BIOGAS PROCESSING

Final Report

Prepared for

THE NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

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Agreement No. 7250

NYSERDA 7250 February 2006

NOTICE

ABSTRACT

Anaerobic digestion offers an effective way to manage dairy manure by addressing the principal problem of odor and environmental control while offering an opportunity to create energy from conversion of biogas with a system of combined heat and power (CHP). The use of biogas as an energy source has numerous applications. However, all of the possible applications require knowledge about the composition and quntity of constituents in the biogas stream. This study provides data on composition of anaerobic digestion biogas (ADG) over time (hourly, daily, weekly and year), results from the use of dairy-manure compost as a biofilter to remove hydrogen sulfide H_2S from the ADG, and an assessment of the feasibility of injecting ADG into the natural gas pieline.

Results agrree well with the often quoted generalized concentrations of 60% CH_4, 40% CO_2 and 600 BTUs for dairy-derived biogas. They also show that, depending on additives to the dairy manure and quality of farm water supply, the H_2S concentrations can vary substantially from less than 1000 ppm to well over 6000 ppm. Utilization of cow-manure compost for removal of H_2S from AD biogas using small-scale reactors was studied and shows promise.. A technical and economic assessment of processing of biogas for injection to the natural gas pipeline, while dependent on biogas quantity, price for processed biogas, proximity of the biogas producer to the natural gas pipeline and the interest rate, suggests that a real possibility exists for injecting biogas to the natural gas pipeline dependent, of course, on the values of the parameters indicated.

Key Words:

dairy manure-derived biogas, biogas composition, biogas cleanup, hydrogen sulfide removal, injection of biogas to natural gas pipeline

ACKNOWLEDGEMENTS

Major specific results in this report represent the work of three Masters of Science students in the Department of Biological and Environmental Engineering at Cornell University: Kimberly Bothi, Kelly Saikkonen and Steven Zicari. An undergraduate student, Michelle Wright, provided much assistance.

Five participating dairies, used for data acquisition, are acknowledged for their important contributions: Dairy Development International (DDI), AA Dairy, Matlink, Noblehurst, and Twin Birch. Special thanks go to DDI, particularly Larry Jones, who provided the opportunity to acquire “real data” with on-site experimentation.

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SUMMARY

Anaerobic digestion offers an effective way to manage dairy manure by addressing the principal problem of odor while offering an opportunity to create energy from conversion of biogas with a system of combined heat and power (CHP). Anaerobic digestion is a microbiological process that produces a gas, biogas, consisting primarily of methane (CH_4) and carbon dioxide (CO_2). The use of biogas as an energy source has numerous applications. However, all of the possible applications require knowledge about the composition and quntity of constituents in the biogas stream.

Measurements of biogas from five New York farms and detailed measurments at Dairy Development International (DDI) provide information about composition and quantity of constituents in biogas over time (day, week and year). Methane (CH_4) content at DDI measured over months averaged 60.3% ± 1% with an average BTU content of 612 ± 11 BTU. Similarly carbon dioxide (CO_2) and Nitrogen (N_2) averaged 38.2 % and 1.5% respectively. Hyrdogen sulfide (H_2S) concentrations at DDI averaged 1984 ppm with a standard deviation of ± 570 ppm over the period of almost a year. Measurements of H_2S at five NY farms ilustrated a rather wide variation in H_2S concentrations from about 600 ppm to over 7000 ppm. It is suggested that the lower concentration of H_2S appears to be due to addition of food wastes to the AD and the higher sulfur concentration of the farm water supply may be the reason for the much higher H_2S concentarions at the one NY farm. For those digesters not adding food waste and not having high concentrations of sulfur in the water, the H_2S concentrations appear to range from about 1500 ppm to 4000ppm. Daily variations in CH_4 were measured and appeared to correlate with ambient temperatures but whether these small daily variations of about ± 0.5% were due to temperature sensitivity of the gas chromatograph or a real CH_4 concentration variation was not determined. These results agrree well with the often quoted generalized concentrations of 60% CH_4, 40% CO_2 and 600 BTUs for dairy-derived biogas. They also show that depending on additives to the dairy manure and quality of farm water supply the H_2S concentrations can vary substantially from less than 1000 ppm to well over 6000 ppm.

A significant goal of this project has been to consider the potential for biofiltration to reduce (remove) the concentration of H_2S because all energy converters need to operate at H_2S levels significantly less than that found in raw biogas. Consistent with the theme of total resource recovery on the farm utilization of cow-manure compost for removal of H_2S from AD biogas using small-scale reactors was studied. Slipstreams of AD biogas from operating systems at AA Dairy and Dairy Development International (DDI) were passed through reactor sections of a cow manure compost mixture within polyvinyl chloride cylinders of 0.1 m in diameter and 0.5 m in length. The mature cow-manure compost was mixed in a 1:1 ratio with dry maple wood chips. Columns have shown over 90% removal efficiency for the early stages of these tests, where removal efficiency (RE) is defined as the difference in inlet and outlet concentrations of H_2S divided by the inlet concentration. Some column operated with RE's above 85% for over 30 days before falling off to 50%

or less. . The total mass of H_2S removed from the gas during these experiments was estimated at 127 and 135 g H_2S.. These values approach a maximum value of 130 g $H_2S/m^3_{packing}$/hr reported in the literature for organic media. Correlation ot bed temperature data with the RE is suggestive of the existence of a very tight optimum temperature operating range, which, when exceeded, creates biological upset and a subsequent reduction in performance (reduced RE).

A potential use of biogas which avoids the large thermodynamic inefficiencies of conversion to electricity is to use biogas for heating directly. An interesting option is the possibility of introducing biogas into the natural gas pipeline, given the basic characteristics of biogas as a "low grade" natural gas. Biogas recovery and processing (includes cleaning and upgrading) for injection into the natural gas pipeline and depends on financial viability. Key questions are: What are local utility standards for gas quality? Is a local utility company or a community pipeline willing to purchase the gas from the farmer? What are contract requirements? If so, how much gas are they willing to purchase and for what length of time?How much will gas processing technology (capital and O&M) cost? How much revenue will the sale of processed biogas generate?

A technical and economic assessment of processing of biogas for injection to the natural gas pipeline, while dependent on biogas quantity, price for processed biogas, proximity of the biogas producer to the natural gas pipeline and the interest rate, suggests that a real possibility exists for injecting biogas to the natural gas pipeline dependent, of course, on the values of the parameters indicated..The results of the economic analysis showed that for all farm sizes studied (500, 1000, 3000, 5000 and 10000) a profit from injecting biogas to a natural gas pipeline is possible depending on primarily the biogas selling price and the proximity to the natural gas pipeline. An innovative demonstration project for upgrading biogas to natural gas pipeline should be considered because upgrading dairy biogas to natural gas quality has not been done in the United States .

INTRODUCTION

Anaerobic digestion is a microbiological process that produces a gas, biogas, consisting primarily of methane (CH_4) and carbon dioxide (CO_2). The use of biogas as an energy source has numerous applications. However, all of the possible applications require knowledge about the characteristics, composition and quntity of constituents in the biogas stream.

This project provides information about the fundamental characteristics of biogas. By better understanding its components, biogas can be processed and utilized in a more efficient, cost-effective way. As shown in Figure 1.1, biogas contains primarily CH_4 with the balance being mostly CO_2 and a small amount of trace components. In comparison, biogas has approximately two-thirds the energy potential of refined natural gas. Although the significant amount of CO_2 and lower CH_4 means a lower energy value than natural gas, the relatively minute concentrations of trace components can also have a particularly complicating and deleterious effect on the way biogas can actually be processed and utilized.

Typical Bulk Biogas Components	Trace Components
Methane 50-60%	Hydrogen
Carbon Dioxide 38-48%	Hydrogen Sulfide
Trace Components 2%	Non-methane volatile organic carbons (NMVOC)
	Halocarbons

Figure 1.1 Biogas composition[1]

One of the goals of this project is to encourage total resource-recovery on the farm. This idea is generated from the concept of engineering agricultural systems for sustainable development where resources are recycled on the farm reducing the use of off-farm non-renewable resources. Thus, this project addresses this opportunity by investigating ways to process anaerobic digester biogas (ADG), and, thereby, increasing its utilization. In particular, any system for conversion of biogas to energy either requires a method to remove toxic and corrosive contaminants from biogas, or special procedures to accommodate the deleterious effects of contaminants in the biogas stream. Presently, the internal combustion (IC) engine is the most effective and economically viable energy converter used with ADG. The two most common on-farm approaches are changing oil (IC engines) on a regular basis (numerous operators change oil weekly), or use of Iron Sponge (iron impregnated wood chips) as a filter to remove contaminants (principally hydrogen sulfide, H_2S) from biogas before introduction of biogas into the energy converter. For more

[1] Source: http://www.novaenergie.ch/iea-bioenergy-task37/Dokumente/Flaring_4-4.PDF

futuristic combined heat and power (CHP) systems such as microturbines and fuel cells, the removal of contaminants is as, or more, critical than for the IC engine.

Specifically the major contaminant is hydrogen sulfide and recent measurements of H_2S concentrations of ADG from six New York farms indicate concentrations ranging from approximately 600 ppm to 6000 ppm. There are numerous chemical, physical and biological methods utilized for removal of H_2S from a gas stream. Many of these methods are labor intensive and generate a waste stream that poses environmental disposal concerns and risks.

SCOPE OF PROJECT

The main goals of this project were to:

- Evaluate the performance and variability of dairy AD systems through extensive monitoring of biogas composition and its temporal variation.
- Determine and assess the performance of biogas processing systems best suited for farm operations.
- Assess the potential for alternative biogas uses.

This report presents the results from: 1) extensive data acquisition from sampling biogas from dairy AD systems for composition and variations in biogas composition over time, 2) an in-depth study of the potential benefits of effectiveness of using cow-manure compost for removal of H_2S in biogas and 3) an assessment of economics of processing biogas for inclusion in a natural gas pipeline.

BACKGROUND

In Governor Pataki's 2004 State of the State address, he emphasized the need to "improve our environment and reduce our dependence on imported foreign energy by leading the nation in the development and deployment of renewable energy resources like…biomass."

Fuel methane can be produced from the anaerobic decomposition of biomass wastes, providing a renewable, alternative energy source, as well as a waste treatment methodology that promotes nutrient recycling and opportunities for power generation on site (Jewel et al., 1980; Walker et al., 1985). Agricultural facilities, as well as wastewater treatment plants, landfills, food processors and pulping mills, produce biogas that consists mostly of methane, carbon dioxide, small amounts of nitrogen and oxygen, and other trace components such as sulfur compounds, halogens, and non-methane organic compounds (NMOCs) (Schomaker et al., 2000).

With approximately 7,900 dairy farms and 700,000 dairy cows (Knoblauch, 2001), New York State (NYS) is the third largest dairy state in the U.S. Therefore, it is very important for NYS to explore the underutilized energy potential of biomass in the form of dairy manure which traditionally imposes serious environmental problems. This project addresses an excellent opportunity for rural NYS to move toward an energy system which features renewable in-state resources and small scale, modular distributed generation plants to improve efficiency and reliability (Alderfer et.al., 2000). Based on our estimates, dairy manure biomass in New York, if all could be collected, will have an annual energy potential of 280 GWh, enough to support the electricity demand of about 47,000 households, if a diesel engine is used for electricity generation. For the more energy efficient fuel cell, the production is estimated at 700 GWh/yr or enough to supply about 118,000 households. However, a transition to these more efficient technologies requires more stringent gas processing to remove impurities (Scott, 2001). While being able to process all dairy manure in New York State in AD systems is unrealistic, processing about half of the dairy manure is not, based on the demographics of New York dairy farms, meaning that the numbers will be one half of the above estimates.

Because of differences in waste composition, processing techniques and operating conditions, biogas composition can vary from site to site as well as over time at a single site. Understanding the composition and variability of biogas is critical to efficient use of biogas and to processing techniques to remove impurities. Gas chromatography analysis, a highly accurate method of identifying specific amounts of trace components, not detectable with other testing methods, was performed. Gas Chromatographs were set up at both Cornell University and DDI to analyze the biogas samples. This biogas study complements the work done under NYSERDA Project 6597, which is a three-year evaluation and monitoring study of five operating digesters in New York. Monthly assessments of manure management systems and characterization of materials inputs, outputs, and energy products are being recorded in this project (6597).

Gas processing is usually necessary to ensure proper functioning of cogeneration units, extend the life of biogas equipment, and increase the energy potential of the gas. Water vapor in the gas can become corrosive when combined with acidic components in the gas. Water vapor must also be removed completely before any gas compression can occur. Hydrogen sulfide is poisonous, odorous, and highly corrosive, causing damage to equipment and piping systems. Carbon dioxide is also slightly corrosive and lowers the caloric value of the gas, thus reducing its value (Schomaker et al, 2000).

Processing for the utilization of biogas in an engine, microturbine, or fuel cell is currently energy, chemical, and investment intensive. This detracts from the profitability and sustainability of anaerobic digester system operations. Gas purification methods typically optimized for use in the natural gas processing industry are for much higher gas flows and different chemical gas compositions than those typically found at agricultural biogas production facilities (Foral and Al-Ubaidi, 1994). Accordingly, there is the need to study gas processing techniques in the context of small biogas production facilities.

At Dairy Development International (DDI), the current method of removing H_2S from biogas is to pass the moisture-saturated biogas through an "Iron Sponge" media, which consists of woodchips impregnated with iron oxide (Aneurosis and Whitman, 1984). When the spent media is exposed to oxygen during regeneration, the reaction is highly exothermic and capable of self-ignition, making regeneration and change-out of this media labor-intensive. Also, buildup of elemental sulfur limits the extent to which the media can be regenerated, requiring that the spent media be disposed of by some way, often landfills (Revel, 2001). These undesirable characteristics necessitate the exploration of alternative adsorbents and processes. Alternative adsorbents to be ideally tested at the bench scale level for optimization with small scale digesters include SulfaTreat™, Potassium-Hydroxide impregnated activated carbon (KOH-carbon), chelated iron, caustic solution, and natural media such as dairy manure compost.

Potential for process optimization exists by utilizing biologically active matrices containing organisms that metabolize and remove unwanted compounds from process streams. Biofilters can be constructed to utilize biologically active compost where oxygen or nitrates serve as the optimum electron acceptors for oxidation of H_2S to sulfate. Air or nitrates can be added directly to the anaerobic digester to accelerate this oxidation. Bio-regeneration of spent iron oxide media can be explored that utilizes sulfur-oxidizing bacteria to remove accumulated elemental sulfur. These process innovations could greatly reduce chemical demands, labor involvement and mitigate environmental disposal concerns. Results from these trials can be a basis to construct a full scale, optimized gas processing apparatus for use at DDI.

Biofiltration using microbially active compost as the filtration media is currently used on farms as an odor management technique (Nicolai et. al., 1997) and has the potential to be used for effective gas processing with anaerobic digestion/cogenerations systems. Biofilters are preferable to chemical adsorption methods because of their reduced labor costs, elimination of the need for chemical or external material inputs and production of sulfate that may contain fertilizer value. Another advantage to biofiltration is the fact that microbial oxidation of H_2S is coupled with CO_2 fixation, thus allowing for removal of unwanted CO_2 from the gas stream.

According to AgSTAR, the number of operational anaerobic digesters in the United States increased by over 100 percent in the 1990's. Subsequently, the increase of successful digester systems has brought about a number of innovative approaches to biogas use and cogeneration technology development (AgSTAR, 2000). For example, the Capstone Microturbines in place at DDI are compact, low emission power generating systems that provide power of up to 28 kW each (Capstone, 2000). At the present time, there is incomplete data pertaining to the performance characteristics of microturbines in biogas applications. The microturbines funded in part by NYSERDA at DDI can provide an opportunity to monitor and validate the performance of these systems.

In addition to microturbines, there are multiple biogas technologies that harness the potential for suitability in the New York agriculture industry. External combustion Stirling engines that operate on biogas with an electric power output ranging from 35 to 75 kW may be available for commercial use in the future. Long lifetime, low service costs, low level emissions and high efficiency are potential benefits of Stirling engine systems, according to research currently being conducted at the Technical University of Denmark (Carlsen, 2001). In demonstration projects it has been shown that the Flex-Microturbine TM has the ability to operate on extremely low Btu and low-pressure biogas. This technology, available possibly in the near future, is intended to provide cost-competitive, safe, reliable and clean renewable energy (Prabhu, 2001).

NYSERDA project 6243 studied the feasibility of using fuel cells for energy conversion on dairy farms and concluded that the potential benefits of fuel cell technologies include on-farm energy self-sufficiency, the sale of energy to the grid and the production of tradable bio-derived commodities. Quantifiable benefits include high electrical conversion efficiency (up to 48%), 90% reduction of non-CO_2 air pollutants and low noise when compared to a traditional IC engine-generator (Scott and Minott, 2003). Upgrading the biogas to natural gas standards by removal of H_2S and CO_2 may also be an attractive alternative for biogas locations near a natural gas pipeline (Schomaker et al, 2000)

FARM PARTICIPANT INFORMATION

New York dairy demographics for 1993 to 2003 show a shift in dairy population from mostly small farms (<100 cows) to medium (100-500 cows) and large (> 500 cows) farms. This trend is clearly demonstrated in Figure 1.2, which shows that in 2003, 60% of the cow population resides on medium to large farms.

Accompanying this shift in the dairy population was a decline in the number of small New York dairy farms from 83% to 76%, and a corresponding increase in the number of medium to large farms, as shown in Table 1.1. With the majority of cows residing on medium to large farms, widespread use of anaerobic digesters seems increasingly feasible. Dairy waste from small farms need not and cannot be ignored because effluent from livestock agriculture accounts for a significant portion of drinking water pollution in New York waters (Minott et al., 2000). However, small farms, which do not own their own digester, might explore the benefits by a shared "community" digester.

DDI

DDI is a 30-acre dairy complex and agri-research facility in Cortland County, approximately 26 miles north of Ithaca, NY. With the capacity to house and milk 850 cows, DDI's facilities include two free-stall barns, a special needs barn, a milking parlor, feed storage grain bins, and an anaerobic digester. The soft-top horizontal plug-flow anaerobic digester at DDI has a retention time of 21 days. The original intention was to use biogas for combined heat and power generation. The slurry is passed through a solids-liquid separator with the solids used for organic material and the liquid stored for use later land application.

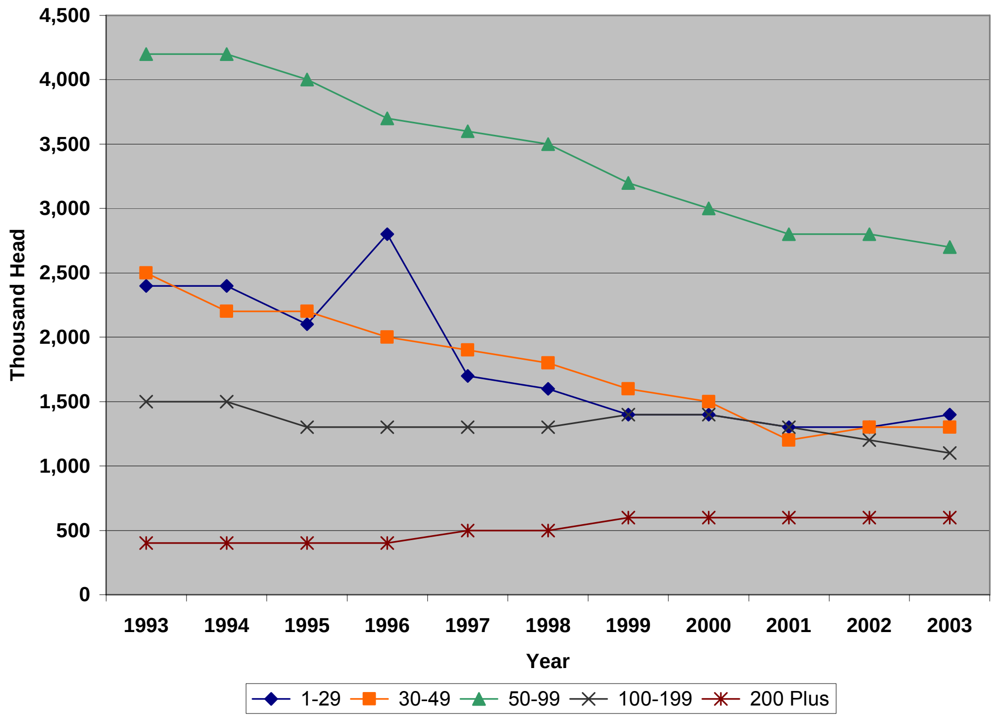

Figure 1.2 Milk cows on NY farms by herd size between 1993 – 2003.

Table 1.1 NY milking operations by herd size and total (1993-2003)[2].

Number of Milk cows per herd	*1993*	*1994*	*1995*	*1996*	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*
1-29	2,400	2,400	2,100	2,800	1,700	1,600	1,400	1,400	1,300	1,300	1,400
30-49	2,500	2,200	2,200	2,000	1,900	1,800	1,600	1,500	1,200	1,300	1,300
50-99	4,200	4,200	4,000	3,700	3,600	3,500	3,200	3,000	2,800	2,800	2,700
100-199	1,500	1,500	1,300	1,300	1,300	1,300	1,400	1,400	1,300	1,200	1,100
200 plus	400	400	400	400	500	500	600	600	600	600	600
total	11,000	10,700	10,000	10,200	9,000	8,700	8,200	7,900	7,200	7,200	7,100
small farms	83%	82%	83%	83%	80%	79%	76%	75%	74%	75%	76%

Although microturbines have been installed to generate electricity for the farm's needs or for sale to the grid in the future, the majority of the biogas is being used to fuel a 1.5 billion Btu boiler for the heating needs of the farm. Any excess biogas generated is flared. DDI is the primary location for the experiments described in this report.

AA Dairy

AA Dairy, a medium-sized farm in Tioga County outside of Candor, NY, has approximately 500 milking cows, an operating digester with an IC genset. Between 35,000-50,000 ft^3/day of biogas is produced from the digester. AA Dairy is located 20 miles from Ithaca. This combination of characteristics, along with the farmers' track record of maintaining data records make AA Dairy a desirable location to use as a sample collection site.

Matlink

Located in Chautauqua County near Clymer, NY, Matlink Dairy houses 750 cows in free stall barns. Approximately 76,440 ft^3/day of higher-methane content, lower-H_2S content biogas is generated from the digester making it an interesting sampling site. It has been suggested that the higher methane and reduced H_2S content is due to the addition of food wastes to the manure in the digester. The biogas is collected and used with an engine-generator to produce electricity for the farm. Matlink is located 220 miles from Ithaca.

Noblehurst

Noblehurst Farms, Inc., located close to the Town of York in Livingston County, is a 1,100 milking cow commercial dairy. Biogas production is estimated to be about 72,000 ft^3 per day. An IC engine-generator is also used to produce electricity on the farm.

Twin Birch

Twin Birch operates a 1,200 cow dairy near Owasco, NY in Cayuga County. Approximately 72,000 ft^3 of biogas is produced each day from a concrete covered digester. Microturbines have been installed to generate electricity, however, the system continued to encounter obstacles during this study and was not operational. One important initial observation that led to further sampling at Twin Birch was the unusually high concentration of H_2S in the biogas.

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[2] Source: http://www.nass.usda.gov/ny/Bulletin/2004/Annp039-41-04.pdf

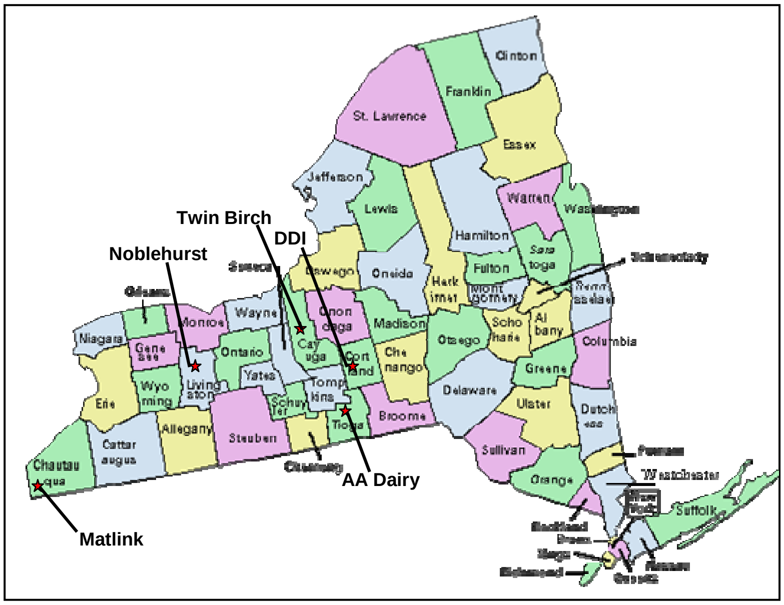


Figure 1.3 Map of New York State showing counties and locations of study participants.
Source: Base map of NY State Counties from http://www.rootsweb.com/~nygenweb/county.htm

BIOGAS CHARACTERIZATION

Two gas chromatographs (GC's) were used to analyze biogas. One was stationed at DDI for the duration of the project to monitor a steady raw biogas stream. This GC (Daniel Danalyzer 570) was also utilized to take measurements of the inlet and outlet gas for the bioreactors constructed for removal of H_2S at DDI. At initial experiment set-up, a Daniel technician was present to perform the necessary maintenance and calibration. The technician also gave the students (Zicari, Bothi, Saikkonen) an orientation to the operation of this particular GC. The system was programmed to take measurements of the raw biogas stream approximately every 3 hours. Although not the only components analyzed, there were 4 readings of significance gathered from each data set: % CH_4, % CO2, % N_2 (nitrogen), and BTU content. The Daniel GC is equipped with a thermal conductivity detector (TCD), which measures the difference in thermal conductivity of each compound in the carrier gas. The carrier gas chosen in this application was helium.

The second GC, a SRI 6010C, was set up at Cornell University. Equipped with multiple detectors, a TCD and a flame ionization detector/flame photometric detector (FID/FPD), this GC has the capability of analyzing a greater number of compounds. A flame ionization detector (FID) is used to detect hydrocarbon peaks in a gas sample whereas a flame photometric detector (FPD) detects sulfur and phosphorus compounds. For the purposes of this study, however, the concentration of sulfur compounds present in the biogas was of greatest interest therefore the FPD was the key detector. The biogas sample passes through a column and is flashed through a hydrogen-air mixture flame. The spectrums of light emitted from the combustion of the sample in the hydrogen-rich flame are analyzed to determine the concentration of sulfur compounds in the biogas. Further information about the SRI GC and detector operation can be found at http://www.srigc.com.

SAMPLING TECHNIQUES

Biogas Bag Samples

The first step in preparation of sample analysis at the lab was to calibrate the GC. The GC was calibrated by analyzing samples of premixed H_2S standards at 1000 ppm, 2000 ppm, 3000 ppm, and 5000 ppm three times each. The results were then entered into the program *PeakSimple* (provided with the SRI 8610C) that sets the calibration parameters according to the results of the standards analysis. This step must be performed prior to collecting samples to avoid delay in the actual sample analysis, if the same person collecting the samples performs calibration.
Collecting the biogas samples should be the last task completed at the farm to ensure minimal sample holding time. A brief study was conducted in the lab to determine the integrity of the type of Tedlar® bags used to collect all biogas samples in this report. The results indicated that the triplicate samples of H_2S (1000ppm, 2500ppm and 5000ppm) analyzed over a 25-hour period

showed a significant decline after 8 hours. The results from the Tedlar® study are provided in the Appendix A.

Biogas samples were collected as follows:

1. Connect a short piece of clean PVC tubing to the barbed screw-lock valve of a 6” x 6” Tedlar sample bag.
2. Turn on gas line, then unscrew valve to fill bag with biogas. Tighten valve before bag becomes over-pressurized and turn off the gas line.
3. Empty bag completely and repeat 2 additional times.
4. After bag has been purged with biogas to be sampled 3 times, reconnect bag/PVC extension line and turn on gas line. Fill sample bag and close valve. Turn off gas line and disconnect bag from line.
5. Transport to Cornell lab for analysis.

On-site Monitoring

No special sampling requirements were necessary because the biogas stream was directly routed to the GC from the main biogas line. The main biogas line ran underground from the digester to an enclosed work shop where the GC and other experimental equipment were set up. Smaller diameter stainless steel and PVC tubing diverted streams of biogas above ground from the main to the GC and equipment. Flow rates to all of the equipment were controlled using parastaltic pumps and flow meters. Important maintenance procedures were followed to ensure quality control of the analyses. Some of these include:

1. Ensure proper seals between valves and line connectors.
2. Calibrate the GC regularly using specified calibration gas supplied by Daniel.
3. Maintain supply of carrier gas (helium).

Manure

Two different manure samples were required for each sampling event: the raw manure entering the digester from the mixing tank and the effluent exiting the digester. The same technique was used for both samples. The object is to obtain a representative sample of the material.

Raw Manure

1. Agitate (power on automated mixer) the manure within the storage pit until completely mixed.
2. Using sampling tool with extendable reach, fill one cup with manure and deposit in a clean plastic bucket. Repeat 10 times, trying to grab samples from various locations/depths in the pit.
3. Immediately mix the manure in the bucket.
4. Fill one 500 mL plastic or glass-sampling jar with manure from the bucket. This will be a representative composite sample of the raw manure.
5. Label jar with sample ID, description, date, and name of sampler.
6. Place jar in a cooler containing ice packs and deliver to lab.

Digested Effluent

1. Using sampling tool with extendable reach, fill one cup with manure and deposit in a clean plastic bucket. Repeat 10 times, trying to grab samples from various locations/depths in the effluent discharge pit.
2. Immediately mix the manure in the bucket.
3. Fill one sterile 500 mL plastic or glass-sampling jar with manure from the bucket. Secure lid firmly. This will be a representative composite sample of the digested manure.
4. Label jar with sample ID, description, date, and name of sampler.
5. Place jar in a cooler containing ice packs and deliver to lab immediately.

Water

Faucet Sample

1. Remove any aerators or nozzles from the cold-water faucet.
2. Turn on tap and let run for 3-5 minutes.
3. Rinse a sterile 250 – 500 mL bottle once with water to be sampled.
4. Fill bottle completely, trying not to leave any headspace.
5. Tighten cap securely and place in a cooler containing ice packs.
6. Label jar with sample ID, description, date, and name of sampler.
7. Deliver sample to lab. Note: water samples must be submitted to the lab within 24 hours to maintain sample integrity.

Forage

Total Mixed Rations Sample

1. Collect only freshly blended rations.
2. Grab 10 handfuls of the mix at evenly spaced locations along the feed row. Samples should be collected at different depths (trying to avoid samples of forage exposed to the surface).
3. Repeat for each row of feed if required.
4. All sub samples should be mixed in a clean plastic bucket to form a composite and placed in a large plastic forage sampling bag.
5. Label sample bag with sample ID, description, date, and name of sampler.
6. Place in cooler containing ice packs and deliver to lab.

ANALYTICAL TECHNIQUES

Determination of H_2S in biogas

Raw biogas samples collected in Tedlar® bags were transported to the Cornell Biological and Environmental Engineering (BEE) laboratory for immediate analysis using a SRI Model 6010C gas chromatograph. Each bag was analyzed three times and the average taken as the recorded measurement. In cases where two duplicate bags were collected, the average of all GC analyses (i.e. 3 runs from each bag for a total of 6) was the recorded. The procedures for equipment calibration and analysis are as follows.

Calibration

1. As mentioned previously, GC calibration should be completed prior to sample analysis. It takes approximately 1.5-2 hours to calibrate the SRI for H_2S analysis. The time required to collect the sample and return to the laboratory should be taken into consideration. In most cases, it is best to calibrate the GC prior to actually collecting the sample (or have someone else perform the calibration while the sample is collected) to save time.
2. Open valve on hydrogen cylinder prior to starting GC. Turn on GC and press ignition switch until flame ignited. Allow the GC to warm for a minimum of 20 minutes or until proper temperatures are reached. Check manufacturer's guidelines to ensure settings are correct for type of analysis to be performed (column temperature, oven temperature, voltage, etc.).
3. While the GC is warming, prepare the calibration sample. Using 1000 ppm (99.99%+ purity) standardized H_2S, purge the sample bag three times, completely evacuating all gas from the bag each time. Fill bag and close valve immediately to avoid gas loss or the entry of air.
4. Using a gastight glass syringe, withdraw a 0.1 mL sample from the bag and inject it in the external sample port. As soon as the entire sample has been injected, manually initiate the PeakSimple run by pressing either the "enter" button on the computer keyboard or the run button on the GC. Repeat 3 times. Record the value measured under "Area" in the results table in PeakSimple. This will provide the results for the 1000-ppm H_2S calibration. The GC must be calibrated within a suitable range relative to the expected concentration of H_2S in the biogas; therefore a calibration range of 1000-5000 ppm is used for the majority of the analyses in this study.
5. Repeat the above procedure for 2000, 3000, and 5000 ppm using syringe volumes of 0.2, 0.3, and 0.5 mL respectively.
6. Record these results in a new calibration file in PeakSimple.

Sample Analysis

1. Using the same technique as in the calibration procedures, inject 0.1 mL of the biogas sample into the external sample port and repeat 3 times for each sample bag. The volume 0.1 mL is used for each analysis.
2. The actual concentration of the biogas sample will be listed under "external" in the PeakSimple results file. Record this value.

Manure Water Forage Samples

Manure, water, and forage samples were submitted to Dairy One for analysis. The analytical procedures used for each of these mediums can be found at http://www.dairyone.com/.

RESULTS FROM BIOGAS COLLECTION AND ANALYSIS

Pellerin et al. (1987) report that water-saturated biogas from dairy manure digesters consist primarily of 50-60% methane, 40-50% carbon dioxide, and less than 1% sulfur impurities, of which the majority exists as hydrogen sulfide. The results from the biogas analysis in this project was consistent within these ranges. The following figures summarize the results of all biogas measurements from DDI and H_2S monitoring from all five farms. Figures 4.1 to 4.6 represent data collected at DDI. The average concentration of H_2S from samples gathered on 13 different occasions between July 2003 and May 2004 was 1984 ppm (less than 0.2%) with a standard deviation of ± 570 ppm. The error bars indicate variation in the actual analytical results. Two duplicate bags were collected for each sampling event and each sample was analyzed three times. The average of these results provided each point on a given date as shown in Figure 3.1. The average of CH_4 measurements was 60.27% (plus or minus approximately 1%) between July and November 2003 (Figure 3.2) and over the same measurements, the BTU content averaged 612 for the same period (Figure 3.5). Figures 3.3 and 3.4 show averages of N_2 and CO_2 at 1.5% and 38.2% respectively. CO_2 is often just estimated as the balance of the biogas when CH_4 is known. The presence of N_2 in the biogas is likely due to air entering the biogas line before passing through the GC for analysis. In pure biogas, N_2 content should be negligible and, in fact, is very low. Figures 3.6 and 3.7 show the daily levels of the biogas (CH_4, CO_2, N_2, BTU level) from July to November 2003 at DDI.

The error bars in these graphs generally became less with time. It is possible that the range of results found over the entire sampling program may have been a result of improved sampling and analysis techniques as practice and experience were gained throughout the project. In addition, the operation of the digester and the characteristics of the inputs will influence the microbial performance, which ultimately affects biogas production. Further analysis of digester inputs may explain some of the minor fluctuations in H_2S and CH_4 content in the biogas.

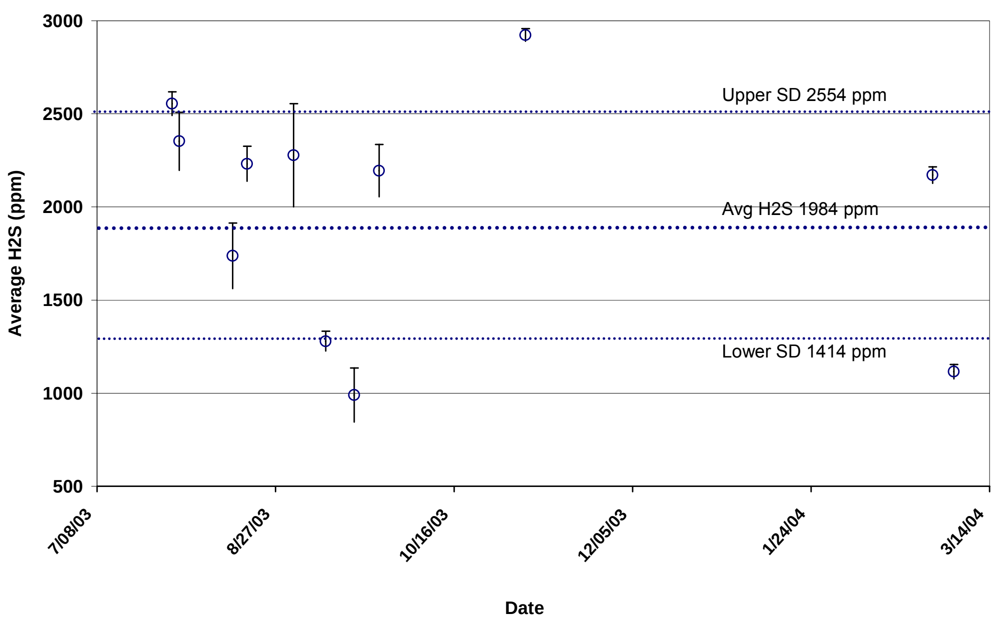


Figure 2.1 Average H_2S measured in biogas at DDI.
July 2003 – March 2004

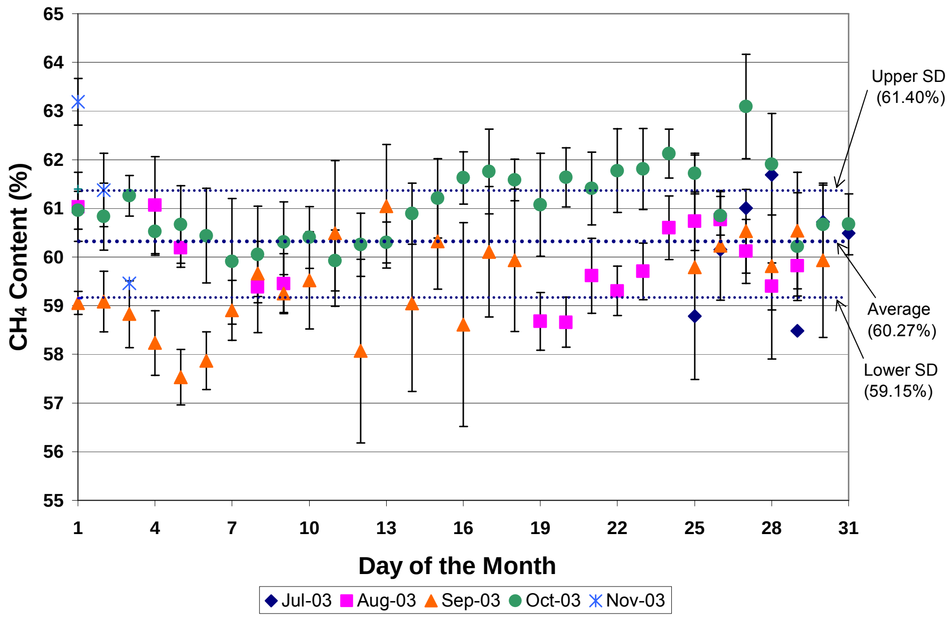


Figure 2.2 Average daily CH_4 measured in biogas at DDI.
July– November 2003

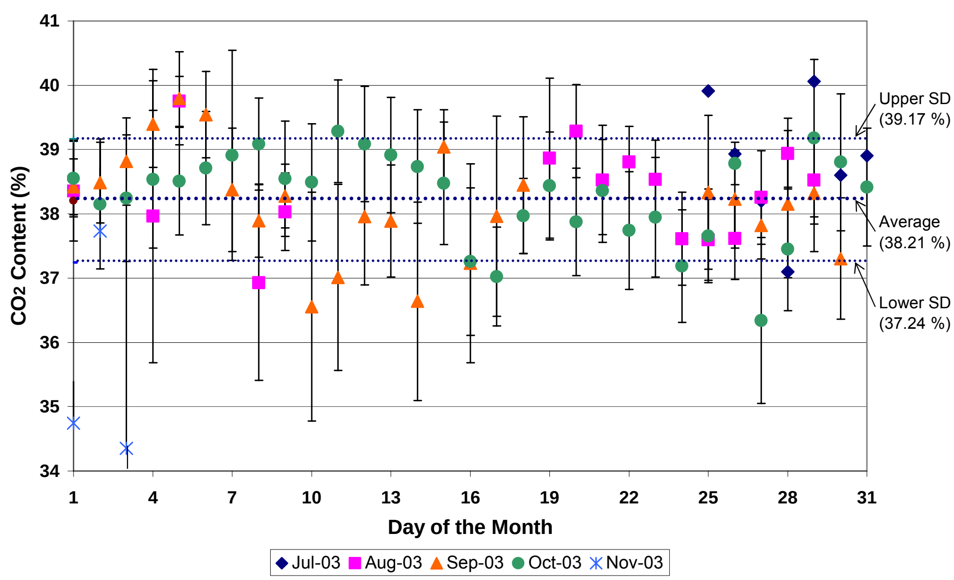


Figure 2.3 Average daily CO_2 measured in biogas at DDI.
July– November 2003

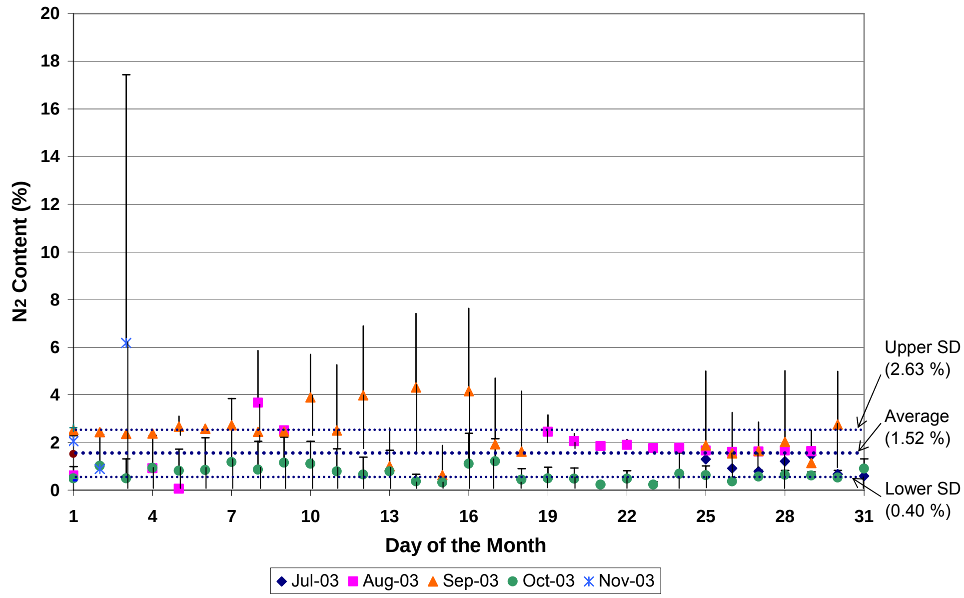


Figure 2.4 Average daily N_2 measured in biogas at DDI.
July– November 2003

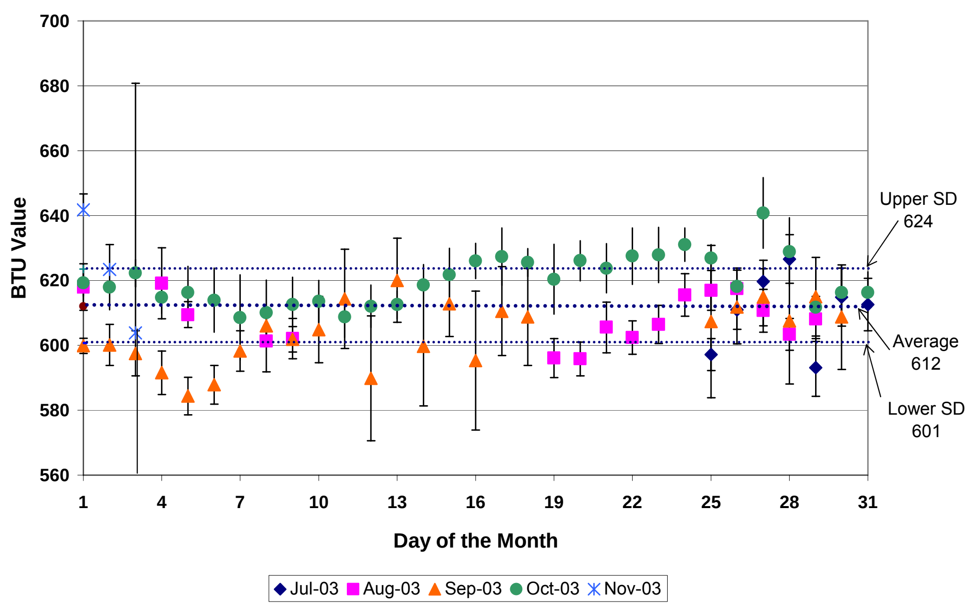


Figure 2.5 Average daily BTU content measured in biogas at DDI.
July– November 2003

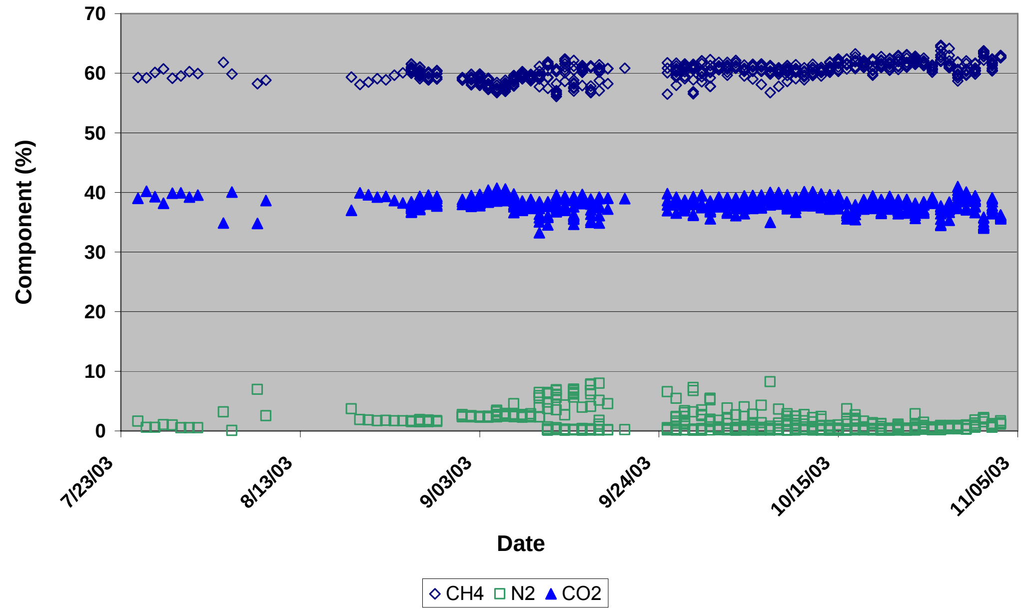


Figure 2.6 Raw biogas analysis at DDI.
July– November 2003

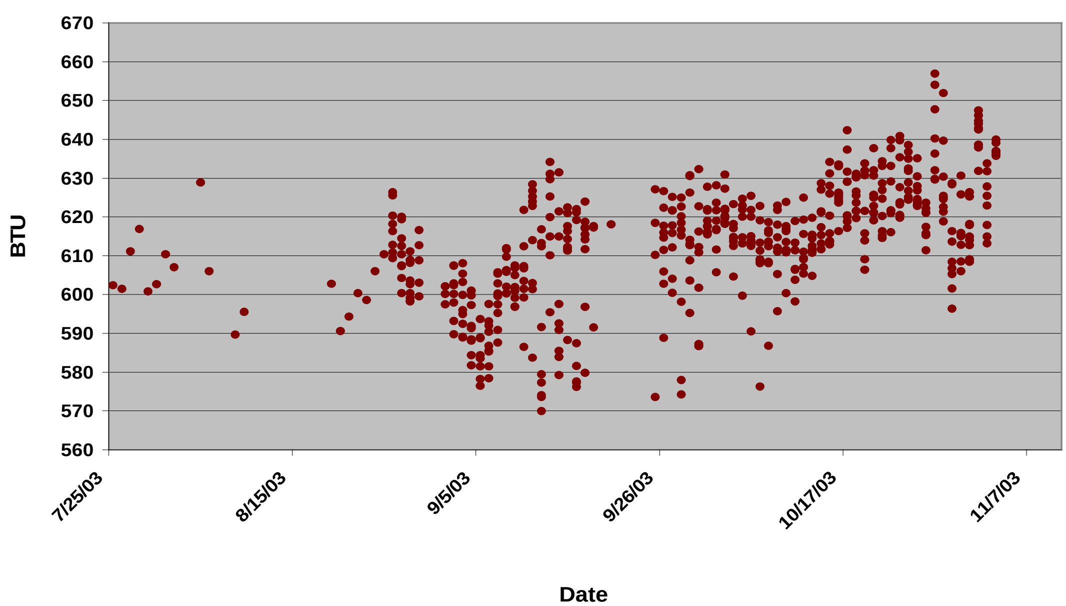


Figure 2.7 Raw biogas BTU at DDI.
July– November 2003

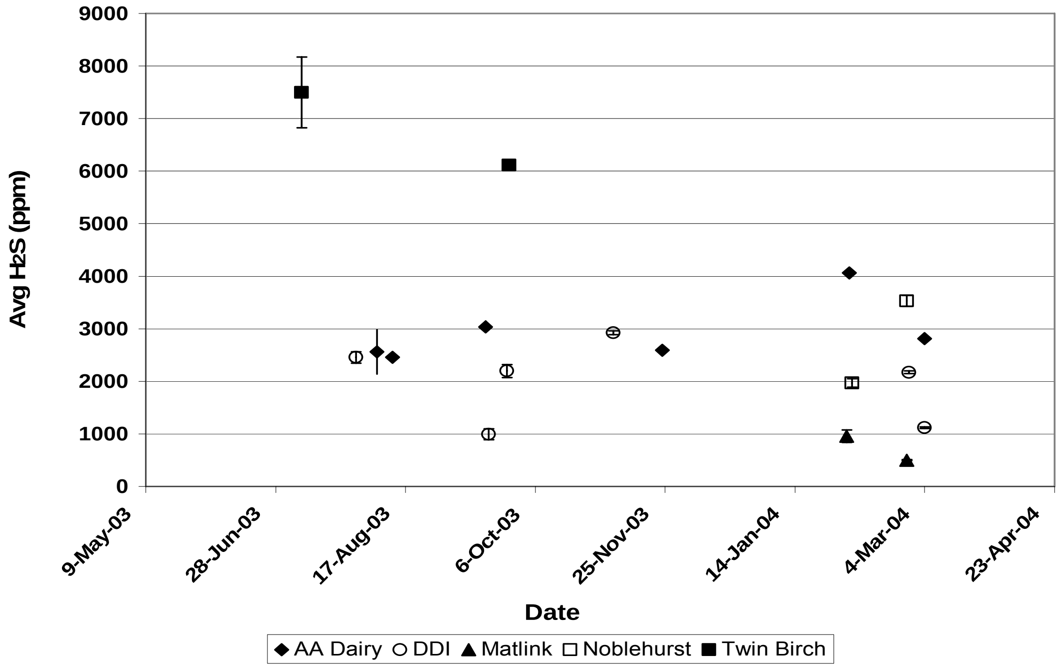


Figure 2.8 Average H_2S concentrations at 5 dairy farms in upstate New York.
July 2003 – March 2004

Figure 3.8 illustrates the variation over time and between the five farms for the concentration of H_2S in the biogas. This clearly indicates that specific characteristics of digester systems such as environmental conditions, animal feed, water, addition of other organic materials to the digester may influence the concentration of H_2S in the biogas generated. Of particular note is that the H_2S concentrations at Matlink is substantially less than the other farms and is potentially attributable to co-digestion with food wastes and manure. Little formal work in this area has been completed, however, "a few dairy farms with anaerobic digesters in the U.S. have tried mixing food wastes with dairy manure for biogas production. Successful results have been reported with increased biogas production and better gas quality" (Scott and Ma, 2004).

Preliminary analysis indicates ambient temperature may affect measured CH_4 content in the biogas. By graphing methane production against ambient temperatures from July 25 to November 3, 2003, a trend was identified as shown in Figure 3.9
for the period of August 22 – August 28, 2003.

For those values greater than the standard deviation 61.4% (less than 6% of all data points), the average ambient temperature for all of these points was 51.7 F. The average temperature for the values of CH_4 production less than the lower standard deviation (59.15%) was 61.0 F. Further statistical analsyis is given Table 3.1.

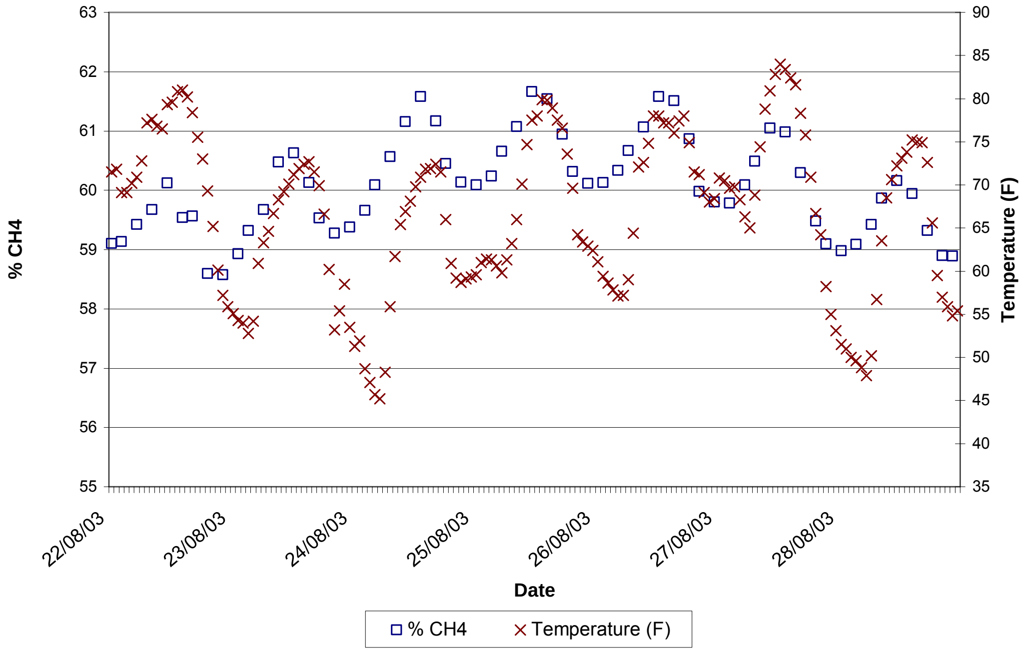


Figure 2.9 Methane generation with ambient temperature at DDI.
August 22 – 28, 2003

Table 2.1 Analysis of various ambient temperature ranges at DDI.

July – November, 2003

Temp Range	**T ≥ 70 F**	**70 > T ≥ 50 F**	**50 > T ≥ 30 F**
No. Data points in range	61	145	162
% of total data points (2441)	2.5%	6%	6.6%

Thus, it appears that ambient temperatures may have a small effect on CH_4 content of biogas at DDI. However, the explanantion for the variation of CH_4 content with temperature, whether due to GC sensitivity to ambient temperature changes or a function in biogas volumetric change as a function of temperature variations is not resolved. Additional graphs depicting the variation in CH_4 content on a daily, weekly and monthly basis are provided in the Appendix B. Temperatures shown in these figures are ambient temperatures and not the biogas temperature itself.

MANURE, WATER, AND FORAGE ANALYSES

Analyses of manure and water for four farms are given in Tables 3.2 and 3.3. Of special interest is the fact that Twin Birch has a much higher concentration of sulfur in the water compared to the other three farms. This may suggest that the significantly higher H_2S concentration (>6000 ppm) in the biogas at Twin Birch is at least partially attributed to the sulfur in the water.

Table 2.2 Manure analyses at various NY State dairies.

Sample ID	6702500	6702510	6702520	6702530	6702540	6702550	6891820	6891830	***Expected***	
Date Sampled	09/26/03	09/26/03	09/19/03	09/19/03	09/18/03	09/18/03	11/24/03	11/24/03		
Location	TB E	TB R	AA E	AA R	DDI E	DDI R	AA E	AA R	Avg (%)*	+/- 1 sd*
Nitrogen (N)	0.46%	0.54%	0.48%	0.57%	0.38%	0.43%	0.46%	0.49%	0.39	0.18 - 0.61
Ammonia Nitrogen	0.25%	0.16%	0.23%	0.21%	0.21%	0.22%	0.26%	0.19%	0.15	0.06 - 0.24
Organic Nitrogen	0.22%	0.38%	0.25%	0.36%	0.17%	0.21%	0.20%	0.29%	0.24	0.08 - 0.41
Phosphorus (P)	0.08%	0.09%	0.14%	0.10%	0.06%	0.07%	0.06%	0.06%	0.08	0.01 - 16
Phosphate Equivalent (P205)	0.17%	0.20%	0.33%	0.23%	0.13%	0.17%	0.15%	0.14%	0.17	0.01 - 0.36
Potassium (K)	0.34%	0.31%	0.27%	0.29%	0.23%	0.29%	0.27%	0.29%	0.27	0.12 - 0.42
Potash Equivalent (K20)	0.42%	0.37%	0.32%	0.34%	0.28%	0.34%	0.32%	0.35%	0.33	0.15 - 0.51
Total Solids	8.16%	12.66%	11.92%	11.87%	6.28%	9.05%	8.31%	11.69%	12.2	3.9 - 20.5
Sulfur	0.04%	0.08%	0.05%	0.05%	0.02%	0.03%	0.02%	0.04%		
Density	1.01 kg/l	0.95 kg/l	0.97 kg/l	0.88 kg/l	1.00 kg/l	0.98 kg/l	0.91 kg/l	0.94 kg/l	0.98	0.91 - 1.06

Notes: TB = Twin Birch, AA = AA Dairy, DDI = Dairy Development Int., E = Digester Effluent, R = Raw Manure
*Manure Stats, Dairy One, Ithaca, NY (04/30/03)

Table 2.3 Water analyses at various NY State dairies.

Sample ID	6702440	6702450	6702460	6891810		
Date Sampled	09/19/03	09/26/03	09/18/03	11/24/03		
Location	AA	TB	DDI	AA	Possible problems for mature cattle	Expected
Total Coliform/100 mL	-	-	-	< 1	15	< 1
e.Coli	-	-	-	-	-	-
Nitrates, ppm	-	-	-	42	100	0 - 44
Nitrates-Nitrogen, ppm	-	-	-	10	23	0 - 10
Sulfates, ppm	15	102	12	12	1000	0 - 250
Sulfates - Sulfur, ppm	5	34	4	4	333	0 - 83
Chlorides, ppm	26	59	33	18	300	0 - 250
Hardness, ppm CaCO3	385	579	247	349	-	0 - 370
Total Dissolved Solids (TDS), ppm	473	827	370	-	3000	0 - 500

Calcium (Ca), ppm	119.6	168	76.3	107.6	500	0 - 100
Magnesium (Mg), ppm	21	38.8	13.7	19.6	125	0 - 29
Potassium (K), ppm	-	-	-	< 0.1	20	0 - 20
Sodium (Na), ppm	16.9	26	23.5	13.5	300	0 - 100
Iron (Fe), ppm	<0.01	<0.01	<0.01	-	0.3 (taste)	0 - 0.3
pH	7.6	7.6	7.9	7.8	<5.5 or >8.5	6.8 - 7.5

Note: AA = AA Dairy, DDI = Dairy Development Int., TB = Twin Birch

Table 2.4 Feed analyses at various NY State dairies.

Sample ID		6702470	6702480	6702490	6891800	6702470	6702480	6702490	6891800
Date Sampled		9/26/03	9/19/03	9/18/03	11/24/03	9/26/03	9/19/03	9/18/03	11/24/03
Location		TB	AA	DDI	AA	TB	AA	DDI	AA
% Moisture	AF	54.4	56.6	56.4	61.8	0.21	0.2	0.19	0.17
	DM					0.45	0.46	0.44	0.44
% Dry Matter	AF	45.6	43.4	43.6	38.2	0.37	0.39	0.42	0.34
	DM					0.81	0.9	0.96	0.9
% Crude Protein	AF	6.9	8.1	7.8	6.8	0.16	0.2	0.17	0.16
	DM	15.	18.7	18	17.7	0.36	0.47	0.4	0.43
Soluble Protein % CP	AF					0.14	0.14	0.11	0.13
	DM	39	36	38	46	0.32	0.32	0.25	0.33
% Acid Detergent Fiber	AF	10.9	9.5	10	9.6	0.61	0.59	0.67	0.72
	DM	24	21.9	22.9	25.1	1.35	1.36	1.53	1.89
% Neutral Detergent Fiber	AF	16.5	15.3	15.9	14.6	0.194	0.154	0.152	0.105
	DM	36.1	35.4	36.5	38.2	0.426	0.355	0.348	0.274
% NFC	AF	17	14.3	14.3	12.4	120	75	184	59
	DM	37.2	33	32.9	32.6	264	172	422	155
% Crude Fat	AF	1.9	2.1	1.9	1.6	26	34	31	15
	DM	4.2	4.7	4.4	4.1	56	78	70	40
% Ash	AF	3.33	3.53	3.63	2.84	8	6	9	4
	DM	7.3	8.13	8.33	7.44	17	15	22	10
% TDN	AF	31	30	30	26	39	26	32	14
	DM	69	69	68	68	86	60	73	37
NEL, (Mcal/Lb)	AF	0.33	0.32	0.31	0.28	0.2	0.3	0.4	0.3
	DM	0.73	0.73	0.72	0.72	0.4	0.7	1	0.9
NEM, (Mcal/Lb)	AF	0.33	0.32	0.31	0.27	0.11	0.11	0.08	0.09
	DM	0.73	0.73	0.71	0.71	0.25	0.25	0.17	0.25

Results appear representative of soybean silage

Note: AA = AA Dairy, DDI = Dairy Development Int., TB = Twin Birch, AF = As fed, DM = Dry matter

BIOGAS PROCESSING

A significant goal of this project has been to consider the potential for biofiltration to reduce (remove) the concentration of H_2S because all energy converters need to operate at H_2S levels significantly less than that found in raw biogas. Zicari (2003) has considered the utilization of cow-manure compost for removal of H_2S from AD biogas using small-scale reactors. Slipstreams of AD biogas (approximately 60% methane, 40 % carbon dioxide and 1000- 4000 ppm of H_2S) from an operating system at AA Dairy and Dairy Development International (DDI) were passed through reactor sections of a cow manure compost mixture within polyvinyl chloride cylinders of 0.1 m in diameter and 0.5 m in length. The mature cow-manure compost (60 days in AA Dairy's outdoor windrow system) was mixed in a 1:1 ratio with dry maple wood chips. Columns have shown over 90% removal efficiency for the early stages of these tests (Figure 4.1 and 4.2). The removal efficiency (RE) is defined as the difference in inlet and outlet concentrations of H_2S divided by the inlet concentration. Column A (Figure 4.1) continued to operate with RE's above 85% for 33 days before falling off to 55% by day 44. Column B (Figure 4.2) decreased to 50 – 60% RE after 16 days and performed at this level for the rest of the run, except for an increase to around 80% RE between days 37-40. Runs were terminated after 44 days, as both columns A and B neared 50% RE, to examine the compost for sulfur accumulation. The H_2S elimination capacity of columns A and B ranged from 24 – 112 and 16 – 118 g $H_2S/m^3_{packing}/hr$, respectively. The total mass of H_2S removed from the gas during these experiments is estimated at 135 and 127 g H_2S, respectively for columns A and B. These values approach a maximum value of 130 g $H_2S/m^3_{packing}/hr$ reported for organic media by Yang and Allen (1994).

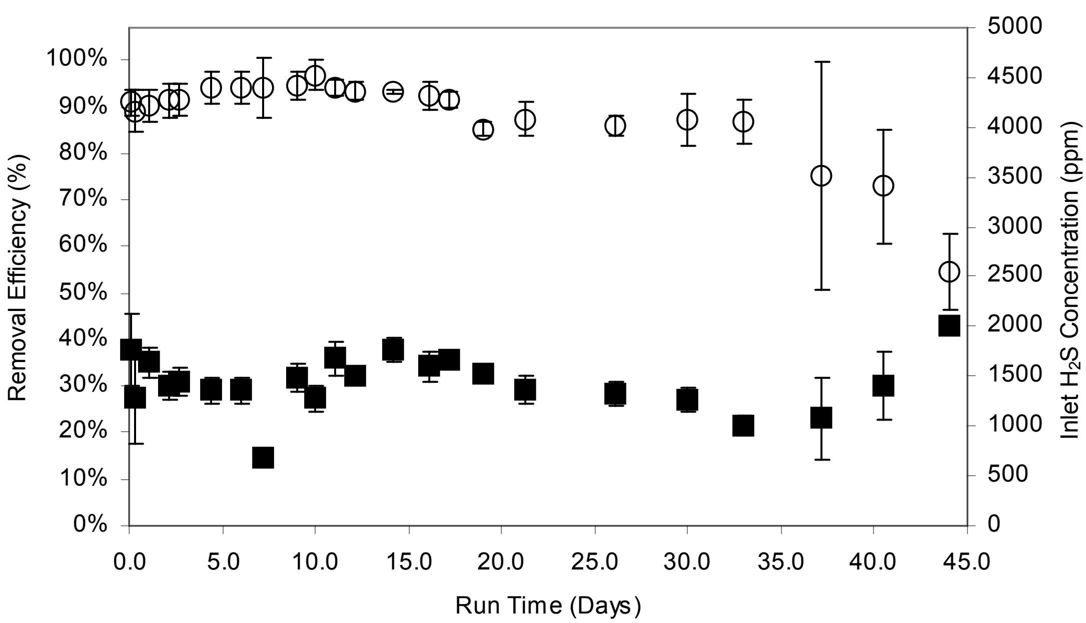


Figure 3.1 Removal efficiencies (○) and inlet concentrations (■) for Column A.

Ambient and bed temperatures were measured for a portion of the study but not throughout. A proposed explanation for the decrease in removal efficiency for Figure 4.2 around day 10 is that an upper critical temperature limit was surpassed, causing the number of active bacterial populations to decrease. Elevated bed temperatures, over both inlet gas and ambient temperatures, indicate that exothermic biological, chemical, or physical reactions are occurring in the bed and could potentially be used to track bed activity or viability. During the first 9 days, both columns exhibited an increased bed temperature of about 5° C over the inlet gas temperature. At day 10, corresponding with the upset in removal efficiency noticed for column B (Figure 4.3), the margin of bed temperature rise over inlet gas temperature fell to around 2° C. Column A, which maintained higher removal efficiency during the first 17 days, also displayed a higher bed temperature elevation of around 4° C during days 10-18.

Columns C and D (Figures 4.3 and 4.4) were operated for 83 days between June and September 2003. In columns C and D, removal efficiencies were between 80-100% for the first 20 days. Sharp decreases in removal efficiencies, to 61% and 54% for columns C and D, respectively, were observed between days 20 and 21. For days 21-83, columns C and D behaved similarly with removal efficiencies varying between 29% and 93%. Relative maxims in removal efficiencies were observed for trial C on days 31 and 59, at 86% and 93%, with relative minima of 39%, 29%, and 34%, occurring on days 26, 37, and 67 respectively (Figure 4.3). Relative maxims in removal efficiencies for trial D were also observed on days 31 and 59, at 84% and 83%, with relative minima of 35%, 34%, and 31%, also occurring on days 26, 37, and 67, respectively (Figure 4.4).

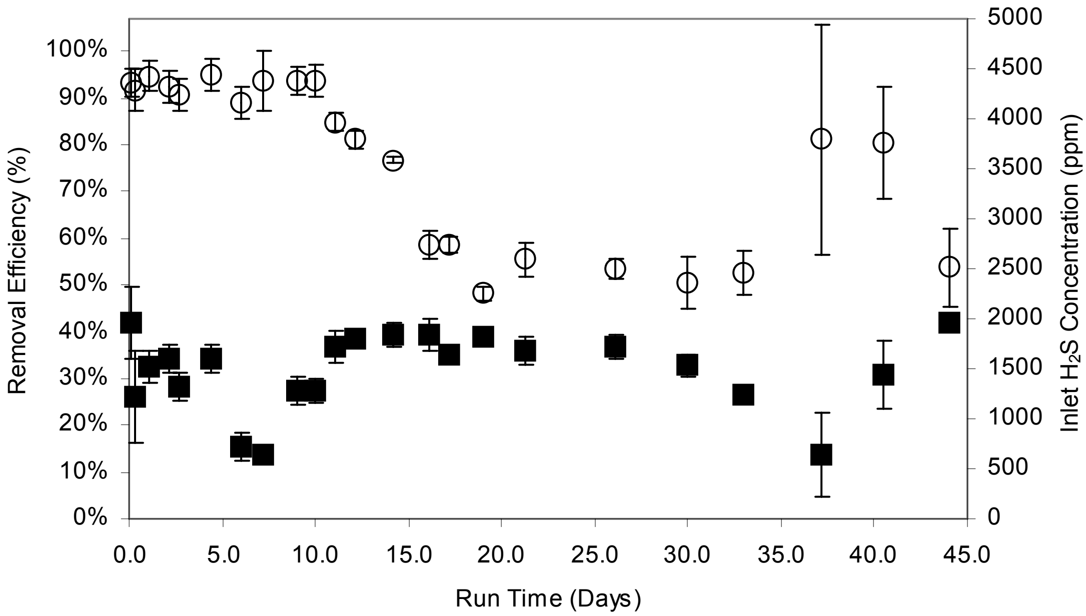


Figure 3.2 Removal efficiency (○) and inlet concentration (■) for Column B.

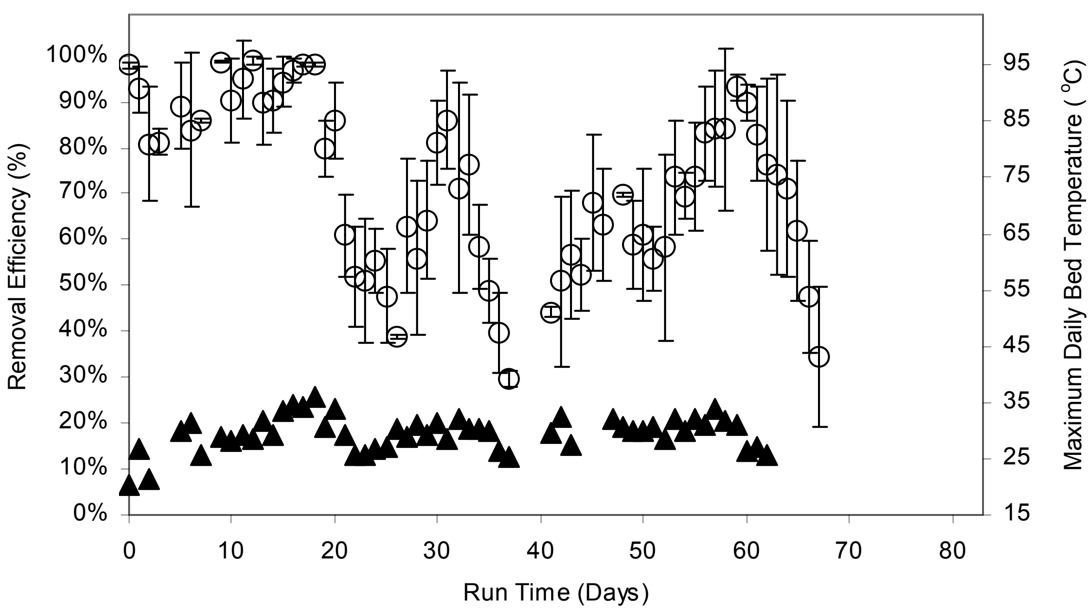


Figure 3.3 Removal efficiency (○) and maximum daily temperatures (▲) for Column C.

Instrument failures were responsible for data loss between days 67-83, and average inlet concentrations with removal efficiencies of 50% were assumed for the following calculations. Elimination capacities ranged from 19-46 (average 32) g $H_2S/m^3_{packing}$/hr for column C, and 17-46 (average 27) g $H_2S/m^3_{packing}$/hr for column D.

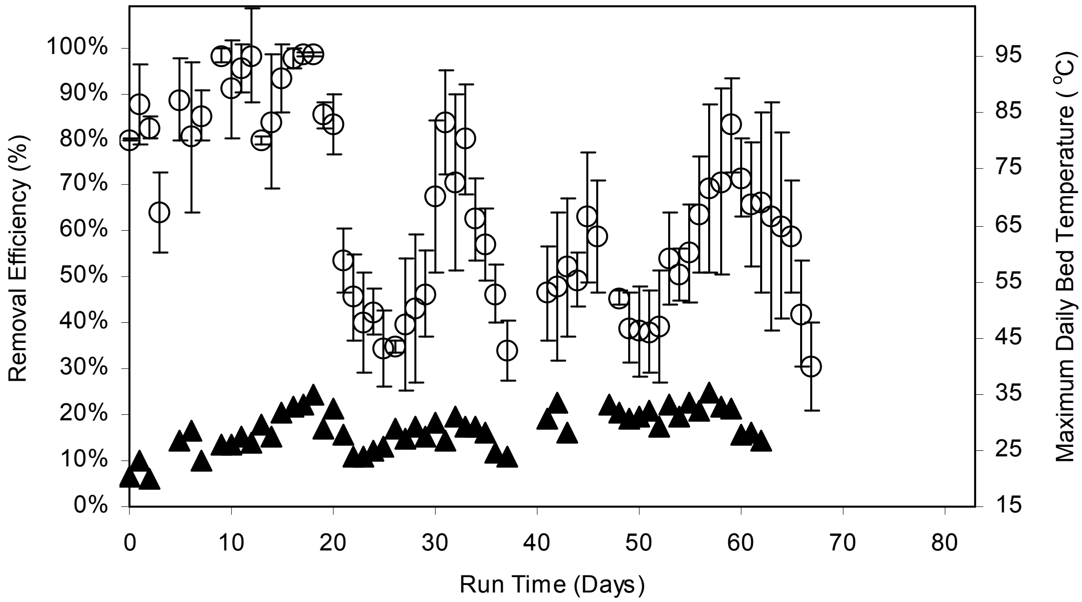


Figure 3.4 Removal efficiency (○) and maximum daily bed temperatures (▲) for Column D.

The highest recorded maximum daily media temperatures for columns C and D (Figures 4.3 and 4.4), 35.9° C and 34.8° C, respectively, occured on day 18, two days prior to the decline in effectiveness around day 20. Additionally, relative maxims in the maximum daily bed temperatures occured on days 32 and 57, corresponding closely with maxims in column removal efficiencies followed shortly by reductions in performance. These data, and that for trials A and B, are suggestive of the existence of a very tight optimum temperature operating range, which, when exceeded, creates biological upset and a subsequent reduction in performance. Maximum daily bed temperatures followed maximum daily ambient temperatures (± 3° C), and relative maxims or minima in the bed temperatures corresponded to those in the ambient temperature record.

"IRON SPONGE" RESULTS

DDI did install an iron sponge system to "clean" H_2S from raw biogas. No systematic and consistent measurements were obtained from this system. Two measurements were taken about a week apart with Draeger indicator tubes to obtain a rough assessment of the effect of the iron sponge. Unfortunately, follow up measumenets over time are not available to assess the life and effectiveness of the iron sponge. The two measuremnets illustrated in Figure 4.5 do show a removal effect early after the istallation of the system at DDI.

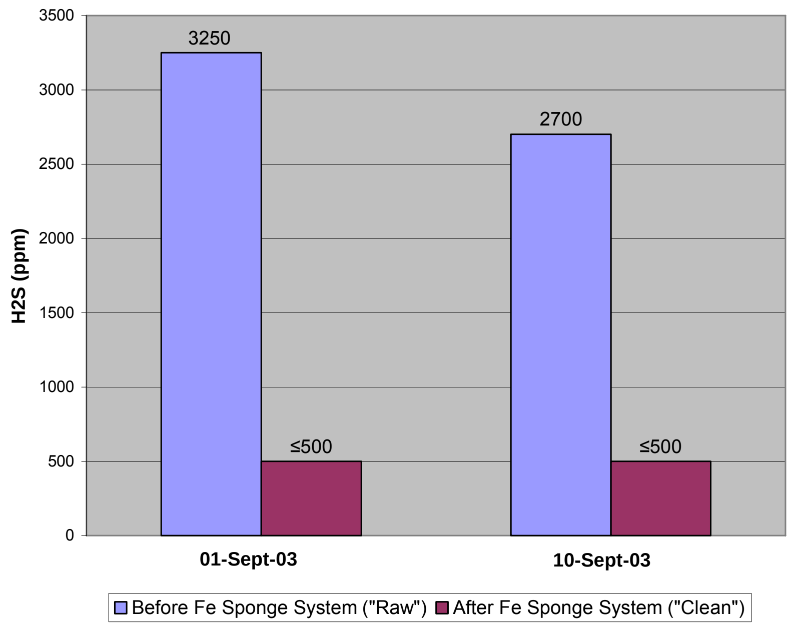


Figure 3.5 Approximate effectiveness of Fe Sponge system at DDI.

ECONOMONIC ASSESSMENT OF DAIRY-DERIVED BIOGAS INJECTION INTO THE NATURAL GAS PIPELINE

Background

Biogas recovery and processing (including cleaning and upgrading) for injection into the natural gas pipeline depends primarily on the financial viability of such a project. From the point of view of the farmer, the use of anaerobic digestion (AD) technology is often driven by community demands for odor control and concentrated animal feeding operations (CAFO) regulations. Because farmers increasingly control odor and manage manure by using AD, it makes sense from an environmental and economical perspective to explore biogas utilization options. However, processing biogas to natural gas pipeline quality, has received limited consideration because it is generally perceived to be too expensive. Nevertheless, we believe the idea is worthy of serious analysis, given the limitations and drawbacks to standard cogeneration technologies.

The main limitations to upgrading biogas to natural gas quality are not technical but economical and political. The willingness of a buyer to purchase the upgraded biogas is crucial and a buyer must be established during the initial stages of the project. A minimum price that the buyer will pay for the biogas during the lifetime of the project also must be established. In addition, it is essential to establish who will purchase the processed biogas gas in order to design the system to meet the gas quality needs of the buyer. One buyer, for instance, may accept processed biogas into the natural gas pipeline that has at least 95% CH_4, while another buyer may only accept gas with at least 98% CH_4. In addition to gas quality, the amount of gas the buyer is willing to purchase for injection into the pipeline is vital information. The buyer may want to be guaranteed that a certain amount of biogas (volume/time) will be available to inject into the line.

The cost of upgrading biogas varies considerably and very few 'hard numbers' are found in the literature. From the literature review, the limited data that is available pertains mainly to upgrading landfill gas. Because of this limitation, most of the economic data presented in this chapter is based on data from sources that have upgraded landfill biogas to natural gas quality. In general, landfill gas (LFG) is approximately 50-58 % CH_4, the primary component of natural gas. The other 42-50 % of the gas is predominantly CO_2, with small amounts of N_2 and O_2, and trace levels of non-methane organic compounds. These include alkanes, chlorocarbons, oxygenated compounds, other hydrocarbons, sulfur dioxide and H_2S. Usually, agricultural biogas has more CH_4 than LFG (58-65%) and does not contain alkanes, chlorocarbons and oxygenated compounds.

To date, most landfill gas recovery projects utilize the gas in direct applications, such as in boilers or to heat greenhouses (Goldstein, 2005). Using the landfill gas to generate electricity with diesel engines or microturbines is another emerging technology. Using LFG as a source of alternate fuel, by upgrading the gas to a high Btu value for pipeline injection or for vehicle fuel, is less prevalent, although there are several operational high Btu projects in the United States. As an example of a high Btu application, the LFG from one relatively small landfill in Monroeville, PA is processed and blended into the natural gas pipeline. Another project, as an example of a medium-Btu application, is blending non-upgraded LFG (impurities such as alkanes, chlorocarbons, oxygenated compounds, water, sulfur dioxide and H_2S are removed, but not CO_2) into the natural gas pipeline. To keep the amount of CO_2 in the pipeline at an acceptable level, the LFG is blended with natural gas in the pipeline (Landfill Methane Outreach Program, 2004). Table 4.1 below displays some operational projects that convert LFG to natural gas for pipeline injection.

Financial Viability of Upgrading Biogas to Pipeline

Because LFG is similar to the biogas produced as a result of AD of manure on a dairy farm, much of the economic information from LFG processing projects can be applied to dairy biogas processing projects. For a landfill with 1 million metric tons of waste in place, it is estimated that, on average, 200 million ft^3/year or 550,000 ft^3/day of gas will be produced (U.S. EPA Landfill Methane Outreach Program, 1996). Presently, due to the high cost of cleaning and upgrading LFG, only large landfills that produce substantial quantities of gas are candidates for converting low Btu LFG to high Btu, pipeline quality gas. From Table 4.1, the smallest landfill from which LFG is upgraded to high Btu gas has two million metric tons of waste in place.

To compare gas produced in a landfill to the gas produced by AD on a dairy farm, the landfill gas production can be converted to a 'cow equivalent'. To determine the amount of biogas a landfill produces each year, taking into account the decrease in gas production as the waste in the landfill disintegrates, the EPA LandGem Model was used. The landfill gas generation rate in this model is based on a first order decomposition model, which estimates the landfill gas generation rate using two parameters:

- L_o, the potential CH_4 generation capacity of the waste and
- k, the CH_4 generation decay rate, which accounts for how quickly the methane generation rate decreases, once it reaches its peak rate.

The methane generation rate is assumed to be at its peak upon placement of the waste in the landfill. This model allows the user to enter L_o and k values using test data and landfill specific parameters, or use default L_o and k values derived from test data collected during the course of research for federal regulations governing air emissions from municipal solid waste landfills. In this case, k and L_o values

Table 4.1 Operational Medium and High Btu LFG Projects Landfill Methane Outreach Program, December 2004

Landfill Name	Landfill City	State	Waste In Place (tons)	Year Landfill Opened	Landfill Closure Year	Landfill Owner Organization	Project Start Date	Project Developer Organization	LFGE Project Type	LFG Flow to Project (10^6 scfd)
Johnson County LF	Shawnee	KS	20,000,000	1979	2030	Deffenbaugh Industries, Inc.	9/1/2001	South Texas Treaters	High Btu	4.900
American LF	Waynesburg	OH	14,157,332	1975		Waste Management, Inc.	6/30/2003	Toro Energy, Inc.	Medium Btu	No Data
Pinnacle Road LF	Dayton	OH	6,150,000	1979	1993	Waste Management, Inc.	4/1/2003	DTE Biomass Energy	High Btu	1.122
Rumpke SLF, Inc.	Cincinnati	OH	11,500,000	1965	2021	Rumpke Waste, Inc.	1/1/1986	Montauk Energy Capital/GSF Energy	High Btu	9.000
Stony Hollow LF	Dayton	OH	7,500,000	1996	2009	Waste Management, Inc.	4/1/2003	DTE Biomass Energy	High Btu	1.550
Monroeville LF	Monroeville	PA	2,000,000	1971	2035	Waste Management, Inc.	10/29/2004	Beacon Generating LLC/Magellan EnviroGas Partners, LLC	High Btu	3.600
Valley LF	Irwin	PA	6,000,000	1990	2025	Waste Management, Inc.	2/27/2004	Beacon Generating LLC/Magellan EnviroGas Partners, LLC	High Btu	No Data
McCarty Road LF	Houston	TX	28,918,718	1977	2001	Allied Waste Services	1/1/1986	Montauk Energy Capital	High Btu	No Data
McCommas Bluff LF	Dallas	TX	26,470,000	1980	2053	City of Dallas	1/1/2000	Pacific Natural Energy, LLC	High Btu	No Data

based on USEPA AP-42, Appendix A, *Thermal Equivalents of Various Fuels*, were used. If a dairy cow produces approximately 100 ft^3/day of biogas, then, averaged over a 10 year period, a landfill with 1 million tons of waste in place will produce approximately as much biogas as 4,800 cows. Landfills with 2 and 3 million tons of waste in place will produce approximately as much biogas as 9,600 and 14,400 cows, respectively. See Table 8.2, below.

In this case, k and L_o values based on USEPA AP-42, Appendix A, *Thermal Equivalents of Various Fuels*, were used. If a dairy cow produces approximately 100 ft^3/day of biogas, then, averaged over a 10 year period, a landfill with 1 million tons of waste in place will produce approximately as much biogas as 4,800 cows. Landfills with 2 and 3 million tons of waste in place will produce approximately as much biogas as approximately 9,600 and 14,400 cows, respectively (Table 4.2).

Table 4.2 Landfill Gas Production and Dairy Biogas Equivalent

YEAR	**Gas Production With 1 Million Tons of Waste in Place (ft^3/yr)**	**Gas Production With 2 Million Tons of Waste in Place (ft^3/yr)**	**Gas Production With 3 Million Tons of Waste in Place (ft^3/yr)**
1	200,000,000	400,000,000	600,000,000
2	194,000,000	388,000,000	582,000,000
3	188,180,000	376,360,000	564,540,000
4	182,534,600	365,069,200	547,603,800
5	177,058,562	354,117,124	531,175,686
6	171,746,805	343,493,610	515,240,415
7	166,594,401	333,188,802	499,783,203
8	161,596,569	323,193,138	484,789,707
9	156,748,672	313,497,344	470,246,016
10	152,046,212	304,092,423	456,138,635
Total Biogas Production over 10 Years (ft^3)	1,750,505,821	3,501,011,641	5,251,517,462
Average Biogas Production over 10 Years (ft^3)	175,050,582	350,101,164	525,151,746
Equivalent Number of Cows	**4,796**	**9,592**	**14,388**

Effect of Farm Size

We will assess the effect of farm size on the financial viability of injection to the natural gas pipeline in this section. We assume that the biogas from dairies has the parameter values of CH_4 = 60%, CO_2 = 38%, N_2 and O_2 Combined = 2%, H_2S = 3,000 ppm.

Recent studies show that adding food waste to the digester increases the biogas generation potential substantially. For further information, see *A Guideline for Co-Digestion of Food Wastes in Farm-Based Anaerobic Digesters* (Scott and Ma, December, 2004) and *Potential of Using Food Wastes In Farm-Based Anaerobic Digesters* (Scott and Ma, January, 2004), which are available at http://www.manuremanagement.cornell.edu. For future projects that consider upgrading dairy biogas to natural gas pipeline quality, the addition of food waste should be considered to increase the biogas generation potential.

This analysis assumes that the minimum gas quality standards for injection into the natural gas pipeline are CH_4 = 97%, CO_2 = 2%, N_2 and O_2 Combined = 1%, H_2S < 4ppm. Given these assumptions, the gas processing system must consist of an H_2S removal system, a gas conditioning system, a CO_2, N_2 and O_2 removal system, and a compressor to increase the treated gas pressure to meet pipeline distribution pressure. A description of the main components of the system is described in Figure 4.1 for a conceptual design of the system. Vessels V_1 and V_2 are used for H_2S removal. Vessels V_3, V_4 and V_5 are pressure swing adsorption vessels (PSA).

H_2S Removal System

This system consists of two vessels containing iron oxide media, such as iron sponge (red iron oxide impregnated on wood chips), in parallel. The vessels are used in parallel so that if one vessel is being cleaned or the media is being changed, the other will operate, allowing the H_2S system to run continuously.

Gas Conditioning Package

The system consists of a coalescing filter, a gas/gas exchanger, a chiller and a gas/liquid exchanger to remove water and impurities from the biogas. The coalescing filter is used for the separation of liquid aerosols and droplets from a gas. It is recommended that as much water and impurities as possible be removed before the biogas enters the PSA. Much of the water will be removed before entering the H_2S removal system via condensation as the biogas moves through the pipe connecting the digester and the H_2S removal system. This will reduce the amount of water that the gas-conditioning package has to remove.

Gas Upgrading System
To remove constituents of the biogas that decrease its calorific value and Wobbe Index, a PSA system may be used. The Wobbe Index is defined as: the Calorific Value of Fuel/(Specific Gravity of the Fuel)$^{1/2}$ The Wobbe Index for CH_4 is approximately 1220 Btu/cubic foot. The PSA system shown in the Figure 4.1 consists of 3 vessels in series, which separates out CO_2, N_2 and O_2 from the methane rich gas by the adsorption/desorption of CO_2, N_2 and O_2 onto activated carbon or zeolites at different pressures.

Two Stage Compression
This step is necessary to increase the pressure of the treated biogas to meet the pipeline pressure specification. Natural gas that is transported through larger pipelines over long distances is at high pressures ranging from 200 to 1500 pounds per square inch (psi). This pressure reduces the volume of the natural gas being transported (by up to 600 times), and provides a propellant force to move the natural gas through the pipeline (NaturalGas.Org, 2004). In shorter, localized or district natural gas pipelines may be pressurized to 100 psi or less.

Capital Cost of Biogas Processing Equipment

Table 4.3 shows capital cost data for a biogas processing system that will clean and upgrade dairy biogas to natural gas quality. The cost data were adapted from that provided by Applied Filter Technology (AFT). AFT is a research and engineering company that has designed, constructed and built LFG processing systems that remove CO_2 and contaminants from the gas stream. The economic data provided by AFT was checked again costing information provided by another company (Cogeneration Technologies, a subsidiary of EcoGeneration™ Solutions, LLC) and was found to be comparable. According to AFT, the capital cost to install a biogas processing plant for a 500 cow dairy and 1,000 cow dairy despite the difference in biogas volume is approximately the same due to economy of scale.

Operation and Maintenance (O&M) Costs for Biogas Processing Equipment

Table 4.4 displays the yearly O&M costs to keep the biogas processing system functional and in good working condition. The data were adapted from that provided by AFT. The O&M costs presented below are based on AFT’s experience in operating several LFG processing systems over the past decade. As with capital costs, AFT estimates that the operational and maintenance costs for a 500 and 1,000 cow biogas processing plant are approximately the same.

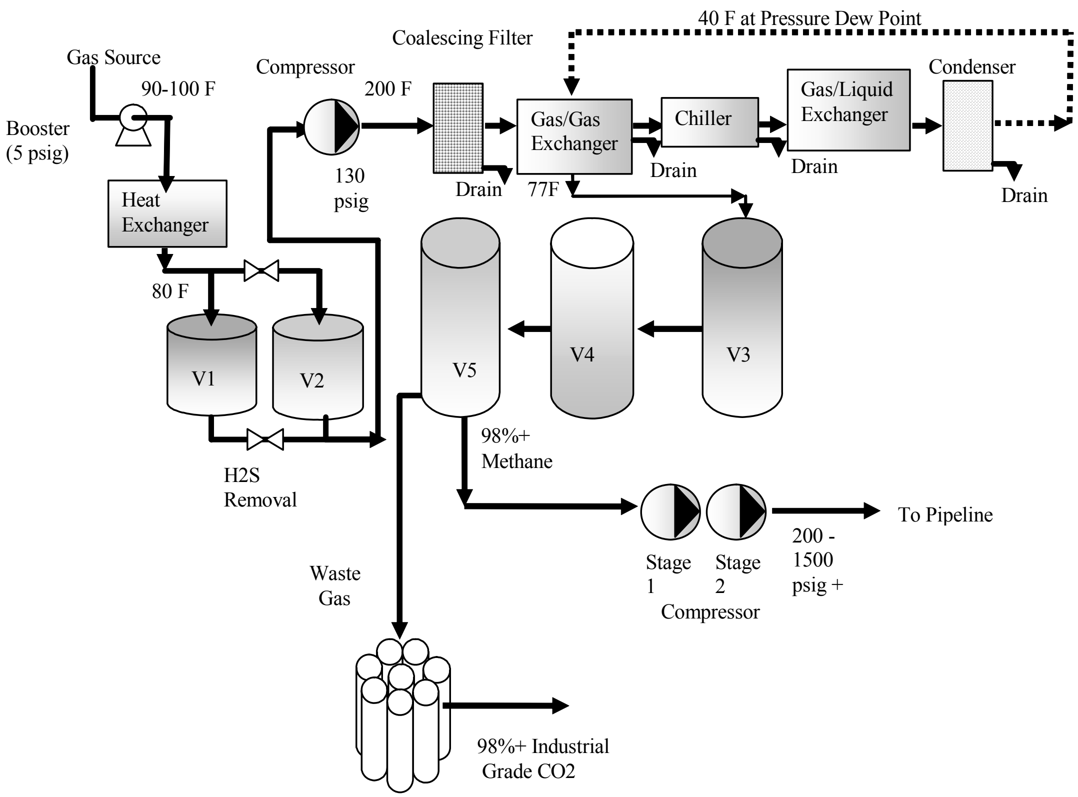


Figure 4.1 Biogas Cleaning/Upgrading System Layout. Adapted from using information provided by Applied Filter Technology, Inc.

Table 4.3 Capital Costs for Biogas Upgrade Equipment at Dairies of Varying Sizes. Adapted from Cost Data Provided by Applied Filter Technology, Inc.

	Biogas Production of 500 or 1,000 cows (500,000 /1,000,000 ft^3/day)	Biogas Production of 3,000 cows (3,000,000 ft^3/day)	Biogas Production of 5,000 cows (5,000,000 ft^3/day)	Biogas Production of 10,000 cows (10,000,000 ft^3/day)
Booster Fan + Heat Exchanger	\$4,500	\$6,000	\$10,000	\$15,000
H2S removal System (2 Vessels, pH and Moisture Control, Mixer, Tank, Pump)	\$75,000	\$110,000	\$200,000	\$375,000
H2S Removal Media (32,760 lb. initial fill)	\$7,500	\$22,000	\$35,000	\$70,000
Chemicals for pH Control (Potassium Carbonate)	\$2,000	\$5,000	\$8,000	\$10,000
Gas Conditioning Package (Compressor, Chiller, Exchangers, Instrumentation)	\$110,000	\$220,000	\$500,000	\$600,000
Condenser for Media Spent Regeneration Gas	\$1,700	\$2,500	\$4,500	\$6,000
PSA System for pipeline grade gas	\$70,000	\$180,000	\$320,000	\$450,000
Two stage compression to high pressure pipeline	\$65,000	\$125,000	\$200,000	\$270,000
Pipeline and Pipeline Connection	Site Specific	Site Specific	Site Specific	Site Specific
Miscellaneous Piping and Controls	\$15,000	\$25,000	\$45,000	\$60,000
Site Civil Preparation and Installation (15% of total)	\$52,305	\$103,575	\$197,175	\$311,400
Total Capital Costs	\$403,005	\$799,075	\$1,519,675	\$2,397,400

Table 4.4 Yearly Costs to Maintain Biogas Upgrade Equipment at Various Size Dairies
Cost Data Adapted from that provided by Applied Filter Technology, Inc.

	Biogas Production of 500/1,000 cows (500,000 /1,000,000 ft^3/day)	Biogas Production of 3,000 cows (3,000,000 ft^3/day)	Biogas Production of 5,000 cows (5,000,000 ft^3/day)	Biogas Production of 10,000 cows (10,000,000 ft^3/day)
Booster Fan + Heat Exchanger	$300	$500	$1,000	$2,000
H2S removal System (2 Vessels, pH and Moisture Control, Mixer, Tank, Pump)	$750	$750	$1,000	$2,000
H2S Removal Media (32,760 lb. initial fill)	$11,350	$30,000	$50,000	$90,000
Chemicals for pH Control (Potassium Carbonate)	$850	$2,500	$4,000	$8,000
Gas Conditioning Package (Compressor, Chiller, Exchangers, Instrumentation)	$6,000	$17,000	$20,000	$25,000
Condenser for Media Spent Regeneration Gas	$150	$150	$250	$250
PSA System for pipeline grade gas	$12,000	$16,000	$20,000	$38,000
Two stage compression to pipeline pressure	$6,000	$8,000	$12,000	$15,000
Pipeline and Pipeline Connection	None	None	None	None
Miscellaneous Piping and Controls	$250	$250	$350	$350
Total	$37,650	$75,150	$108,600	$204,400

Transportation Costs of Adding Processed Biogas to the Natural Gas Pipeline

In order to deliver the processed dairy biogas to the natural gas pipeline, an additional local pipeline may have to be installed. Pipeline designers and construction companies are often hesitant to give generalized cost estimates for pipeline installation and construction because costs are dependent on numerous location specific factors. For example, a pipeline through a sparsely populated, rural area can cost five times less than a pipeline of the same length and diameter through a densely populated, urban area.

Pipeline construction costs can be broken down into four main categories. Material costs, on average, account for 26% of total construction costs while labor, right of way and miscellaneous costs make up 45%, 22% and 7%, respectively (Parker, 2005). Depending on natural gas flow rates, pipelines can measure anywhere from 6 to 48 inches in diameter, although certain component pipe sections consist of small diameter pipes. Pipes of smaller diameters are found in collection and local distribution systems. Lateral pipelines, which deliver natural gas to or from the main, are typically between 6 and 16 inches in diameter, but can be smaller for smaller gas flows.

Small lines, called service lines, connect to the mains and go directly to homes or buildings where gas is used. In this case, a lateral pipeline would be used to transport processed biogas to the natural gas pipeline. To calculate the appropriate diameter of the lateral gas line based on processed biogas flow rates, GASCalc, software was used. The software calculates the appropriate pipe diameter using the Darcy-Weisbach equation (Equation 4.1). For lateral pipeline diameters, based on processed biogas flow rates for various sized dairies, see Table4.5.

$$D = \frac{fLV^2}{2h_I g} \qquad \{\text{Equation 4.1}\}$$

Where

h	=	head loss
f	=	friction factor
L	=	pipe length
D	=	pipe diameter
V	=	flow velocity
g	=	acceleration of gravity

Table 4.5 Diameter of lateral pipeline, in inches, depending on processed biogas flow rates (Values calculated using GASCalc Software)

	1/4 mile steel pipeline	1/2 mile steel pipeline	1 mile steel pipeline
1,000 Cows, Producing 100,000 ft^3 biogas/day	0.66	0.75	0.88
3,000 Cows, Producing 300,000 ft^3 biogas/day	1.00	1.15	1.33
5,000 Cows, Producing 500,000 ft^3 biogas/day	1.20	1.40	1.60
10,000 Cows, Producing 1,000,000 ft^3 biogas/day	1.60	1.88	2.17

Pipeline Costs

Once the appropriate pipe diameter is calculated, it is possible to determine the cost to install the pipeline of given length. Table 4.6 illustrates the material and labor costs for installing pipelines of various diameters, per linear foot. The cost data are from R.S. Means, a software package that is an industry standard for pricing civil, environmental and mechanical engineering projects. In order to choose the correct diameter of pipe to be installed, the gas flow rate through the pipe must be known. The gas flow rate is based on the digester's biogas generation potential and the number of cows on the dairy farm.

Table 4.6 Pipeline Construction and Installation Costs
(Data from R.S. Means, CostWorks 2005, Equipment and Labor Rates for Syracuse, NY)

	Unit	Bare Material (Carbon Steel)	Bare Labor	Bare Total	Total, Including Company Overhead and Profit
¼" Diameter	Linear Foot	6.15	5.10	11.25	14.45
3/8" Diameter	Linear Foot	7.35	5.20	12.55	15.95
½" Diameter	Linear Foot	9.50	5.35	14.85	18.50
¾" Diameter	Linear Foot	11.80	5.40	17.20	21.00
1" Diameter	Linear Foot	15.45	6.15	21.60	26.00
1-1/4"	Linear Foot	18.90	6.50	25.40	33.00
1-1/2"	Linear Foot	25.70	7.20	32.90	42.10
2" Diameter	Linear Foot	31.50	8.70	40.20	47.50

In order to assess the economic feasibility of upgrading biogas to natural gas quality for injection into the natural gas pipeline when the biogas processing station is not located near the pipeline, three pipeline scenarios were considered. Table 4.7 illustrates the costs of transporting upgraded biogas ¼ mile, ½ mile and 1 mile to the natural gas pipeline. In addition to the cost of the pipe installation itself, it is standard to add 25% to 50% of the cost to include valves and fittings (R.S. Means, 2005).

In order to install the pipeline underground, a trench must be dug. Table 4.8 demonstrates the cost for digging the trench in which the lateral pipeline is placed. Depending on local regulations, location of the water table, depth to frost and the location of other utility lines, the trench may be anywhere from 4 to 14 feet deep.

Table 4.7 Construction and Installation Costs for Pipeline of Various Lengths (Not Including Excavation and Backfill).

Diameter	Length	Cost of Pipe and Installation	Cost Plus Cost of Fittings*	Cost Plus Cost of Fittings**
1/4"	0.25 Miles	$19,074	$23,842.50	$28,611.00
	0.50 Miles	$38,148	$47,685.00	$57,222.00
	1.0 Mile	$76,296	$95,370.00	$114,444.00
3/8"	0.25 Miles	$21,054	$26,317.50	$31,581.00
	0.50 Miles	$42,108	$52,635.00	$63,162.00
	1.0 Mile	$84,216	$105,270.00	$126,324.00
1/2"	0.25 Miles	$24,420	$30,525.00	$36,630.00
	0.50 Miles	$48,840	$61,050.00	$73,260.00
	1.0 Mile	$97,680	$122,100.00	$146,520.00
3/4"	0.25 Miles	$27,720	$34,650.00	$41,580.00
	0.50 Miles	$55,440	$69,300.00	$83,160.00
	1.0 Mile	$110,880	$138,600.00	$166,320.00
1"	0.25 Miles	$34,320	$42,900.00	$51,480.00
	0.50 Miles	$68,640	$85,800.00	$102,960.00
	1.0 Mile	$137,280	$171,600.00	$205,920.00
1-1/4"	0.25 Miles	$43,560	$54,450.00	$65,340.00
	0.50 Miles	$87,120	$108,900.00	$130,680.00
	1.0 Mile	$174,240	$217,800.00	$261,360.00
1-1/2"	0.25 Miles	$55,572	$69,465.00	$83,358.00
	0.50 Miles	$111,144	$138,930.00	$166,716.00
	1.0 Mile	$222,288	$277,860.00	$333,432.00
2"	0.25 Miles	$62,700	$78,375.00	$94,050.00
	0.50 Miles	$125,400	$156,750.00	$188,100.00
	1.0 Mile	$250,800	$313,500.00	$376,200.00

*Fittings usually run between 25% and 50% of the cost of the pipe. These numbers include pipe cost and installation, plus 25% for fittings and valves.

** These numbers include pipe cost and installation, plus 50% for fittings and valves.

Table 4.8 Cost of Excavation for Pipeline Installation*
(Data from R.S. Means, CostWorks 2005, Equipment and Labor Rates for Syracuse, NY)

	Excavation Cost	Excavation Cost	Excavation Cost
Length	Depth of Trench = 4' to 6' Deep*	Depth of Trench = 6' to 10' Deep**	Depth of Trench = 10' to 14' Deep***
0.25 Miles	$5,476	$12,320	$13,884
0.50 Miles	$10,951	$24,640	$27,769
1.0 Mile	$21,902	$49,280	$55,538

* Using a 13 ft^3 tractor loader/backhoe
** Using a 20 ft^3 hydraulic backhoe
*** Using a 27 ft^3 hydraulic backhoe

After the pipe is installed, the trench must be backfilled to fill the trench and cover the pipeline. Table 4.9 demonstrates the cost to backfill a trench that is 6 to 10 feet in depth.

Table 4.9 Cost of Backfilling Excavation Trench After Pipeline Installation*,
(Cost Data from R.S. Means, CostWorks 2005, Equipment and Labor Rates for Syracuse, NY)

Length	Backfill Cost
0.25 Miles	$2,112
0.50 Miles	$4,224
1.0 Mile	$8,448

*Using a 27-ft3 front-end loader, Backfill material is hauled less than 100'.

Present Worth Analysis

In order to determine if a biogas-upgrading project is economically viable on dairy farms of various sizes, present worth analyses were conducted. In order to determine the present worth (PW) of upgraded dairy biogas sales, several factors or parameters were taken into considerations. They include:

- Number of cows on the dairy farm
- Selling price of the processed dairy biogas
- Interest rate

For the purpose of this analysis, four different size dairies were considered. According to the U.S. Energy Information Administration, wellhead natural gas prices have ranged from $2.00/million BTU (MBtu) to over $8.00/MBtus in the past five years (U.S. Energy Information Administration Website, Updated 8/30, 2005). In the fall of 2005, wellhead prices of up to $10.00/MBtu were observed and as of December 2005 wellhead natural gas prices were up to $14.00/MBtu (U.S. Energy Information Administration Website, Natural Gas Weekly Update, 12/15/05). Based on this information, selling prices of $2.00, $4.00, $6.00, $8.00,$10.00, $12.00 and $14.00 per MBTU were considered for this analysis. As a third variable, interest rates of 3%, 5% and 7% were used. Tables 4.10 to 4.13 display the present worth of processed biogas sales, given the parameters described above. Any future amount compared to any present amount is known as the present worth (PW) and is calculated using Equation 4.2.

$P= F (1+i)^{-n}$ {Equation 4.2}

From Equation 4.3, the PW of upgraded biogas sales is a function of the future amount of revenue generated by biogas sales, interest rates and the number of compounding periods. To determine F, biogas production, the methane content of the processed biogas and the amount of money the processed biogas is sold for must be known. To determine F, the following steps were used:

- Determine the amount of biogas generated by the AD process. The volume of biogas produced depends on the number of cows on the farm and the amount of biogas each produces.
- Once the amount of biogas generation is known, determine the amount of biogas that will be used to heat the digester. The biogas that is used to heat the digester is subtracted from the total amount of biogas available for processing.
- Next, the total amount of methane available for sale to the natural gas pipeline after the biogas is processed must be determined. This takes into account any losses during processing.
- After the total methane available for sale is determined, the PW of the upgraded biogas can be determined, depending on the selling price to the buyer.

We assumed that:

- Each cow produces 100 ft^3 of biogas per day
- 60% of the biogas is methane and 90% of the methane is recovered from the upgrading process.
- 25% of the biogas is used to heat the digester

An Excel spreadsheet was developed to calculate the present worth with the variables of cow numbers, selling price for biogas and interest rates. The results from this analysis for farm sizes of 500, 1000, 3000, 5000 and 10000 cows are given in Figures 4.10 through 4.14.

Table 4.10. Present Worth Analysis for 500 Cow Dairy

Number of Cows	Interest Rate	Gas Selling Price	PW of Processed Gas Sales
500	3%	$2.00/MBtu	$126,098
		$4.00/MBtu	$252,195
		$6.00/MBtu	$378,293
		$8.00/MBtu	$504,391
		$10.00/MBtu	$630,489
		$12.00/MBtu	$756,586
		$14.00/MBtu	$882,684
	5%	$2.00/MBtu	$114,147
		$4.00/MBtu	$228,293
		$6.00/MBtu	$342,440
		$8.00/MBtu	$456,586
		$10.00/MBtu	$570,733
		$12.00/MBtu	$684,879
		$14.00/MBtu	$799,026
	7%	$2.00/MBtu	$103,826
		$4.00/MBtu	$207,652
		$6.00/MBtu	$311,478
		$8.00/MBtu	$415,304
		$10.00/MBtu	$519,130
		$12.00/MBtu	$622,957
		$14.00/MBtu	$726,783

Table 4.11. Present Worth Analysis for 1,000 Cow Dairy

Number of Cows	Interest Rate	Gas Selling Price	PW of Processed Gas Sales
1,000	3%	$2.00/MBtu	$252,195
		$4.00/MBtu	$504,391
		$6.00/MBtu	$756,586
		$8.00/MBtu	$1,008,782
		$10.00/MBtu	$1,260,977
		$12.00/MBtu	1,513,173
		$14.00/MBtu	1,765,368
	5%	$2.00/MBtu	$228,293
		$4.00/MBtu	$456,586
		$6.00/MBtu	$684,879
		$8.00/MBtu	$913,172
		$10.00/MBtu	$1,141,465
		$12.00/MBtu	1,369,759
		$14.00/MBtu	1,598,052
	7%	$2.00/MBtu	$207,652
		$4.00/MBtu	$415,304
		$6.00/MBtu	$622,957
		$8.00/MBtu	$830,609
		$10.00/MBtu	$1,038,261
		$12.00/MBtu	1,245,913
		$14.00/MBtu	1,453,565

Table 4.12. Present Worth Analysis for 3,000 Cow Dairy

Number of Cows	Interest Rate	Gas Selling Price	PW of Processed Gas Sales
3,000	3%	$2.00/MBtu	$756,586
		$4.00/MBtu	$1,513,173
		$6.00/MBtu	2,269,759
		$8.00/MBtu	3,026,345
		$10.00/MBtu	$3,782,932
		$12.00/MBtu	$4,539,518
		$14.00/MBtu	$5,296,104
	5%	$2.00/MBtu	684,879
		$4.00/MBtu	1,369,759
		$6.00/MBtu	2,054,638
		$8.00/MBtu	2,739,517
		$10.00/MBtu	$3,424,396
		$12.00/MBtu	$4,109,276
		$14.00/MBtu	$4,794,155
	7%	$2.00/MBtu	622,957
		$4.00/MBtu	1,245,913
		$6.00/MBtu	1,868,870
		$8.00/MBtu	2,491,826
		$10.00/MBtu	$3,114,783
		$12.00/MBtu	$3,737,739
		$14.00/MBtu	$4,360,696

Table 4.13. Present Worth Analysis for 5,000 Cow Dairy

Number of Cows	Interest Rate	Gas Selling Price	PW of Processed Gas Sales
5,000	3%	$2.00/MBtu	1,260,977
		$4.00/MBtu	2,521,954
		$6.00/MBtu	3,782,932
		$8.00/MBtu	5,043,909
		$10.00/MBtu	$6,304,886
		$12.00/MBtu	7,565,863
		$14.00/MBtu	8,826,841
	5%	$2.00/MBtu	1,141,465
		$4.00/MBtu	2,282,931
		$6.00/MBtu	3,424,396
		$8.00/MBtu	4,565,862
		$10.00/MBtu	$5,707,327
		$12.00/MBtu	6,848,793
		$14.00/MBtu	7,990,258
	7%	$2.00/MBtu	1,038,261
		$4.00/MBtu	$2,076,522
		$6.00/MBtu	$3,114,783
		$8.00/MBtu	$4,153,044
		$10.00/MBtu	$5,191,072
		$12.00/MBtu	6,229,566
		$14.00/MBtu	7,267,827

Table 4.14. Present Worth Analysis for 10,000 Cow Dairy

Number of Cows	Interest Rate	Gas Selling Price	PW of Processed Gas Sales
10,000	3%	$2.00/MBtu	$2,521,954
		$4.00/MBtu	$5,043,909
		$6.00/MBtu	$7,565,863
		$8.00/MBtu	$10,087,818
		$10.00/MBtu	$12,609,772
		$12.00/MBtu	$15,131,727
		$14.00/MBtu	$17,653,681
	5%	$2.00/MBtu	$2,282,931
		$4.00/MBtu	$4,565,862
		$6.00/MBtu	$6,848,793
		$8.00/MBtu	$9,131,724
		$10.00/MBtu	$11,414,655
		$12.00/MBtu	$13,697,586
		$14.00/MBtu	$15,980,517
	7%	$2.00/MBtu	$2,076,522
		$4.00/MBtu	$4,153,044
		$6.00/MBtu	$6,229,566
		$8.00/MBtu	$8,306,088
		$10.00/MBtu	$10,382,609
		$12.00/MBtu	$12,459,131
		$14.00/MBtu	$14,535,653

Financial Viability of Processing Biogas to Natural Gas Quality on Dairy Farms of Various Sizes

In New York State (NYS), most dairies have 500 cows or less. However, as the shift from smaller dairies to CAFOs continues, the number of large dairies is likely to increase in coming years. Also, current research suggests that centralized digesters may be feasible, allowing manure from multiple farms to be digested at one centralized location. For further information, see *Centralized Anaerobic Digestion Options for Groups of Dairy Farms* (Bothi and Aldrich, May, 2005) and *Feasibility of a Central Anaerobic Digester for Ten Dairy Farms in Salem, NY* (Bothi and Aldrich, June 2005).

In other parts of the country, such as California and Illinois, larger dairies with 3,000 to 10,000 cows exist. In several states, like New York, where smaller dairies exist in close proximity to each other, a community digester that accepts waste from several farms and possibly food processing plants may be an option to make processing biogas to natural gas quality feasible from a financial standpoint. Additionally, NYS is following the nation-wide trend toward larger, more efficient dairy operations.

In 2003, the Cayuga County Soil and Water Conservation District (SWCD) proposed to build a community digester in Auburn, NY. The feasibility study for this project was partially funded by NYSERDA. The plug flow digester is sized to treat an equivalent herd of 3,500 animals, with the digester influent containing dairy manure and other organic wastes, such as food waste and food processing wastes. The proposed digester will treat manure from 2,800 cows, approximately 28% of animals in the area and 21,200 tons of food waste per year. This will result in the production of 350,000f^3/biogas per day, assuming the equivalent herd of 3,500 cows (biogas produced from dairy manure and food waste digestion) produces 100f^3/biogas daily. To date, this project seeking funds and has not begun construction, but demonstrates the potential that community digesters have to treat large amounts of waste while producing significant quantities of biogas. This project, as an example, demonstrates that farmers, communities and government agencies are interested in pursuing community digesters in New York State.

In additions, a project being developed by Global Common will collect manure from about 7,000 dairy cows at four farms in Cayuga County, NY. The manure will be transported to a centralized digester by pipeline or trucks. In order to increase biogas output and quality, the digesters will also utilize organic wastes from food processing plants. The biogas that is generated will be used to fire a co-generation system that will provide electricity to a nearby prison.

For the purpose of this analysis, five different size dairies are considered (500, 1,000, 3,000, 5,000 and 10,000 cows. We assume 90% of the biogas that is generated during the digestion process is captured for use and that 25% of the biogas is used to heat the digester. The present worth income (or loss) of processed, high Btu biogas sales over a ten year period for the five different size dairies and considering the estimated gas processing and O&M costs to transform raw dairy biogas into natural gas quality gas as is given in Table 4.3 and Table 4.4, we show in Tables 4.15 to 4.19 a summary of the PW income of upgraded biogas sales, taking into account capital costs to build the gas processing system and O&M costs to run the system. The present worth income (or loss) is calculated using Equation 4.3.

PW of Income = PW of Revenue from Gas Sales - PW of Capital Costs – PW of O& M Costs {Equation 4.3}

These cost estimates do not include the installation of additional pipeline to bring the processed biogas to the main natural gas pipeline. Here, it is assumed that the biogas production and processing site is located adjacent to the natural gas pipeline that it will be injected into.

Table 4.15. Present Worth of Processed Biogas Sales from a 500 Cow Dairy. Parameters Include Gas Selling Price and Interest

	3% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
Present Worth (PW) of CAPITAL COSTS	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
O&M COSTS							
Total Annual O&M	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650
Present Worth (PW) of O&M COSTS	$321,162	$321,162	$321,162	$321,162	$321,162	$321,162	$321,162
PW of INCOME	$126,098	$252,195	$378,293	$504,391	$630,489	$756,586	$882,684
Alternative PW	**-$598,069**	**-$471,972**	**-$345,874**	**-$219,776**	**-$93,679**	**$32,419**	**$158,517**
	5% Interest						
CAPITAL COSTS	$2.00/MB tu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
Present Worth (PW) of CAPITAL COSTS	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
O&M COSTS							
Total Annual O&M	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650
Present Worth (PW) of O&M COSTS	$290,723	$290,723	$290,723	$290,723	$290,723	$290,723	$290,723
PW of INCOME	$114,147	$228,293	$342,440	$456,586	$570,733	$684,879	$799,026
Alternative PW	**-$579,582**	**-$465,435**	**-$351,289**	**-$237,142**	**-$122,996**	**-$8,849**	**$105,298**

Table 4.15 (Continued)

	7% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
Present Worth (PW) of CAPITAL COSTS	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
O&M COSTS							
Total Annual O&M	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650
Present Worth (PW) of O&M COSTS	$264,438	$264,438	$264,438	$264,438	$264,438	$264,438	$264,438
PW of INCOME	$103,826	$207,652	$311,478	$415,304	$519,130	$622,957	$726,783
Alternative PW	**-$563,617**	**-$459,791**	**-$355,965**	**-$252,138**	**-$148,312**	**-$44,486**	**$59,340**

Table 4.16. Present Worth of Processed Biogas Sales from a 1,000 Cow Dairy. Parameters Include Gas Selling Price and Interest

	3% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
Present Worth (PW) of CAPITAL COSTS	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
O&M COSTS							
Total Annual O&M	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650
Present Worth (PW) of O&M COSTS	$321,162	$321,162	$321,162	$321,162	$321,162	$321,162	$321,162
PW of INCOME	$252,195	$504,391	$756,586	$1,008,782	$1,260,977	1,513,173	1,765,368
Alternative PW	**-$471,972**	**-$219,776**	**$32,419**	**$284,615**	**$536,810**	**$789,006**	**$1,041,201**

Table 4.16 (Continued)

	5% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
Present Worth (PW) of CAPITAL COSTS	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
O&M COSTS							
Total Annual O&M	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650
Present Worth (PW) of O&M COSTS	$290,723	$290,723	$290,723	$290,723	$290,723	$290,723	$290,723
PW of INCOME	$228,293	$456,586	$684,879	$913,172	$1,141,46 5	1,369,759	1,598,052
Alternative PW	**-$465,435**	**-$237,142**	**-$8,849**	**$219,444**	**$447,737**	**$676,030**	**$904,323**
	7% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
Present Worth (PW) of CAPITAL COSTS	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005	$403,005
O&M COSTS							
Total Annual O&M	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650	$37,650
Present Worth (PW) of O&M COSTS	$264,438	$264,438	$264,438	$264,438	$264,438	$264,438	$264,438
PW of INCOME	$207,652	$415,304	$622,957	$830,609	$1,038,26 1	1,245,913	1,453,565
Alternative PW	**-$459,791**	**-$252,138**	**-$44,486**	**$163,166**	**$370,818**	**$578,470**	**$786,122**

Table 4.17. Present Worth of Processed Biogas Sales from a 3,000 Cow Dairy. Parameters Include Gas Selling Price and Interest

	3% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075
Present Worth (PW) of CAPITAL COSTS	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075
O&M COSTS							
Total Annual O&M	$75,150	$75,150	$75,150	$75,150	$75,150	$75,150	$75,150
Present Worth (PW) of O&M COSTS	$641,045	$641,045	$641,045	$641,045	$641,045	$641,045	$641,045
PW of INCOME	$756,586	$1,513,17 3	$2,269,75 9	$3,026,345	$3,782,932	$4,539,518	$5,296,104
Alternative PW	**-$683,534**	**$73,053**	**$829,639**	**$1,586,226**	**$2,342,812**	**$3,099,398**	**$3,855,985**
	5% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075
Present Worth (PW) of CAPITAL COSTS	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075
O&M COSTS							
Total Annual O&M	$75,150	$75,150	$75,150	$75,150	$75,150	$75,150	$75,150
Present Worth (PW) of O&M COSTS	$580,288	$580,288	$580,288	$580,288	$580,288	$580,288	$580,288
PW of INCOME	$684,879	$1,369,75 9	$2,054,63 8	$2,739,517	$3,424,396	$4,109,276	$4,794,155
Alternative PW	**-$694,484**	**-$9,604**	**$675,275**	**$1,360,154**	**$2,045,033**	**$2,729,912**	**$3,414,792**

Table 4.17 (Continued)

	7% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075
Present Worth (PW) of CAPITAL COSTS	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075	$799,075
O&M COSTS							
Total Annual O&M	$75,150	$75,150	$75,150	$75,150	$75,150	$75,150	$75,150
Present Worth (PW) of O&M COSTS	$527,822	$527,822	$527,822	$527,822	$527,822	$527,822	$527,822
PW of INCOME	$622,957	$1,245,91 3	$1,868,87 0	$2,491,826	$3,114,783	$3,737,739	$4,360,696
Alternative PW	**-$703,940**	**-$80,984**	**$541,973**	**$1,164,929**	**$1,787,886**	**$2,410,842**	**$3,033,799**

Table 4.18. Present Worth of Processed Biogas Sales from a 5,000 Cow Dairy.Parameters Include Gas Selling Price and Interest

	3% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675
Present Worth (PW) of CAPITAL COSTS	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675
O&M COSTS							
Total Annual O&M	$108,600	$108,600	$108,600	$108,600	$108,600	$108,600	$108,600
Present Worth (PW) of O&M COSTS	$926,380	$926,380	$926,380	$926,380	$926,380	$926,380	$926,380
PW of INCOME	$1,260,977	$2,521,954	$3,782,932	$5,043,909	$6,304,886	7,565,863	8,826,841
Alternative PW	**-$1,185,078**	**$75,899**	**$1,336,877**	**$2,597,854**	**$3,858,831**	**$5,119,808**	**$6,380,786**

Table 4.18 (Continued)

	5% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675
Present Worth (PW) of CAPITAL COSTS	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675
O&M COSTS							
Total Annual O&M	$108,600	$108,600	$108,600	$108,600	$108,600	$108,600	$108,600
Present Worth (PW) of O&M COSTS	$838,580	$838,580	$838,580	$838,580	$838,580	$838,580	$838,580
PW of INCOME	$1,141,465	$2,282,931	$3,424,396	$4,565,862	$5,707,327	6,848,793	7,990,258
Alternative PW	**-$1,216,790**	**-$75,324**	**$1,066,141**	**$2,207,607**	**$3,349,072**	**$4,490,537**	**$5,632,003**
	7% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675
Present Worth (PW) of CAPITAL COSTS	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675	$1,519,675
O&M COSTS							
Total Annual O&M	$108,600	$108,600	$108,600	$108,600	$108,600	$108,600	$108,600
Present Worth (PW) of O&M COSTS	$762,761	$762,761	$762,761	$762,761	$762,761	$762,761	$762,761
PW of INCOME	$1,038,261	$2,076,522	$3,114,783	$4,153,044	$5,191,072	6,229,566	7,267,827
Alternative PW	**-$1,244,175**	**-$205,914**	**$832,347**	**$1,870,608**	**$2,908,636**	**$3,947,130**	**$4,985,391**

Table 4.19. Present Worth of Processed Biogas Sales from a 10,000 Cow Dairy. Parameters Include Gas Selling Price and Interest

	3% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$2,397,400	$2,397,400	$2,397,400	$2,397,400	$2,165,400	$2,397,400	$2,165,400
Present Worth (PW) of CAPITAL COSTS	$2,397,400	$2,397,400	$2,397,400	$2,397,400	$2,165,400	$2,397,400	$2,165,400
O&M COSTS							
Total Annual O&M	$204,400	$204,400	$204,400	$204,400	$180,600	$204,400	$180,600
Present Worth (PW) of O&M COSTS	$1,743,573	$1,743,573	$1,743,573	$1,743,573	$1,540,555	$1,743,573	$1,540,555
PW of INCOME	$2,521,954	$5,043,909	$7,565,863	$10,087,818	$12,609,772	$15,131,727	$17,653,681
Alternative PW	**-$1,184,001**	**$1,337,954**	**$3,859,908**	**$6,381,863**	**$8,903,817**	**$11,425,772**	**$13,947,727**
	5% Interest						
CAPITAL COSTS	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
Total Capital Cost of Gas Processing System	$2,397,400	$2,397,400	$2,397,400	$2,397,400	$2,165,400	$2,397,400	$2,165,400
Present Worth (PW) of CAPITAL COSTS	$2,397,400	$2,397,400	$2,397,400	$2,397,400	$2,165,400	$2,397,400	$2,165,400
O&M COSTS							
Total Annual O&M	$204,400	$204,400	$204,400	$204,400	$180,600	$204,400	$180,600
Present Worth (PW) of O&M COSTS	$1,578,323	$1,578,323	$1,578,323	$1,578,323	$1,394,545	$1,578,323	$1,394,545
PW of INCOME	$2,282,931	$4,565,862	$6,848,793	$9,131,724	$11,414,655	$13,697,586	$15,980,517
Alternative PW	**-$1,277,014**	**$1,005,917**	**$3,288,848**	**$5,571,779**	**$7,854,710**	**$10,137,640**	**$12,420,571**

Table 4.19 (Continued)

	7% Interest						
CAPITAL COSTS	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/Mbut	$12.00/MBtu	$14.00//M
Total Capital Cost of Gas Processing System	$2,397,400	$2,397,400	$2,397,400	$2,397,400	$2,165,400	$2,397,400	$2,165,400
Present Worth (PW) of CAPITAL COSTS	$2,397,400	$2,397,400	$2,397,400	$2,397,400	$2,165,400	$2,397,400	$2,165,400
O&M COSTS							
Total Annual O&M	$204,400	$204,400	$204,400	$204,400	$180,600	$204,400	$180,600
Present Worth (PW) of O&M COSTS	$1,435,620	$1,435,620	$1,435,620	$1,435,620	$1,268,459	$1,435,620	$1,268,459
PW of INCOME	$2,076,522	$4,153,044	$6,229,566	$8,306,088	$10,382,609	$12,459,131	$14,535,653
Alternative PW	**-$1,357,337**	**$719,185**	**$2,795,707**	**$4,872,229**	**$6,948,750**	**$9,025,272**	**$11,101,794**

Financial Viability of Processing Biogas to Natural Gas Quality on Dairy Farms of Various Sizes with Addition of Pipeline Installation

Realistically, it is unlikely that the biogas production and processing site will be located right next to the natural gas pipeline. Therefore, pipeline installation costs can play an important part in determining the economic viability of the project. Tables 4.20 to 4.24 show the PW analysis of selling upgraded biogas with ¼ mile, ½ mile and 1 mile pipeline installations for the five dairies. The PW of processed biogas sales was determined by Equation 4.4.

PW of Income = PW of Revenue from Gas Sales - PW of Capital Costs – PW of O& M Costs – Cost of Pipeline Installation {Equation 4.4}

Table 4.20. Present Worth of Processed Biogas Sales from a 500 Cow Dairy, Parameters include Gas Selling Price, Interest and Pipeline Costs

Interest Rate	3% Interest						
Upgraded Gas Selling Price	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
1/4 Mile Pipeline	-$673,686	-$547,588	-$421,490	-$295,392	-$169,295	-$43,197	$82,901
1/2 Mile Pipeline	-$749,302	-$623,204	-$497,106	-$371,009	-$244,911	-$118,813	$7,285
1 Mile Pipeline	-$900,534	-$774,436	-$648,339	-$522,241	-$396,152	-$270,063	-$143,973
Interest Rate	5% Interest						
Upgraded Gas Selling Cost	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
1/4 Mile Pipeline	-$655,198	-$541,051	-$426,905	-$312,758	-$198,612	-$84,465	$29,681
1/2 Mile Pipeline	-$730,814	-$616,668	-$502,521	-$388,375	-$274,228	-$160,081	-$45,935
1 Mile Pipeline	-$882,047	-$767,900	-$653,753	-$539,607	-$425,468	-$311,329	-$197,190
Interest Rate	7% Interest						
Upgraded Gas Selling Cost	$2.00/ MBtu	$4.00/ MBtu	$6.00/ MBtu	$8.00/ MBtu	$10.00/ MBtu	$12.00/ MBtu	$14.00/ MBtu
1/4 Mile Pipeline	-$639,233	-$535,407	-$431,581	-$327,755	-$223,929	-$120,102	-$16,276
1/2 Mile Pipeline	-$714,849	-$611,023	-$507,197	-$403,371	-$299,545	-$195,719	-$91,893
1 Mile Pipeline	-$866,082	-$762,255	-$658,429	-$554,603	-$450,784	-$346,965	-$243,146

Table 4.21. Present Worth of Processed Biogas Sales from a 1,000 Cow Dairy, Parameters include Gas Selling Price, Interest and Pipeline Costs.

Interest Rate	3% Interest						
Upgraded Gas Selling Price	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$547,588	-$295,392	-$43,197	$208,998	$461,194	$713,389	$965,585
1/2 Mile Pipeline	-$623,204	-$371,009	-$118,813	$133,382	$385,577	$637,773	$889,969
1 Mile Pipeline	-$814,036	-$561,841	-$309,646	-$57,450	$234,337	$486,524	$738,711
Interest Rate	5% Interest						
Upgraded Gas Selling Cost	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00//M
1/4 Mile Pipeline	-$541,051	-$312,758	-$84,465	$143,828	$372,120	$600,414	$828,707
1/2 Mile Pipeline	-$616,668	-$388,375	-$160,081	$68,212	$296,504	$524,798	$753,091
1 Mile Pipeline	-$807,500	-$579,207	-$350,914	-$122,621	$145,264	$373,550	$601,835
Interest Rate	7% Interest						
Upgraded Gas Selling Cost	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00//M
1/4 Mile Pipeline	-$535,407	-$327,755	-$120,102	$87,550	$295,202	$502,854	$710,506
1/2 Mile Pipeline	-$611,023	-$403,371	-$195,719	$11,934	$219,586	$427,238	$634,890
1 Mile Pipeline	-$801,855	-$594,203	-$386,551	-$178,899	$68,346	$275,991	$483,637

Table 4.22. Present Worth of Processed Biogas Sales from a 3,000 Cow Dairy ,Parameters include Gas Selling Price,Interest and Pipeline Costs

Interest Rate	3% Interest						
Upgraded Gas Selling Price	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$772,515	-$15,928	$740,658	$1,497,244	$2,253,831	$3,010,417	$3,767,003
1/2 Mile Pipeline	-$898,918	-$142,331	$614,255	$1,370,841	$2,127,419	$2,883,997	$3,640,575
1 Mile Pipeline	-$1,114,303	-$357,716	$398,870	$1,155,457	$1,912,035	$2,668,621	$3,425,207
Interest Rate	5% Interest						
Upgraded Gas Selling Cost	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$783,466	-$98,586	$586,293	$1,271,172	$2,127,419	$2,640,931	$3,325,810
1/2 Mile Pipeline	-$909,869	-$224,989	$459,890	$1,144,769	$1,829,640	$2,514,520	$3,199,399
1 Mile Pipeline	-$1,125,253	-$440,373	$244,506	$929,385	$1,614,256	$2,299,136	$2,984,015
Interest Rate	7% Interest						
Upgraded Gas Selling Cost	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$792,921	-$169,965	$452,992	$1,075,948	$2,078,771	$2,321,861	$2,944,818
1/2 Mile Pipeline	-$919,325	-$296,369	$326,588	$949,544	$1,572,494	$2,195,451	$2,818,407
1 Mile Pipeline	-$1,134,709	-$511,753	$111,204	$734,160	$1,357,110	$1,980,066	$2,603,023

Table 4.23. Present Worth of Processed Biogas Sales from a 5,000 Cow Dairy, Parameters include Gas Selling Price, Interest and Pipeline Costs

Interest Rate	3% Interest						
Upgraded Gas Selling Price	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$1,292,770	-$31,793	$1,229,185	$2,490,162	$3,751,139	$5,012,116	$6,273,093
1/2 Mile Pipeline	-$1,449,111	-$188,134	$1,072,844	$2,333,821	$3,241,379	$4,855,775	$6,116,753
1 Mile Pipeline	-$1,770,881	-$509,904	$751,074	$2,012,051	$2,800,944	$4,533,997	$5,794,966
Interest Rate	5% Interest						
Upgraded Gas Selling Cost	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$1,324,483	-$183,017	$958,448	$2,099,914	$3,594,798	$4,382,845	$5,524,311
1/2 Mile Pipeline	-$1,480,823	-$339,357	$802,108	$1,943,574	$3,085,039	$4,226,504	$5,367,970
1 Mile Pipeline	-$1,802,593	-$661,127	$480,338	$1,621,804	$2,644,603	$3,904,727	$5,046,185
Interest Rate	7% Interest						
Upgraded Gas Selling Cost	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$1,351,867	-$313,606	$724,655	$1,762,916	$3,273,028	$3,839,437	$4,877,698
1/2 Mile Pipeline	-$1,508,208	-$469,947	$568,314	$1,606,575	$2,763,269	$3,683,097	$4,721,358
1 Mile Pipeline	-$1,829,978	-$791,717	$246,544	$1,284,805	$2,322,826	$3,361,313	$4,399,567

Table 4.24. Present Worth of Processed Biogas Sales from a 10,000 Cow Dairy. Parameters include Gas Selling Price, Interest and Pipeline Costs

Interest Rate	3% Interest						
Upgraded Gas Selling Price	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$1,765,470	$756,485	$3,278,439	$5,800,394	$8,757,367	$11,279,321	$13,801,276
1/2 Mile Pipeline	-$1,911,921	$610,034	$3,131,988	$5,653,943	$7,708,259	$11,132,871	$13,654,825
1 Mile Pipeline	-$2,259,351	$262,604	$2,784,558	$5,306,513	$6,802,299	$10,350,404	$12,872,350
Interest Rate	5% Interest						
Upgraded Gas Selling Cost	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$1,839,242	$443,689	$2,726,620	$5,009,551	$8,610,916	$9,991,190	$12,274,120
1/2 Mile Pipeline	-$1,985,693	$297,238	$2,580,169	$4,863,100	$7,561,808	$9,844,739	$12,127,670
1 Mile Pipeline	-$2,333,124	-$50,193	$2,232,738	$4,515,669	$6,655,849	$9,081,516	$11,364,439
Interest Rate	7% Interest						
Upgraded Gas Selling Cost	$2.00/MBtu	$4.00/MBtu	$6.00/MBtu	$8.00/MBtu	$10.00/MBtu	$12.00/MBtu	$14.00/MBtu
1/4 Mile Pipeline	-$1,902,949	$173,573	$2,250,095	$4,326,617	$7,828,458	$8,878,822	$10,955,344
1/2 Mile Pipeline	-$2,049,399	$27,123	$2,103,645	$4,180,167	$6,798,593	$8,732,371	$10,808,893
1 Mile Pipeline	-$2,396,830	-$320,308	$1,756,214	$3,832,736	$5,909,250	$7,985,765	$10,062,280

Sensitivity Analysis

A sensitivity analysis was conducted to determine the relative influence (sensitivity) on financial viability of the project as affected by: a) processed gas selling price, b) pipeline installation costs and c) interest rates. Conducting a sensitivity analysis is a method to analyze uncertainty by changing input variables and observing the sensitivity of the result. The method can be employed on a variable-by-variable basis or by changing groups of variables at once using scenario analysis. For a variable by variable analysis, the following approach was used.

- List the important factors that affect the financial viability of the project
- For each factor, define a range of possible values. The range usually consists of three to five values. The values can be based on a relative measure. For example, estimates for each factor could be categorized as "optimistic', "most likely", or "pessimistic". In practice, these values are usually based on past experience with similar projects or with current market values.
- Calculate net present value for each factor holding all other factors at their expected or “most likely” values.
- The resulting net present values may be examined to determine the degree of overall variation and which factor (or factors) is most responsible for variation in the estimates.

Tables 4.25, below, illustrates the first two steps of the method applied to the five different sized dairies. For upgraded biogas selling price, values of \$14/MBtu, \$10/MBtu and \$6/MBtu were used for "optimistic', "most likely", or "pessimistic", for respectively. For pipeline construction and installations costs, no pipeline installation was used as an “optimistic” value, while ½ mile and 1 mile pipeline costs were used for “most likely” and “pessimistic”. Interest values of 3%, 5% and 7% were used for "optimistic', "most likely" and “pessimistic".

The first column in Table 4.22 lists the factors believed to be most important to the financial viability of the project. Once values for each factor have been determined, the next step is to calculate a net present value using the most likely values for each parameter.

After the net present value is calculated using the “most likely” values, additional net present values are calculated by allowing one factor to vary while the others are held constant at their most likely values. The outcome of the sensitivity analysis is show in Table 4.26.

Table 4.25.Parameters Used in the Three Parameter Sensitivity Analysis for Five Different Size Dairies

Factor	Optimistic	Most Likely	Pessimistic
500 Cows			
Upgraded Gas Selling Price ($/Mbtu)	14	10	6
Pipeline Costs	$0	$151,232	$302,465
Interest Rate	3%	5%	7%
1,000 Cows			
Upgraded Gas Selling Price ($/Mbtu)	14	10	6
Pipeline Costs	$0	$151,232	$302,465
Interest Rate	3%	5%	7%
3,000 Cow			
Upgraded Gas Selling Price	14	10	6
Pipeline Costs	$0	$215,384	$430,769
Interest Rate	3%	5%	7%
5,000 Cows			
Upgraded Gas Selling Price	14	10	6
Pipeline Costs	$0	$264,033	$585,803
Interest Rate	3%	5%	7%
10,000 Cows			
Upgraded Gas Selling Price	14	10	6
Pipeline Costs	$0	$292,901	$640,332
Interest Rate	3%	5%	7%

Table 4.26. Sensitivity Analysis Results

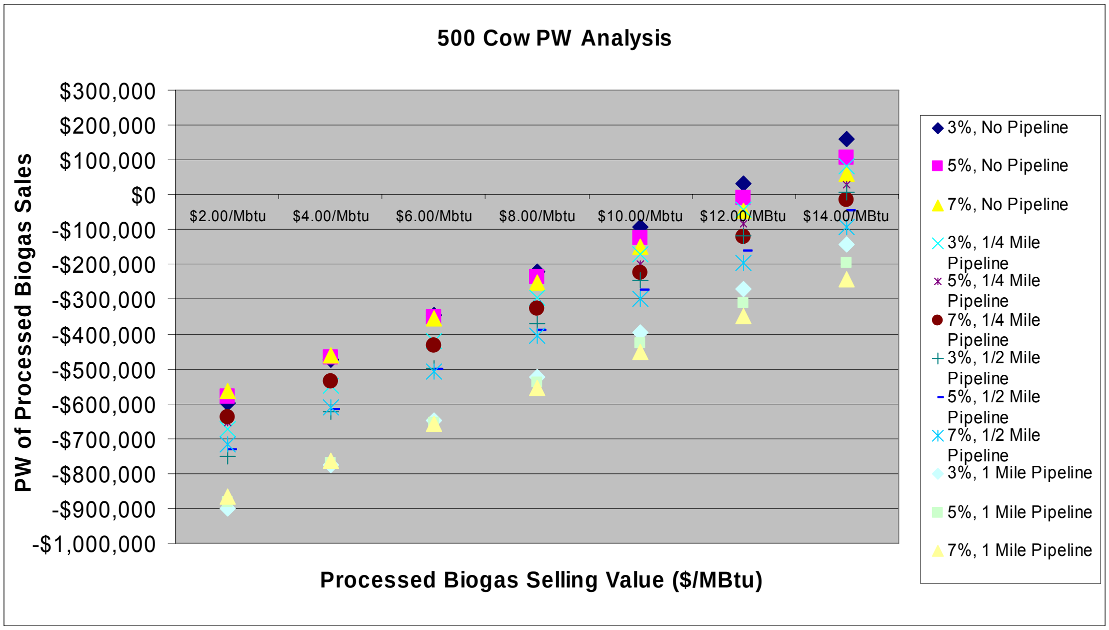
Factor	Optimistic	Most Likely	Pessimistic
500 Cows			
Upgraded Gas Selling Price ($/MBtu)	0.77	1.00	1.23
Pipeline Costs	0.70	1.00	1.30
Interest Rate	0.99	1.00	1.01
1,000 Cows			
Upgraded Gas Selling Price ($/MBtu)	-0.43	1.00	2.43
Pipeline Costs	0.06	1.00	2.19
Interest Rate	0.74	1.00	1.22
3,000 Cow			
Upgraded Gas Selling Price	2.49	1.00	-0.49
Pipeline Costs	1.47	1.00	0.89
Interest Rate	1.34	1.00	0.71
5,000 Cows			
Upgraded Gas Selling Price	2.52	1.00	-0.42
Pipeline Costs	1.33	1.00	0.60
Interest Rate	1.34	1.00	0.71
10,000 Cows			
Upgraded Gas Selling Price	1.78	1.00	0.11
Pipeline Costs	1.05	1.00	0.82
Interest Rate	1.15	1.00	0.77

The results show how sensitive the net present value ratios are to changes in individual factors. For example, the smallest variation is caused by changes in interest rates. The largest changes in net present value ratios are caused by processed gas selling price and pipeline costs. The price received for the selling of processed biogas has the greatest impact on the economic viability of a project, when selling price, pipeline costs (up to 1 mile) and interest rates are taken into consideration.

RESULTS

Figure 4.2 – Figure 4.5 illustrate the present worth of biogas sales based on processed biogas selling value, pipeline installation and interest rates.

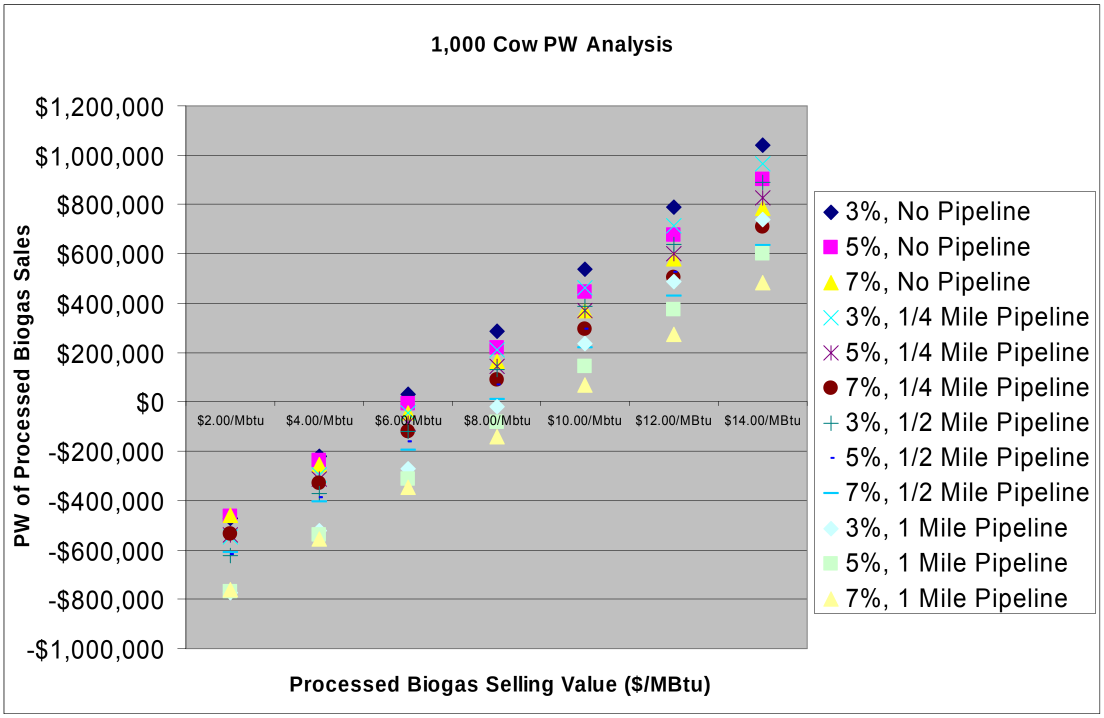
Figure 4.2. 500 Cow Present Worth Analysis



For a 500 cow dairy, the graph shows that a profit begins to be made if the processed biogas is sold for $12.00/MBtu, assuming that no additional pipeline is installed and that the interest rate is low (3%). A profit can be made if pipeline is installed (up to ½ mile), as long as the processed biogas sells for at least $14.00/MBtu.

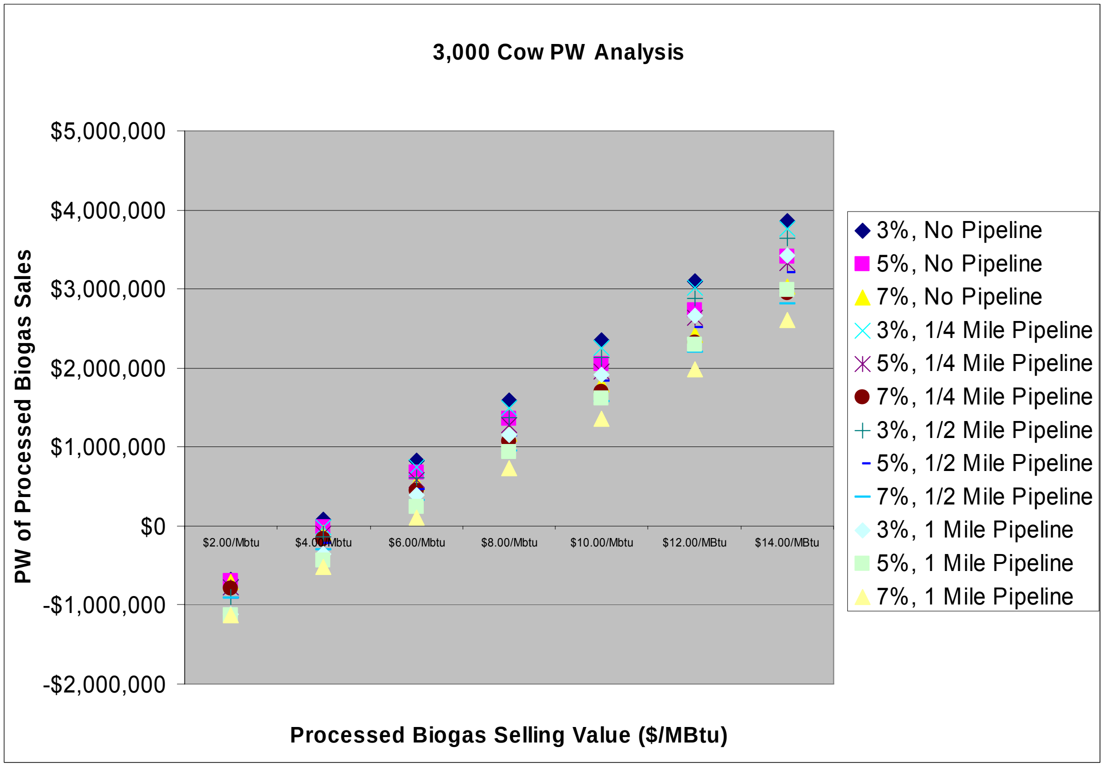
For a 1,000 cow dairy, the data show that a profit will not be made unless the upgraded biogas is sold for at least $6.00/MBtu, assuming a low interest rate of 3%. If the upgraded biogas is sold for less than $6.00/MBtu, regardless of the amount of pipeline installed or interest rate over the lifetime of the project, money will be lost. If the biogas is sold for $8.00/MBtu, a profit is made as long as the pipeline installation is not over ½ mile long. At a selling price of $10.00/MBtu, a profit may be made even if up to 1 mile of pipeline is installed and at a higher interest rate.

Figure 4.3. 1,000 Cow Present Worth Analysis



For a 3,000 cow dairy, a profit begins being made if the upgraded biogas is sold for at least $4.00/MBtu, provided that no pipeline is installed and that the interest rate is low (3%).

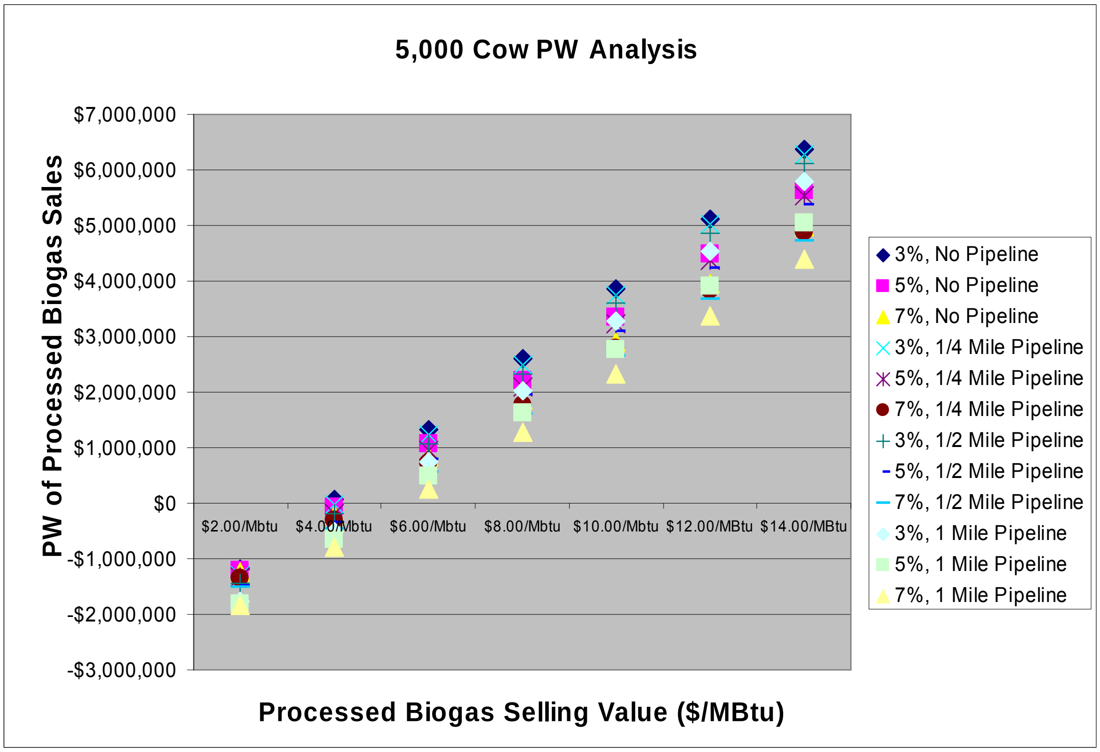
Figure 4.4. 3,000 Cow Present Worth Analysis



If it is necessary to install a pipeline to connect to the natural gas network, the gas must be sold for at least $6.00/MBtu. With a dairy of this size, if a pipeline of up to one mile must be installed, a profit can still be made, even at a high interest rate (7%), as long as the processed gas is sold for $6.00/MBtu or more.

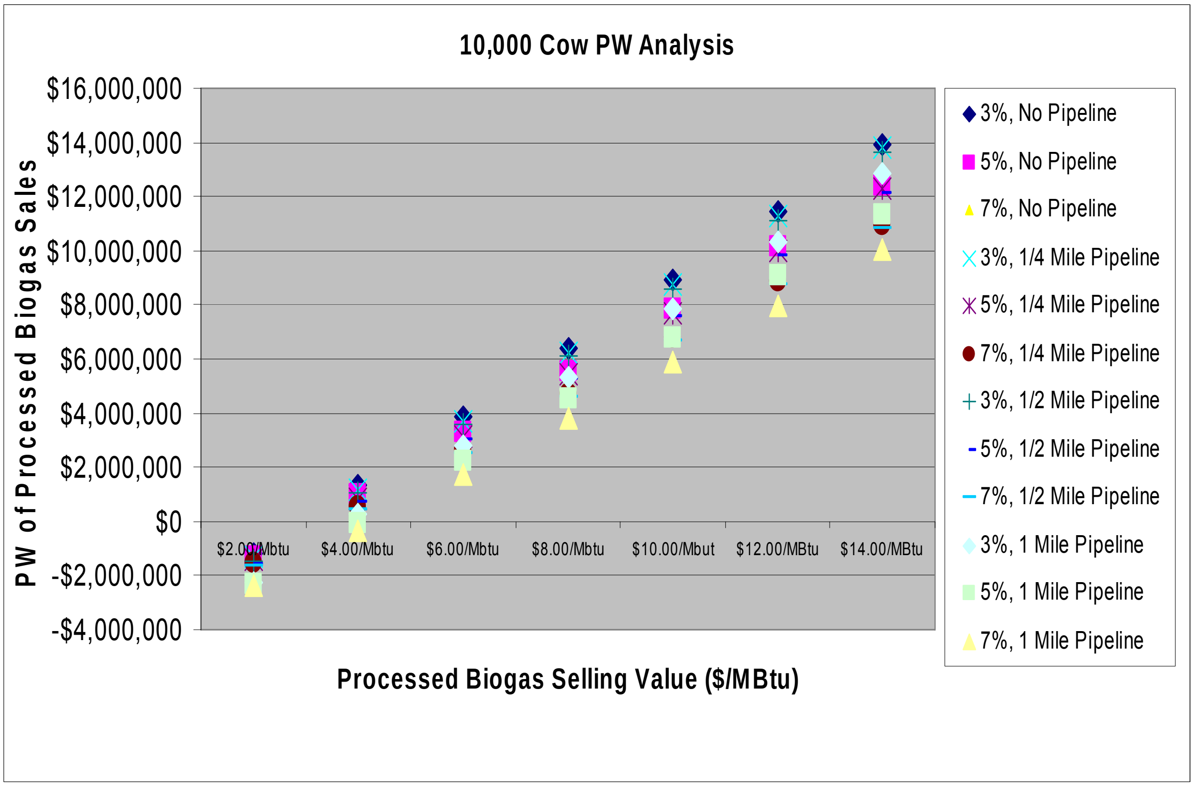
As with the 3,000 cow dairy, a profit can be made on a 5,000 cow dairy if the processed gas is sold for at least $4.00/MBtu, provided that no pipeline installation is necessary and that the interest rate is relatively low. If the processed biogas seller receives at least $6.00/MBtu for the gas, and installs ½ mile or less of pipeline, significant revenue can be made over the 10 year life of the project. For example, if the seller installs ½ mile pipeline, at 3% interest, over $1,000,000 in revenue will be made.

Figure 4.5. 5,000 Cow Present Worth Analysis



Extrapolating the data, the “break even” price that the processed biogas must sell for on a 10,000 cow is $3.50/MBtu. If the gas is sold for at least $4.00/MBtu, with no pipeline installation and a low interest rate (3%), over $1,000,000 in profit can be made over the course of the project. If the gas is sold at a higher rate ($8.00 – $10.00 per MBtu), a significant profit of approximately $3,832,736 and $5,909,250 can be made, respectively, even if up to one mile of pipeline must be installed and at a high interest rate (7%).

Figure 4.6. 10,000 Cow PW Analysis



Figures 4.7 – 4.9 show farm size (number of cows) versus profitability (revue generated from the sales of upgraded biogas, minus capital and O&M costs), assuming a 5% interest rate over the life of the project. These figures demonstrate the importance of establishing a minimum buying price for the processed biogas. Each series of vertical points on each figure represents the processed biogas selling prices of $2.00, $4.00, $6.00, $8.00, $10.00, $12.00 and $14.00 per MBtu, respectively, from bottom to top.

These figures reiterate the importance of the minimum processed biogas selling price to the economic viability of the project. If a smaller dairy of 500 cows receives at least $12.00/MBtu, with a low interest rate and no pipeline installation, revue is generated from the sale of the processed biogas. As dairy size increases, the minimum amount the processed biogas must be sold for to make a profit decreases. For a very large dairy (10,000 cows), the minimum selling price drops to $3.50/MBtu in order for a profit to be made.

Figure 4.7. Farm Size versus Profitability No Pipeline Installation, 5% Interest

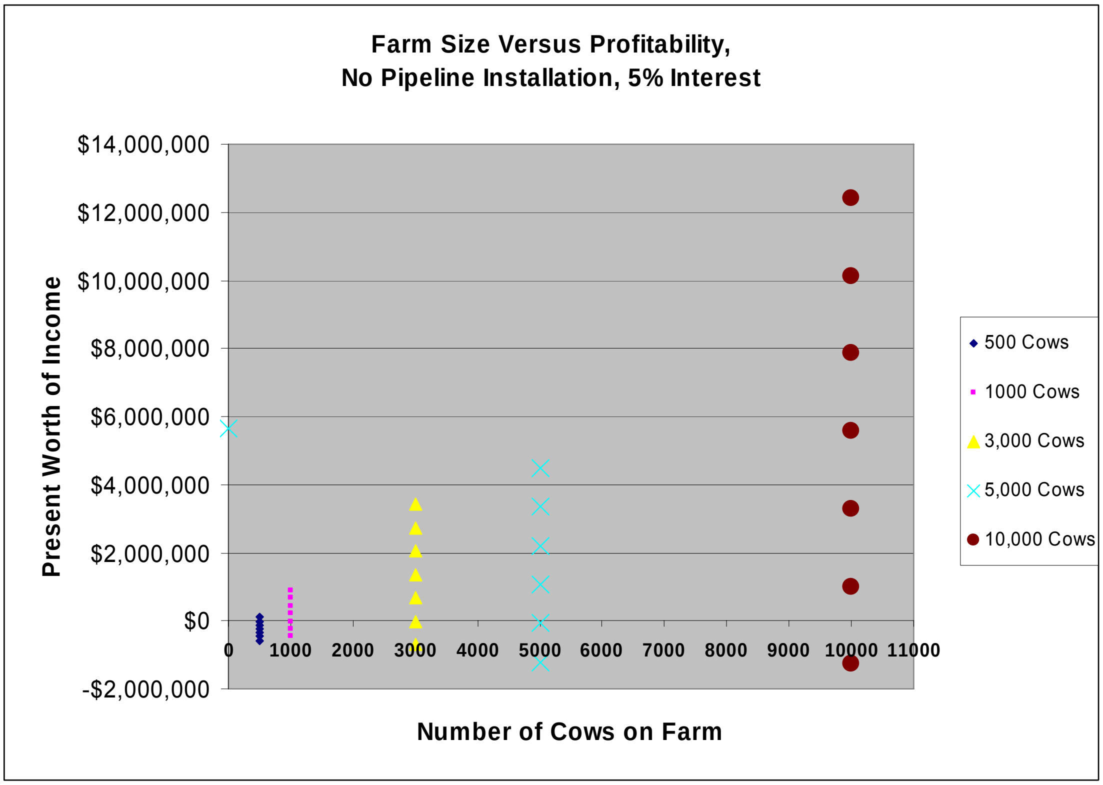


Figure 4.8, Farm Size Versus Profitability,1/4 Mile Pipeline Installation, 5% Interest

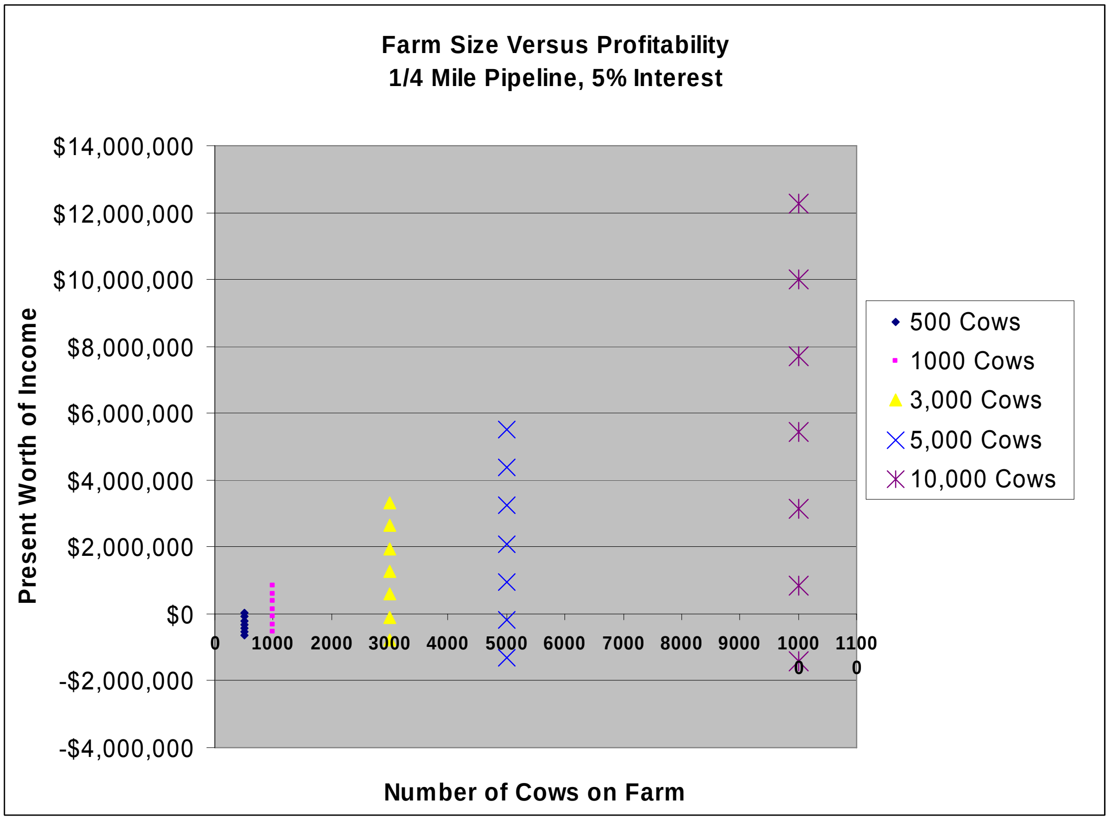


Figure 4.9. Farm Size Versus Profitability, 1/2 Mile Pipeline Installation, 5% Interest

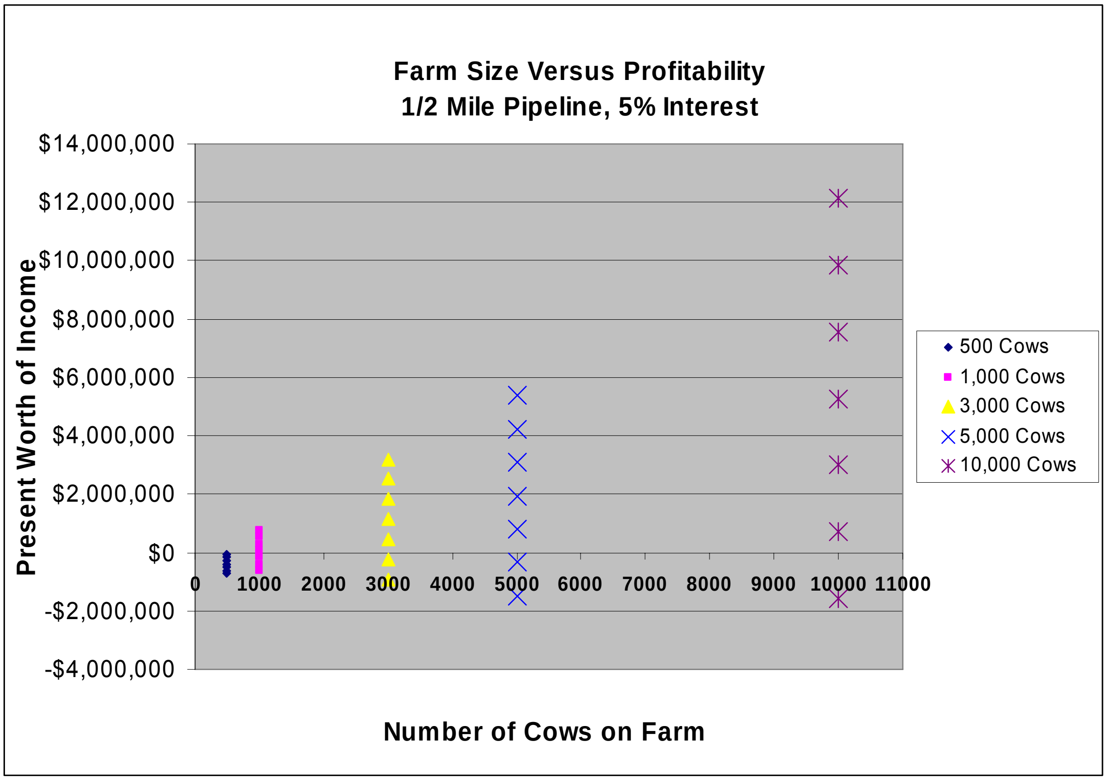
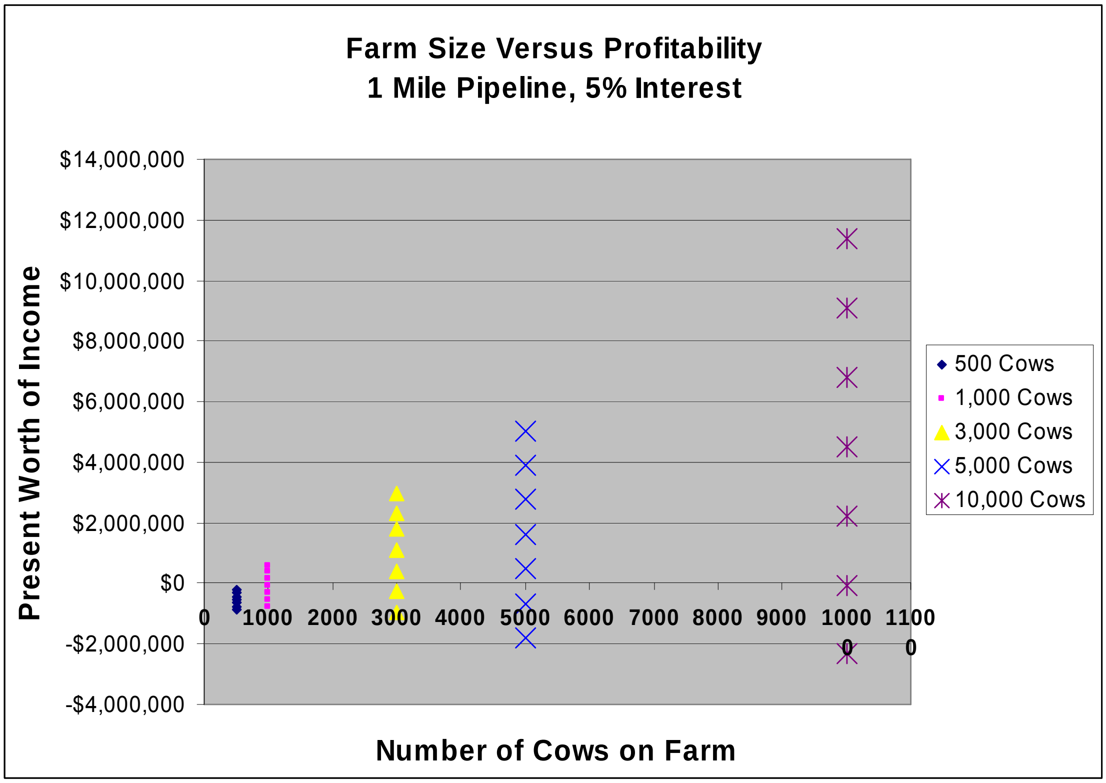


Figure 4.10. Farm Size Versus Profitability, 1 Mile Pipeline Installation, 5% Interest



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APPENDIX A

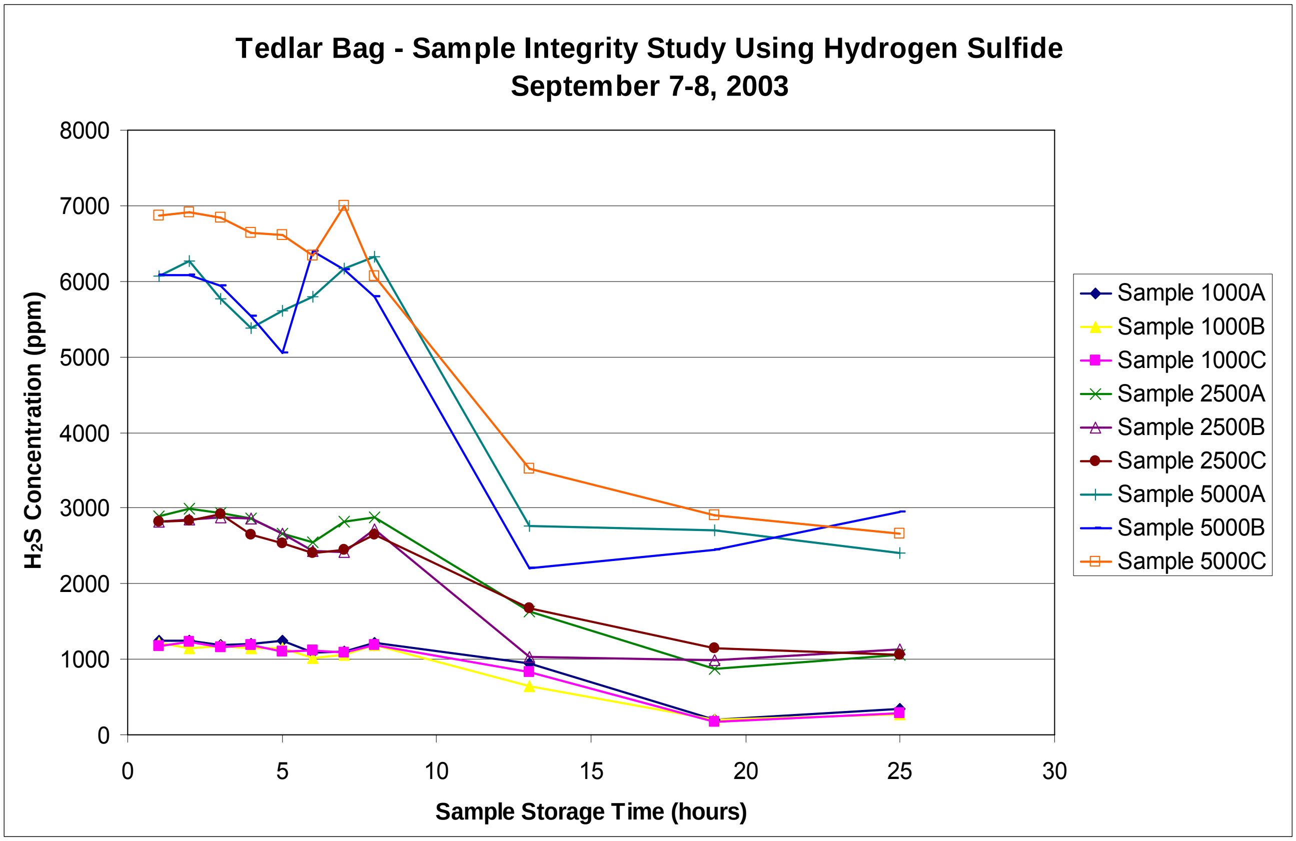

Figure A-1 Test of the rate of decline in hydrogen sulfide from Tedlar sampling bags.

APPENDIX B

Gas Composition Curves

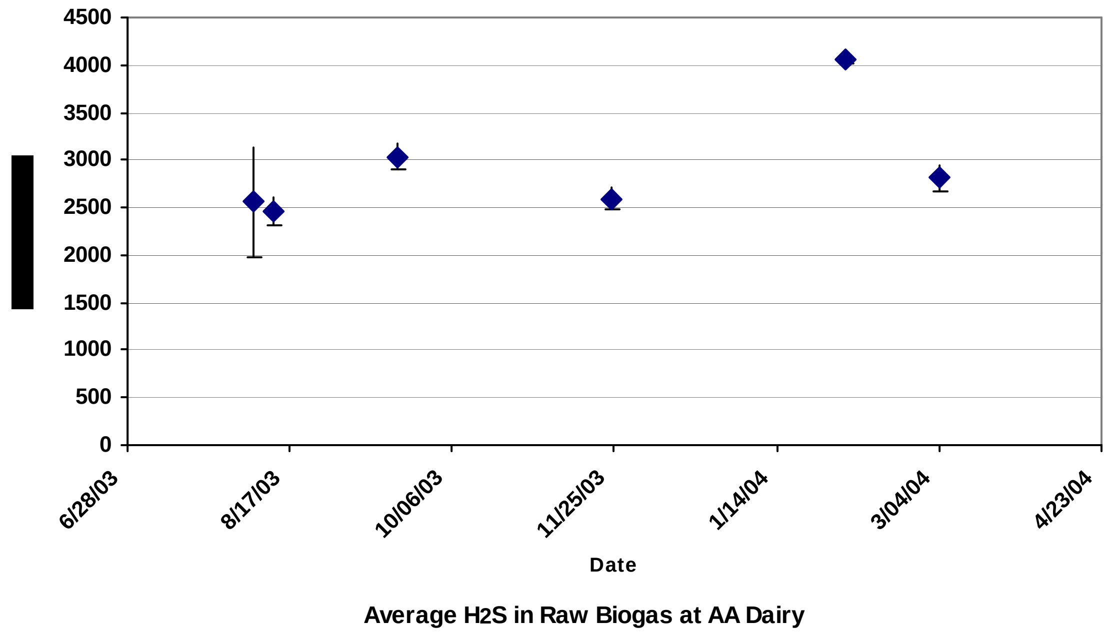

Figure B-1 Average H_2S measured in biogas at AA Dairy, July 2003- March 2004

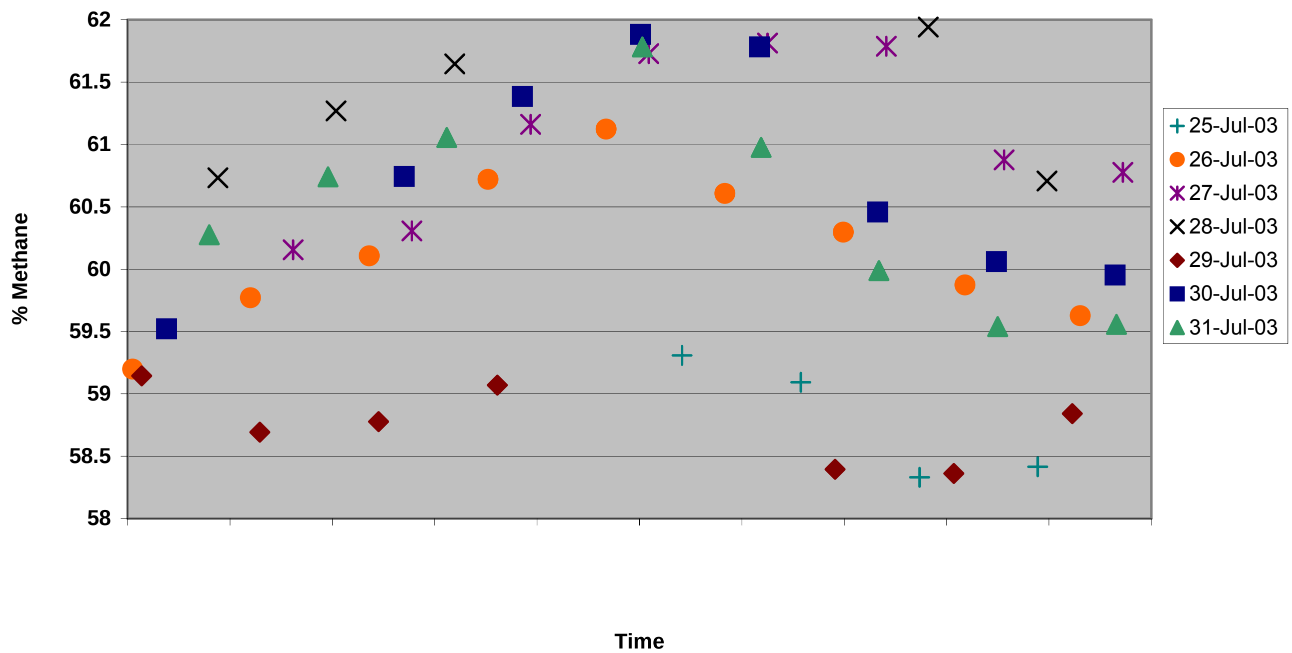

Figure B-2 Daily Average Methane Concentration in Biogas at DDI (July 2003)

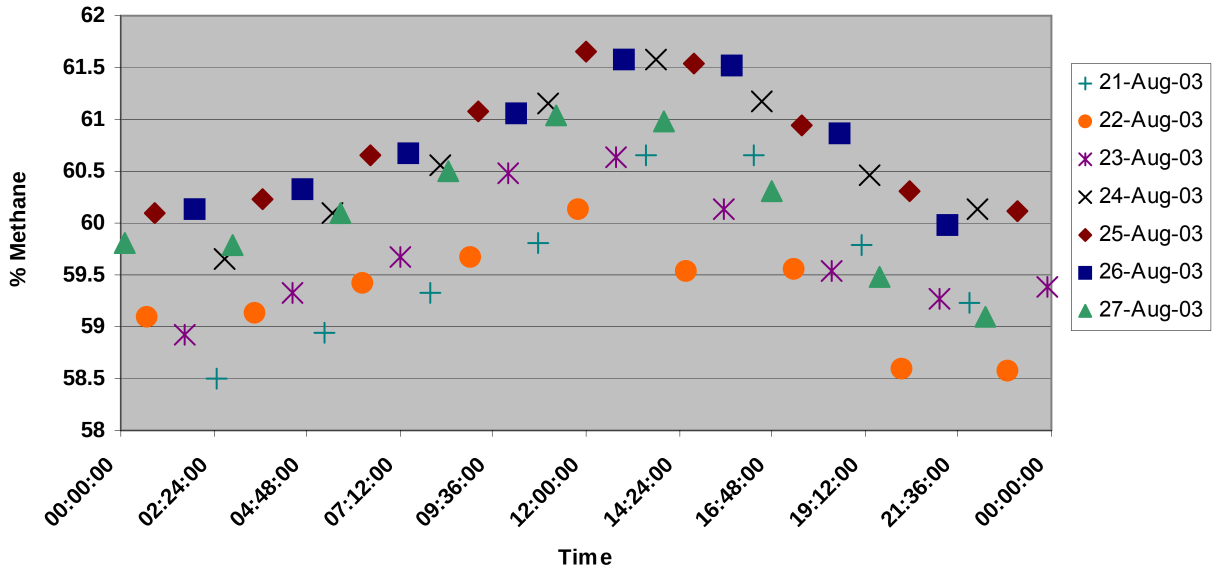

Figure B-3 Daily Average Methane Concentration in Biogas at DDI (August 2003)

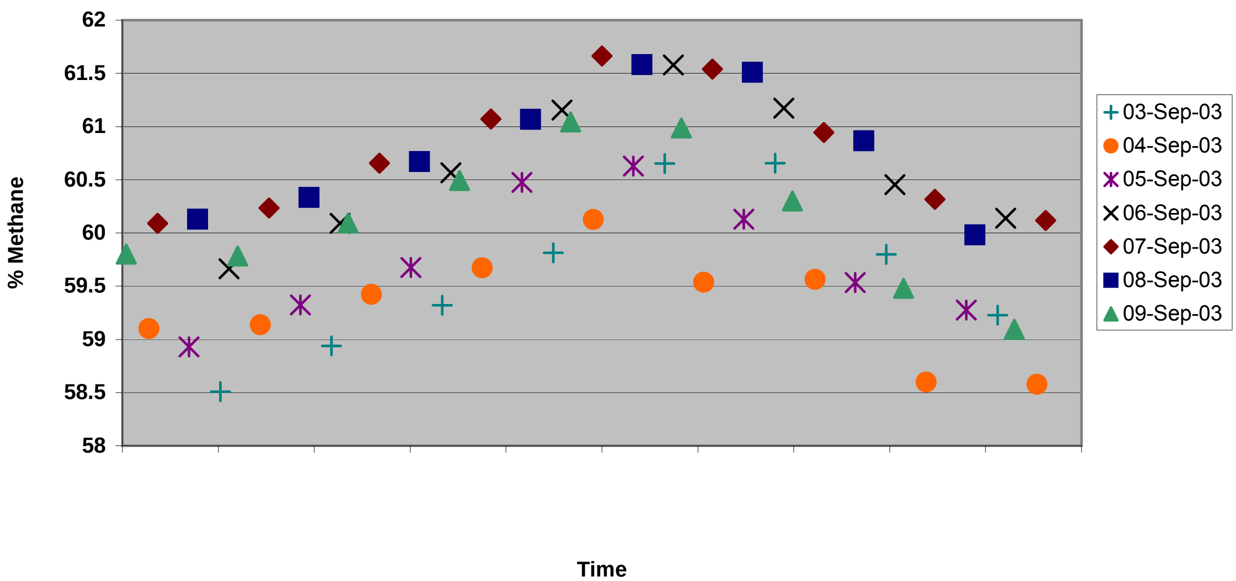

Figure B-4 Daily Average of Methane Concentration in Biogas at DDI (September 2003)

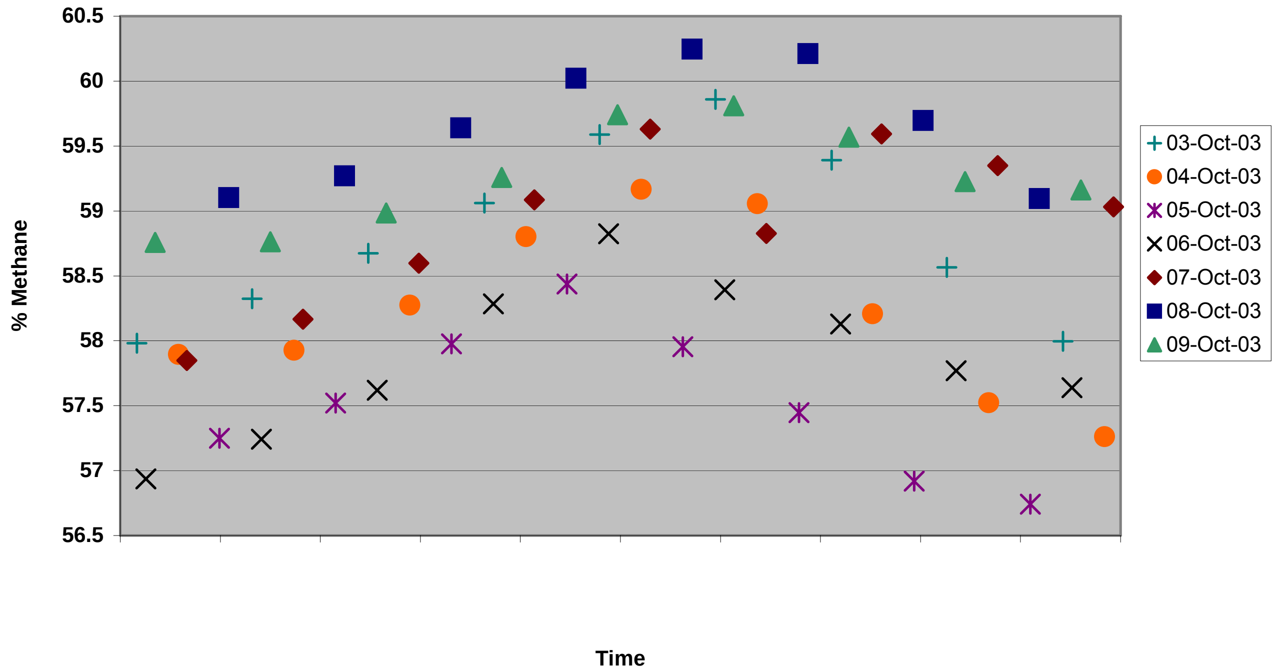

Figure B-5 Daily Average of Methane Concentration in Biogas at DDI (October 2003)

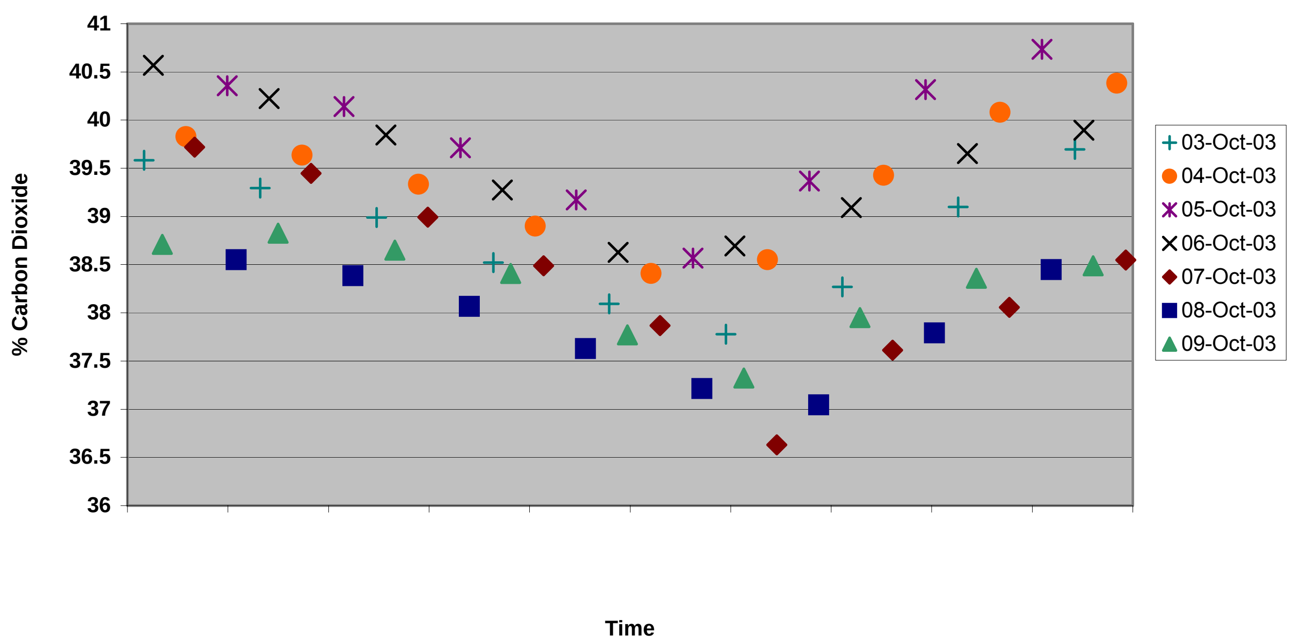

Figure B-6 Daily Average of CO_2 Concentration in Biogas at DDI (October 2003)

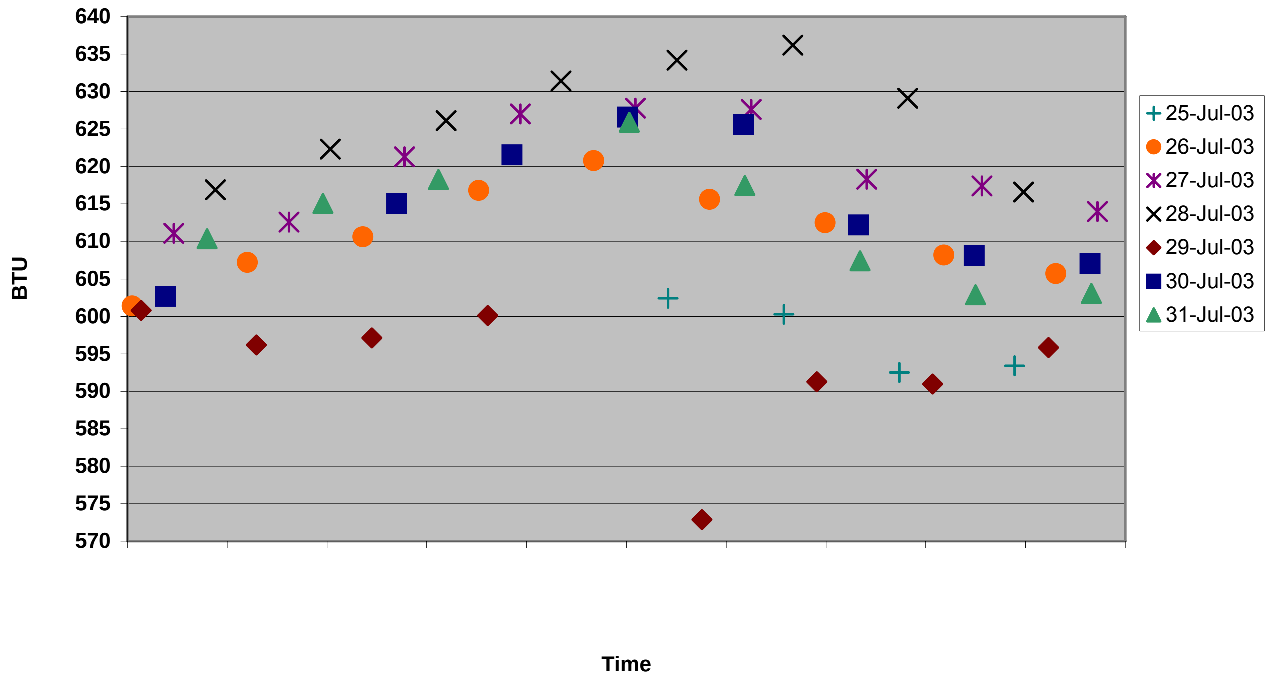

Figure B-7 Daily Average Heating Value of Biogas at DDI (July 2003)

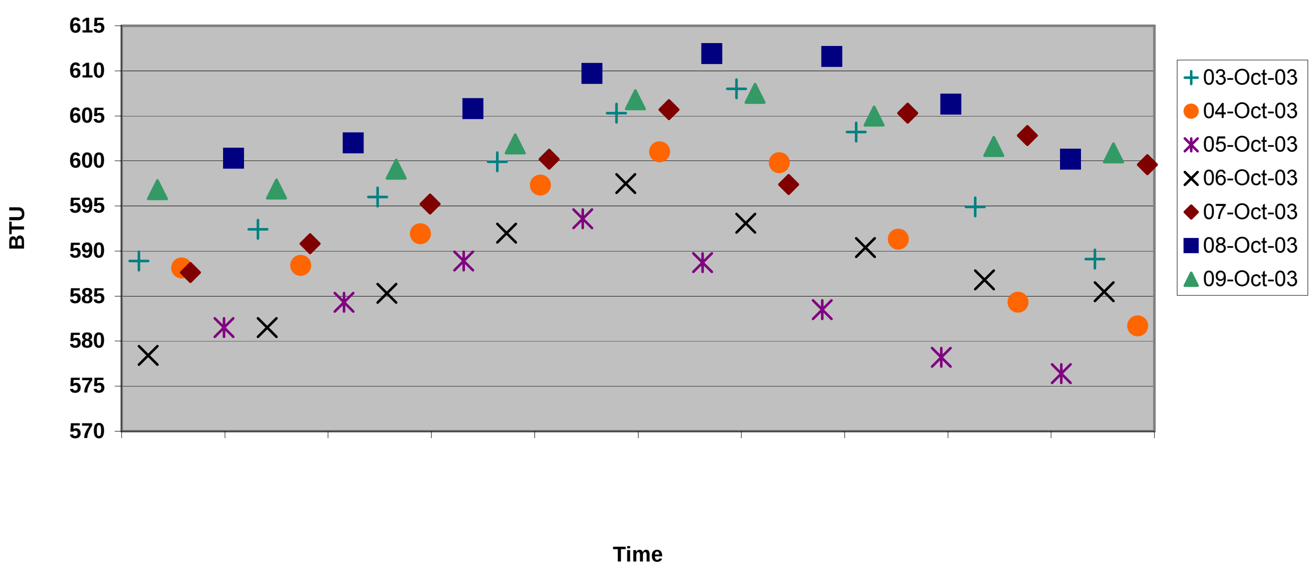

Figure B-8 Daily Average Heating Value of Biogas at DDI (October 2003)

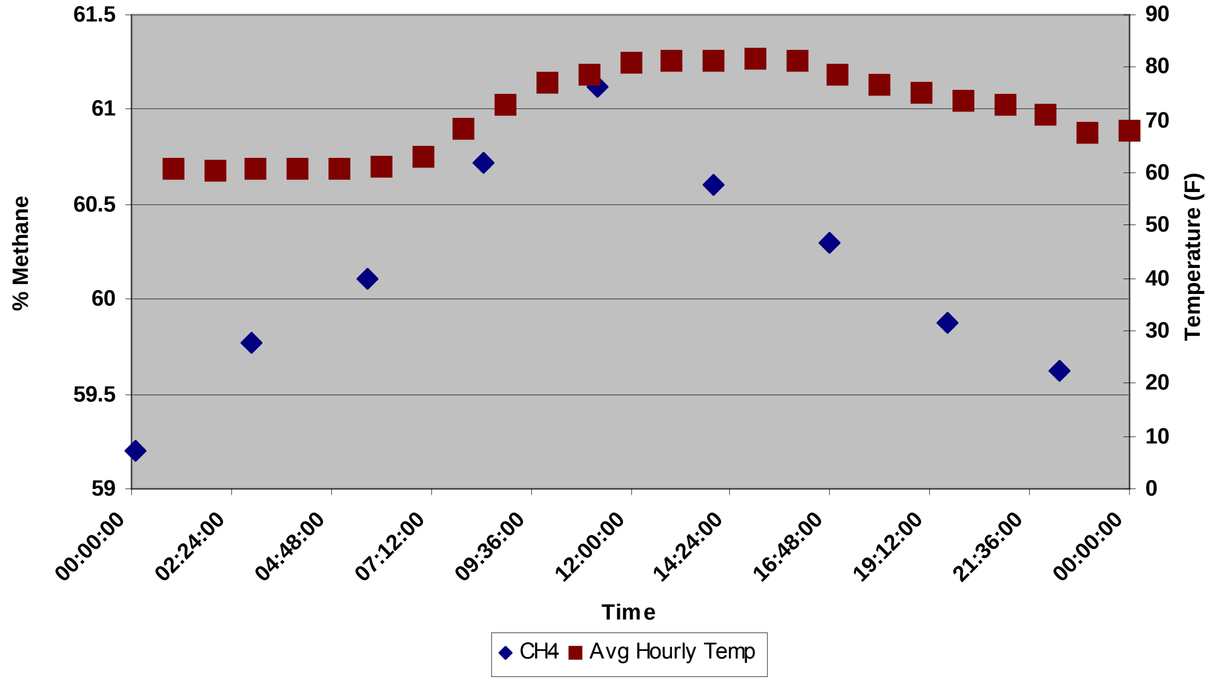

Figure B-9 Methane Concentration in Biogas at DDI (July 26, 2003)

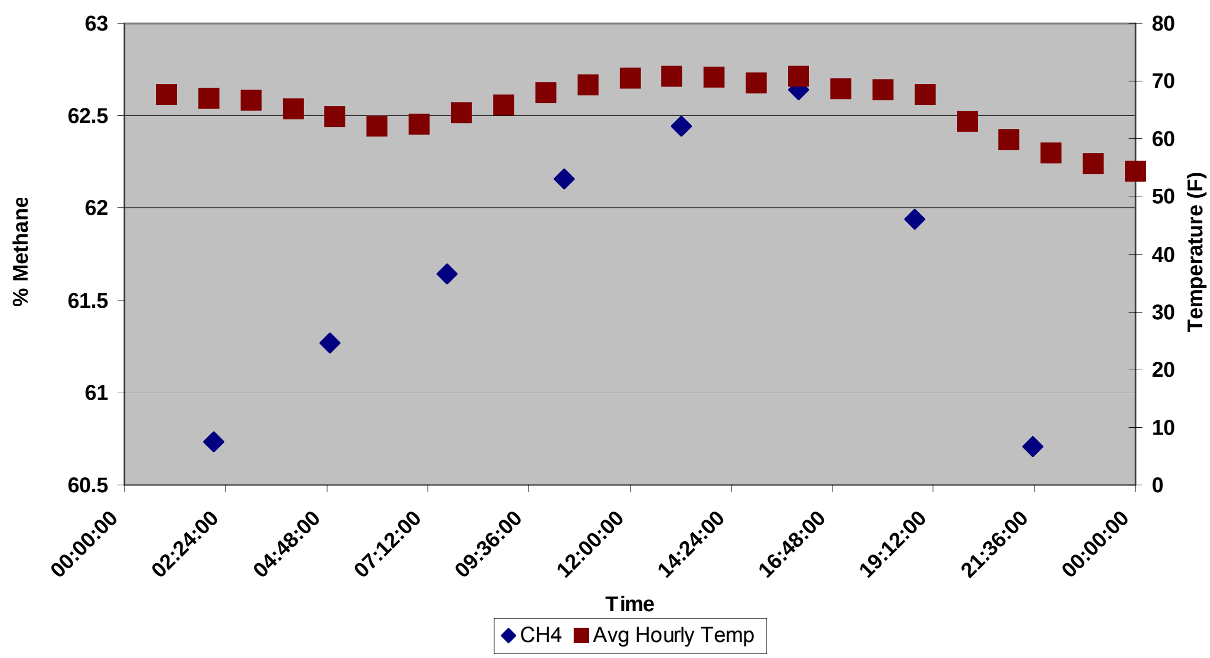

Figure B-10 Methane Concentration in Biogas at DDI (July 28, 2003)

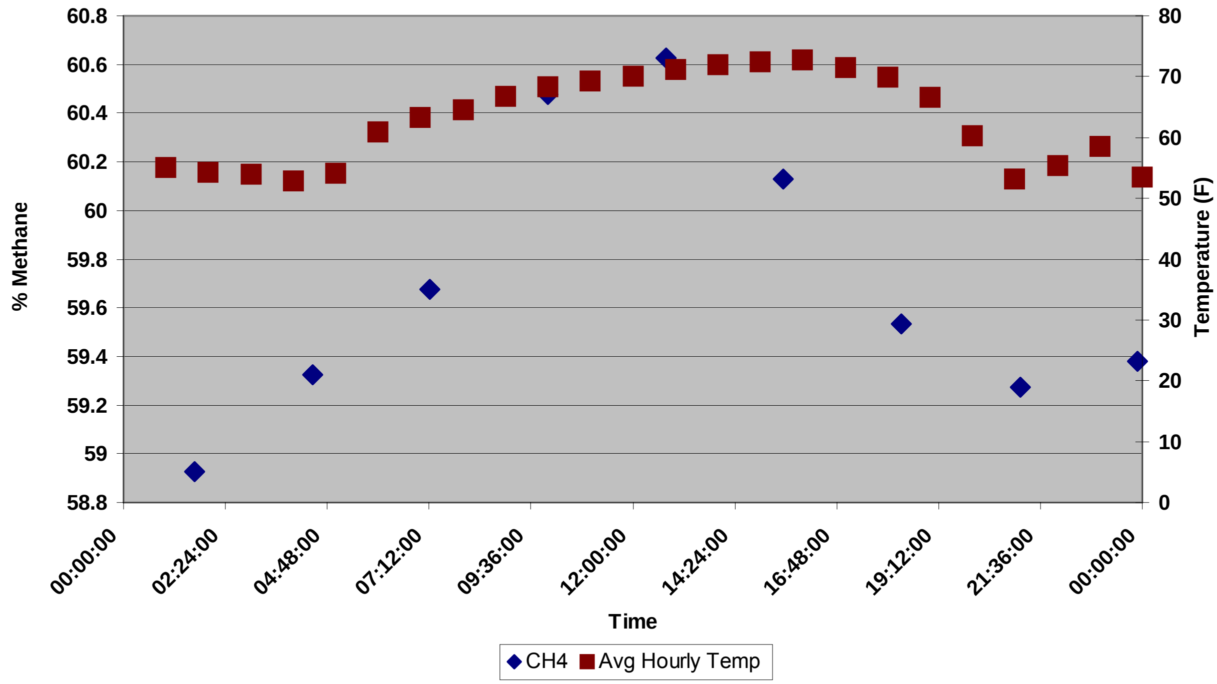

Figure B-11 Methane Concentration in Biogas at DDI (August 23, 2003)

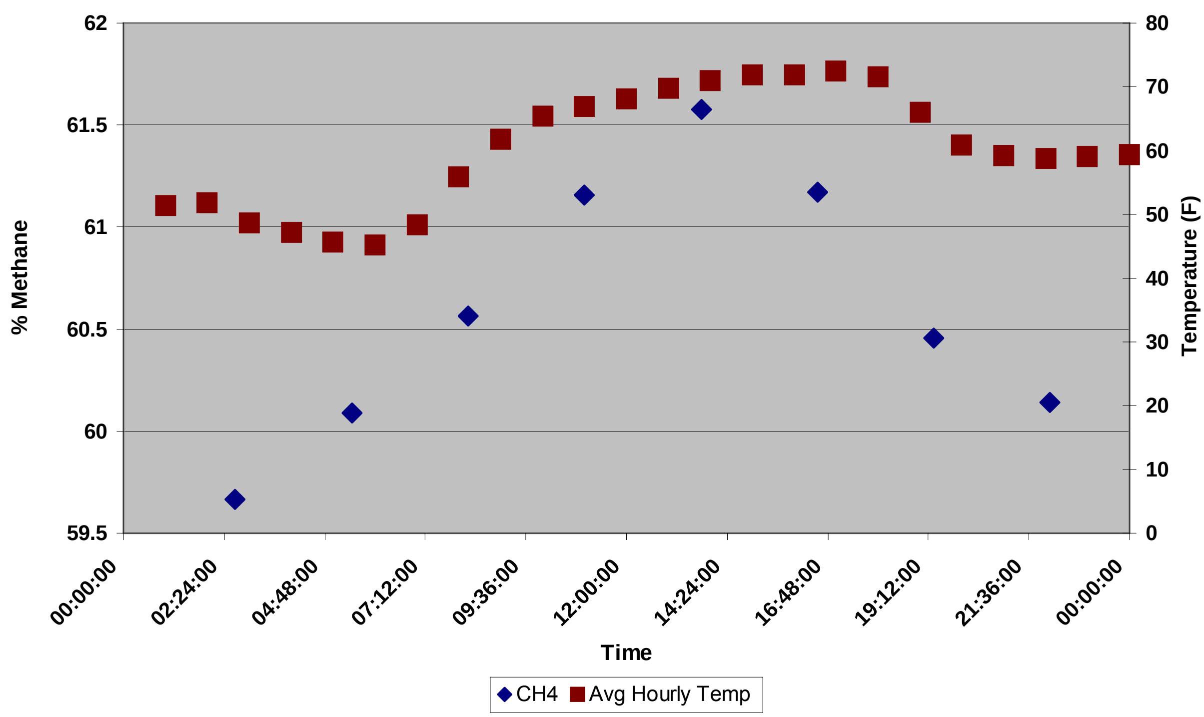

Figure B-12 Methane Concentration in Biogas at DDI (August 24, 2003)

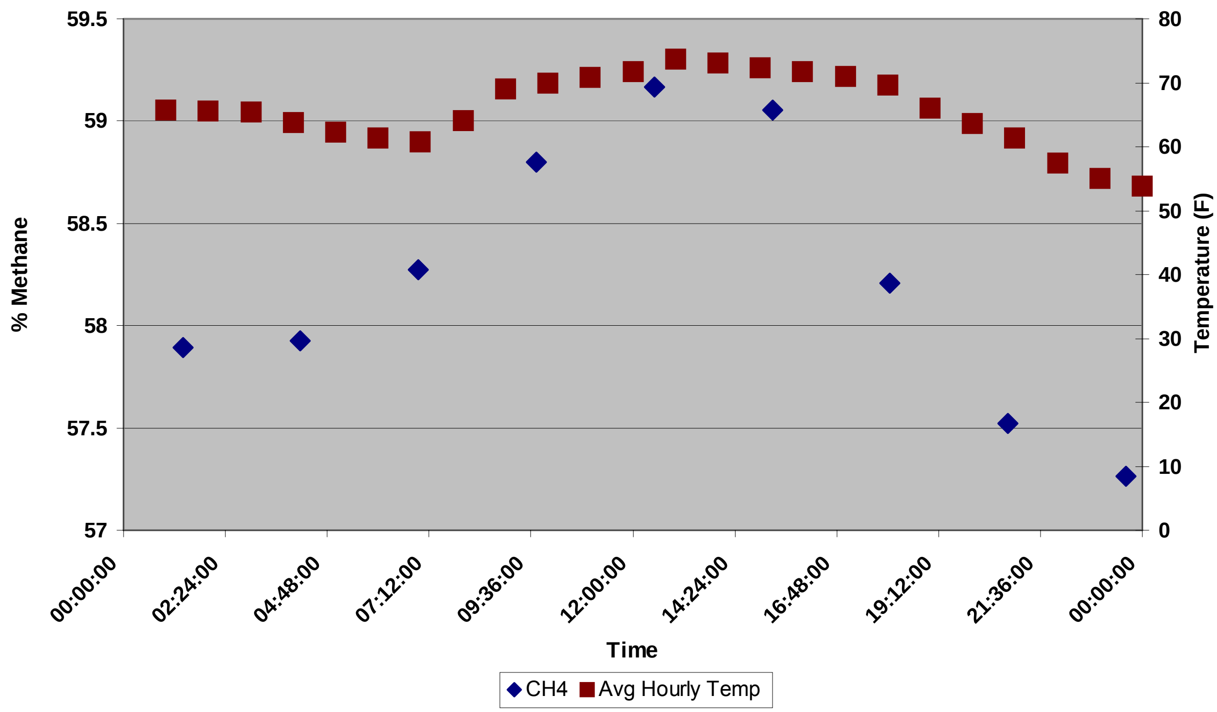

Figure B-13 Methane Concentration in Biogas at DDI (September 4, 2003)

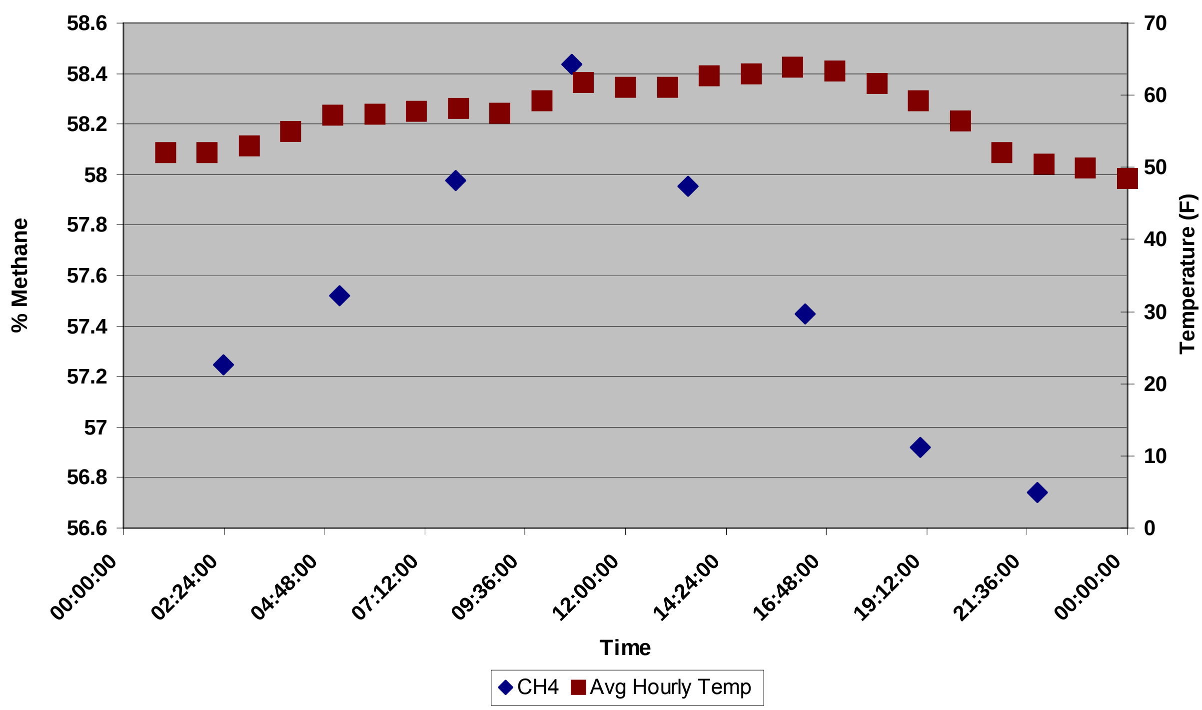

Figure B-14 Methane Concentration in Biogas at DDI (September 5, 2003)

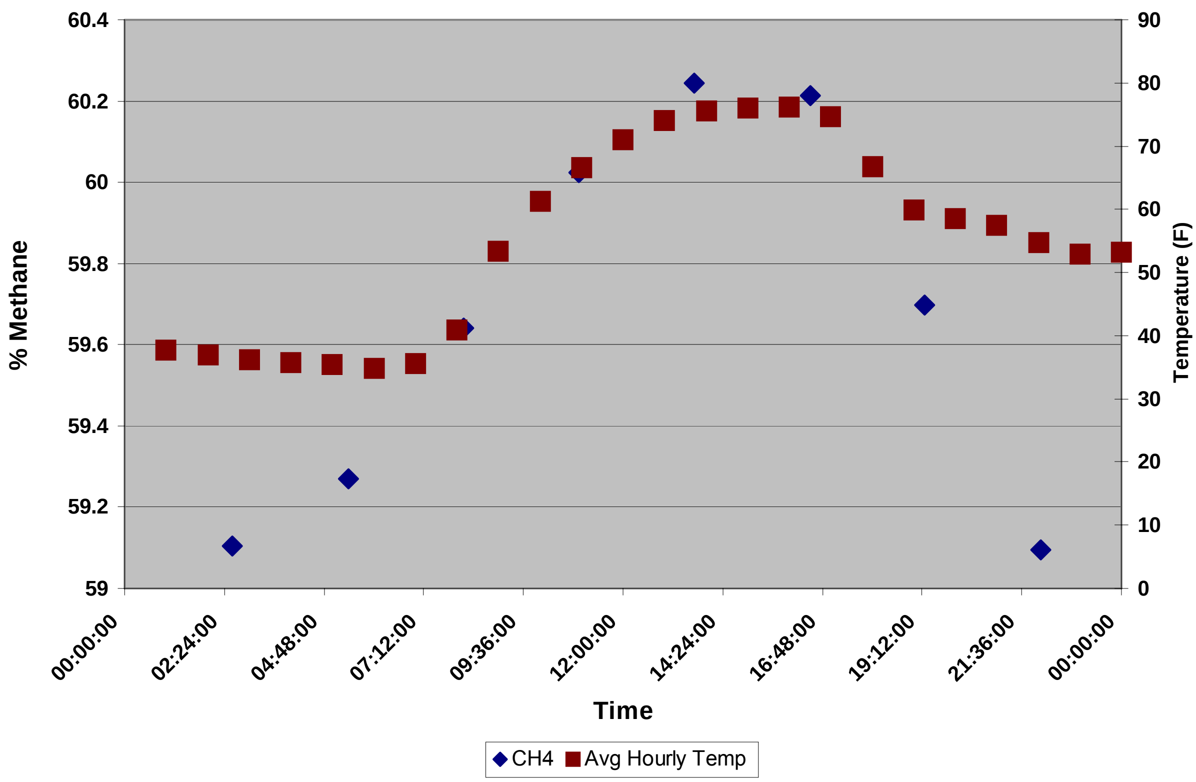

Figure B-15 Methane Concentration in Biogas at DDI (October 8, 2003)

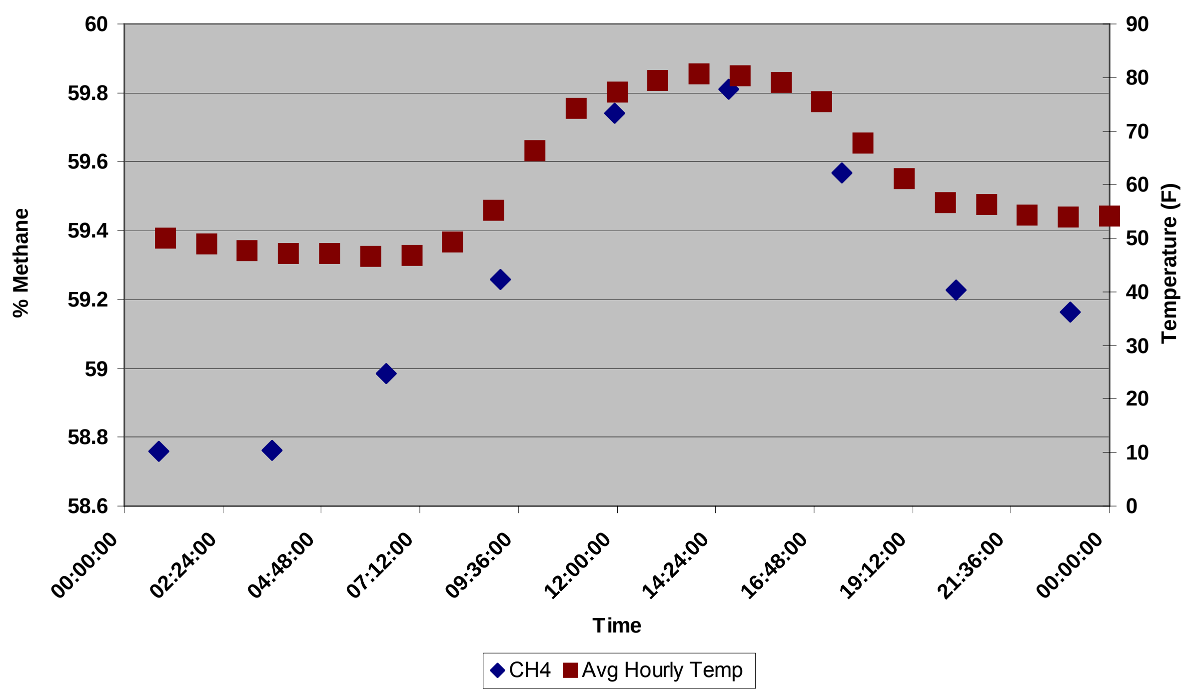

Figure B-16 Methane Concentration in Biogas at DDI (October 9, 2003)