COMPARATIVE ANALYSIS OF LANDFILL GAS UTILIZATION TECHNOLOGIES

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EXECUTIVE SUMMARY

This report, prepared for the Northeast Regional Biomass Program (NRBP), is intended to show federal and state environmental agencies that there are real environmental benefits to using LFG as an energy source, including the trading of emission reduction credits in non-attainment areas. The report can be used to gain interest in and support for the economic and environmental viability of LFG utilization. Also intended for LFG developers and equipment manufacturers/suppliers, the report outlines new LFG conversion technologies and compares their total economic and emissions impacts with those of conventional LFG conversion technologies.

LFG CONVERSION TECHNOLOGIES

Table ES-1 summarizes the performance characteristics of the following technologies:

- ***Otto Cycle*** - internal combustion reciprocating engine.
- ***Brayton Cycle*** - gas turbine.
- ***Organic Rankine Cycle (ORC)*** - vapor turbogenerator system.
- ***Stirling Cycle*** - external combustion engine.
- ***Fuel Cells*** - Phosphoric Acid Fuel Cell (PAFC) and Molten Carbonate Fuel Cell (MCFC).

Table ES-1

	Otto Cycle	**Brayton Cycle**	**ORC**	**Stirling Cycle**	**PAFC**	**MCFC**
Efficiency	33%	28%	18%	38.5%	36%	50%
Heat Rate (Btu/kWh)	10,400	12,200	18,200	8,900	9,400	6,800
Emissions (g/bhp-hr)						
Nox	2	0.54	0.7	0.11	0.046	0.000847
CO	2	0.67	1.2	0.55	0.09	0.05

ENVIRONMENTAL EXTERNALITIES AND PROJECT INCENTIVES

Prices regulated utilities were required to pay for purchased power from qualifying facilities ranged from 1.38¢ to 4.92¢ per kWh in the Northeast. An approximate average of 3¢/kWh was used for the comparative analysis. In addition to the power purchase price, LFG recovery projects may benefit from environmental externalities considerations, from Emission Reduction Credits (ERCs), where recognized, and from federal incentive programs.

Environmental Externalities and Emission Reduction Credits

States are increasingly contemplating the inclusion of market externality costs and benefits associated with different generation options in electricity resource planning and procurement decisions. Six of the eleven states in the Northeast either consider externalities in some form in the planning process, or are developing market mechanisms to meet emissions standards; a seventh gives preference to “green” generating facilities.

Title I of the Clean Air Act Amendments (CAAA) requires states with non-attainment areas for criteria pollutants to adopt programs to bring these areas into compliance. Since LFG recovery facilities "control" emissions of Volatile Organic Compounds (VOCs) and in some cases NOx, they may qualify for Emission Reduction Credits (ERCs) which could be sold to businesses wishing to expand or locate in the non-attainment area.

Federal Incentive Programs for LFG Projects[1]

The federal government offers incentives in the form of tax credits, early depreciation, and other subsidies for the generation of alternative fuels, such as LFG. These incentives can be a vital component for making an otherwise borderline project workable and profitable. Two programs that directly impact on LFG project development are:

- ***Section 29*** **-** tax credits for producing fuel from a non-conventional source.

- ***Renewable Energy Production Incentives (REPI)*** **-** a 1.5¢/kWh payment to owners and operators of municipally owned facilities who produce electricity from renewable sources, including biomass, at qualifying projects.

Project partnerships must be structured to take advantage of applicable incentives.

COMPARATIVE ANALYSIS

Performance information and cost estimates for each of the conversion technologies were input to a model built on the baseline value of a 1,000 kW capacity power plant. Two scenarios were developed for presentation:

- ***Landfill that does not have a LFG collection system*** **-** cost of constructing the collection system is included in the capital cost, and potential environmental externalities are calculated based on the difference between emissions from the conversion processes and surface emissions from a landfill with no controls.

- ***Landfill that already has a LFG collection and flare system*** **-** capital cost does not include the cost of constructing a collection system, and potential environmental externalities are calculated based on the difference between emissions from the conversion processes and emissions from a landfill flare.

Other assumptions were made as to: run-time availability (ranging from 80-95%); O&M costs (assumed to be $50,000 per year); royalty payments (no value assigned); capital debt service (10 years at 10% interest); all costs presented in 1995 dollar terms; power sales revenues (3¢/kWh, including both avoided and capital cost); no value to use of waste heat; tax credits and REPI payments (99.3¢/MMBtu and 1.5¢/kWh, respectively); emission credits (applied as discussed above).

Conclusions

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[1]This report was revised in March of 1997. Minor edits to the text and two technical modifications were made. It must be noted that the report references section 29 of the Internal Revenue Code relating to tax credits for producing fuel from non-conventional sources. Although those tax credits were extended for one year, as of this writing the credits are no longer available.

As shown in Table ES-2, all the conversion technologies cost significantly more than the assumed power sales revenue of 3¢/kWh to own and operate. Accordingly, *both* tax credits *and* sales revenues totaling more than 3¢/kWh are required to make a project feasible.

Table ES-2 - Power Production Costs (¢/kWh)

	Otto	Brayton	Rankine	PAFC	MCFC
No Existing LFG Collection System:					
Excluding all credits	5.7	6.1	5.6	9.9	12.8
Including tax credits	4.7	4.8	3.8	9.0	12.1
Including tax credits & REPI	3.2	3.3	2.3	7.5	10.6
Including tax credits, REPI & Emission Credits	(0.1)	(3.3)	(8.0)	1.4	5.8
LFG Collection/Flare System Already in Place:					
Excluding all credits	4.7	5.0	4.5	8.8	11.6
Including tax credits	3.7	3.8	2.7	7.9	10.9
Including tax credits & REPI	2.2	2.3	1.2	6.4	9.4
Including tax credits, REPI & Emission Credits	4.0	2.1	0.4	5.5	8.6

Under both scenarios, the Organic Rankine and the Otto Cycle conversion technologies are the least-cost approaches for LFG utilization, closely followed by the Brayton Cycle. When tax credits are accounted for, the Organic Rankine Cycle becomes significantly more attractive than either the Otto or Brayton Cycles. The Organic Rankine Cycle is the least efficient and, therefore, requires more LFG. Because the tax credits are based on the volume of LFG used, using the finite amount of LFG available from a given landfill faster accelerates short-term access to the tax credits.

When the system includes constructing and operating a LFG collection system, revenues of 5.6¢ and 5.7¢/kWh for the Organic Rankine and Otto Cycles, respectively, are required to cover the cost. (Fuel cell technology production costs are excessive due to high capital costs. If these can be halved, which is the long-term goal of the manufacturers, power production costs could become competitive.) When an LFG collection and flare system exists, the unit costs of the Organic Rankine and Otto Cycles are 4.5¢ and 4.7¢/kWh, followed by the Brayton Cycle at 5¢/kWh. With tax credits included, net production costs decrease to 2.7¢/kWh for the Organic Rankine Cycle; 3.7¢/kWh for the Otto Cycle; and 3.8¢/kWh for the Brayton Cycle.

Lacking other values, the values of emission credits were calculated based on Massachusetts values, which are no longer applicable. In comparison to the surface emissions from landfills with no controls, emission credits of one to three times the power sales revenues could be realized from each of the technologies. However, it is doubtful whether state regulatory agencies would recognize such high credits. If emission reduction credits are allowed, it can be anticipated that they will not exceed those calculated by comparing emissions from the respective technology against the emissions from a LFG collection system and flare. In this case, emission credits of 25 to 30 percent of the power sales revenues could be realized from the

Organic Rankine Cycle and the fuel cell technologies. Only limited emission credits would be realized from the Brayton Cycle. Air emissions from the Otto Cycle are far more than from a flare, and therefore emission credits would be a negative number.

SECTION 1

INTRODUCTION

This report was prepared on behalf of the Northeast Regional Biomass Program, which is administered by the CONEG Policy Research Center, Inc. It presents a comparative analysis of landfill gas (LFG) utilization conversion technologies and is intended primarily to inform state and federal energy policy makers, regulatory agencies, and public utility commissions (PUCs) about alternative technologies for LFG utilization.

BACKGROUND

Landfills produce LFG as organic materials decompose under anaerobic (without oxygen) conditions. LFG is composed of approximately equal parts of methane (CH_4) and carbon dioxide (CO_2) with trace concentrations of other gases, including non-methane organic compounds (NMOCs). The combustibility of methane can be both an asset and a liability to a landfill owner: an asset when the gas becomes a source of energy recovered from LFG; and a liability (1) when subsurface migration of LFG results in accumulations of methane gas in structures, and (2) because LFG emissions can increase the potential for the greenhouse effect. LFG can be used in place of conventional fossil fuels. The LFG low heating value typically ranges from 400 to 600 British thermal units (Btus) per standard cubic foot (scf), which is approximately one-half the heating value of natural gas.

The Industry's Beginnings

The LFG recovery industry started in California in the early 1970s. The first project was at the Palos Verdes Landfill in Los Angeles County, where the extracted LFG was upgraded to pipeline quality gas. Several LFG-to-energy projects have been operating in California for about 15 years. From the late 1970s until the mid-1980s, LFG recovery for use as an energy source was supported by favorable energy prices, and projects were implemented in most regions of the country. From the late 1980s to the present, however, LFG developers have experienced lower energy prices, stiff competition, and additional regulation. Nevertheless, projects have continued to be implemented. There are approximately 140 operating LFG utilization projects in the U.S.

Environmental and Economic Benefits

Small landfills (less than 0.5 million tons) and old landfills generally cannot support LFG-to-energy projects. Medium sized landfills (0.5-3.0 million tons) are capable of supporting projects only in the 500 to 2,000 kilowatt (kW) range. Traditional conversion technologies (primarily internal combustion engines) in this range may not be cost-effective at current low energy prices without special pricing supports. They also may be difficult to permit, because they produce a significant amount of nitrogen oxides (NO_x) and carbon monoxide (CO). Because of its impact on ozone formation, NO_x in particular is undesirable in the Northeast; most of this region is classified as a non-attainment area for ozone.

Capturing the environmental and economic benefits associated with LFG resources requires conversion technologies that neutralize environmental damage associated with landfill sites, and at the same time produce salable energy at marketable prices. At present, electricity purchase prices are depressed due to excess electric capacity and the current low prices of primary fuels. Increased LFG recovery depends on low cost conversion technologies capable of producing electricity at prices that electric utilities are willing or required by regulation to pay.

Utilities are required to buy power generated at landfills because they are "Qualified Facilities" under the Public Utility Regulatory Policies Act (PURPA). Developers do not have to go through the competitive process to obtain a power sales agreement if they can sell the power at a price that the utility typically offers (i.e., published, standard rate schedule). In Massachusetts, for example, for projects whose design capacity is not greater than 5 megawatts (MW), the utility is required to offer a purchase price, through a long-run standard contract, equivalent in value to the weighted average price paid to all project developers from the most recent final award group.

The reduction in environmental emissions due to an energy project may eventually have a monetary value in the marketplace as an off-site emission reduction (OER) item. For example, the Massachusetts Department of Public Utilities (DPU) has required the consideration of externalities in utility decision-making since 1988. Environmental externalities are incorporated in integrated resource planning and competitive bidding. In 1992, the DPU established monetary values for emission reductions, and the Department of Environmental Protection proposed regulations regarding emission averaging, banking, and trading. The potential sale of OERs by LFG projects would help underwrite associated capital investments and operating costs, thus making such projects more economically attractive.

The Industry Today

Using LFG as an alternative fuel source may become more attractive to developers and investors for several reasons. Increases in fossil fuel costs, government support of LFG-to-energy projects, and costs of complying with environmental regulations all play a role. For example, landfill owners can offset a portion of the cost of complying with federal and state regulations for control of air emissions by selling the landfill byproduct, LFG. The required pollution control measure thus can improve the economics of LFG recovery.

REPORT OBJECTIVES

This report is intended to show federal and state environmental agencies that there are real environmental benefits to using LFG as an energy source, including the trading of emission reduction credits in non-attainment areas. The report can be used to gain interest in and support for the economic and environmental viability of LFG utilization. Also intended for LFG developers and equipment manufacturers/suppliers, the report outlines new LFG conversion technologies and compares their total impacts with those of conventional LFG conversion technologies.

Specific objectives of the report are to:

- Perform a comparative analysis of traditional and non-traditional LFG conversion technologies, in the 1,000 to 3,000 kW capacity range, addressing the technologies and their economic and environmental (air emissions) costs and benefits. Technologies to be considered are:

  - **Otto Cycle** - internal combustion reciprocating engine.
  - **Brayton Cycle** - gas turbine.
  - **Organic Rankine Cycle** - vapor turbogenerator system.
  - **Stirling Cycle** - external combustion engine.
  - **Fuel Cells** - Phosphoric Acid Fuel Cell (PAFC) and Molten Carbonate Fuel Cell (MCFC).

- Identify conversion technologies that maximize environmental benefits and can be

permitted.

- Identify the prices electric utilities offered under their standard offer contracts and the values, if any, given to environmental externalities.

- Identify types of project partnerships which may maximize federal economic incentives.

- Estimate air emission changes at landfills (before and after implementation of each LFG conversion technology).

- Identify areas for further study/analyses.

REPORT ORGANIZATION

This report is divided into the following sections:

- ***Section 1: Introduction***

- ***Section 2: LFG Conversion Technologies*** - a general description of each of the selected technologies (Otto Cycle, Brayton Cycle, Stirling Cycle, Organic Rankine, and Phosphoric Acid and Molten Carbonate Fuel Cells).

- ***Section 3: Environmental Externalities and Project Incentives*** - a summary by state of the utility rates and value of environmental externalities. Identifies potential revenue streams available, including electricity sales, tax credits, renewable energy production incentive payments, and externality values. A discussion of possible partnership arrangements to take advantage of Federal incentive programs.

- ***Section 4: Comparative Analysis of LFG Conversion Technologies*** - a comparison of the performance, cost, revenue potential, and emissions for each of the selected technologies.

SECTION 2

LFG CONVERSION TECHNOLOGIES

TYPES OF SYSTEMS CONSIDERED

Internal Combustion Systems

For purposes of this study, internal combustion systems include **reciprocating engines** that operate on a thermodynamic "Otto Cycle," and **gas turbines** that operate on a thermodynamic "Brayton Cycle." Conceptually, internal combustion systems ignite and combust a fuel/air mixture within the engine or turbine. The combustion causes a pressure force which can be directly translated into usable energy.

External Combustion Systems

External combustion systems use an external combustion source as a heat supply for the energy conversion system. This study includes the "**Organic Rankine Cycle**," and the "**Stirling Cycle**," each of which uses a working fluid or gas which is heated and cooled using external heat. The changes in temperature cause changes in volume and pressure which can be translated into usable energy.

Electrochemical Systems

Electrochemical systems use a variety of chemical reactions to create an electron transfer and thus a direct current. These are not combustion processes. The technology reviewed in this study was **fuel cells**. Two types of fuel cells that appear to be promising for LFG conversion are the Phosphoric Acid Fuel Cell (PAFC) and the Molten Carbonate Fuel Cell (MCFC).

INTERNAL COMBUSTION SYSTEMS

Internal Combustion Reciprocating Engines

Internal combustion reciprocating engines (ICREs) have been used for a wide variety of applications, the most familiar of which is the automobile engine. The thermodynamics of the ICRE are referred to as the "Otto Cycle." This cycle can be broken down into four strokes:

- ***Intake Stroke:*** A vacuum is created within a cylinder by lowering a piston. The vacuum draws in a mixture of air and fuel vapor.

- ***Compression Stroke:*** The piston is then raised to compress the fuel/air mixture, thus raising the pressure and temperature.

- ***Power Stroke:*** The compressed air/gas mixture is ignited by an electric spark. The combustion of the fuel/air mixture creates very high pressure and temperature which force the piston down the cylinder.

- ***Exhaust Stroke:*** At the bottom of the piston stroke, a valve is opened to release the pressurized combustion products. The piston is raised in the cylinder, causing the combusted products to exit through the exhaust valve.

Another major application for reciprocating engines is power generation. An engine can be connected to a generator through the crankshaft. The transmitted rotational power is then used to turn a generator for creating electricity.

A number of manufacturers have been developing engines for use with low-Btu fuels such as LFG. Cooper Superior has many of their installations in California. In the northeastern states, Caterpillar and Waukesha are more prevalent. For the purposes of this study, Caterpillar and Waukesha are the primary reference sources. Figure 1 is a photograph of a representative engine generator installation.

Fuel System Options

Mechanically, internal combustion engines are all fairly similar; however, the largest variations lie in the fuel system. Fuel system options include natural aspiration; lean-burn, turbocharged, high-pressure fuel system; and lean-burn, turbocharged, low-pressure fuel system.

- ***Naturally Aspirated:*** Naturally aspirated engines commonly range in size from 100 kW to 1,000 kW output. These utilize standard carburetion to supply the engine with a fuel/air mixture at only slightly elevated pressure (1 to 2 pounds per square inch gauge [psig]). Because of the low pressure requirement, a simple fuel supply system can be used.

  Due to relatively higher NO_x and CO emission rates, and a high capital cost to power output ratio ($/kW), these engines are not commonly used for LFG applications.

- ***Lean-Burn, Turbocharged, Aftercooled:*** Lean-burn refers to the fuel/air mixture relative to its chemically correct (or "stoichiometric") requirement for complete combustion of the fuel and air. A lean mixture contains excess air, whereas a rich mixture would contain excess fuel.

  Lean-burn engines are typically turbocharged and aftercooled. This "supercharges" the combustion chamber and provides greater engine power output. The fuel/air mixture can be leaned to provide 7 to 11 percent excess oxygen to achieve complete combustion of the fuel, optimizing fuel consumption and lowering the temperature.

- *High-Pressure Fuel Supply* - Until recently, lean-burn, turbocharged engines required high pressure fuel in the range of 30 to 50 psig. To deliver fuel gas at this high pressure, substantial power is required by the fuel gas compressor (FGC).

- *Low-Pressure Fuel Supply* - Systems have been developed with a supply fuel pressure requirement similar to that of a naturally aspirated engine, 1 to 2 psig. These employ the turbocharger to provide the necessary fuel pressure which lowers the power consumption for the FGC. Both Caterpillar and Waukesha offer low-pressure systems.

figure 1 ENGINE PICTURE

Rotational Speeds

Reciprocating engines can also be categorized by their rotational speeds, ranging from low speeds (less than 700 rpm) to high speeds (greater than 1,200 rpm). The lower speed engines are larger in physical size with a higher capital cost to power output ratio. In comparison, higher speed engines are smaller and provide a lower capital cost to power output ratio. Of the existing systems in operation, the higher speed (1,200 rpm) lean-burn, turbocharged, aftercooled engines are the most common. These include the Caterpillar 3516 SITA and the Waukesha 7100 GL.

Conceptual Design

Figure 2 presents a simplified process flow schematic for an LFG conversion facility utilizing reciprocating engines. A 1,000 kW system will generally include one or two engines, while a 3,000 kW system may include three to four engines operating simultaneously from a common LFG collection and pre-conditioning system.

Performance Characteristics

As stated previously, the Caterpillar 3516 SITA and the Waukesha 7100 GL are the most common engine/generator sets in the Northeast states. For that reason, the performance/ operating characteristics noted below are based on information provided by the manufacturers of these models and from application data from operating systems.

Efficiency	33 percent
Heat Rate (Btu/kWh)	10,400
Emission Production: (g/bhp-hr)	
NO_x	2
CO	2

FIGURE 2 ENGINE CONCEPTUAL DESIGN

Estimated Capital and Operation and Maintenance Costs

A LFG industry rule-of-thumb estimate of the cost for equipment procurement, installation, and start-up operation of reciprocating engine gen-sets is $1,000 per kilowatt. This rule-of-thumb estimate does not include the cost of land, the LFG system, and "soft" costs such as engineering, permitting, planning, management financing, etc.

Although there are economies of scale for 3,000 kW power plants compared to 1,000 kW power plants, these economies commonly are offset by providing enhancements for the larger power plants; e.g., a masonry building to house the engine gen-set, an office and restroom may be constructed for a 3,000 kW power plant, whereas a 1,000 kW power plant may be open-air or installed in a skid-mounted trailer. Likewise, more LFG clean-up may be provided for a larger plant, compared to a 1,000 kW plant. The total capital cost for power plants is estimated as follows:

Description	1,000 kW Plant	3,000 kW Plant
Equipment, installation, start-up cost	$1,000,000	$3,000,000
"Soft" costs, such as investigation, engineering, permitting, planning, management, financing, legal	20% or 200,000	15% or 450,000
Land costs. Plants are normally located on the landfill at no cost.	---	---
Total Capital Cost	$1,200,000	$3,450,000

For purposes of the comparative analysis in Section 4, an average unit cost of $1,200/kW was used as the total capital cost.

An old rule-of-thumb estimate of the cost to operate and maintain a reciprocating engine power plant using LFG as the fuel was 1.5¢/kWh. In recent years several LFG operators report use of somewhat higher unit rates -- e.g., 1.75 to 1.85¢/kWh. For purposes of the comparative analysis in Section 4, an average unit cost of 1.8¢/kWh was used for O&M.

Gas Turbines

Gas turbines operate based on a thermodynamic "Brayton Cycle." A common use of gas turbines is aircraft engines. A simple gas turbine consists of an air compressor, a combustor, and the expansion turbine. In operation, the gas turbine and the compressor are connected through a single shaft. As the turbine spins, the following occurs:

- Air is pulled through the compressor section of the turbine. The compressor consists of a number of feathered blades attached to the spinning shaft. While the blades turn with the shaft, air is compressed through a restricted area.

- The compressed air is delivered to the combustor. Fuel is supplied to the combustor at a steady flow to maintain a continuous flame. Air heated in the combustor expands through nozzles to develop a high velocity.

- The energy in the combustor air stream is transferred to the turbine expansion blades. Approximately three quarters of the energy is used to drive the air compressor; the rest is available from the shaft to perform work.

The majority of gas turbines presently operating at landfills are simple cycle, single shaft machines. A LFG gas turbine is very similar to a natural gas turbine except that, because of the low Btu value, twice the number of fuel regulating valves and injectors are used.

Gas turbines require a high pressure fuel supply in the range of 165 to 200 psig. Using a fuel gas compressor (FGC) to supply such pressure can consume a significant portion of the power being generated (parasitic losses). Studies of gas turbine facilities operated by Waste Management, Inc. have shown system parasitic losses due to the FGC, lighting, heat, etc., to be 15 to 20 percent of the power output.

Conceptual Design

Figure 3 is a photo of a gas turbine installation at a landfill, and Figure 4 is a process flow diagram. The gas turbine and generator are the primary components for generating electricity. Gas turbine installations are suitable for LFG utilization projects that are capable of generating 3,000 kW of electricity or more. Smaller gas turbine units (e.g., 1,000 kW) have been used at landfills, but normally not as a primary generating unit.

Performance Characteristics

The most common gas turbine in operation at LFG recovery projects is the Centaur, manufactured by Solar Turbines, a subsidiary of Caterpillar. The net rated generating capacity is 3,000 kW; the gross capacity (prior to parasitic losses) is 3,500 kW or more, depending on the model and its application. Solar also supplies a 1,000 kW unit, called the Saturn. It is seldom used at landfills. Operating characteristics for the Centaur, as outlined below, were used for the subsequent analysis:

Net Rated Generating Capacity	3,000 kW
Efficiency	28 percent
Heat Rate (Btu/kWh)	12,200
Emission Production: (g/bhp-hr)	
No_x	0.54
CO	0.67

Estimated Capital and Operation and Maintenance Costs

Gas turbine installations are not as common as reciprocating engines, and are more customized facilities. Accordingly, rule-of-thumb estimates for gas turbine installations do not exist. The capital cost of gas turbine installations was estimated based on the cost of projects constructed several years ago and escalated to account for inflation, downsizing to a single 3,000 kW unit, and accounting for the "soft" costs. The breakdown of these estimated costs are shown below for a 3,000 kW unit, excluding the cost of the LFG collection system. No costs are shown for a 1,000 kW unit because small units are not normally used. For purposes of the comparative analysis in Section 4, the costs for the 3,000 kW unit were divided by three and rounded to arrive at the $1,500,000 cost per 1,000 kW of capacity.

FIGURE 3 GAS TURBINE AND FACILITY

FIGURE 4 GAS TURBINE PROCESS FLOW DIAGRAM

Description	Cost
Building and site work	$231,000
Prime mover (turbine and generator)	2,020,000
Fuel gas compressor	866,000
Electrical equipment and controls	231,000
Utility interconnect	144,000
Subtotal, Equipment, Installation, and Start-up	$3,492,000
Cost Escalation and "Soft" Costs, such as investigation, engineering, permitting, planning, management, financing, legal (30 percent)	1,048,000
Land costs. Locate on landfill at no cost	--
Total Capital Cost	$4,540,000

Again, no rule-of-thumb estimates for O&M of gas turbine installations exist. The following O&M estimate was based on costs reported for operating projects, escalated to account for downsizing to a single 3,000 kW unit, and adding "soft" costs. The breakdown of these estimated costs are shown below for a 3,000 kW unit. For the comparative analysis, the estimate was divided by three to arrive at the 1.3¢/kWh unit cost, which equates to $102,000 per 1,000 kW of capacity.

Description	Cost
Labor (employees and outside)	$ 92,000
Consumable Supplies (oil, chemicals, etc)	14,000
Equipment Parts and Repairs	52,000
Major Overhauls	64,000
Building and Site Maintenance	14,000
Subtotal	$236,000
"Soft" Costs, such as permit compliance, management, accounting, insurance, taxes (30 percent)	71,000
Total	$307,000

Advantages and Disadvantages - ICRE vs. Gas Turbines

The most common types of internal combustion technologies used to produce electricity from LFG are reciprocating engines and gas turbines. Listed below are some advantages and disadvantages of utilizing reciprocating engines versus gas turbines.

ADVANTAGES - ICRE	***ADVANTAGES - Gas Turbines***
HIGHER EFFICIENCY *UTILIZE LOW PRESSURE FUEL GAS COMPRESSOR* *ADAPTABLE TO VARIABLE LFG SUPPLIES* *SUITABLE FOR MODERATE SIZE LANDFILLS* *LOWER CAPITAL COST*	*HIGHER EMISSIONS* *MORE COMPLEX COOLING SYSTEM* *MORE MOVING PARTS* *HIGHER MAINTENANCE COST*
DISADVANTAGES - ICRE	***DISADVANTAGES - Gas Turbines***
LOW EMISSIONS *NO COOLING WATER REQUIRED* *SIMPLE LUBRICATION SYSTEM* *FEW MOVING PARTS AND WEAR POINTS* *VIBRATION FREE OPERATION* *EXHAUST CAN BE UTILIZED IN COGENERATION*	*LOWER EFFICIENCY* *HIGH PRESSURE FUEL GAS COMPRESSOR REQUIRED* *HIGH CAPITAL COST* *NOT SUITABLE FOR MODERATE SIZE LANDFILLS* *SENSITIVE TO VARIED LFG SUPPLY LOADS* *SENSITIVE TO AMBIENT AIR TEMPERATURE VARIATIONS*

ORGANIC RANKINE CYCLE

Organic Rankine Cycle (ORC) operation is based on the "Rankine Cycle," which has been known as the "complete expansion cycle." The Rankine Cycle was the first accepted standard of comparison for steam power plants. One of the more common uses of this cycle is the steam turbine bottoming cycle in combined cycle cogeneration plants. In such a cycle, the working fluid is water. It is raised to a set pressure by a pump and then evaporated at constant pressure, producing steam. The steam is expanded in a turbine to produce mechanical power.

The ORC operation is based on the Rankine Cycle, with one major difference; the working fluid is a hydrocarbon, iso-butane or propane. This is known as a dry cycle. The most commonly used expansion turbine consists of a single-stage, inflow-type turbine. The system is designed to be modular, allowing for factory assembly of the equipment in small, easily shipped modules. Power units of 1,000 kW and less are designed as six truck-transportable modules ready for operation following minimum site installation. The largest power unit is a 3,000 kW system that consists of 8 (or possibly 10) modules. All equipment employed in the design and construction of the power units are proven industrial components.

The basic components of an ORC system and their functions are as follows:

- *Boiler/Vaporizer*. Transfers thermal energy from the heat source (flue gas from an enclosed flare, incinerator stack, turbine exhaust, etc.) to the working fluid, causing the working fluid to change phase from a liquid to a vapor.

- *Expansion Turbine-Generator*. Converts the recoverable thermal energy of the working fluid to mechanical energy. The expansion of the working fluid within the turbine is an isentropic process and is capable of obtaining isentropic efficiencies of 85 percent and higher.

- *Recuperator*. Transfers the low-level heat of the working fluid (in a gaseous state) existing in the turbine to the high-pressure working fluid (in a liquid state) from the charge pumps.

- *Condenser*. Condenses the working fluid from a gas to a subcooled liquid state.

- *Accumulator Vessel*. Serves both as a storage vessel for the system and as the head tank for the charge pumps.

- *Charge Pump(s)*. Elevates the working fluid pressure from that maintained in the head tank to that required by the boiler.

- *Switchgear Control Room*. Minimum 1,200 amp rating at 100°F.

- *Transformer Substation*. Normally supplied by local utility.

The majority of ORC systems are in geothermal power conversion applications. An LFG "ORC" system would be similar to the geothermal system, except the heat source would be the flue gas from the burner assembly, rather than hot, geothermal water. Figure 5 is a picture of an ORC modular unit.

FIGURE 5 ORC PICTURE

Where wet cooling is not available, dry cooling will be employed requiring air-cooled condensers. Utilizing air-cooled condensers can consume a portion of the power being generated. Typical geothermal facilities' parasitic loads due to the condensers, site lighting, charge pumps, etc., range from 15 to 20 percent of the gross power.

Conceptual Design

Figure 6 is a process flow diagram for an ORC LFG conversion facility utilizing a module expander-generator system. The expander/generator and vaporizer are the key pieces of equipment in converting LFG to electrical power. Units can be used for systems capable of generating 3,000 kW of power. Smaller units (e.g., 1,000 kW), can be employed in areas with high electrical costs.

Performance Characteristics

The most common ORC power plant in operation with over 100 MW of saleable power are in geothermal applications. Operating characteristics for an ORC plant are noted below.

Thermal Efficiency	18 percent
Heat Rate (Btu/kWh)	18,200
Emission Production: (g/bhp-hr)	
NO_x	0.7
CO	1.2
NMOC Destruction Efficiency	98 percent

Estimated Costs

ORC technology has been developed primarily to produce electricity from geothermal projects. No ORC projects using the hot exhaust from LFG flares have been installed. However, ORC manufacturers Perennial Energy and Ormat indicate that much of the design and technology developed for geothermal applications can be directly applied to LFG flares. A typical system would be designed as a modular unit mounted on a skid with the electric distribution, control, flame safety, and operational devices pre-installed and pre-wired. Capital costs for the ORC unit, installation, and start-up should not exceed $1500/kW.

ORC units installed at geothermal projects reportedly require limited maintenance. They can be operated without daily servicing and check-ups; i.e., alarms tied into key components can be used to alert the operator of problems or potential problems. Of course, periodic servicing, on-site monitoring, and parts replacement/repairs are needed, but the labor requirements are limited. It is expected that O&M comparable to that required for geothermal projects would be required for LFG installation. For the comparative analysis, an average unit cost of 0.8¢/kWh was used for O&M.

FIGURE 6 0RC CONCEPTUAL LAYOUT

Advantages and Disadvantages of ORC

The ORC system has two primary advantages over other LFG conversion technologies such as gas turbines and reciprocating engines. These advantages are (1) the ability to convert the heat energy from the combustor to mechanical power, allowing for a very high capacity factor, and (2) low pollutant emissions without secondary equipment. Advantages and disadvantages of ORC systems are listed below.

ADVANTAGES
HIGH CAPACITY FACTOR *EMISSIONS LIMITED TO FUGITIVE LOSSES* *NOT SENSITIVE TO VARIED FUEL SUPPLY LOADS* *SIMPLE AUXILIARY SYSTEM* *LIMITED MOVING COMPONENTS* *VIBRATION FREE LOW NOISE OPERATION* *CAN BE ADDED TO EXISTING FLARE SYSTEM* *NO OPERATOR REQUIRED*
DISADVANTAGES
HIGH HEAT RATE *HIGH CAPITAL COST* *SENSITIVE TO AMBIENT AIR TEMPERATURE VARIATIONS*

STIRLING CYCLE ENGINES

Much of the development for the Stirling Cycle engine occurred during the 19th Century prior to development of the Otto and Diesel Cycle engines. At the beginning of the 20th Century, progress to develop Stirling engines came to a virtual stop because the Otto and Diesel Cycle engines produced higher power output in a smaller engine. In order to increase the power output from a Stirling engine, a working gas with a higher thermal conductivity than air was required. Today, a variety of gases are being researched with helium being the most promising, and development of the Stirling Cycle has slowly resumed.

A Stirling Cycle engine is an external combustion engine that produces power by alternately expanding and compressing a working gas within a closed vessel. The internal volume of the closed vessel is typically separated into hot and cold regions by a displacer piston. The piston shuffles the working gas back and forth between the hot and cold regions. A power piston is used to vary the internal volume of the closed vessel. Movement of the displacer piston and the power piston are sequenced to cause the expanding working gas to push against the power piston when the working gas is being heated and to pull the power piston in the opposite direction when the working gas is being cooled.

The idealized Stirling Cycle consists of the following, in sequential order:

- Isothermally compressing the working gas.
- Adding heat at constant gas volume.
- Isothermally expanding the working gas.
- Rejecting the heat at constant gas volume.

- Repeating the process.

Conceptual Design

To date, few organizations have produced trial Stirling engines using exhaust from fossil fuel combustors. Those that have been produced are designed to generate less than 200 kW of power, and none of these are commercially available. Mechanical Technology Incorporated (MTI) is currently developing a Stirling engine called the Mod III, which could be adapted to use LFG (see Figure 7). Stirling engines have been developed using solar energy as the heat source.

Figure 8 presents a process flow diagram for a Stirling Cycle engine using the exhaust gases from a LFG flare as the heat source.

Performance Characteristics

The following performance characteristics are based on research and demonstrated performance of the MOD III Stirling engine being developed by MTI.

Efficiency	38.5 percent
Heat Rate (Btu/kWh)	8,900
Emission Production: (g/bhp-hr)	
NO_x	0.11
CO	0.55

FIGURE 7 PICTURE

FIGURE 8 CONCEPTUAL FLOW DESIGN

Costs

No cost estimates were developed for this report because Stirling Cycle engines are in a conceptual and experimental phase of development for small power output (e.g., 200 kW). Cost predictions at this point would be speculative.

Advantages and Disadvantages of Stirling Cycle

At present, the primary disadvantage for a Stirling Cycle engine is its early stage of development. As with any new technology, development costs can be very expensive, and it can take time and experience to prove a technology for open acceptance in the market.

ADVANTAGES
WORKING GAS SEALED INSIDE A VESSEL *LOW EMISSIONS* *LOW NOISE* *INTERNAL PARTS NOT IN CONTACT WITH CONTAMINANTS FROM LFG FUEL*
DISADVANTAGES
NOT COMMERCIALLY AVAILABLE *HIGH CAPITAL COST* *NOT A PROVEN TECHNOLOGY*

FUEL CELLS

Fuel cell technology, although not new, is now being looked at more thoroughly as a public and commercial power source. Some of the first fuel cells were used on NASA space programs in the 1960s and 1970s, including Apollo and Gemini, and are currently being used on shuttle programs. The fuel cell itself is an electrochemical device, which uses a fuel such as hydrogen or natural gas and an electrochemical process similar to that of a battery to produce low-voltage direct current (DC) electricity, heat, carbon dioxide, and water.

A fuel cell system generally is configured in three major sections: a reforming section, the fuel cell stack, and the power conditioning section. These sections can be skid-mounted, which allows for rapid installation in the field. These sections are often enclosed, as shown on Figure 9. This photograph also shows the gas pre-conditioning/contaminant removal equipment.

The reforming section receives a clean fuel such as natural gas and processes it with heat and catalytic reactions to extract a hydrogen-rich gas that is supplied to the fuel cell stack. The gas needs to be processed through a pre-conditioning/removal system prior to being supplied to the reforming section, because LFG contains many contaminants such as sulfur and various halide compounds, If not removed, these contaminants will "poison" the catalyst in the reforming section, reducing its performance.

A fuel cell stack is made up of many individual fuel cells connected in series. The fuel cell itself consists of a positively charged electrode, a negatively charged electrode, and an electrolyte filling between the two.

The hydrogen-rich gas from the reforming section is introduced at one electrode and oxygen, from

FIGURE 9 FUEL CELL PICTURE

FIGURE 10

air, is introduced at the other electrode. The electrolyte between the electrodes acts as a medium for electron-ion transfer. The hydrogen is oxidized at the hydrogen electrode, electrons are released, transported through the electrolyte, and absorbed at the oxygen electrode. The flow of electrons produces DC electricity. The power conditioning section is used to convert the DC electricity generated from the fuel cell to alternating current (AC) electricity with a voltage to match the utility company system.

Different types of fuel cells are identified by the type of electrolyte used, such as phosphoric acid, molten carbonate, and solid oxide. Phosphoric acid and molten carbonate fuel cells appear to be furthest along in research and development, and thus are the focus of this study.

Conceptual Design

Figure 10 is a process flow diagram for a LFG conversion facility utilizing fuel cell technology.
The two fuel cells currently being studied are a 200 kW phosphoric acid fuel cell produced by International Fuel Cell, and a 2,000 kW molten carbonate fuel cell produced by Energy Research Corporation. Fuel cells can be connected in series, to achieve the desired power requirements.

Performance Characteristics

Following are the performance characteristics of the phosphoric acid and the molten carbonate fuel cells. They are presented separately because they have far different operating characteristics.

PHOSPHORIC ACID FUEL CELL	
Efficiency	36 percent
Heat Rate (Btu/kWh)	9,400
Operating Temperature	400°F to 600°F
Emission Production: (g/bhp-hr)	
NO_x	0.046
CO	0.09

MOLTEN CARBONATE FUEL CELL	
Efficiency	50 percent
Heat Rate (Btu/kWh)	6,800
Operating Temperature	1,200°F
Emission Production: (g/bhp-hr)	
NO_x	0.000847
CO	0.05

Note that the emissions shown are not created within the fuel cell stack; rather, they are from the incomplete combustion of gas in the reformation process.

Estimated Costs

Fuel cells for commercial use are currently in the development and demonstration phase, which makes them expensive. Prototype designs can easily cost 5 to 10 times more than the predicted production cost. For example, the 2,000 kW molten carbonate fuel cell facility that Energy Research Corporation is developing in Santa Clara, California, is expected to cost $23,000/kW; their production sales price goal is $1,200/kW. Likewise, International Fuel Cell Corporation currently sells their 200 kW phosphoric acid fuel cell for the equivalent of $3,000/kW; their production sales price goal is $1,200 to $1,500/kW.

Based on cost figures from International Fuel Cell Corporation, the capital and O&M costs for the PAFC were extrapolated, as follows:

Capital Cost	1,000 kW net	3,000 kW net
Current: $3,000/kW	$3,000,000	$9,000,000
Goal: $1,500/kW	$1,500,000	$4,500,000
Operation & Maintenance Cost		
Based on 65 percent run-time, 1.6¢/kWh	$91,000	$273,000

Currently, the molten carbonate fuel cell (MCFC) technology is more costly than the PAFC technology. Its current capital cost is estimated at $4,000/kWh for a 1,000 kW plant. For purposes of the comparative analysis in Section 4, capital costs of $3,000/kW and $4,000/kW were used for the PAFC and MCFC technologies, respectively. O&M costs of 1.6¢/kWh were used for both technologies, although these unit costs should decrease as the technology advances and operating experience is gained.

Data from operations of fuel cells show that run-time is only 65 percent. A lot of time is spent making repairs, replacements, etc. The manufacturers claim that run-times have increased, and expect that their fuel cells will be able to operate at least 90 percent of the time. For purposes of the comparative analysis, it was assumed that in the near future, the PAFC and MCFC would run 85 and 80 percent of the time, respectively, assuming the fuel and heat supply is available at all times.

Advantages and Disadvantages of Fuel Cells

Currently, the phosphoric acid fuel cell appears to be further along in development and operation; however, the molten carbonate fuel cell is gaining interest because of its higher operating temperature. The increase in heat simplifies the reforming section by allowing the reformation process to occur within the fuel cell, which further reduces pollutant emissions. The temperature also generates a higher grade heat for cogeneration.

The following advantages and disadvantages generally apply to both types of fuel cells.

ADVANTAGES
HIGH EFFICIENCY *LOW EMISSIONS* *LOW NOISE* *SUITABLE IN URBAN AREAS* *MODULAR CONSTRUCTION* *LOW WATER REQUIREMENT* *HIGH GRADE WASTE HEAT FOR COGENERATION* *REMOTE OPERATION* *FEW MOVING PARTS*
DISADVANTAGES
HIGH CAPITAL COST *NEW TECHNOLOGY* *REQUIRES COMPLEX LFG PRETREATMENT SYSTEM*

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SECTION 3

ENVIRONMENTAL EXTERNALITIES AND PROJECT INCENTIVES

ENVIRONMENTAL EXTERNALITIES

In recent years, integrated resource planning (IRP) has developed as a comprehensive process for addressing electricity planning. IRP considers a broad array of factors that may impact future utility operating conditions. Among these factors are non-market related environmental and social concerns, or "externalities." In economics, a market externality occurs when some of the costs of a market transaction are borne, or benefits received, by parties not directly involved in the transaction. These externalities therefore represent costs or values that may not be directly reflected in the market pricing of the transaction. An example includes power plant air emissions, where residents outside the generating utility's service territory may incur health or aesthetics-related costs of air pollution.

States are increasingly contemplating the inclusion of market externality costs and benefits associated with different generation options in electricity resource planning and procurement decisions. Six of the eleven states in the Northeast either consider externalities in some form in the planning process, or are developing market mechanisms to meet emissions standards; a seventh gives preference to “green” generating facilities.

EMISSION REDUCTION CREDITS

Title I of the Clean Air Act Amendments (CAAA) requires states with non-attainment areas for criteria pollutants to adopt programs to bring these areas into compliance with relevant standards. One such program, the New Source Review (NSR) program, requires "major sources" to obtain a preconstruction permit. Among other requirements, these permits require new facilities to obtain emission offsets, which are enforceable emission reductions from other operations or facilities, to balance the proposed emissions increase from the facility seeking the permit.

A new facility or major modification to an existing facility is considered a "major source" if its emissions, not counting fugitive emissions, exceed an applicable threshold of 100 tons per year (tpy) in marginal and moderate ozone areas, 50 tpy in serious, 25 tpy in severe, and 10 tpy in extreme areas. Additionally, thresholds for major modifications may be lower.

Emission Reduction Credits (ERCs) are certified reductions beyond regulatory standards of air emissions of volatile organic compounds (VOCs), nitrogen oxides (NOx), particulates (PM-10), or carbon monoxide (CO). Businesses that want to expand or locate new facilities may need to purchase ERCs to offset the amount of new VOCs, NOx, PM-10, or CO that they may emit.

Since LFG recovery facilities "control" VOC emissions from landfills beyond regulatory standards, they may qualify for VOC ERCs. Additionally, depending on the recovery facility's history and type of equipment, it may qualify for NOx ERCs. ERCs could be a valuable commodity that facility owners can sell to other firms or use for their own future projects.

On the Federal level, the EPA is planning to propose a generic trading rule, called an Open Market Trading Rule (OMTR) for VOCs and NOx, which will provide more flexibility for companies to trade emission credits.

STATE PROGRAMS

Several different approaches have been used in integrating externality concerns into resource planning. The most direct has been the monetization of environmental externalities.

In 1994, 11 northeastern states Public Utility Commissions (PUCs) were asked for the following information:

- Current purchase prices that regulated electric utilities are required to offer for electricity from LFG projects of 5,000 kW or less.
- The use and value of environmental externalities for air emissions in resource planning, or whether such programs are being considered.

A summary by state of these findings follows.

Connecticut

The Connecticut Department of Public Utility Control (DPUC) requires utility companies to examine environmental externalities in both supply and demand side bidding. The utility companies also are required to examine the environmental externality bidding process, and their weighting systems. However, the DPUC does not require utilities to consider externalities when dispatching power from generating facilities. The Connecticut Legislature requires the DPUC to consider externalities for all new resource additions and authorizes a 1 percent to 5 percent rate-of-return bonus for cost-effective demand side management (DSM) investments to reflect their environmental benefits.

The Connecticut Legislature passed a law requiring electric utilities to purchase electricity generated by resource recovery facilities (including LFG projects) at the same rates that electric utility companies charge municipalities for electricity. The resource recovery facilities had to be owned or operated by or for the benefit of a municipality(ies) with a minimum 20-year contract period.

In January 1995, the Federal Energy Regulatory Commission (FERC) found that this law violated the Public Utility Regulatory Policies Act of 1978 (PURPA); i.e., a utility company could not be required to pay more than their avoided cost for Qualifying Facilities, even if the State had a valid reason for requiring the higher rate. Rather than going to court to challenge the law that requires higher payments, utility companies have negotiated rates with developers that are more than their approximate 3¢/kWh avoided cost, but considerably less than the commercial rates charged to municipalities.

Delaware

The Delaware Public Service Commission requires utility companies to qualitatively consider environmental externalities in integrated resource planning. However, utility companies are not required to make their resource decisions on the basis of externality values; consideration of externalities is not required in dispatch; nor are utilities required to monetize externality values.

Like in many other states, utility companies in Delaware establish and publish rate schedules for purchasing power from Qualified Facilities. Delmarva Power & Light Company has the following rate schedule for energy payments:

Service Time	Summer Billing Months of June - September	Winter Billing Months of October - May
On-Peak	3.36¢/kWh	3.71¢/kWh
Off-Peak	2.10¢/kWh	2.54¢/kWh
Average Rate	2.59¢/kWh	3.07¢/kWh

When a customer contracts with Delmarva to deliver capacity of 1,000 kW or less, Delmarva pays for such capacity based on the length of contract. Annual rates for capacity range from zero to $45.59 per kW for 1 to 20 years, respectively.

Maine

The Maine PUC does not require consideration of externalities in resource planning.

The current purchase price is based on the avoided cost of the individual utility company, with no provisions for capacity payments. Avoided cost information is considered confidential and is not available for public information.

Currently, Maine has a surplus of electricity. Accordingly, existing contracts for biomass are being bought back by utility companies because the purchase prices stipulated in existing contracts are higher than actual avoided costs. The State is guaranteeing financing for utility companies to buy back the contracts. This financing usually is spread out for more years than the original contract, which makes it more cost effective. After the buy out, most plants are sitting idle.

See the Massachusetts section for a discussion of the New England Power RFP for renewable energy projects.

Maryland

The Maryland Public Service Commission (PSC) currently does not require consideration of externalities in utility decision making. The PSC has considered externalities, but nothing currently is proposed.

Purchase prices are individually negotiated for Qualifying Facilities that are larger than 1 MW. The four utility companies in the State establish and publish rate schedules for purchase of power from Qualifying Facilities less than 1 MW. These rates for energy payments range from 1.38 to 3.804 ¢/kWh. Two of the utility companies offer capacity payments ranging up to $93.76/kW, depending on the length of the contract. The other two utility companies have a capacity payment structure in place, but currently do not offer capacity payments.

Massachusetts

The Massachusetts Department of Public Utilities (DPU) has required the consideration of externalities in utility decision-making since 1988. Environmental externalities are incorporated in integrated resource planning and competitive bidding. They are not required to be considered in utility dispatch or rate making.

In December 1992, the Department of Environmental Protection (DEP) proposed regulations regarding emission averaging, banking, and trading. In 1992, the DPU established monetary values for emission reductions, as shown below:

Release	Value ($/Ton)
Nitrogen Oxides NO_x	$7,200
Sulfur Oxides (SO_x)	$1,700
Volatile Organic Compounds (VOCs)	$5,900
Total Suspended Particulates (TSP)	$4,400
Carbon Monoxide (CO)	$960
Carbon Dioxide (CO_2)	$24
Methane (CH_4)	$240
Nitrous Oxide N_2O	$4,400

Source: Commonwealth of Massachusetts, DPU 91-131, November 10, 1992.

In December 1994, the Massachusetts Supreme Court voided the DPU order regarding payment for environmental externalities. This action effectively stopped the state initiative. The Court would allow the DPU to include reasonably foreseeable regulatory compliance costs in rate case reviews.

Since this study project was developed around the Massachusetts values, the above values were used for the comparative analysis in Section 4, although the values are no longer in force.

The purchase price for electricity is based on avoided cost, which in some cases may include a capacity payment. A DPU staff member reported that, avoided costs based on RFPs issued by utility companies several years ago, energy costs ranged from 4.09 to 5.82 ¢/kWh and capacity payments were 1.06 and 1.01 ¢/kWh, respectively. New projects likely would receive significantly lower prices for long term contracts. Short run avoided costs presently are in the 2 to 3 ¢/kWh range.

In 1992, New England Power (a New England Electric System Company) issued the first RFP exclusively for renewable energy projects in the U.S. Seven projects were selected:

- Maine - a 20 MW wind energy facility located in the Boundary Mountains of Franklin and Somerset Counties, developed by U.S. Windpower, Inc.

- Barre, Massachusetts - a 1.0 MW LFG utilization project, developed by Phillips Energy.

- Randolph, Massachusetts - a 2.6 MW LFG utilization project, developed by Browning Ferris, Inc.

- Plainville, Massachusetts - a 3.0 MW LFG utilization project, developed by Laidlaw Gas Recovery Systems.

- Shirley, Massachusetts - a 5.9 MW total solid waste management facility, developed by Traitement Industriel Des Residus Urbains (a French firm).

- Nashua, New Hampshire - a 1.5 MW LFG utilization project, developed by Suncook Energy Corporation.

- Rhode Island - a 2.0 MW waste heat energy conversation facility at the Central Landfill in Johnston, developed by Genesis Energy Systems.

The project contracts were executed and submitted to the PUCs in Massachusetts, New Hampshire, and Rhode Island for approval since NEES operates retail utility companies in all three states. The New Hampshire Public Utility Commission (PUC) rejected the contracts because the rates were higher than avoided costs. The sponsors negotiated a settlement by refunding Granite State Electric $188,000 for direct refund to its ratepayers. This payment resulted in the projects receiving a 5 percent premium over avoided cost. Unfortunately, they would not acknowledge value for the environmental offsets of the projects.

The Rhode Island PUC rejected the projects for similar reasons. A compromise was achieved where each project made contributions to Narragansetts Electric Company to pay back the avoided cost premium over the contract term. The Massachusetts DPU approved the original terms of the contracts. The DPU assigned some value to the project concept (a set aside for renewable energy) and considered the externality values.

This approval process took over 2 years and significant expenditures from the project developers. All of the projects except the Rhode Island project are presently in some stage of development.

New Hampshire

Legislation was enacted in 1991 that suggests that the PUC examine the environmental and health-related impacts of utility resource options during their reviews of integrated resource plans. However, the PUC does not require consideration of externalities in utility planning, dispatch, or rate making.

The reported purchase prices in New Hampshire range from 1.693 to 4.920¢/kWh.

See the Massachusetts section for a discussion of the New England Power RFP for renewable energy.

New Jersey

The New Jersey Board of Regulatory Commissioners (BRC) requires consideration of demand side management planning and provides incentives for these considerations.

On August 2, 1995, Governor Whitman signed legislation amending the New Jersey Air Pollution Control Act, N.J.S.A. 26:23C-1 (APCA). The legislation requires the Department of Environmental Protection (DEP) to propose rules to establish emission trading and banking programs that use economic incentives to make progress toward the attainment or maintenance of the National Ambient Air Quality Standards.

The DEP is required to propose these rules by October 31, 1995. The DEP has initiated a two stage program to establish the basic framework for the trading program and to solicit public comment and participation in the rule-making process.

The purchase prices in New Jersey are based on long term avoided costs; they range from about 2 to

3¢/kWh.

New York

The New York Public Service Commission (PSC) has extensively addressed and researched environmental externalities. It requires consideration of environmental externalities in all source bidding, DSM planning, and in rate-making, and have quantitatively assessed values for externality credits and emissions.

In New York, the market for ERCs is not well defined. Several inquiries provided the following conflicting responses:

- A Department of Environmental Conservation (DEC) representative stated that a recent trade of NOx ERCs in the New York Metropolitan Area went for $2,000 per ton, and VOC ERCs were significantly higher.

- A Department of Economic Development (DED) representative stated that the price range for NOx ERCs is probably $5,000 to $20,000 per ton.

- A news brief in the July 1995 edition of Pollution Engineering noted that NOx discrete emission reductions (DERs) recently sold for $1,600 per ton (DERs are one time credits with units of tons as opposed to ERCs with units of tons per year, which are a continuous stream and hence, of high value).

New York's 1992 State Energy Plan recommended that 300 MW of renewable energy be procured by January 1, 1994 in order for utility companies to increase their fuel diversity. A portion of this capacity was to be reserved for LFG projects. The utility companies agreed to systematically study all methane sources in the state and to develop projects that are economically feasible. The projected development time frame is 1998 to 2001.

The current electricity purchase prices are based on long term avoided costs; they range from 3.07 to 3.76¢/kWh; however the PSC only requires the utility companies to enter into minimum 5-year contracts. These short term contracts are not attractive to developers, and no contracts have been signed recently.

Recently, Niagara Mohawk began a campaign to solicit a voluntary contribution of $6 per month from its customers to finance future "green" projects. They are anticipating participation from up to 12,000 customers. Their goal is to have these projects self- financed. If they do not have 12,000 customers participating by the end of 1995, they may look at other means to finance 'green" projects.

Pennsylvania

The Pennsylvania PUC has ordered utility companies to consider externalities as part of their cost-effectiveness evaluation of demand side management programs, although the PUC does not require consideration of externalities in dispatch or rate-making.

Pennsylvania Power & Light's (PP&L) 10-year projections of avoided cost ranged from 2.38 ¢/kWh in 1993 to 4.31 ¢/kWh in 2002 for projects with energy payments only. Projects providing capacity and energy payments ranged from 2.24 ¢/kWh in 1993 to 3.46 ¢/kWh in 2002.

Rhode Island

The Rhode Island PUC currently does not require utilities to consider externalities in decision-making.

Purchase prices are based on avoided cost and energy payments range from 3.25 to 3.44 ¢/kWh during peak hours and 2.50 to 2.53 ¢/kWh during off-peak hours. Capacity payments currently are not made because excess capacity is available. However, one utility company is planning to issue an RFP in 1999 for additional capacity.

See the Massachusetts section for a discussion of the New England Power RFP for renewable energy projects.

Vermont

The Vermont Public Services Board (PSB) has not considered the sale of emission credits.

The PSB currently is rewriting its rule for bidding to provide a preference for Qualifying Facilities that are "green." These facilities would have rights to long term contracts.

The purchase prices are based on avoided cost.

FEDERAL INCENTIVE PROGRAMS FOR LFG UTILIZATION PROJECTS

The federal government offers incentives in the form of tax credits, early depreciation, and other subsidies for the generation of alternative fuels, such as LFG. These incentives can be a vital component for making an otherwise borderline project workable and profitable. Two programs that directly impact LFG development are discussed below:

Section 29 — Tax Credits for Producing Fuel from a Non-Conventional Source

If biomass can be converted to gas before being used as a fuel, the project can qualify for a tax credit of 99.3¢ per million Btu of the gas under Section 29 of the Internal Revenue Code. This tax credit amounts to about 1¢/kWh, compared to utility companies' typical avoided cost of 3¢/kWh.

The Section 29 tax credits were initiated in 1979. A $3 credit per barrel of oil equivalent (5.8 million Btus) is available for the production and sale of certain qualified fuels to unrelated parties. The credit is adjusted each year for inflation (subject to limitations dependent upon the well head price of oil). The credit would phase out if the price per barrel of oil exceeded $29.50. The Energy Policy Act of 1992 extended the Section 29 tax credits to new projects that begin operating before the end of 1996.

The following requirements must be met for an LFG developer to qualify for the tax credits:

- Produce gas from biomass, or liquid, gaseous, or solid synthetic fuels produced from coal (or lignite).
- Sell the gas to an unrelated party,
- Have a binding written contract by December 31, 1995 to place the facility in service.
- Place the facility in service before December 31, 1996.
- Apply tax credits through the year 2007 for a facility placed in service after January 1,

1993. Existing facilities (those placed in service prior to 1993) may receive the tax credits through the year 2002.

The availability of tax credits usually results in a second or third party being brought into LFG utilization projects. The tax credit is available only if the gas produced is sold to an "unrelated party" and is of benefit only if the producer can use the tax credits. In recent years, many LFG development companies have become interested in "selling" their Section 29 tax credits, but relatively few buyers had been available. In 1994, institutional equity investors came into the market in search of Section 29 tax credits, with the result that tax credits have begun to be sold at a discounted value.

Renewable Energy Production Incentives (REPI)

The Renewable Energy Production Incentive (REPI) program was authorized by the Energy Policy Act of 1992. It offers a 1.5¢/kWh payment to owners and operators of municipally owned facilities who produce electricity from solar, wind, biomass, or geothermal sources at qualifying projects. The program will be in effect over a 10-year period and is subject to annual appropriations by Congress and the Department of Energy (DOE). To qualify, a project must:

- Generate electricity from solar, wind, biomass, or geothermal sources. Burning municipal solid waste for energy is not included.
- Be a public entity or non-profit electric cooperative.
- Use the facility for the first time in 1993 or later, excluding existing facilities.
- Petition DOE for payments.

The incentive payments are subject to the following conditions:

- The power plant must be owned by a state or local government or non-profit electric cooperative.
- The payments can be made to the owner **or** the operator.
- A project qualifies for the payments only if it is "first used" during the period October 1993 through September 2002.
- The electricity must be "for sale in, or affect, interstate commerce."

The Final Rule for implementing this program was published in the Federal Register on July 19, 1995 (10 CFR Part 451). Applications for incentive payments for energy produced in fiscal year 1994 were due by September 5, 1995. Congress appropriated $10 million for fiscal year 1994 projects. In order to continue the program, Congress will have to appropriate funds each year, and will have to re-authorize the program after the initial 3-year period.

This program can benefit LFG projects, although other types of projects such as solar, wind, geothermal, and closed-loop biomass have priority for funding. Closed-loop biomass means plant matter, other than standing timber, grown for the sole purpose of being burned to generate electricity.

The Rule clarifies that LFG qualifies as "biomass." However, if the available money in a particular year is

insufficient to cover all projects that are eligible for payments, then power plants that use sunlight, wind, geothermal energy, and "closed-loop" biomass would share in the money on a pro rata basis. Other types of biomass projects like LFG would have a lower priority and receive no money.

PROJECT PARTNERSHIPS

Early in the development process, developers typically evaluate the potential incentive payments and decide which benefits are applicable to the project. The next step, of course, is to try to structure the project to make it eligible for as many benefits as possible.

Of the approximately 140 LFG utilization projects in the U.S., an estimated 50 percent of the projects take advantage of the Section 29 tax credits. Figure 11 presents one developer's approach to structuring such a project. A discussion of the relationships between the landfill owner, LFG developer, and electric utility follows:

Landfill Owner

- The landfill owner leases the LFG development rights to a LFG developer.
- The owner receives lease payments, royalty payments, and other compensation for the development rights.
- The landfill owner maintains ownership of the landfill and, typically, responsibility for LFG migration control.
- The landfill owner receives additional value by avoiding annual O&M costs associated with the LFG collection system.

LFG Developer

Gasco--

- The LFG developer sets up a "Gasco" which owns the LFG collection system.
- The Gasco pays the landfill owner production payments, royalties, etc. for the LFG.
- The Gasco constructs, operates and maintains the LFG collection system.
- The Gasco sells LFG to the Genco and receives payments for the LFG.
- The Gasco receives Section 29 tax credits based on the sale of LFG to the Genco. The Gasco files for the credits on its tax return with the Internal Revenue Service. Alternatively, if the Gasco cannot use the tax credits to offset income taxes, it can sell the tax credits at a discounted value to an entity which can use the credits.

Genco--

- The LFG developer sets up a "Genco" to own and construct the power plant.
- The Genco purchases LFG from the Gasco and generates power.

- The Genco sells the energy to an electric utility company or another user, and receives energy payments.
- The Genco operates and maintains the power plant.

FIGURE 11. POTENTIAL BUSINESS ARRANGEMENT TO TAKE ADVANTAGE OF THE SECTION 29 TAX CREDITS

Source: LFG Generation Outline - Financing Options for Utilities. NEO Corporation. Proceedings of the Landfill Gas Energy Recovery Financing Workshop. June 1-2, 1995.

Electric Utility Company

- The utility company contracts with the Genco to purchase power over the project term, normally 10 years or longer.

The economics of these various relationships are negotiated between the respective parties.

Renewable Energy Production Incentive (REPI) Program

At least two projects are structured to take advantage of both the Section 29 tax credits and the REPI payments. Since the funding of the REPI program is subject to Congressional appropriations, there is limited value in structuring a project to take advantage of both programs. The Section 29 tax credits are more valuable than the REPI payments. Projects should be structured to take advantage of a known program.

Since future REPI payment funding levels are unknown and since a municipality or non-profit electric cooperative must own the Genco; more effort is required to set up a project that can take advantage of both programs. If the Section 29 tax credits are not extended, new projects likely will be structured to pursue the REPI payments since an uncertain program may be preferable to none.

SECTION 4

COMPARATIVE ANALYSIS OF LFG CONVERSION TECHNOLOGIES

Section 2 described select LFG conversion technologies and their approximate costs. Section 3 presented the results of surveys of 11 Northeastern states as to (1) the price paid by utility companies for electricity generated by LFG power plants, and (2) the status of recognizing air emission reduction credits. Additionally, Section 3 described Federal incentive programs for LFG projects. This section uses that information and an air emission discussion to compare the several LFG conversion technologies in terms of performance, air emissions, environmental externalities, and costs.

PERFORMANCE

The LFG conversion technology performance information and cost estimate for the Otto Cycle (IC engines) and Brayton Cycle (gas turbine) were derived from a combination of operating information from power plants, literature sources, and engine equipment manufacturers. With these numerous sources of information, and considering the variations due to differences in landfills, LFG collection and pre-treatment systems, and the variety of equipment and appurtenances used, the performance and cost values used for this comparative analysis are considered as representative, although costs will vary significantly from project to project. Likewise, the economies of scale for these technologies are overshadowed by these variations; accordingly, the comparative analysis is presented in terms of units per 1,000 kW of capacity.

The performance information and cost estimates for the Organic Rankine Cycle, Stirling Cycle, and fuel cell technologies are based primarily on information from equipment and process developers, and secondarily on analyses conducted by researchers and engineers, technology transfer from other applications, and pilot testing. None of these technologies are in use at landfills on a full-scale, 1,000 kW or larger, operation.

Figures 12 and 13 illustrate the electricity generation efficiency and the fuel (LFG) consumption per 1,000 kW of capacity for each of the six technologies. Efficiency generally is inversely proportional to LFG consumption. Higher LFG consumption is not necessarily a negative; by collecting more LFG, air emissions are reduced, an environmental benefit. As shown, the Organic Rankine Cycle is the least efficient, highest fuel consumption technology, and the Stirling Cycle and fuel cell technologies are the most efficient and consume the least LFG.

Figures 12 and 13

[*CORRECT CAPTION FOR FIGURE 13 SO THAT IT READS AS FOLLOWS*]:

Figure 13. LFG Consumption Rate per 1000 kW (scfm)

EMISSIONS

LFG Composition

LFG composition is dependent on the incoming refuse and landfill characteristics, LFG collection system design and operation, and other factors. Typical characteristics are presented below:

Characteristic	Range	Typical
Low Heating Value (LHV)	350 - 550 Btu/cf	450 Btu/cf
Methane (CH_4)	35 - 60%	50%
Carbon Dioxide (CO_2)	30 - 50%	45%
Nitrogen (N_2)	0 - 15%	4%
Oxygen (O_2)	0 - 4%	<1% (for safety)
Sulfur as H_2S	1 - 300 ppmv	<10 ppmv
Non-Methane Organic Compounds (NMOCs)	200 - 4,000 ppmv (as hexane)	500 ppmv (as hexane)

Although not all NMOCs are volatile organic compounds (VOCs), this report uses those terms synonymously, as do some state regulatory agencies. The literature does not report nitrogen oxides (NOx), sulfur oxides (SOx), total suspended particulates (TSP) carbon monoxide (CO), and nitrous oxide (N_2O) in raw LFG. An exception to this general statement is CO. CO detections in raw LFG indicate that a subsurface fire may exist within the landfill.

NOx and CO are products of combustion of LFG and are the pollutants of concern emitted from LFG utilization systems. The concentration of H_2S in LFG normally is sufficiently low that minimal SOx is produced by the combustion of LFG. Moisture and particulates in raw LFG need to be removed upstream of the LFG utilization processing equipment in order to keep the equipment operational and to avoid rapid corrosion and plugging. For the purpose of this discussion and analysis of emissions, it is assumed that most of the particulates are removed by the LFG pre-treatment system, and particulate emissions from the processes are negligible.

Conversion Processes

The approximate NOx and CO emissions from each of the LFG conversion technologies were presented in Section 2. These unit rates were converted into tons per year per 1,000 kW for each of the six technologies and plotted on Figures 14 and 15.

High temperature, long residence times, and poor fuel/air mixing during fuel combustion give Internal Combustion Reciprocating Engines (ICREs) comparatively high NOx and CO emission rates. As noted in Section 2, a new generation of electronic control fuel and ignition systems for ICREs is expected to significantly decrease NOx and CO emissions.

Figures 14 and 15

Gas turbines have lower NOx and CO emissions than ICREs because they operate at lower temperatures and higher air/fuel mixes. The Organic Rankine Cycle is considered to be a clean process. Its emissions, as shown on Table 1, are attributed to the emissions
from the landfill flare.

Fuel cell conversion is an electro-chemical reaction which does not produce NOx and CO emissions. The overall fuel cell system, though, includes a reformation process to extract hydrogen from methane. This is a heated catalytic process where the heat is generated using a burner and a small portion of the fuel stream. This combustion process creates the NOx and CO values shown in the figures. Because the molten carbonate fuel cell operates at a higher temperature than the phosphoric fuel cell, much of the reformation actually occurs within the fuel cell, requiring less heat and, thus, lower emissions.

All of the conversion technologies, including the common LFG flares, have combustion processes with destruction efficiencies of 98 percent or more of the NMOCs in LFG.

SOx is generated over a wide variety of combustion temperatures and is primarily a function of the sulfur concentration in the LFG, not the type of conversion technology. Accordingly, SOx emissions normally are minimal because H_2S concentrations in LFG are relatively low.

Potential Emission Reduction Credits

The potential value of emission reductions, referred to as environmental externalities, are calculated and presented in Table 1. The bases of these calculations are as follows:

- The LFG composition, as discussed above.
- LFG conversion technology characteristics as discussed in Section 2, using a 1,000 kW power plant as the common basis for comparison.
- Emissions of pollutants from the conversion processes, except for the Stirling Cycle, as discussed above and presented on Figures 13 and 14.
- Emissions from landfills with no controls and from landfill flares in order to calculate reduction in emissions.
- The monetary values in dollars per ton per year that the Massachusetts Department of Public Utilities established for emission reductions in 1992. Although the Massachusetts Supreme Court voided the order regarding environmental externalities (December 1994) and this action effectively stopped the state initiative, these values were used for this analysis, lacking any other values.

These simplified calculations do not include a credit for displaced emissions from fossil fuel-based power.

Table 1

[CORRECTION: In second line from bottom of first page of table 1 - currently reads:

“CO Emission Realease (gram/bhp-hr)”

“Realease” ---> “Release” [STRIKE THE EXTRA “a”]

Table 1 (continued)

As discussed above, several simplifying assumptions were made for this comparative analysis:

- The negligible SOx, TSP, and N_2O were assumed to be zero for the conversion processes and for the landfill surface emissions and landfill flare emissions.

- All of the methane (CH_4) is combusted by all of the processes except landfill surface emissions, which have no controls.

- The landfill flare operates 100 percent of the time (compared to the 80 to 95 percent run-times for the conversion technologies).

Observations from the result of the calculations in Table 1 are:

- Conversion Technology Emissions and Environmental Costs.

  - The primary compound emitted that has an environmental cost is CO_2, which is emitted from all the conversion technologies.

  - The fuel cells technologies have the lowest releases due to their operational characteristics, and because of their high efficiencies. They require the least amount of LFG.

  - The highest environmental cost technology is the Organic Rankine Cycle, due to its low efficiency and high amount of LFG required. As shown below, that can be considered a benefit.

  - The relatively high release of NOx from the Otto Cycle (IC engines) causes that technology to have high environmental costs.

- Environmental Costs of Conversion Technologies Compared to Flaring.

  - Again, the primary compound emitted from a flare that has an environmental cost is CO_2.

  - The environmental cost of emissions from the Organic Rankine Cycle and from fuel cells are less than from a landfill flare, and the Brayton Cycle (gas turbine) is about the same.

  - Fuel cells are a "clean technology" and their high fuel efficiency reduces the amount of LFG required for equal energy output.

  - The Organic Rankine Cycle releases less pollutants than the flare primarily because its operating time was assumed to be 90 percent and the flare was assumed to be 100 percent. Thus, the reduction in environmental cost is not a characteristic of the technology.

  - The NOx emissions from the Otto Cycle (IC engines) create an environmental cost significantly higher than a landfill flare.

- Environmental Costs of Conversion Technologies Compared to No LFG Controls.

  - The primary compound emitted from a landfill with no controls that has an environmental cost is CH_4; the second compound is CO_2; and the third is VOCs.

  - The environmental costs are directly proportional to the amount of LFG required. Accordingly, the highest cost is shown to be the Organic Rankine Cycle, which has the lowest efficiency, and the lowest costs are the two fuel cell processes, which are the most fuel efficient.

  - As a result of the low efficiency of the Organic Rankine Cycle, it produces the highest environmental credit, followed by the Brayton Cycle and then the two fuel cell technologies. The Otto Cycle creates the lowest net environmental credit due to its relatively high NOx emissions.

  - These calculations show the potential of the Organic Rankine Cycle as an approach for reducing emissions. Adding an Organic Rankine Cycle unit to an existing or new flare benefits the environment while producing energy from a source that would otherwise be wasted.

It should be noted that these observations do not take into account fossil fuel-based utility emissions offset when LFG is used to produce electricity.

COSTS

The cost information presented in Section 2 was compiled into unit costs per 1,000 kW of power plant capacity. The estimated capital and O&M costs for each technology (except the Stirling Cycle) are shown in Figures 16 and 17. Cost data for the Stirling Cycle was not available because its development is not sufficiently advanced. Accordingly, the Stirling Cycle was not included in the subsequent comparative analyses or the previous air emission analyses.

As shown on Figure 16, the Otto Cycle (reciprocating engines) has the lowest capital cost, $1,200,000 per 1,000 kW of power plant capacity. The lower capital cost, combined with its flexibility to install modules and its reliability, explains why the Otto Cycle is the predominant LFG conversion technology in operation. On the other hand, the Otto Cycle has the highest O&M cost, as shown on Figure 17.

The capital cost of gas turbines (Brayton Cycle) is about 25 percent higher than reciprocating engines, but their O&M cost is about 25 to 30 percent less. However, gas turbines are only suitable for larger sites (3,000 kW and larger power plants) and require more careful control of the methane content in the LFG supply.

Organic Rankine Cycle units have been installed at more than 100 geothermal power plants. To date, none have been installed at landfills. However, based on their experience, manufacturers are confident that units can be placed in service at landfills at a total cost of $1,500,000/1,000 kW. O&M costs are estimated at 0.8¢/kWh.

Figures 16 and 17

Fuel cells are at least several years away from full-scale applications on landfills. Capital costs must be reduced to the $1,200 to $1,500/kW range to be seriously considered for commercial use, and advances in LFG clean-up are required.

COMPARATIVE ANALYSIS

Performance information and cost estimates discussed above for each of the conversion technologies were input to a model that allowed this comparative analysis. A power plant capacity of 1,000 kW was used as the baseline value from which to build the model. Two scenarios were developed for presentation:

- Table 2 shows the model run assuming that the LFG utilization plant is constructed at a landfill that does not have a LFG collection system. Thus, the cost of constructing the collection system is included in the capital cost, and potential environmental externalities were calculated based on the difference in emissions from the conversion processes and the surface emissions from a landfill with no controls; that is, all LFG produced in the landfill discharges to the atmosphere.

- Table 3 shows the model run assuming that the LFG utilization plant is constructed at a landfill that already has a LFG collection and flare system. Thus, the capital cost does not include the cost of constructing a collection system, and potential environmental externalities were calculated based on the difference in emissions from the conversion processes and the emissions from a landfill flare.

Assumptions used for and bases of these comparative analyses, in addition to those discussed above, are:

- Run-time availability of each of the technologies was estimated between 80 percent for the MCFC to 95 percent for the Otto Cycle. These availabilities assume no LFG shortfalls.

- Under both scenarios, O&M costs for the LFG collection system were assumed to be $50,000 per year, which is in addition to the cost of the power plant. At some landfills, LFG collection system O&M is paid by the landfill owner/operator, which reduces the total O&M cost charged to power generation.

- No value was assigned to royalty payments by the power plant owner to the landfill owner.

- Capital debt service was assumed to extend over 10 years at 10% interest.

- O&M costs and revenue projections were not escalated; that is, all costs are presented in terms of 1995 dollars.

- Power sales revenues of 3¢/kWh were used for revenue projections. This unit price includes both avoided cost and capital cost.

- No value was given to use of waste heat.

Table 2

Table 3

- Tax credits and REPI payments, as discussed in Section 3, were 99.3¢/MMBtu and 1.5¢/kWh, respectively. The full value of tax credits was considered for this analysis.

- Emission credits were applied as discussed above.

Conclusions

As shown in Tables 2 and 3, all the conversion technologies cost significantly more than the assumed power sales revenue of 3¢/kWh to own and operate. Accordingly, *both* tax credits *and* sales revenues totalling more than 3¢/kWh are required to make a project feasible.

Under the scenarios shown in Tables 2 and 3, the Organic Rankine and the Otto Cycle conversion technologies are the least-cost approaches for LFG utilization, closely followed by the Brayton Cycle. When tax credits are accounted for, the Organic Rankine Cycle becomes significantly more attractive than either the Otto or Brayton Cycles. The Organic Rankine Cycle is the least efficient and, therefore, requires more LFG. Because the tax credits are based on the volume of LFG used, using the finite amount of LFG available from a given landfill faster increases the amount of tax credits available in the short term.

The highlighted sections of Tables 2 and 3, Power Production Costs, present estimated unit costs for each of the technologies with and without tax credits, REPI payments, and emission credits. Table 2 shows that revenues of 5.6¢ and 5.7¢/kWh for the Organic Rankine and Otto Cycles, respectively, are required to cover the costs when the system includes constructing and operating a LFG collection system. Fuel cell technology production costs are excessive due to the high capital costs. If their capital costs can be halved, which is the long-term goal of the manufacturers, power production costs could become competitive.

Table 3 shows that when an LFG collection and flare system exists, the unit costs of the Organic Rankine and Otto Cycles are 4.5¢ and 4.7¢/kWh, followed by the Brayton Cycle at 5¢/kWh. With tax credits included, net production costs decrease to 2.7¢/kWh for the Organic Rankine Cycle; 3.7¢/kWh for the Otto Cycle; and 3.8¢/kWh for the Brayton Cycle.

The values of emission credits are calculated based on the Massachusetts values (which are no longer applicable). In comparison to the surface emissions from landfills with no controls, Table 2 indicates that emission credits of one to three times the power sales revenues could be realized from each of the technologies. It is doubtful whether state regulatory agencies would recognize such high credits. The NSPS, when promulgated, will establish maximum allowable levels of emissions equal to those released by a collection system and flare. If emission reduction credits are allowed, it can be anticipated that the credits will not exceed those calculated by comparing emissions from the respective technology against the emissions from a LFG collection system and flare as discussed below.

Compared to the landfill with a LFG collection and flare system, emission credits of 25 to 30 percent of the power sales revenues could be realized from the Organic Rankine Cycle and the fuel cell technologies (see Table 3). On the other hand, limited emission credits would be realized from the Brayton Cycle; air emissions from the Otto Cycle are far more than from a flare, and therefore emission credits are a negative number on Table 3.