/kW	Energy, $/kWh
1	7.58	4.690	0.037
2	7.88	4.845	0.039
3	8.20	5.005	0.040
4	8.53	5.170	0.041
5	8.87	5.340	0.042
6	9.22	5.517	0.044
7	9.59	5.699	0.045
8	9.97	5.887	0.047
9	10.37	6.081	0.048
10	10.79	6.282	0.050

The nominal annual discount rate was assumed to be 8.0% --twice that of the general inflation rate. Ideally, the discount rate should be equivalent to the PHA's minimum acceptable rate of return for investments of equivalent risk and duration. In every-day business activity, nominal discount rates are usually based on market interest rates, which include the investor's expectation of general inflation.

7.2 Life Cycle Costs

Tables 7.3 through 7.6 list the projected annual cash flows for each proposed biogas utilization project option. Below is a description of the columns in these tables.

Year

Each project alternative is assumed to have a ten-year life.

Capital and Salvage Costs

Installed capital costs are assigned to year one. This is due to the expectation that the design and construction period would be brief for all project options; avoided energy costs would follow the initial capital expenditure within a few months.

Cash flows that reflect a project's salvage value are assigned to year ten. However, for each of the options considered, the residual value was assumed to be equivalent to the disposal cost, i.e., the salvage value is assumed to be zero.

Annual Maintenance Costs

Cash flows in this column reflect routine maintenance costs that occur each year.

Refurbishment Costs

Cash flows in this column reflect equipment refurbishment costs that are required once every few years.

Avoided kWh Costs

Cash flows in this column reflect the portion of avoided electric utility costs that result from a reduced consumption of utility-provided electrical energy (kWh). The reduction is equal to the net amount of electrical energy that would be generated by the microturbine for the PHSTP.

Avoided kW Costs

Cash flows in this column reflect the portion of avoided electric utility costs that result from a reduced peak demand (kW) for utility-provided electricity. The total demand charge that is avoided in one year is calculated by summing the twelve monthly reductions in peak demand that are obtained by operating the microturbine. At design conditions, the microturbine would continuously generate 25 kW (net), resulting in a 25 kW reduction in monthly peak demand. However, in a given year there could be months during which the microturbine operates at part-load for a few hours, and months during which it would experience a complete outage. Therefore, for the purpose of calculating the annual avoided electricity demand costs, the following (conservative) assumptions were made.

For eight months each year, the microturbine would continuously generate 25 kW (net), reducing peak demand by 25 kW.

For brief periods during two months each year, the microturbine would be operated at part-load, resulting in a peak demand reduction of only 12.5 kW.

For a few days during two months each year, the microturbine would be taken out of service, resulting in no reduction in peak demand.

This analysis assumed that the electric utility would not charge PHA with a fee for the service of standing by to provide 25 kW of back-up power in the event the microturbine becomes unavailable. If assessed, such a fee could have a significant adverse impact on project economics.

Avoided Natural Gas Costs

Cash flows in this column reflect the avoided natural gas utility costs that result from a reduced consumption of utility-provided natural gas. Depending on the project option, these reductions result from fueling the boiler with biogas and/or heating process water with heat recovered from the microturbine.

Table 7.3: Annual Cash Flows for Option 1

	Capital &	Annual Maint.	Refurbish	Avoided kWh	Avoided kW	Avoided Nat.	Net Cash
Year	**Salvage Costs, $**	**Costs, $**	**Costs, $**	**Costs, $**	**Costs, $**	**Gas Costs, $**	**Flows, $**
1	-60,000	-9,000	0	0	0	27,453	-41,547
2	0	-9,360	0	0	0	28,551	19,191
3	0	-9,734	0	0	0	29,693	19,958
4	0	-10,124	0	0	0	30,880	20,757
5	0	-10,529	0	0	0	32,116	21,587
6	0	-10,950	0	0	0	33,400	22,450
7	0	-11,388	0	0	0	34,736	23,348
8	0	-11,843	0	0	0	36,126	24,282
9	0	-12,317	0	0	0	37,571	25,254
10	0	-12,810	0	0	0	39,074	26,264

Table 7.4: Annual Cash Flows for Option 2a

	Capital &	Annual Maint.	Refurbish	Avoided kWh	Avoided kW	Avoided Nat.	Net Cash
Year	**Salvage Costs, $**	**Costs, $**	**Costs, $**	**Costs, $**	**Costs, $**	**Gas Costs, $**	**Flows, $**
1	-61,410	-2,330		7,756	1,055	0	-54,929
2	0	-2,423		8,012	1,090	0	6,679
3	0	-2,520	-3,245	8,276	1,126	0	3,637
4	0	-2,621		8,550	1,163	0	7,092
5	0	-2,726	-3,510	8,832	1,202	0	3,798
6	0	-2,835	-11,558	9,123	1,241	0	-4,029
7	0	-2,948	-3,796	9,424	1,282	0	3,962
8	0	-3,066		9,735	1,325	0	7,993
9	0	-3,189	-4,106	10,056	1,368	0	4,130
10	0	-3,317		10,388	1,413	0	8,485

Table 7.5: Annual Cash Flows for Option 2b

	Capital &	Annual Maint.	Refurbish	Avoided kWh	Avoided kW	Avoided Nat.	Net Cash
Year	**Salvage Costs, $**	**Costs, $**	**Costs, $**	**Costs, $**	**Costs, $**	**Gas Costs, $**	**Flows, $**
1	-74,052	-2,563		7,756	1,055	15,824	-51,980
2	0	-2,666		8,012	1,090	16,457	22,894
3	0	-2,772	-3,245	8,276	1,126	17,115	20,501
4	0	-2,883		8,550	1,163	17,800	24,630
5	0	-2,999	-3,510	8,832	1,202	18,512	22,037
6	0	-3,118	-11,558	9,123	1,241	19,253	14,940
7	0	-3,243	-3,796	9,424	1,282	20,023	23,690
8	0	-3,373		9,735	1,325	20,824	28,510
9	0	-3,508	-4,106	10,056	1,368	21,656	25,468
10	0	-3,648		10,388	1,413	22,523	30,676

Table 7.6: Annual Cash Flows for Option 3

	Capital &	Annual Maint.	Refurbish	Avoided kWh	Avoided kW	Avoided Nat.	Net Cash
Year	**Salvage Costs, $**	**Costs, $**	**Costs, $**	**Costs, $**	**Costs, $**	**Gas Costs, $**	**Flows, $**
1	-134,052	-11,563		7,756	1,055	20,671	-116,133
2	0	-12,026		8,012	1,090	21,498	18,574
3	0	-12,507	-3,245	8,276	1,126	22,358	16,009
4	0	-13,007		8,550	1,163	23,252	19,958
5	0	-13,527	-3,510	8,832	1,202	24,182	17,178
6	0	-14,068	-11,558	9,123	1,241	25,149	9,887
7	0	-14,631	-3,796	9,424	1,282	26,155	18,435
8	0	-15,216		9,735	1,325	27,201	23,045
9	0	-15,825	-4,106	10,056	1,368	28,289	19,783
10	0	-16,458		10,388	1,413	29,421	24,765

7.3 Net Present Values

Figure 7.1 shows the net present values (NPV) of the cash flows that were listed for each proposed biogas utilization option in the previous section. The net present value is the difference, measured in today's dollars, between:

- the net return you would obtain from investing in the proposed project, and
- the net return you would obtain from investing the same cash flows in an alternative investment that has a return equal to your discount rate, which was assumed to be 8%.

Option 2a's strongly negative NPV indicates that PHA would be better off investing their money in an alternative 8% investment.

Option 3's near-zero NPV indicates that its rate of return is very close to 8%.

The strongly positive NPVs of Options 1 and 2b indicate that PHA would be better off investing their money in either of the proposed projects than in an alternative 8% investment.

Figure 7.1: Projected Net Present Values of Bio-gas Utilization Project Options

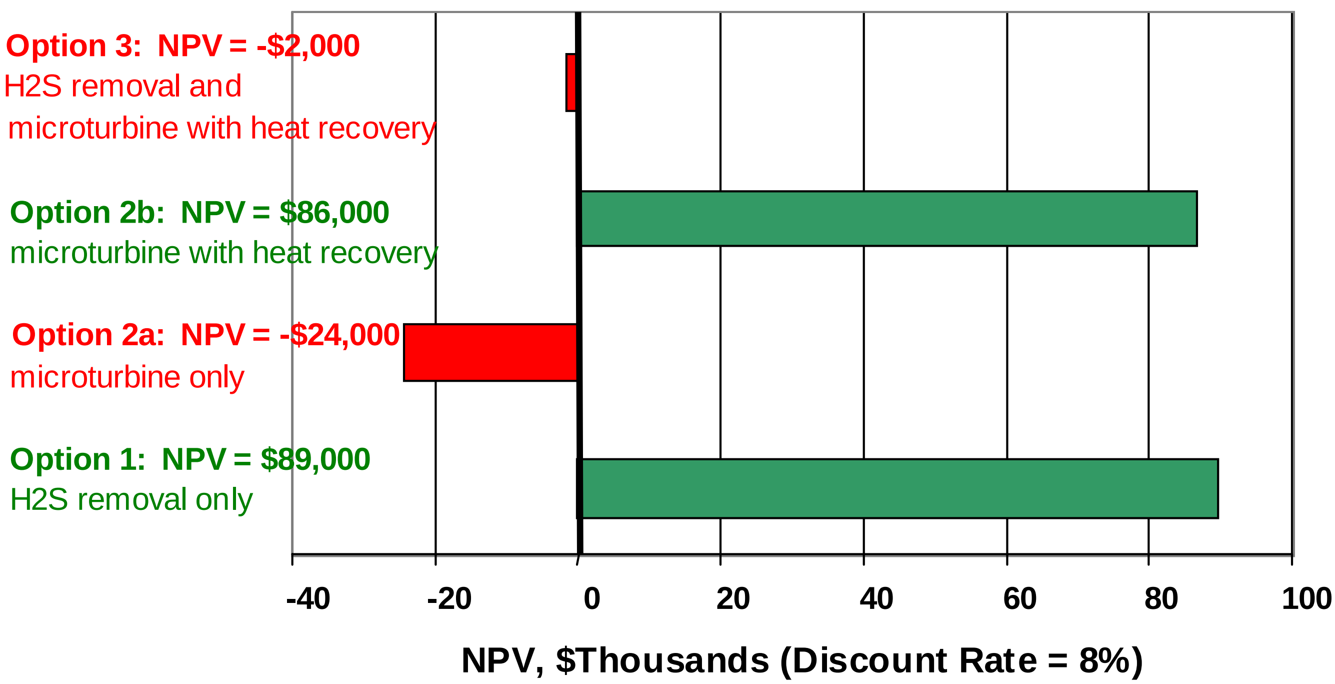


Table 7.7 lists the internal rates of return (IRR) for each project option. Although the IRR of Option 1 is 7% higher than that of Option 2b, one must remember that their NPVs show that the monetary difference between these options is relatively insignificant ($3,000).

Table 7.7: Projected Internal Rates of Return

Option 1: H_2S removal only	48%
Option 2a: microturbine only	-5%
Option 2b: microturbine with heat recovery	41%
Option 3: H_2S removal and microturbine with heat recovery	8%

7.4 Sensitivity Analyses

The above LCC analysis indicates that Options 1 and 2b would be the most economically attractive of the proposed biogas utilization projects. Therefore, these two options were selected for a sensitivity analysis to determine the effect of varying the assumed values of key economic and technical variables.

Sensitivity of Discount and Inflation Rates

Figures 7.2 and 7.3 show the effect on project NPV of varying the discount and inflation rates. The NPVs of Options 1 and 2 would remain positive for a wide range of credible discount rates.

Relative to the discount rate, the inflation rate would have a weak effect on NPV.

Figure 7.2: Sensitivity of Discount and Inflation Rates
Case 1: H_2S Removal; Combustion in Boiler

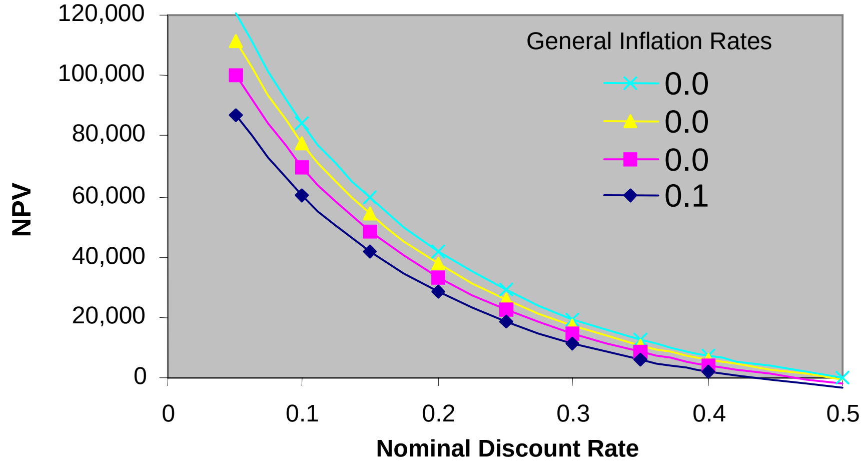
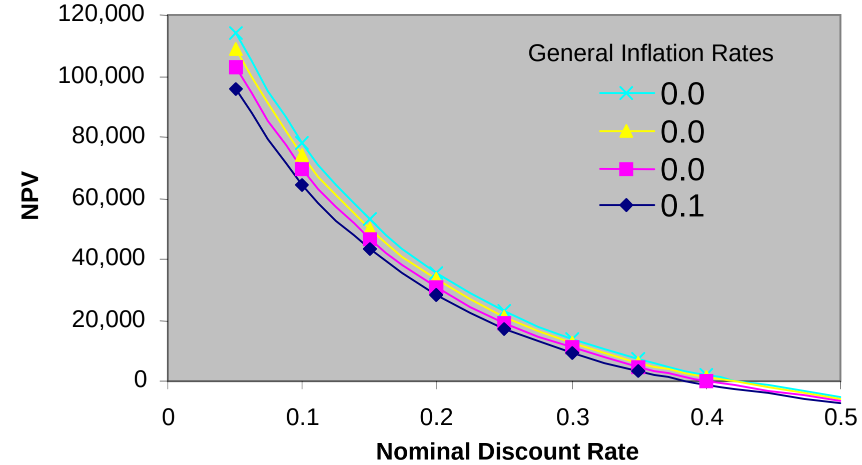


Figure 7.3: Sensitivity of Discount and Inflation Rates
Case 2b: Microturbine with Heat Recovery



Sensitivity of Capital and Maintenance Costs

Figures 7.4 and 7.5 show the effect on project NPV of varying capital and maintenance costs. The NPVs of Options 1 and 2b would remain positive over a wide range of credible capital and maintenance costs.

Figure 7.4: Sensitivity of Capital & Maintenance Costs
Case 1: H_2S Removal; Combustion in Boiler

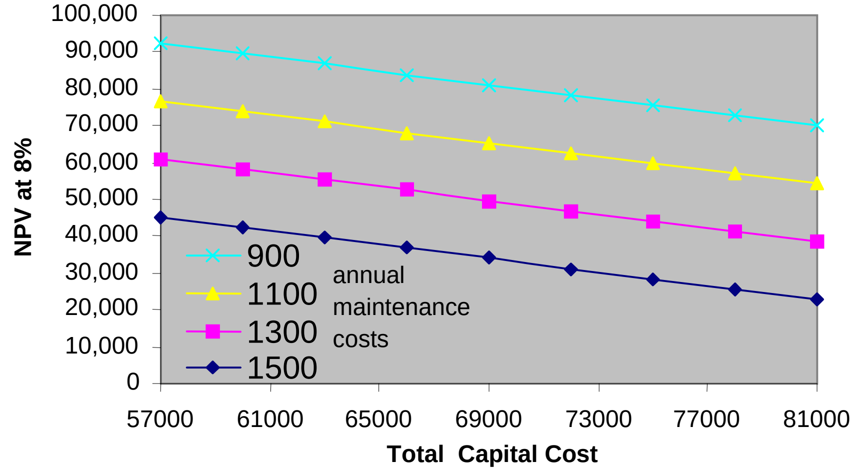
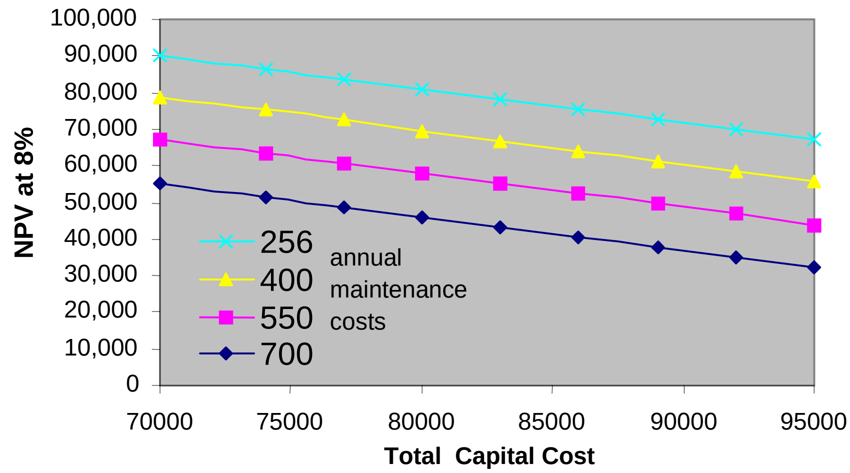


Figure 7.5: Sensitivity of Capital & Maintenance Costs
Case 2b: Microturbine with Heat Recovery



Sensitivity of Natural Gas and Electricity Escalation Rates

Figures 7.7 and 7.8 show the effect on project NPV of varying escalation rates for the utility costs of natural gas and electricity. The NPVs of Options 1 and 2b would remain positive over a wide range of credible escalation rates for both natural gas and electricity.

Figure 7.9 plots, over the same wide range of energy cost escalation rates, the difference between the NPVs that Options 1 and 2b would achieve. For combinations of escalation rates that fall above the x-axis (where the NPV delta is positive), Option 1 would be economically preferred. For combinations of energy cost escalation rates that fall below the x-axis (where the NPV delta is negative), Option 2b would be economically preferred. In general, higher natural gas costs favor Option 1 while higher electricity costs favor Option 2b.

Figure 7.7: Sensitivity of Energy Cost Escalation Rates
Case 1: H_2S Removal; Combustion in Boiler

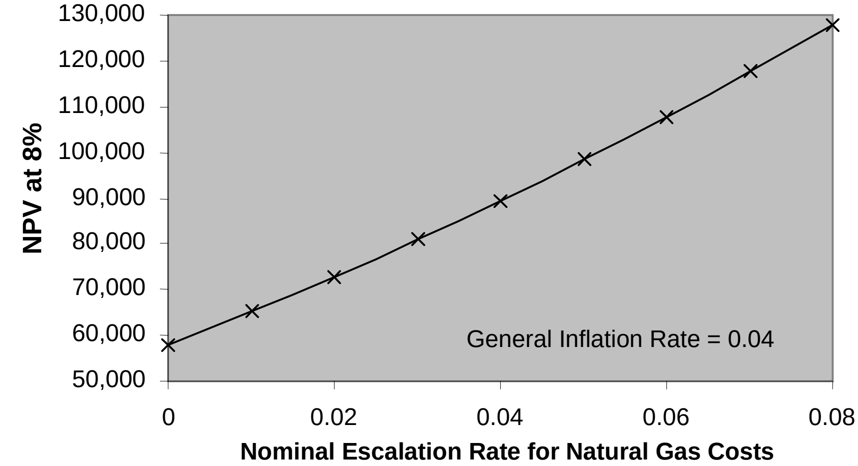


Figure 7.8: Sensitivity of Energy Cost
Case 2b: Microturbine with Heat

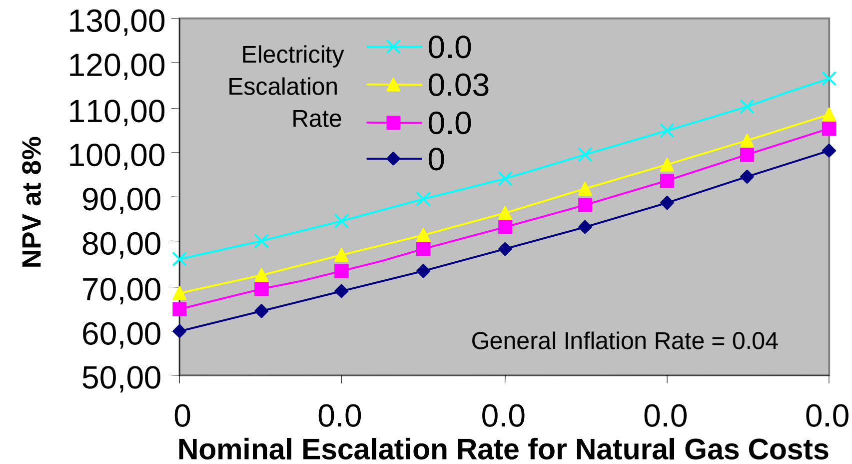
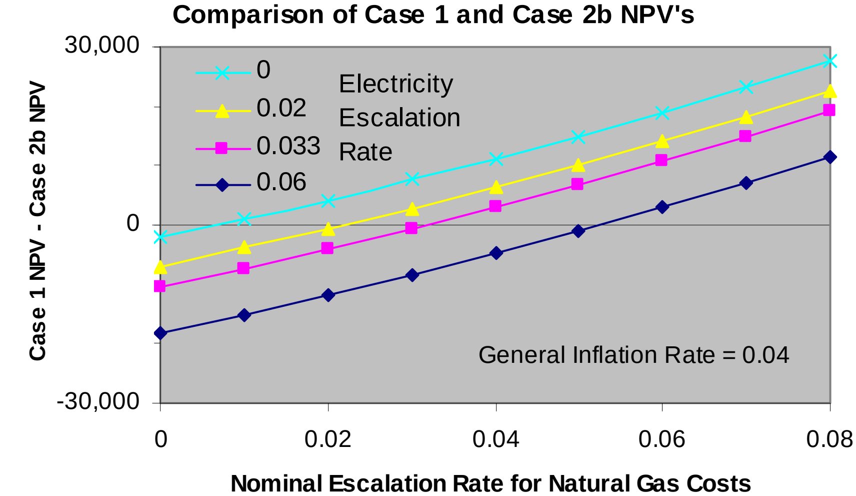


Figure 7.9: Sensitivity of Energy Cost Escalation Rates
Comparison of Case 1 and Case 2b NPV's



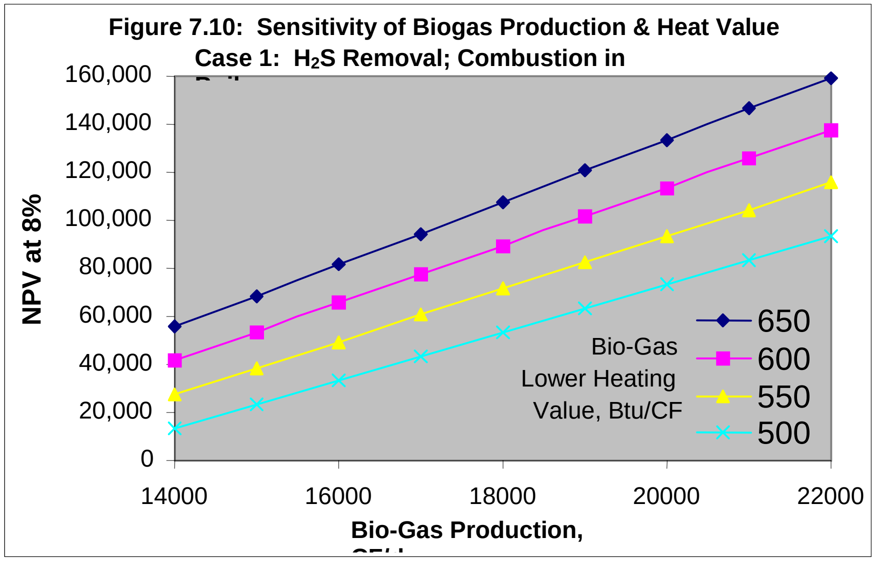
Sensitivity of Biogas Production Rate and Heating Value

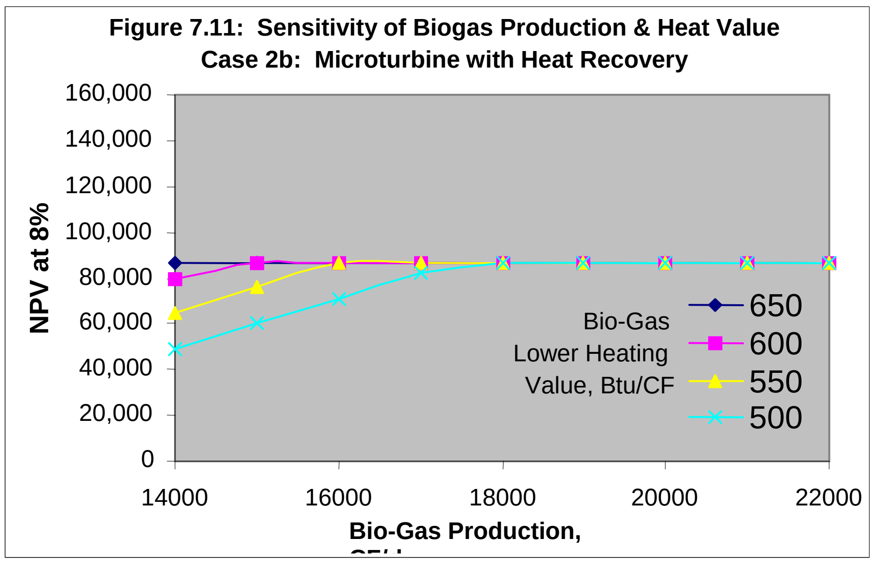
Figures 7.10 and 7.11 show the effect on project NPV of varying the biogas production rate and heating value. The NPVs of Options 1 and 2b would remain positive over a wide range of credible biogas production rates and heating values.

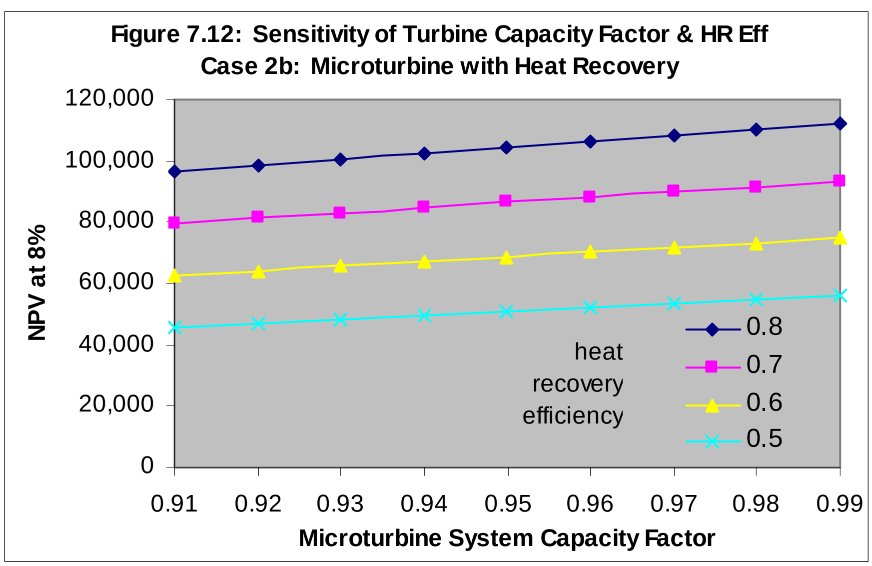
As the assumed value for biogas production is increased, the NPV of Option 2b is limited by the fact that only one microturbine is included in the system. If biogas production dramatically increased, more microturbines could be installed to utilize it.

Sensitivity of Microturbine Capacity Factor and Heat Recovery Efficiency

Figure 7.12 shows the effect on project NPV of varying the microturbine's capacity factor and the heat recovery system's "efficiency." The NPV of Option 2b would remain positive over a wide range of credible values for microturbine capacity factor and heat recovery system efficiency. (These technical parameters are not applicable to Option 1.)







8.0 CLIMATE CHANGE AND EMISSIONS

The current PHSTP emissions are comprised of greenhouse gas and criteria pollutants. Criteria pollutants, sulfur dioxide (SO_2) and nitrous oxide (NO_X) affect smog development, while greenhouse gases are cited as a major source of global warming.

Local Climate Change

Criteria pollutants cause ground level development of ozone; ground-level ozone is also known as smog. The 1990 Clean Air Act regulates both particulate and criteria pollutant emissions, which bring about ground level pollution. While the 1990 Act primarily addresses large stationary sources mobile sources, it also concerns a variety of sources and mitigation strategies. As ground level pollution levels worsen, pollution controls may be required for smaller stationary sources.

Global Climate Change

Concern for the potential effect of anthropogenic emissions upon global climate has led to the U.S. agreement in Kyoto to a 7% decrease in greenhouse gas (GHG) emission between 2008 and 2012, based on 1990 levels, which must still be ratified by the U.S. Senate[26]. Carbon and other GHG emissions are not yet regulated; the most populous carbon compounds in U.S. emissions are carbon dioxide, CO_2, and methane, CH_4. Carbon dioxide is the most prevalent GHG and has a considerably longer lifetime than methane. The compounds exist in the atmosphere for 50-200 years and 12 years, respectively. However, methane emissions are of great concern because it has 21 times the ability of carbon dioxide to trap heat in the atmosphere. Furthermore, it is possible to accurately measure carbon dioxide emissions within 3-5% because sources of carbon dioxide are easily isolated[7, 14].

However, accurate measurement of methane source emissions is not easily achieved, although they are believed to account for 10% of U.S. GHG emissions[7, 19]. Most methane is emitted accidentally or occurs naturally as a byproduct of farming and therefore is not easily measured. About 95% of the methane in the U.S. is emitted in large quantities from landfills, livestock management, natural gas systems, coal mining, and manure management. Smaller sources include rice farming, wastewater treatment, and biomass burning, all of which account for less than 1.5% of the total methane emitted nationally[14,19].

GHG Emissions and Reductions Data for U.S.

The Energy Policy Act of 1992 requires the Energy Information Administration (EIA) to prepare a report on aggregate U.S. national emissions of greenhouses gases for the period 1987-1990, with annual updates thereafter[8]. The EIA report presents estimates of U.S. anthropogenic emissions of carbon dioxide, methane, nitrous oxide, halocarbons and criteria pollutants. Industrial wastewater treatment is not addressed in this survey because it is believed that methane emissions from industrial wastewater treatment are a byproduct of the method used to treat wastewater. Due to limited data available regarding wastewater treatment methods or the amount of water treated, it is not possible to present estimates of methane emissions from industrial wastewater[9].

The EIA has a voluntary program that records the results of voluntary measures taken to reduce, avoid, or sequester greenhouse gas emissions (Section 1605(b) of the Energy Policy Act of 1992). In 1994, the first year of the program, 108 facilities reported aggregate reductions of 74 million tons carbon equivalent (mtce). In 1998, 187 facilities reported 212 mtce[10]. Several participants have perceived EIA's Voluntary Reporting Program as a method to achieving regulatory credit[10]. However, this program is designed to be a registry of reduction levels achieved, not provide and arena for emissions trading or to provide credit for early reductions.

One wastewater treatment entity, the City of Fairfield Wastewater Division in Ohio, reported reduction of emissions during 1998. The method of reducing greenhouse emissions for this facility was to recover biogas for energy use, thus reducing carbon dioxide emissions by 631 metric tce, and no changes in methane emissions[11].

GHG Emissions and Reductions in Pennsylvania

In 1990, Pennsylvania participated in the EPA's State and Local Outreach Program to create and inventory of GHG emissions and reduction action plans[12]. Tabulated data of carbon dioxide and methane emissions by sector in Pennsylvania are presented in Table 8.1. According to this report, major contributors to methane emissions were landfills (51%), coal mining and natural gas production (38%), domesticated animals (10%) and manure management (1%)[13].

Table 8.1 - Selected Pennsylvania Greenhouse Gas Emissions for 1990

Sector	Carbon Dioxide (mmtce)	Methane (mmtce)	Nitrous Oxide (mmtce)	Total Carbon GHG emissions (mmtce)
Energy Use	65.5	2.8	-	68.3
Waste	-	3.6	-	3.6
Agriculture	-	0.8	2.5	3.3
Industry	0.7	-	-	0.7
Land Use	0.1	-	-	0.1
TOTAL	**66.3**	**7.2**	**2.5**	**76.0**

A dash (-) indicates that emissions of the gas from the sector were zero, insignificant, or not reported.
Energy use includes residential, industrial, transportation, utility, and commercial applications.

Pleasant Hills Case Overview

Although wastewater treatment is not identified as a significant source of methane, opportunities to mitigate methane should be not overlooked if the cost of reduction is affordable. There are also local benefits to be gained from lowering GHG emission levels. To date, Pleasant Hills Authority has estimated that methane comprises 68% of the fugitive gas from their sewage treatment plant that treats wastewater for approximately 12,000 households for the Pleasant Hills borough of Pittsburgh, PA. The potential for biogas collection will be quantified and analyzed to determine the feasible level of GHG mitigation and resources for energy production application.

This preliminary case study is the result of a feasibility team investigation of alternatives to reduce GHG emissions at the Pleasant Hills wastewater treatment plant. The benefits of Pleasant Hills Authority participation in a pilot GHG reduction project with NETL are two-fold. The Authority obtains retrofit technology that may result in economic gain and serve as a prototype for other such projects for municipal sewage treatment plants across the country. Retrofitting the current process to collect methane may collect a sufficient amount of gas for power generation, so that the facility may provide energy for in-house use, or sale to the utility distribution. Ancillary benefits from collecting methane gas include a decrease in "stink" from hydrogen sulfide and decreases in carbon dioxide emissions[19] as well as a decrease in criteria pollutant emission[4].

Currently, nitrous oxide, methane, and carbon dioxide are the main constituents of GHG emissions from the Pleasant Hills facility, as will be discussed in the Section 9.0, "Emissions from Alternate Options". Many methods of decreasing methane emissions similarly decrease carbon dioxide emissions[19]. Nitrous oxide is of particular concern; although it comprises an insignificant percentage of wastewater treatment emissions, it has 300 times the global warming potential of carbon dioxide[8]. As mentioned before, hydrogen sulfide is not a greenhouse gas, but may play a future role in health concerns, since sulfur oxides, criteria pollutants regulated by the Clean Air Act, result from combustion of hydrogen sulfide. Additionally, analysis of hydrogen sulfide concentrations in sewage air have reported in literature of correlation between hydrogen sulfide concentration and unpleasant, "rotten egg", odor in the air surrounding a treatment facility[20]. Determined to be an irritant to mucous membranes and a potential carcinogen by the EPA National Center for Environmental Assessment, hydrogen sulfide is being considered for listing as a hazardous air pollutant (HAP) as defined under the Clean Air Act[11].

9.0 EMISSIONS FROM ALTERNATE PROCESS OPTIONS

The following is an estimation of potential emissions that may be expected from the installation of each proposed case as described in Section 6. Estimations of current pollutant emissions, Case 0, are summarized from the existing system involving flared biogas and natural gas boiler use, then compared to potential emissions from Cases 1, 2a, 2b, and 3 to determine potential change in emissions. Estimates are based on current digester gas composition and microturbine operations data. Combustion coefficients and calculations are adapted from Steam, its generation and use, 40th ed., by Babcock and Wilcox Company[1].

In order to estimate the potential for GHG emission reduction, emissions levels are converted to their metric ton carbon equivalent (mtce) by a factor of their relative global warming potential. After determining their carbon equivalence, their potential economic value may be determined by a factor of the cost of avoided health and environmental damages[21]; approximately $14 per mtce. This value is well below the EIA's estimated tax of $348 per mtce required to achieve Kyoto budgets in 2010 without global GHG credit trading[4]. Global warming potential factors are a means of determining the ability of GHG to trap heat in the atmosphere. It has been determined that the global warming potentials of methane, nitrous oxide and nitrogen oxide are 21, 310 and 290 times that of carbon dioxide[18, 17], respectively.

Of additional importance is criteria pollutant reduction through technology installation. Sulfur oxide (SO_X), and nitrous oxide (NO_X) emissions are regulated by the Clean Air Act. Criteria pollutant reductions are valuable, since they may be traded and sold as a commodity; trading options will be discussed further in Section 9.3, "Determining Potential Economic Value of Emissions Reduction".

Overview of Available Biogas and Natural Gas

Biogas Composition

Current estimates of digester biogas flow, 18,000 cfd, heat value, 600 BTU/cf, and measured composition (Table 3.1) for the PHSTP were used to analyze greenhouse gas emissions under current conditions and possible alternatives for reducing emissions.

Note that oxygen and nitrogen are present at the same ratio as that for air, which suggests that some air leaked into the sample. Using current biogas data, the molar composition of 100 lbs of biogas to be used in combustion may be stoichiometrically determined, and consequently used to determine emissions. The molar composition, x_N, where N is N component, is used to determine the amount of oxygen and air used for combustion, as well as combustion products.

Table 9.1 presents the biogas weight and density data used to estimate emission composition.

Table 9.1 - Stoichiometric Composition of Biogas.

Compound N	Mole Fraction	MW_N (lb/mole)	Weight (lbs)	Mass Fraction	Composition, x_N (Moles/100 lbs)	Density^{-1} (cf/lb)	Volume, v_N (cf/100 lbs)
O_2	0.96	32	32.83	1.23	0.04	11.82	14.52
N_2	2.95	28	82.53	3.29	0.12	7234.07	23795.27
CH_4	65.28	16	1044.45	41.63	2.60	23.55	980.42
CO_2	30.36	44	1335.79	53.24	1.21	8.55	455.09
H_2S	0.45	34	15.43	0.61	0.02	10.98	6.75
TOTAL			2509.02	100.00	3.99		25252.04

Since methane, CH_4, and hydrogen sulfide, H_2S, are the only combustible elements in the available biogas, the air (moles) theoretically required for the complete combustion of fuel is:

$$x^1_{Air} = 17.235 x_{CH_4} + 16.093 x_{H_2S} \qquad (1)$$

where
x^1_{Air} = Molar amount of air to combust 100 lbs of digester gas = 44.95 moles
x_{CH4} = Molar amount of methane in 100 lbs of digester gas = 2.60 moles
x_{H2S} = Molar amount of hydrogen sulfide in 100 lbs of digester gas = 0.02 moles
The combustion coefficients, 17.235 and 16.093, and other coefficients throughout the following equations are determined from Steam, its generation and use, 40th ed., by Babcock and Wilcox Company[1].

The theoretical amount of oxygen is determined similarly:

$$x^1_{O_2} = 3.989 x_{CH_4} + 1.41 x_{H_2S} \qquad (2)$$

where
x^1_{O2} = Molar amount of oxygen to combust 100 lbs of biogas = 10.40 moles
x_{CH4} = Molar amount of methane in 100 lbs of biogas = 2.60 moles
x_{H2S} = Molar amount of hydrogen sulfide in 100 lbs of biogas = 0.02 moles

Natural Gas Composition

Average natural gas composition in western Pennsylvania[24] is shown in Table 9.2. Lower heating value, LHV, of available natural gas is assumed to be 22379 Btu/lb.

Table 9.2 - Average Natural Gas Composition, Western PA

Compound Y	Mole Fraction	MW_Y (lb/mole)	Weight (lbs)	Mass Fraction	Composition, x_y (Mols/100 lbs)	$Density^{-1}$ (cf/lb)	Volume, v_Y (cf/100 lbs)
CH_4	83.4	16	1334.4	72.89	4.56	23.55	107.28
C_2H_6	15.8	30	474	25.89	0.86	1.10	0.95
N_2	0.8	28	22.4	1.22	0.04	7234.07	316.11
TOTAL	100						424.33

Methane and ethane, C_2H_6, are the combustible elements in natural gas, so the air and oxygen necessary for combustion may be determined following the same method to determine air and oxygen levels for biogas combustion:

$$x^1_{Air} = 17.235 x_{CH_4} + 16.092 x_{C_2H_6} \qquad (3)$$

where
x^1_{Air} = Molar amount of air to combust 100 lbs of natural gas = 92.40 moles
x_{CH4} = Molar amount of methane in 100 lbs of natural gas = 4.56 moles
x_{H2S} = Molar amount of hydrogen sulfide in 100 lbs of natural gas = 0.86 moles

The theoretical amount of oxygen is determined similarly:

$$x^1_{O_2} = 3.989 x_{CH_4} + 3.724 x_{H_2S} \qquad (4)$$

where
x^1_{O2} = Molar amount of oxygen to combust 100 lbs of biogas = 21.39 moles
x_{CH4} = Molar amount of methane in 100 lbs of biogas = 4.56 moles
x_{C2H6} = Molar amount of hydrogen sulfide in 100 lbs of biogas = 0.86 moles

Emissions from Case 0: Status Quo

Current estimation of carbon emission from wastewater treatment at the Pleasant Hills Authority site is based on biogas and natural gas data summarized in Tables 5 and 6, respectively. Offsite emissions from electricity generation are summarized in Table 7. The estimated electricity emissions are based on average daily electricity demand for the period of January 20, 1999 – February 26, 2000. To date, natural gas is burned in a boiler and biogas is flared on site. The following calculations assume that both the flare is burning continuously, 24 hours daily, and 365 days a year, and the boiler is operating at 80% efficiency. Flare combustion product calculations do not account for turbulence in the air surrounding the flame or reaction rates between the fuel components and surrounding air. Furthermore, it is assumed that the air is supplied in a 1:1 fuel to air ratio, and has no volatile components that will obstruct normal combustion.

Determining Flare Emissions

Having determined the amount of air and oxygen used for combustion per 100 lbs of biogas, the composition of the exhaust gas may be determined as follows, where x'_Y is the molar amount of compound Y generated from combusting 100 lbs of biogas, and xa_Y is the amount of compound Y present in air. The results of equations 5 – 9 are tabulated in Table 9.3.

$$x'_{CO_2} = x_{CH_4} + x_{CO_2} \qquad (5)$$

$$x'_{SO_2} = x_{H_2S} \qquad (6)$$

Due to flaring conditions, it is assumed that some thermal nitrous oxides, NO_X, are formed. Diatomic nitrogen, N_2, is a fairly stable compound and will not react with oxygen directly. However, in some flames, nitrous oxides may be formed at temperatures in excess of 1000 K (1340.6°F)[1,15] according to the radical-driven Zeldovitch mechanism:

$$N_2 + O \rightarrow N + NO$$
$$N_2 + O_2 \rightarrow N_2O + O$$
$$N_2O + O = NO + NO$$

Since methane, the most populous compound in the gas, has an adiabatic flame temperature of 2236 K (3565.4°F)[15], it is assumed that the gas is flared at temperatures high enough to generate NO_X, which is assumed to be NO_2:

$$x'_{NO_X} = x_{N_2} \qquad (7)$$

The weight of the exhaust constituents may be determined by multiplying the molar amount by the molecular weight of the compound:

$$w_Y = x'_Y \times MW_Y \qquad (8)$$

where
w_Y = Pound output of combustion product, Y, per 100 pounds of fuel input [=] lbs/100 lbs
x'_Y = Molar output of compound, Y, per 100 pounds of fuel input [=] moles/100 lbs
MW_Y = Molecular weight of compound Y (table 1) [=] lbs N/mole

The daily exhaust output at Pleasant Hills is estimated by scaling the calculated exhaust output, w_Y:

$$eo_Y = w_Y \times F \times v_{TOT} \qquad (9)$$

where
eo_Y = Daily exhaust output of component Y [=] lbs/day
w_Y= Pound output of combustion product, Y, per 100 pounds of fuel input [=] lbs/100 lbs
F = Biogas flowrate = 18,000 cf/d
v_{TOT} = Total volume of biogas = 25,252 ft^3/100 lbs

Table 9.3 - Flare emissions composition estimates and carbon equivalent output after flaring.

Compound, Y	**Composition, x_Y (mols/100 lbs)**	**Exhaust Output, w_Y (lbs Output/100 lbs Fuel)**	**Daily Exhaust Output, eoY (lbs/day)**	**Annual Carbon Equivalent Output (mtce/year)**	**Annual Criteria Pollutant Output (tonne Y/year)**
CO_2	3.81	167.72	119.66	5.4	-
SO_X	0.02	1.16	0.83	-	0.14
NO_X	0.06	2.70	1.93	-	0.64
TOTAL				**5.4**	**0.78**

Determining Boiler Emissions

Boiler emissions are estimated similarly to the flare emissions, adjusting for an assumed 80% efficiency. It is also assumed that the boiler operates at 15% excess air (3% O_2); the typical boiler operates at 10-20% excess air (2-4% O_2). Further assumptions, based on typical boiler operations: 95% of sulfur is emitted as SO_2, 1-5% as SO_3, 80% conversion of carbon[j].

Since the boiler operates at a 115% fuel to air ratio, the actual amounts of air (Eq. 3) and oxygen (Eq. 4) needed for combustion may be determined as follows:

$$x^1_{Air} = \left(\frac{115}{100}\right) x_{Air} \qquad (10)$$

$$x^2_{O_2} = \left(\frac{115}{100}\right) x_{O_2} \qquad (11)$$

Where
x^1_{Air} = Molar amount of air needed for 115% fuel to air combustion = 106.26 moles
x_{Air} = Molar amount of air to combust 100 lbs of natural gas = 92.40 moles
x^2_{O2} = Molar amount of oxygen needed for 115% fuel to air combustion = 24.60 moles
x^1_{O2} = Molar amount of oxygen needed to combust 100 lbs of digester gas = 21.39 moles
The composition of boiler gas emissions is determined using the same method used to determine flare exhaust.

[j] Cleaver Brooks: Emissions. http://www.cleaver-brooks.com/Emissions1.html

However, it is necessary to consider the assumed efficiency of the equipment and excess air in the exhaust due to the 115% fuel to air combustion. No sulfur oxide emissions are expected because there is not sulfur component in natural gas; carbon dioxide and nitrogen oxide emissions are calculated as follows:

$$x_{CO_2} = 0.8\left(x_{CH_4} + x_{C_2H_6}\right) \qquad (12)$$

$$x_{NO_2} = 0.4x_{N_2} \quad (13)$$

Where
x_{CO_2} = Molar emission of carbon dioxide from boiler = 5.03 moles
x_{NO_2} = Molar emissions of nitrogen oxide from boiler = 0.02 moles

Greenhouse and criteria pollutant emissions are calculated by Eq. 8 and 9, where the average natural gas flowrate, F, is 3.4 mcfd, based on average boiler flowrate, and V_{TOT}, total volume of natural gas, is 424 cf/100lbs. Case 0 emissions data for natural gas combustion in the boiler are summarized in Table 9.4.

Table 9.4 - Boiler Emissions, Case 0.

Compound, Y	Composition, x_Y (mols/100 lbs)	Exhaust Output, w_Y (lbs Output/100 lbs Fuel)	Daily Exhaust Output, eo_Y (lbs/day)	Annual Carbon Equivalent Output (mtce/year)	Annual Criteria Pollutant Output (tonne Y/year)
CO_2	5.03	221.11	1771620.65	79980.4	-
NO_X	0.03	1.61	12884.51	-	2132.81
TOTAL				**79980.4**	**2132.81**

Determining Emissions from Electricity Use, Case 0

According to Pleasant Hills Authority billing records from January 20, 1999 – February 26, 2000, the average daily electricity use was 8434 kWh. The plant that supplies electricity to the Pleasant Hills Authority facility is Allegheny Power's Mitchell plant. Power generation at the Mitchell plant produces, on average, 3.65 lbs NO_X, 1.33 lbs SO_2, and 2039.50 lbs CO_2 per MWh, based on 1999 data.

Using plant emissions and Pleasant Hills electricity use data, it may be determined that annual offsite greenhouse gas and criteria pollutant emissions from electricity use are 776.55 mtce and 6.96 tonnes, respectively.

Overall Emissions

As may be determined from Tables 9.4, 9.5, and estimated offsite power generation emissions, the Pleasant Hills Authority facility currently emits 0.39 x 10^6 mtce and 10.36 x 10^3 tonnes of criteria pollutant annually from flare and boiler operations.

Emissions from Case 1: Hydrogen Sulfide Removal Only

In Case 1, the available biogas is stripped of hydrogen sulfide, H_2S, and burned in the existing boiler to heat water. Expected biogas production is 3942 MMBtu/year. It is assumed that the boiler is used for 90% of the biogas utilization operation, since the boiler may require maintenance. The remaining 10% of the operating year, the biogas is flared. While some manufacturers and end users[k] claim 100% treatment efficiency, a conservative estimate of 95% treatment efficiency is assumed. The same boiler assumptions are made as for Case 0.

Analysis of Biogas After Hydrogen Sulfide Removal

To determine the change in gas composition, available gas data was normalized for the case that the original hydrogen sulfide content is reduced by 98%. As may be seen in Table 9.6, hydrogen sulfide content is negligible after the stripping process. The air and oxygen necessary to combust the treated gas may be determined using Eq. 3-4.

Table 9.6 - Biogas Composition after Hydrogen Sulfide Stripping

Compound Y	Mole Fraction	MW_Y (lb/mole)	Weight (lbs)	Mass Fraction	Composition, x_y (Mols/100 lbs)	$Density^{-1}$ (cf/lb)	Volume, v_Y (cf/100 lbs)
O_2	0.97	32	30.93	1.23	0.04	11.82	14.59
N_2	2.96	28	82.82	3.31	0.12	7234.07	23921.14
CH_4	65.58	16	1049.25	41.89	2.62	23.55	986.61
CO_2	30.48	44	1340.95	53.54	1.22	8.55	457.63
H_2S	0.02	34	0.77	0.03	0.00	2.26	0.00
TOTAL	100						25380.32

[k] Reference Library Peroxide Applications: Municipal Wastewater. H_2S Control: Scrubbing Hydrogen Sulfide with Hydrogen Peroxide. <http://www.h2o2.com/applications/municipalwastewater/scrubbing.html>

Biogas Emissions

Emissions from Boiler, Case 1

Boiler emissions in this case, Table 9.7, are determined in the same manner as boiler emissions in Case 0, while accounting for 90% utilization of the available biogas. No sulfur oxide emissions are expected, since there is no available hydrogen sulfide after stripping. Biogas flowrate, *F*, is 17,639 cfd and total volume of biogas is 25384.8 cf/100 lbs.

Table 9.7 - Boiler Emissions, Case 1

Compound, Y	Composition, x_Y (mols/100 lbs)	Exhaust Output, w_Y (lbs Output/100 lbs Fuel)	Daily Exhaust Output, eo_Y (lbs/day)	Annual Carbon Equivalent Output (mtce/year)	Annual Criteria Pollutant Output (tonne Y/year)
CO_2	2.76	121.49	86.16	3.89	-
NO_X	0.04	1.95	1.39	-	0.23
TOTAL				**3.89**	**0.23**

Emissions from Flare, Case 1

Flare emissions in Case 1, Table 9.8, are also determined according to the method used for Case 0. It is assumed that only 10% of the annual biogas supply is combusted in the flare, since the boiler operation will utilize 90% of available biogas.

Table 9.8 - Flare Emissions, Case 1.

Compound, Y	Composition, x_Y (mols/100 lbs)	Exhaust Output, w_Y (lbs Output/100 lbs Fuel)	Daily Exhaust Output, eo_Y (lbs/day)	Annual Carbon Equivalent Output (mtce/year)	Annual Criteria Pollutant Output (tonne Y/year)
CO_2	0.38	16.87	11.97	0.54	-
NO_X	0.01	0.27	0.19	-	0.03
TOTAL				**0.54**	**0.03**

Natural Gas Emissions

Avoided Natural Gas Emissions, Case 1

Just as there is an economic benefit to avoided natural gas use, there is an environmental benefit of avoided greenhouse gas and criteria pollutant emissions (Table 9.8). Based on estimated annual natural gas savings of \$27,453, heating value of 22,379 BTU/lb., and natural gas costs of \$7.58/MMBTU, it can be determined that 161,838 lbs./year of natural gas use is avoided. Assuming that this amount of natural gas would otherwise be used in the boiler for 80% of the plant operating hours, the avoided emissions may be determined using Eq. 8, 9, 12, and 13, assuming a fuel flow rate, *F*, of 161,838 lbs/year in Eq. 8.

Table 9.9 - Avoided Natural Gas Emissions, Case 1.

Compound, Y	**Composition, x_Y (mols/100 lbs)**	**Exhaust Output, w_Y (lbs Output/100 lbs Fuel)**	**Daily Exhaust Output, eo_Y (lbs/day)**	**Annual Carbon Equivalent Output (mtce/year)**	**Annual Criteria Pollutant Output (tonne Y/year)**
CO_2	5.03	221.11	98036.37	4425.88	-
NO_X	0.03	1.61	713.00	-	118.02
TOTAL				4425.88	118.02

Net Natural Gas Emissions

The overall natural gas emission from the system may be determined as the difference between the base case, Case 0, natural gas emissions, and Case 1 natural gas emissions. Therefore, Case 1 emits 75,554.52 mtce and 2014.8 tonnes of criteria pollutants annually from natural gas use.

Offsite Electricity Production Emissions, Case 1

The Pleasant Hills Authority will be using the same amount of off-site generated electricity as in Case 0. Therefore, the emissions from electricity use will be the same as in Case 0.

Total Overall Emissions, Case 1

Net emissions from the PHSTP may be determined after considering the emissions resulting from both the utilization of biogas and avoided emissions from not using natural gas in the boiler, as well as offsite electricity generation emissions. As may be determined from Tables 9.8 and 9.9, biogas combustion emits a total of 4.43 mtce, and 0.26 tonnes of NO_X annually. Including net natural gas and offsite electricity generation emissions, overall greenhouse gas emissions are 76,335.41 mtce/year and overall criteria pollutant emissions are 2022 tonnes/year.

Emissions from Case 2a: Microturbine without Heat Recovery

As explained in Section 6.3, Case 2a projects the results of burning biogas in a microturbine without heat recovery. Excess biogas is flared. Microturbine emissions are based upon emissions data for similar composition landfill gas flaring by Capstone[4]. More accurate emissions data may be collected by measuring emissions from microturbine test runs with gas of a similar composition to the Pleasant Hills biogas.

Microturbine Emissions, Case 2a

It is assumed that microturbine emissions from biogas will be similar to those for landfill gas. Normalized emissions data from three Puente Hills Landfill samples is tabulated in Table 9.10 and used to estimate potential emissions from microturbine use to burn biogas.

Table 9.10 - Microturbine Emissions, Case 2a.

Combustion Product	Landfill Emissions, Normalized % Output	Estimated Biogas Emissions, lb/100 lbs Output	Estimated Biogas GHG Output, mtce/year	Estimated Biogas Criteria Pollutant Output, tonnes/year
CO_2	2.82	4.25	4.6	-
SO_2	0.00	0.00	-	-
SO_3	0.00	0.00	-	-
NO_2	6.00×10^{-5}	0.00	-	-
N_2	79.12	75.93	-	-
O_2	18.06	19.81	-	-
TOTAL	**100.00**	**100.00**	**4.6**	**-**

As may be seen in Table 9.10, there are no criteria pollutant emissions. The negligible amount of NO_X emissions is inherent in Capstone's microturbine design, while the lack of SO_X emissions may be a result of little or no sulfur content in the landfill gas burned. It is probable that there will be some SO_X emissions from biogas burning in the microturbine, since there is available H_2S in the biogas.

Biogas Emissions

Flare Emissions, Case 2a

Emissions from the flare (Table 9.11) in Case 2a are determined using Eq. 5-9, where biogas flowrate, *F*, is 3474 cfd.

Table 9.11 - Flare Emissions, Case 2a.

Compound, Y	Composition, x_Y (mols/100 lbs)	Exhaust Output, w_Y (lbs Output/100 lbs Fuel)	Daily Exhaust Output, eo_Y (lbs/day)	Annual Carbon Equivalent Output (mtce/year)	Annual Criteria Pollutant Output (tonne Y/year)
CO_2	3.81	167.72	28.14	1.27	-
SO_X	0.02	1.16	0.19	-	0.03
NO_X	0.12	5.40	0.91	-	0.15
TOTAL				**1.27**	**0.18**

Natural Gas Emissions

Boiler Emissions, Case 2a

Since Case 2a uses the boiler in the system as in Case 0, natural gas emissions from the boiler will be the same as for Case 0 (Table 9.5).

Offsite Electricity Production Emissions, Case 2a

Avoided Emissions from Avoided Electricity Use, Case 2a

Use of a microturbine results in approximately 208,047 kWh of avoided electricity. Using Mitchell plant emissions data, annual avoided greenhouse gas and criteria pollutant emissions may be estimated to be 52.48 mtce and 0.47 tonnes, respectively.

Overall Emissions, Case 2a

As may be determined from the net biogas, natural gas and electricity emissions, the Pleasant Hills Authority facility would emit 80710.37 mtce greenhouse gases and 2139.45 tonnes of criteria pollutant annually if they decided to undertake Case 2a, after considering the avoided emissions due to lower electricity demand.

Emissions from Case 2b: Microturbine with Heat Recovery

Case 2b allows for use of a microturbine with the added benefit of heat recovery to aid the process and cut natural gas demand. As in Case 2a, available biogas is burned in turbine to produce power, while excess biogas is flared. Microturbine exhaust heat is recovered to heat water.

Biogas and Natural Gas Emissions, Case 2b

It is assumed that microturbine and flare emissions are the same as for case 2a (Tables 9.10 and 9.11). However, it is expected that there will be avoided emissions through $15,824/year, or 93,284 lbs/year of avoided natural gas use (Table 9.12).

Table 9.12 - Avoided Natural Gas Emissions, Case 2b.

Compound, Y	Composition, x_Y (mols/100 lbs)	Exhaust Output, w_Y (lbs Output/100 lbs Fuel)	Daily Exhaust Output, eo_Y (lbs/day)	Annual Carbon Equivalent Output (mtce/year)	Annual Criteria Pollutant Output (tonne Y/year)
CO_2	5.03	221.11	53533.59	2416.79	-
NO_X	0.03	1.61	389.34	-	64.45
TOTAL				**2416.79**	**64.45**

Net Natural Gas Emissions

As in Case 1, the overall natural gas emissions may be determined as the difference between Case 0 and Case 2b natural gas emissions. The system would emit 77,429.3 mtce and 2065.78 tonnes of NO_X annually.

Offsite Electricity Production Emissions, Case 2b

Since Case 2b engages the microturbine in the same manner as in Case 2a, the estimated emissions from offsite electricity generation in Case 2b may be expected to be the same as in Case 2a.

Overall Emissions, Case 2b

As may be determined from the summarized net biogas, natural gas and electricity generation emissions, estimated net emissions from Case 2b are 78,159.27 mtce greenhouse gases and 2071.42 tonnes of criteria pollutant annually.

Emissions from Case 3: Use of Microturbine, Heat Recovery and Hydrogen Sulfide Removal

As explained in Section 6, Case 3 projects the outcome the combined use of a microturbine, heat recovery and hydrogen sulfide removal. This section summarizes estimates of potential greenhouse gas and criteria pollutant emissions from Case 3.

Biogas Emissions

Microturbine Emissions, Case 3

It is assumed that the microturbine will use treated biogas of the composition tabulated in Table 9.13. However, for simplicity, the Puente Landfill data is used since there are no SO_X emissions from the sample burn data, which is consistent with expected emissions from Case 3 because hydrogen sulfide is stripped from biogas in Case 3. More accurate emissions data from the microturbine may be obtained from microturbine and biogas test burns.

Table 9.13 - Potential Emissions from Microturbine, Case 3.

Combustion Product	Landfill Emissions, Normalized % Output	Estimated Biogas Emissions, lb/100 lbs Output	Estimated Biogas GHG Output, mtce/year	Estimated Biogas Criteria Pollutant Output, tonnes/year
CO_2	2.82	4.25	4.6	-
SO_2	0.00	0.00	-	-
SO_3	0.00	0.00	-	-
NO_2	6.00×10^{-5}	0.00	-	-
N_2	79.12	75.93	-	-
O_2	18.06	19.81	-	-
TOTAL	**100.00**	**100.00**	**4.6**	**-**

Flare Emissions, Case 3

Flare emissions for Case 3 are negligible, due to a low biogas feed flowrate, 79 MMBtu/year.

Boiler Emissions, Case 3

An estimated 682 MMBtu of biogas is used in the boiler each year in Case 3. The boiler emissions (Table 9.14) are determined using the same method described for Case 0.

Table 9.14 - Boiler Emissions, Case 3.

Compound, Y	**Composition, x_Y (mols/100 lbs)**	**Exhaust Output, w_Y (lbs Output/100 lbs Fuel)**	**Daily Exhaust Output, eo_Y (lbs/day)**	**Annual Carbon Equivalent Output (mtce/year)**	**Annual Criteria Pollutant Output (tonne Y/year)**
CO_2	2.76	121.49	14.91	0.67	-
SO_X	0.00	0.05	0.01	-	0.00
NO_X	0.04	1.95	0.24	-	0.04
TOTAL				**0.67**	**0.04**

Natural Gas Emissions

Avoided Natural Gas Emissions

While Cases 1 and 2b cut natural gas use by utilizing waste heat from the microturbine, Case 3 further decreases the facility demand for natural gas by substituting biogas for natural gas in the boiler. Annual natural gas heating savings are $15,824, or 93,284 lbs/year, of avoided gas use. Additionally, $4,847 boiler natural gas savings equates to 28572 lbs/year of avoided gas use. Estimated avoided natural gas emissions due to biogas substitution in heating and boiler operation are tabulated in Tables 9.15 and 9.16, respectively.

Table 9.15. Avoided Natural Gas Emissions via Heat Recovery, Case 3.

Compound, Y	**Composition, x_Y (mols/100 lbs)**	**Exhaust Output, w_Y (lbs Output/100 lbs Fuel)**	**Daily Exhaust Output, eo_Y (lbs/day)**	**Annual Carbon Equivalent Output (mtce/year)**	**Annual Criteria Pollutant Output (tonne Y/year)**
CO_2	5.03	221.11	56508.52	2551.1	-
NO_X	0.03	1.61	410.97	-	68.03
TOTAL				**2551.1**	**68.03**

Table 9.16 - Avoided Natural Gas Emissions via Biogas Combustion in the Boiler, Case 3.

Compound, Y	Composition, x_Y (mols/100 lbs)	Exhaust Output, w_Y (lbs Output/100 lbs Fuel)	Daily Exhaust Output, eo_Y (lbs/day)	Annual Carbon Equivalent Output (mtce/year)	Annual Criteria Pollutant Output (tonne Y/year)
CO_2	5.03	221.11	17308.14	781.38	-
NO_X	0.03	1.61	125.88	-	20.84
TOTAL				**781.38**	**20.84**

Net Natural Gas Emissions, Case 3

The overall emissions from natural gas use may be determined as the difference between Case 3 and Case 1 emissions. Annual greenhouse gas and criteria pollutant emissions are 76657.92 mtce and 2043.94 tonnes, respectively.

Offsite Electricity Production Emissions, Case 2b

As in Cases 2a and 2b, the microturbine is the only equipment used in Case 3 lowers electricity needs. Therefore the emissions from electricity use in Case 3 are the same as in Cases 2a and 2b.

Net Emissions, Case 3

Overall, the PHSTP would emit 7377.27 mtce of greenhouse gas and 2050.81 tonnes of criteria pollutant will be emitted annually if Case 3 is installed.

10.0 DETERMINING POTENTIAL ECONOMIC VALUE OF EMISSIONS REDUCTION

Comparing the estimated pollutant emissions for the current process, Case 0, and after the proposed alterations, Cases 1-3, provides a means to determine the costs and benefits of decreased emissions. Greenhouse gas values may based on the mean value of carbon emissions, \$14/mtce[21], and criteria pollutant penalty values are approximately \$200/tonne SO_X and \$1200/tonne NO_X[22]. Criteria pollutant nitrous oxide is marketable only during ozone season, from May 1 – September 30. Therefore, annual potential value of nitrous oxide as a criteria pollutant is the value of nitrous oxide emitted for 5 months. The monetary values determined for emissions reductions are considered "good will" dollars towards the community. While any organization may participate in SO_X trading, only utilities can participate in NO_X trading. Actual economic benefit from NO_X reductions may not be realizable by the Pleasant Hills Authority. Data from the emissions analysis of the current process and microturbine are summarized in Table 10.17.

Table 10.17 - Pollutant Emissions Valuation, Case 0.

Gas	**Current Annual Emissions (units/year)**	**Current Potential Unit Value (\$/unit)**	**Current Potential Value (\$/year)**
Greenhouse Gas[a]			
CO_2	80762.35	14	119801
Criteria Pollutant [b]			
SO_X	1.99	200	11
NO_X	2138.55	1200	1066724
TOTAL			**2186537**

[a]CO_2 emissions [=] mtce CO_2 emissions/year
[b]SO_X emissions [=] tonne SO_X emissions/year, NO_X emissions [=] tonne NO_X/year.

Comparisons between Case 0 and Alternatives

Determination of potential benefit value for Cases 1, 2a, 2b, and 3 solely accounts for emissions generated from the process, not emissions from offsite electricity generation. Tables 10.18 – 10.21 summarize expected benefit of adopting each alternative process.

Table 10.18 - Emissions Valuation Comparison, Case 1.

Gas	Case 0 Emissions (Units/year)	Case 0 Potential Value ($/year)	Case 1 Emissions (Units/year)	Case 1 Potential Value ($/year)	Difference in Potential Value ($/year)
Greenhouse Gas					
CO_2	80762.35	119801	76335.41	1057824	61977
Criteria Pollutant					
SO_X	1.99	11.38	1.86	0.23	11.15
NO_X	2138.55	1066724.01	2020.14	1007521.68	59202.33
TOTAL		**2186537**		**2065346**	**121191**

Table 10.19 - Emissions Valuation Comparison, Case 2a.

Gas	Case 0 Emissions (Units/year)	Case 0 Potential Value ($/year)	Case 2a Emissions (Units/year)	Case 2a Potential Value ($/year)	Difference in Potential Value ($/year)
Greenhouse Gas					
CO_2	80762.35	119801	80710.37	119808	-7
Criteria Pollutant					
SO_X	1.99	11.38	1.76	2.2	9
NO_X	2138.55	1066724.01	2137.69	1066467	257
TOTAL		**2186537**		**2186278**	**259**

Table 10.20 - Emissions Valuation Comparison, Case 2b

.Gas	Case 0 Emissions (Units/year)	Case 0 Potential Value ($/year)	Case 2b Emissions (Units/year)	Case 2b Potential Value ($/year)	Difference in Potential Value ($/year)
Greenhouse Gas					
CO_2	80762.35	119801	78159.27	1084093	35708
Criteria Pollutant					
SO_X	1.99	11.38	1.76	2.2	9
NO_X	2138.55	1066724.01	2069.66	1032452	34272
TOTAL		**2186537**		**2116547**	**69989**

Table 10. 21-Emissions Valuation Comparison, Case 3.

Gas	Case 0 Emissions (Units/year)	Case 0 Potential Value ($/year)	Case 3 Emissions (Units/year)	Case 3 Potential Value ($/year)	Difference in Potential Value
Greenhouse Gas					
CO_2	80762.35	119801	77377.27	1073145	46656
Criteria Pollutant					
SO_X	1.99	11.38	1.73	0.03	11
NO_X	2138.55	1066724.01	2049.08	1021992	44732
TOTAL		**2186537**		**2095137**	**91400**

As may be seen in Tables 10.18 – 10.21, Case 1 offers the greatest potential environmental benefit through pollutant emissions reductions. However, this benefit is due to the significant decrease in natural gas demand in Case 1. Case 1 avoids the use of 161,832 lbs of natural gas annually, while Cases 2b and 3 avoid lesser amounts of 98,284 lbs and 121,857 lbs respectively. Case 2a is by far the least environmentally beneficial, possibly because there is no decrease in natural gas use, and estimated microturbine emissions were based on another study. More accurate emissions data and environmental benefit of Cases 2a, 2b, and 3 may be determined through microturbine test runs of biogas to determine actual system emissions.

This crude environmental valuation offers a means to determine the “goodwill” benefits of emissions reduction, the results of this analysis should be used in conjunction with the economics review Section 7 to make a well-informed decision about which process alternative provides the best solution for the PHSTP.

11.0 Conclusions and Recommendations

11.1 Conclusions

The main objective of this endeavor was to develop a project that could yield economic and environmental benefits for the region with the potential for nationwide replication. In the process, the partnerships developed could lead to problem solutions from which all the project participants could benefit. The problem identified for this project was that a local sewage treatment plant (PHSTP) was flaring the biogas produced in their anaerobic digester. In addition to causing a malodorous problem for the neighbors, the gases released through the flare included CH_4 and CO_2 which are associated with undesirable global climate change. The flaring of this potential fuel was also a waste of an energy resource.

The assembled task group completed a detailed study that determined the technical and economic feasibility of several biogas project options at PHSTP. The overall result of the study was an economically- and technically-viable and environmentally-sound process to capture, clean/dry and utilize all the available biogas. The PHA accepted and embraced the findings from the study and has authorized the project to continue into Phase II, which involves the installation of a turbine/generator/heat recovery assembly at the plant site. The plant will now have the capability to generate some of its own power and co-produce thermal energy to aid in the digester operation. The operating plant and the community of those living and working around the facility will be able experience the most benefits from this effort. The odors emanating from the plant will be reduced significantly. The community will notice some savings in the operating costs of the facility over the next several years and most importantly it will be seen as a community that takes its role as an environmental steward, seriously. The stakeholders who participated on the project team as partners all experienced some level of benefit related to their specific needs and reasons for joining in this effort.

The timing of this report comes as parts of the western United States are facing energy-related problems. The information and data gathered from this project may well be used by energy developers as well as policy makers and planners to develop alternate energy source stragegies. Capturing and using this type of energy resource from a waste could be added to the energy mix required in today's climate of higher energy demands. The development of this energy at the source can relieve some of the pressures on the electric supply grid. This redirecting of energy supplies to other end users can benefit the entire power generation and transmission network. The economic and environmental benefits from this approach are obvious, based on the findings in this report.

It is hoped that this report will find its way to help other small communities with similar-sized sewage treatment facilities that could benefit from reduced operating costs. Larger facilities could also benefit as the information presented shows improvements with scale increases due to improved economics. In most cases there will be an environmental benefit that comes with the reduction of the greenhouse gases and criteria pollutants.

11.2 Recommendations

This project has shown that public and private partnering can be successful in solving problems and help create opportunities for business growth. NETL plans to continue its efforts in regional development by looking for areas where this type of approach can be utilized. Energy and environmental issues will continue to drive this outreach program.

This project will include continued research into evaluating the progress of the implemented options at the facility as a way of verifying the projections stated in this report. It is also recommended that sometime in the near term, negotiations be started to incorporate additional technologies at the facility. Of notable priority would be gas-cleaning and gas-quality upgrading technologies to remove CO_2 and other impurities from the digester biogas. CO_2 sequestration and reuse options should also be evaluated. This can be approached with a partnering of representatives from local and national interest groups, industry and utilities.

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13.0 Nomenclature

Btu	British thermal unit
CF	cubic foot
DOE	Department of Energy
H_2S	hydrogen sulfide
IRR	internal rate of return
kW	kilowatt
kWh	kilowatt-hour
LCC	life cycle cost
LHV	lower heating value
MCF	thousand cubic feet
MMBtu	million British thermal units
NETL	National Energy Technology Laboratory
NPV	net present value
PHA	Pleasant Hills Authority
psig	pounds per square inch, gauge

Attachment 1
Summary of PHA Natural Gas Bills: Feb-1999 to Mar-2000

Equitable Account #	1-42-100-006065-0
? #	P 00026
Rate	T
Tariff Rate	GSL
Gas Service Agreement	Firm
Meter #	752417
Equitable Gas Account Manager	Liz Bernoth, 412/395-3194

Marginal Rates as of 9/8/00

commodity rate, $/MCF	6.79
surcharge, $/MCF	0.227
balancing charge, $/MCF	0.18
standby charge, $/MCF	0.38
total marginal rate, $/MCF	**7.58**

Billing History

Billing End Date	Days in Period	MCF Used	Average MCF/Day	Commodity Charge	Surcharge	Winter Reservation High Load Charge	Balancing Charge	Service Charge	Total Charge
2/12/99	--	674	--	--	--	--	--	--	--
3/12/99	28	570	20.4	--	--	--	--	--	--
4/16/99	35	600	17.1	--	--	--	--	--	--
5/14/99	28	449	16.0	--	--	--	--	--	--
6/14/99	31	486	15.7	--	--	--	--	--	--
7/14/99	30	395	13.2	--	--	--	--	--	--
8/12/99	29	376	13.0	--	--	--	--	--	--
9/13/99	32	389	12.2	--	--	--	--	--	--
10/11/99	28	315	11.3	--	--	--	--	--	--
11/8/99	28	423	15.1	--	--	--	--	--	--
12/12/99	34	565	16.6	--	--	--	--	--	--
01/08/00	27	510	18.9	$3,462.90	$115.77	$193.80	$91.80	$150.00	$4,014.27
02/12/00	35	640	18.3	$4,345.60	$145.28	$243.20	$115.20	$150.00	$4,999.28
03/11/00	28	747	26.7	$5,072.13	$169.57	$283.86	$134.46	$150.00	$5,810.02

Notes

1) Under PHA's current contract with Equitable, the commodity rate is fixed until 9/30/01. However, the other three rate components could change over the contract period.
2) Through late spring of 2000 (around May), digester bio-gas was sometimes used as a supplementary boiler fuel. After May 2000, the use of bio-gas in the boiler was discontinued to avoid corrosion/deposition problems.

Attachment 2
Analysis of PHA's Electricity Usage
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Table A2.1: Summary of PHA Electricity Bills: Jan-1999 to Feb-2000

Utility:	Allegheny Power
Account # :	1/39/22/000/47023/1
Rate Schedule:	30
Allegheny Account Manager:	Earl Sarain, 724/489-3231

	Billing Period Start Date						
Meter Data	**20-Jan-99**	**19-Feb-99**	**22-Mar-99**	**21-Apr-99**	**24-May-99**	**22-Jun-99**	**20-Jul-99**
Days in Billing Period	30	31	30	33	29	28	30
Energy Usage (kWh)	252,000	261,600	236,000	268,800	228,800	230,400	235,200
Demand (kW)	413	396	393	398	405	403	397
RKVA	229	250	258	302	240	243	227
Charges							
Distribution Demand	299.97	288.24	286.17	289.62	294.45	293.07	288.93
Distribution Energy	1,344.64	1,394.75	1,261.12	1,432.34	1,223.54	1,231.89	1,256.94
Distribution Voltage Discount	-82.60	-79.20	-78.60	-79.60	-81.00	-80.60	-79.40
Distribution RKVA Demand	91.60	100.00	103.20	120.80	96.00	97.20	90.80
Transmission Demand	-63.21	-60.32	-59.81	-60.66	-61.85	-61.51	-60.49
Transmission Energy	803.56	833.61	753.48	856.14	730.94	735.95	750.98
Scheduling, Control & Dispatch	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy Imbalance	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reactive & Voltage Control	33.04	31.68	31.44	31.84	32.40	32.24	31.76
Regulation Frequency Response	33.04	31.68	31.44	31.84	32.40	32.24	31.76
Spinning Reserve	90.86	87.12	86.46	87.56	89.10	88.66	87.34
Supplemental Reserve	82.60	79.20	78.60	79.60	81.00	80.60	79.40
Competitive Transition Demand	261.93	251.56	249.73	252.78	257.05	255.83	252.17
Competitive Transition Energy	1,185.84	1,230.19	1,111.92	1,263.46	1,078.66	1,086.05	1,108.22
Intangible Transition Demand							
Intangible Transition Energy							
Generation Demand	1,318.78	1,266.76	1,257.58	1,272.88	1,294.30	1,288.18	1,269.82
Generation Energy	5,987.96	6,211.93	5,614.68	6,379.90	5,446.70	5,484.03	5,596.02
Subtotal	11,388.01	11,667.20	10,727.41	11,958.50	10,513.69	10,563.83	10,704.25
PA Tax Surcharge	-7.97	-8.17	-7.51	-8.37	-12.15	-13.73	-13.92
Total	11,380.04	11,659.03	10,719.90	11,950.13	10,501.54	10,550.10	10,690.33
Monthly Calculations							
kWh/day	8,400	8,439	7,867	8,145	7,890	8,229	7,840
$/kWh	$0.0452	$0.0446	$0.0454	$0.0445	$0.0459	$0.0458	$0.0455
Average Demand, kW	350	352	328	339	329	343	327
Peak:Average Demand Ratio	1.18	1.13	1.20	1.17	1.23	1.18	1.22

Marginal Rates (from PA Schedule 30)	
Total Demand Charge (over 100 kW), $/kW	4.69
Total Energy Charges (over 40,000 kWh/month), $/kWh	0.03728
Other Calculations	
Average Monthly Peak	418
Overall Average Demand	351
Overall Average Demand Ratio	1.19
Average Monthly Bill	$11,641
Avg. Monthly Demand Charges	$2,126
Overall $/kWh	0.0454

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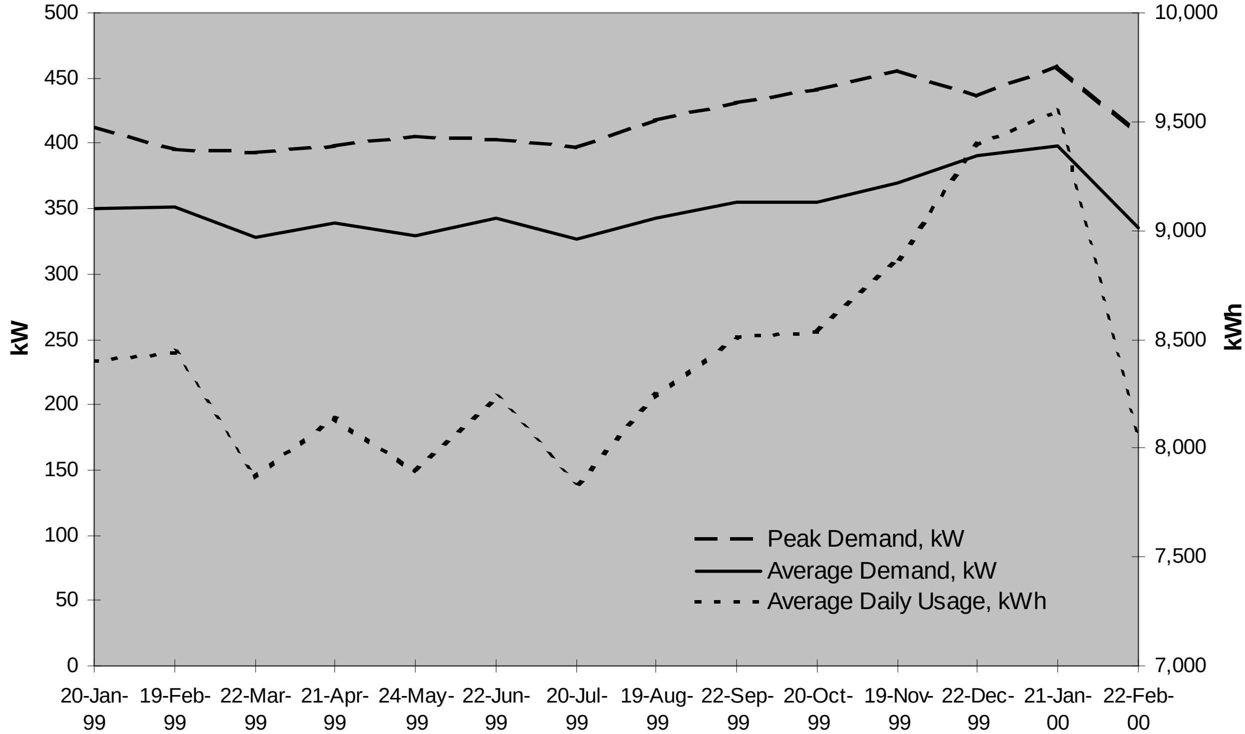
Table A2.1 (continued): Summary of PHA Electricity Bills: Jan-1999 to Feb-2000

	Billing Period Start Date						
Meter Data	**19-Aug-99**	**22-Sep-99**	**20-Oct-99**	**19-Nov-99**	**22-Dec-99**	**21-Jan-00**	**22-Feb-00**
Days in Billing Period	34	28	30	33	30	32	28
Energy Usage (kWh)	280,000	238,400	256,000	292,800	281,600	305,600	225,600
Demand (kW)	418	431	441	456	436	459	408
RKVA	263	253	272	277	249	253	244
Charges							
Distribution Demand	303.42	312.39	319.29	329.64	352.46	386.79	345.48
Distribution Energy	1,490.80	1,273.65	1,365.52	1,557.62	1,692.33	1,923.92	1,427.92
Distribution Voltage Discount	-83.60	-86.20	-88.20	-91.20	-87.20	-91.80	-81.60
Distribution RKVA Demand	105.20	101.20	108.80	110.80	99.60	101.20	97.60
Transmission Demand	-64.06	-66.27	-67.97	-70.52	-67.12	-71.03	-62.36
Transmission Energy	891.20	760.99	816.08	931.26	896.21	971.33	720.93
Scheduling, Control & Dispatch	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy Imbalance	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reactive & Voltage Control	33.44	34.48	35.28	36.48	34.88	36.72	32.64
Regulation Frequency Response	33.44	34.48	35.28	36.48	34.88	36.72	32.64
Spinning Reserve	91.96	94.82	97.02	100.32	95.92	100.98	89.76
Supplemental Reserve	83.60	86.20	88.20	91.20	87.20	91.80	81.60
Competitive Transition Demand	264.98	272.91	244.16	18.24	11.34	9.18	8.16
Competitive Transition Energy	1,315.20	1,123.01	1,060.16	140.42	105.02	99.79	74.19
Intangible Transition Demand			34.85	269.92	258.52	271.63	242.56
Intangible Transition Energy			144.16	1,233.92	1,187.44	1,287.04	955.04
Generation Demand	1,334.08	1,373.86	1,404.46	1,450.36	1,395.26	1,468.72	1,311.64
Generation Energy	6,641.20	5,670.67	6,081.28	6,939.82	6,708.66	7,285.09	5,406.69
Subtotal	12,440.86	10,986.19	11,678.37	13,084.76	12,805.40	13,908.08	10,682.89
PA Tax Surcharge	-16.17	-14.28	-15.18	-17.01	-4.91	0.00	0.00
Total	12,424.69	10,971.91	11,663.19	13,067.75	12,800.49	13,908.08	10,682.89
Monthly Calculations							
kWh/day	8,235	8,514	8,533	8,873	9,387	9,550	8,057
$/kWh	$0.0444	$0.0460	$0.0456	$0.0446	$0.0455	$0.0455	$0.0474
Average Demand, kW	343	355	356	370	391	398	336
Peak:Average Demand Ratio	1.22	1.21	1.24	1.23	1.11	1.15	1.22

Figure A2.1: PHA Monthly Electricity Usage
(based on billing data)



Attachment 2: (Continued)

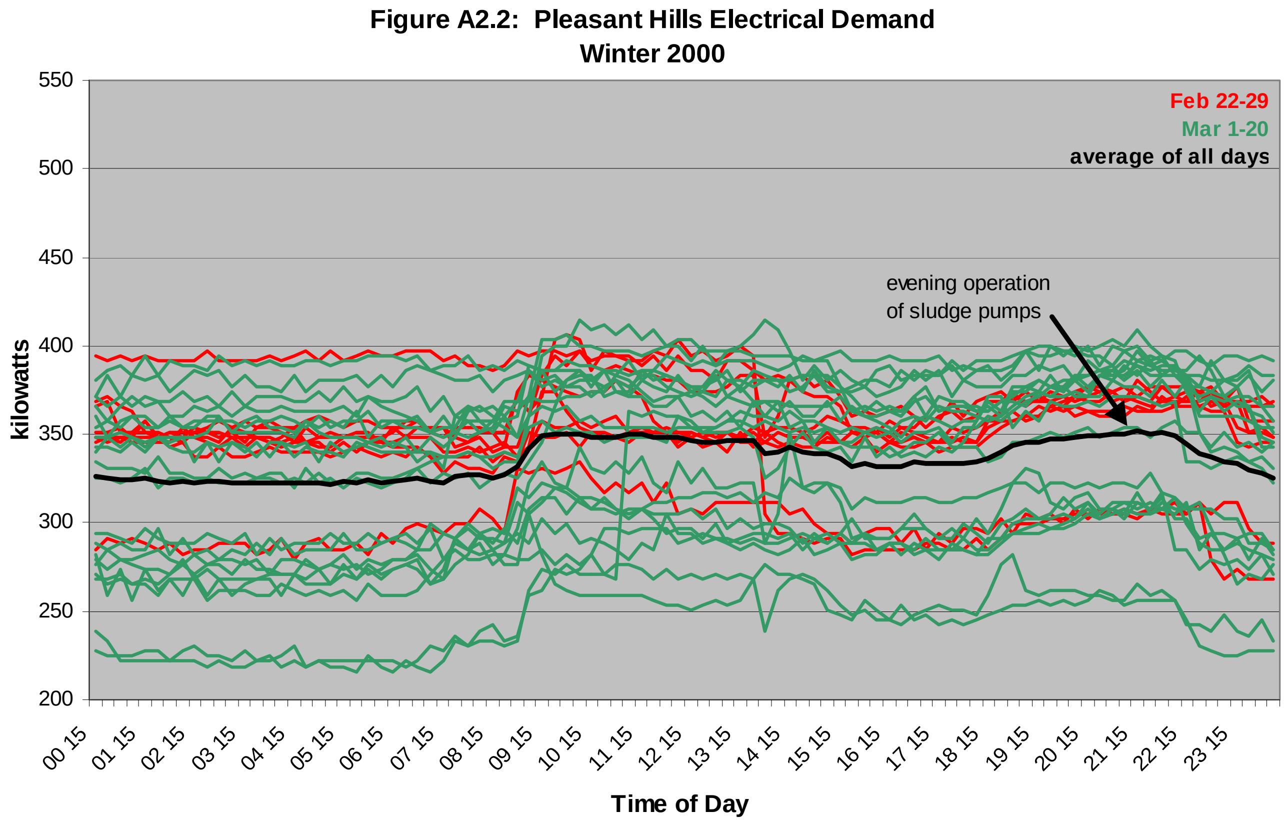


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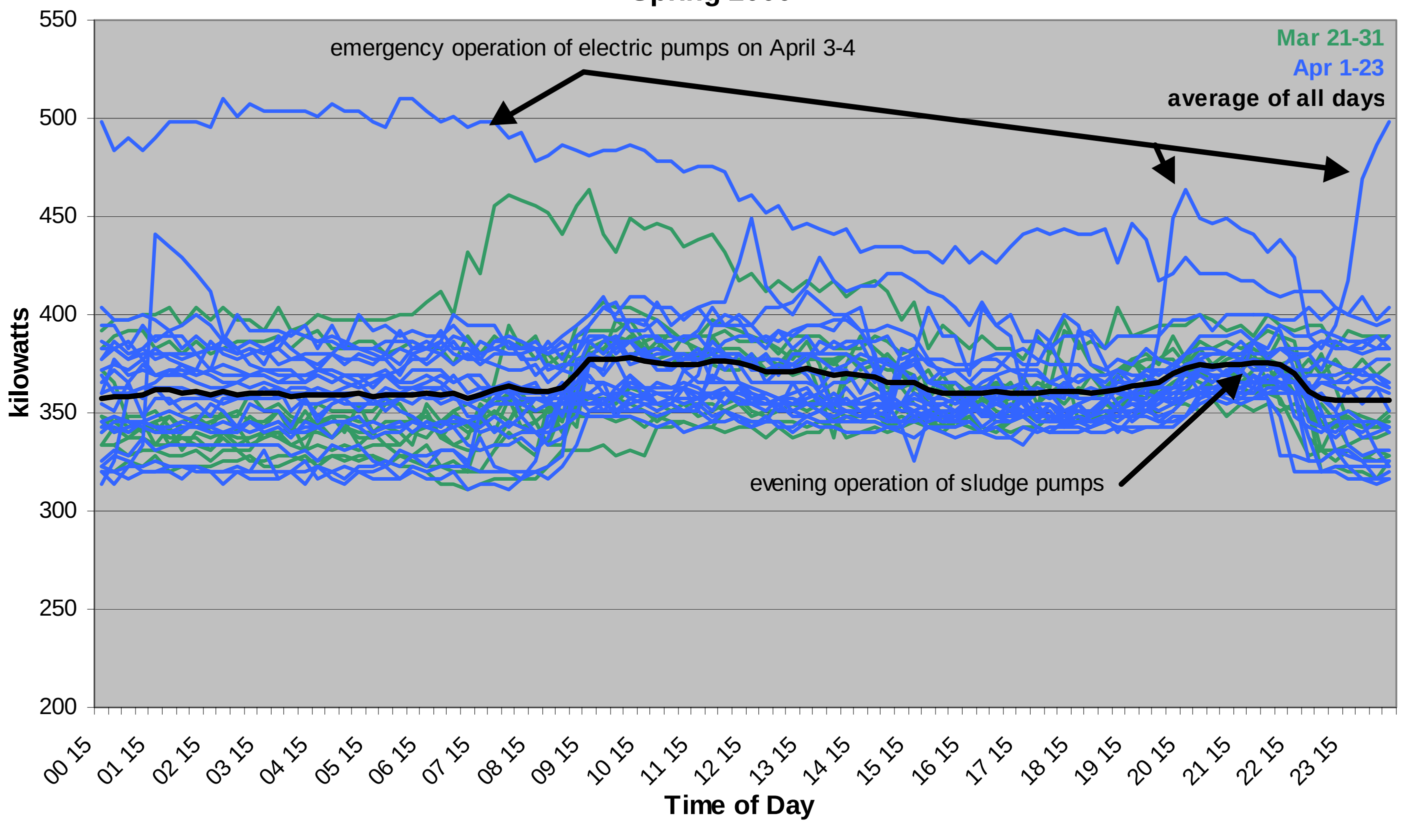
Figure A2.3: Pleasant Hills Electrical Demand
Spring 2000



Attachment 3
Capstone Turbine Corporation Equipment Specification Sheets
(not included electronically; hard copies inserted)