Anaerobic and aerobic digestions have been used for treatment of municipal and agricultural wastewater and solid wastes for several decades. Anaerobic digestion is the biological decomposition of organic materials in the absence of oxygen. It involves a complex microbial process with three different groups of bacteria, the fermentative bacteria, the acetogenic bacteria and the methanogens. In a closed system of anaerobic digestion, organic material is converted by bacteria to a variety of end products, in which the principal gases are methane and carbon dioxide. The application of anaerobic digestion in North America is predominantly in the traditional domain of municipal sewage sludge stabilization, anaerobic treatment of industrial wastewater or slurry digestion. Anaerobic digestion has also been applied to the treatment of agricultural wastes from livestock operations to produce a biogas for energy production. The benefits of anaerobic digestion for sewage treatment include:

- Reduces odor problems.
- Protects water resources.
- Controls pathogens.
- Reduces methane emissions -- a potent greenhouse gas by capturing and using the gas.

Compared to the aerobic digestion, anaerobic digestion for treatment of solid wastes has the following advantages and disadvantages.

**Advantages:**

- A high degree of waste stabilization at high organic loading rates.
- Substantially decreasing the weight of sludge solids.
- Good dewatering characteristics of the excess sludge.
- Low nutrient requirements.
- Low energy needs due to lack of aeration.
- Production of a useful end product in the form of methane.
- Less sensitive to toxic compounds than aerobic processes.

**Disadvantages:**

- Longer initial start-up period.
- Easily upset and difficult to control.
- It cannot digest some material that can be aerobically digested, such as lignin containing biomass.

Figure 1 shows a schematic of a sludge treatment system. Anaerobic digestion rate and gas production increase with temperature so a source of heat is used to maintain digester temperature around 30 to 40°C.
Biogas

Heat

Air

Organic fraction of MSW

High-solids anaerobic digester

Aerobic compost

Complete-mix reactor

Complete-mix reactor

Soil amendment

Fuel for power plants

Figure 1: Example combined Anaerobic – Aerobic Sewage Treatment System

**Electric Power Generation from Digester Biogas**

Anaerobic digestion processes produce a biogas that is mainly 60 percent methane and 40 percent carbon dioxide with trace amount of other gases. The gas is saturated with water and, depending on the feed material to the digester, the product gas may also contain hydrogen sulfide, ammonia and some oxygen.

Biogas properties will have a significant impact on the selection of technology for conversion to heat and/or electricity. Biogas composition and flow rate will be influenced by both the digestion process and by the feed material. Gross composition and heating value will affect the choice of equipment for utilization of the gas. Components of concern from an emissions point of view are:

- reduced sulphur compounds (mercaptans, H$_2$S, COS, and CS$_2$) due to their contribution to SO$_2$ emissions, safety concerns, corrosion, and odors,
- compounds containing nitrogen due to their potential to increase NO$_x$ emissions and potential to form N$_2$O (a serious greenhouse gas)
- chlorinated compounds due to potential to form dioxins during combustion
- siloxanes, which are a degradation product of plastics
- and metals.

Typical biogas composition from digesters operating in Europe contain 55 to 70% CH$_4$, 30 to 45% CO$_2$, 0 to 10,000 ppm H$_2$S and 0 to 590 ppm NH$_3$ (Schomaker et al., 2000). H$_2$S concentration is strongly influenced by the feed material composition to the digester. The maintenance cost for reciprocating engines increases with increasing H$_2$S concentration in the feed gas. H$_2$S must be removed from the gas if concentrations are higher than 1,000 ppm.

**Biogas Purification**

Purification of the biogas may be required prior to combustion or power generation equipment. The extent of gas cleaning required will depend on the end equipment selected for the pilot plant and on applicable emissions regulations. For example, an internal combustion engine generator may require:

- removal of water to prevent condensation of acid gas and subsequent corrosion during startup and shutdown
- removal of particulate and entrained liquids
- removal of reduced sulfur compounds, such as hydrogen sulfide, to reduce corrosion and engine oil contamination
- boosting and control of gas pressure to maintain constant feed to engine with greater than 1 psl.
- removal of ammonia to reduce NOx emissions

The variability of gas heating value, flow rate and pressure may affect engine performance for both internal combustion and turbine engines.

**Free Water and Particulate Reduction**

Digesters typically are long residence time reactors with relative slow gas velocities. Other than entrained water droplets, the gas will contain little or no solid particulates. If filters are required, fabric filters are a well proven technology. They can effectively remove particles <10 microns and their performance is not affected by composition or particle properties. Water droplets can be removed with a simple water knockout drum or mesh pads.

Biogas from the digester is saturated with water and contains acid gases. Any decrease in the temperature of the gas will result in condensation and subsequent corrosion of fuel supply and other engine components. Gas and metal temperatures between the digester and the combustion system should be maintained above the dew point.

**Removal of Sulphur Compounds**

Information from the literature suggests that biogas from a manure and sewage digestion may contain about 200 ppm to 1500 ppm of H\textsubscript{2}S, although H\textsubscript{2}S concentration can approach 10,000 ppm (Schomaker et al., 2000). The amount of H\textsubscript{2}S to be removed will depend on the composition of the feed material to the digester. For example, the predicted gas flow rate from anaerobic digestion of the manure from 5,000 head of cattle will be 4,800 m\textsuperscript{3}/day. Most H\textsubscript{2}S removal systems are sized by the weight of sulphur to be removed. Figure 1 shows the amount of sulphur that must be removed from a flow rate of 4,800 m\textsuperscript{3}/day of biogas for H\textsubscript{2}S concentrations from 0 to 1500 ppm. At 1,000 ppm H\textsubscript{2}S concentration, about 6.2 kg/day of sulfur must be removed from the gas and disposed of in an acceptable manner.

![Figure 2: Variation of Sulphur Removal Required with H\textsubscript{2}S Concentration](image-url)
When selecting an H₂S scavenging process for biogas treatment, desirable features include:

- low cost per pound of H₂S removed
- rapid reaction with H₂S to reduce reaction vessel size
- virtually complete H₂S removal (<10 ppm H₂S in product gas)
- consistent removal until additive is spent
- no problems disposing of waste or by-products
- minimum need for operator or maintenance
- potential to remove other sulphur compounds such as COS, CS₂ and mercaptans

Existing H₂S removal technologies for low levels of H₂S removal from natural gas fall into two broad groups, liquid scrubber based techniques and solid, fixed bed reactors. These groups can be further broken down into processes that regenerate and reuse the sorbent and those that dispose of the spent liquid or solid sorbent. Table 1 briefly describes some of these processes including their stage of development and advantages/disadvantages.

**Table 1: Some Existing Processes for Low Concentration H₂S Removal**

<table>
<thead>
<tr>
<th>Stage of Development</th>
<th>Description</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>commercial</td>
<td>solid iron-oxide inert carrier mix that reacts with H₂S to form iron sulfide compounds</td>
<td>- cost of scavenger and restrictions on disposing of spent scavenger limits use to low H₂S concentrations and low amounts of sulfur/day</td>
</tr>
<tr>
<td>commercial</td>
<td>a liquid triazine is contacted with the gas and chemically reacts to remove H₂S, spent scavenger is disposed by deep well injection</td>
<td>- cost of scavenger and restrictions on disposing of spent scavenger limits use to low H₂S concentrations and low amounts of sulfur/day</td>
</tr>
<tr>
<td>commercial</td>
<td>aqueous based iron chelate compounds used in a scrubber. Spent chemical is regenerated with air in a separate vessel.</td>
<td>- operation and reliability problems due to foaming, plugging - cost of iron chelate chemicals and their degradation with use</td>
</tr>
<tr>
<td>pilot plant</td>
<td>Low temperature H₂S oxidation catalyst in a fixed bed to convert H₂S to solid sulfur at about 90°C. Spent bed is regenerated with hot gas to remove sulfur.</td>
<td>- operates above 90°C and below 140°C, regenerate bed at &gt;300°C to recover sulphur - cyclic reaction with 2 or more reactors; does not treat H₂S in natural gas directly</td>
</tr>
<tr>
<td>demonstration</td>
<td>- H₂S is removed from natural gas with a liquid scrubber, bacteria converts H₂S to sulphur - scrubbing solution regenerated in a separate reactor with air</td>
<td>- requires separate extraction and regeneration vessels. - requires careful control of temperature, nutrients and pH to keep the bugs happy.</td>
</tr>
<tr>
<td>pilot plant</td>
<td>- uses a bacteria process to convert H₂S to sulfuric acid</td>
<td>- requires careful control of temperature, nutrients and pH to keep the bugs happy. -need to use or dispose of sulfuric acid</td>
</tr>
</tbody>
</table>

The cost of H₂S removal will vary with size of the equipment and the amount of H₂S to be removed. Iron oxide based fixed bed systems can remove concentrations of H₂S less than 500 ppm for about US$0.010 to 0.025/m³ of gas treated or about US$0.40 to $1.10/GJ of thermal energy in the gas.

**Air/Oxygen Dosing**

Two H₂S removal processes ideally suited to digesters were developed in Europe. One process makes use of biological activity in the digester to oxidize H₂S to solid sulphur and water. Air or oxygen is added to the biogas in contact with a liquid manure surface. The bacteria that oxidize the H₂S grow on the manure surface. The process is inexpensive to install and operate and can reduce H₂S levels to below 200 ppm, which is suitable for internal combustion engines. Addition of air to
biogas will reduce the heating value and also poses a combustion/explosion hazard if not controlled properly.

**Addition of Iron Chloride to Digester Slurry**

$H_2S$ can also be reduced by the addition of ferric chloride ($FeCl_3$) to the biomass feed to the digester. This material reacts with $H_2S$ to form FeS that precipitates. No capital costs are required and $H_2S$ levels below 200 ppm can be achieved. Operating costs will depend on $H_2S$ concentration and chemical costs of $FeCl_3$.

Due to their potential low capital cost, both the air dosing and the iron chloride methods for reducing $H_2S$ levels should be investigated further.

**Removal of Ammonia**

Digester gas can contain in the order of 600 ppm of ammonia, depending on the feed material to the digester (Schomaker et al., 2000). Ammonia will likely be present and may lead to increased NO$_x$ emissions from combustion of the gas. If required, options for control of NO$_x$ include removal from the digester gas by scrubbing, combustion of the gas in a low NO$_x$ burner technology or catalytic treatment of the exhaust gas to convert NO$_x$ to nitrogen.

**Gas Utilization Equipment**

Digester biogas is often flared to dispose of the gas and remove associated odors by converting reduced sulfur compounds to sulfur dioxide. However biogas represents a significant power source that can be converted to electricity with remaining waste heat used to heat the digesters. The following describes some of the technologies that can be used to convert biogas to more useful forms of energy.

**Heating Systems**

One application for the digester gas is direct use in a boiler for producing hot water. A hot water heater would have a low capital equipment cost and will operate at about 80% thermal efficiency based on the higher heating value of the fuel. The estimated concentrations of $H_2S$ and NH$_3$ should not affect operation of a hot water system, other than the need to construct the boiler from materials resistant to acid gas corrosion.

**Electric Power Production**

Table 3 summarizes technologies currently available or being developed for combined heat and power that might be applicable for use with biogas. The technologies that are commercially available or near commercially available in the range of 400 kW are internal combustion reciprocating engine-generator sets and gas turbine-generator sets.

Of the technologies listed in Table 2, the reciprocating engine or industrial gas turbine are commercially available as standalone power generators or as combined heat and power units. There are several companies in North America and Europe that supply either gas turbine or reciprocating engine-generator sets with or without recovery of waste heat for combined heat and power units.

Table 3 compares the reciprocating and gas turbine options. Selection of the best system must take into consideration the following:

- initial capital cost
- maintenance costs
- relative demand for electricity and heat
- relative prices of electricity and heat (which determines importance of electric conversion efficiency)
- emissions of pollutants
- noise
- tolerance of engine to sulphur and/or nitrogen compounds and to changes in gas composition

<table>
<thead>
<tr>
<th>Table 2: Small Combined Heat and Power Options</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reciprocating Engine</strong></td>
</tr>
<tr>
<td>Current Size Range (kW)</td>
</tr>
<tr>
<td>Electric Efficiency (%)</td>
</tr>
<tr>
<td>Current Capital Cost ($/kW)</td>
</tr>
<tr>
<td>Future Capital Cost ($/kW)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 3: Comparison of Reciprocating Engine and Gas Turbine Options at 98.3 GJ/day Fuel Input</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reciprocating Engine</strong></td>
</tr>
<tr>
<td>Capital cost</td>
</tr>
<tr>
<td>Maintenance cost</td>
</tr>
<tr>
<td>Electric Efficiency</td>
</tr>
<tr>
<td>Efficiency including waste heat recovery</td>
</tr>
<tr>
<td>H₂S tolerance</td>
</tr>
<tr>
<td>NOₓ emissions</td>
</tr>
<tr>
<td>fuel supply pressure</td>
</tr>
<tr>
<td>low heating value gas</td>
</tr>
</tbody>
</table>

Reciprocating Engines

Reciprocating engine based systems are the most developed and most common cogeneration systems. Reciprocating engines fueled by natural gas or hydrocarbon liquid fuels are available in sizes from several kW to 10 MW. The amount of fuel energy converted to electricity generally increases with size, ranging from 30% for small units to 40% for large engines. The amount of fuel converted to thermal energy is from 40 to 50% resulting in overall efficiencies of 80 to 85%. Of the small cogeneration systems available, reciprocating engines offer the highest conversion of fuel energy to electricity. Figure 3 shows a combined heat and power system that uses a diesel engine for combustion of the gas with recovery of heat from the engine coolant, engine oil circulating system and exhaust manifold.

Operating and maintenance costs can be a significant portion of total electricity cost with reciprocating engine cogeneration plants as discussed above. The engine requires frequent oil changes and minor overhauls. Most engines require a major overhaul about every 5 years. These costs must be factored in during the selection and costing process.
Table 4 shows example predicted capital and operating costs for a reciprocating engine combined heat and power unit sized for 300 kW of electricity production. Based on 200 m$^3$/hr of biogas production with a conservative heat content equivalent to 40% methane the engine generator set would produce 300 kW of electric power. The capital cost shown does not include the synchronizing switch gear that may be required if the generator was to be tied into the electric grid to enable electricity sales to the transmission system.

Table 4: Estimated Costs for Internal Combustion Engine Combined Heat and Power Unit 300 kW

<table>
<thead>
<tr>
<th>Biogas H$_2$S Concentration</th>
<th>0 ppm</th>
<th>200 ppm</th>
<th>500 ppm</th>
</tr>
</thead>
<tbody>
<tr>
<td>capital</td>
<td>$270,200</td>
<td>$270,200</td>
<td>$270,200</td>
</tr>
<tr>
<td>maintenance ($/kWh)</td>
<td>0.0113</td>
<td>0.0134</td>
<td>0.0134</td>
</tr>
<tr>
<td>oil change interval (hours)</td>
<td>1,000</td>
<td>360</td>
<td>360</td>
</tr>
</tbody>
</table>
Maintenance costs are a significant portion of the total cost of ownership of a reciprocating engine generator set. Table 5 shows an example breakdown of lifecycle costs for a reciprocating engine generator set and the impact of 200 ppm H$_2$S in the feed gas on the relative proportion of maintenance and fuel cost. Some of the cogeneration options under development promise lower maintenance costs. Industrial turbines and microturbines potentially have low maintenance costs but their conversion efficiency to electricity is not as high as reciprocating engines. Stirling cycle engines have totally enclosed moving parts that do not come into contact with combustion gases and also no need for oil changes. Although not yet commercially available, Stirling engines should have minimal maintenance costs.

### Table 5: Predicted Operating Costs of Reciprocating Engine Combined Heat and Power Unit for Two H$_2$S Levels

<table>
<thead>
<tr>
<th></th>
<th>0 ppm H$_2$S</th>
<th>200 ppm H$_2$S</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Life Cycle Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>maintenance</td>
<td>15.1%</td>
<td>17.5%</td>
</tr>
<tr>
<td>fuel</td>
<td>84.9%</td>
<td>82.5%</td>
</tr>
<tr>
<td><strong>Maintenance Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>lube oil</td>
<td>16.0%</td>
<td>29.5%</td>
</tr>
<tr>
<td>planned service</td>
<td>30.5%</td>
<td>25.6%</td>
</tr>
<tr>
<td>top end overhaul</td>
<td>23.4%</td>
<td>19.6%</td>
</tr>
<tr>
<td>bottom end overhaul</td>
<td>30.2%</td>
<td>25.3%</td>
</tr>
<tr>
<td>oil change interval</td>
<td>1,000 hrs</td>
<td>360 hrs</td>
</tr>
</tbody>
</table>

**Gas Turbines**

Conventional combustion turbines are a mature technology with several suppliers worldwide. Turbines can be fueled with natural gas or oil. Units range in size from 500 kW to 250 MW. Single cycle turbines have efficiencies from 20 to 45% at full load, with efficiency increasing with size. Combining a gas turbine with a steam turbine cycle can improve efficiencies further to over 50% for large units. Gas turbines generally have a higher capital cost than reciprocating engines but this is balanced by lower operating costs. For plants above 10 MW, gas turbines are generally less expensive than reciprocating engines.

Gas turbines require a supply of high pressure feed gas and would require a gas compressor to operate on sewage biogas. This will increase the capital cost and reduce the efficiency of conversion to electricity. Construction of cogeneration plants using gas turbines is well developed commercial technology. Typical turbine exhaust temperature is about 500°C. A Heat Recovery Steam Generator (HRSG) is installed to recover energy from the turbine exhaust and this energy could be used to supply heat demands to the waste treatment system. Figure 4 is an example of a gas turbine system operating in a combined cycle mode with some of the thermal energy from the HRSG used to drive a steam turbine and generate more electricity.
Microturbines are a recent development of the gas turbine industry. Generally ranging in size from 25 to 500 kW, microturbines were developed from turbocharger turbines used in the truck and aircraft industry. Most microturbines are single-stage turbine with high rotating speeds (90,000 rpm) and often directly coupled to a generator. Efficiencies of conversion to electricity range from 15 to 30% depending on size, fuel supply pressure, and whether the design includes a recuperator. Microturbine exhaust temperatures are relatively low (about 200 to 300°C) and the waste heat can only be used to generate low pressure steam and/or hot water.

Because of their simplicity (most designs have only one moving part), microturbines potentially have very low operating costs, although they have not been in commercial use long enough to confirm this. Due to their low efficiency of electricity production, microturbines are best applied in a cogeneration application. Like large gas turbines, microturbines should be tolerant to humidity and corrosive gases in the fuel gas as long as condensation is avoided in the fuel delivery system. Other challenges in applying microturbines to power production from sewage gas include the need for a fuel gas compressor and the low heating value of the biogas relative to natural gas. The fuel gas compressor adds to the initial capital cost and is a parasitic load that reduces the amount of electricity produced.
Near Commercial Technologies

There are several technologies under development or near commercial application that could find application in generating electric power from biogas. Table 6 lists some of these technologies and their predicted conversion efficiency and capital cost as compared to conventional reciprocating engines. In a cogeneration application high efficiency of conversion to electricity may not be the determining factor in a technology selection. If the cogeneration system is sized to supply the thermal load for the sewage treatment plant, high reliability, fast response time and low capital cost may be more important factors.

Table 6: Comparison of New Generation Technologies Suitable for Cogeneration

<table>
<thead>
<tr>
<th></th>
<th>Reciprocating Engine</th>
<th>Microturbine</th>
<th>Stirling Engine</th>
<th>Fuel Cell</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current size range (kW)</td>
<td>5 to 50,000</td>
<td>30 to 200</td>
<td>0.3 to 25</td>
<td>&lt;250 kW</td>
</tr>
<tr>
<td>Electric efficiency (%)</td>
<td>20 - 45</td>
<td>25 - 30</td>
<td>15 - 30</td>
<td>40 - 50</td>
</tr>
<tr>
<td>Capital cost ($/kW)</td>
<td>$600 - $1,000</td>
<td>$1,500 - $1,600</td>
<td>$&gt;1,500</td>
<td>-</td>
</tr>
<tr>
<td>Future capital cost ($/kW)</td>
<td>&lt;$500</td>
<td>$200 - $400</td>
<td>$200 - $300</td>
<td>-</td>
</tr>
</tbody>
</table>
Stirling Engines

A Stirling engine is a closed system that converts thermal energy into mechanical energy by cyclic compression and expansion of the working fluid. The work energy can subsequently be converted into electricity using a generator. A Stirling engine can use several sources of heat, which makes it theoretically ideal for electricity generation from waste heat sources. Test engines have been run on solar heat, heat from gas, oil or biomass flames and waste heat from existing operations. As the Stirling engine uses an external combustor and all moving parts are sealed from the combustion products, unlike internal combustion engines and turbines there is no need for high quality fuel. By design, Stirling engines are quiet and should require little maintenance, which makes them attractive for remote sites or for domestic use.

Stirling engines are a technology within 1 to 5 years of commercial production, assuming they can be demonstrated to have acceptable reliability and energy conversion efficiency for their target markets. Stirling engines have several potential applications in cogeneration, conversion of waste heat to electricity and remote power generation. Beta test units are available at sizes up to 25 kW. To be effective, Stirling engines should be used in a cogeneration mode as efficiencies of conversion from heat energy to electricity are only 15 to 25%. When used in a cogeneration system, overall energy use will be 80 to 85%.

Stirling engines would be suitable for biogas applications as they do not have a requirement for pressurized fuel gas supply and should also be tolerant to moisture and corrosive gases such as hydrogen sulfide in the fuel gas. Figure 6 is a cutaway drawing of a Stirling engine showing the burner and high temperature side of the Stirling engine.

![Figure 6: Cutaway Schematic of a Stirling Cycle Engine](image)

Fuel Cells

Fuel cells are devices that directly convert chemical energy to electricity at high efficiency. There are several types of fuel cells with different operating conditions, fuel requirements and efficiencies. Fuel cell technology is developing rapidly due to their potential for simplicity and high efficiency of conversion to electricity. The leading fuel cell technologies are proton exchange membranes (PEM) and solid oxide electrolytes.

Fuel cells are likely 5 to 10 years to commercial production. For use in a fuel cell, sewage gas will require extensive cleaning to remove corrosive compounds such as hydrogen sulfide.
Conclusions

Biogas produced from anaerobic digestion of municipal and agricultural wastes is a valuable energy source that can be converted to electricity. There are commercially available systems for treating digester product gas and burning this gas to produce both hot water and electricity. Typical equipment that would be required includes:

- water knockout or demister for particulate and free water removal
- system to remove H₂S to below about 200 ppm.
- modified diesel engine generator set to operate on low heating value gas and for recovery of waste heat as hot water for use in the digester.

Maintenance costs are significant with conventional internal combustion engines. Microturbine or Stirling engine-based combined heat and power units are just now becoming commercially available. Both promise much lower maintenance cost as oil changes are not required. Currently the capital cost of these options is still over 60% higher than IC engines but these costs are predicted to drop dramatically with time and increased production of the units. Microturbines would generate less electricity as their conversion efficiency to electricity is only about 25%.

References


