Turning Methane into Money: Cost-Effective Methane Co-Generation Using Microturbines at a Small, Rural Wastewater Plant

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ABSTRACT

Application of microturbines for methane-fueled combined heat and power generation represents an innovative, renewable energy technology. While methane-based co-generation has been widely implemented at large wastewater facilities, it is generally not considered to be cost-effective for smaller plants. The Village of Essex Junction, with the support of Efficiency Vermont, has successfully implemented microturbine technology at its 2.0 million gallon per day (MGD) average-flow, municipal wastewater treatment facility, and can provide firsthand information on its financial benefits. The Essex Junction facility design is 3.3 MGD with flows at 2.0 MGD. This clarification is often important to design professionals as flow growth lends conservatism to the numbers.

The Essex Junction co-generation project installed two, 30 kilowatt (kW) microturbines that combust waste methane gas to generate electricity. Waste heat from the microturbines is used to maintain 100-degree Fahrenheit temperatures for the site's anaerobic digestion process. Total system efficiency of electricity and heat generation is greater than 80%. With nearly 100% use of its waste methane, the facility now saves approximately 450,000 kilowatt-hours (kWh) (45% of annual usage) and $43,000in electricity costs per year. As a result, more than 600,000 pounds of carbon dioxide emissions from power plants will be prevented because of this project.

The Essex Junction project is the first of its kind at a small New England wastewater facility. Similar projects could likely be implemented at 5-15% of the nation's 16,000 publicly-owned wastewater treatment facilities. Efforts to expand methane-based co-generation at wastewater facilities would yield significant energy savings, while also supporting pollution prevention, renewable energy, and distributed generation efforts. This paper will describe the benefits of methane-fueled microturbine co-generation, provide lessons learned from the experience of a 2.0 MGD facility, and show the cost-effectiveness of this innovative technology.

Introduction

The Village of Essex Junction, Efficiency Vermont, and other project partners were able to leverage each other's technical and financial resources to complete a project that will help Essex Junction's taxpayers for years to come. While many municipalities are struggling with maintaining infrastructure in the face of increasing costs and stable tax rates, there are innovative and effective ways to increase efficiency, conserve energy resources, and reduce operating costs. Methane-fueled microturbine co-generation provides such an opportunity at Essex Junction.

The Village of Essex Junction is a small town in northwestern Vermont with a land area of 4.6 square miles and a population of approximately 8,700 people. It is located approximately 10 miles from Burlington, Vermont, which is the State's largest city with 38,000 people. Both Essex Junction and Burlington are in Vermont's most populous county, Chittenden County, which is home to approximately 100,000 residents. The total population of Vermont is roughly

620,000. Given the small size and rural nature of the state, it is difficult for individual municipalities to collect sufficient taxes to cover the cost of large projects with high initial capital costs and maintain user rate stability (even when projects achieve long-term operating cost reductions).

Efficiency Vermont, the nation's first energy efficiency utility, was created by the Vermont legislature and the Vermont Public Service Board in 1999 to help all Vermonters save energy, reduce energy costs, and protect Vermont's environment. Efficiency Vermont is operated by Vermont Energy Investment Corporation, an independent, non-profit organization under contract to the Vermont Public Service Board. Efficiency Vermont administers virtually all system-wide, electric-ratepayer funded energy efficiency at a statewide level. The Efficiency Vermont contract is a multi-year, competitively bid, performance-based contract that includes a great deal of freedom and flexibility to achieve clearly specified, quantitative energy savings. While commercial and industrial customers have access to prescriptive incentives for simple efficiency measures[1], the large majority of electric energy savings are achieved through custom projects and services. Typical services that may be provided by Efficiency Vermont include project-specific technical assistance (e.g., electric and cost savings analyses, economic analyses, technical recommendations, etc.), education and training, and financial incentives.

Anaerobic Digestion and Methane

Methane is produced as a by-product of a process known as anaerobic (i.e., without oxygen) digestion, which decomposes organic material. At wastewater plants, anaerobic digestion is used to stabilize wastewater sludge, reduce sludge volume, and eliminate pathogens. Volume reduction of sludge results in smaller disposal quantities and lower disposal costs. The methane generated from anaerobic digestion at wastewater facilities is typically considered a "waste." In fact, methane gas can be a troublesome waste since it is also a "greenhouse gas" that contributes to global warming. Most wastewater plants with anaerobic digestion are required to collect the resulting methane gas and burn it (usually with a flare), rather than letting it discharge directly to the atmosphere, in order to control and reduce the emission of greenhouse gases[2]. Many do burn a portion for heating the digester.

Based on information collected by the US EPA in its Clean Watersheds Needs Survey in 2000, there are approximately 16,000 public wastewater facilities in the U.S., referred to as publicly owned treatment works (POTWs). Anaerobic digestion is a process that is used at roughly 20% of these POTWs (EPA 2003a). Many of these facilities use their waste methane gas as a fuel to provide process heat for the anaerobic digesters, which are typically maintained at 95 degrees Fahrenheit; the rest is often flared. Few use the methane to generate electricity on-site. In fact, the possibility of using methane gas to produce electricity is mentioned only briefly in the Water Environment Federation (WEF) 2003 edition of Wastewater Treatment Plant Design, and then indicated only for "larger treatment plants." (Vesilind et al. 2003, 15-1)

[1] Prescriptive incentives are currently available to Vermont businesses from Efficiency Vermont for some lighting products, LED traffic signals, vending machine controllers, energy star transformers, some refrigeration equipment, premium efficient motors, and "tier 2" air conditioning units.

[2] The by-products of methane combustion are carbon dioxide and water. Although carbon dioxide is also a greenhouse gas, it is 20 times less effective at trapping heat than methane.

Methane is a renewable energy source, specifically, a biofuel. As a fuel, methane contains approximately half the energy content of natural gas on a per unit basis. That is, a cubic foot of waste methane gas typically has 500-600 British Thermal Units (Btu), whereas a cubic foot of natural gas contains 1,000-1,100 Btu.

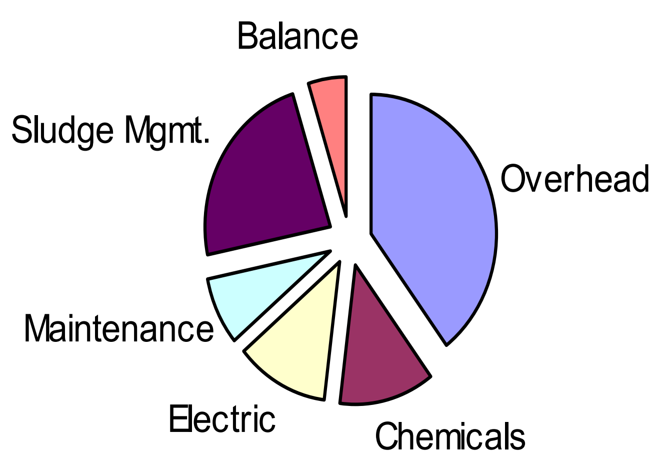
Essex Junction Wastewater Facility Background

The Village of Essex Junction upgraded its Wastewater Treatment Facility (WWTF) in 1985 to a secondary conventional activated sludge plant with advanced treatment using mesophilic anaerobic digestion. The Village constructed its new plant to serve a "tri-town" area in Vermont that includes the Village of Essex Junction, the Town of Essex, and the Town of Williston. The WWTF has a design flow of 3.3 million gallons per day (MGD) and an average flow of 2.0 MGD. Although a plant of this size is considered small by national standards, the Essex Junction WWTF is one of the ten largest municipal wastewater plants in the state of Vermont.

As a municipal wastewater facility, the Essex Junction WWTF is challenged to meet its budget needs without increasing tax rates or sewer rates. Building budget capacity when much of the WWTF's annual operating budget consists of fixed costs that escalate with inflation is a difficult objective, but one that the WWTF pursues vigorously. Of the WWTF's $750,000 annual operating budget, 90.5% is made up of only five categories.

Figure 1: Major Budget Categories for WWTF Annual Operating Budget

- Staffing /Overhead – 4 FTEs (37%)
- Sludge Management (23%)
- Chemicals (13%)
- Electricity (12.5%)
- Maintenance (5%)



Electric power demand for the WWTF is typically between 150-200kW, though it can be as high as 250kW. Electric usage is approximately 1,000,000 kWh each year, representing approximately $93,000 in annual electric utility costs. As with most municipalities, the WWTF is the most energy intensive facility it owns and operates.

The Essex Junction WWTF seeks continuous improvement in all aspects of its business. In 1985, the plant was upgraded to remove phosphorus to 0.8 mg/L and provide seasonal nitrification. A 1998 upgrade was to provide for flow equalization and reduce peak hydraulic demand on the affected treatment operations. This project was a funding priority to protect the water quality of Lake Champlain. Current work is focused on meeting new federal and state regulations regarding storm water collection and management. In addition to required process upgrades over the years, WWTF personnel were seeking energy conservation and efficiency projects to build budget capacity through reduced operating costs. As with most wastewater facilities, there are constant competing priorities for time and budget. By 2000, the WWTF was able to complete most of the energy efficiency recommendations made to the facility in a 1993 report, even while improving operations and treatment at the plant. Some examples of efficiency projects include

- T8 lighting upgrades
- Hot water management
- Load shifting
- Load shedding
- Aeration blower variable frequency drive (VFD)
- 3 Phase power conversion (VFD conversion from single phase to three phase power at point of application).

Now the challenge became – how to achieve more cost savings beyond standard efficiency measures?

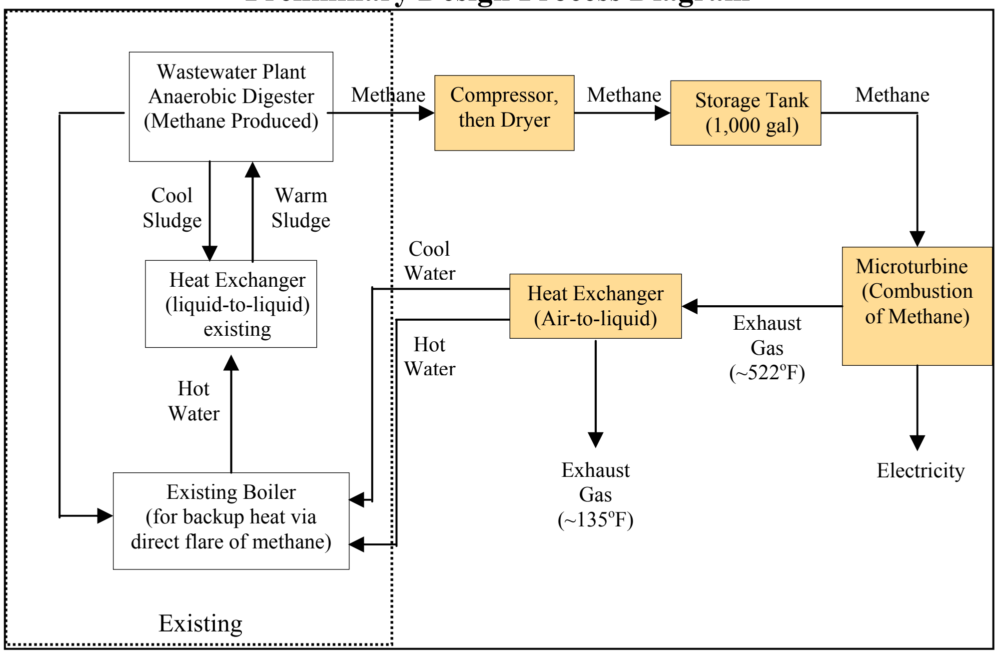
Making the Case for Co-Generation

Essex Junction WWTF personnel had been considering implementing a combined heat and power (CHP) system since 1992. Given the high initial capital cost, it simply wasn't deemed cost-effective for the Village to pursue CHP at that time. The sewer facility governing board has a requirement that any energy-saving/cost-saving proposal have a simple payback of no more than 7 years in order to proceed. Moreover, since the project would be expending taxpayer dollars, municipal decision makers had to feel confident that the project would deliver the estimated savings. On the whole, municipalities tend to be highly risk-averse when making project and budget decisions, as they have to defend their decisions to entire communities.

The Essex Junction WWTF used the waste methane gas to fire a boiler that provided process heat to the anaerobic digesters and flared any remaining methane. On an annual basis, only about 50% of the methane gas produced was utilized. Could the facility increase its overall efficiency by using more of its methane to generate power and heat, rather than flaring it as a waste? In order to estimate a payback period for the project, the Village of Essex Junction needed to know how much electricity generation they could achieve, given the facility's treatment flow, amount of methane produced, and need for digester process heat. When methane is used as fuel for a CHP project, an important consideration is whether the process heat available after combusting the methane will be sufficient to maintain digester temperatures. Given Vermont's cold climate, special attention had to be paid to the lower methane production rates in winter, coupled with the greater need for process heat in the winter.

The WWTF hired an engineer to perform initial design work, cost estimates, and feasibility analyses. One of the first questions to consider was what type of electric generator to use: engine, microturbine, fuel cell, etc. While engines were considered, the microturbine was a preferred alternative since municipal personnel wanted to be sure that emissions from any new system would be at least as "clean" as existed before installation of the system. The basic plan for the system was to combust collected methane in a microturbine to generate electricity. The waste heat from the combustion would then be used to provide process heat to the anaerobic digesters. The 18-year old dual-fuel boiler currently used for process heat would be kept as a backup heating source. Figure 2 shows the system process.

Figure 2: Essex Junction Methane-Fueled Cogeneration Preliminary Design Process Diagram



During initial investigations, it became clear that methane-fueled cogeneration at a facility the size of Essex Junction was not typical. In fact, no such system existed in New England. The closest, similar facility was in Lewiston, NY. During conversations with Lewiston plant personnel, and a site visit to the Lewiston facility, a variety of "lessons learned" were discussed and incorporated into initial design work. In particular, the issue of siloxanes was raised. Siloxanes are silica-based compounds, typically found in shampoo, which can glassify when subjected to high temperatures. Glassified materials can reduce the effectiveness of heat exchangers, and can create imbalance in microturbines, potentially causing failure. It was determined that a siloxane removal strategy would need to be part of any cogeneration system. As knowledge grew regarding all the required elements for a successful cogeneration project, the estimated initial capital cost grew. In order to meet the 7-year payback requirement from the water board, it became critical to identify additional funding sources and leverage outside resources. The local electric utility was supportive of the project since reduced demand from the WWTF would assist in a transmission and distribution (T&D) constrained area. Unfortunately, there was no funding available from them. Efficiency Vermont was able to commit funding to the project, and help with economic and savings analyses. Efficiency Vermont also helped to "spread the word" about the project, soliciting additional support for it. Ultimately, a project team was put together with 5 different funding sources; a creative solution that made this project a reality.

Project Design, Contractor Selection, and Construction

Preliminary design work was performed by a local engineer. The focus of the effort was to determine if implementation of CHP would be cost-effective for the WWTF, given the existing electric rate structure, capital costs, and the required maximum payback period. The initial basis of design included the following components:

- Two – 30 kW micro-turbines
- Continuous generation for 1 microturbine
- Additional peak shaving for 2nd microturbine
- Natural gas and methane blending option
- 3 Phase 480 volt generation
- Operate parallel to the utility, reduce purchased electricity
- UL 1741 protection for voltage & Grid

Although the municipality had completed initial design work, the RFP was structured to allow for alternate designs. It included a large amount of information for potential bidders in order to solicit the best possible performance and allowed a bidder to propose a system based on the preliminary design, or to propose an alternate design. The RFP was written such that the selected contractor would enter into a performance-based, design/build contract. In order to generate quality system designs, the following facility background information was provided in the RFP:

- The WWTF generates an average of 30,300 cu.ft./day of methane
- The facility's methane has a typical energy content of 520 btu/cu.ft.

Additional RFP content included system requirements and evaluation priorities.

- The system should emit no additional pollutants(i.e., SOx, NOx, methane) compared to the current practice of flaring methane
- The system must remove siloxanes to protect equipment operation and life (e.g., heat exchanger, microturbines)
- The electrical system interconnect must meet utility requirements and safety protocols (e.g., no power feed onto grid during power outages)
- Generated power must be line-synchronized with grid-supplied power to maintain power quality.
- The system must not exceed facility maximum allowed noise levels, based on nearby residences and neighborhood park.
- The system must be highly reliable and require minimal maintenance that can be performed by facility personnel at reasonable cost.
- The system must meet all relevant permit and other federal, state and local requirements

Bids came in more than $90,000 higher than expected (low bid cost of $275,000 v. estimated cost of $184,000). The higher initial cost meant that the project did not meet the sewer facility governing board 7-year payback requirement to move forward. Many projects may have simply been abandoned at this point. The key difference in the Essex Junction project is that project champions actively solicited additional financial support in order to make the project a reality. Efficiency Vermont increased its incentive offer from $25,000 to $40,000. Other key contributors also stepped forward. The Vermont-based Biomass Energy Resource Center (BERC) committed $25,000 toward the project. Another Vermont-based organization, NativeEnergy offered $10,000 toward the carbon credits that would be created from the project as a result of onsite generation and the reduction in demand for power plant generation. The Department of Energy, Region 1 provided $5,000 toward the project to assure data collection and dissemination, so that other facilities could benefit from the knowledge gained from the Essex Junction experience. And negotiations with the low bidder, Vermont-based company Northern Power Systems, provided important technical insight to optimize system performance while containing costs. Without the financial support and personal dedication of all of these organizations, and especially the commitment of Essex Junction personnel, the WWTF's methane-fueled cogeneration system would not have materialized.

The final, installed system is based on a design/build approach with performance standards and includes the following characteristics.

- 480 Volt – 3 Phase Power
- 3% Maximum Voltage Distortion
- 5% Maximum Harmonics Distortion, and compliance with IEEE 519-1992
- Full compliance with IEEE interconnect standards
- Dual-fuel microturbines (with natural gas/methane blending capability)

Start-Up and Ongoing Operations

Project start up included several activities prior to "going live" with the system. The local electric utility was subcontracted to perform the electrical installation. This ensured that all utility requirements were met during the installation. An area of some difficulty was enabling a smooth transition from methane-fueled cogeneration to natural gas-fueled cogeneration and back again. Although a dual fuel microturbine was specified, the actual control and sequencing of switching from one fuel source to another was not a trivial matter. Contractor personnel ultimately developed a successful proprietary protocol that provided methane/natural gas blending during transitions from one fuel to the other without fuel fault to the generators. Another activity included the need to update the supervisory control and data acquisition (SCADA) system with new screen views and monitoring/control capabilities. Computer programming was necessary to integrate the monitor and control functions with the actual equipment. Recent condensation and cooling work has built on initial system, pre-compression moisture removal capabilities.

Preliminary design work estimated that the level of methane generated at the WWTF would be sufficient to operate two 30kW microturbines an average of approximately 40 total hours each day. Since installation of the system in October 2003, there has been sufficient methane generation to run the two microturbines 48 total hours each day. One reason for consistently high methane production is that, prior to the cogeneration installation, the WWTF had its two anaerobic digesters cleaned to ensure proper process heating and to maximize methane gas generation. These extra 8 hours of run time each day represent more than 80,000 kWh of electricity each year. And now that methane is a valuable energy resource for the WWTF, it is monitored and managed more carefully than when it was simply a waste by-product. In addition, the WWTF has also now installed two utility-grade sub-meters to more definitively document the net power generation and net purchased power.

Results

To date, all aspects of the cogeneration system have operated as well or better than anticipated, with the exception of the methane compressors (These are the compressors that raise the 0.5 pounds per square inch (psi) methane to 100 psi prior to drying and combustion in the microturbines.). Over the first year of operation, the system achieved 90% reliability. While actual maintenance costs for the siloxane removal system (filter media, etc.) are lower than anticipated, the compressor maintenance cost is presently anticipated to be higher. The presence of moisture in the compressors has been the single largest reason for equipment downtime and failure to date. An effective strategy for moisture removal from methane and keeping moisture out of the methane compressors is key to successful system operation and maximizing system run time. When a compressor is not working, the down time has a direct impact on the daily electrical generation and subsequent facility cost savings. Table 1 provides information on the power demand from the electric utility after startup of the 60kW of microturbines. One item of interest is that the facility power factor decreased since installation of the microturbines. Facility personnel are working to pinpoint the cause and ensure that plant-wide power factors remain above 90% to avoid power factor penalty fees from the electric utility. Table 2 compares pre-installation cost estimates and post-installation actual costs.

Table 1: Facility Power Information Before and After System Installation

	Before (Oct 2002 – Sept 2003)	After (Oct 2003 – Sept 2004)
On Peak Demand	134-235 kW	118-215 kW[3]
Off Peak Demand	130-226 kW	94-226 kW[4]
Monthly Avg. Usage	166,000 kWh	64,000 kWh
Power Factor	90	89

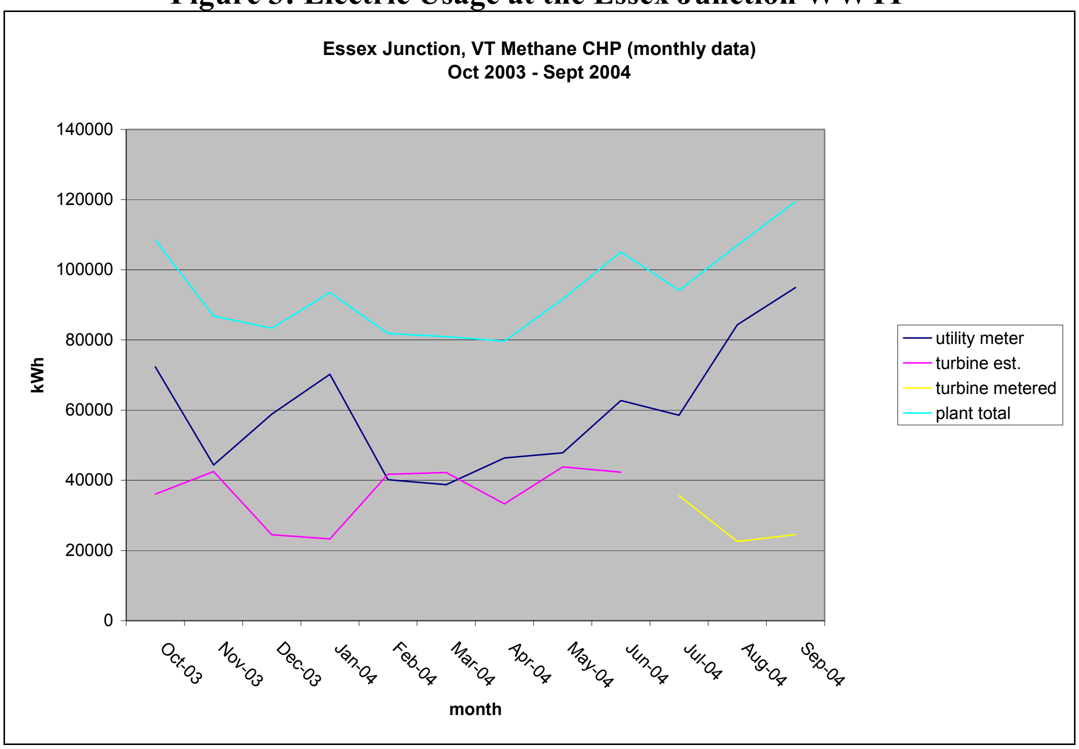
[3] Oct 2003 value is 215 kW. With out start up month 203 kW is maximum
[4] Oct 2003 value is 226 kW. With out start up month 190 kW is maximum

Table 2: Estimated and Actual Project Payback Analysis

	Pre-Construction (estimates)	Post-Construction (actuals)
System capital cost	$184,000	$303,000
Incentives	$25,000	$80,000
Net customer cost	$159,000	$223,000
Electric generation	396,000 kWh/yr	480,000 kWh/yr
Electric cost savings	$26,600/yr[5]	$44,000/yr[6]
Maintenance costs	$3,700/yr	$4,000/yr
Net annual savings	$22,900	$44,000
Payback without incentives	8.0 yrs	5.6 yrs
Payback with incentives	6.9 yrs	3.6 yrs

Figure 3 illustrates the amount of on-site electrical generation compared to purchased electricity at the WWTF.

Figure 3: Electric Usage at the Essex Junction WWTF



[5] Demand rate savings were not included in original estimates to be conservative
[6] Actual blended rate of electricity Oct 2003-Sept 2004 $0.09/kWh

Recommendations to Other Facilities

For those facilities that may be interested in implementing a CHP project, there are several things to keep in mind while designing and installing a system. The first step is to talk with others who are involved in CHP operations. Their experiences and lessons learned can prove vital for project success. They can also provide input on whether you should pursue a performance-based, design/build project, or cost plus materials for installation of an engineered system. For those who use a design/build request for proposals (RFP) based on performance requirements, it is important to specify the outcomes you require and provide potential bidders data to use for design purposes. For instance, the chemical composition of the methane gas should be analyzed, including Btu content, chemical content, and moisture content, and this information should be provided with the RFP. Assumptions should be stated regarding methane production rates, weather/temperature conditions, indoor v. outdoor siting (and/or maximum noise levels), historical electric kWh and kW quantities, electric rate structure, interconnect requirements, permit requirements, and power quality requirements. When evaluating bid proposals, include a knowledgeable engineer on the review team to assist in "fatal flaw analysis," so that significant issues or omissions can be caught as early as possible. The RFP should also require that the following items are clearly identified for proposed systems.

- Process for siloxane removal from methane
- Process for moisture removal from methane
- Life expectancy of compressors and microturbines
- Warrantees and service obligations/protocols
- Dual-fuel capability (methane and natural gas), including blending options
- Total kWh generated, parasitic loads, net kWh generation
- Sequencing strategy (e.g., base load constant operation, peak shaving, etc.)
- Equipment efficiency and total system efficiency
- Anticipated maintenance and related costs
- Emissions/ air quality
- Material costs associated with backup (i.e., spare) equipment to be kept on hand (e.g., extra compressor)

Beyond technical considerations, probably the most important requirement is to have project "champions" that will advocate for the project throughout the many obstacles that are sure to arise. The Essex Junction project had many! Without champions who are committed to overcome implementation barriers, many projects that are cost-effective will not secure funding, community support, and decision-maker approval.

Conclusions

The Essex Junction WWTF's methane-fueled microturbine CHP installation was presented with a 2003 Vermont Governor's Award for Environmental Excellence and Pollution Prevention. These awards are given for projects that reduce or eliminate the generation of pollutants and wastes at the source. Selection criteria include benefits to the environment, use of innovative approaches, economic efficiency, and the ability of an activity to serve as a model for other efforts. Awardees were recognized as having "chosen to see the world of possibilities and achieved excellence in pursuit of a preferred future."

The project is noteworthy and successful for numerous reasons.

- The facility now uses nearly 100% of a former "waste" as fuel. This waste was only about 50% utilized before.
- The Essex Junction community is now using a renewable energy source to reduce costs and prevent pollution.
- A small, rural municipality has been able to implement innovative microturbine technology while maintaining community confidence and rate stability.
- Implementation of distributed generation reduces power demand and helps ensure power availability in a local electric utility T&D constrained area.
- The facility, and its ratepayers, are saving 40% off their electric bills each year.
- Many other wastewater facilities can install similar systems and achieve similar results.

Of the 16,000 POTWs in the country, approximately 20% of these facilities use anaerobic digestion, and roughly 1,100 use anaerobic digestion and have average flows of 2 MGD or more. In addition to POTWs, there are also industrial and private wastewater facilities for which CHP would be applicable and cost-effective. By recognizing that methane-fueled microturbines can be cost-effective at small, rural wastewater plants, and not just larger facilities, an entire new segment of the wastewater market is now open to distributed generation opportunities. For efficiency organizations, and other potential funding sources, this is what you can do to facilitate implementation of wastewater CHP projects. Show that it's been done before to reduce the perception of taxpayer risk. Understand the economic requirements of your customer (e.g., payback requirements, ROI requirements, etc.). Provide funding when possible. Help the facility find other funding sources. Spread the news to generate support and excitement for the project. Let others know about your experience. The technology continues to improve, the costs continue to come down, and methane can mean money for wastewater facilities.

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