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March 23, 2012

Mr. Mark Ritter
RDF Grant Administrator
Xcel Energy, Inc.
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

Dear Mr. Ritter:

Subject: Milestone 12 Final Report Entitled "Integrated Gas Turbine–Gasifier Pilot-Scale Power Plant"; Contract No. RD3-71; EERC Fund 15625

Enclosed please find the Milestone 12 and final report for the RD3-71 Program. The report summarizes the overall program and includes discussions of overall project outcomes and how well they met the expectations at the beginning of the project, lessons learned, and the value of this work for Xcel ratepayers.

If you have any questions, please contact me by phone at (701) 777-5243 or by e-mail at bfolkedahl@undeerc.org. Thank you.

Sincerely,

Bruce C. Folkedahl
Senior Research Manager

BCF/cs

Enclosure

Energy & Environmental Research Center, University of North Dakota
15 North 23rd Street, Stop 9018, Grand Forks, ND 58202-9018

Project Title: Integrated Gas Turbine–Gasifier Pilot-Scale Power Plant

Contract Number: RD3-71 Milestone Number: 12 Report Date: December 30, 2011

Principal Investigator: Bruce Folkedahl Contract Contact: Corey Irion

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Congressional District: Not Applicable

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FINAL REPORT

Project funding was provided by customers of Xcel Energy through a grant from the Renewable Development Fund.

Executive Summary: Waste biomass and opportunity fuels represent an enormous unutilized biomass resource for electricity production. Studies have shown that up to 600 million tons of waste biomass is produced each year in the United States. This represents a potential renewable electricity resource of up to 120 GWe. Much of this is currently unutilized because of its distributed nature and low energy density. Conventional power production technology is not cost-effective for power systems below 10 MW, and the low energy density of the biomass makes it cost-prohibitive to transport it to a centralized power station. The solution for greater biomass utilization is to develop an economical power system in the size range typically associated with distributed biomass resources and opportunity fuels.

The goal of this project was to combine a distributed-scale biomass gasification system with a novel low-Btu turbine to utilize the produced syngas from the gasifier in an integrated fashion providing a unique small-scale electrical generation system capable of taking advantage of the untapped sources of biomass. Such a technology could be a paradigm shift in engineering from larger-scale fossil fuel-powered electricity with a broad regional grid connection to smaller renewable distributed power that is connected to a smaller grid array or microgrid.

In a conventional system, syngas from a gasifier must be cleaned of particulates and acid gases and compressed to high pressure to inject into the combustor. The compressor cannot handle hot input gases, requiring cooling of the syngas before compression. This, in turn, requires extensive syngas-scrubbing systems between the gasifier and compressor. The capital and operating costs of the syngas-scrubbing system in this type of design may exceed those of the gasifier and gas turbine, making this system uneconomical for distributed power production.

To overcome these issues, the Energy & Environmental Research Center (EERC) system was designed to employ an indirectly heated gas turbine. Hot syngas is fed to an atmospheric combustor which then heats high-temperature air through a high-temperature heat exchanger. The high-temperature heat exchanger is designed to reduce gas temperatures to an acceptable

level for the stock recuperator. For the C30 microturbine, the stock recuperator requires an input temperature below 650°C (1202°F). Since the syngas never contacts the high-speed turbine, particulate cleanup requirements are greatly reduced. The external compressor is eliminated, and the need to cool the syngas below the condensation temperature of tars is also eliminated. This eliminates tar fouling in the pipes and greatly reduces the particulate cleanup requirements.

The specific objectives of the project were as follows:

- Produce and demonstrate a power system designed specifically to economically exploit renewable biomass resources and opportunity fuels within the Xcel Energy service territory.

- Take two complementary enabling EERC–Xcel Energy technologies for biomass power from the bench scale to the final stage of development and testing, just prior to field testing.

- Demonstrate the marketability and application of a distributed biomass power system.

All of these objectives were met within the context of research and development, and the project has exacted many benefits and advances to the fledgling small renewable power industry in the Xcel Energy service territory, including the following:

- A fixed-bed biomass gasification system about the size of a small backyard storage shed was designed, built, and made to operate with only two operators. The system's feed rate of a few tons a day of biomass was an excellent fit for the common, relatively small quantities of biomass or organic waste residues regionally, as is the case for the Xcel Energy power distribution territory. Biomass of this nature, such as tree trimmings, is often considered waste. The gasifier of this research project can consume biomass as fuel, eliminating the economic and environmental cost of landfilling many types of biomass. Landfill decay of biomass releases methane, which has more severe deleterious greenhouse gas impacts than do the emissions of a gasifier–turbine system.

- The gasifier operated successfully on nine different fuel feedstocks, including wood pellets, pressed wood cubes, wood chips, coal, coal–wood chip mixtures, mulch, sawdust, switchgrass, charcoal, meat and bone meal, and fish-rendering waste. In addition, several mixtures of these different fuels were tested. This activity is a testament to the versatility of the system.

- Solid biomass materials were successfully converted to synthetic gas or syngas during steady-state gasification, producing a low-tar (less than 200 ppm) syngas with a heating value of 120–140 Btu/scfm. While some fuels are easier to handle, such as wood pellets, in general, all of the fuels produced an acceptable-quality gas, and the system was able to operate at a steady state.

- The turbine system was successfully operated in an integrated fashion with the gasifier. Gasification producer gas was introduced and burned in a uniquely modified Capstone

C10 turbine resulting in renewable electricity production—a great innovative stride for integrated gasifier–turbine technology. The system was not without flaws, however, in that the Capstone C10 turbine operated at only about 14% of rated power output. This was due primarily to limitations related to system control software, with secondary limitations attributed to turbine design and performance. The research goal was to operate the modified turbine on syngas, and this goal was achieved at a power output of 5 kW. The ideal goal was to produce up to 30 kW of power, and this goal was not met, but operation of an integrated gasifier–turbine was achieved nonetheless.

- The performance of biomass syngas burning in a modified gas turbine to produce a few thousand watts of electricity in an integrated assembly validates the potential of an indirectly fired biomass gasifier–gas turbine system operating on a synthetic low-Btu gas. This accomplishment is a great success and brings an integrated gasifier–turbine system concept closer to reality and eventual investment for commercialization. Current conventional small gasification systems and microturbines have not been able to achieve the results of the EERC system. Typical distributed-scale air-blown gasifiers on the market today produce tar levels above 3000 ppm and with Btu levels usually less than 110 Btu/scfm. Small gas turbines in the range of 30–60 kW at the time of this study were commercial systems, but they could only operate on high-energy pipeline-quality natural gas. An innovative fixed-bed biomass gasification system rated at about 150 kWth (70–100 lb/hr biomass fuel) was integrated with a 30-kW microturbine and operated successfully on several types of biomass fuel. Although the highest performance targets were not achieved on the turbine side of the integrated system, this innovative renewable power plant was nonetheless a success.

- The work accomplished and information generated show that the system has great future commercial market potential. Research and development garnered through this project reveals that further engineering improvements will be necessary before accurate commercial market assessments can be made and commercial ventures developed. Briefly, the gasifier system requires automation in fuel feeding and char removal and improvements in emission control. The turbine system requires improved combustion control and heat exchange optimization. These and other minor adjustments and improvements need to be realized before market-based cost and performance targets can be met. Still, the integrated system holds great hope for distributed power in a commercial package in future developments.

Technical Progress: During this performance period, the EERC completed analysis of the data collected during the testing of the integrated gasifier–modified turbine system and reported all results and system assessments. Quantification of the performance of the gasifier and the turbine are discussed as follows.

Quantification of Gasifier Performance: Testing of the gasification system was performed over the course of several weeks from February 2009 through July 2011. Total run time with nine different fuels was greater than 144 hours. This run time does not include system and fuel preparation, system warm-up, system cooldown, and system cleaning and servicing. Fuels tested included wood pellets, pressed wood cubes, wood chips, coal, coal–wood chip mixtures, mulch, sawdust, switchgrass, charcoal, meat and bone meal, and fish-rendering waste. During gasification testing, it was found that steady-state conditions were achieved with feed rates of 70–80 pounds an hour and air injection rates of 1700 to 2100 scfh. Under these conditions, solid conversion efficiency varied between 60% and 89%, with typical conversion being 80%; i.e., for every 100 lb of fuel fed, 80 lb was converted to a combustible syngas, with the remaining 20 lb exiting as biochar and system heat losses.

During testing, syngas composition was monitored using a continuous emission monitor for five gases: hydrogen, carbon monoxide, carbon dioxide, oxygen, and methane. These five gases indicate the quality of the syngas and, based on their variation, can indicate what is occurring in the gasifier. Additionally, once steady-state conditions were achieved, a gas sample was collected and analyzed with a gas chromatograph, quantifying 23 separate gases and calculating a heat of combustion for the composite. In multiple tests, the syngas produced had an energy content between 105 and 196 Btu/scf. Table 1 shows a typical gas composition produced by the gasifier. For comparative purposes, Table 2 shows the composition of natural gas in various markets across the United States. In the syngas, the heat content is contained in the carbon monoxide, hydrogen, methane, ethane, propane, propylene, and acetylene, which have a much smaller volume per standard cubic foot when compared to the natural gas. Natural gas will average a heat content of approximately 1000 Btu/scfm, whereas the syngas produced during this project averaged about 137 Btu/scf. This required modification of the turbine's heat exchange system to utilize the much greater volume of syngas but obtain the same result.

The goal of the gasifier development phase of this project was to design and construct a gasifier that could integrate with and run a Capstone C30 microturbine. The C30 is a 30-kW unit, with 25% conversion efficiency as specified by the manufacturer, which dictates 120 kW of total energy input to operate. If the average steady-state operational conditions of the gasifier are examined, typically 70 lb/hr of feed with 2000 scfh of air resulted in 80% solid conversion and produced a syngas with, on average, 137 Btu/scf. This condition combines to yield a system capable of producing 119.3 kW from the heat of combustion of the syngas, which is sufficient to operate the turbine.

Over the course of testing the gasifier, the unit produced syngas with a heat content of 94.7 kW for extremely wet biomass (>40 wt% moisture content) and as high as 145.3 kW for fairly dry (<10 wt% moisture content) fuel. This range represented the total thermal energy available at standard temperature and pressure (STP). However, the integration process was designed specifically to close-couple the gasifier with the turbine, allowing for hot gas to be fed into the turbine. By doing this, issues related to condensation of high-molecular-weight hydrocarbons (tar) are eliminated and the thermal energy of the gas, because of its elevated temperature, can also be utilized in the generator. During testing, syngas typically reached the turbine feed at nearly 800°F. This is 723°F above STP. By taking the specific heat of the gas (0.63 Btu/scf) and multiplying it by the difference between STP and delivery temperature, an additional 17.9 kW of thermal energy is potentially available. The sum of syngas heat of combustion and the thermal energy result in a gasification system with total production potential of 112.6 to 163.2 kW, depending on the quality of the fuel being gasified.

Table 1. Syngas Composition and Heat Content Gasifying Wood Pellets

Sample	mol%	Normal mol%	Ideal Btu	Specific Gravity	Compress.	Avg. mol wt%
Helium		0.0000	0.00	0.00	0.00	0.00
Hydrogen	5.2248	5.2688	17.12	0.00	0.00	0.11
Carbon Dioxide	5.1904	5.2341	0.00	0.08	0.00	2.30
Propane	4.2231	4.2587	107.45	0.06	0.01	1.88
Propylene	0.0016	0.0016	0.04	0.00	0.00	0.00
Acetylene	0.0033	0.0033	0.05	0.00	0.00	0.00
Isobutane		0.0000	0.00	0.00	0.00	0.00
Carbonyl Sulfide		0.0000	0.00	0.00	0.00	0.00
n-Butane		0.0000	0.00	0.00	0.00	0.00
Hydrogen Sulfide		0.0000	0.00	0.00	0.00	0.00
1-Butene		0.0000	0.00	0.00	0.00	0.00
Isobutylene		0.0000	0.00	0.00	0.00	0.00
t-2-Butene		0.0000	0.00	0.00	0.00	0.00
Isopentane		0.0000	0.00	0.00	0.00	0.00
c-2-Butene		0.0000	0.00	0.00	0.00	0.00
n-Pentane		0.0000	0.00	0.00	0.00	0.00
1,3-Butadiene		0.0000	0.00	0.00	0.00	0.00
Ethylene	0.2407	0.2427	3.89	0.00	0.00	0.07
Ethane	0.1562	0.1575	2.79	0.00	0.00	0.05
Oxygen/Argon	1.1702	1.1801	0.00	0.01	0.00	0.38
Nitrogen	64.2642	64.8053	0.00	0.63	0.01	18.15
Methane	1.0016	1.0100	10.22	0.01	0.00	0.16
Carbon Monoxide	17.6890	17.8379	57.31	0.17	0.00	5.00
Total	99.1651 0.9917	100.0000	198.87	0.97	0.02	28.09

K = 0.00
L = 0.00
M = 0.11 M1 = 0.00 M2 = 0.00
Z = 1.00

Real Btu (saturated)	195.54
Real Btu (dry)	199.00
Ideal Specific Gravity	0.97
Real Specific Gravity	0.97
Average mol wt	28.09

During testing of the system with multiple fuels, a set of operating parameters such as fuel feed rate, airflow, gas temperature in various gasifier zones, gas composition exiting the gasifier, and other parameters were measured and tracked. Using this information, engineers and operators were able to establish a set of optimal operating conditions and procedures to achieve steady-state gasification. During all gasifier tests, the parameters found to be most critical for steady-state operation were the temperatures within the gasifier.

Table 2. Typical Composition of Natural Gas, mol%

Source	Methane	Ethane	Propane	Butane	Nitrogen
Alaska	99.72	0.06	0.0005	0.0005	0.20
Algeria	86.98	9.35	2.33	0.63	0.71
Baltimore Gas and Electric	93.32	4.65	0.84	0.18	1.01
New York City	98.00	1.40	0.40	0.10	0.10
San Diego Gas & Electric	92.00	6.00	1.00	–	1.00

Source: *Liquid Methane Fuel Characterization and Safety Assessment Report;* Cryogenic Fuels Inc. Report No. CFI-1600; Dec 1991.

Figure 1 shows a typical operational thermal profile for the gasifier from start-up through achievement of steady state. Based on experience gained over the project and knowledge gained through operating other EERC gasification systems, steady-state operation is reached when all temperatures in the system, excluding fuel feed temperature, are greater than 800°F. Once this temperature is reached, sufficient heat is generated to sustain the gasification reaction and produce syngas with the desired composition consisting of major amounts of H_2, CO, and CO_2 with minor amounts of methane and water and minor amounts of hydrocarbon tars, sulfur compounds, and trace metals. The system was found to operate best when temperatures were maintained between 800° and 1500°F at any point within the system. Temperatures in excess of 1500°F were usually indicative of combustion occurring, rather than gasification, as was also indicated by increased CO_2 in the syngas. When this occurred, action was taken to decrease the air-to-fuel ratio through increasing fuel injection or decreasing air input.

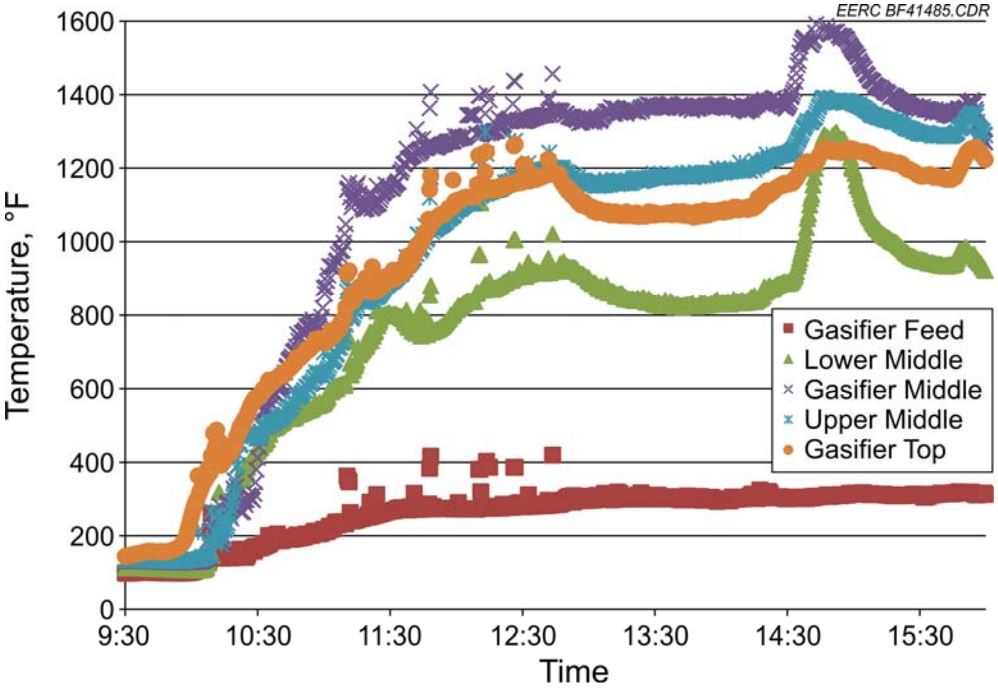


Figure 1. Typical gasifier thermal profile.

Quantification of Turbine Performance: The turbine was fired with natural gas multiple times on 19 separate days from October of 2010 to July of 2011 to shake down the system and test the efficacy of the modified heat exchanger. Because of an inability to modify Capstone's control software, testing of the system on natural gas was done in an attempt to find the optimum location for the system's control thermocouple which feeds into the turbine's control software. The majority of these tests were for short periods of time because, as previously reported, the proprietary software utilized by the turbine proved problematic for this endeavor. In addition to the inability to modify the system code, the turbine programming was extremely stringent in how it operated. If any of over 100 variables deviated from the programming's expected value, the turbine would shut down. For example, if temperature rise at start-up did not occur within 30 seconds, the turbine would shut down. If rpm deviated or pressure, etc., deviated, it would also shut down. Based on these findings, it was decided early on that in order to succeed in the integration process, modification and testing would have to ensure that all standard operating conditions were mimicked as closely as possible. Of all variables examined, temperature was the most difficult to mimic. This was due to differences in how the syngas flame burned within the reactor vessel compared to natural gas. Flame length and the stability of the flame were vastly different between the syngas and natural gas. To achieve values within acceptable parameters, experimental measurement throughout the system over time was conducted until the optimal location was identified for thermocouple placement to allow the software to identify the required heat rates.

To quantify the optimal placement points for the temperature input, a multipoint thermocouple was inserted during shakedown to measure the thermal profile across the newly installed heat exchanger. The purpose of this measurement was to not only identify the new turbine exit temperature (TET) location but to determine if this location might vary depending on the shortening or lengthening of the flame or versus variability caused by the new heat exchanger. Choosing an optimal location was critical to achieving acceptable operation. To achieve this requirement, monitoring and measurement of the multipoint thermocouple was done using an external software package from Omega Engineering called TRH Central. Using this external data acquisition package, a thermal profile across the heat exchanger was collected. Figure 2 illustrates this profile while the turbine system was operating on natural gas. Because of the configuration of the turbine–gasifier, this information was not collected during the integrated test run.

The thermal profile of the heat exchanger in the turbine system is shown in Figure 2. Starting at 10:15, the unit was ignited and began to heat. Because of the thermal mass of the unit, multiple attempts were required to induce enough of a temperature gain within the system to force the C30 to enter cooldown mode. This occurred at approximately 10:35. At this time, two short cooldown test periods occurred from roughly 10:35 to 11:10. Also seen in the figure is the TET, which was recorded by the internal software of the C30 turbine system. Because of the continued communication issues experienced with the system, this information was only recorded for the last 10–15 minutes of the test.

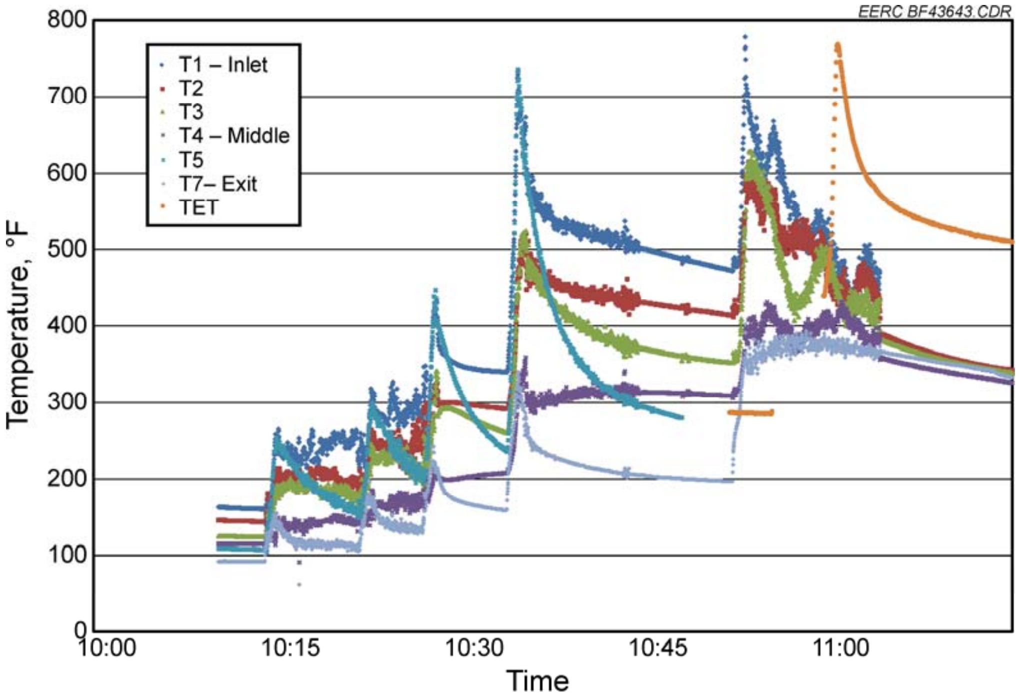


Figure 2. Thermal profile across modified heat exchanger on natural gas.

Based on how the multipoint thermocouple reacted, a point approximately ⅔ of the way from the combustor to the end of the heat exchanger was decided to be the optimal point at which to connect the turbine's input. At any distance closer, the thermocouple would have experienced direct flame impingement. This pushed temperatures rapidly above 1350°F, which triggered internal safeties and forced shutdown. Beyond this impingement point, two points were found to be within an acceptable range, followed by the farthest point found outside the acceptable temperature range. At this point farthest from the combustor point, turbulence near the end of the exchanger caused the temperature to occasionally experience rapid changes, which caused the turbine to shut down.

This profile shows significantly different variability than that of the original system. Figure 3 shows a thermal profile for the original turbine operating on sour gas at 15 and 30 kW. The most important information that this trend illustrates is the 1100° and 1200°F control temperatures and the minimal variability of these temperatures once the system is running. As is evident from the figure, during normal operation, temperatures have minimal variability and raise and lower nearly instantly as power demand changes. This is significantly different from the final system configuration, which shows very slow changes in temperature resulting from the thermal mass of the new heat exchanger.

As previously addressed, additional challenges were encountered with communication between the turbine software and the data-recording system on a laptop computer. Capstone technical support diagnosed the issue several times through remote communications analysis using the

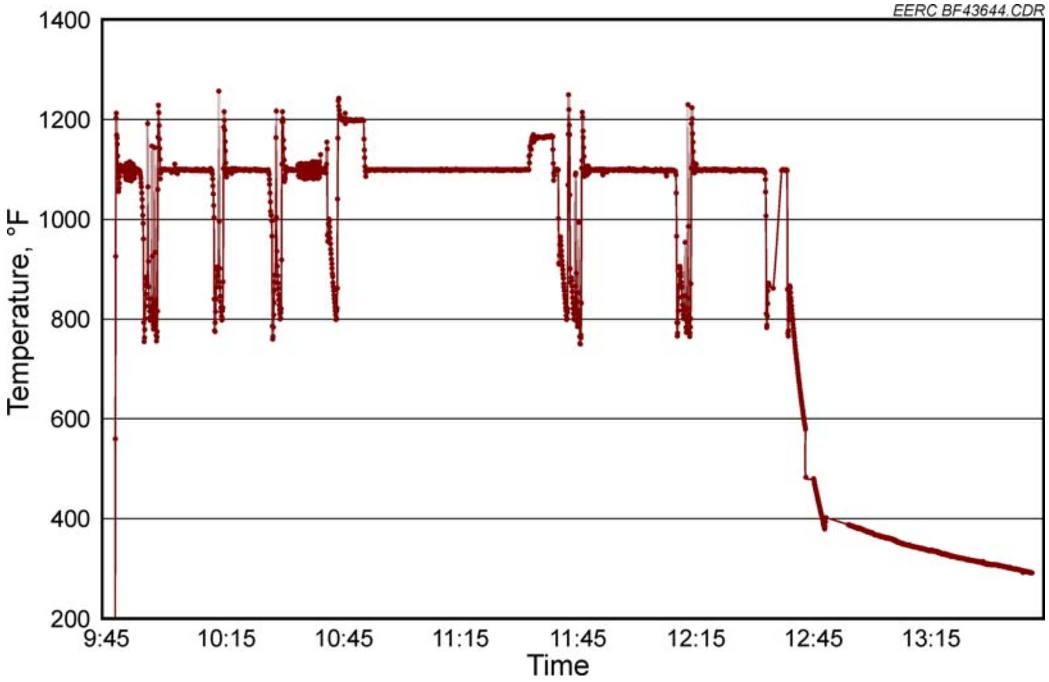


Figure 3. C30 TET operation on sour gas at 15 and 30 kW.

Internet. These sessions resulted in Capstone directing the EERC to purchase new communication boards several times. This change forced a long session of reloading turbine programming and, each time, failed to correct the issue. In the final days of the project, a novel approach was suggested by the network staff, and a laptop computer with an RS-232 connection was attached to the communication board–transmitter interface. This allowed for the collection of some data near the end of project, but data were not collected for all turbine testing. Figure 4 illustrates the erratic nature of data collection prior to the fix.

In Figure 4, approximately 20 attempts to start the system over 2 hours can be observed. Each peak is the system drawing power in order to initiate the turbine rotation. As the distance between points indicates, the data were intermittently collected because of faulty communication between the turbine software and the data-recording system. Another important factor that Figure 4 illustrates is that the intermittent data cause important information to be missed. During start-up, the turbine draws 9800 watts in order to initiate rotation prior to adding fuel. In Figure 4, the data never have a chance to record this information, thus misleading the user into believing peak power usage is closer to 6200 watts.

Having corrected the communication problems, the final experiment conducted involved the integration of the gasifier with the C30 turbine. Integration required several modifications to the original test plan. Concurrent with troubleshooting the turbine operational parameters and locating the optimal data measurement positions, developmental testing leading up to integration determined that because of Capstone's software, there was no feasible way for the EERC to facilitate operation under normal firing conditions. To overcome this issue and achieve project goals, a system state called "cooldown" mode was identified in the turbine software system operational modes that would allow limited operation. This mode is designed to allow the turbine

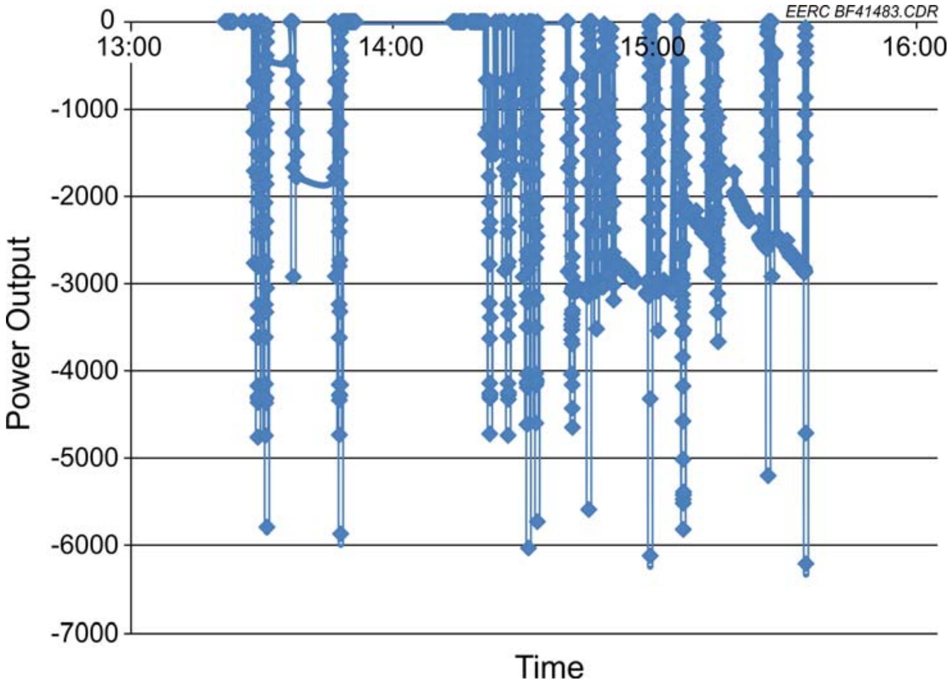


Figure 4. Example of repeated attempts to start the turbine system.

to cool appropriately after having been run at standard elevated temperatures. In cooldown mode, the microturbine ramps up to 45,000 rpm by drawing electricity from external sources while shutting off the fuel input. This increases airflow through the turbine until the combustor is cooled below 190°C (374°F). It was determined that by externally controlled input of natural gas and syngas, turbine operation up to the steady-state operating temperature of 900°C (1652°F) in the combustor could be maintained. Under this mode, the following achievements occurred:

1. Obtained steady-state operating temperatures.
2. Obtained self-sustained operation on 100% syngas.
3. Verified ability to control turbine temperature.
4. Produced some shaft work, albeit much lower than during normal operation.

As this fuel entered the turbine and was combusted, heat transferred through the modified heat exchanger and steady state was achieved. Simultaneously, the power being drawn from the grid, the 9800 watts drawn from external sources to power the turbine at the 45,000 rpm specified for this mode of operation, was gradually reduced. It was determined at this stage of the project that full integration of the turbine with the gasifier would need to be accomplished by operating the turbine with the modified heat exchanger and running the system in cooldown mode.

Quantification of Integrated Gasifier Turbine System: Having determined that the turbine and modified heat exchanger could be operated in cooldown mode, the turbine and gasifier were integrated into one complete system in a full simulation of biomass to renewable electricity on the grid. The test of the integrated system consisted of a full day of operation. Up to this point, both systems had previously undergone multiple days of testing, but as stand-alone units.

The integrated system began with the gasifier being started up on wood pellets. This material was used because of its availability, consistency of chemical and physical properties, and the ease with which it could be fed into the gasifier. Once the gasifier reached steady state, the turbine was slowly heated to approximately 1200°F using natural gas. After reaching the desired temperature in the turbine, the fuel bypass valve was opened and syngas flowed into the turbine. Figure 5 illustrates the thermal profile achieved during the integration process for the gasifier.

As Figure 5 shows, during integration with the turbine, the temperature within the gasifier started to drop shortly after coupling because of a brief misadjustment in airflow to the gasifier unit. Lower airflow resulted in less partial combustion of the fuel in the gasifier and, in turn, a reduction in overall gasifier temperature. With target temperatures being 1200°–1400°F, syngas composition can fluctuate. However, this lower temperature was still within the acceptable range. Airflows were corrected, and the test continued.

Upon initiation of cooldown mode for the turbine, as previously stated, the turbine began to draw 9800 watts of electricity from external sources. Figure 6 illustrates a period from start-up through shutdown during the integration test.

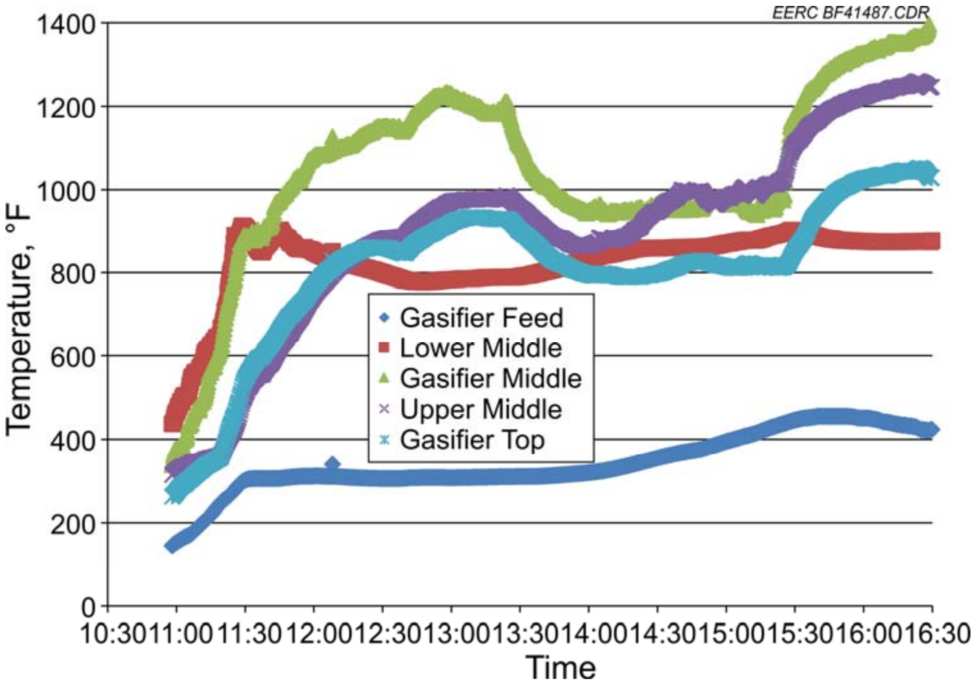


Figure 5. Example of the thermal profile across the gasifier during integration testing.

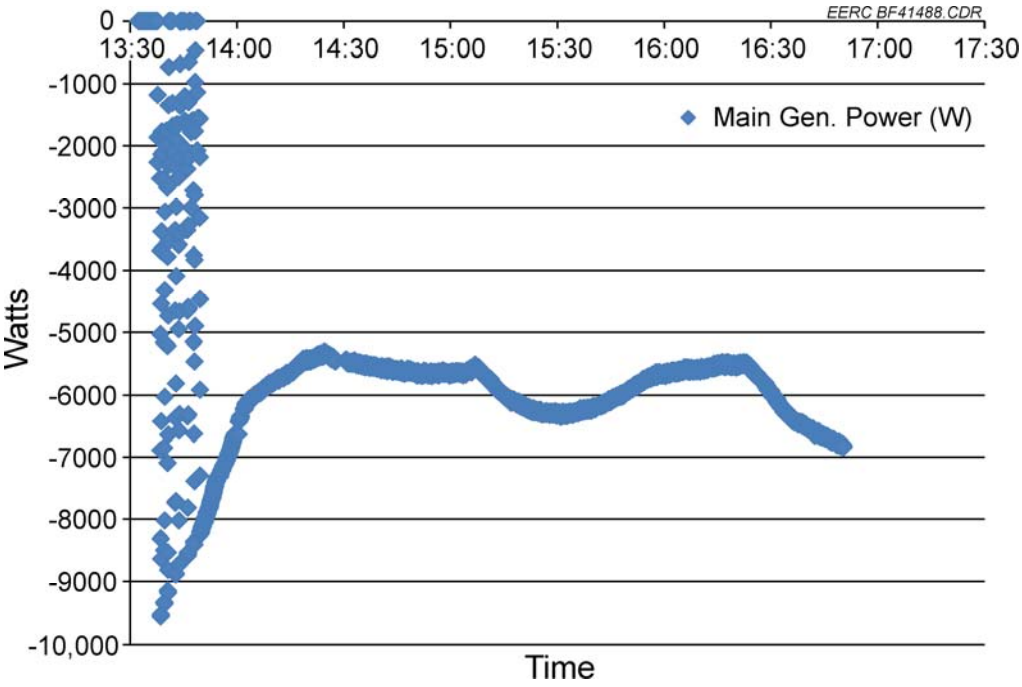


Figure 6. Example of power use and production by syngas combustion in the turbine.

Examination of Figure 6 shows that, initially, the turbine drew the expected 9800 watts. As the syngas entered the system, power began to be generated by the combustion of the syngas, offsetting the turbine's power requirement to maintain 48,000 rpm. Looking closely at the figure, the data show that over approximately 45 minutes, the system reduced its power consumption and then operated at an average of about 6000 watts of consumption. This indicates that during this integrated test period, the turbine was able to generate power from syngas combustion. If this change in power draw is normalized, with 9800 watts being zero, then the power production over the test can be observed. Figure 7 shows the resulting power based on the normalized data.

Examination of Figure 7 shows that during the integration testing, the turbine generated between 4250 and 3250 watts. The drop at 16:30 represents termination of the test and the syngas being shut off. The slow drop in power production is a result of the modified turbine heat exchanger. The turbine's heat exchanger, postmodification, contains a significant quantity of metal that most likely retained residual heat, which continued to power the turbine until it dropped to equilibrium. For comparative purposes, Figure 8 shows a similar power curve generated by firing natural gas through the heat exchanger in shakedown testing of the heat exchanger turbine system prior to the integration of the heat exchanger turbine gasification system. Maximum power production shown here peaked at 3681 watts prior to shutting off the gas.

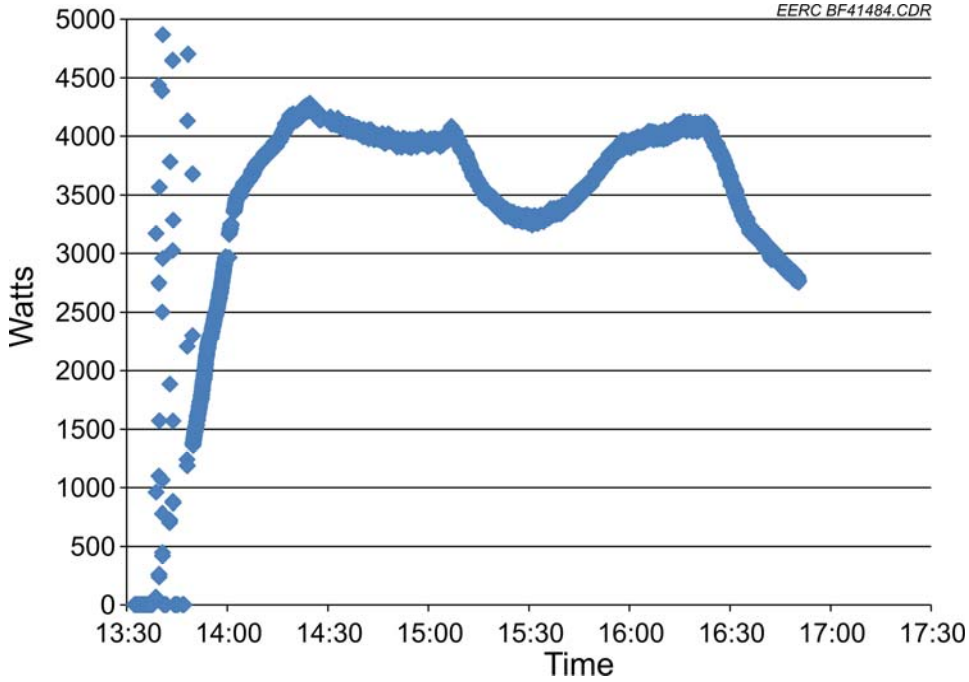


Figure 7. Illustration of normalized power produced from syngas.

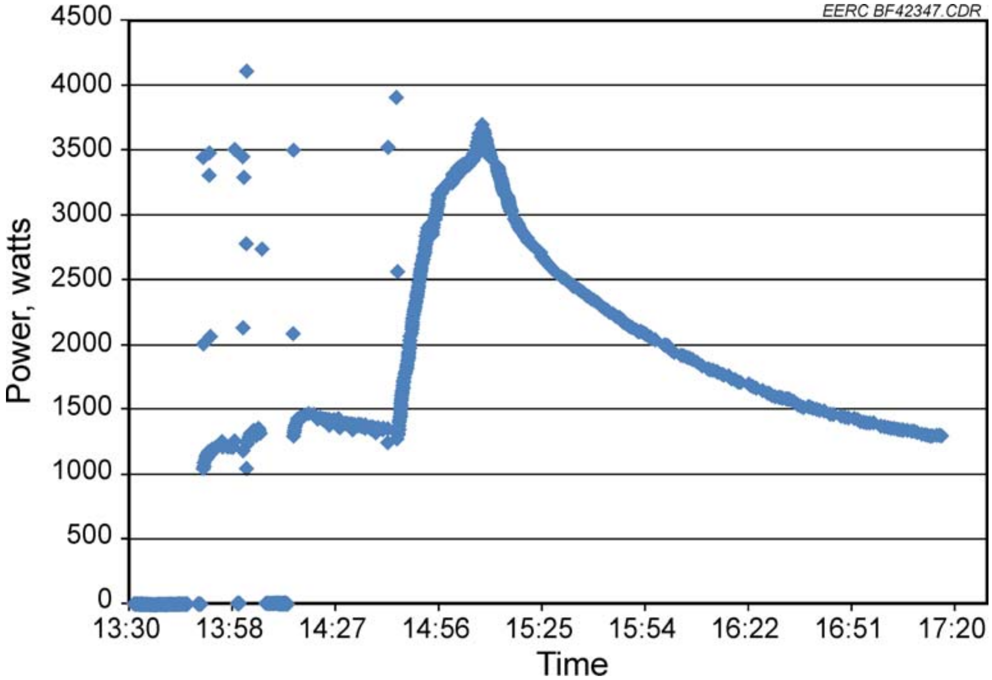


Figure 8. Example of power produced with natural gas.

As described earlier, TET is the variable that most affects the turbine's power output and control. The modified turbine and heat exchanger system and control software were set up to maintain a TET of 1200°F. As testing protocol required manual control of fuel addition to the turbine through a bypass assembly, the TET fluctuated over time. Figure 9 shows the thermal profile for the turbine's TET during integration testing.

As illustrated in Figure 9, TET fluctuated between 1300° and 1100°F over the integration test. With the turbine's TET goal of 1200°F, the test fluctuated ±8% from targeted operating temperature.

Postintegration Test Findings:

After testing the gasifier–turbine assembly as a fully integrated system, engineers decided to examine the system for any information that might explain the lower-than-expected power yield. Project engineers had expected that the heat exchanger modifications would have provided the necessary heat exchange. While the theoretical heat exchange area of the new exchanger was theoretically sound, the low power production suggested a physical examination of the exchanger should be conducted. The heat exchanger, which comprised three sections with offset longitudinal fins, was sized to provide a large surface area and an increased volume to reduce velocity, thereby increasing residence time for the high volume of low Btu gas. As shown in the turbine quantification section, the heat exchange efficiency allowed for only about 13% of the designed power generation. This implies that while physical surface area was significant, the effective surface area was significantly lower. If only 13% of the heat was transferred,

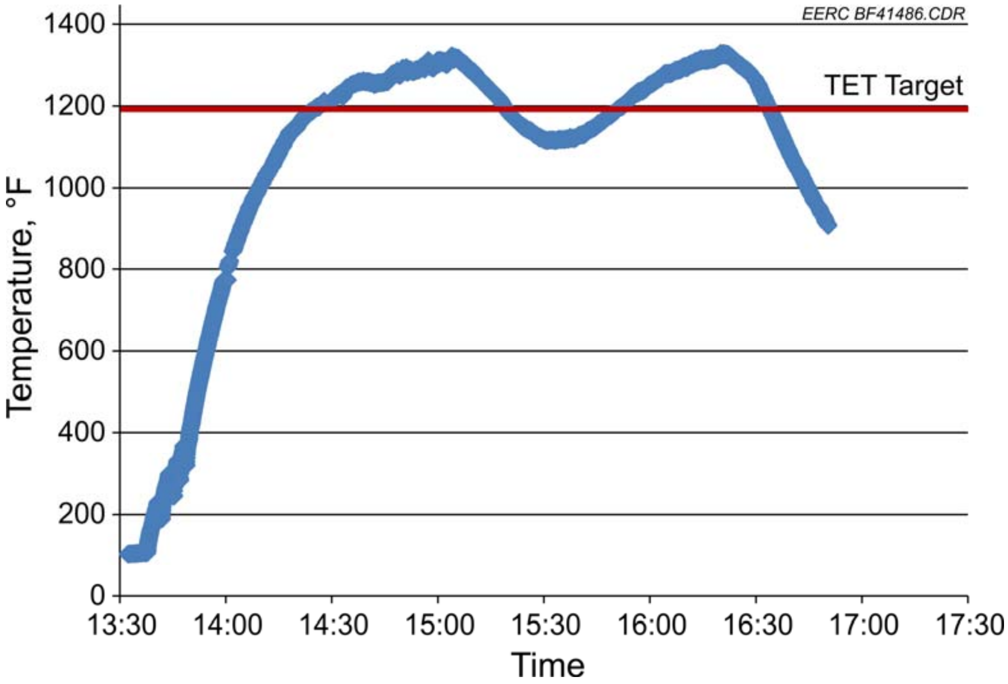


Figure 9. Example of TET during syngas combustion testing.

a simple conclusion to make is that failing to redesign the exchanger using a simple expansion of the current design area by 7–8 times should, in theory, result in the required area to produce at or near the designed electrical output.

Because of the material and labor costs to perform this modification, plus the physical limitations on dimensions, this approach was deemed impractical and a new design with greater affective surface area was determined to be the most appropriate action to overcome the heat-transfer issue. The second finding with respect to the heat exchanger was that its physical reliability was insufficient to deal with operating conditions. Upon opening the unit, mechanical failure was evident. Figures 10 and 11 show that mechanical failures in the form of fin deformation and deterioration occurred as a result of overheating and resultant thermal expansion during the testing.

Project Benefits: As previously described, waste biomass and opportunity fuels represent an enormous, underutilized biomass resource for electricity production. Biomass of this sort is underutilized primarily because of its distributed nature and low energy density. Conventional technology is not cost-effective for power systems below 10 MW, and the low energy density of the biomass makes it cost-prohibitive to transport to a centralized power station. This project was aimed at developing a technology that could take advantage of the distributed biomass resources and opportunity fuels in Xcel Energy's service territory.

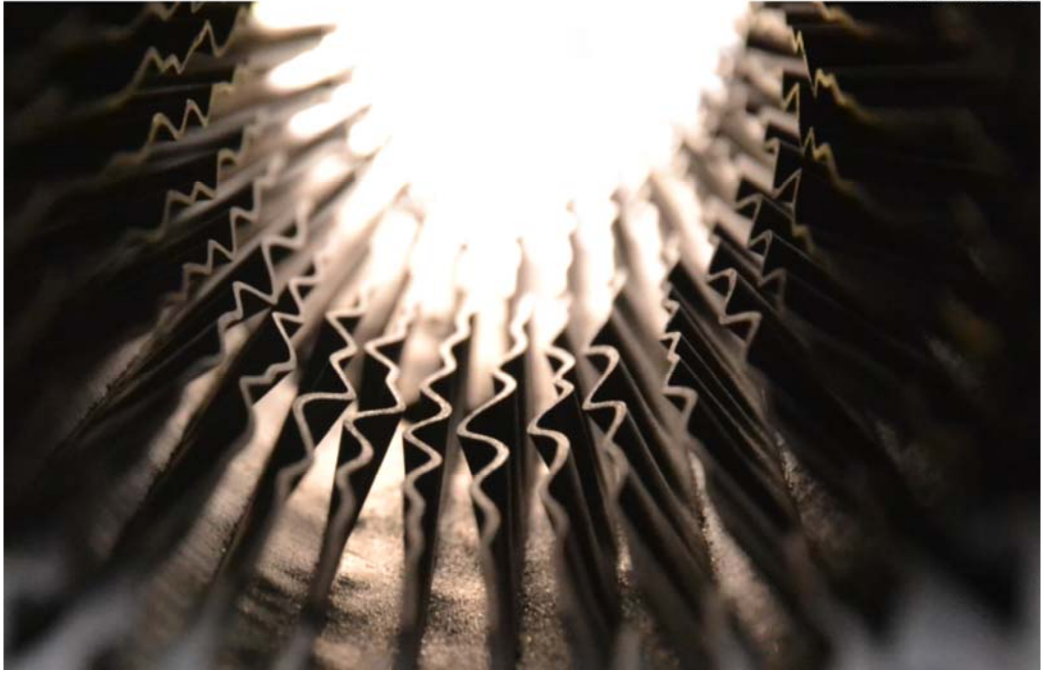

EERC BF43647.CDR

Figure 10. Thermal expansion failure of fins in heat exchanger.

EERC BF43648.CDR

Figure 11. Fin failure due to elevated temperatures at combustor inlet.

The project demonstrated many benefits and advances to the fledgling small renewable power industry in the Xcel Energy service territory. A small distributed-scale biomass gasification system was designed, built, and made to operate with only two operators. The gasifier system operated successfully on nine different biomass feedstocks singularly and during several tests utilizing mixtures of these different fuels—a demonstration of system versatility.

Operationally, a great environmental benefit was demonstrated, including the potential to lessen the amount of biomass or organic waste residue material that might be permanently placed in local landfills and have the benefit of well-contained effluents and emissions. The gasification system performed well with all of the fuels tested, achieving steady-state production of a low-tar (less than 200 ppm) syngas with a heating value of 120–140 Btu/scfm. Carbon conversion efficiency was, for the most part, close to 90% with unconverted carbon removed from the system as char, which in itself has the benefited value as fertilizer. Turbine combustion of the low-tar syngas yielded basically just carbon dioxide and water. The power system illustrated the potential to minimize operating costs by using a gas turbine thermally integrated with a gasifier and allowing the use of higher-moisture biomass. This is important to the Xcel Energy ratepayers for future power production needs that can utilize renewable, CO_2-neutral, sources of energy. Technologies such as this can help to reduce the amount of fossil fuels required to provide the necessary electricity for Xcel Energy ratepayers at an acceptable cost. Additional benefits from technologies such as the integrated system developed under this project include reduced emissions other than CO_2 as well. Woody biomass is generally much lower in sulfur than traditional fuels such as coal. The emission of SO_2 is, therefore, going to be dramatically lower than typical fossil-based power generation. While CO_2 emissions are normal, the source of the CO_2 is biomass. This makes it carbon-neutral. NO_x and particulate matter (PM) emissions are lower since the lower-Btu syngas provides a lower peak temperature in the combustor, and subsequent NO_x production is dramatically reduced. To quantify the benefits of using biomass over coal, Table 3 shows sulfur content of numerous biomass materials versus coal.

As Table 3 shows, the typical sulfur content of coal is 4–6 times the maximum content found in most biomass. The direct benefit of this is that, for an equal amount of fuel consumption, sulfur-based compound emissions will drop to approximately 1/5th that of the emissions associated with coal-derived energy.

Solid waste generated is based on the ash content of fuel. In general, carbon conversion of typical woody residue is greater than 95%, and ash content is typically below 1%. Using these values as upper limits, the solid waste levels are expected to be below 0.130 lb carbon per kWh and 0.026 lb of inorganic ash per kWh. Again, a reduced waste compared to traditional fossil fuels, which contain up to 20% by weight ash, is shown in Table 4.

Technologically, this project represents a great benefit in demonstrating a promising new type of renewable energy system. The 5 kW of power produced by the Capstone C10 turbine, as derived from biomass syngas, proved the benefit of a new innovative integrated renewable energy system that can produce electricity from biomass residues or wastes. The ideal goal was to produce up to 30 kW of power, and this goal was not met, but operation of an integrated gasifier–turbine was achieved nonetheless. The project, while not able to bring the technology to the point of commercial readiness, did demonstrate the feasibility of the system that, with more work, could provide a biomass power system specifically designed to address the constraints of distributed biomass resources. The system shows promise for distributed-scale gasifier–turbine power plants in this size of a few tons a day of biomass consumption which could greatly benefit small industries or communities that have limited, albeit sustainable, quantities of biomass such as tree trimmings that would normally go to landfills.

The work accomplished and information generated also provide the benefit of showing the state of commercial application. The integrated biomass power system has great market potential, as demonstrated by the operation of the unit, and it can now be said that further engineering and improvements will be necessary before commercial manufacturers can produce and sell such systems in energy markets. Critical next steps toward commercialization of such systems were determined and include automated sustainable low-maintenance gas cleanup, improved turbine combustion control for optimized power output, and additional automated systems for removal of char and scrubber solutions.

Table 3. Fuel Sulfur Content Comparison

Biomass Fuels	% Sulfur, dry-weight basis	Reference
Alfalfa Seed Straw	0.3	(1)
Almond Shells	<0.02	(1)
Barley Straw	0.14	(1)
Coffee Hulls	0.2	(2)
Corn Cobs	0.001–0.007	(1,3)
Corn Fodder	0.15	(1,2)
Corn Stalks	0.05	(1)
Oat Straw	0.23	(2)
Cotton Gin Trash	0.26–0.31	(1)
Flax Straw, pelleted	<0.01	(1)
Furfural Residue	0.4	(4)
Olive Pits	0.02	(1)
Peach Pits	0.04	(1)
Peanut Husks	0.1	(4)
Peat (Finnish)	0.05–0.2	(5)
Peat, general	1.5–2.0	(6)
Rice Hulls	0.16	(1)
Rice Straw	0.10	(1)
Walnut Shells	0.03–0.09	(1)
Wheat Straw	0.17	(2)
Wood, chipped	0.08	(1)
Wood, general	0.02	(1,7)
Wood, pine bark	0.1	(4)
Wood, green fir	0.06	(4)
Wood, kiln-dried	1.0	(4)
Wood, air-dried	0.08	(4)

Typical Sulfur Content in Coal, wt% (8)
Anthracite Coal: 0.6 – 0.77
Bituminous Coal: 0.7 – 4.0
Lignite Coal: 0.4

Table 4. Ash Content of Coal

Coal	wt%
Anthracite	97–20.2
Bituminous	3.3–11.7
Lignite	4.2

Finally, economic benefits, once the technology is commercially ready, are provided by targeting waste biomass and opportunity fuels. The characteristics of this market are that the biomass is produced on-site, oftentimes a financial liability, and is usually too small to power a full-size (greater than 10 MW) power plant. However, current technology does not provide the right economics for this market. This technology, once commercially ready, is designed to open this market by producing a cost-effective packaged-power system for distributed biomass resources. No current cost-effective alternative exists to convert this resource into electricity. Currently, much of this resource is being landfilled. Conversion to electricity would reduce the amount of landfilled waste and the pollution associated with transporting the waste to the landfill. In addition, manufacturing jobs would be created to produce this power system.

Project Lessons Learned: The goals of the project were to modify a Capstone C30 to operate on indirectly fired low-pressure syngas, construct and test a 120-kW gasifier capable of supplying the modified turbine with the required syngas equivalent, and successfully integrate the two systems to produce power. All of these objectives were achieved over the course of the project, with varying degrees of success.

Based on the tests conducted to date, the gasification system has been a success. The gasification system has been operated on multiple fuels and has proven its versatility and robustness. The gasification system performed well with all of the fuels tested, achieving steady-state production of a low-tar (less than 200 ppm) syngas with a heating value of 120–140 Btu/scfm. Carbon conversion efficiency was, for the most part, close to 90% with unconverted carbon removed from the system as char, which in itself has benefited value as fertilizer. Future upgrades to the gasifier proper should include fully automating the gas cleanup system to alleviate operator attention, adding an automated char removal system, and redesigning certain elements of the feed system to alleviate plugging of material. These improvements are minor.

The turbine, however, is where additional work is most definitely required. Optimally, the modified turbine would have operated on syngas and produced up to 30 kW of power. This was not the case, and multiple issues limited the system’s operability and performance. With an output power of 4250 watts, the system only produced 14% of the turbine’s rated power output and, without additional development, is not a viable stand-alone product at this time, although the performance obtained validates the potential to indirectly fire a turbine on low-Btu gas.

Two areas need investigation to produce a viable turbine system. As stated, the C30 turbine chosen for use in this project has proprietary software that was cumbersome to work with at best and did not allow for modifications to be made to account for the lower-Btu syngas and the experimental heat exchanger design. This caused difficulty in just operating the turbine on natural gas with the experimental heat exchanger. The result was that the only way to allow the turbine to produce power with the syngas heat exchanger system was to run the turbine in cooldown mode. Since cooldown mode is designed for shutting down the turbine after having run at high temperatures, this was obviously less than optimal. The system ran depressurized in this mode, and only a small amount of the predicted work could be generated by the syngas. To remedy this, a newer model turbine with user-friendly, user-programmable software would be required, which is outside the budget of this project.

The second item requiring more work would be to build a better heat exchange system to power the turbine. During the running of the integrated system, what appeared to be molten metal was seen inside the heat exchanger. Upon examination after the testing, it was discovered that the burner nozzles were positioned allowing impingement of the flame on the heat exchanger fins, which are constructed of a thin metal for good thermal conductivity. The leading-edge fins had melted, and potential small holes had developed in the heat exchanger shell. This would have two effects on the heat exchanger: 1) compromising the structural stability of the heat exchanger itself because of degradation of the shell and 2) allowing combustible gas to pass from the flame side to the exhaust side of the heat exchanger, possibly creating an explosion potential.

Continuation of testing of the integrated system would require a complete redesign and rebuild of the heat exchanger, which is outside the budget and scope of this project. However, running the system in cooldown mode, which is a depressurized operation condition of the turbine, and obtaining the amount of work that was generated illustrates that the concept of the integrated gasification indirectly fired turbine system is at least plausible and, with more work, may become commercially viable.

Since the initiation of project work, the small turbine market continues to evolve. At the start of work, the EERC chose to utilize a Capstone C30 turbine. This choice was made for several reasons, including the following:

1. At initiation of work, only two major manufacturers of small turbines existed. These included Capstone and Elliot.

2. The EERC possessed a Capstone C30 turbine that had been acquired through previous work in the oil industry.

3. Previous project work with the Capstone had allowed for multiple EERC personnel to be factory-certified on the unit, which included significant exposure to the system and its function and design.

4. Using a system that personnel are intimately knowledgeable with significantly reduced the learning curve and cost that would have been required with a new and untested unit.

At the completion of work, the single greatest issue facing the technology is the ability to control/modify the operational parameters of the base system. While all turbines come with a base control package, the Capstone design was closed and didn’t allow modification of operational parameters.

As the technology stands today, no system has been identified whereby the turbine and control package are separate. This technology is a paradigm shift, which means off-the-shelf technology does not exist. Successful development will require the identification of a turbine with open control architecture, which from experience is not available and is therefore unlikely. Outside of identifying an open system, success will be dependent on real commercial application and production. With acceptance and production by manufacturers, attention to success will require cooperation between turbine builders and control software technicians.

Usefulness of Project Findings: The project benefits have already been discussed, but it is important to reiterate that this project has demonstrated the potential of an integrated distributed gasification turbine system to take advantage of the enormous renewable resources available in Xcel Energy's service territory and reduce the need to generate electricity utilizing fossil energy, thereby reducing CO_2 emissions as well as nitrate and sulfur emissions compared to fossil power generation.

Reduction of emissions using a biomass system may save Xcel Energy's ratepayers costs incurred on existing coal-powered systems for removing fossil fuel CO_2 emissions. While the integrated gasifier–turbine technology is not commercially ready at this point, investment in this project has pushed the technology much closer to a commercially ready state. This technology could be a paradigm shift in engineering from larger-scale fossil fuel-powered electricity with a broad regional grid connection to smaller renewable distributed power that is connected to a smaller grid array or microgrid.

In short, much has been accomplished through this work, not the least of which is the demonstration of the distributed gasification design and its ability to utilize various wet feedstocks that would typically either be landfilled or simply left unused. In addition, the potential of a small-scale turbine to operate on low-Btu syngas generated from biomass has been demonstrated. Further development of this technology to bring it to a commercially ready state will ensure that Xcel Energy has options available to reduce its emission footprint and produce power sustainably while holding down costs to its customers.

Future Development, Commercialization, and Economic Analysis

A great advancement in small biomass power system development has been accomplished through this project. Through the research and development that was accomplished, great strides have been made to demonstrate an innovative system that is next-level technology above conventional small gasification systems and microturbines that have not been able to achieve the results of the EERC system.

An innovative fixed-bed biomass gasification system rated at about 150 kWth (70–100 lb/hr biomass fuel) was integrated with a 30-kW microturbine and operated successfully on several types of biomass fuel. Although the highest performance targets were not achieved on the turbine side of the integrated system, this innovative renewable power plant was nonetheless a success. Two complementary enabling EERC–Xcel Energy technologies for biomass power were combined, and the potential of the power system to economically exploit renewable biomass resources was demonstrated. The work accomplished and information generated show that the system has great market potential, but future development commercially depends on good engineering improvements, sound commercialization strategies, and accurate economic analysis.

Because of the problems encountered during the research and development of the indirectly fired turbine, the next logical step in the development of this technology is to take the lessons learned and attempt a second-generation system.

Future upgrades to the gasifier proper should include fully automating the gas cleanup system to alleviate operator attention and redesigning certain elements of the feed system to alleviate plugging of material. These improvements are minor.

The small turbine system, however, requires additional technical development. Optimally, the modified turbine would have operated on syngas and produced up to 30 kW of power. This was not the case, and multiple issues limited the system's operability and performance. With an output power of 4250 watts, the system only produced 14% of the turbine's rated power output and, without additional development, is not a viable stand-alone product at this time, although the performance obtained validates the potential to indirectly fire a turbine on low-Btu gas. One barrier to this new process is the availability of small turbines. During the reporting phase, a survey of manufacturers was conducted, and it appears that aside from Capstone, the small turbine market has disappeared. The only small system is the C30 by Capstone, which has been determined to be inadequate for the purpose because of its closed architecture. The C30 was chosen for this project because it was the most robust system of this size that had some experience with low-Btu biogas. For the small EERC gasifier, this C30 was a perfect fit, and it also had stainless steel construction which was assessed as an excellent structure for modification to function optimally on the gasifier gas input. To build a new system, it would now be necessary to increase the size of the system. At this time, the smallest turbine appears to be a 100-kW unit manufactured by Turbek AB which quoted $151,000 or $1510/kW. After these units, the market opens up considerably with many companies, including Ingersoll Rand and GE, offering 250-kW units. This changes the target market from very small manufacturers who may only operate day shifts to larger industrial clients who have larger base electrical loads, operate 24/7, and can afford to invest upwards of $750,000 on a system.

To become commercially viable, the economics of the proposed system components must be examined. The integrated system designed, built, and tested in this research project is a prototype; therefore, the individual component costs will be much higher than a commercial mass manufactured technology. As the state of small gasifier and turbine development improves, the accuracy of projected costs will improve. For reporting purposes and fulfillment of proposed objectives, a best attempt at providing an economic assessment or cost estimate of the integrated system was performed.

Several base assumptions were made for the economic or cost analysis of the integrated gasifier–turbine system. These assumptions were as follows:

1. The smallest commercially available system in today's U.S. market are 100 kW or larger. Therefore, 100 kW is the basis used in analysis.

2. A 30-kW turbine can be scaled by a factor of 3.3 to estimate new costs for a 100-kW system.

3. A laborer will be required to monitor the integrated system while it is running, as in a full-time operator for a 24-hr operation. This requirement will likely decrease in the future as automation is fully vetted, but at this stage an operator will be required at all times.

4. Biomass or waste residues are considered to have no cost.

5. Power produced would be purchased/sold at Minnesota's residential average rate of \$0.102 per kWhr.

Based on the above assumptions and cost factors occurring through the duration of this project (2008 to a projected time period) an economic analysis shows that the prototype system does not currently have a net positive return on investment. Table 5 shows this scenario. The total capital investment is about \$1.2 million. Operational costs range from \$140,000 to 160,000 annually. Facility income would not exceed \$77,000 annually through the projected time period, which means the system would cost nearly twice as much to run as it would generate. Another common comparison often made is the capital cost per kW. New coal, nuclear, or gas power plants generally cost between \$900–\$3000 per kW to build. Various incentives or regulations may raise or lower this capital expenditure. The integrated gasifier–turbine of this project carries a capital cost of \$11,800 per kW. This is, of course, too high for any investment in new power, but the caveat to remember is that this is a raw cost based on a prototype. In the future, as competitive systems develop with improved economies of scale, these capital costs will plummet. Mass manufacturing always improves efficiency and lowers cost.

To further analyze the cost of the integrated gasifier–turbine system, a second analysis was conducted using different assumptions. Table 6 displays cost information for the scenario that assumes the integrated system has gone commercial and is being mass-produced:

1. Power cost is closer to the median national cost of \$0.12/ kWhr than Minnesota's cost of \$0.102/kWhr (see Figure 12 for the average national power cost).

2. Labor required is only 4 hours a day to perform daily maintenance.

3. Postcommercialization cost of equipment drops by 30% because of mass manufacturing.

Under these new assumptions, the economics begin to become favorable, as is shown in Table 6. Although the capital costs are still high at about \$8200 per kW, the income generated through sale of power exceeds the operation and maintenance costs through a period of 10 years. Under these criteria, the payback becomes favorable with an expected payback of 13 years. While these assumptions are reasonable, the final economics have a high degree of uncertainty not only because of capital cost estimation accuracy but potential location energy value. Figure 13 shows a sensitivity analysis for the system under the previous conditions but with electricity cost as the major variable.

As Figure 13 shows, using the best-available estimates for costs yields an asymptotic simple payback at less than \$0.10 per kWhr. Above this cost for power, the payback increases and shows that, for numerous regions, the system once developed is feasible.

Table 5. Economic ROI (return on investment) and IRR (internal rate of return) Estimate for Prototype System

PLANT GENERATION:					**Base Case**	**Electrical Generation**				
	Design Basis	100 kW	Determined			**Fuel :**	**Biomass**			
	Biomass		1050	tons/yr						
	Electricity Production		100	kW		Cost Estimator		Total Cost	**Escalation Rates**	
			840,000	kWh/yr		Turbine		$ 151,000	Electricity Bought	0.3%
						Heat Exchanger		$ 300,000	Labor	2.0%
	Motors		10	hp		GasiferTurbine		$ 12,000	Electricity Sold	0.3%
			7.5	kW		Controls and Data Acquisition Turbine		$ 10,000	General	1.0%
			62,664	kWh/yr		Piping		$ 12,000		
						Cyclone		$ 8,000		
			Calculated			Insulation		$ 7,000		
	Biomass		3.0	tons/day		Feed System		$ 15,000		
						Gasifier		$ 225,000		
						Total Capital Cost		**$ 740,000**	**Maintenance, annual**	**$7,550**
									General, annual	$7,550
						Installation Cost = Capital Total X 0.6		$ 444,000.0		
						Total Project Cost		**$ 1,184,000**		

CASH FLOW ANALYSIS													
			YEAR	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
FACILITY OPERATIONAL COSTS				1	2	3	4	5	6	7	8	9	10
		Value	Units										
	Electricity, price	$0.102	/kWh										
	Annual Use	62,664	kWh/yr	$6,392	$6,411	$6,430	$6,449	$6,469	$6,488	$6,508	$6,527	$6,547	$6,566
	Labor, price	$15	/hr										
	1 person, 3 shifts	8424	hrs/yr	$126,360	$128,887	$131,465	$134,094	$136,776	$139,512	$142,302	$145,148	$148,051	$151,012
	Maintenance			$7,550	$7,626	$7,702	$7,779	$7,857	$7,935	$8,014	$8,095	$8,176	$8,257
A	**Total**			**$140,302**	**$142,924**	**$145,597**	**$148,322**	**$151,101**	**$153,935**	**$156,824**	**$159,770**	**$162,773**	**$165,836**
FACILITY INCOME													
	Electricity, price	$0.1020	per kWh										
	Electricity Production	840,000	kWh/yr	$85,680	$85,937	$86,195	$86,453	$86,713	$86,973	$87,234	$87,496	$87,758	$88,021
B	**Total**			**$85,680**	**$85,937**	**$86,195**	**$86,453**	**$86,713**	**$86,973**	**$87,234**	**$87,496**	**$87,758**	**$88,021**
REVENUE (B-A)				**($54,622)**	**($56,987)**	**($59,402)**	**($61,869)**	**($64,389)**	**($66,962)**	**($69,590)**	**($72,274)**	**($75,015)**	**($77,814)**
Years			0	1	2	3	4	5	6	7	8	9	10
Years	Consumer price index escalation rate	3.60%											
-22	Simple Payback (years)		**IRR**										

Table 6. Economic Estimate for System Approaching Full Commercialization

PLANT GENERATION:

Base Case **Electrical Generation**

Fuel : **Biomass**

Design Basis	Determined	
Biomass	1050	tons/yr
Electricity Production	100	kW
	840,000	kWh/yr
Motors	10	hp
	7.5	kW
	62,664	kWh/yr
	Calculated	
Biomass	3.0	tons/day

Cost Estimator	Total Cost
Turbine	$ 151,000
Heat Exchanger	$ 300,000
GasiferTurbine	$ 12,000
Controls and Data Acquisition Turbine	$ 10,000
Piping	$ 12,000
Cyclone	$ 8,000
Insulation	$ 7,000
Feed System	$ 15,000
Gasifier	$ 225,000
Total Capital Cost	**$ 740,000**
Installation Cost = Capital Total X 0.6	$ 444,000.0
Total Project Cost	**$ 1,184,000**
Cost after Commercialization = Project Total X 0.7 =	**$ 828,800.0**

Escalation Rates	
Electricity Bought	0.3%
Labor	2.0%
Electricity Sold	0.3%
General	1.0%
Maintenance, annual	**$7,550**
General, annual	$7,550

CASH FLOW ANALYSIS

			YEAR	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
FACILITY OPERATIONAL COSTS				1	2	3	4	5	6	7	8	9	10
		Value	Units										
	Electricity, price	$0.120	/kWh										
	Annual Use	62,664	kWh/yr	$7,520	$7,542	$7,565	$7,588	$7,610	$7,633	$7,656	$7,679	$7,702	$7,725
	Labor, price	$15	/hr										
	1 person, 3 shifts	1460	hrs/yr	$21,900	$22,338	$22,785	$23,240	$23,705	$24,179	$24,663	$25,156	$25,659	$26,173
	Maintenance			$7,550	$7,626	$7,702	$7,779	$7,857	$7,935	$8,014	$8,095	$8,176	$8,257
A	**Total**			**$36,970**	**$37,506**	**$38,051**	**$38,607**	**$39,172**	**$39,748**	**$40,333**	**$40,930**	**$41,537**	**$42,155**
FACILITY INCOME													
	Electricity, price	$0.1200	per kWh										
	Electricity Production	840,000	kWh/yr	$100,800	$101,102	$101,406	$101,710	$102,015	$102,321	$102,628	$102,936	$103,245	$103,554
B	**Total**			**$100,800**	**$101,102**	**$101,406**	**$101,710**	**$102,015**	**$102,321**	**$102,628**	**$102,936**	**$103,245**	**$103,554**
REVENUE (B-A)				**$63,830**	**$63,597**	**$63,354**	**$63,103**	**$62,843**	**$62,573**	**$62,295**	**$62,006**	**$61,708**	**$61,399**
Years			0	1	2	3	4	5	6	7	8	9	10
Years	Consumer price index escalation rate	3.60%											
13	Simple Payback (years)	**-4.81%**	**IRR**										

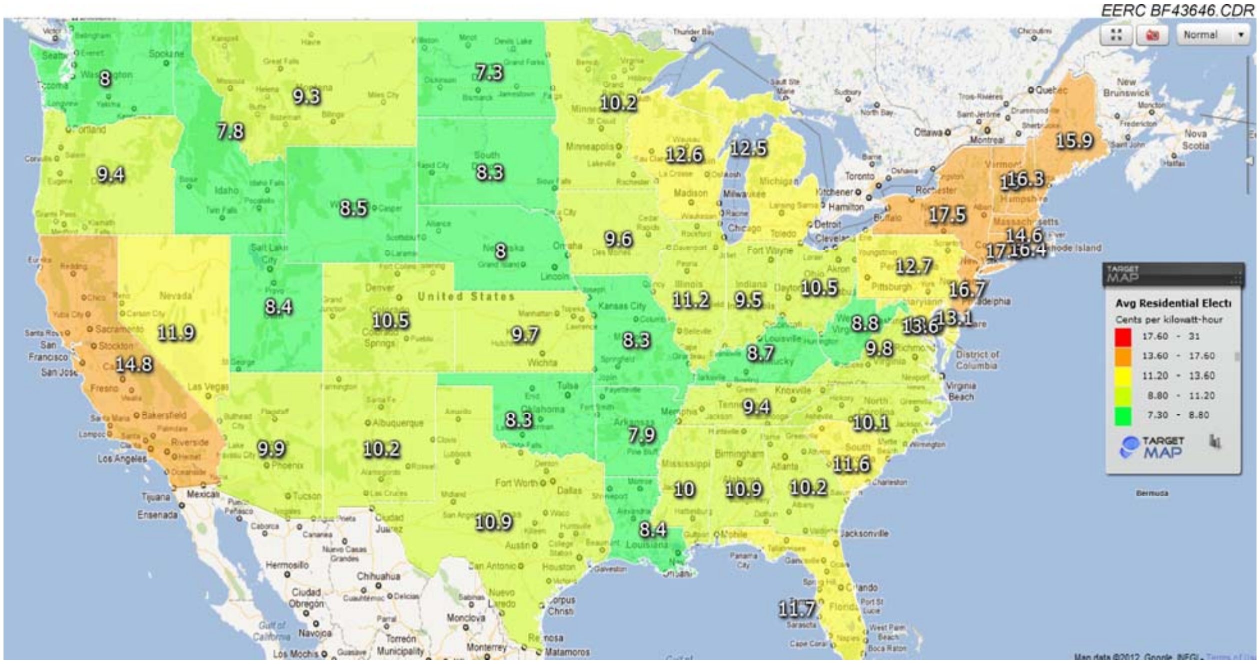
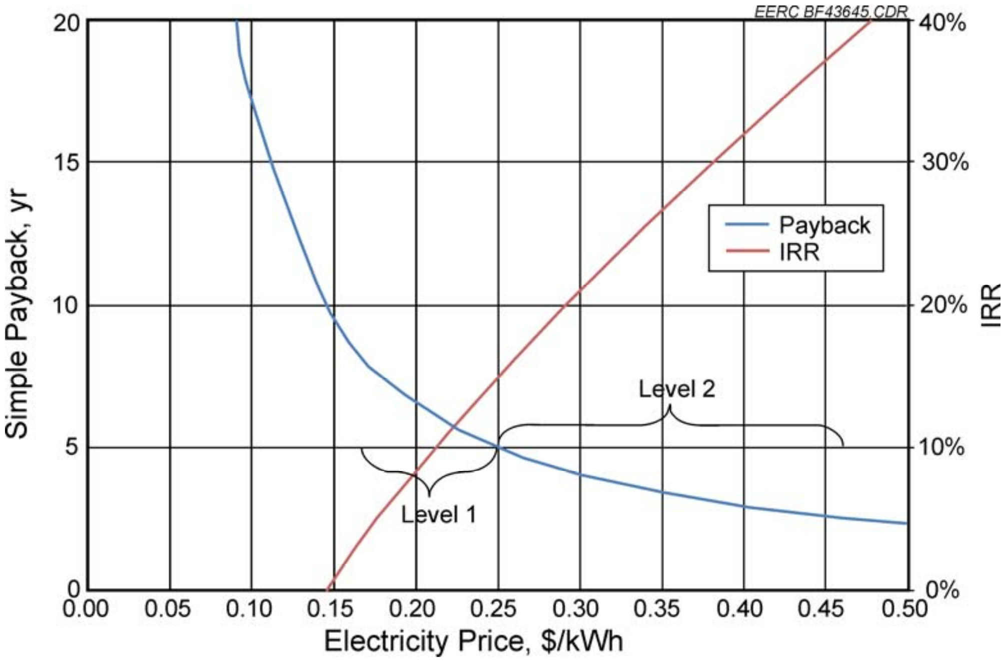


Figure 12: Average residential electricity price from EIA.gov (9).



Level 1 [$0.15-0.25/kWh]: AK, AL, CA, CO, CT, DE, FL, HI, MA, MD, MI, NC, NJ, NM, NV, NY, OK, PA, SC, TX, VT, WI, WV
Level 2 [>$0.25/kWh]: AK, HI, ME, NY, RI

Figure 13. Sensitivity analysis for an estimated near-commercial system (IRR refers to internal rate of return).

A commercialization plan for this technology, while it is not quite ready for that step, would be to target specific niche markets for the first operating units. These markets would have several key criteria for utilization of this next-generation technology, including fuel feedstock that has a negative value, localized use for waste heat, and existing infrastructure capable of reducing upfront capital costs. An example of such a market could be animal agriculture production facilities that produce an animal waste stream that may have been land-applied in the past but because of regulations may require a new disposal technique. This manure would then have a cost for disposal which, if used as feedstock for a gasifier, would offset the processing costs of the gasification system, lowering overall energy production costs. Animal agriculture growers typically require heat for barns and could use any excess or waste heat to also offset their heating costs. Other sites might be landfills that accept tree trimmings that could be used as a feedstock with the tipping fee for accepting the waste used to offset overall system processing costs, reducing the electricity production costs. Once an acceptable niche market has been determined locally, the manufacturing plan would be based on a sound engineering design that utilizes as many off-the-shelf components as possible, minimizing the need for custom fabrication and reducing system cost. The larger components requiring fabrication such as the heat exchanger for the turbine and the gasifier itself can be fabricated by any good fabrication shop, of which thousands exist around the country. This allows for reduction of shipping costs by having the needed fabrication performed locally to the system market. As shown in the analysis above, payback periods of less than 15 years can be achieved currently with a zero-cost fuel feedstock, and when a negative-cost feedstock is utilized, the economics improve. Overall implementation and costs will depend on the specific application. The realization of this strategy will require forward-thinking financiers willing to take some risk. While the current embodiment of the technology is not quite ready for commercialization, the funding provided through Xcel Energy and its global ratepayers has certainly moved this technology another step closer to deployment, which would allow Xcel Energy to develop a more diversified power generation portfolio and reduce dependence on fossil fuel, thereby reducing overall greenhouse gas emissions while still meeting the needs of the ratepayer for reliable sustainable power.

Conclusions: Renewable energy is considered one solution for alleviating the production and accumulation of greenhouse gases in the earth's environment. If biomass or organic waste residues can be converted to energy without expending an equal amount of fossil fuel, then they are a viable solution to the issue of accumulating atmospheric greenhouse gases. Biomass utilization for energy production is also often a practical means to reduce organic wastes and prohibit the production of methane by converting the biomass to energy and carbon dioxide. Methane is twenty times worse as a greenhouse gas accelerator than is carbon dioxide. One challenge in utilizing biomass as a fuel is that it often takes many inconsistent forms with respect to physical and chemical properties, and quantities are normally small in distribution and require great expense to gather and transport.

The answer to utilizing this distributed biomass resource is to use small power generators that are more distributed in nature, similar to the biomass fuels. The challenge then becomes that today's conventional power production technology for electricity generation is not cost-effective for power production below 10 MW. The solution is to develop an economical power system in the size range typically associated with distributed biomass resources and opportunity fuels.

A research and development project was conducted by the EERC as funded by the Xcel Energy Renewable Development Fund with cost-matching funds provided by the U.S. Department of Energy to address the challenge of developing a small biomass power plant. The goal of this project was to combine a distributed-scale biomass gasification system with a novel low-Btu turbine to utilize the produced syngas from the gasifier in an integrated fashion providing a unique small-scale electrical generation system capable of taking advantage of the untapped sources of biomass. Such a technology could be a paradigm shift in engineering from larger-scale fossil fuel-powered electricity with a broad regional grid connection to smaller renewable distributed power that is connected to a smaller grid array or microgrid.

All of the major research objectives were met within the context of a research project, and the project exacted many benefits and advances to the fledgling small renewable power industry in the Xcel Energy service territory.

An innovative fixed-bed biomass gasification system rated at about 150 kWth (70–100 lb/hr biomass fuel), about the size of a small backyard storage shed, was designed, built, and made to operate with only two operators. The system's feed rate of a few tons a day of biomass was an excellent fit for the common, relatively small, quantities of biomass or organic waste residues regionally, as is the case for the Xcel Energy power distribution territory. The gasifier operated successfully on nine different fuel feedstocks, including wood pellets, pressed wood cubes, wood chips, coal, coal–wood chip mixtures, mulch, sawdust, switchgrass, charcoal, meat and bone meal, and fish-rendering waste, demonstrating the versatility of the system.

All of the biomass types and the blends of coal and biomass were successfully converted to synthetic gas or syngas during steady-state gasification, producing a low-tar (less than 200 ppm) syngas with a heating value of 120–140 Btu/scfm.

In parallel, a Capstone C10 turbine system was successfully modified. The turbine system was then fully integrated physically and operationally with the gasifier to formulate a gasifier-turbine power plant system. The integrated system produced clean syngas, which was then burned in the turbine, resulting in renewable electricity production—a great innovative stride for integrated gasifier–turbine technology. The system was not without flaws, however, in that the Capstone C10 turbine operated only at about 14% of rated power output. This was due primarily to limitations related to system control software, with secondary limitations attributed to turbine design and turbine-based computer control software. The research goal was to operate the modified turbine on syngas, and this goal was achieved at a power output of 5 kW.

The performance of biomass syngas burning in a gas turbine to produce a few thousand watts of electricity in an integrated assembly validated the potential of an indirectly fired biomass gasifier–gas turbine system operating on a synthetic low-Btu gas. This accomplishment is a great success and brings an integrated gasifier–turbine system concept closer to reality and eventual investment for commercialization. Current conventional small gasification systems and microturbines have not been able to achieve the results of the EERC system. Typical distributed-scale air-blown gasifiers on the market today produce tar levels above 3000 ppm and with Btu levels usually less than 110 Btu/scfm. Small gas turbines in the range of 30–60 kW at the time of this study were commercial systems, but they could only operate on high-energy, pipeline-quality, natural gas. The innovative integrated gasifier–turbine system operated successfully on several types of biomass fuel. Although the highest performance targets were not achieved on the turbine side of the integrated system, this innovative renewable power plant was nonetheless a success.

The work accomplished and information generated show that the system has great future commercial market potential. Research and development garnered through this project reveals that further engineering improvements will be necessary before accurate commercial market assessments can be made and commercial ventures developed. Initial cost estimates show the gasifier–turbine system would cost between $8000–$12,000 per kW to build. Operation and maintenance costs will exceed income generated through unincentivized (competitive electricity rates with no incentives such as carbon or renewable credits) electricity sales until mass manufacturing of the systems can be achieved.

In the future, this system holds great promise as a distributed power plant for producing renewable electricity in niche markets.

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