Sustainable Application Of Reciprocating Gas Engines Operating On Alternative Fuels

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INTRODUCTION

The concern for the anthropogenic release of methane (CH_4) into the environment and methane's potential for global warming – 21 times higher than that of carbon dioxide – continues to draw international attention. As such, those engaged in industries such as coal mining, landfills, agriculture and wastewater treatment are looking for ways to safely and economically mitigate the release of methane-based gases.

There is considerable opportunity for growth in the Asia-Pacific region for sustainable electric power applications using alternative fuels. As power demands in countries like China and India increase, industrial activity also increases and resulting landfill material grows, creating more sustainable, readily available alternative fuels. This paper discusses those opportunities, incorporating coal mine methane, landfill gas and biogas.

Profiles of existing applications that document reliable, efficient utilization of alternative fuels for gas reciprocating engines are offered to illustrate the success of such systems.

Finally, as proven reciprocating gas engine technology is described in more detail, methane gas evaluation and efficient power system design are discussed.

THE MARKET FOR COAL

The restructuring of China's economy and the resulting rapid growth of both agriculture and industry have contributed to a more than tenfold increase in gross domestic product (GDP) since 1978—and that figure grows at a higher rate each year. In 2007 alone, the real growth rate of China's GDP was an estimated 11.4 percent. Measured on a purchasing power parity basis, China stands as the second-largest economy in the world after the United States. [1]

With this very swift economic growth comes increasing demands for power from both industries and consumers – China's energy consumption has more than quadrupled since 1980. In 2006, China's electricity usage reached 2.859 trillion kWh, and natural gas consumption was approximately 55.6 billion cubic meters; estimated 2007 oil consumption equaled 6.93 million barrels per day. [1]

As service and manufacturing industries grow in India, where the industrial production growth rate for 2007 was 8.9 percent, similar new power needs exist. In 2005, oil was consumed at a rate of 2.438 million barrels per day and the country used 488.5 billion kWh of electricity. [1]

Coal accounts for 67.1 percent of total national energy consumption in China. The country is estimated to have more than 26,000 mines that produce about 1.4 billion metric tons of coal each year (illustrated in Figure 1). The U.S. Environmental Protection Agency (EPA) reported in 1996 that underground mining accounted for 95 percent of Chinese coal production; that number is now closer to 90 percent.

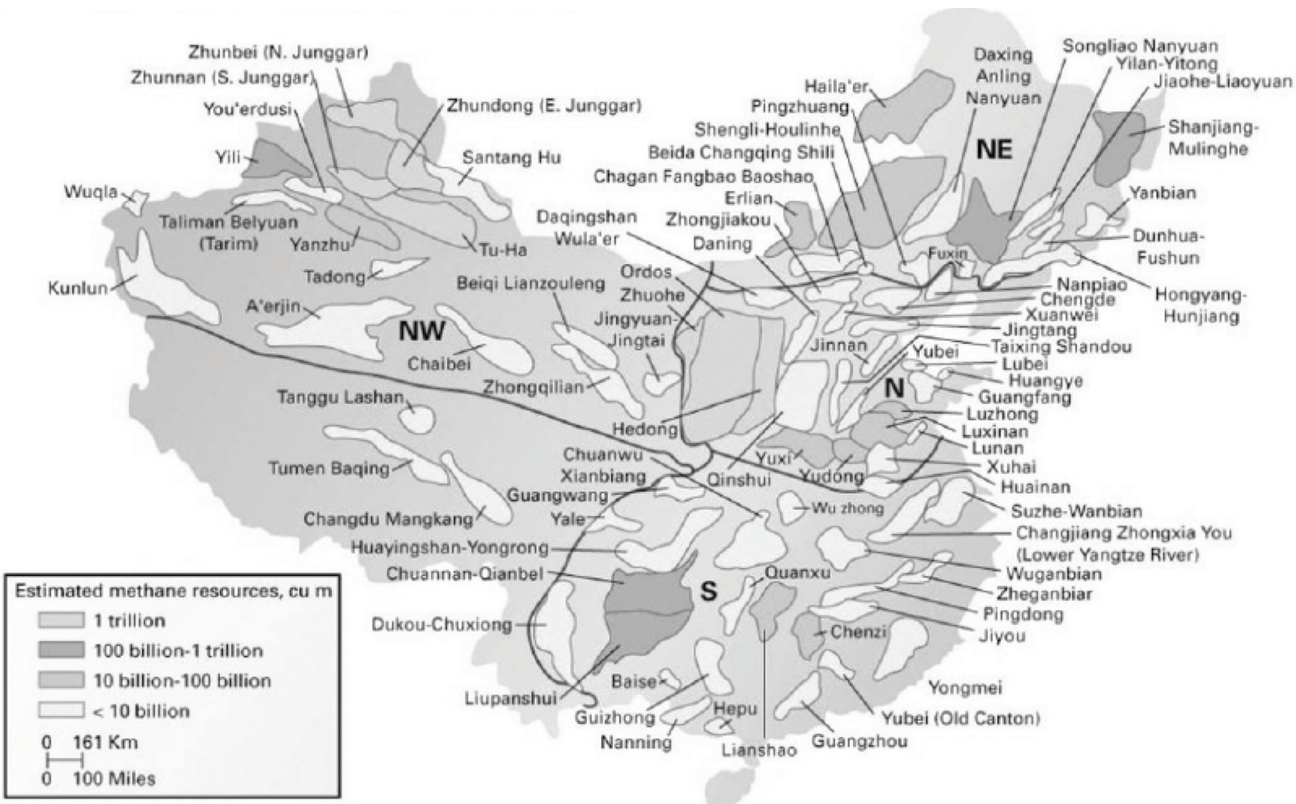

Figure 1: China's Coal Basins and Coal Bed Methane Resources

Today, the continued building of new power plants in China has made news – some estimate the pace to be two new plants per week. [2] From 2002 to 2006, China produced over 112,000 GW of new electric capacity from coal-powered plants. This figure is expected to slow through 2011 (to about 55,000 GW of new coal-powered capacity), but other countries, like India, will likely increase capacity. By 2011, India is projected to have a 200 percent increase in its new electric capacity from coal-powered plants. [3]

A Massachusetts Institute of Technology study about the future of coal consumption estimates that India's coal use will match current Chinese usage by about 2030. As the world's third largest coal producer, India would therefore have a unique opportunity to build new power capacity in an environmentally responsible way. [4]

ENVIRONMENTAL EFFECTS

Methane can be released into the atmosphere through sources where it naturally occurs: landfill decomposition, agriculture, gas and oil extraction systems, and coal mining activities. When released into the atmosphere through these and other processes, methane remains in the atmosphere for approximately nine to 15 years. Figure 2 shows past, current and projected amounts of methane released through coal mining activities. [5]

Globally, coal mines emit approximately 400 million metric tons or 28 billion cubic meters of carbon dioxide equivalent annually.

About 8 percent of total anthropogenic methane emissions come from coal mines. This amount is equivalent to the consumption of 818 million barrels of oil or the carbon dioxide emissions of 64 million passenger cars. In 2005, U.S. coal mines emitted about 4 billion cubic meters of methane. Between 1994 and 2005, U.S. emissions decreased by over 20 percent, in large part due to the coal mining industry's increased recovery and utilization of drained gas. China leads the world in coal mine methane emissions with about 14 billion cubic meters of CO_2 equivalent emitted annually—a 2004 measurement estimated nearly 200 million metric tons were emitted that year. Aside from the U.S. and China, other leading emitters include Ukraine, Australia, Russia and India. [5]

Regions	1990	1995	2000	2005	2010	2015	2020
Africa	9.7	10.7	9.3	8.4	8.2	8.2	8.7
China/CPA[1]	152.1	177.3	145.5	162.5	179.5	196.6	213.9
Latin America	5.4	5.3	6.9	7.6	8.4	9.5	10.7
Middle East	0.3	0.3	0.4	0.4	0.4	0.4	0.5
Non-EU Eastern Europe	1.0	1.0	1.9	2.3	3.0	3.9	5.3
Non-EU FSU[2]	142.0	84.4	67.6	59.5	58.6	57.0	55.6
OECD90[3] & EU	188.0	154.3	124.6	123.2	121.5	116.7	116.3
SE Asia	18.1	18.3	20.8	24.3	27.9	33.1	38.5
World Totals	516.7	451.5	376.9	388.1	407.6	425.6	449.5

[1]CPA = Centrally Planned Asia
[2]FSU = Former Soviet Union
[3]OECD90 = Organization for Economic Cooperation and Development (Member States at 1990)

Figure 2: Methane Emissions [Metric Ton of CO2 Equivalent] from Coal Mining Activities

As shown in Figure 3, methane is a greenhouse gas with an estimated global warming potential of 21. This means that emissions of methane have an estimated effect on global warming equal to 21 times the effect of carbon dioxide. Implementing methods to use methane instead of emitting it to the atmosphere will help mitigate global warming, improve mine safety and productivity, and generate revenues and cost savings.

Gas	Atmospheric Lifetime	100-year GWP[a]	20-year GWP	500-year GWP
Carbon dioxide (CO_2)	50-200	1	1	1
Methane (CH_4)[b]	12 ± 3	21	56	6.5
Nitrous oxide (N_2O)	120	310	280	170
HFC-23	264	11,700	9,100	9,800
HFC-125	32.6	2,800	4,600	920
HFC-134a	14.6	1,300	3,400	420
HFC-143a	48.3	3,800	5,000	1,400
HFC-152a	1.5	140	460	42
HFC-227ea	36.5	2,900	4,300	950
HFC-236fa	209	6,300	5,100	4,700
HFC-4310mee	17.1	1,300	3,000	400
CF_4	50,000	6,500	4,400	10,000
C_2F_6	10,000	9,200	6,200	14,000
C_4F_{10}	2,600	7,000	4,800	10,100
C_6F_{14}	3,200	7,400	5,000	10,700
SF_6	3,200	23,900	16,300	34,900

Source: IPCC (1996)
[a]GWPs used here are calculated over 100-year time horizon.
[b]The methane GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Figure 3: Global Warming Potentials (GWP) and Atmospheric Lifetimes (Years)

COAL MINE METHANE

World governments recognize the need for environmental responsibility in the pursuit of greater power production. The Kyoto Protocol is an international agreement under the United Nations Framework Convention on Climate Change that requires participating developed countries to reduce their greenhouse gas emissions below levels specified for each of them. These targets must be met within a five-year time frame between 2008 and 2012. [6]

One of the ways Kyoto participants pursue this goal is through the Clean Development Mechanism (CDM). CDM allows developed countries to earn and trade emissions credits, which they can use toward meeting their commitments through projects implemented either in other developed countries or in developing countries where projects are less expensive. CDM projects receive Certified Emission Reduction (CER) credits by demonstrating the difference in environmental impact their cleaner processes produce compared to a conventional method that might otherwise have been used, such as burning coal. The greater the reduction of greenhouse gas emissions, the more credits a project may receive. Today, CERs are being traded in the range of US$12 to US$20 (82 to 137 yuan or 488 to 813 rupees) per CER. [6]

One of the most promising and effective greenhouse gases used in CDM projects is coal mine methane (CMM), a methane gas formed as a byproduct during coalification that is found within subterranean coal seams. When released during active coal mining, the methane concentration is generally between 25 and 60 percent. Figure 4 provides a reference point for the composition of CMM compared to other fuel sources. As the table shows, CMM has a higher mix of oxygen and nitrogen than pipeline natural gas and coal bed methane (CBM), which has such a high concentration of methane it can be used in natural gas pipelines with very little treatment. Therefore, CMM requires different equipment considerations when used to power generator sets.

Component	Symbol	Units	Pipeline Natural Gas	CBM	CMM*
Methane	CH_4	vol %	92.3	85.9	40.0
Ethane	C_2H_6	vol %	2.5	3.8	---
Hydrogen Sulfide	H_2S	vol %	---	---	---
Oxygen	O_2	vol %	---	2.1	12.6
Nitrogen	N_2	vol %	3.5	8.2	46.8
Others	---	vol %	1.8	0.0	0.6
Lower Heating Value	LHV	MJ/Nm^3	33.2	32.5	13.4
Caterpillar Methane Number	MN	---	80	86	100

*Represents one particular site at one particular time

Figure 4: Typical Fuel (CMM) Composition and Physical Properties

There are several options currently available for CMM mitigation, including reciprocating gas engines, gas turbines, industrial boilers and furnaces, and chemical processing. Other technologies like catalytic systems and fuel cells are also being developed.

CONSIDERATION FOR CMM PROJECT DEVELOPMENT

CMM power plant development typically requires 12 to 18 months from start to completion. Duration very much depends on site accessibility and the preparation and complexity of the power plant. For mobility and ease of installation, some generator set manufacturers offer containerized sets, which can shorten the completion period.

When considering CMM generator set projects, perhaps the most important decision is choosing a generator set manufacturer. The manufacturer should support customers with design, service, logistical and technical support, and financing. An understanding of local needs and economics and the ability to provide fast, direct service and support are crucial to the success of CMM generator set projects. The manufacturer and dealership staff must also be highly qualified to meet customers' needs for any project, including CMM plants with unique needs. A manufacturer that provides financing support and payment options can also be helpful when considering the capital investment required.

EXISTING CMM INSTALLATIONS

There are several existing CMM fuel projects in China that have demonstrated the potential for this green energy and its associated economic benefits (see Figure 5).

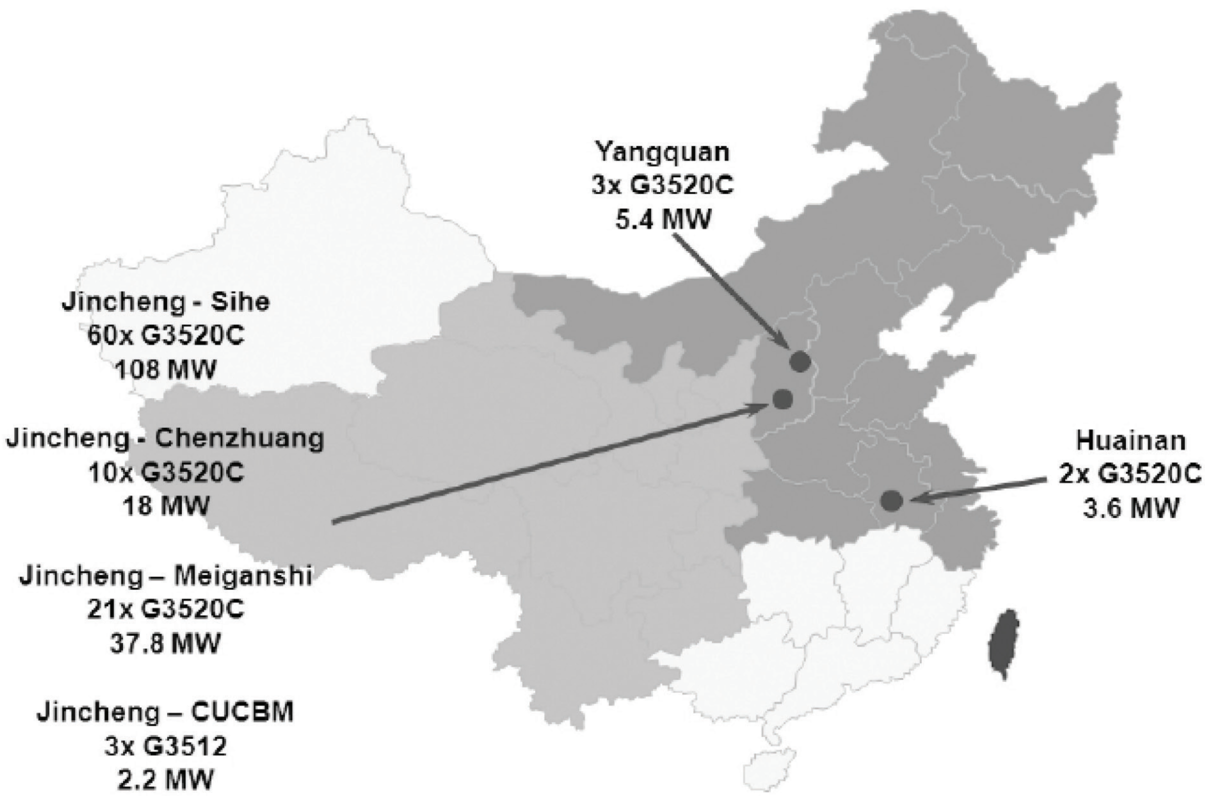

Figure 5: Existing Caterpillar Coal Mine Methane Projects in China

COAL MINE METHANE

Sixty Cat® G3520C generator sets with low energy fuel packages run on CMM at the Sihe mine in Jincheng, Shanxi province (as illustrated in Figure 6). When fully commissioned, the 60 generator sets will produce over 108 MW of electric power. Additionally, the exhaust heat will be recovered and used to drive steam turbines to produce an additional 12 MW of electric power.

The eventual production target is a combined 120 MW with jacket water heat recovery for hot water production. This project is the largest of its kind in the world and is expected to be fully commissioned by the third quarter of 2008.

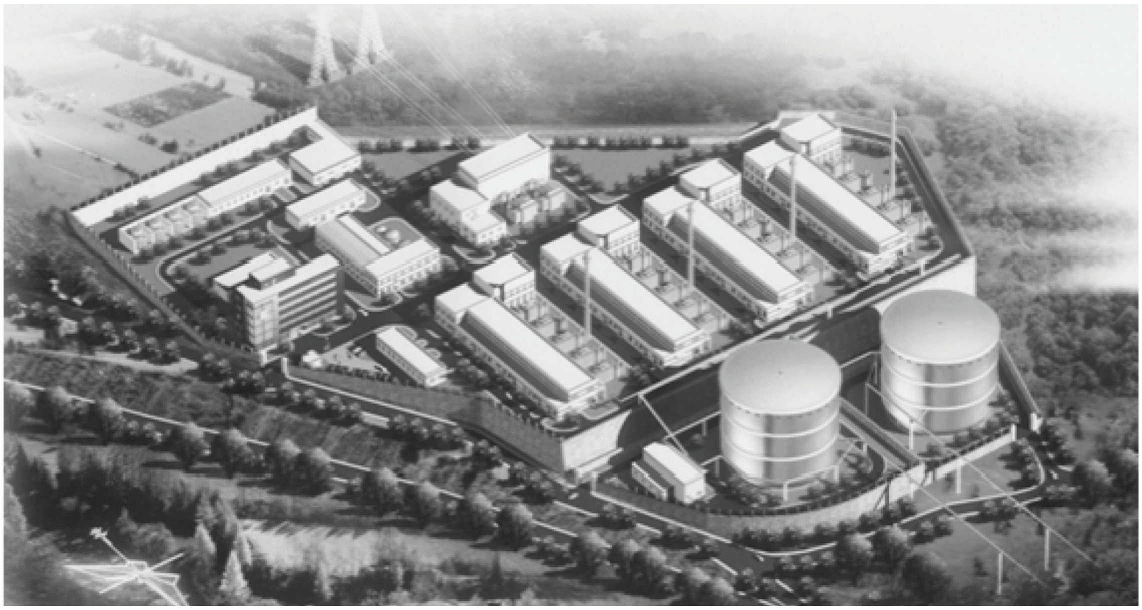

Figure 6. Jincheng Coal Mine Methane 120 MW Power Project

In the City of Yangquan in central eastern Shanxi province, a large CMM fuel project utilizes Cat generator set equipment and that of two other manufacturers. This allowed the customer the opportunity to evaluate the performance of both the hardware and the technical aftermarket support. The Cat equipment includes three G3520C-CMM gas engines running at 1,800 ekW each at 40 percent electrical efficiency. The generator sets are grid parallel and operate continuously.

Figure 7 is a summary report based on the evaluation of the Cat G3520C at the Yangquan site comparing performance and service after a year of continuous operation. Some of the most important findings are that the Cat generator sets had the least amount of downtime and lowest operating and maintenance cost of the three power systems. Furthermore, Caterpillar is the only supplier at the site with local service when technical or parts support has been needed.

Manufacturer		**Caterpillar**
Model		G3520C
Rated Power	ekW	1800
Reliability		High
Availability		High
Stability		High
Control Interface	Language	Chinese
Derates	Summer (ekW)	None
	Ext. Ancillaries (ekW)	None
Noise Level	Mechanical (dBA)	112
	Exhaust (dBA)	115
Minimum CH_4 for Stable Operation	%	30
Fuel Flexibility		User/self adjustable
Voice of Customer	Reliability	Lowest downtime with most reliable and stable operation
	Production vs. Downtime	2007 production targets reached
	Support	Local service and support staff are experienced and fast responding

Figure 7: Yangquan Summary Matrix

While China has several newer successful installations, there are other CMM generator set projects that have proven successful and efficient in the long term. One such mature project has been running continuously for over ten years on Australia's southeastern coast.

The Appin and Tower project (shown in Figure 8) is one of the largest coal seam gas energy systems in the world and one of the world's largest reciprocating engine-generator installations of any kind. The Appin and Tower project consumes 600,000m^3 of coal seam gas per day from two separate mines in New South Wales, Australia. Supplementing with natural gas when necessary, the Appin and Tower project uses more than 90 Cat G3516 lean burn generator sets, each of which produces 1,030 kW of continuous power. As of the summer of 2008, most of the units had completed 80,000 running operating hours.

Figure 8: Appin and Tower Coal Seam Energy Project

After more than a decade of operation, the Appin and Tower energy facilities have exceeded expectations for return on investment from the sale of electricity to Integral Energy's grid. The project demonstrates the viability of coal seam gas as a significant source of supply to help meet the region's growing need for clean, efficient energy.

LANDFILL GAS

Landfill gas (LFG) is produced naturally as organic waste decomposes in landfills. LFG is composed of about 50 percent methane, about 50 percent carbon dioxide and a small amount of non-methane organic compounds (see Figure 9). The energy content of landfill gas is 400 to 550 Btu per cubic foot (or 14.9 to 18.6 MJ/m^3). A landfill must be at least 40 feet (12 meters) deep and have at least one million tons of waste in place for landfill gas collection and power production to be technically feasible. LFG develops in landfills in approximately one to three years, depending on the type of waste and environment; peak production of LFG is five to seven years after waste is dumped.

Component	Symbol	Units	Natural Gas	Landfill Gas	Biogas
Methane	CH_4	vol %	92.3	45-60	50-75
NMOC	---	vol %	2.5	---	---
Carbon Dioxide	CO_2	vol %	---	40-65	25-50
Oxygen	O_2	vol %	---	0-1	0-2
Nitrogen	N_2	vol %	3.5	2-5	0-10
Hydrogen and Hydrogen Compounds	H_2, H_2S, etc.	vol %	---	0-0.2	0-1
Others	NH_3, F, Cl, Siloxane, etc.	vol %	1.8	0.1	0-3
Lower Heating Value	LHV	MJ/Nm^3	33.2	14-20	15-25

Figure 9: Typical Fuel Composition and Physical Properties of Various Low Energy Fuels [7]

China and India together account for about 8 percent of the world's landfill methane emissions, as estimated in 2005 (see Figure 10). Of a total 747.38 MMTCO2e, that 8 percent, along with emissions from other countries in the Asia-Pacific region, represents a significant opportunity for power generation from landfill gas.

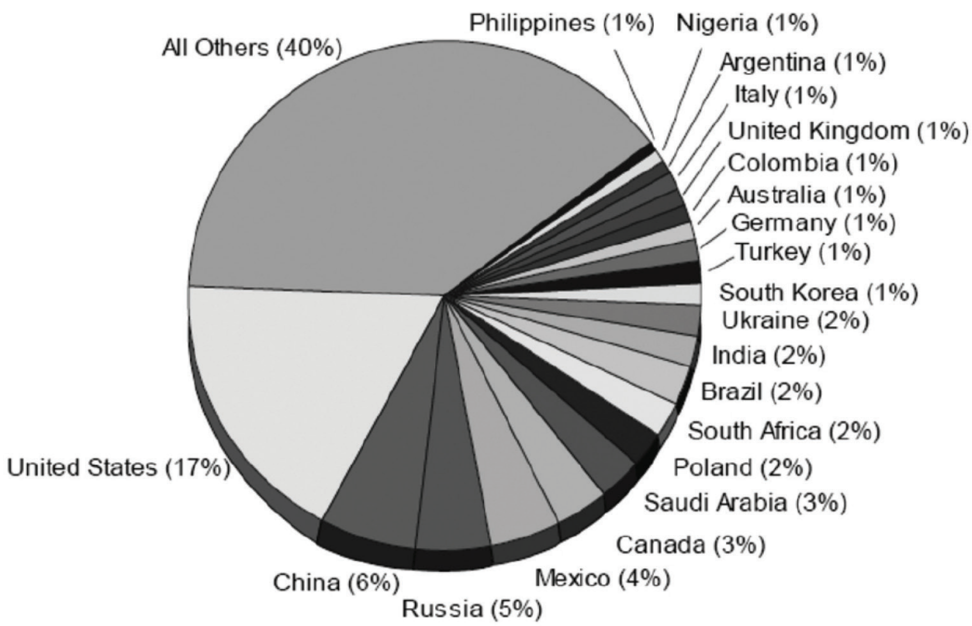

Figure 10: Estimated Global Landfill Methane Emissions (2005) [8]

At most municipal solid-waste landfills, the methane and carbon dioxide mixture is destroyed in a gas collection and control system or utility flare. However, to use LFG as an alternative fuel, the gas is extracted from landfills using a series of wells and a vacuum system (illustrated in Figure 11). Pipes are inserted deep into the landfill to provide a point of release for the landfill gases. A slight vacuum is then applied in the pipe to draw the gases into and through it to a central point, where it can be processed and treated for use in generating electricity, replacing the need of conventional fossil fuels.

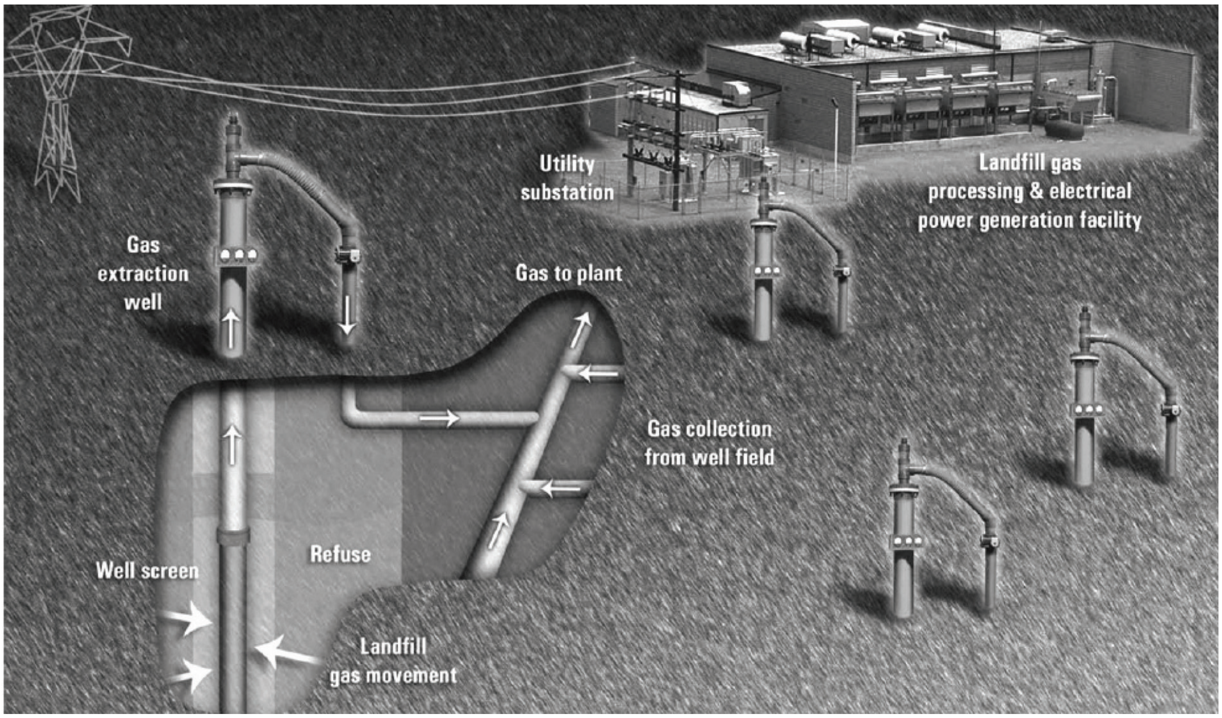

Figure 11: Typical Landfill Gas Collection and Extraction System

LFG must either be thoroughly pretreated or used in engines that are designed to operate on impure fuel. LFG can contain sulfur compounds, halides, water vapor, silicon crystals or siloxanes. In traditional engines, these materials are highly corrosive and damaging. A comparison of engine contaminant thresholds in standard engines and those designed for use with low energy fuels is shown in Figure 12.

Contaminant	Units	Standard Engine	Low Energy Fuel Engine
Sulfur Compounds as H_2S [1, 2]	mg H_2S/MJ ug H_2S/Btu	0.43 0.45	57 60
Halide Compounds as Cl [1, 3]	mg Cl/MJ ug Cl/Btu	0 0	19 20
Ammonia	mg NH_3/MJ ug NH_3/Btu	0 0	2.81 2.96
Oil Content	mg/MJ ug/Btu	1.19 1.25	1.19 1.25
Particulates in Fuel [1, 4]	mg/MJ ug/Btu	0.80 0.84	0.80 0.84
Particulate Size in Fuel	microns	1	1
Silicon in Fuel [1, 4]	mg SI/MJ ug SI/Btu	0.10 0.10	0.56 0.60
Maximum Temperature	°C °F	60 140	60 140
Minimum Temperature	°C °F	10 50	10 50
Fuel Pressure Fluctuation	kPa ± psig ±	1.7 0.25	1.7 0.25
Water Content		Saturated fuel or air is acceptable. Water condensation in the fuel lines or engine is not acceptable. It is recommended to limit the relative humidity to 80% at the minimum fuel operating temperature.	

Footnotes

(1) Note carefully that the limits given also cover contaminants that may be ingested by the combustion air supply. For example, if chlorine is being ingested to the engine in the fuel and in the air, the total amount may not exceed 20.0 ug Cl/Btu of fuel on a Low Energy Fuel equipped engine. If the fuel is: 50% methane, 40% carbon dioxide, 8% nitrogen, and 2% oxygen, the Lower Heating Value (LHV) is 456 Btu/scf and the stoichiometric air/fuel ratio is 4.76:1, as calculated by the Caterpillar Methane Number Program. Now the maximum amount of chlorine is: (limit for Cl)(LHV)= amount of Cl in fuel, in this example (20 ug/Btu)(456 Btu/scf)= 9120 ug Cl/scf of fuel, assuming there is no chlorine in the air. If chlorine is present in the air, the following example is instructive. Assume that the fuel has 2.2 ug Cl/Btu and that the engine is operating at a lambda of 1.5. What is the maximum allowable chlorine in the air? For every one standard cubic foot of fuel burned there is: (stoichiometric air/fuel ratio)(lambda), in this example (4.76)(1.5)=7.14 scf of air per scf of fuel. Chlorine present in the fuel is: (Cl concentration)(LHV)= Cl in fuel, in this example (2.2 ug/Btu)(456 Btu/scf fuel)=1000 ug Cl/scf fuel and then maximum allowable chlorine in the air is: (maximum permitted Cl - Cl in fuel)/(scf of air burned per scf of fuel), (9120-1000)/(7.14)=1137 ug Cl/scf air. If there was no chlorine in the fuel, the maximum amount of chlorine allowable in the air would be: (9120-0)/(7.14)=1277 ug Cl/scf air.

(2) Sulfur compounds are those which contain sulfur. Total sulfur level should account for all sulfur and be expressed as hydrogen sulfide (H2S). See conversion below. Consult Lubrication section of the A&I Guide for information on proper lubrication and oil sampling when fuel or air contain sulfur compounds.

(3) Halide compounds are those which contain chlorine, fluorine, iodide, or bromine. Total halide level should account for all halides and be expressed as chlorine. See conversion below. Consult Lubrication section of the A&I Guide for information on proper lubrication and oil sampling when fuel or air contain halide compounds.

(4) Total particulate level must include inorganic silicon. Limit shown for silicon must account for the total organic (siloxanes, etc) and inorganic silicon content.

Figure 12: Engine Contaminant Allowance for Low Energy Fuels

While fuel pretreatment has a longer history and more popularity in the landfill gas-to-energy market, Cat engine designs that deal with fuel contaminants have a 20-year track record of effectiveness. Engine designs have improved steadily and are available on even the most technologically advanced, high-efficiency gas engines on the market. Protections against impure fuel include the following (illustrated in Figure 13).

- Gas-to-air coolers lower the temperature of the gas after it is compressed, reducing moisture and preventing condensation and attendant acid formation later in the fuel delivery system or inside the engines.
- Gas-to-gas heat exchangers, typically made of stainless steel, pre-cool the gas entering the dryer to reduce dryer power demand. The gas leaving the dryer is reheated later in the process by the gas-to-gas heat exchanger to prevent water from condensing downstream.
- Gas dryers reduce halogens and hydrogen sulfide (H2S) in the gas. The device is usually a gas-to-liquid heat exchanger that uses a refrigerant. The gas is dried by chilling to a dew point of 36 to 37 degrees F (2 to 3 degrees C). Because halogens and H2S are water soluble, reducing water content also reduces their concentrations. The dryer also reduces, to a lesser extent, some species of gas-borne siloxanes.
- Coalescing filters remove any remaining water or oil droplets and remaining solid matter as small as 0.4 microns.
- Condensate drains collect water removed from the gas. The water may be treated for discharge to a sewer system or, in some locations, reintroduced to the landfill to stimulate methane production.

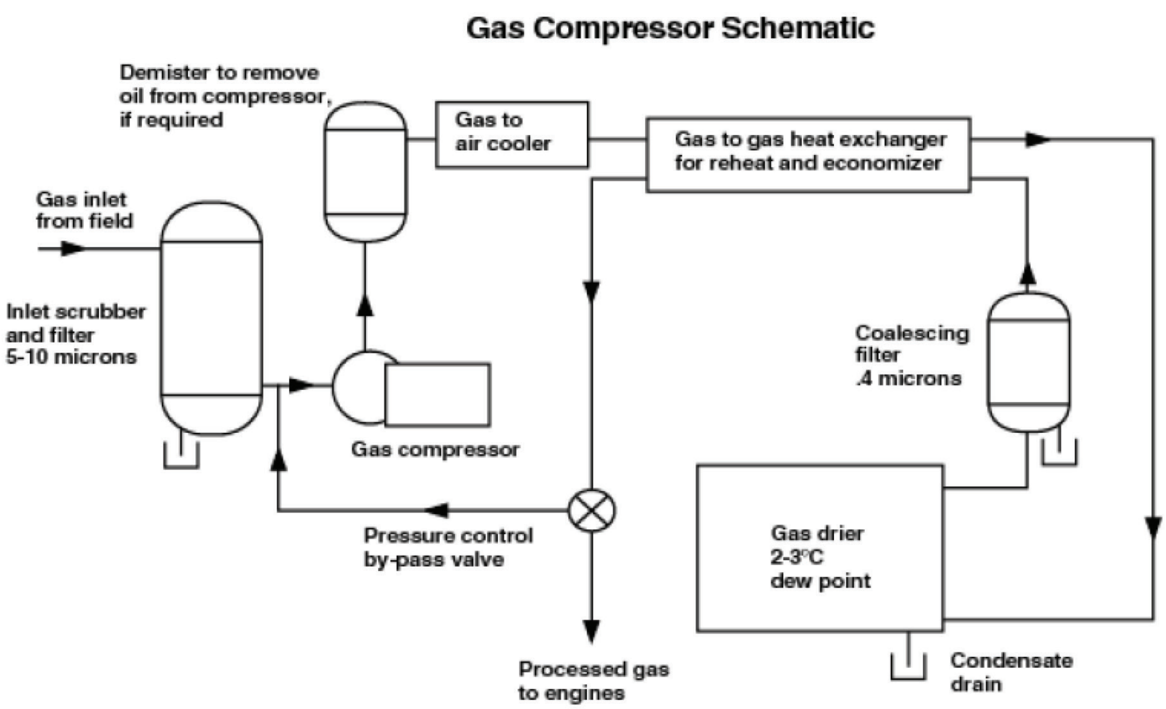

Figure 13: Typical Fuel Treatment System for Landfill Gas Applications

EXISTING LANDFILL GAS INSTALLATIONS

The South East New Territories Landfill (Figure 14), located in Hong Kong, is operated by Green Valley Landfill Ltd. The site installed two Cat G3516 landfill generator sets in 1997. Each unit is rated at 970 kW, providing 1.9 MW of continuous power for the landfill infrastructure and an on-site wastewater treatment plant. The units operate in parallel with the local utility, exporting excess power to the grid. The generator sets have oversized radiators to compensate for tropical heat and humidity. Green Valley Landfill provides regular maintenance in-house while top-end, in-frame and major overhauls are performed by China Engineers Limited (CEL), the local Cat dealer. Management reports that the facility is online 99 percent of the time.

Figure 14: South East New Territories Landfill, Hong Kong

BIOGAS

Biogas is produced through the natural anaerobic decomposition or fermentation of organic waste, such as manure, municipal solid waste, biodegradable waste or any other biodegradable feedstock within an anaerobic environment. Biogas consists primarily of methane (50 percent to 80 percent) and carbon dioxide (20 percent to 50 percent). Trace levels of other gases such as hydrogen, carbon monoxide, nitrogen, oxygen and H_2S can also be found in biogas. When burned, each cubic foot (0.028 cubic meter) of biogas yields about 10 Btu (10.6 kJ) of heat energy per percentage of methane composition. In practice, biogas composed of 65 percent methane will yield approximately 600 Btu (633 kJ) per cubic foot in terms of lower heating value.

Biogas can be extracted for commercial use from almost any of its sources. For example, some livestock farms or large livestock feeder operations use a lagoon to store the manure generated by their livestock. Instead of releasing the methane and carbon dioxide generated by the decomposition of this manure into the atmosphere, the methane can be extracted and burned at the farm in biogas-fueled boilers, heaters or other gas-consuming devices, including gas engines (illustrated in Figure 15).

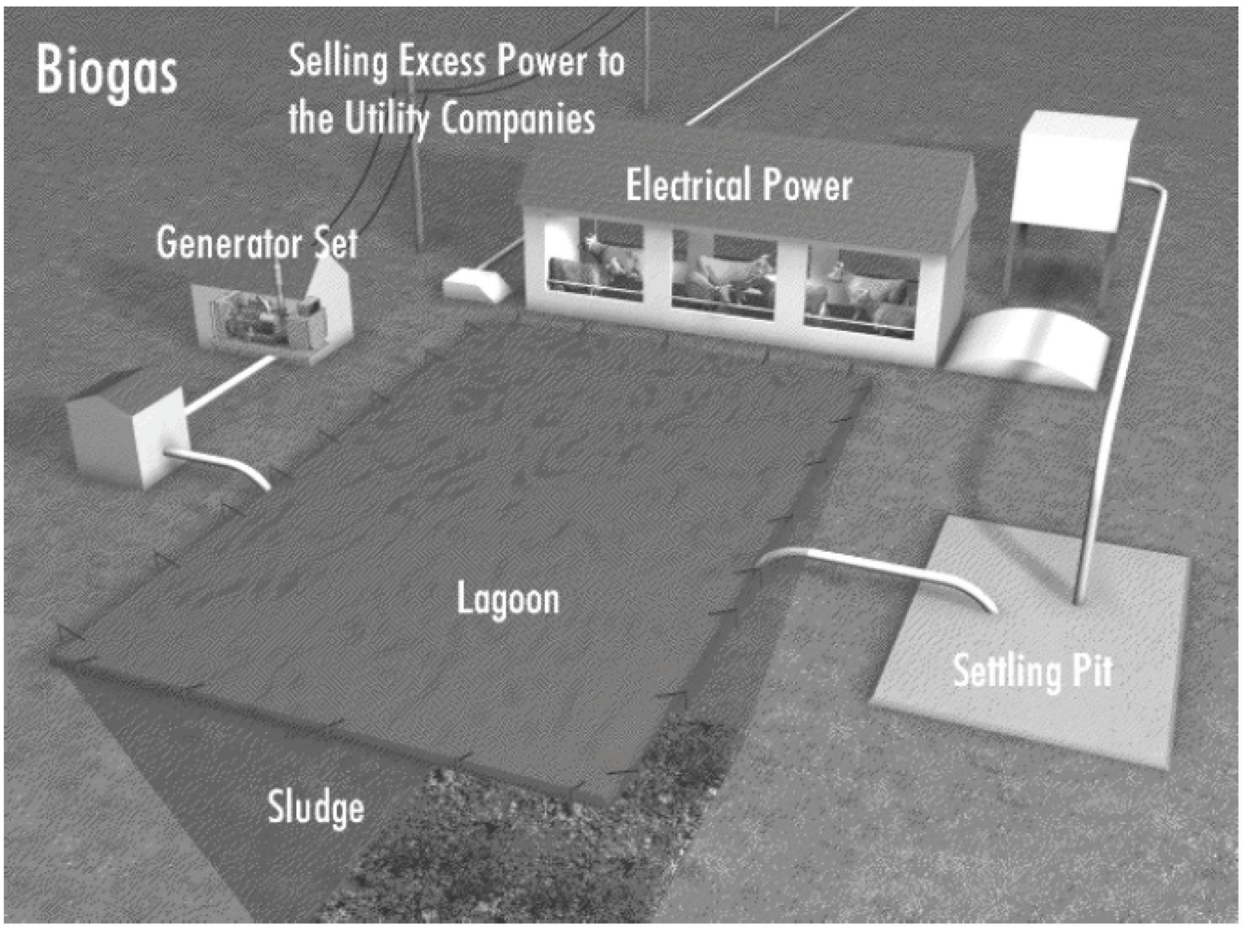

Figure 15: Typical Biogas Farm Gas Production, Collection and End Use

In addition to livestock farms, other agricultural operations afford opportunities for biogas production. For example, cassava-processing plants, which produce starch, are common in China, India and Indonesia and may utilize biogas for electric power. At such plants, anaerobic biodigesters are installed to convert organic-rich wastewater into methane. By tapping their biogas resource, these plants not only avoid the costs of purchasing heavy fuel oil and electricity but also reclaim valuable land that would otherwise have to be used to purify the factory's wastewater. By utilizing an anaerobic digestion system, organic matter decomposes in a contained environment to produce methane that is then consumed by the engine, thus virtually eliminating odor and pest issues caused by large-scale decomposition of organic material.

USING BIOGAS

Because of the impurities and inconsistencies in biogas, it must be either pretreated before use or used in engines that have been designed specifically for it.

A front-end gas-processing (or pretreatment) system can add significantly to a project's capital cost. System components must be chosen based on their function, reliability and resistance to corrosive damage from the impurities they remove. In theory, pretreatment should deliver near pipeline-quality gas, but that is seldom, if ever, economical. Therefore, the pretreatment system design usually requires a compromise: production of fuel pure enough to enable reliable engine performance under a reasonable maintenance regimen.

The level of pretreatment required is directly related to the quality of the biogas generated. For example, installations utilizing fuels with less than 80 percent relative humidity may not require any water filtration. However, fuels with 80 percent or more relative humidity or condensates may need to include a system that incorporates coalescing filters or chillers to remove water droplets from the gas and trap solid matter. In addition, a gas compressor may be necessary to deliver fuel to the engine at the necessary volume and pressure.

The second option for ensuring the reliability of biogas-fueled engines is to design and build them to meet the more rigorous demands imposed by their fuel. While these resulting low energy fuel engines will function with untreated biogas, they will still require fuel conditioning and compressing, and they may need other fuel treatment steps under certain fuel conditions.

These modifications add to the capital cost of the installation, but the capital and maintenance costs of pretreatment equipment can be reduced, sometimes significantly. The main design goals of engines that run on biogas are the following.

- Preventing harmful substances from forming inside the engine.
- Manufacturing highly susceptible components to be corrosion-resistant.
- Ejecting potentially corrosive gases from the engine.

Specific engine modifications include optimized jacket-water temperature, crankcase ventilation and use of corrosion-resistant materials. As further protection against naturally forming acids, biogas-specific engine designs minimize the use of bright metals (such as copper and unprotected steel) in components likely to come in contact with fuel contaminants or exhaust gases. For example, the aftercooler cores, composed of copper alloys in standard gas engines, are made of stainless steel in the biogas-fueled versions of these engines to resist corrosion by contaminants.

EXISTING BIOGAS INSTALLATIONS

Thailand has seen a burgeoning growth of livestock feeder operations—primarily swine farms (see Figure 16)—and cassava-processing plants. Both operations produce vast quantities of biogas in the manure and wastewater they generate.

Nong Rai Farm, in Rayong, Thailand, was seeking a means of tapping its biogas resources to fuel electrical generators for on-site power. The farm partners with the CP Group, one of the largest food suppliers in Thailand, and operates a feeder operation for more than 30,000 hogs. Nong Rai Farm consumes approximately 200 kW of power for blowers, drying systems and other auxiliary needs associated with its operations. The manure produced by its hogs is piped into a digester pond, where it generates biogas that is used to fuel the generator sets. While Nong Rai Farms recognized that the initial investment in biogas-fueled generator sets would be higher, management was confident that the long-range savings associated with a reliable, durable platform would be significant. The Cat G3406NA and G3306NA gas generator sets produce 105 kW and 70 kW, respectively—power sufficient for all of Nong Rai Farm's electric power requirements.

Figure 16: Buffer Tank and Digestion Process (Front) at Kampangpetch Swine Farm, Thailand

Key to the success of these systems has been the installation of a special “hardened” engine designed by Caterpillar engineers to withstand the corrosive effects of high levels of H2S and other acid-producing chemicals that are often present as impurities in locally produced biogas. When combined with water vapor during biogas pressurization and transportation, sulfuric acid and other corrosive byproducts are often produced.

CONCLUSIONS AND RECOMMENDATIONS

With the implementation of new policies to drive a cleaner environment, the mitigation of emissions through generator sets is likely to offer opportunities to benefit from alternative fuel investments. Creating power from sustainable resources such as CMM, landfill gas and biogas is mature and proven technology that is also environmentally responsible.

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