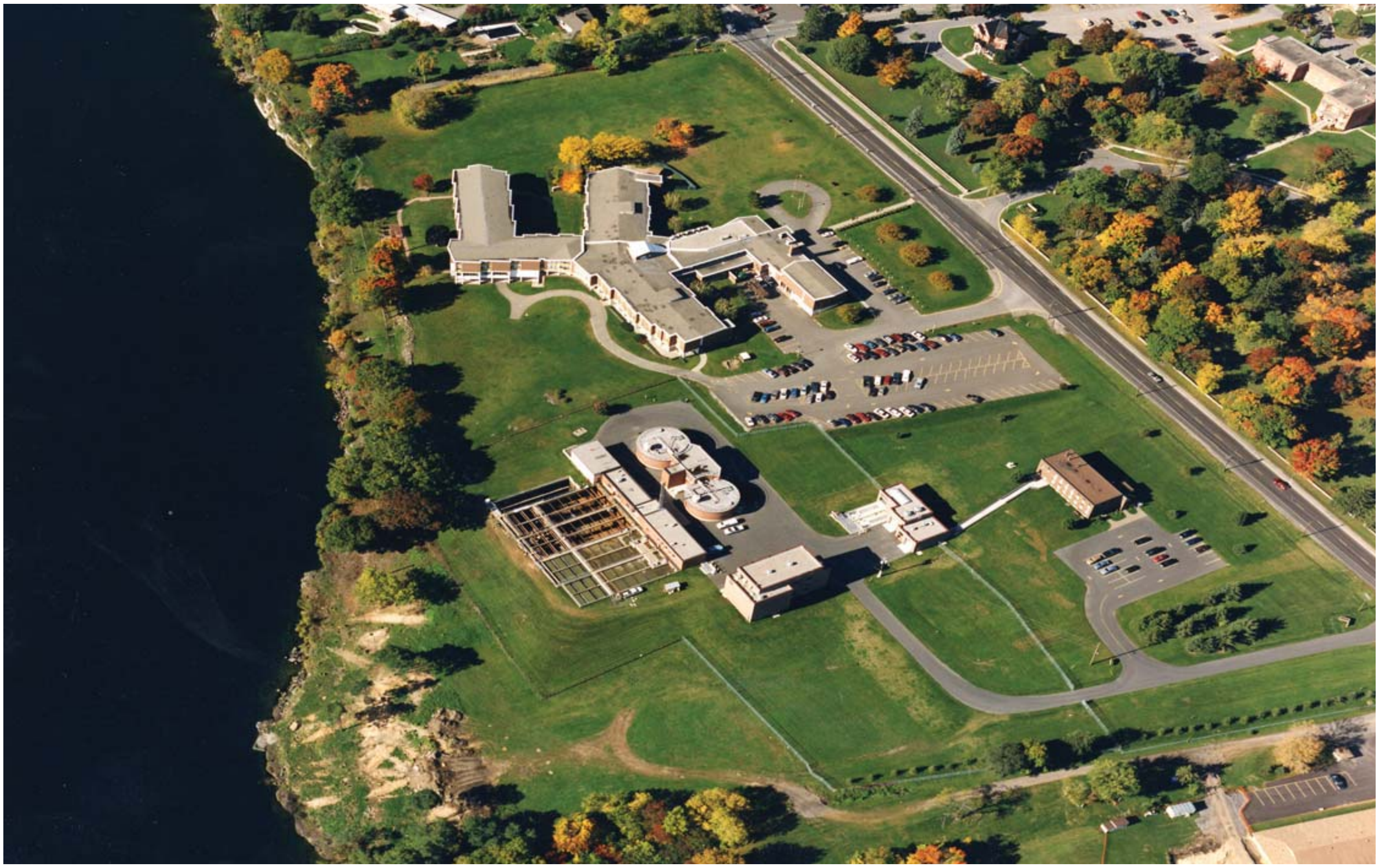

Final Report

City of Brockville Water Pollution Control Centre Cogeneration Feasibility Assessment

January 2007

Prepared for

City of Brockville

Prepared by

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January 5, 2006

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Subject: City of Brockville Water Pollution Control Centre Cogeneration Feasibility Assessment Final Report

Dear Mr. Cosgrove:

I am pleased to submit our final report for the Brockville Water Pollution Control Centre Cogeneration Feasibility Assessment. This document includes the economic analysis of two cogeneration technologies, internal combustion engines and microturbines, and addresses your comments from the review of the draft report. Both hard and soft copies of the document are included.

I have reviewed the requirements of Schedule D of the Green Municipal Fund document provided by the City at our review meeting, and have determined that a separate report to cover their requirements does not appear to be required. They specifically have two items that they require to be addressed (financing and implementation plan and expected environmental benefits of the preferred option), however, in this case, as we are not recommending that the City proceed with a cogeneration project, these items do not seem to be applicable in this case. If the GMF requires additional information not included in the final study document enclosed, please do not hesitate to ask, and we will prepare the information for you. The GMF does require one hard copy and one PDF version of the report, therefore, we have included 2 CD's so that you may forward one to the GMF, for your convenience.

I will contact you shortly to schedule our final conference call to review our conclusions and receive your feedback. I look forward to hearing any comments you may have on the report.

Sincerely,

CH2M HILL Canada Limited

Marcelle Jordan, P.Eng.
Project Manager

cc. Clare Humphrey, Client Service Manager

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1. Introduction

The City of Brockville (City) currently operates a wastewater treatment plant (the Brockville WPCC) with primary treatment and disinfection. Primary sludge is treated using anaerobic digesters that generate biogas which is utilized internally through industrial boilers offsetting a portion of the in-plant heating loads. The City was issued an order by the Ministry of the Environment (MOE) to complete an environmental assessment (EA) to upgrade the WPCC to secondary treatment, currently the minimum level of wastewater treatment required in Ontario.

The City continues to move toward its upgrade goal by completing an EA, as required by the MOE order, and by participating in a working group of local municipalities to study the feasibility of a regional septage receiving and treatment facility as part of the future Brockville WPCC upgrade. As a further step progressing toward the ultimate upgrade of the plant, this feasibility study was undertaken to determine whether a cogeneration system should be included as part of the ultimate plant upgrade project.

2. Background Information

The Class Environmental Assessment Report, completed by Simcoe Engineering Group Limited and Hydromantis, Inc. in January 2005 was used as a basis for this cogeneration feasibility assessment with respect to wastewater influent characteristics and flows. More discussion is provided with regard to design basis assumptions in Section 4.

3. Objective

The objective of this feasibility assessment is to determine whether cogeneration will be feasible for the Brockville WPCC in conjunction with the upgrade secondary treatment. The decision with regard to feasibility will consider both qualitative information such as advantages and disadvantages of each technology with respect to commercial availability and ease of operation, and cost information including capital, operating & maintenance (O&M) cost, and life cycle cost. Life cycle cost will be an important consideration, given that Brockville must carefully consider the payback period of a cogeneration project in light of the overall secondary treatment process, for which they are currently seeking funding assistance.

4. Process Design Basis

4.1 Review of Septage Quantities

Septage quantities were provided by the City for use in this study. These quantities are based on work the City is doing in a cooperative effort with other local municipalities to determine potential future septage and commercial haulage volumes that may be brought to a central treatment facility. Consideration is being given to provide this capacity at the upgraded Brockville plant. The volumes estimated are based on records of the various municipalities and from commercial hauling companies.

The assumed volumes of imported septage or commercial haulage for this study are:

- Residential = 51, 492 m^3 annually
- Commercial = 91, 980 m^3 annually

These quantities result in an average assumed increase to the plant influent flow of approximately 400 m^3/day, based on receiving septage 365 days per year. The influent loadings are increased to the plant, along with the increase in volume, to account for the strength of the septage loads in terms of plant loading.

4.2 Secondary Treatment Alternatives

Three secondary treatment alternatives were recommended for further consideration for the upgraded Brockville WPCC in the EA study. These are conventional activated sludge (CAS), biological aerated filtration (BAF) and moving bed bioreactor (MBBR). These three secondary treatment alternatives were considered in this study.

4.3 PRO2D Input

The City is referred to *Technical Memorandum #1 – Pro2D Modelling – Cogeneration*, included in Appendix A, for a description of the process modelling completed for this study. The modeling was used to determine expected biogas generation and possible electrical generation potential for several different scenarios that represent potential treatment process trains for the future WPCC upgrade. The treatment alternatives considered included:

- Conventional primary treatment versus enhanced primary treatment in combination with CAS, BAF and MBBR secondary treatment
- Influent wastewater strength with and without septage loadings

The analysis resulted in the modeling of eight different scenarios. Technical Memorandum #1 provides the background and assumptions for the modeling, the design basis for plant influent flows and wastewater strength, and sample calculations for electrical potential.

4.4 PRO2D Model Results

The model results indicate that enhanced primary treatment provides greater biogas production potential, which is expected. Enhanced primary treatment results in greater capture of biosolids. Additionally, the greater wastewater loadings associated with septage receiving at the plant would provide increased gas production potential.

The model results indicate that the greatest biogas production potential would result from enhanced primary treatment, with CAS or BAF as a secondary treatment process. The digester gas production from both the enhanced primary treatment with CAS and enhanced primary treatment with BAF will be approximately the same because it is anticipated that both systems will have similar solids production.

The following Table 1 from Technical Memorandum #1 shows the potential biogas production and electrical generation potential for each scenario that was modeled. The enhanced primary/conventional activated sludge process shows biogas production ranging from 1450 to 2100 m^3/day, with results in estimated electrical generation potential of 110 to 170 kWe. This estimation of electrical generation potential from the biogas is based upon a heating value of 22 MJ per m^3 of biogas, and an electrical efficiency of 32%. An example calculation is provided in Technical Memorandum #1 in Appendix A. The digesters will not produce the maximum biogas consistently, and for the purposes of providing cogeneration equipment, it is conservative to use a value of 80% of this potential electrical generation in order to allow for variances in biogas production from the process. Therefore, for this study, an assumed electrical potential value of 100 kWe was used (similar to the value provided in the proposal) for discussion with equipment suppliers and for estimated capital and operations costs.

TABLE 1
Estimated Biogas and Electrical Production (Average Conditions)

Scenario	Description	Gas Production (m^3/d)	Electrical Production (kWe)
1a	CPT, CAS, FT (Raw)	1100	90
1b	CPT, CAS, FT (Combined)	1600	130
2a	EPT, CAS, FT (Raw)	1450	110
2b	EPT, CAS, FT (Combined)	2100	170
3a	EPT, BAF, No FT (Raw)	1450	110
3b	EPT, BAF, No FT (Combined)	2100	170
4a	No PT, MBBR, FT (Raw)	420	35
4b	No PT, MBBR, FT (Combined)	620	50

Notes:

1. CAS – Conventional Activated Sludge
2. BAF – Biological Aerated Filter
3. MBBR – Moving Bed Biofilm Reactor
4. CPT – Conventional Primary Treatment
5. EPT – Enhanced Primary Treatment
6. FT – Final Tanks
7. Raw – Influent is raw sewage to the plant only
8. Combined – Influent is combined, raw sewage, residential septage and commercial haulage

5. Cogeneration Technology Review

5.1 What is Cogeneration?

Cogeneration is the conversion of energy in one form (burning fuel) into energy in two forms (electricity and heat). Methane can be utilized in various equipment, such as engine/generator sets, to produce both electricity and heat, simultaneously - hence the name cogeneration.

Solids removed during the wastewater treatment process, typically during primary and secondary treatment, are separated from the wastewater through removal of "waste sludge" in clarifier tanks. At Brockville, the solids stream then enters an anaerobic digestion phase that stabilizes this material. The digested sludge is then dewatered and is ready for disposal. Anaerobic digestion is a bacterial process in which bacteria produce a mix of methane gas (60 to 65% by volume) and carbon dioxide (35 to 40% by volume) referred to as digester gas. Digester gas has about 60% of the energy value of natural gas. This gas can be used for cogeneration, i.e. production of electricity and heat through cogeneration using an engine or other prime mover technology, as will be described in following sections.

Distributed generation systems can be used for standby power and/or peak shaving, provide higher-quality electricity than available from the grid, reduce the cost of electricity where prices are high (e.g. due to deregulation), and provide process heat through cogeneration. Another important benefit is the ability to use alternative "waste" gases, such as anaerobic digester gas, to produce electricity and heat and thereby minimize purchased electricity and reduce emissions of greenhouse gases such as methane.

Disadvantages of distributed generation include higher capital costs per kilowatt, lower commercial availability (some technologies are still in the early commercialization stage), and safety and standardization issues related to grid interconnection.

5.2 Scope of Cogeneration Review

Available cogeneration technology alternatives have been evaluated and compared for use in energy recovery using digester gas. The technology options are described in the following sections and have been compared with respect to size, fuel requirements, efficiency, costs, environmental emissions, health & safety, and their overall compatibility with the Brockville WPCC. Gas pretreatment requirements have been investigated, and a discussion on gas contaminants and an appropriate level of gas pre-treatment have been included in this memorandum, and also in a following section. A discussion of advanced (enclosed) flaring versus traditional (open) flaring of waste gas generated is also provided.

Five technologies were selected for analysis and comparison for the Brockville WPCC as follows:

- Reciprocating (internal combustion) engine/generator sets
- Gas turbine engine /generator sets
- Microturbine/generator sets
- Stirling engine cogenerators
- Fuel cells

These technologies can also be aggregated into "combined-cycle" or "hybrid" systems, that is, systems that use two (or more) different technologies to increase the overall electrical and/or total efficiency. For example, there are studies being done on a silicon oxide fuel cell + turbine engine hybrid system. However, no hybrid system is near the commercialization stage so they will not be considered here.

Induction generators (or alternators) are part of cogeneration systems, with the exception of fuel cells, however, a separate section has been included in this memorandum, to provide clarity with regard to this technology, and in response to the City's request for information with regard to this equipment.

The City also requested information with regard to exhaust gas hot water boilers (or heat exchangers). These are not specifically a separate technology, but can be used in combination with a number of the above technologies such as internal combustion engines, mircoturbines, and gas turbines. These heat exchangers can be used to recover heat generated from the engine to improve the efficiency of the system. Discussion with regard to exhaust gas hot water boilers is included in Section 5.3.

Equipment suppliers were requested to supply information and budgetary quotations for several of the reviewed technologies. This information is included in Appendix B. Appendix B also includes a list of all equipment suppliers that were contacted, although not all were able to provide information for this project (most often as they did not supply equipment in the size range needed).

5.3 Reciprocating Engines

5.3.1 Description

Reciprocating engines, or internal combustion (IC) engines, are the most mature technology for distributed energy generation, i.e. they are the most commonly used. There are many installations of IC engines in biogas and cogeneration applications around the world; hence, the industry has a long proven track record and experience with this system. Reciprocating engines are mass-produced, readily available, and have been used previously for energy recovery from anaerobic digester gas in Canada.

Annacis Island Cogeneration

Reciprocating engines are available in many sizes, ranging from less than 5kW to 2,000 kW. They use almost any commonly available fuel; including gasoline, diesel, propane, natural gas, and anaerobic digester gas (ADG). Reciprocating engines use a spark ignition for fast-burning fuels such as gasoline and natural gas, and compression ignition for slow-burning fuels such as diesel. Reciprocating engines are classified as high-speed (1200-3600 rpm), medium speed (275-900 rpm), and low speed (58-275 rpm).

Good conversion of energy from gas to electricity can be obtained with reciprocating engines – i.e., in the order of 30 to 36%. With heat recovery, the overall energy conversion efficiency is about 80%. Heat recovery is achieved though recovery of waste heat available from the engine jacket water cooling system and exhaust system.

Reciprocating engines have higher nitrogen oxide (NO_X) emissions than gas turbines, micro turbines or fuel cells. However, lean-burn engines have NOx emissions that meet air emission regulations.

Reciprocating engines have fairly short start-up times, ranging from 0.5 – 15 minutes, and can tolerate repetitive starts and stops. However, they have a lower available heat recovery than gas turbines, but similar overall energy efficiency.

Reciprocating engines are classified into three basic categories:

- Natural draft (naturally aspirated) engines
- Turbo charged engines
- Low emission, turbocharged engines

Naturally aspirated engines draw combustion air and biogas through a carburator in stoichiometric proportions. Just enough air is drawn into the combustion chamber to ignite the air/gas mixture. Generally, a naturally aspirated engine can produce 80 – 85% of its continuous natural gas rating when operating on digester gas. This type of engine typically runs at a slower speed (1,200 rpm or less) and produces higher NO_X emissions as a result of longer retention time within the combustion chamber. The slower speed units (900 rpm or less) typically have lower operating concerns or issues with deposits and corrosion. However, the units are generally larger due to the limited output and have higher associated capital costs per output power when compared to a turbocharged engine.

Turbo charged engines include the use of a turbocharger to boost the air/gas mixture pressure and result in higher power output. Turbocharged engines generally maintain 100% of their continuous natural gas rating and operate at higher engine speeds (1,200 rpm or greater). As they operate faster, they are more prone to increased wear and corrosion depending of course, on the level of contaminants found in the biogas stream. Turbo charged engines result in lower NO_X emissions than a comparable naturally aspirated engine.

Many engine manufacturers have further developed low emission, lean-burn turbo charged engines which limit NO_X emissions to less than 1.5 g/bhp-h.

Engine manufacturers such as Waukesha, Caterpillar, Jenbacher, and Deutz supply IC engines suitable for biogas cogeneration applications. These engines have been modified for biogas service to enable the engine to operate with the lower heating value fuel. Other modifications include higher operating oil and cooling water temperatures, and stainless steel components.

Reciprocating engines generally have a lower capital cost than other competing technologies, but there is also a slightly higher operating cost associated with oil changes and both top-end and major overhauls. The engines require oil and filter changes at approximately 700 – 1,000 hours of operation and engine head and block rebuild occurs after about 8,000 hours operation. Maintenance costs will tend to increase as the gas quality decreases. Hydrogen sulphide (H_2S) content will increase the frequency of oil changes and potential corrosion problems. Siloxane (organic silicate compound) concentrations in the gas should be minimized to prevent excessive buildup of silicate deposits and wear on the engine combustion components. Each manufacturer specifies the fuel quality required for their engine. A discussion of gas contaminants and pre-treatment is provided in Section 6.

Table 2 summarizes one engine manufacturer's fuel requirements.

TABLE 2
Summary of Waukesha Gaseous Fuel Specifications (S7884-7, 3/03)

Parameter	Limit	Notes
Saturated Lower Heating Value (SLHV)	15.73 MJ/m^3	Biogas applications
Total Organic Halide	150 μg/l	Expressed as chloride (TOH/Cl).
Total Sulfur Compounds	1000 ppmv	Generally based on concentration per fuel heating value
Total Siloxanes	25 μg/l	Recommend refrigerating gas to 4°C, followed by a 0.3 μm filter and reheat to 29 – 35°C
Liquid Water	None permitted	Dew point should be at least 11°C below temperature of gas entering engine. Saturated is acceptable on engines without prechamber fuel systems
Solid Particulate	5 micron	

It can be assumed that gas treatment for hydrogen sulphide, siloxanes, and moisture content is required for digester gas to meet the requirements for an IC engine, to reduce annual engine operating costs and increase the longevity of the engine. A gas treatment system that lowers H_2S from the gas would also decrease SO_X and other emissions from the plant. Ammonia in the digester can contribute to increased NO_X emissions, so a "lean burn" low NO_X engine should be considered for use in biogas applications. Although NO_X emissions may not be mandated in Ontario, low NO_X lean burn technology should be a consideration when selecting an IC engine, based on the opportunity to reduce atmospheric emissions with minimal additional capital costs associated. Typical emissions depending on the manufacturer are: NO_X < 46 ppm; CO < 90 ppm.

It is also recommended that a turbo-charged engine be used to reduce capital expenditure and the required size of the engine. Providing an adequate gas treatment system is used, the effect of decreased engine life due to turbo-charging should be minimized compared with a naturally aspirated engine. All manufacturers offer a low-pressure fuel system configuration that removes the requirement for up-stream gas compression on turbo-charged low NO_X units. Most engines available for digester gas applications can be configured as dual fuel units – i.e. to operate on either biogas or natural gas.

5.3.2 Advantages and Disadvantages

A summary of the advantages and disadvantages of reciprocating engines is shown in Table 3.

TABLE 3
Advantages and Disadvantages of Reciprocating Engines

Advantages	Disadvantages
Low capital cost per kW	Higher environmental air emissions
Readily available, many sizes	Noisy
Good electrical efficiency	Frequent maintenance
Quick start-up	
Fuel flexibility	
High reliability, proven	
Low natural gas pressures required	
Experience with anaerobic digester gas (ADG)	

5.3.3 Exhaust Gas Hot Water Boilers

Hot water boilers can be used in conjunction with cogeneration equipment such as reciprocating engines, to recover waste heat from the engine exhaust and use it for in-plant heating. These boilers (or heat exchangers) are not specifically a stand alone cogeneration technology, but are used in combination with other technologies to provide the heat recovery aspect of the system. Generally the exhaust gas boilers are provided with the cogeneration equipment as a package by the supplier. One manufacturer that supplies this equipment is VaporPhase.

Heat generated from an engine is utilized and can be transferred to the plant-wide heating system to reduce the requirement for traditional plant heating such as electrical or natural gas. As an example, heat is captured from internal combustion engines in two ways:

- Via the engine jacket water and auxiliary/oil cooling loops. Each engine is cooled by circulating cooling water through the cavities in the engine body. Excess heat from the combustion of digester gas raises the coolant temperature to approximately 120°C. The coolant flows to a heat exchanger where the heat is transferred to the plant heating system.
- Via the exhaust gas leaving the engine. at about 450°C runs through a heat exchanger (boiler) where it is cooled to about 150°C.

The recovered heat is transferred to the plant heating hydronic system and the cool water return loop provides the engine cooling requirements. Heat dumps and exhaust gas diverters are required when the WPCC heat load is less than the cogeneration heat recovery.

5.4 Gas Turbine Generators

5.4.1 Description

Combustion gas turbines are a very mature technology since most engines used for power generation are generally derived from aeronautical applications (i.e. jet engines). They typically range in size from 500 kW to 25 MW or larger, although the smallest commercial gas turbine engines are generally greater than 1 MW.

Heat is recovered in a combined cycle application through exhaust heat recovery systems. They generally use natural gas, oil, or a combination of fuels and have gas-to-electric energy efficiencies ranging from 20 – 45% with the higher efficiencies achieved by the larger turbines. Gas turbines offer gas-to-electric energy conversion efficiencies slightly lower than the conversion available with IC engines, but overall heat and electricity conversion efficiency is very similar (approximately 80%).

Combustion turbines have three main components: compressor, combustor, and turbine. The compressor compresses the incoming air to high pressure (160 – 610 psig depending on the manufacturer), fuel is added and combusted to produce high-temperature high-pressure gas, and the turbine extracts energy from this exhaust gas. Some of the energy from the turbine is used to power the compressor and gas pressurization reduces overall output by 2 to 4%.

The additional equipment results in higher parasitic load and capital cost than an IC engine. Although the capital costs associated with turbines are higher than they are with IC engines, maintenance costs are typically lower over the life of the system (providing the fuel gas meets the manufacturer's specification). While IC engines will run on fuel with a low heating value, some turbines will not. This may necessitate natural gas blending.

Turbines are more tolerant of high H_2S content than IC engines; however, are less tolerant of high siloxane concentrations. Since the siloxane content must be very low for the turbine, a similar gas treatment system to the IC engine would be required. One gas turbine manufacturer, Solar Turbines, has recently issued a white paper (PIL-176) that sets a zero-tolerance for silicon in any form. Solar's definition of "zero" siloxanes corresponds to the lowest detectable concentration, which is 0.1 mg/nm^3 (0.087 ppmv).

The gas treatment system would generally consist of a refrigerated dryer, final carbon filtration polishing, and gas reheating above the moisture dew point. One advantage of the gas turbine is that the NO_X and other emissions are generally lower than they are with an IC engine. Manufacturers that can supply gas turbines include Kawasaki (200 - 3,600 kW), Vericor AES8 (500 kW and up), and Solar Turbines (600 to 10,000 kW). Typical exhaust emissions are in the order of NO_X = 14 - 25 ppm, CO = 50 ppm (at O_2 = 15%). Table 4 indicates the typical gas quality required for a gas turbine prime mover.

TABLE 4
Summary of Typical Gaseous Fuel Specifications for Solar Turbines

Parameter	Limit	Notes
Saturated Lower Heating Value (SLHV)	16 MJ/m^3	
Total Sulfur Compounds	Various up to 10,000 ppmv	Manufacturer dependent
Total Siloxanes	0.1 μg/l (0.087 ppmv) of methane (CH_4)	Recommend to use carbon filtration or refrigerating gas to 4°C, followed by a 0.3 μm filter and reheat 20°C above dewpoint
Liquid water	None permitted	Dew point typically required to be at least 20°C below temperature of gas entering engine
Solid Particulate	10 micron	Use of 0.3 micron coalescing filter recommended

For gas turbines, electrical output decreases with increasing ambient air temperature and increasing elevation due to lower air density. Start-up times are about 2 – 5 minutes.

5.4.2 Advantages and Disadvantages

A summary of the advantages and disadvantages of combustion gas turbines is shown in Table 5.

TABLE 5
Advantages and Disadvantages of Combustion Gas Turbines

Advantages	Disadvantages
Low capital cost per kW for large systems	Not available in small enough size for Brockville
Readily available, many sizes	Environmental air emissions (requires emission controls)
High electrical efficiency	Reduced efficiency at partial load
High heat recovery (can produce high temperature steam)	Sensitive to ambient air conditions
Quick start-up	Cost higher and efficiency lower for smaller engines
Fuel flexibility	Efficiency reduced due to fuel gas pressurization
High reliability, proven	
Experience with anaerobic digester gas	

5.5 Microturbines

Microturbines are small gas combustion turbines of 25 – 500 kW. They are derived from auxiliary power units in aircraft and from turbocharger technology found in large trucks. Most of the manufacturers provide units in the 60 - 100 kW range, and some have larger units in the 250 and 400 kW range. Two or more units may be required to provide the same electrical output as one of the other prime mover alternatives.

Most microturbines are single-stage, radial-flow devices with high rotating speeds of 80,000 to 100,000 rpm. Micro turbines for digester gas applications are an emerging technology and have been in the market place since 1999. Numerous installations exist and in operation on natural gas cogeneration applications. There are fewer installations with limited operating history for digester gas cogeneration applications. The claimed advantages over the conventional reciprocating engine (internal combustion) technology are higher availability, lower O&M costs and lower air emissions. The higher availability and lower O&M costs can be debated; however, overall they do result in lower air emissions.

Currently, there are still some technical risks, primarily related to the fuel compressor and gas cleaning requirements, associated with the micro turbine technology system which could impact the economics.

Two types of microturbines are available, recuperated and non-recuperated, although most manufacturers are focusing on recuperated microturbines since they have higher electrical efficiency (but higher capital cost). Recuperators are heat exchangers that pre-heat the incoming air before it enters the combustor. Excess exhaust heat can be recovered in a cogeneration scheme which several manufacturers have taken advantage of by creating a pre-packaged combined heat and power (CHP) unit (microturbine with integrated heat recovery system). Using cogeneration (i.e. the inclusion of heat recovery) substantially increases the overall efficiency. The heat recovery equipment can be by-passed if it is required to generate power without recovering heat. Some designs allow “banking” where a number of micro turbines supply one heat recovery unit; this can reduce capital costs. Microtubines operating on low pressure biogas will require an external fuel gas compressor which decreases the net electrical generation scheme efficiency.

The microturbine system incorporates a fuel compressor, recuperator, combustor, expansion turbine and permanent magnet generator. The rotating components are mounted on a single shaft that rotates at up to 96,000 rpm (full load) and is supported by air bearings (Capstone units). The generator is cooled by intake airflow, thus eliminating the need for liquid cooling. (Ingersol Rand microturbines are oil cooled and operate at ~ 76,000 rpm).

Microturbines, like reciprocating engines and larger combustion gas turbines, can operate on a variety of fuel types including natural gas, propane, landfill gas (LFG) or anaerobic digester gas (ADG). Because of their simple design, microturbines have a lower electrical efficiency than their larger counterparts but offer the advantage of less maintenance (manufacturer estimates of 5000 – 8000 hours of operation before first maintenance). The micro turbine is designed to operate for 40,000 hours between major overhauls. There are no actual units running sufficiently long enough on biogas to validate this design data.

The following are key features and parameters for micro turbines:

- For a 30 kW Capstone C30 unit, the typical exhaust gas temperature is 260°C and the total exhaust energy is 306,000 kJ.
- The electrical output is at 400 – 480 VAC, 60 Hz. Therefore, for installations in Canada with 575 VAC plant voltage, a power transformer is required.

- Electric efficiency (fuel in to electricity out) is 25 – 29% based on lower heating value. Heat recovery from the exhaust gas can increase total recoverable energy efficiency to over 75%.
- Heat rate (lower heating value): 13,300 kJ/kWh or 12,600 Btu/kWh.
- Required digester gas pressure for both Capstone and Ingersol Rand micro turbine is about 65 psig. If the pressure is lower, a fuel compressor is required. The typical power draw of the fuel compressor is about 2 to 5 kW on the 30 kW micro turbine.

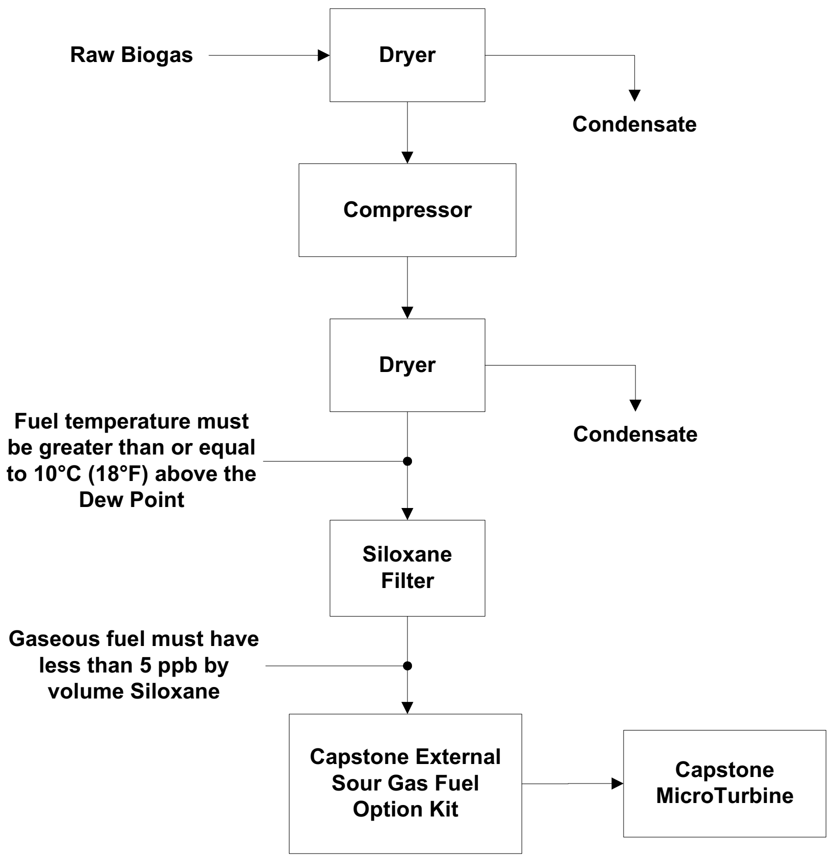
Although microturbines are more tolerant of moisture and H_2S in the fuel supply, they are less tolerant of siloxanes, which would require a fuel cleaning system similar to that of the IC engine. The main gas quality issues for microturbines pertain to moisture and siloxanes. Figure 1 is a typical flowsheet for biogas fuel preparation provided by one manufacturer.

Biogas by nature is typically saturated with moisture. A condensate knockout pot and particulate filter is generally installed in the incoming line from the main gas manifold. Moisture can also be removed by use of desiccant dryers or by cooling/reheating. The pressurized gas at the turbine manifold block should be at least 10°C above its dew point temperature during all seasons.

In the microturbine unit, the silica particles from siloxanes cause erosion of the nozzles, combustor, turbine wheels, recuperator and heat exchanger. The trailing edges of the turbine nozzle vanes in the micro turbine are the most susceptible component. Erosion can result in a significant loss of power output requiring the engine to be rebuilt. For the Capstone microturbine, siloxanes must be limited to less than 9 ppb by volume, which is approximately the detection limit.

Hydrogen sulfide is preferentially absorbed on the siloxane filter media (carbon based) for siloxane removal.

FIGURE 1
Typical Flowsheet for Biogas Fuel Preparation for Capstone Microturbine



Ingersol Rand, Capstone, Bowman Power, Elliot Ebara, and Turbec manufacture microturbines that are available commercially. As with gas turbines, microturbines have a slightly lower electrical energy conversion efficiency than IC engines, but they have a similar combined heat and power (CHP) efficiency of about 80%. While microturbines generate a lower exhaust gas temperature (about 400°F) than a gas turbine, , they still have good exhaust gas destruction efficiency compared to an IC engine. Typical emissions are: NO_X <9 ppmv @ 15% O_2, and CO <9 ppmv @15% O_2.

Table 6 indicates the typical gas quality needed for a microturbine system.

TABLE 6
Summary of Typical Micro Turbine Gaseous Fuel Specifications

Parameter	Limit	Notes
Saturated Lower Heating Value (SLHV)	14 MJ/m^3	Have operated as low as 13 MJ/m^3
Total Organic Halide	Not reported	
Total Sulfur Compounds	Up to 10,000 ppmv	Generally recommend H_2S removal
Total Siloxanes	Non-detectable	Recommend refrigerating gas to 4°C, followed by a 0.3 μm filter and reheat to 29 – 35°C and carbon filtration
Liquid water	None permitted	Gas temperature should be maintained at least 10°C above water dew point
Solid Particulate	10 micron	Use of coalescing filter recommended, especially for biogas

5.5.1 Advantages and Disadvantages

A summary of the advantages and disadvantages of microturbines is shown in Table 7.

TABLE 7
Advantages and Disadvantages of Microturbines

Advantages	Disadvantages
High efficiency with cogeneration	Higher capital cost per kW
Low maintenance (few moving parts)	Low electrical efficiency
Small size, light weight	Reduced efficiency at partial load
Low noise	Sensitive to ambient air conditions
Commercially available as engine alone or pre-packaged CHP unit	Reliability not yet proven
Fuel flexibility	Limited experience with digester gas
Quick start-up	Fuel gas compression required
Lower environmental air emissions (no emission controls required)	

5.6 Stirling Engine

Stirling engines for use in biogas applications is a very recent development. They are manufactured by STM power and supplied through distributors. The first wave of commercial units was officially available during the summer of 2004. A 55 kW unit is now available, with larger units under development. The Stirling engine is an external combustion (EC) engine that combusts fuel in a chamber outside of any moving parts. The engine can operate on any heat source by expanding and cooling a working fluid (hydrogen) within a sealed system. The fluid expansion and contraction is used to drive pistons, through a swashplate which drives a generator. STM Power Units claim to achieve 31% net electrical efficiency and 80% in a combined heat and power (CHP) mode.

Maintenance is stated to be low, capable of continuous operation with simple maintenance at 10,000-hour intervals. Since the combustion process does not occur near any moving parts, the engine claims to be more resistant to fuel contaminants associated with biogas. One advantage is the engine can easily be run on "dual fuels." At this time, gas conditioning requirements are unknown, but conditioning the digester gas to remove siloxanes would likely help to reduce silicate buildup and maintain heat transfer efficiency within the engine. Since the combustion takes place at a relatively high temperature, destruction efficiency is relatively high.

5.6.1 Advantages and Disadvantages

A summary of the advantages and disadvantages of Stirling engines is shown in Table 8.

TABLE 8
Advantages and Disadvantages of Stirling Engines

Advantages	Disadvantages
High efficiency with cogeneration	Higher capital cost per kW
Low maintenance (few moving parts)	
Small footprint	Few commercial units in operation
Low noise	Limited authorized service providers
Commercially available as engine alone or pre-packaged CHP unit	Reliability not yet proven Very limited experience with digester gas
Fuel flexibility	
Lower environmental air emissions (no emission controls required)	

5.7 Fuel Cells

Fuel cells are similar to batteries in that an electrochemical reaction is used to generate electricity. However, unlike batteries, fuel cells use an external fuel source that is continually replenished. There are many different types of fuel cells, with four being the most common: phosphoric acid (PAFC), molten carbonate (MCFC), solid oxide (SOFC), and proton exchange membrane (PEMFC). Fuel cell types are named after the electrolyte used. Table 9 provides a comparison of the differences between the various types of fuel cells.

Fuel cell usage in biogas applications is very new, and some testing has been done using fuel cells in digester gas and landfill gas for pilot studies. One such installation is at the City of Portland wastewater treatment facility. The City installed a 200-kilowatt phosphoric acid UTC Fuel Cell that converts anaerobic digester gas generated by the wastewater treatment facility into usable heat and electricity for the facility. Emissions from the fuel cell are very low – in the order of NO_X < 1 ppmv; CO < 2 ppmv; SO_X = negligible. The City estimates that the use of fuel cell technology has prevented the annual release of 621 tons of CO_2 as well as methane emissions, both of which are greenhouse gases. The facility received a Clean Air Excellence Award from the U.S. EPA for its use of fuel cell technology.

The PC25 phosphoric acid fuel cell from UTC Fuel Cells has over 5.1 million combined hours of operating experience as of May 2002. CH2M HILL was involved with the largest biogas fuel cell installation for King County in Seattle – 1 MW MCFC supplied by Fuel Cell Energy. The other two technologies are in the early stages of commercialization.

TABLE 9
Comparison of Fuel Cell Types

	PAFC	SOFC	MCFC	PEMFC
Commercially Available	Yes	No	Yes	No
Electrical Efficiency	36 – 42%	45 – 50% up to 60% with turbine hybrid	45 – 55%	30 – 40%
Overall Efficiency with Heat Recovery	90%	80 – 90%	80 – 90%	80 – 90%
Operating Temperature	200 °C	1000 °C	650 °C	80 °C
Time to Operation	2 – 4 hours	>10 hours	>10 hours	Seconds
Commercial Status	Available	Available late 2003	Field trials in progress	Planned late 2002

The electrolyte is sandwiched between an anode and a cathode yielding a particular (low) voltage. These sandwiches are combined into a fuel cell "stack" to achieve the desired output voltage. A fuel cell system normally consists of the stack, fuel reformer, power electronics, and controls. The fuel cell itself requires oxygen and hydrogen to operate, thus, a fuel reformer may be required where hydrogen is not directly available. Steam reforming of a hydrogen-rich fuel such as methane is common. Fuel cells with a high operating temperature (MCFC and SOFC) allow direct hydrogen-rich fuel feed because the high temperature combined with a catalyst allows auto-dissociation of the fuel yielding hydrogen. Fuel cells with a high operating temperature are also ideal for cogeneration.

Phosphoric acid fuel cells (PAFC) use liquid phosphoric acid as the electrolyte. Electrical energy conversion is high, about 50%, with a CHP efficiency of around 80% (similar to other technologies). Because PAFC power plants are usually large, heavy, and require warm-up time, they are used mainly for stationary applications. The fuel cell requires very clean fuel and, as such, requires a gas conditioning system similar to those of the other prime movers. Some performance information on the UTC PC25 fuel cell is included in Table 10.

TABLE 10
PC25™ Performance Data

Feature	Characteristics
Rated Electrical Capacity	200 kW/235kVA
Fuel Consumption	Natural gas: 60 cm/h @ 1-3.5 kPag
	Anaerobic digester gas: 91 cm/h at 60% CH_4
Efficiency (LHV Basis)	87% Total: 37% Electrical, 50% Thermal
Emissions	<2 ppmv CO, <1 ppmv NOx and negligible SOx (on 15% O_2, dry basis)
Thermal Energy Available	
Standard:	950 MJ/h @ 60°C
High heat options:	475 MJ/h @ 60°C
	475 MJ/h @ 121°C
Sound Profile	Conversational level (60dBA @ 9 m), acceptable for indoor installation
Power Module: Dimensions and Weight	3 m x 3 m x 5.5 m
	18,150 kg
Cooling Module: Dimensions and Weight	1.2 m x 4.3 m x 1.2 m
	171 kg

Fuel cells generally have very low maintenance requirements, typically consisting of a yearly inspection. The most significant advantage of fuel cells over the other technologies is a very high electrical efficiency, especially with the high operating temperature systems.

5.7.1 Advantages and Disadvantages

A summary of the advantages and disadvantages of fuel cells is shown in Table 11.

TABLE 11
Advantages and Disadvantages of Fuel Cells

Advantages	Disadvantages
High electrical efficiency	High capital cost per kW
High efficiency with cogeneration	Limited fuel options (usually natural gas)
Low maintenance	Reliability not yet proven (except UTC PC25 PAFC unit)
Quiet operation	Limited experience with anaerobic digester gas
Quick start-up (PEMFC only)	
Low environmental air emissions (no emission controls required)	
Not sensitive to ambient air conditions	
Constant efficiency at partial load	

5.8 Induction Generators

5.8.1 Description

Induction generators have a simple design (basically an induction motor, a prime mover, plus some controls) and therefore can be less costly to purchase and install than a permanent magnet alternator. An induction generator does not in itself generate power, it must be powered by another source, which in the case of Brockville could be hydraulically using available head from the outfall. An induction generator may also be driven by a fuel burning engine (such as diesel/natural gas/bio-gas), but becomes necessarily more complex and therefore more expensive to own and operate. This application needs to be carefully evaluated to confirm the economics of such an installation.

Induction generators are different from a "synchronous" generator, which supplies power that is synchronized to the electrical power grid. An induction generator is essentially a special purpose motor that is run slightly above synchronous speed by an external source. If shaft power is applied to an induction motor already running, it will operate as a generator and push electricity back into the source used to operate it. It receives its excitation (of the stator coils) from the utility. Induction generators have no means of producing voltage until it is connected to the utility.

Induction generators have generally been employed in remote areas where limited power is required. They can provide a dependable source of electric power close to the user. They have been typically used in hydraulically driven micro-turbines and wind turbine applications.

Because the prime mover is generally a "free" source of power, such as water or wind power, an induction generator can be also inexpensive to operate. If the plant has sufficient hydraulic head, a water driven generator is a viable option.

The frequency and voltage of the power produced with an induction generator is governed by the frequency and voltage of the connected utility line. In this context, the system is fail safe; if the grid power fails, generator output ceases also. This obviously means that the generator cannot provide standby power during a utility outage.

While the generator supplies real power (kW) to the grid, it consumes reactive power (kVAR) during operation and should not be used to supply more than approximately 1/3 of the total plant load.

5.9 Cost Comparison

Table 13 provides a comparison of technologies including costs per kW the five evaluated technologies.

TABLE 13
Comparison of Cogeneration Technologies including Costs

Engine Type	Efficiency (%Electrical/ %CHP)	Equipment Cost ($/kW)	Annual Maintenance Cost ($/kW)	Fuel Quality Requirements	Exhaust Emissions
IC Engine	30/80	$1,300	$500	Low	Med/High
Gas Turbine	20-30/80	$2,500	$300	Med	Med
Microturbine	15-30/80	$2,500	$300	Med	Low
Fuel Cell	40-50/80	>$3,600	N/A	High	Low
Stirling Engine	31/80	$2,500	$200	Low	Low

Table 14 provides a cost summary of expected capital and maintenance costs based on the values per kW included in Table 13. For this screening level costing exercise total installed capital cost for cogeneration projects is assumed at a three times multiplier of the equipment cost. This allows for cost associated with a building, new electrical equipment and controls, tie-ins to existing plant electrical systems, etc.

TABLE 14
Cost Summary of Cogeneration Technologies for Brockville WPCC

Engine Type	Equipment Cost ($/kW)	Total Installed Capital Cost (3x Equipment Cost)	Annual Maintenance Cost ($/kW)
IC Engine	$130,000	$390,000	$50,000
Gas Turbine	N/A[1]	N/A[1]	N/A[1]
Microturbine	$250,000	$750,000	$30,000
Fuel Cell	$360,000	$1,080,000	N/A[2]
Stirling Engine	$250,000	$750,000	$20,000

*Note: 1 – The gas turbine is not available in small enough size for Brockville. 2 - The fuel cell maintenance requirements are minimal relative to the other technologies that utilize engine equipment. The fuel cell stack will require replacement every few years.

5.9.1 Carbon Credits

Biogas is considered to be a renewable energy source. As such, there is a potential for generating revenue from the sale of carbon credits for the offset of fossil fuels. The biogas used as fuel for boilers or for electricity or heat generation, results in displacement of fossil fuels, such as natural gas or diesel, that would normally have been used.

The GHG credits generated from electrical or heat generation may be sold in the carbon emission trading market. Canada has implemented a couple of pilot emission reduction programs; however, a national emissions trading market has not been established. There are a number of voluntary emissions trading schemes available internationally including bilateral trades and/or international emissions trading organizations. For example, the Chicago Climate Exchange (CCX) is a North American voluntary, legally biding greenhouse gas (GHG) emission reduction system. The International Emissions Trading Association (IETA) is another organization that is in the process of establishing a marketplace for buying and selling GHG emission offsets.

Further information on these programs can be found at the following internet addresses:

- Chicago Climate Exchange (CCX), 2006
  http://www.chicagoclimatex.com/about/index.html
- International Emissions Trading Association (IETA), 2006. About IETA.
  http://ieta.org/ieta/www/pages/index.php?IdSiteTree=2

5.10 Analysis of Alternatives and Applicability for the Brockville WPCC and Recommendation of Cogeneration Technology

Of the technologies reviewed for potential cogeneration at the Brockville WPCC, the most feasible for consideration are those that have current operating history for cogeneration at wastewater plants. This would be the reciprocating (internal combustion) engine or the microturbine. The conventional gas turbines are too large for the scale of the Brockville application, and fuel cells are not widely used and considerably more expensive than either reciprocating engines or microturbines.

The use of an induction generator at Brockville would most likely be used with hydraulic power generation, which could be achieved at a small scale; however, most manufacturers do not provide equipment in the Brockville size range. This equipment could be utilized in conjunction with a biogas cogeneration system to provide additional power for use at the plant.

As with fuel cells, the Stirling engine is still in its infancy for use with digester gas cogeneration systems, with only a few systems under pilot study. Capital and operating costs cannot be estimated as confidently as other technologies, and claims regarding no need for gas pretreatment may not entirely be entirely accurate based on operating experience. As such, this technology is not recommended for use at Brockville at this time.

Table 15 provides an overall summary of the most commonly used cogeneration technologies.

TABLE 15
Overall Comparison of Cogeneration Technologies

Parameter	Reciprocating Engines	Combustion Gas Turbines	Microturbines	Fuel Cells
Available Sizes	350 kW – 2 MW	400 kW – 30 MW	30 kW – 250 kW	<5 kW – 250 kW
Cooling Requirements	Active cooling	Active cooling	Active cooling in some models	No active cooling
Pre-Treatment Required	Yes	Yes	Yes	Yes
Electrical efficiency and potential total cogen efficiency	34.5% electrical 87% total	>24% electrical >75% total	26% electrical 76% total	37% electrical 87% total
Emissions	High	Moderate	Low	Low
Noise Level	High	High	High	Low
Maintenance Requirements	High	Moderate to high	Moderate to high	low to moderate
Reliability	high	High	Moderate	Reliability not fully proven (PC25 good reliability)

Current cogeneration installations in Canada based on CH2M HILL knowledge are shown in Table 16. This table illustrates that reciprocating engines are the most commonly used cogeneration prime mover at wastewater treatment plants today, as all of these installations utilize this type of technology.

Based on the cost comparison, background information provided in Sections 5.3 through 5.8, the comparison information provided in Table 15, and the current operating history associated with cogeneration technologies, it is recommended that both the reciprocating (internal combustion) engine and microturbine technologies be evaluated for life cycle cost comparison. This will be conducted as the second phase of this feasibility study, once review of this draft document has been completed by the City and endorsement of the information and recommendation has been provided.

The economic life cycle analysis will help the City in determining if cogeneration is ultimately feasible in the long term, and whether such a project should be incorporated into the design of a secondary treatment facility for the upgraded Brockville WPCC.

TABLE 16
Summary of Cogeneration Facilities in Canada for Surveyed WWTPs

Plant	Location	Population Equivalent	Manufacturer	Date Started	Installed Capacity (kWe)	Operating Capacity (kWe)
Annacis Island	Vancouver, BC	770,000	Jenbacker	1997	3,200	2,750
Barrie WPCP	Barrie, ON	100,000	Waukesha	1999	500	250
Clarkson WPCP	Mississauga, ON	200,000	Caterpillar	1999	810	250
Guelph WPCP	Guelph ON	106,000	Waukesha	1995	500	250
Humber STP	Toronto, ON	540,000	Caterpillar	2005	4,700	2,000
Iona Island	Vancouver, BC	570,000	Caterpillar	1999	4,100	1,800
J.A.M.E.S Plant	Matsqui, BC	130,000	Waukesha	1983	180	180
Lethbridge STP	Lethbridge, AB	25,000	Caterpillar	2002	1,620	810
R.O. Pickard	Ottawa, ON	500,000	Caterpillar	1997	2,400	2,000
Woodward Ave	Hamilton, ON	300,000	Caterpillar	2006	1,600	950
Bonny Brook WWTP	Calgary, AB	1,000,000	White Superior	1985	4,000	2,000
TOTAL		4,241,000			223,610	13,240

6. Gas Pretreatment Technology

6.1.1 The Need for Gas Pre-Treatment

Digester gas has been used as a fuel in boilers for many decades. The use for cogeneration in gas engine/generators is more recent. In the early days of cogeneration, it was recognized that contaminants such as water and hydrogen sulphide (H_2S) could cause damage to engines through acid corrosion to the engine parts and indirectly through contamination of the lubricating oil. Engine manufacturers include limits for H_2S in their engine specifications. More recently, they have included limits on moisture and other contaminants, such as siloxanes in their engine specifications.

Gas pre-treatment is recommended for all of the common cogeneration equipment reviewed as part of this study, as indicated in Section 5.3 through 5.7, including reciprocating engines, gas turbines, microturbines, and fuels cells. Stirling engines claim not to require pre-treatment, however, recent information indicates this may not be the case. Induction generation using water flow as an energy source is not subject to the gas pre-treatment consideration.

Contaminants in the feed digester gas can cause excessive and premature wear on cogeneration equipment and associated systems. Operating issues were identified at a CH2M HILL project for the City of Barrie related to siloxanes in the feed gas, including:

- The cogeneration system could not operate on digester gas efficiently, without excessive maintenance.
- The boilers required excessive maintenance and cleaning to remove siloxane deposits and to repair tubing badly corroded from the cleaning operation.
- Equipment life cycles were prematurely reduced.
- Additional maintenance requirements required staff to spend more effort on the maintenance of the system and which increased O&M costs due to staffing hours required.

The assessed siloxanes situation presented the following risks to the City of Barrie:

- Continued failures of the combustion equipment could result in uncombusted discharges of digester gas to the atmosphere. This would be a violation of the Certificate of Approval.
- Combustion related issues could result in emissions from the combustion units to the atmosphere that violate the Certificate of Approval (Air).
- Due to degradation of the boilers, major failures could result in inability to generate enough hot water to provide process and domestic heating during seasonal heating periods, the potential of condensation, freezing equipment and buildings, and resulting in additional damage.

These operational issues are common to cogeneration systems, and therefore generally result in the need for gas pre-treatment. This would most likely be required for a system at Brockville as it has been indicated verbally by the City that there are signs of the presence of siloxanes in the existing system, including visible white powder buildup on boiler equipment.

6.1.2 Background - Siloxanes

In the mid to late 80's, utilization of landfill gas by cogeneration or purification became popular in the United States, because of its economical and environmental acceptance. After some early failures, it was discovered that white scaling and/or powdery deposits contributed to these failures. This was identified as a silica deposit and later attributed to siloxanes in the landfill gas. Engine manufacturers suggested that the gas be specially treated in application notes developed in 1990. However, it was not until several years later that the manufacturers developed specifications for landfill gas that included limits for siloxanes.

More recently, the deposition of increased levels of silicate from the combustion of digester gas for heat and power generation in wastewater treatment plants has become an issue.

Siloxanes enter the sewer and the WPCC in the liquid phase and are transferred to the digesters in the sludges. Within the digestion process, the siloxanes change from the liquid phase into the gaseous phase within the digester gas or biogas.

Silicate and silica are formed during the combustion of biogas containing siloxanes. Siloxanes combine with free oxygen or other elements in combustion gas using the principles of thermodynamics, combustion and pressure. The buildup of siloxanes within cogeneration engines, turbine systems and boilers has resulted in increased maintenance costs and in some cases has caused systems to fail requiring shut down for extended periods of time. Build up within the system can lead to increased wear on the engine, increased levels of silicon within the lubrication oils as well as clogging of improper sealing of the valves. Silica deposits also decrease the transfer efficiency of heat exchangers.

Further information on the composition of siloxanes in included in Appendix C.

Removing siloxanes from digester gas prior to combustion will provide the following benefits:

Cogeneration (IC engine) Systems

- Longer intervals between maintenance
- Cleaner fuel and increased operational efficiencies
- Longer intervals between maintenance for cogeneration equipment
- Decreased down time for equipment
- Longer spark plug life
- Increased life of engine oil
- Extending life of engine heads, cylinder linings, pistons, impellers and heat recovery components
- Increasing engine runtime

Cogeneration (Microturbine) Systems

- Longer intervals between maintenance
- Cleaner fuel and increased operational efficiencies
- Longer intervals between maintenance for cogeneration equipment
- Decreased down time for equipment
- Increased injector and hot section life
- Increased recuperator life
- Increasing engine genset runtime

Boilers

- Longer intervals between maintenance
- Cleaner fuel and increased operational efficiencies
- Increased heat transfer capabilities
- Increased life of ignition system and combustion chamber
- Increased life of boiler tubes

6.1.3 Pretreatment Technologies

Conventional gas removal technologies have been investigated to determine their efficiency at removing siloxane compounds. These include liquid absorption, refrigeration/condensation, solid phase adsorption or a combination of these. There are currently no known “green” technologies, such as biological systems that can remove siloxanes from digester gas.

Liquid absorption or "solvent washing" was tested as a siloxane removal technique. The effectiveness of this procedure varied and was found to be expensive on a large scale.

Refrigeration/condensation has been used effectively to remove siloxanes from digester gas and landfill gas in a number of facilities. The City of Barrie pre-treatment system uses a refrigeration system followed by a carbon based adsorption system. This process removes siloxane compounds by treating the biogas through a gas chiller, a moisture separator and gas reheater. The condensate from this system is usually recycled back to the plant. These systems are effective by themselves only when the gas is compressed to medium to high pressures (700 kPa to 3500 kPa). The reason is that the humidity ratio at the dew point of a gas is lower at higher pressures. For example, digester gas, which is saturated at 35° C contains about 35,000 mg of water/m^3 of gas. When cooled at atmospheric pressure to 4° C, the gas will contain about 6,500 mg water/m^3 of gas. If the same digester gas was compressed to 700 kPag prior to cooling, it would contain about 6,000 mg of water/m^3 of gas. If cooled to 4° C at 700 kPag, it would contain less than 1,000 mg of water/m^3 of gas.

Activated carbon media is commonly used to remove siloxane from biogas. Siloxane is removed by mass transfer via solid phase adsorption. The carbon vessels may be installed in series or in parallel. Most units are installed in series. This configuration allows the first vessel to remove most of the siloxane with a second unit as a polisher. This also allows one vessel to be taken offline to replace the media as required. The vessels can be installed indoors or outdoors. They consist of silo type tanks with valved inlet and outlet manifolds that are arranged to feed digester gas to the bottom of the tanks and discharge at the top. The tanks contain walkways and access hatches at the top of the tank and a coned bottom. The carbon is supplied in "super sacks" (1.14 m^3, 500 – 600 kg), drums (0.2 m^3, 90 – 110 kg) or paper sacks (0.06 m^3, 25 – 30 kg). The carbon can be loaded manually or pneumatically. For initial manual loading, the sacks are raised to the tank walkway by a forklift truck or a portable hoist and loaded into the top of the tank. For initial pneumatic loading, the carbon is loaded into the hopper of the pneumatic system and blown into the top of the tank.

To replace the carbon, the spent carbon must be removed prior to loading new carbon. The tank is first isolated and vented. The carbon is then emptied from the bottom of the tank into containers for shipment to a landfill or back to the vendor for regeneration. Once the new carbon has been installed, the tank is replaced into service. This includes purging the tank with nitrogen in accordance with the digester gas code.

6.1.4 Gas Pre-Treatment Experience at WWTPs and Landfill

European countries have been successfully implementing siloxane removal for a number of years. The most common removal process is a combination of refrigerated gas drying along with carbon adsorption.

Siloxane removal in North America, and especially Canada, is not as prevalent, although the number of installations is growing. The most common applications being used for siloxane removal are a combination of gas drying and carbon adsorption.

A number of cogeneration facilities currently performing siloxane removal were surveyed. These facilities include:

- Bergen Count WPCP – Bergen County, New Jersey
- Ocean Count Utilities WPCP - Ocean County, New Jersey
- Alvarado WWTP – Union City, California
- Santa Layo WWTP - Santa Layo, California
- Lewiston PCP - Lewiston, New York
- Santa Cruz WWTP - Santa Cruz, California
- Capstone Turbine - California
- Santa Margarita Water - Santa Margarita, California

Siloxane removal systems have been in place at these locations ranging from nine months to three years. These facilities are all using carbon adsorption vessels as the final stage in their siloxane treatment systems. The majority of the facilities have a refrigerated dryer upstream of carbon vessels. Some of the plants use non-refrigerated dryers. The treatment is reported to reduce total siloxanes in these systems from about 10,000 ppbv to <100 ppbv.

A number of the facilities that use refrigerated dryer systems recycle the condensate back to the plant. It is possible that any siloxanes removed in the condensate could be recycled into the digester gas and require removal by the carbon adsorption unit. The facilities that recycle the condensate back to the plant indicated that they had not noticed any impact on the gas treatment system.

6.1.5 Recommended Pre-Treatment System

The recommended gas treatment system for a reciprocating (internal combustion) engine system or microturbine would generally consist of the following:

- A refrigeration system to remove moisture and an initial amount of siloxanes from the gas
- Carbon filtration to further polish H_2S and siloxane content to below acceptable limits
- Gas reheating to a minimum of 10°C above the moisture dew point of the gas

This type of system would also be applicable to the other cogeneration technologies and would be recommended for us at Brockville if a cogeneration facility is installed.

Two types of refrigeration systems are available: a 4°C dewpoint dryer, and a –20°C dewpoint dryer. Although both dryer systems have proven to be effective in removing siloxanes from the gas, the -20°C system reduces the load on the carbon filters by reducing siloxanes by as much as 90%, and by reducing moisture content transferred to the carbon filters, which decreases their effectiveness. Since siloxane content in the digester gas can be quite high, it is advantageous to remove as much as possible prior to final carbon filtration. This decreases the frequency at which the carbon is spent, lowering the maintenance cost and decreasing the amount of waste product. Both systems result in a final siloxane level of approximately 1 ppm, far below that required by the engine manufacturers. However, the -20°C dryer would also require less frequent monitoring of the treated gas for siloxane breakthrough on the carbon filtration vessels. Note that the carbon vessels would operate in series, so that once the first vessel is loaded, breakthrough would be carried over to the second vessel, preventing siloxanes from entering the engine. The carbon vessel train can be set up in a lead-lag configuration for convenient spent media change out and efficient use of the carbon media. Projects incorporating the -20°C dryer for siloxane removal are currently in operation in Lancaster WWTP California, Aurora LFG Project Aurora, ON and at the East Calgary and Shepard LFGTE projects, Calgary, AB.

If the H_2S concentration is expected to be as high as 4,000 ppmv, an additional treatment system to reduce carbon media consumption could be the addition of ferric chloride (iron salts) upstream of the digesters to reduce the amount of H_2S carried over into the digester gas or one of the many H_2S removal technologies, including precipitation, scavenging, chemical scrubbing with chemical or biological oxidation and absorption. These procedures have been shown to reduce H_2S to acceptable levels.

Additional detailed information on gas pre-treatment and a recommended system schematic is included in Appendix C.

Testing of digester gas is recommended to determine contaminant components and levels for design of a new cogeneration system, and would be recommended for Brockville. Also, a preliminary visual screening can be conducted by investigating the existing boilers and exhaust stacks, to see if siloxane residue (a white powder) is visible. Other indications that gas pre-treatment may be required include the presence of cosmetics or soap manufacturing that contribute influent to the WPCC or the use of sodium silicates at the water treatment plant.

The cost of a biogas pre-treatment system for Brockville would be in the range of $250,000 to $500,000 depending on the capacity required, final gas flow rate, and degree of contaminants in the digester gas. A system recently designed and tendered for the Barrie wastewater plant was approximately $580,000. This was for a gas pre-treatment system treating 7,000 m^3/day of gas flow, feeding two 250 kW Waukesha internal combustion engines. The estimated operations and maintenance costs for this system were $34,000 annually, which included carbon replacement every three months. Operations costs at Brockville would be less with a similar sized system, as carbon would likely not require replacement as frequently due to the lower gas flow. Alternatively, a smaller, lower capital cost system could be installed, and carbon replacement would be required more frequently.

Additional capital cost considerations might include refurbishment or replacement of the existing boilers depending on any degradation due to gas contaminants currently. Increase in the size of gas boosters may only be required, due to headloss through the gas pre-treatment system.