SRI/USEPA-GHG-VR-22
September 2004

Environmental Technology Verification Report

Swine Waste Electric Power and Heat Production – Capstone 30 kW Microturbine System

Prepared by:

Greenhouse Gas Technology Center
Southern Research Institute

Under a Cooperative Agreement With
U.S. Environmental Protection Agency

and

Under Agreement With
Colorado Governor's Office of Energy Management and Conservation

EPA REVIEW NOTICE

This report has been peer and administratively reviewed by the U.S. Environmental Protection Agency, and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

THE ENVIRONMENTAL TECHNOLOGY VERIFICATION PROGRAM

U.S. Environmental Protection Agency

SOUTHERN RESEARCH INSTITUTE

ETV Joint Verification Statement

TECHNOLOGY TYPE:	Biogas-Fired Microturbine Combined With Heat Recovery System
APPLICATION:	Distributed Electrical Power and Heat Generation
TECHNOLOGY NAME:	Capstone 30 kW Microturbine System
COMPANY:	Colorado Pork, LLC
ADDRESS:	Lamar, Colorado

The U.S. Environmental Protection Agency (EPA) has created the Environmental Technology Verification (ETV) program to facilitate the deployment of innovative or improved environmental technologies through performance verification and dissemination of information. The goal of the ETV program is to further environmental protection by accelerating the acceptance and use of improved and cost-effective technologies. ETV seeks to achieve this goal by providing high-quality, peer-reviewed data on technology performance to those involved in the purchase, design, distribution, financing, permitting, and use of environmental technologies.

ETV works in partnership with recognized standards and testing organizations, stakeholder groups that consist of buyers, vendor organizations, and permitters, and with the full participation of individual technology developers. The program evaluates the performance of technologies by developing test plans that are responsive to the needs of stakeholders, conducting field or laboratory tests, collecting and analyzing data, and preparing peer-reviewed reports. All evaluations are conducted in accordance with rigorous quality assurance protocols to ensure that data of known and adequate quality are generated and that the results are defensible.

The Greenhouse Gas Technology Center (GHG Center), one of six verification organizations under the ETV program, is operated by Southern Research Institute in cooperation with EPA's National Risk Management Research Laboratory. A technology of interest to GHG Center stakeholders is the use of microturbines and engines as distributed generation sources. Distributed generation (DG) refers to power-generation equipment that provides electric power at a site much closer to customers than central station generation. Recently, biogas production from livestock manure management facilities has become a promising alternative for fueling DG technologies. These technologies, commonly referred to as anaerobic digesters, decompose manure in a controlled environment and recover methane produced from the manure digestion. The recovered methane can fuel power generators to produce electricity, heat, and hot water. Digesters also reduce foul odor and can reduce the risk of ground- and surface-water pollution.

The GHG Center collaborated with the Colorado Governor's Office of Energy Management and Conservation (OEMC) to evaluate the performance of two combined heat and power systems (CHP systems) that operate on biogas recovered from swine waste generated at the Colorado Pork facility in Lamar, Colorado. This verification statement provides a summary of the test results for the Capstone 30 kW Microturbine CHP system.

TECHNOLOGY DESCRIPTION

The following technology description is based on information provided by Capstone and OEMC and does not represent verified information. The microturbine system tested at Colorado Pork consists of a Capstone Model 330 Microturbine and a heat-recovery system developed by Cain Industries. The CHP system also includes a CompAir gas compressor which is needed to boost the gas pressure to about 100 psig. A permanent magnet generator produces high-frequency alternating current which is rectified, inverted, and filtered by the line power unit into conditioned 480 volts alternating current (VAC). The unit supplies an electrical frequency of 60 hertz (Hz) and is equipped with a control system that allows for automatic and unattended operation. An active filter in the generator is reported by the turbine manufacturer to provide power free of spikes and unwanted harmonics. All operations, including startup, setting of programmable interlocks, grid synchronization, operational setting, dispatch, and shutdown, can be performed manually or remotely using the internal power-controller system.

The gas booster compressor is a CompAir Hydrovane Model 704PKGS with a nominal volume capacity of 48 standard cubic feet per minute (scfm) and the capability of compressing gas from inlet pressures ranging from 0.25 to 15 pounds per square inch gauge (psig) to outlet pressures of 60 to 100 psig. The compressor is boosting gas pressure from approximately 1 to 100 psig in this application. The compressor imposes a parasitic load of approximately 4 kW on the overall CHP system generating capacity.

Waste heat from the microturbine exhaust is recovered using a Cain Industries heat recovery and control system. It is a steel fin-and-tube Heat Recovery Silencer (HRS) radial heat exchanger and silencer (Model 112B28.SSS) suitable for up to 700 °F exhaust gas. Potable water is used as the heat-transfer media to recover energy from the microturbine exhaust gas. The water is circulated at a rate of approximately 28 gallons per minute (gpm). A digital controller monitors the water outlet temperature. When the temperature exceeds the user set point, a damper automatically opens and allows the hot exhaust gas to bypass the heat exchanger and release the heat through the stack. The damper allows hot gas to circulate through the heat exchanger when heat recovery is required (i.e., the water outlet temperature is less than user setpoint). This design allows the system to protect the heat recovery components from the full heat of the turbine exhaust while still maintaining full electrical generation from the microturbine.

The Colorado Pork facility is a sow farrow-to-wean farm in Lamar, Colorado that began operation in 1999 and houses up to 5,000 sows. The facility employs a complete mix anaerobic digester to reduce odor and meet water quality regulations mandated by the Colorado Department of Public Health and Environment. The anaerobic digester promotes bacterial decomposition of volatile solids in animal wastes. The resulting effluent stream consists of mostly water, which is allowed to evaporate from a secondary lagoon. Solids produced by the process accumulate in the digester and are manually removed. Recovered heat from the microturbine CHP is circulated through the waste in the digester to maintain the digester temperature at approximately 100 °F. Cool water returning from the digester remains relatively constant throughout the year. A temperature sensor continuously monitors this temperature, and in the event this temperature exceeds 105 °F, an automated mixing valve reduces the flow of hot water entering the digester.

VERIFICATION DESCRIPTION

Testing was conducted on February 14 and 15, 2004. The verification included a series of controlled test periods in which the GHG Center intentionally controlled the unit to produce electricity at nominal power output levels of 30, 24, 20, and 15 kW. Three replicate test runs were conducted at each setting. A 7-day extended monitoring period was planned to verify power and heat production, power quality performance, and emissions offsets during normal site operations. However, this could not be completed due to system startup and shakedown delays that resulted in GHG Center scheduling conflicts. Instead, the CHP performance was monitored continuously for a period of approximately 35 hours to evaluate power and heat production and power quality. In light of this, the emission offsets analysis was not conducted and the completeness data quality objective of 7-days was not met. During all test periods, waste heat was recovered and routed through the digester at temperatures of approximately 100 °F. The classes of verification parameters evaluated were:

- **Heat and Power Production Performance**
- **Emissions Performance (NO_x, CO, THC, CH_4, SO_2, TRS, TPM, NH_3, and CO_2)**
- **Power Quality Performance**

Evaluation of heat and power production performance included verification of power output, heat recovery rate, electrical efficiency, thermal efficiency, and total system efficiency. Electrical efficiency was determined according to the ASME Performance Test Code for Gas Turbines (ASME PTC-22). Tests consisted of direct measurement of fuel flow rate, fuel lower heating value (LHV), and power output. Heat recovery rate and thermal efficiency were determined according to ANSI/ASHRAE test methods and consisted of direct measurement of heat-transfer fluid flow rate and differential temperatures. Ambient temperature, barometric pressure, and relative humidity measurements were also collected to characterize the condition of the combustion air used by the microturbine. All measurements were recorded as 1-minute averages during the controlled test periods and throughout the 7-day monitoring period.

The evaluation of emissions performance occurred simultaneously with efficiency testing. Pollutant concentration and emission rate measurements for nitrogen oxides (NO_X), carbon monoxide (CO), total hydrocarbons (THC), methane (CH_4), sulfur dioxide (SO_2), total reduced sulfur (TRS), total particulate matter (TPM), ammonia (NH_3), and carbon dioxide (CO_2) were conducted in the turbine exhaust stack. All test procedures used in the verification were U.S. EPA reference methods recorded in the Code of Federal Regulations (CFR). Pollutant emissions are reported as concentrations in parts per million volume, dry (ppmvd) corrected to 15-percent oxygen (O_2), and as mass per unit time (lb/hr). The mass emission rates are also normalized to microturbine power output and reported as pounds per kilowatt hour (lb/kWh).

Electrical power quality parameters, including electrical frequency and voltage output, were measured during the controlled tests and the 35-hour monitoring period. Current and voltage total harmonic distortions (THD) and power factors were also monitored to characterize the quality of electricity supplied to the end user. The guidelines listed in “The Institute of Electrical and Electronics Engineers’ (IEEE) Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems” were used to perform power quality testing.

Quality Assurance (QA) oversight of the verification testing was provided following specifications in the ETV Quality Management Plan (QMP). The GHG Center’s QA Manager conducted an audit of data quality on at least 10 percent of the data generated during this verification and a review of this report. Data review and validation was conducted at three levels including the field team leader (for data generated by subcontractors), the project manager, and the QA manager. Through these activities, the QA manager has concluded that, with the exception of the extended monitoring completeness goal described earlier, the data meet the data quality objectives that are specified in the Test and Quality Assurance Plan.

VERIFICATION OF PERFORMANCE

Heat and Power Production Performance

MICROTURBINE CHP HEAT AND POWER PRODUCTION					
Test Condition (Power Command)	Electrical Power Generation		Heat Recovery Performance		Total CHP System Efficiency (%)
	Net Power Delivered (kW)	Net Efficiency (%)	Heat Recovery (10^3Btu/hr)	Thermal Efficiency (%)	
30 kW	19.9	20.4	111	33.3	53.7
24 kW	19.3	20.3	116	35.8	56.2
20 kW	15.0	18.6	108	39.2	57.7
15 kW	10.1	15.7	96.9	44.1	59.8

- The relatively high altitude of the facility (roughly 3,700 feet) and the parasitic load introduced by the gas compressor limit the turbine's power output performance. At the full power output command of 30 kW, the average net power delivered to the facility was 19.9 kW. Corresponding electrical efficiency at full load was 20.4 percent.

- Average electrical efficiencies at the reduced power commands of 24, 20, and 15 kW decreased to 20.3, 18.6, and 15.7 percent, respectively.

- Total CHP efficiency during the controlled test periods ranged from a low of 53.7 percent at the 30 kW load to a high of 59.8 percent at 15 kW. Normal heat recovery operations were maintained during the controlled test periods with the system configured to maintain the digester temperature at approximately 100°F.

Emissions Performance

MICROTURBINE EMISSIONS (lb/kWh)									
Power Command	NO_X	CO	THC	CH_4	SO_2	TRS	TPM	NH_3	CO_2
30 kW	8.21×10^{-5}	0.009	0.0027	0.0022	0.037	0.0008	0.0006	6.07×10^{-7}	3.45
24 kW	9.47×10^{-5}	0.010	0.0032	0.0027	0.039	0.0002	Not tested	Not tested	3.61
20 kW	1.95×10^{-3}	0.010	0.0035	0.0028	0.040	0.0005	Not tested	Not tested	3.79
15 kW	2.19×10^{-3}	0.017	0.0105	0.0087	0.042	0.0002	Not tested	Not tested	3.90

- NO_X emissions at 30 kW were 8.21×10^{-5} lb/kWh and increased as power output decreased. CO emissions averaged 0.009 lb/kWh at 30 kW and also increased slightly at the reduced loads.

- THC emissions at full load averaged 2.69×10^{-3}lb/kWh and increased as the power output was decreased. CH_4 emissions were similar, averaging 2.23×10^{-3} at full load, and representing approximately 80 percent of the THC emission rate.

- Emissions of SO_2 and TRS averaged 0.037 and 0.0008 lb/kWh respectively at full load and were not significantly impacted by load changes. Emissions of TPM and NH_3 were very low during the full load tests.

NO_X emissions per unit electrical power output at 30 kW (0.00008 lb/kWh), were well below the published weighted average U.S. and Colorado regional fossil fuel emission factors of 0.0066 and 0.0077 lb/kWh. The generator system CO_2 emission rate at full load is higher than the weighted average fossil fuel emission factors for both the U.S. and Colorado regional grids (2.02 and 2.13 lb/kWh, respectively). This indicates a likely increase in annual CO_2 emissions for power production from this system, based solely on electrical generation. Due to the reduction in the extended monitoring period, a true estimation of annual emissions offsets could not be completed.

Power Quality Performance

- Average electrical frequency was 59.999 Hz and average voltage output was 487.25 volts.
- The power factor remained relatively constant at full load, averaging 94.53 percent.
- The average current total harmonic distortion was 3.21 percent and the average voltage THD was 1.89, both well below the threshold specified in IEEE 519 of ± 5 percent.

Details on the verification test design, measurement test procedures, and Quality Assurance/Quality Control (QA/QC) procedures can be found in the Test plan titled *Test and Quality Assurance Plan for Swine Waste Electric Power and Heat Production Systems: Capstone Microturbine and Martin Machinery Internal Combustion Engine* (SRI 2002). Detailed results of the verification are presented in the Final Report titled *Environmental Technology Verification Report for Swine Waste Electric Power and Heat Production – Capstone 30 kW Microturbine System* (SRI 2004). Both can be downloaded from the GHG Center's web-site (www.sri-rtp.com) or the ETV Program web-site (www.epa.gov/etv).

Signed by Lawrence W. Reiter, Ph.D. 9/27/04	Signed by Stephen D. Piccot 9/13/04
Lawrence W. Reiter, Ph.D. Acting Director National Risk Management Research Laboratory Office of Research and Development	Stephen D. Piccot Director Greenhouse Gas Technology Center Southern Research Institute

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Greenhouse Gas Technology Center

A U.S. EPA Sponsored Environmental Technology Verification (ETV) Organization

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Swine Waste Electric Power and Heat Production – Capstone 30 kW Microturbine System

Prepared By:
Greenhouse Gas Technology Center
Southern Research Institute
PO Box 13825
Research Triangle Park, NC 27709 USA
Telephone: 919/806-3456

Under EPA Cooperative Agreement CR 829478

U.S. Environmental Protection Agency
Office of Research and Development
National Risk Management Research Laboratory
Air Pollution Prevention and Control Division
Research Triangle Park, NC 27711 USA

EPA Project Officer: David A. Kirchgessner
Colorado Governor's Office Project Officer: Edward Lewis

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ACRONYMS AND ABBREVIATIONS

Abs Diff.	absolute difference
AC	alternating current
acf	actual cubic feet
ADQ	Audit of Data Quality
amp	amperes
ANSI	American National Standards Institute
APPCD	Air Pollution Prevention and Control Division
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc.
ASME	American Society of Mechanical Engineers
Btu	British thermal units
Btu/hr	British thermal units per hour
Btu/lb	British thermal units per pound
Btu/min	British thermal units per minute
Btu/scf	British thermal units per standard cubic foot
CAR	Corrective Action Report
C1	quantification of methane
CH_4	methane
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
CT	current transformer
DAS	data acquisition system
DG	distributed generation
DOE	U.S. Department of Energy
DP	differential pressure
DQI	data quality indicator
DQO	data quality objective
dscf/10^6Btu	dry standard cubic feet per million British thermal units
EA	Engineering Assistant
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ETV	Environmental Technology Verification
°C	degrees Celsius
°F	degrees Fahrenheit
FID	flame ionization detector
fps	feet per second
ft^3	cubic feet
gal	U.S. gallons
GC	gas chromatograph
GHG Center	Greenhouse Gas Technology Center
gpm	gallons per minute
GU	generating unit
HHV	higher heating value
hr	hour
Hz	hertz
IC	internal combustion

(continued)

ACRONYMS/ABBREVIATIONS
(continued)

IEEE	Institute of Electrical and Electronics Engineers
ISO	International Standards Organization
kVA	kilovolt-amperes
kVAr	kilovolt reactive
kW	kilowatts
kWh	kilowatt hours
kWh_e	kilowatt hours electrical
kWh_{th}	kilowatt hours thermal
kWh/yr	kilowatt hours per year
lb	pounds
lb/Btu	pounds per British thermal unit
lb/dscf	pounds per dry standard cubic foot
lb/ft^3	pounds per cubic feet
lb/hr	pounds per hour
lb/kWh	pounds per kilowatt-hour
lb/yr	pounds per year
LHV	lower heating value
10^3Btu/hr	thousand British thermal units per hour
10^6Btu/hr	million British thermal units per hour
10^6cf	million cubic feet
mol	mole
N_2	nitrogen
NDIR	nondispersive infrared
NIST	National Institute of Standards and Technology
NO	nitrogen oxide
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O_2	oxygen
O_3	ozone
ORD	Office of Research and Development
PEA	Performance Evaluation Audit
ppmv	parts per million volume
ppmvw	Parts per million volume wet
ppmvd	parts per million volume, dry
psia	pounds per square inch, absolute
psig	pounds per square inch, gauge
PT	potential transformer
QA/QC	Quality Assurance/Quality Control

(continued)

ACRONYMS/ABBREVIATIONS
(continued)

QMP	Quality Management Plan
Rel. Diff.	relative difference
Report	Environmental Technology Verification Report
RH	relative humidity
rms	root mean square
rpm	revolutions per minute
RTD	resistance temperature detector
scf	standard cubic feet
scfh	standard cubic feet per hour
scfm	standard cubic feet per minute
Southern	Southern Research Institute
T&D	transmission and distribution
Test plan	Test and Quality Assurance Plan
THCs	total hydrocarbons
THD	total harmonic distortion
TSA	technical systems audit
U.S.	United States
VAC	volts alternating current

1.0 INTRODUCTION

1.1. BACKGROUND

The U.S. Environmental Protection Agency's Office of Research and Development (EPA-ORD) operates the Environmental Technology Verification (ETV) program to facilitate the deployment of innovative technologies through performance verification and information dissemination. The goal of ETV is to further environmental protection by accelerating the acceptance and use of improved and innovative environmental technologies. Congress funds ETV in response to the belief that there are many viable environmental technologies that are not being used for the lack of credible third-party performance data. With performance data developed under this program, technology buyers, financiers, and permitters in the United States and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

The Greenhouse Gas Technology Center (GHG Center) is one of six verification organizations operating under the ETV program. The GHG Center is managed by EPA's partner verification organization, Southern Research Institute (Southern), which conducts verification testing of promising greenhouse gas mitigation and monitoring technologies. The GHG Center's verification process consists of developing verification protocols, conducting field tests, collecting and interpreting field and other data, obtaining independent peer-reviewed input, and reporting findings. Performance evaluations are conducted according to externally reviewed verification Test and Quality Assurance Plans (test plan) and established protocols for quality assurance.

The GHG Center is guided by volunteer groups of stakeholders. These stakeholders guide the GHG Center on which technologies are most appropriate for testing, help disseminate results, and review Test plans and Technology Verification Reports (report). The GHG Center's Executive Stakeholder Group consists of national and international experts in the areas of climate science and environmental policy, technology, and regulation. It also includes industry trade organizations, environmental technology finance groups, governmental organizations, and other interested groups. The GHG Center's activities are also guided by industry specific stakeholders who provide guidance on the verification testing strategy related to their area of expertise and peer-review key documents prepared by the GHG Center.

A technology of interest to GHG Center stakeholders is the use of microturbines as a distributed generation source. Distributed generation (DG) refers to power-generation equipment, typically ranging from 5 to 1,000 kilowatts (kW), that provide electric power at a site much closer to customers than central station generation. A distributed power unit can be connected directly to the customer or to a utility's transmission and distribution system. Examples of technologies available for DG include gas turbine generators, internal combustion engine generators (e.g., gas, diesel), photovoltaics, wind turbines, fuel cells, and microturbines. DG technologies provide customers one or more of the following main services: stand-by generation (i.e., emergency backup power), peak shaving capability (generation during high-demand periods), baseload generation (constant generation), or cogeneration {combined heat and power (CHP) generation}.

Recently, biogas production from livestock manure management facilities has become a promising alternative for fueling DG technologies. EPA estimates U.S. methane emissions from livestock manure management at 17.0 million tons carbon equivalent, which accounts for 10 percent of total 1997 methane emissions. The majority of methane emissions come from large swine and dairy farms that manage manure as slurry. EPA expects U.S. methane emissions from livestock manure to grow by over 25 percent from 2000 to 2020. Cost effective technologies are available that can stem this emission growth by recovering methane and using it as an energy source. These technologies, commonly referred to as anaerobic digesters, decompose manure in a controlled environment and recover methane produced from the manure. The recovered methane can fuel power generators to produce electricity, heat, and hot water. Digesters also reduce foul odor and can reduce the risk of ground- and surface-water pollution.

The GHG Center and the Colorado Governor's Office of Energy Management and Conservation (OEMC) agreed to collaborate and share the cost of verifying two DG technologies that operate on biogas recovered from swine waste. These verifications evaluated the performance of a microturbine combined heat and power (CHP) system offered by Capstone Turbine Corporation and an internal combustion (IC) engine CHP system offered by Martin Machinery, Inc. Both units are currently in operation at an anaerobic digestion facility managed by Colorado Pork, LLC near Lamar, Colorado. This is the only swine farm in Colorado that is producing electrical power from animal waste. The electricity is used by Colorado Pork to offset electricity purchases from the local electric cooperative. Some of the recovered heat is used to control digester temperature, which optimizes and enhances biogas production. Both CHP systems are interconnected to the electric utility grid, but excess power is not presently exported.

The GHG Center evaluated the performance of the two CHP systems by conducting field tests over a fourteen-day verification period (February 2 – 15, 2004). These tests were planned and executed by the GHG Center to independently verify the electricity generation and use rate, thermal energy recovery rate, electrical power quality, energy efficiency, emissions, and greenhouse gas emission reductions for the Colorado Pork farm. This verification statement and report provides the results of the Capstone 30 microturbine CHP performance evaluation. Results of the testing conducted on the IC engine CHP system are reported in a separate report titled *Environmental Technology Verification Report – Swine Waste Electric Power and Heat Production – Martin Machinery Internal Combustion Engine* [1].

Details on the verification test design, measurement test procedures, and Quality Assurance/Quality Control (QA/QC) procedures can be found in the test plan titled *Test and Quality Assurance Plan – Swine Waste Electric Power and Heat Production Systems: Capstone Microturbine and Martin Machinery Internal Combustion Engine* [2]. It can be downloaded from the GHG Center's web-site (www.sri-rtp.com) or the ETV Program web-site (www.epa.gov/etv). The Test plan describes the rationale for the experimental design, the testing and instrument calibration procedures planned for use, and specific QA/QC goals and procedures. The Test plan was reviewed and revised based on comments received from OEMC and the EPA Quality Assurance Team. The Test plan meets the requirements of the GHG Center's Quality Management Plan (QMP) and satisfies the ETV QMP requirements. Deviations from the Test plan were required in some cases. These deviations and the alternative procedures selected for use were initially documented in Corrective Action Reports (CARs) and are discussed in this report.

The remainder of Section 1.0 describes the microturbine CHP system technology and test facility and outlines the performance verification procedures that were followed. Section 2.0 presents test results, and Section 3.0 assesses the quality of the data obtained.

1.2. COMBINED HEAT AND POWER TECHNOLOGY DESCRIPTION

The microturbine system verified at Colorado Pork consists of a Capstone Model 330 Microturbine and a Cain Industries heat-recovery system. These primary system components are shown in separate photos in Figure 1-1. The CHP system also includes a CompAir gas compressor which is needed to boost the delivered gas pressure to about 100 psig. Figure 1-2 illustrates a simplified process flow diagram of the microturbine CHP system at this site and a discussion of each component is provided below.

Capstone 30 kW Microturbine

Cain Industries Heat Recovery System

Figure 1-1. The Colorado Pork Capstone 330 Microturbine CHP System

Electric power is generated from a high-speed, single-shaft, recuperated, air-cooled turbine generator with a nominal rated power output of 30 kW net (59 °F, sea level). Table 1-1 provides Capstone 330 microturbine specifications. The Capstone 330 is designed to operate on biogas and consists of an air compressor, recuperator, combustor, turbine, and a permanent magnet generator. The recuperator is a heat exchanger that recovers some of the heat from the exhaust stream and transfers it to the incoming compressed air stream. The preheated air is then mixed with the fuel and this compressed fuel and air mixture is burned in the combustor under constant pressure conditions. The resulting hot gas is allowed to expand through the turbine section to perform work, rotating the turbine blades to turn a generator, which produces electricity. The need for a gearbox and associated moving parts is eliminated because of the inverter-based electronics that enable the generator to operate at high speeds and frequencies. The rotating components are mounted on a single shaft – supported by patented air bearings – that rotates at over 96,000 revolutions per minute (rpm) at full load. The exhaust gas exits the turbine and enters the recuperator which pre-heats the air entering the combustor to improve the efficiency of the system. The exhaust gas then exits the recuperator and is directed to a heat-recovery unit.

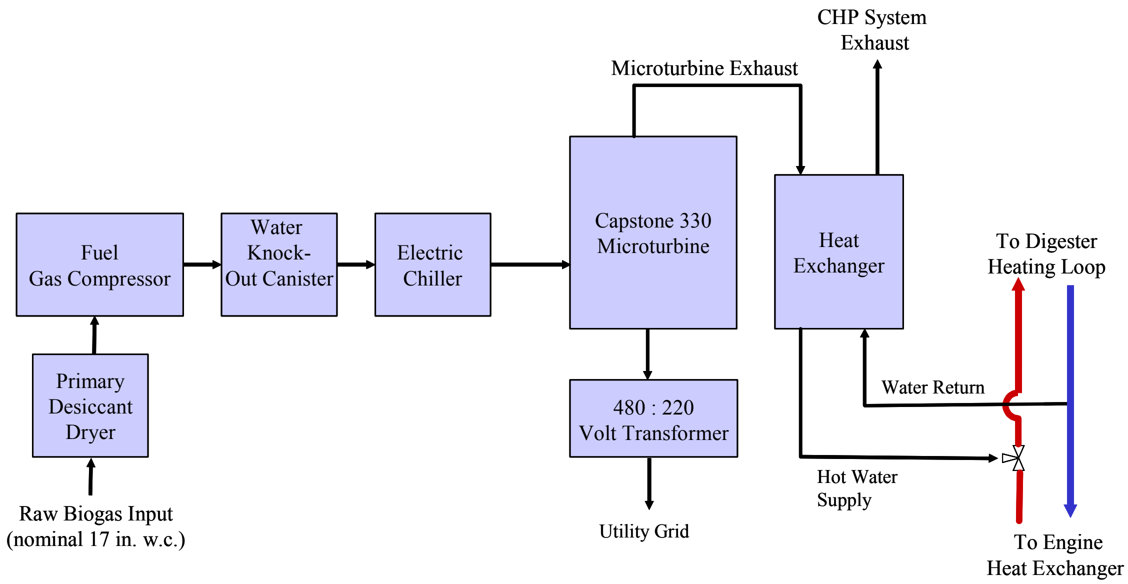


Figure 1-2. Colorado Pork Microturbine CHP System Process Diagram

The permanent magnet generator produces high-frequency alternating current which is rectified, inverted, and filtered by the line power unit into conditioned 480 volts alternating current (VAC). The unit supplies an electrical frequency of 60 hertz (Hz) and is supplied with a control system which allows for automatic and unattended operation. An active filter in the generator is reported by the turbine manufacturer to provide power free of spikes and unwanted harmonics. All operations including startup, setting of programmable interlocks, grid synchronization, operational setting, dispatch, and shutdown, can be performed manually or remotely using the internal power-controller system.

The gas booster compressor is a CompAir Hydrovane Model 704PKGS with a nominal volume capacity of 48 standard cubic feet per minute (scfm) and the capability of compressing natural gas from inlet pressures ranging from 0.25 to 15 pounds per square inch gauge (psig) to outlet pressures of 60 to 100 psig. The compressor is boosting gas pressure from approximately 1 to 100 psig in this application. The compressor imposes a parasitic load of approximately 4 kW on the overall CHP system generating capacity.

Figure 1-2 shows that waste heat from the microturbine exhaust, at approximately 580 °F, is recovered using a heat recovery and control system developed by Cain Industries. It is a steel fin-and-tube Heat Recovery Silencer (HRS) radial heat exchanger and silencer (Model 112B28.SSS) suitable for up to 700 °F exhaust gas. Potable water is used as the heat-transfer media to recover energy from the microturbine exhaust gas stream. The water is circulated at a rate of approximately 28 gallons per minute (gpm). A digital controller monitors the water outlet temperature, and when the temperature exceeds user set point, a damper automatically opens and allows the hot exhaust gas to bypass the heat exchanger and release the heat through the stack. The damper allows hot gas to circulate through the heat exchanger when heat recovery is required (i.e., the water outlet temperature is less than user setpoint). This design allows the system to protect the heat recovery components from the full heat of the turbine exhaust while still maintaining full electrical generation from the microturbine.

Table 1-1. Capstone Microturbine Model 330 Specifications (Source: Capstone Microturbine Corporation, Colorado Pork)		
Dimensions	Width Depth Height	28.1 in. 52.9 in. 74.8 in.
Weight	Microturbine only	1,052 lb
Electrical inputs	Power (startup) communications	Utility grid or black start battery Ethernet IP or modem
Electrical outputs	Power at ISO conditions (59 ^oF @ sea level)	30 kW, 400-480 VAC, 50/60 Hz, 3-phase
Noiselevel	Typical reported by Capstone	58 dBA at 33 ft
Fuel pressure required	w/o compressor w/ compressor	50 to 100 psig 5 to 15 psig
Fuel heat content	Higher heating value	350 to 1,200 Btu/scf
Electrical performance at full load (landfill or digester gas)	Heat input Power output Efficiency - w/o compressor Efficiency - w/ compressor Heat rate	378,000 Btu/hr, LHV basis 30 kW ±1 kW 27% ± 2%, ISO conditions, LHV basis 26% ± 2%, ISO conditions, LHV basis 12,600 Btu/kWh, LHV basis
Heat recovery potential at full load	Exhaust gas temperature Exhaust energy available for heat recovery	500 ^oF 290,000 Btu/hr
Emissions (full load)	Nitrogen oxides (NO_X) Carbon monoxide (CO) Total hydrocarbon (THCs)	< 9 ppmv at 15% O_2 < 40 ppmv at 15% O_2 < 9 ppmv at 15% O_2

1.3. TEST FACILITY DESCRIPTION

The Colorado Pork facility is a sow farrow-to-wean farm in Lamar, Colorado that began operation in 1999 and houses up to 5,000 sows. The facility employs a complete mix anaerobic digester (Figure 1-3) to reduce odor and meet water quality regulations mandated by the Colorado Department of Public Health and Environment. The anaerobic digester promotes bacterial decomposition of volatile solids in animal wastes. The resulting effluent stream mostly consists of water, which is allowed to evaporate from a secondary lagoon.

Waste from the 5,000 sows is collected in shallow pits below the slatted floors of the hog barns. These pits are connected via sewer lines to an in-ground concrete holding tank (50,000 gallon capacity). Each morning, the pits are drained on a rotating basis to flush about 15,000 gallons of waste to the holding tank. The holding tank is equipped with a 17 horsepower (Hp) chopper pump that breaks up large pieces of waste. Each morning, about 15,000 gallons of waste is pumped from the holding tank into the digester (requires approximately 20 minutes).

Figure 1-3. Colorado Pork Anaerobic Digester

The digester is a 70 x 80 x 14 foot deep in-ground concrete tank with a capacity of 500,000 gallons. The digester is equipped with two propeller type mixers on each end. The mixers normally operate for 30 minutes daily to rejuvenate gas production that would otherwise decline between waste charging events. Hot water is circulated through the digester using a matrix of 3-inch black steel pipe (total length of about 0.5 mile) to maintain the digester temperature at 100 °F. Small adjustments to the water flow rate are required periodically and are conducted manually by the site operator. The retention time in the digester is about 40 days.

The effluent exits the digester over a weir, and is directed gravimetrically to a lagoon for sludge settling and water evaporation. The lagoon is designed to hold up to 20 years of sludge production. Tests performed by environmental regulatory personnel have determined the site meets current odor and discharge requirements.

The biogas produced from the decomposed waste is collected under a high-density polyethylene (HDPE) cover at a pressure of 15 to 20 inches water column. A manifold collects the biogas and routes it to the engine/turbine building. A pressure relief valve senses pressure buildup when neither the engine nor turbine are operating, and diverts the biogas to a flare. The digester is currently producing about 20,000 cubic feet of biogas per day. The primary gas constituents of the raw biogas are CH_4 (around 67%) and CO_2 (approximately 32%). Analysis of samples collected at the site show hydrogen sulfide (H_2S) concentrations in the gas ranging from 700 to 6,800 parts per million (ppm) and averaging about 6,000 ppm. The gas also contains trace amounts of ammonia (NH_3), mercaptans, and other noxious gases, and is saturated with water vapor. The lower heating value (LHV) of the biogas is approximately 625 Btu/scf.

Figure 1-4 is a schematic of the waste-to-energy production process at Colorado Pork showing integration of the digester, microturbine CHP, and engine CHP. In May 2000, the IC engine CHP system was installed first to offset electricity purchase costs. The microturbine CHP system was installed in February 2002, to evaluate the feasibility and economics of the two different power generation technologies. Both systems are currently housed in a building adjacent to the digester.

With the microturbine CHP system, the biogas is treated and compressed to produce high-pressure, dry biogas for electricity production. The site operator sets the heat recovery unit at 110 °F during normal operations. Any unused heat is discarded automatically through the exhaust stack. With the IC engine CHP system, biogas is not pre-treated. The IC engine's heat recovery system produces hot water at approximately 105 °F. In the event this temperature exceeds 185 °F (i.e., during extremely hot summer days), an automatic valve is activated, which discards some of the excess heat through a radiator. The radiator's return water line is used to cool the engine water jacket and prevent overheating the engine.

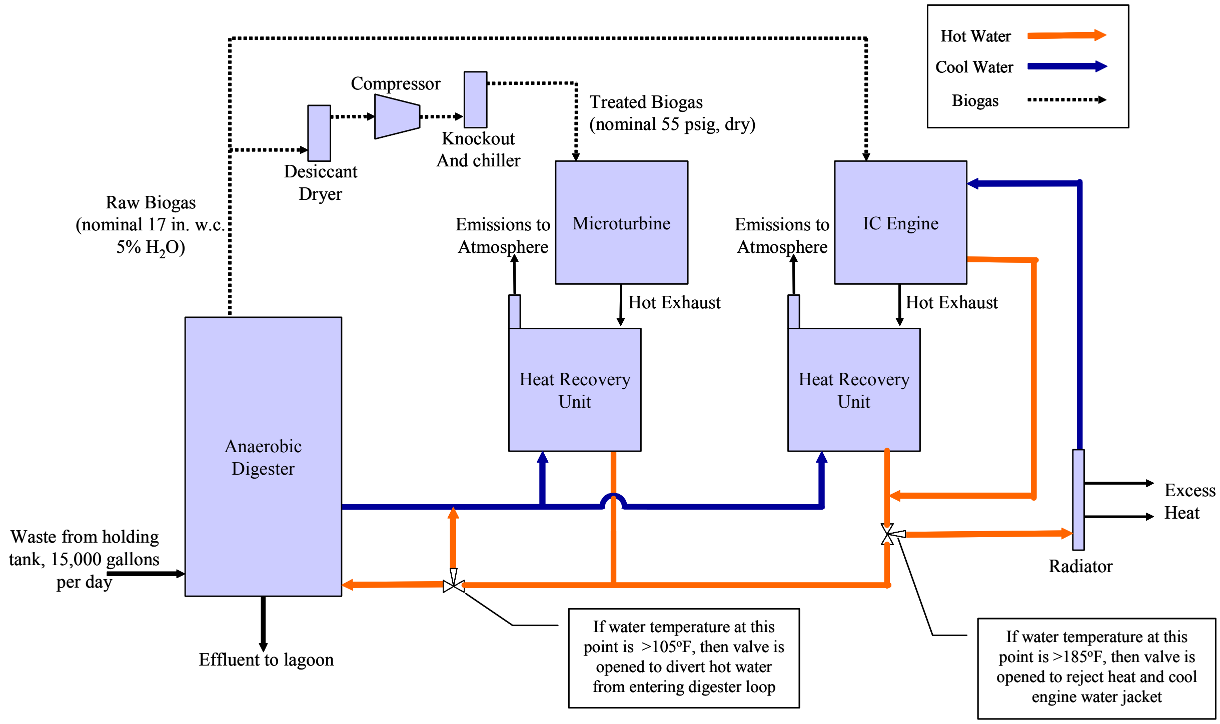


Figure 1-4. Colorado Pork Waste-to-Energy Process Diagram

The IC engine hot water line combines with the microturbine hot water line, and the mixture is circulated through the waste in the digester to maintain the digester temperature at 100 °F. Cool water returning from the digester remains relatively constant throughout the year (approximately 100 °F). A temperature sensor continuously monitors this temperature, and in the event this temperature exceeds 105 °F, an automated mixing valve reduces the flow of hot water entering the digester. This adjustment is performed only a few times per year, as digester temperatures remain relatively stable.

Typically, the engine is run at 45 kW and switched to run on natural gas overnight to avoid reducing biogas pressure and collapsing the digester cover. When the microturbine is used, it can be run on biogas continuously. The system is fully grid parallel. When power demand of the farm operations exceed the available capacity of the power generation systems, power is drawn from the utility grid. Colorado Pork purchases electricity from the Southeast Colorado Power Association, a rural electric cooperative.

1.4. PERFORMANCE VERIFICATION OVERVIEW

This verification test was designed to evaluate the performance of the microturbine CHP system—not the overall system integration or specific management strategy. The test plan specified a series of controlled test periods in which the GHG Center intentionally modulated the unit to produce electricity at nominal power output commands of 15, 20, 24, and 30 kW. Three replicate test runs were conducted at each of these power commands. These tests are identified herein as controlled test periods. During these controlled test periods, the engine was shut down to make maximize biogas availability.

Originally, the test plan specified that these tests would be conducted with the heat recovery potential maximized by increasing the hot water supply temperature from the heat recovery unit to approximately 125 ^oF. However, changes in CHP system operations at the farm have occurred since development of the test plan. Specifically, hot water supply temperatures are controlled at about 105 ^oF to maintain the optimum digester temperature of approximately 100 ^oF. It was not possible during the verification testing to reach the supply temperatures originally proposed without adversely affecting digester operations. All of the heat generated by the heat recovery unit was being used to warm the digester. These test conditions represent normal site operations with the amount of biogas currently available, and the maximum achievable heat recovery rate for this application (that is, heat is only recovered and used to maintain the optimum digester temperature).

The test plan also specified that the controlled test periods would be followed by a 1-week period of extended monitoring to evaluate power and heat production and power quality over a range of ambient conditions and farm operations. However, numerous delays and false starts to this test program caused by problems with microturbine operations (primarily gas compressor functionality) produced serious scheduling conflicts for the GHG Center's operations. In response to this, the center was forced to deviate from the test plan on this monitoring. After consultation with the GHG QA manager and the GHG Center director, it was decided to conduct an abbreviated evaluation of power and heat production and power quality using data collected continuously over a limited time period of 35 hours. This 35-hour period includes the controlled test periods.

The specific verification parameters associated with the test are listed below. Brief discussions of each verification parameter and its method of determination are presented in Sections 1.4.1 through 1.4.5. Detailed descriptions of testing and analysis methods are not provided here but can be found in the test plan.

Heat and Power Production Performance

- Electrical power output and heat recovery rate at selected loads
- Electrical, thermal, and total system efficiency at selected loads

Power Quality Performance

- Electrical frequency
- Voltage output
- Power factor
- Voltage and current total harmonic distortion

Emissions Performance

- Nitrogen oxides (NO_X), carbon monoxide (CO), total hydrocarbons (THC), ammonia (NH_3), total reduced sulfur (TRS), total particulate matter (TPM), carbon dioxide (CO_2), and methane (CH_4) concentrations at selected loads
- NO_X, CO, THC, NH_3, TRS, TPM, CO_2, and CH_4 emission rates at selected loads

Each of the verification parameters listed were evaluated during the controlled or continuous monitoring periods as summarized in Table 1-2. This table also specifies the dates and time periods during which the testing was conducted.

Table 1-2. Controlled and Continuous Test Periods

Controlled Test Periods

Start Date, Time	End Date, Time	Test Condition	Verification Parameters Evaluated
02/14/04, 09:26	02/14/04, 16:45	Power command of 30 kW, three 30-minute test runs (120 minutes for TPM and NH_3)	NO_X, CO, SO_2, THC, TRS, TPM, NH_3, CH_4, CO_2 emissions, and electrical, thermal, and total efficiency
02/14/04, 16:53	02/14/04, 18:23	Power command of 24 kW, three 30-minute test runs	NO_X, CO, SO_2, THC, TRS, CH_4, CO_2 emissions, and electrical, thermal, and total efficiency
02/15/04, 10:00	02/15/04, 11:30	Power command of 20 kW, three 30-minute test runs	
02/15/04, 12:00	02/15/04, 13:30	Power command of 15 kW, three 30-minute test runs	

Continuous Test Period

Start Date, Time	End Date, Time	Verification Parameters Evaluated
02/14/04, 11:30	02/15/04, 22:26	Power and heat generation rate and power quality

Simultaneous monitoring for power output, heat recovery rate, heat input, ambient meteorological conditions, and exhaust emissions were performed during each of the controlled test periods. Manual samples of biogas were collected to determine fuel lower heating value and other gas properties. Replicate and average electrical power output, heat recovery rate, energy conversion efficiency (electrical, thermal, and total), and exhaust stack emission rates are reported for each test period.

Results from the continuous monitoring period are used to report the average power and heat production rate during normal facility operations and power quality performance.

1.4.1. Heat and Power Production Performance

Electrical efficiency determination was based upon guidelines listed in ASME Performance Test Code for Gas Turbines (PTC-22) [3], and was calculated using the average measured net power output, fuel flow rate, and fuel lower heating value (LHV) during each controlled test period. PTC-22 specifies that test runs be over time intervals of not less than 4 minutes and not greater than 30 minutes to compute electrical efficiency.

These restrictions minimize electrical efficiency determination uncertainties due to changes in operating conditions (e.g., turbine or engine speed, ambient conditions). Within this time period, PTC-22 specifies the maximum permissible limits in power output, fuel input, atmospheric conditions, and other parameters to be less than the values shown in Table 3-4. The CHP system has one primary internal parasitic load at this facility – the gas-pressure booster compressor which is rated to draw about 4 kW. The water fluid circulation pump also introduces a small internal parasitic load (approximately 500 watts). The chiller used to help in biogas moisture removal also draws about 500 watts, but this parasitic load is external to the CHP system. This verification did not include separate measurement of these parasitic loads and therefore reports the net system power output and efficiency (based on the usable power delivered by the system). Comparison of the net power output measured by the GHG Center and the microturbine's indicated power output (gross power generated is displayed on the control panel), however, confirms that the parasitic load was approximately 4.5 kW during all test periods.

The electrical power output (in kW) was measured continuously throughout the verification period with a 7500 ION Power Meter (Power Measurements Ltd.) and logged on the Center's data acquisition system (DAS) as 1-minute averages. Biogas fuel input was determined by recording manual meter readings during each of the controlled test periods. The biogas used to fuel the microturbine is metered on a wet basis, but fired on a dry basis after moisture removal and compression. Measured biogas flow to the microturbine was corrected for moisture content as well as temperature and pressure to determine fuel consumption as dry standard cubic feet per hour (scfh).

Fuel gas sampling and energy content analysis (via gas chromatograph) was conducted according to ASTM procedures to determine the lower heating value of the biogas. Ambient temperature, relative humidity, and barometric pressure were measured near the turbine air inlet to support the determination of electrical conversion efficiency as specified in PTC-22. Electricity conversion efficiency was computed by dividing the average electrical energy output by the average energy input using Equation 1.

$$\eta = \frac{3412.14\ kW}{HI} \qquad \text{(Equation. 1)}$$

where:

η	=	efficiency (%)
kW	=	average net electrical power output measured over the test interval (kW), (Capstone 330 power output minus power consumed by gas compressor and water circulation pump)
HI	=	average heat input using LHV over the test interval (Btu/hr); determined by multiplying the average mass flow rate of biogas to the system converted to standard cubic feet per hour (scfh) times the gas LHV (Btu per standard cubic foot, Btu/scf)
3412.14	=	converts kW to Btu/hr

Simultaneous with electrical power measurements, heat recovery rate was measured using a heat meter (Controlotron Model 1010EP). The meter enabled 1-minute averages of differential heat exchanger temperatures and water flow rates to be monitored. Published fluid density and specific heat values for water were used so that heat recovery rates could be calculated at actual conditions per ANSI/ASHRAE Standard 125 [4].

$$\textit{Heat Recovery Rate (Btu/min)} = V\rho\, C_p\, (T1\text{-}T2) \qquad \text{(Equation. 2)}$$

where:

V	=	total volume of liquid passing through the heat meter flow sensor during a minute (ft^3)
ρ	=	density of water solution (lb/ft^3), evaluated at the avg. temp. (T2 plus T1)/2
C_p	=	specific heat of water solution (Btu/lb ^oF), evaluated at the avg. temp. (T2 plus T1)/2
T1	=	temperature of heated liquid exiting heat exchanger (^oF), (see Figure 1-4)
T2	=	temperature of cooled liquid entering heat exchanger (^oF), (see Figure 1-4)

The average heat recovery rates measured during the controlled tests and the continuous monitoring period represent the heat recovery performance of the CHP system. Thermal energy conversion efficiency was computed as the average heat recovered divided by the average energy input:

$$\eta_T = 60 * Q_{avg} / HI \qquad \text{(Equation. 3)}$$

where:

η_T = thermal efficiency (%)
Q_{avg} = average heat recovered (Btu/min)
HI = average heat input using LHV (Btu/hr); determined by multiplying the average mass flow rate of biogas to the system (converted to scfh) times the gas LHV (Btu/scf)

Figure 1-5 illustrates the location of measurement variables contained in Equations 1 through 3. Power output was measured using a 7500 ION Power Meter (Power Measurements Ltd.) at a rate of approximately one reading every 8 to 12 milliseconds and logged on the center's data acquisition system (DAS) as 1-minute averages. The power meter was located in the main switchbox connecting the electrical output of the CHP system to the host site. This location represented net power delivered to the farm after internal parasitic loads. The logged one-minute average power output (kW) readings were averaged over the duration of each controlled test period for use in computing electrical efficiency. The kW readings were integrated over the duration of the 35-hour verification period to calculate total electrical energy generated in units of kilowatt hours (kWh).

Biogas fuel input was measured with an in-line Dresser-Roots Series B Model 3M175 rotary displacement meter. Meter readings were recorded, manually at 10-minute intervals during the controlled test periods. Gas temperature and pressure sensors were installed to enable flow rate compensation to provide mass flow output at standard conditions (60 ^{o}F, 14.696 psia).

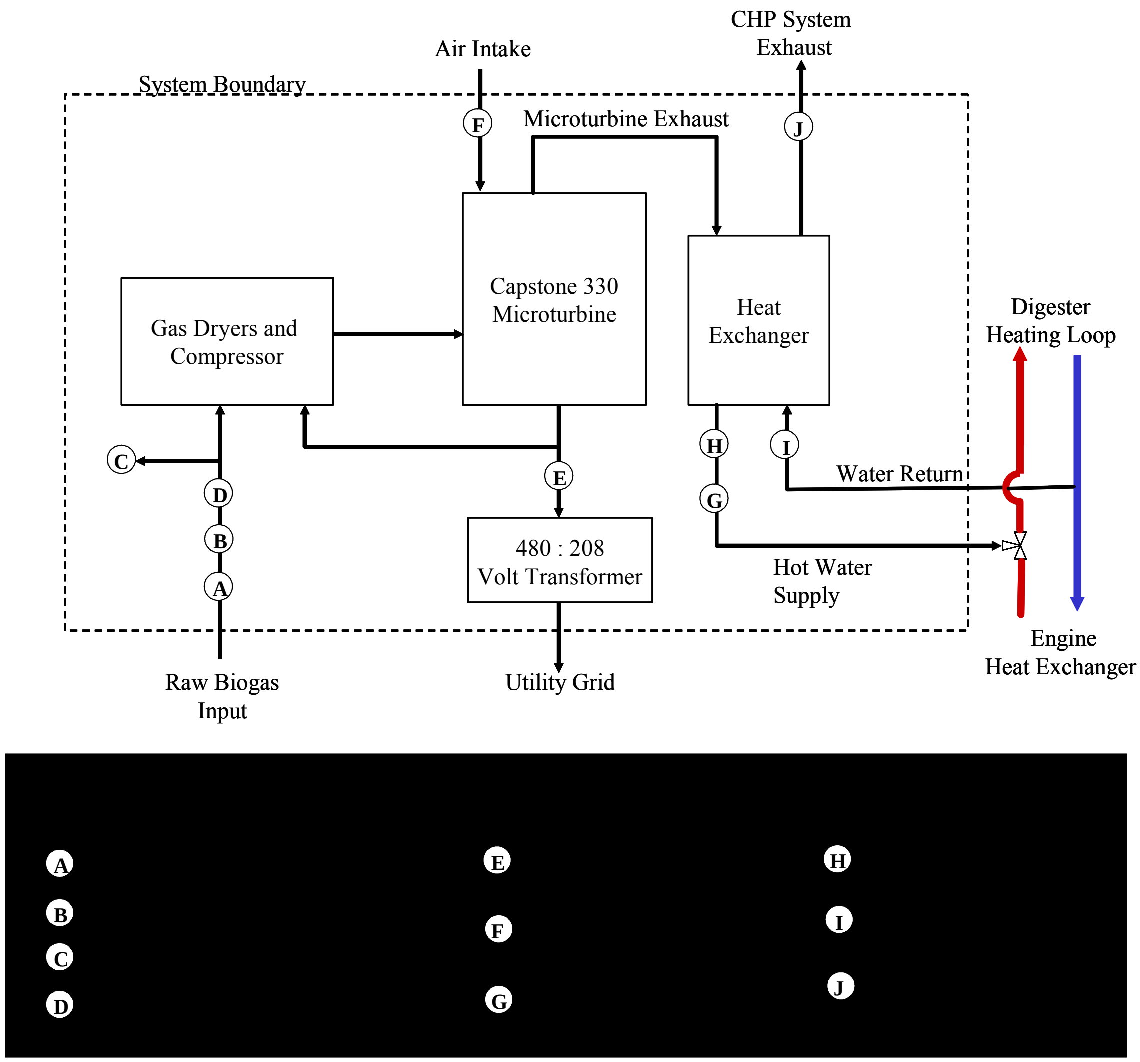
The biogas flow rates, metered on a wet basis, were corrected to dry basis to represent the volume of gas actually consumed by the microturbine. Biogas moisture content was determined for each controlled test run using the average measured biogas temperature and pressure, and the published partial pressure of saturated gas [5]. It was then assumed that the biogas as fired was dry (after the 3-stage moisture removal system and compression to 100 psig). Dry biogas flow rate was then calculated as:

$$V_d = V_w * (1 - B_w) \qquad \text{(Equation. 4)}$$

where:

V_d = biogas volume, wet basis (dscf)
V_w = biogas volume, dry basis (wscf)
B_w = biogas moisture content (%)

The TQAP specified a stain tube method of moisture determination that has an estimated 25 percent uncertainty. However, the GHG Center has learned on similar verifications conducted since the TQAP was written, that the approach used here is more reliable and has less uncertainty than the stain tube procedure.



[redacted]

Figure 1-5. Schematic of Measurement System

A total of six biogas samples were collected and analyzed during the controlled test periods to determine gas composition and heating value. Samples were collected at a point in the biogas delivery line downstream of the meter, but upstream of the gas drying system and compressor due to sampling restrictions (high gas pressure and the absence of sampling ports). The samples were submitted to Empact Analytical Systems, Inc., of Brighton, CO, for compositional analysis in accordance with ASTM Specification D1945 for quantification of methane (C1) to hexane plus (C6+), nitrogen, oxygen, and carbon dioxide [6]. The compositional data were then used in conjunction with ASTM Specification D3588 to calculate LHV and the relative density of the gas [7].

In addition to the ASTM D1945 compositional analyses, ASTM Method 5504 provided an extended analysis to quantify biogas concentrations of H_2S [8]. This method is essentially an extension of the ASTM D1945 procedures that uses additional chromatographic columns to separate H_2S and heavier hydrocarbons.

A Controlotron Model 1010EP1 energy meter was used to monitor water flow and supply and return temperatures. This meter is a digitally integrated system that includes a portable computer, ultrasonic fluid flow transmitters, and 1,000-ohm platinum resistance temperature detectors (RTDs). The meter has an overall rated accuracy of ± 2 percent of reading and provides a continuous 4-20 mA output signal over a selectable range. The meter was installed in the 1-1/2-inch carbon steel water supply line.

The water flow rate and supply and return temperature data used to determine heat recovery rates were logged as one-minute averages throughout all test periods. The heat transfer fluid density and specific heat were determined by using ASHRAE and ASME density and specific heat values for water corrected to the average water temperature measured by the RTDs.

1.4.2. Power Quality Performance

The GHG Center and its stakeholders developed the following power quality evaluation approach to account for these issues. Three documents [9, 10, 11] formed the basis for selecting the power quality parameters of interest and the measurement methods used. The GHG Center measured and recorded the following power quality parameters during the continuous monitoring period:

- Electrical frequency
- Voltage
- Voltage THD
- Current THD
- Power factor

The 7500 ION power meter used for power output determinations was used to perform these measurements as described below and detailed in the test plan. The ION power meter continuously measured electrical frequency at the generator's distribution panel, and the DAS was used to record one-minute averages throughout the verification. The mean, maximum, and minimum frequencies as well as the standard deviation are reported.

The CHP unit generates power at nominal 480 volts (AC). The electric power industry accepts that voltage output can vary within ± 10 percent of the standard voltage (480 volts) without causing significant disturbances to the operation of most end-use equipment [11]. Deviations from this range are often used to quantify voltage sags and surges. The ION power meter continuously measured true root mean square (rms) line-to-line voltage at the generator's distribution panel for each phase pair. True rms voltage readings provide the most accurate representation of AC voltages. The DAS recorded one-minute averages for each phase pair throughout the monitoring period as well as the average of the three phases. The mean, maximum, and minimum voltages, as well as the standard deviation for the average of the three phases, are reported.

THD is created by the operation of non-linear loads. Harmonic distortion can damage or disrupt many kinds of industrial and commercial equipment. Voltage harmonic distortion is any deviation from the pure AC voltage sine waveform. THD gives a useful summary view of the generator's overall voltage quality. The specified value for total voltage harmonic is a maximum THD of 5.0 percent based on "recommended practices for individual customers" in the IEEE 519 Standard. The ION meter continuously measured voltage THD up to the 63rd harmonic for each phase. The DAS recorded one-minute voltage THD averages for each phase throughout the test period and reported the mean, minimum, maximum, and standard deviation for the average THD for the three phases.

Current THD is any distortion of the pure current AC sine waveform. The current THD limits recommended in the IEEE 519 standard range from 5.0 to 20.0 percent, depending on the size of the CHP generator, the test facility's demand, and its distribution network design as compared to the capacity of the local utility grid. Detailed analysis of the facility's distribution network and the local grid are beyond the scope of this verification. The GHG Center, therefore, reported current THD data without reference to a particular recommended THD limit. The ION power meter, as with voltage THD, continuously measured current THD for each phase and reported the average, minimum, and maximum values for the period.

The ION power meter also continuously measured average power factor across each generator phase. The DAS recorded one-minute averages for each phase during all test periods. The GHG Center reported maximum, minimum, mean, and standard deviation power factors averaged over all three phases.

1.4.3. Emissions Performance

Pollutant concentration and emission rate measurements for NO_X, CO, THCs, SO_2, TRS, CH_4, and CO_2 were conducted on the turbine exhaust stack during all of the controlled test periods. Testing for determination of TPM and NH_3 was conducted at full load only. Emissions testing coincided with the efficiency determinations described earlier. The test procedures used are U.S. EPA reference methods, which are well documented in the Code of Federal Regulations (CFR). The reference methods include procedures for selecting measurement system performance specifications and test procedures, quality control procedures, and emission calculations (40CFR60, Appendix A) [12]. Table 1-3 summarizes the standard test methods that were followed. A complete discussion of the data quality requirements {for example, NO_X analyzer interference test, nitrogen dioxide [NO_2] converter efficiency test, sampling system bias and drift tests} is presented in the test plan.

Table 1-3. Summary of Emissions Testing Methods

Pollutant	EPA Reference Method	Analyzer Type	Range
NO_X	7E	California Analytical Instruments (CAI) 400-CLD (chemiluminescense)	0 – 50 ppm
CO	10	TEI Model 48 (NDIR)	0 - 300 ppm
SO_2	6C	Bovar 721-AT (NDUV)	0 – 300 ppm
THC	25A	California Analytical Instruments (FID)	0 – 300 ppm
CH_4	18	Hewlett-Packard 5890 GC/FID	0 - 300 ppm
CO_2	3A	CAI 200 (NDIR)	0 – 25%
O_2	3A	CAI 200 (electrochemical)	0 – 25%
TRS	EPA 16A	Ametek 921 White Cell (NDUV)	0 - 25 ppm
NH_3	BAAQMD ST-1B	Ion Specific Electrode	Not specified
TPM	EPA 5	Gravimetric	Not specified

Emissions testing was conducted by Cubix Corporation of Austin, Texas under the on-site supervision of the GHG Center field team leader. A detailed description of the sampling system used for each parameter listed is provided in the test plan and is not repeated in this report. Sampling was conducted during each test for approximately 30 minutes at a single point near the center of the 10-inch diameter stack. Results of the gaseous pollutant testing are reported in units of parts per million volume dry (ppmvd) and ppmvd corrected to 15-percent O_2. Concentrations of TPM are reported in units of grains per standard cubic foot (gr/dscf).

To convert measured pollutant concentrations to mass emissions, exhaust gas flow rate determinations were conducted during each test run in accordance with EPA Method 2C. Stack gas velocity and temperature traverses were conducted using a calibrated thermocouple, a standard pitot tube, and an inclined oil manometer. The number and location of traverse points sampled was selected in accordance with EPA Method 1. At the conclusion of each test run, equations specified in the reference methods were used to calculate exhaust gas velocity, actual volumetric flow rate, and volumetric flow rate at standard conditions.

After converting measured pollutant concentrations to mass units of lb/dscf, emission rate values were calculated in units of lb/hr using the standardized volumetric flow rates. The mean of the three test results at each load factor is reported as the average emission rate for that load factor. Emission rates for each pollutant are then normalized to system power and reported in terms of lb/kWh.

1.4.4. Estimated Annual Emission Reductions

The electric energy generated by the microturbine offsets electricity otherwise supplied by the utility grid. Consequently, the reduction in electricity demand from the grid caused by this offset will result in changes in CO_2 and NO_X emissions associated with producing an equivalent amount of electricity at central power plants. If the CHP emissions per kWh are less than the emissions per kWh produced by an electric utility, it can be inferred that a net reduction in emissions will occur at the site. If the emissions from the on-site generators are greater than the emissions from the grid, possibly due to the use of higher efficiency power generation equipment or zero emissions generating technologies (nuclear and hydroelectric) at the power plants, a net increase in emissions may occur.

The test plan included a detailed approach for estimating the emission reductions that this CHP system can provide. Briefly, the proposed approach estimated the annual microturbine NO_X and CO_2 emissions using the emission rates measured during the full load testing, and the average generating rate measured during an extended test period. The estimated annual CHP emissions could then be calculated in units of tons per year, and compared to average emission rates published by the Energy Information Administration (EIA) for the U.S. and Colorado. The proposed approach did not include emission reductions associated with heat recovery, as this process requires baseline GHG emission assessment from standard waste management practices. Due to the significant resources required to do this, OEMC elected to verify emission reductions from electricity generation only.

Due to the cancellation of the extended test period, estimation of annual power production CHP emissions could not be completed. For this reason, results of the microturbine CHP testing only provide measured emission rates. A simple comparison of these emission rates for NO_X and CO_2 to the U.S. and Colorado regional fossil fuel emission factors is all that the GHG Center can report here with the limited data set collected during this verification.

2.0 VERIFICATION RESULTS

2.1. OVERVIEW

The verification testing was conducted on February 14 and 15, 2004. This included the controlled tests at the four operating loads and the abbreviated continuous monitoring period to examine heat and power output and power quality. The GHG Center acquired several types of data that represent the basis of verification results presented here. The following types of data were collected and analyzed during the verification:

- Continuous measurements (biogas pressure, biogas temperature, power output and quality, heat recovery rate, and ambient conditions)
- Manual biogas flow meter readings
- Biogas compositional data
- Emissions testing data
- CHP and facility operating data

The field team leader reviewed, verified, and validated some data, such as DAS file data and reasonableness checks while on site. The team leader reviewed collected data for reasonableness and completeness in the field. The data from each of the controlled test periods was reviewed on site to verify that PTC-22 variability criteria were met. The emissions testing data was validated by reviewing instrument and system calibration data and ensuring that those and other reference method criteria were met. Factory calibrations for fuel flow, pressure, temperature, electrical and thermal power output, and ambient monitoring instrumentation were reviewed on site to validate instrument functionality. Other data such as biogas analysis results were reviewed, verified, and validated after testing had ended. All collected data was classed as either valid, suspect, or invalid upon review, using the QA/QC criteria specified in the test plan. Review criteria are in the form of factory and on-site calibrations, maximum calibration and other errors, audit gas analyses results, and lab repeatability results. Results presented here are based on measurements which met the specified Data Quality Indicators (DQIs) and QC checks and were validated by the GHG Center.

With the exception of the reduced load test conditions, the microturbine CHP performance data collected during the 35-hour verification period are representative of normal site operations. Due to the cancellation of the extended monitoring period, the GHG Center was unable to obtain a reasonable set of data to examine daily trends in atmospheric conditions and their impact on electricity and heat production. It should be noted that the results presented here may not represent performance over longer operating periods or at significantly different operating conditions.

Test results are presented in the following subsections:

Section 2.1 – Heat and Power Production Performance
(controlled testing and monitoring period)
Section 2.2 – Power Quality Performance
(continuous monitoring)
Section 2.3 – Emissions Performance and Reductions
(controlled test periods)

The results show that the quality of power generated by the CHP system is generally high and that the unit is capable of operating in parallel with the utility grid. The unit produced between 19 and 24 kW of net electrical power depending on ambient temperature (35 to 60 ^oF) during the monitoring period. The highest heat recovery rate measured during the extended monitoring period was approximately 138 x 10^3Btu/hr. Electrical and thermal efficiencies at full power averaged 20.4 and 33.3 percent, respectively with a corresponding total CHP system efficiency of 53.7 percent. NO_X emissions were very low at full load, averaging 1.8 ppmvd at 15% O_2 and 8.2 x 10^{-5} lb/kWh.

In support of the data analyses, the GHG Center conducted an audit of data quality (ADQ) following procedures specified in the QMP. A full assessment of the quality of data collected throughout the verification period is provided in Section 3.0. The data quality assessment was used to demonstrate that the data quality objectives (DQOs) introduced in the test plan were met for this verification.

2.2. HEAT AND POWER PRODUCTION PERFORMANCE

The heat and power production performance evaluation included electrical power output, heat recovery, and CHP efficiency determinations during controlled test periods. The performance evaluation also included determination of total electrical energy generated and used and thermal energy recovered over the continuous monitoring period.

2.2.1. Electrical Power Output, Heat Recovery Rate, and Efficiency During Controlled Tests

Table 2-1 summarizes the power output, heat recovery rate, and efficiency performance of the CHP system. Ambient temperature ranged from 45 to 58 ^oF, relative humidity ranged from 23 to 41 percent, and barometric pressure was between 12.69 and 12.71 psia during the controlled test periods. The results shown in Table 2-1 and the discussion that follows are representative of conditions encountered at this site and are not intended to indicate performance at other operating conditions such as cooler temperatures and different elevations. Biogas fuel conditions and heat recovery unit operation data corresponding to the test results are summarized in Table 2-2.

Biogas fuel conditions and heat recovery unit operation data corresponding to the test results are summarized in Table 2-2. A total of 12 samples were collected for compositional analysis and determination of LHV. There was very little variability in the biogas composition. Average biogas CH_4 and CO_2 concentrations were 68.1 and 31.2 percent, respectively. The average LHV was 625 Btu/scf and biogas compressibility averaged 0.997. H_2S concentrations in the biogas averaged 3,730 ppm.

The average net electrical power delivered to the farm was 19.9 kW_e at full load. The average electrical efficiency corresponding to these measurements was 20.4 percent. Electrical efficiencies at the 24, 20, and 15 kW power commands averaged 20.3, 18.6, and 15.7 percent, respectively. Electric power generation heat rate, which is an industry-accepted term to characterize the ratio of heat input to electrical power output, averaged 16,726 Btu/kWh_e at full power.

The average heat-recovery rate at full power was 111 x 10^3 Btu/hr, or 32.4 kW_{th}/hr, and thermal efficiency was 33.3 percent. The average total efficiency (electrical and thermal combined) was 53.7 percent for the three test runs. The net heat rate, which includes energy from heat recovery, was 6,354 Btu/kWh_t.

Table 2-1. Microturbine Heat and Power Production Performance									
Test ID	Test Condition	Heat Input, HI (10^3Btu/hr)	Electrical Power Generation Performance		Heat Recovery Performance		Total CHP System Efficiency (%)	Ambient Conditions [c]	
			Power Delivered [a] (kW_e)	Efficiency (%)	Heat Recovery Rate [b] (10^3Btu/hr)	Thermal Efficiency (%)		Temp (°F)	RH (%)
Run 1	30 kW power command	330	19.7	20.4	113	34.4	54.8	55.4	26.1
Run 2		336	20.1	20.4	105	31.4	51.8	58.4	24.1
Run 3		330	19.8	20.4	113	34.1	54.5	56.8	24.5
Avg.		**332**	**19.9**	**20.4**	**111**	**33.3**	**53.7**	**56.9**	**24.9**
Run 4	24 kW power command	323	19.2	20.3	111	34.3	54.6	56.3	23.4
Run 5		324	19.3	20.3	117	36.1	56.4	53.1	25.9
Run 6		322	19.3	20.4	119	37.1	57.5	49.7	29.4
Avg.		**323**	**19.3**	**20.3**	**116**	**35.8**	**56.2**	**53.0**	**26.2**
Run 7	20 kW power command	279	15.0	18.3	110	39.4	57.7	45.0	41.1
Run 8		274	15.0	18.7	108	39.6	58.3	46.1	39.8
Run 9		274	15.0	18.7	106	38.5	57.2	47.6	38.0
Avg.		**276**	**15.0**	**18.6**	**108**	**39.2**	**57.7**	**46.2**	**39.6**
Run 10	15 kW power command	221	10.1	15.6	93.5	42.4	58.0	50.6	34.6
Run 11		220	10.1	15.7	97.8	44.4	60.2	50.8	34.9
Run 12		219	10.2	15.8	99.6	45.4	61.2	50.6	35.2
Avg.		**220**	**10.1**	**15.7**	**96.9**	**44.1**	**59.8**	**50.6**	**34.9**

[a] Represents actual power available for consumption at the test site.
[b] Divide by 3.412 to convert to equivalent kilowatts (kW_{th}).
[c] Barometric pressure was within the range of 12.69 to 12.71 psia throughout the test period.

Table 2-2. Fuel Input and Heat Recovery Unit Operating Conditions									
Test ID	Test Condition	Biogas Fuel Input				Heating Loop Fluid Conditions			
		Gas Flow Rate (scfm)	LHV (Btu/scf)	Gas Pressure (psia)	Gas Temp (^oF)	Fluid Flow Rate, V (gpm)	Outlet Temp., T1 (^oF)	Inlet Temp., T2 (^oF)	Temp. Diff. (^oF)
Run 1	30 kW power command	8.76	**627.6[a]**	13.89	94.5	28.3	101.3	93.2	8.1
Run 2		8.91		13.85	96.6	28.4	100.8	93.3	7.5
Run 3		8.77		13.83	96.8	28.4	100.8	92.8	8.0
Avg.		**8.81**		**13.86**	**95.9**	**28.4**	**101.0**	**93.1**	**7.9**
Run 4	24 kW power command	8.59		13.84	95.8	28.4	101.1	93.3	7.9
Run 5		8.60		13.84	94.7	28.3	101.2	92.9	8.3
Run 6		8.55		13.85	92.7	28.4	100.8	92.3	8.5
Avg.		**8.58**		**13.84**	**94.4**	**28.4**	**101.0**	**92.8**	**8.2**
Run 7	20 kW power command	7.35	**632.5[b]**	13.96	88.1	28.5	96.9	89.1	7.8
Run 8		7.21		13.95	89.1	28.4	97.3	89.6	7.7
Run 9		7.23		13.95	90.0	28.4	97.5	90.0	7.5
Avg.		**7.26**		**13.95**	**89.1**	**28.4**	**97.6**	**89.6**	**7.7**
Run 10	15 kW power command	5.81		13.97	93.5	28.4	97.3	90.6	6.6
Run 11		5.80		13.97	94.7	28.4	97.8	90.8	7.0
Run 12		5.78		13.94	94.9	28.4	97.9	90.9	7.1
Avg.		**5.80**		**13.96**	**94.4**	**28.4**	**97.7**	**90.8**	**6.9**

[a] Average of three separate samples collected on February 14, 2004.
[b] Average of three separate samples collected on February 15, 2004.

Results of the reduced load tests are also included in the tables. Results show that electrical efficiency decreases slightly as the power output is reduced. Thermal efficiency, however, increases as power output (and biogas consumption) decreases. These trends are illustrated in Figure 2-1 which displays the electrical and thermal CHP system efficiency at each of the controlled test conditions.

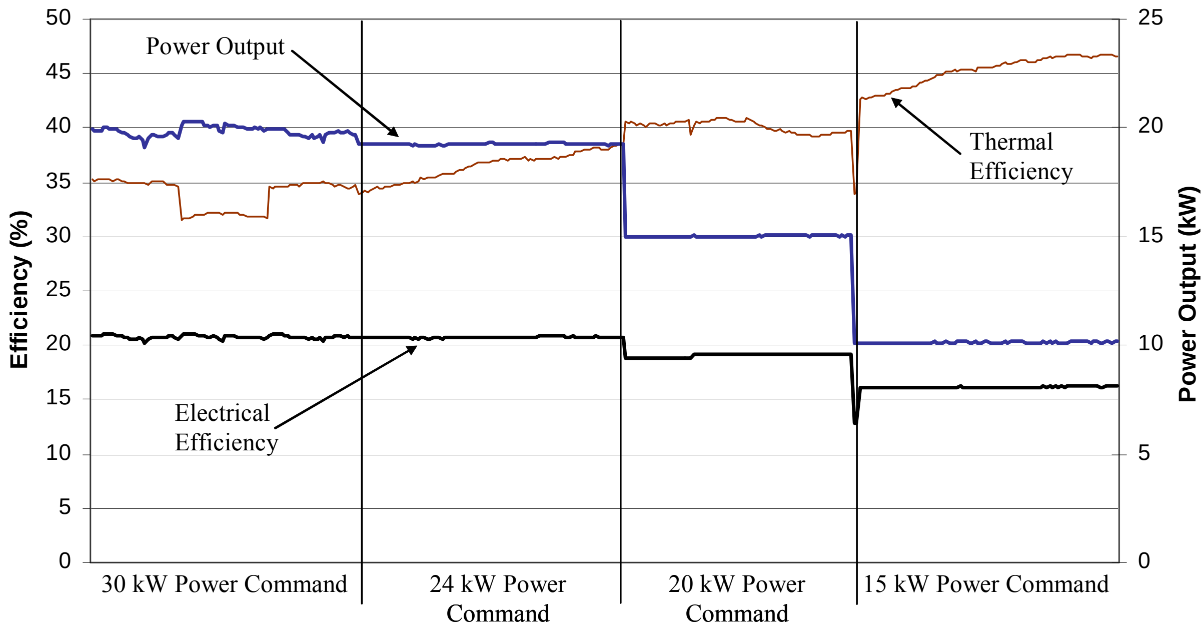


Figure 2-1. Electrical and Thermal Efficiency During Controlled Test Periods

As expected, the high altitude of the test location (approximately 3,700 feet above sea level) derated microturbine power output. Table 2-1 and Figure 2-1 show that the power delivered at full load (after parasitic loads) was only 19.9 kW. Power delivered at the 24 kW power command was nearly the same at 19.3 kW.

2.2.2. Electrical and Thermal Energy Production During the Continuous Monitoring Period

Figure 2-2 presents a time series plot of power production and heat recovery during the abbreviated 35-hour monitoring period. The system was operated continuously at a power command of 30 kW except for periods when reduced load tests were conducted. The CHP system was operated under typical farm conditions with the engine shut down and the heat recovery system configured to maintain digester temperature at around 100 ^{o}F. A total of 683.4 kWh_e electricity and 1,025 kWh_{th} of thermal energy were generated over the 35-hour operating period. The average power generated over the continuous monitoring period (excluding the reduced load testing) was 20.6 kW_e, and the average heat recovery rate was 117.7 x 10^3 Btu/hr.

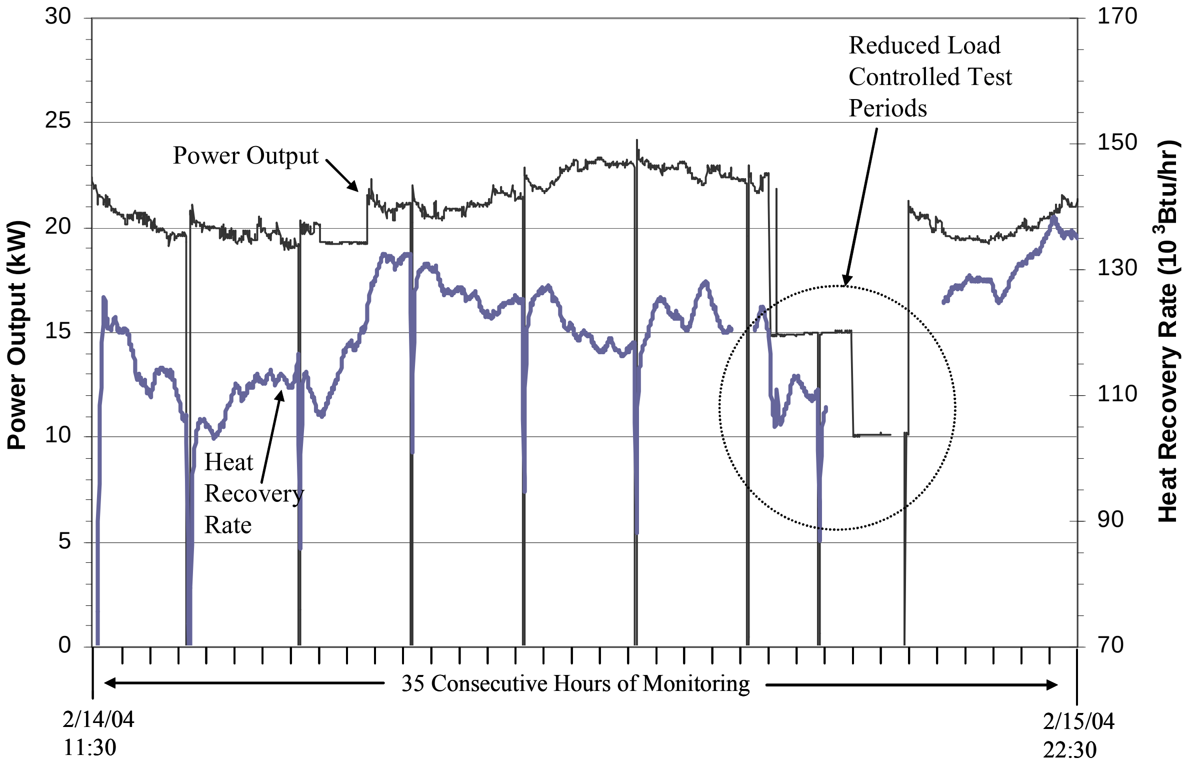


Figure 2-2. Heat and Power Production During the Monitoring Period

The power output trace shows periodic trips at intervals of approximately four hours. This was caused by the manner in which the facility was operating the biogas compressor. To prevent damage to the compressor caused by moisture buildup in the condensate trap, the trap was configured to automatically open momentarily to drain every four hours. This caused a brief loss of fuel pressure, thereby causing the microturbine to trip and restart. The entire sequence normally took about 4 minutes to complete and in most cases, the turbine was back to full power in 4 minutes. The farm reports that the microturbine is no longer operated in this way.

As is typical for gas fired turbines, power output was also affected by ambient temperature. The impact of temperature on this turbine is illustrated in Figures 2-3 and 2-4.

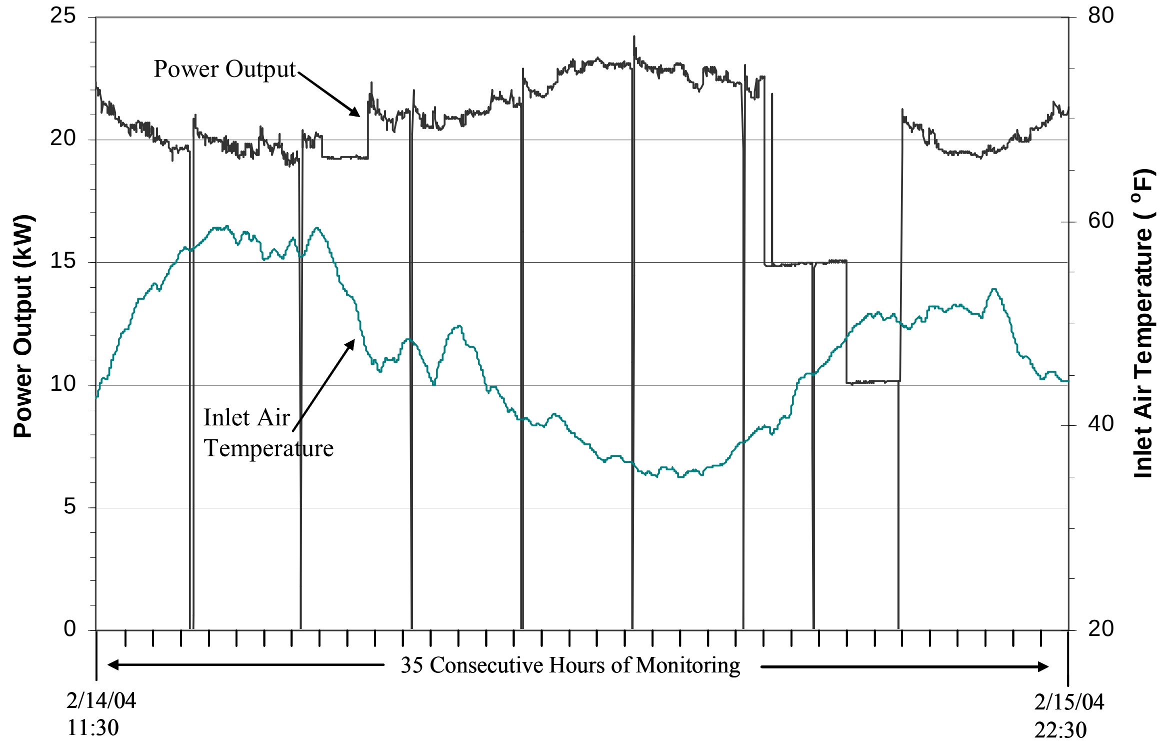


Figure 2-3. Power Output and Ambient Temperature During the Verification Period

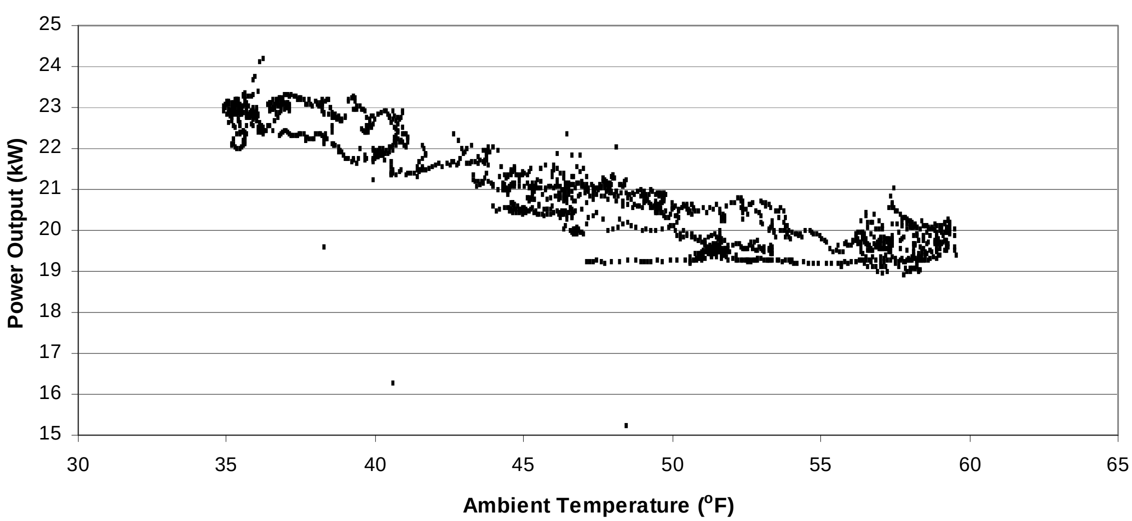


Figure 2-4. Ambient Temperature Effects on Power Production During the Verification Period

Figure 2-4 plots power output at full load over the limited test period as a function of ambient temperature and indicates a generally linear relationship. The generating rate ranged from about 19 to 23.5 kW across a temperature range of 34.9 to 59.6 °F.

2.3. POWER QUALITY PERFORMANCE

2.3.1. Electrical Frequency

Electrical frequency measurements (voltage and current) were monitored continuously during the verification period. The one-minute average data collected by the electrical meter were analyzed to determine maximum frequency, minimum frequency, average frequency, and standard deviation for the verification period. These results are illustrated in Figure 2-5 and summarized in Table 2-3. The average electrical frequency measured was 59.999 Hz and the standard deviation was 0.010 Hz.

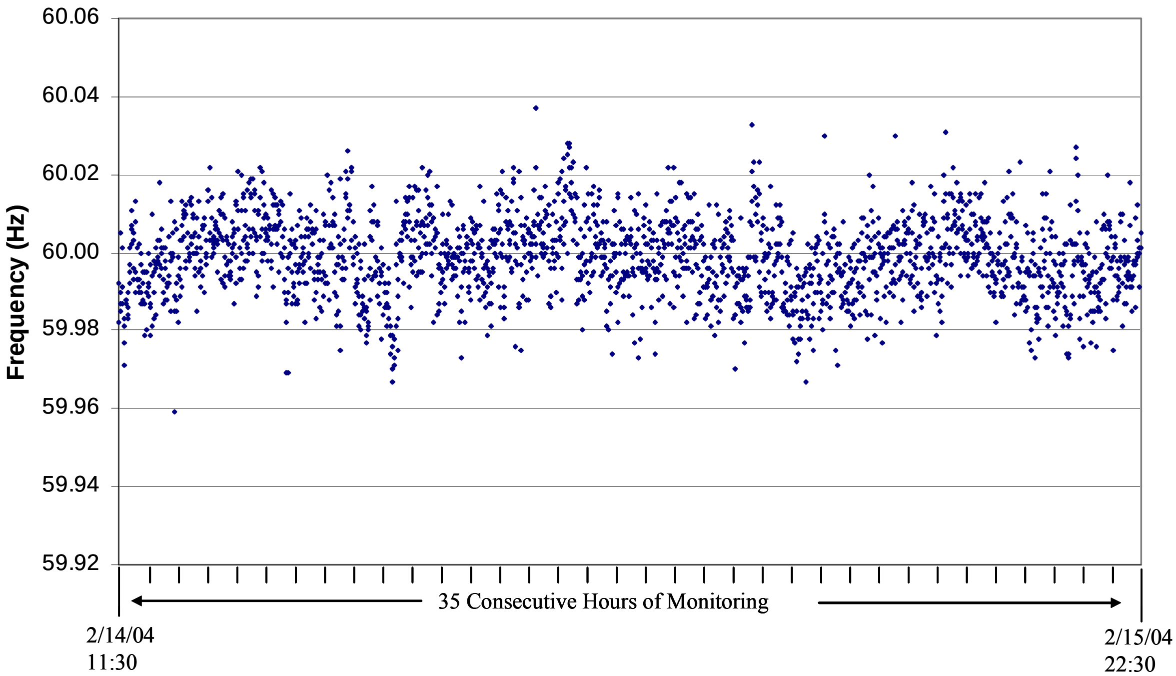


Figure 2-5. Microturbine Frequency During Verification Period

Table 2-3. Electrical Frequency During Monitoring Period	
Parameter	**Frequency (Hz)**
Average Frequency	59.999
Minimum Frequency	59.959
Maximum Frequency	60.037
Standard Deviation	0.010

2.3.2. Voltage Output

It is typically accepted that voltage output can vary within ± 10 percent of the standard voltage (480 volts) without causing significant disturbances to the operation of most end-use equipment (ANSI 1996). The 7500 ION electric meter was configured to measure 0 to 600 VAC. The turbine was grid-connected and operated as a voltage-following current source. The voltage levels measured are, therefore, more indicative of the grid voltage levels that the Capstone tried to respond to.

Figure 2-6 plots one-minute average voltage readings and Table 2-4 summarizes the statistical data for the voltages measured on the turbine throughout the verification period. The voltage levels were well within the normal accepted range of ± 10 percent.

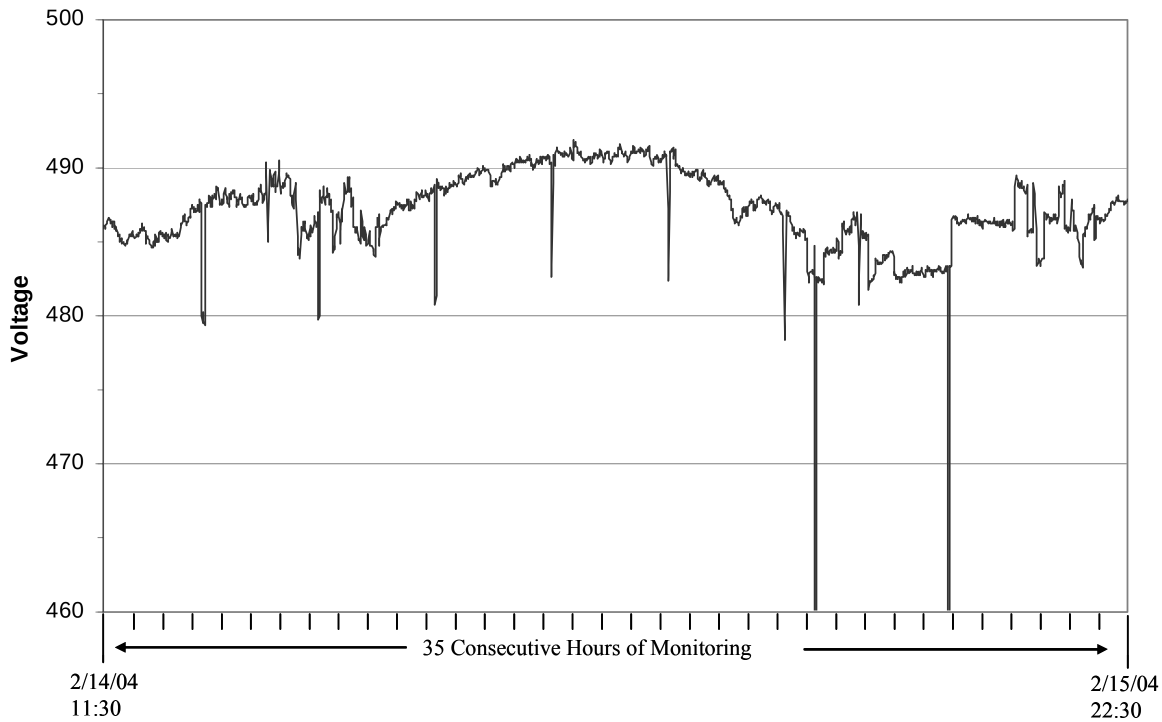


Figure 2-6. Microturbine Voltage During Verification Period

Table 2-4. Microturbine Voltage During Monitoring Period	
Parameter	**Volts**
Average Voltage	487.25
Minimum Voltage	478.43
Maximum Voltage	491.86
Standard Deviation	2.45

2.3.3. Power Factor

Figure 2-7 plots one-minute average power factor readings and Table 2-5 summarizes the statistical data for power factors measured on the turbine throughout the verification period. The data include only periods when the microturbine was operating. Data collected during the periodic trips are not included in the figure or summary table. Test results show that the power factor was very stable throughout the period with the turbine at full load. The power factor decreased during the low load controlled test periods.

Figure 2-7. Microturbine Power Factor During Verification Period

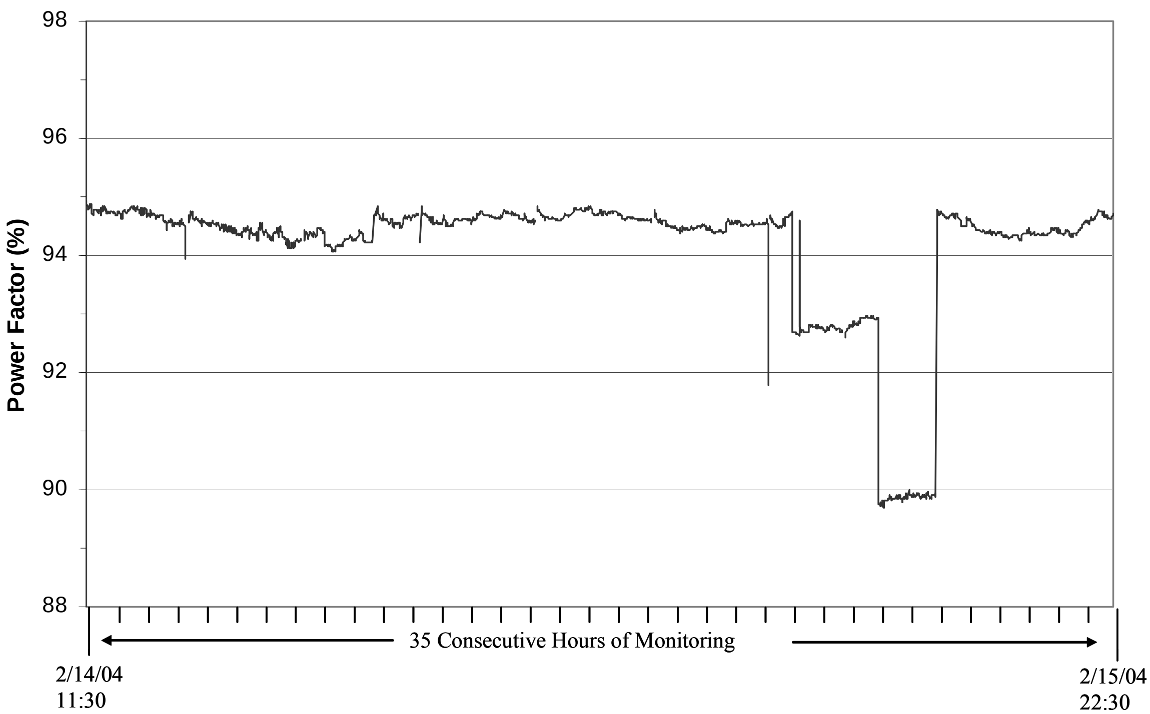


Table 2-5. Power Factors During Monitoring Period	
Parameter	**%**
Average at full load	94.53
Minimum at full load	91.77
Maximum at full load	94.93
Standard Deviation at full load	0.240
Average at 20 kW	92.80
Average at 15 kW	89.87

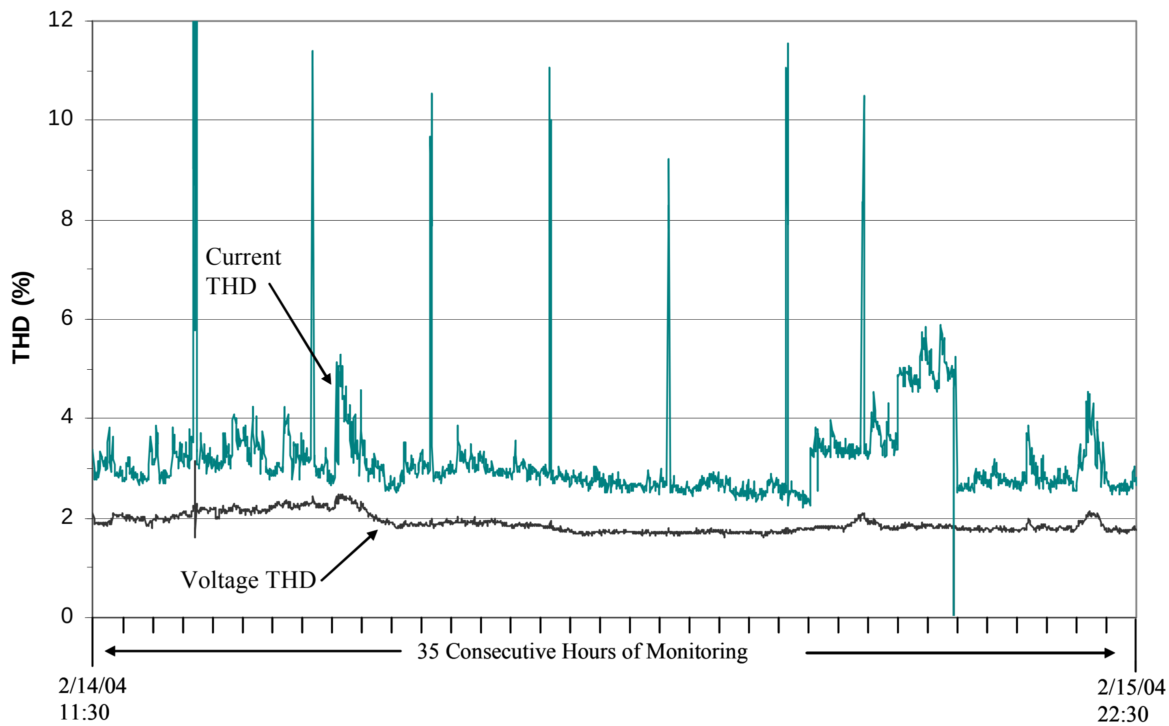
2.3.4. Current and Voltage Total Harmonic Distortion

The turbine total harmonic distortion, up to the 63rd harmonic, was recorded for current and voltage output using the 7500 ION. The average current and voltage THD were 3.21 and 1.89 percent, respectively (Table 2-6). Both were well within the IEEE 519 specification of ± 5 percent. Figure 2-8 plots the current and voltage THD throughout the verification period. Figure 2-8 clearly shows a spike in current THD each time the microturbine was tripped by the biogas pressure loss. The highest of the spikes was 32 percent.

Table 2-6. Microturbine THD During Monitoring Period

Parameter	Current THD (%)	Voltage THD (%)
Average	3.21	1.89
Minimum	2.22	1.60
Maximum	32.5	3.16
Standard Deviation	1.15	0.18

Figure 2-8. Microturbine Current and Voltage THD During Verification Period



2.4. EMISSIONS PERFORMANCE

2.4.1. Microturbine CHP System Emissions

Testing was conducted on the turbine exhaust stack to determine emission rates for NO_X, CO, THC, SO_2, TRS, CH_4, and CO_2 at each of the four controlled test conditions. Testing for determination of TPM and NH_3 was conducted at full load only. Stack emission measurements were conducted using the reference methods summarized in Table 1-3 and detailed in the test plan. The CHP system was maintained in a stable mode of operation during each test run based on PTC-22 variability criteria.

Sampling system QA/QC checks were conducted in accordance with test plan specifications to ensure the collection of adequate and accurate emissions data. These included analyzer linearity tests and sampling system bias and drift checks. Results of the QA/QC checks are discussed in Section 3.2.5. The results show that DQOs for all gas species met the reference method requirements. Table 2-7 summarizes the emission rates measured during each run and the overall average emissions for each set of tests.

NO_X concentrations averaged 1.75 ppmvd at 15% O_2 at full load, and increased to 34.6 ppmvd at the lowest load tested (setting of 15 kW). The overall average NO_X emission rate at full load, normalized to power output, was 0.00008 lb/kWh. The benefits of lower NO_X emissions from the CHP system are further enhanced by the fact that some of the exhaust heat is recovered and used. Annual published data from Energy Information Administration (EIA) reveal that the measured CHP system NO_X emission rate is well below the weighted average US and Colorado regional grid emission factors identified in the test plan, which are 0.0066 and 0.0077 lb/kWh, respectively. As stated earlier, the center could not estimate annual emission reductions due to insufficient power production data, but the emissions testing results clearly indicate that reductions will be realized through use of this CHP system. The emission reductions are further increased when transmission and distribution system losses are accounted for.

Average exhaust gas CO concentrations ranged from a low of 305 ppmvd at 15% O_2 at full load to a high of 451 ppmvd at 15% O_2 at the 15 kW power command. Corresponding average CO emission rates at these power commands were approximately 0.009 and 0.017 lb/kWh, respectively.

Similarly, THC (and CH_4) concentrations increased as power output decreased and ranged from 165 ppmvd at 15% O_2 at full load to 475 ppmvd at 15% O_2 at the 15 kW power command. Corresponding average THC emission rates at these power commands were approximately 0.003 and 0.011 lb/kWh, respectively. The CH_4 emissions consistently comprised about 80 percent of the THC emissions.

Concentrations of CO_2 in the CHP system exhaust gas averaged 2.3 percent at full load and decreased as power output was reduced to a low of 2.0 percent. These concentrations correspond to average CO_2 emission rates of 3.45 lb/kWh and 3.90 lb/kWh, respectively. The CHP system CO_2 emission rate at full load is higher than the weighted average fossil fuel emission factors for both the US and Colorado regional grids (2.02 and 2.13 lb/kWh, respectively). This indicates a likely increase in annual CO_2 emissions for power production from this system, but this increase would likely be offset by efficiency gains resulting from heat recovery and use and elimination of transmission and distribution system losses.

Table 2-7. Microturbine CHP System Emissions During Controlled Test Periods

	Power Command (kW)	Electrical Power Output (kW)	Exhaust	NO_x Emissions			CO Emissions			THC Emissions			CH_4 Emissions			CO_2 Emissions		
			O_2 (%)	(ppm at 15% O_2)	(lb/hr)	(lb/kWh)	(ppm at 15% O_2)	(lb/hr)	(lb/kWh)	(ppm at 15% O_2)	(lb/hr)	(lb/kWh)	(ppm at 15% O_2)	(lb/hr)	(lb/kWh)	(%)	(lb/hr)	(lb/kWh)
Run 1	30	19.7	19.1	1.70	1.61E-03	8.17E-05	250	0.144	0.007	141	0.046	2.35E-03	112	0.037	1.87E-03	2.3	68.2	3.46
Run 2		20.1	19.1	1.80	1.67E-03	8.31E-05	310	0.175	0.009	163	0.052	2.61E-03	141	0.045	2.26E-03	2.3	66.8	3.32
Run 3		19.8	19.2	1.74	1.61E-03	8.14E-05	354	0.199	0.010	190	0.061	3.10E-03	157	0.051	2.56E-03	2.3	70.7	3.58
AVG		**19.9**	**19.1**	**1.75**	**1.63E-03**	**8.21E-05**	**305**	**0.173**	**0.009**	**165**	**0.053**	**2.69E-03**	**137**	**0.044**	**2.23E-03**	**2.3**	**68.6**	**3.45**
Run 4	24	19.2	19.1	1.90	1.84E-03	9.54E-05	319	0.188	0.010	184	0.062	3.21E-03	141	0.047	2.46E-03	2.3	69.6	3.62
Run 5		19.3	19.2	2.01	1.84E-03	9.52E-05	345	0.191	0.010	194	0.061	3.19E-03	155	0.049	2.54E-03	2.3	69.6	3.61
Run 6		19.3	19.2	1.98	1.80E-03	9.36E-05	364	0.202	0.010	200	0.063	3.28E-03	183	0.058	3.00E-03	2.3	69.6	3.61
AVG		**19.3**	**19.2**	**1.96**	**1.83E-03**	**9.47E-05**	**343**	**0.194**	**0.010**	**193**	**0.062**	**3.23E-03**	**160**	**0.051**	**2.67E-03**	**2.3**	**69.6**	**3.61**
Run 7[a]	20	15.0	19.3	5.05	0.004	2.48E-04	590	0.263	0.018	365	0.093	6.22E-03	293	0.075	4.99E-03	2.2	56.9	3.80
Run 8		15.0	19.3	57.5	0.042	2.81E-03	192	0.086	0.006	132	0.034	2.25E-03	97	0.025	1.65E-03	2.2	56.9	3.79
Run 9		15.0	19.3	57.2	0.042	2.79E-03	199	0.089	0.006	126	0.032	2.14E-03	105	0.027	1.79E-03	2.2	56.9	3.78
AVG		**15.0**	**19.3**	**39.9**	**0.029**	**1.95E-03**	**327**	**0.146**	**0.010**	**208**	**0.053**	**3.54E-03**	**165**	**0.042**	**2.81E-03**	**2.2**	**56.9**	**3.79**
Run 10	15	10.1	19.0	33.2	0.022	2.19E-03	441	0.179	0.018	483	0.112	1.10E-02	360	0.083	8.24E-03	2.0	39.5	3.91
Run 11		10.1	19.1	35.1	0.022	2.18E-03	459	0.176	0.017	484	0.106	1.05E-02	413	0.091	8.93E-03	2.0	39.5	3.90
Run 12		10.2	19.1	35.4	0.022	2.20E-03	452	0.174	0.017	457	0.100	9.87E-03	410	0.090	8.85E-03	2.0	39.5	3.90
AVG		**10.1**	**19.1**	**34.6**	**0.022**	**2.19E-03**	**451**	**0.176**	**0.017**	**475**	**0.106**	**1.05E-02**	**394**	**0.088**	**8.67E-03**	**2.0**	**39.5**	**3.90**

a The NO_X, CO, and CH_4 concentrations during run 7 are questionable when compared to the data collected during runs 8 and 9. A brief 4-minute microturbine shutdown occurred at the conclusion of run 7, but the GHG Center was unable to resolve this anamoly after reviewing all available system operating data.

Table 2-7. Microturbine CHP System Emissions During Controlled Test Periods (Continued)

	Power Command (kW)	Electrical Power Output (kW)	Exhaust	Particulate Emissions			NH_3 Emissions			SO_2 Emissions			TRS Emissions		
			O_2 (%)	(gr/dscf)	(lb/hr)	(lb/kWh)	(ppm at 15% O_2)	(lb/hr)	(lb/kWh)	(ppm at 15% O_2)	(lb/hr)	(lb/kWh)	(ppm at 15% O_2)	(lb/hr)	(lb/kWh)
Run 1	30	19.7	19.1	0.0055	0.016	8.11E-04	0.05	1.70E-05	8.62E-07	488	0.64	0.032	15.5	0.020	1.01E-03
Run 2		20.1	19.1	0.0053	0.015	7.46E-04	0.04	1.31E-05	6.54E-07	582	0.73	0.036	14.4	0.018	9.13E-04
Run 3		19.8	19.2	0.0022	0.006	3.04E-04	0.02	6.00E-06	3.04E-07	614	0.81	0.041	5.70	0.008	4.06E-04
AVG		**19.9**	**19.1**	**0.0043**	**0.012**	**6.20E-04**	**0.04**	**1.20E-05**	**6.07E-07**	**561**	**0.73**	**0.037**	**11.9**	**0.015**	**7.78E-04**
Run 4	24	19.2	19.1	ND	ND	ND	ND	ND	ND	560	0.77	0.040	4.83	0.0067	3.48E-04
Run 5		19.3	19.2	ND	ND	ND	ND	ND	ND	596	0.76	0.039	3.27	0.0042	2.18E-04
Run 6		19.3	19.2	ND	ND	ND	ND	ND	ND	584	0.75	0.039	1.96	0.0025	1.30E-04
AVG		**19.3**	**19.2**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**580**	**0.76**	**0.039**	**3.35**	**0.0045**	**2.32E-04**
Run 7	20	15.0	19.3	ND	ND	ND	ND	ND	ND	594	0.61	0.041	8.20	0.0084	5.61E-04
Run 8		15.0	19.3	ND	ND	ND	ND	ND	ND	590	0.60	0.040	6.78	0.0069	4.61E-04
Run 9		15.0	19.3	ND	ND	ND	ND	ND	ND	588	0.61	0.041	5.81	0.0060	4.01E-04
AVG		**15.0**	**19.3**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**591**	**0.61**	**0.040**	**6.93**	**0.0071**	**4.74E-04**
Run 10	15	10.1	19.0	ND	ND	ND	ND	ND	ND	477	0.43	0.043	2.68	0.0024	2.37E-04
Run 11		10.1	19.1	ND	ND	ND	ND	ND	ND	500	0.43	0.042	2.29	0.0020	1.98E-04
Run 12		10.2	19.1	ND	ND	ND	ND	ND	ND	496	0.43	0.042	2.28	0.0020	1.98E-04
AVG		**10.1**	**19.1**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**491**	**0.43**	**0.042**	**2.42**	**0.0021**	**2.11E-04**

ND = No data collected. These pollutants not tested at reduced loads
NA = Not applicable

Emissions of total particulate matter and NH_3 were extremely low during each of the three test replicates conducted at full power. SO_2 emissions from the CHP were fairly consistent throughout the range of operation. At full load, SO_2 concentrations averaged 561 ppmvd at 15% O_2 and corresponding emission rates averaged 0.037 lb/kWh. Emissions of TRS, the sulfurous compounds in the fuel that were not oxidized during combustion, averaged approximately 78.0 ppmvd at 15% O_2 and 0.005 lb/kWh during the full load tests.

3.0 DATA QUALITY ASSESSMENT

3.1. DATA QUALITY OBJECTIVES

The GHG Center selects methodologies and instruments for all verifications to ensure a stated level of data quality in the final results. The GHG Center specifies data quality objectives (DQOs) for each verification parameter before testing commences. Each test measurement that contributes to the determination of a verification parameter has stated data quality indicators (DQIs) which, if met, ensure achievement of that verification parameter's DQO.

The establishment of DQOs begins with the determination of the desired level of confidence in the verification parameters. Table 3-1 summarizes the DQOs established in the test planning stage for each verification parameter. The actual data quality achieved during testing is also shown. The next step is to identify all measured values which affect the verification parameter and determine the levels of error which can be tolerated. These DQIs, most often stated in terms of measurement accuracy, precision, and completeness, are used to determine if the stated DQOs are satisfied. The DQIs for this verification - used to support the DQOs listed in Table 3-1 - are summarized in Table 3-2.

Table 3-1. Verification Parameter Data Quality Objectives

Verification Parameter	Original DQO Goal[a] Relative (%) /Absolute (units)	Achieved[b] Relative (%) /Absolute (units)
Power and Heat Production Performance		
Electrical power output (kW)	± 1.5% / 0.98 kW	± 1.0% / 0.20 kW
Electrical efficiency (%)	± 1.5% / 0.41%[c]	± 1.3% / 0.27%[c]
Heat recovery rate (10^3Btu/hr)	± 1.7% / 5.75 x 10^3Btu/hr[c]	± 2.4 / 2.7 x 10^3Btu/hr[c]
Thermal energy efficiency (%)	± 1.7% / 0.71%[c]	± 2.5% / 0.83%[c]
CHP production efficiency (%)	± 1.2% / 0.82%[c]	± 1.6% / 0.87%[c]
Power Quality Performance		
Electrical frequency (Hz)	± 0.01% / 0.006 Hz	± 0.01% / 0.006 Hz
Voltage	1.0 % / 4.8 V[c]	1.0 % / 4.9 V[c]
Power factor (%)	± 0.50% / TBD	± 0.50% / 0.47%
Voltage and current total harmonic distortion (THD) (%)	± 1.00% / TBD	± 1.00% / 0.03%
Emissions Performance		
NO_X, CO, CO_2, O_2, TRS, and SO_2 concentration accuracy	± 2.0% of span[d]	± 2.0% of span[d]
CH_4, and THC concentration accuracy	± 5.0% of span[d]	± 5.0% of span[d]
TPM and NH_3 concentration accuracy	± 5.0%	± 10.0%

[a] Original DQO goals as stated in test plan. Absolute errors were provided in the test plan, where applicable, based on anticipated values.
[b] Overall measurement uncertainty achieved during verification. The absolute errors listed are based on these uncertainties, and the average values measured during the verification.
[c] Calculated composite errors were derived using the procedures described in the corresponding subsections (Sections 3.2.2 through 3.2.5).
[d] Qualitative data quality indicators based on conformance to reference method requirements.

The DQIs specified in Table 3-2 contain accuracy, precision, and completeness levels that must be achieved to ensure that DQOs can be met. Reconciliation of DQIs is conducted by performing independent performance checks in the field with certified reference materials and by following approved reference methods, factory calibrating the instruments prior to use, and conducting QA/QC procedures in the field to ensure that instrument installation and operation are verified. The following sections address reconciliation of each of the DQI goals.

This verification was supported by an Audit of Data Quality (ADQ) conducted by the GHG Center QA manager. During the ADQ, the QA manager randomly selected data supporting each of the primary verification parameters and followed the data through the analysis and data processing system. The ADQ confirmed that no systematic errors were introduced during data handling and processing. A performance evaluation audit (PEA) and a technical systems audit (TSA) were planned but not conducted. Similar PEAs were recently conducted on two recent CHP verifications [13, 14] and it was decided to not repeat the PEA a third time. Likewise, a full TSA was recently completed on a similar verification [13] where the same measurement systems were used, so this QA activity was not repeated here. Instead, the GHG Center QA manager conducted an abbreviated project review to ensure that the verification approach and analytical procedures specified in the TQAP were followed or, in cases where changes to the verification were necessary, these changes were justified and documented. Corrective action reports (CARs) are completed, signed by the GHG Center QA manager, and filed at the GHG Center that document significant changes to the verification approach or methodologies that occurred during the verification.

3.2. RECONCILIATION OF DQOs AND DQIs

Table 3-2 summarizes the range of measurements observed in the field and the completeness goals. Completeness is the number or percent of valid determinations actually made relative to the number or percent of determinations planned. The completeness goals for the controlled tests were to obtain electrical and thermal efficiency as well as emission rate data for three test runs conducted at each of four different load conditions. This completeness goal was achieved.

Completeness goals for the extended tests were to obtain 90 percent of 7 days of power quality, power output, heat recovery rate, and ambient measurements. This goal was not achieved. As explained in Section 2.1, the Center was not able to complete the entire 7-day extended monitoring period. A total of 35 hours of data were logged, including the controlled test periods.

Table 3-2 also includes accuracy goals for measurement instruments. Actual measurement accuracy achieved is also reported based on instrument calibrations conducted by manufacturers, field calibrations, reasonableness checks, or independent performance checks with a second instrument. Table 3-3 includes the QA/QC procedures that were conducted for key measurements in addition to the procedures used to establish DQIs. The accuracy results for each measurement and their effects on the DQOs are discussed below.

Table 3-2. Summary of Data Quality Indicator Goals and Results									
Measurement Variable		**Instrument Type and Manufacturer**	**Instrument Range**	**Range Observed in Field**	**Accuracy**			**Completeness**	
					Goal	**Actual**	**How Verified or Determined**	**Goal**	**Actual**
CHP System Power Output and Quality	Power	Electric Meter/ Power Measurements 7500 ION	0 to 100 kW	0 to 24.2 kW	± 1.5% reading	± 1.0% reading	Instrument calibration from manufacturer prior to testing	Controlled tests: three valid runs per load meeting PTC 22 criteria. Extended test: 90% of one minute readings for 7 days.	Controlled tests: three valid runs at each load. Extended test: 35 consecutive hours of one minute readings.
	Voltage		0 to 600 V	478 to 492 V	± 1.0% reading	± 1.0% reading			
	Frequency		55 to 65 Hz	59.9 to 60.0 Hz	± 0.01% reading	± 0.01% reading			
	Current		0 to 200A	5 to 29 A	± 1.0% reading	± 1.0% reading			
	Voltage THD		0 to 100%	1.6 to 3.2%	± 1.0% full scale	± 1.0% full scale			
	Current THD		0 to 100%	2.2 to 32.5%	± 1.0% full scale	± 1.0% full scale			
	Power Factor		0 to 100%	91.8 to 94.9%	± 0.5% reading	± 0.5% reading			
CHP System Heat Recovery Rate	Inlet Temperature	Controlotron Model 1010EP	80 to 150 °F	89 to 94 °F	Temps must be ± 1.5 °F of ref. Thermocouples	± 0.7 °F for outlet, ± 0.8 °F for inlet	Independent check with calibrated thermocouple		
	Outlet Temperature		80 to 150 °F	93 to 102 °F					
	Water Flow		0 to 150 gpm	28.1 to 28.6 gpm	± 1.0% reading	± 0.1% reading	Instrument calibration from manufacturer prior to testing		
Ambient Conditions	Ambient Temperature	RTD / Vaisala Model HMD 60YO	-50 to 150 °F	35 to 60 ° F	± 0.2 °F	± 0.2 °F	Instrument calibration from manufacturer prior to testing		
	Ambient Pressure	Setra Model 280E	0 to 25 psia	12.68 to 12.72 psia	± 0.1% full scale	± 0.05% full scale			
	Relative Humidity	Vaisala Model HMD 60YO	0 to 100% RH	21 to 49% RH	± 2%	± 0.2%			

(continued)

Table 3-2. Summary of Data Quality Indicator Goals and Results (continued)

Measurement Variable		Instrument Type and Manufacturer	Instrument Range	Measurement Range Observed	Accuracy			Completeness	
					Goal	Actual	How Verified or Determined	Goal	Actual
Fuel Input	Gas Flow Rate	Dresser-Roots Model 2M175 SSM Series B3 rotary displacement	0 to 30 scfm	5 to 10 scfm	1.0% of reading	± 0.3% of reading	Factory calibration with volume prover	Controlled tests: three valid runs per load meeting PTC 22 criteria. Extended test: 90% of one-minute readings for 7 days.	Controlled tests: three valid runs at each load. Extended test: 35 hours of one-minute readings.
	Gas Pressure	Omega Model PX205-030AI transducer	0 to 30 psia	12 to 14 psia	± 0.75% full scale	± 0.25% full scale	Instrument calibration to NIST traceable standards		
	Gas Temperature	Omega TX-93 Type K thermocouple	0 to 200 °F	75 to 97 °F	± 0.10% reading	± 0.10% reading			
	LHV	Gas Chromatograph / HP 589011	0 to 100% CH_4	67 to 69% CH_4	± 3.0% accuracy, ± 0.2% repeatability	± 0.5% accuracy, ± 0.05% repeatability	analysis of NIST-traceable CH_4 standard, and duplicate analysis on 3 samples	Controlled tests: two valid samples per load	Controlled tests: two valid samples per load
				627 to 633 Btu/ft^3	0.1% repeatability	± 0.06% repeatability	Conducted duplicate analyses on 3 samples		
Exhaust Stack Emission	NO_X Levels	Chemiluminescent/ CAI 400-CLD	0 to 50 ppmvd	0 to 3 ppmvd	± 2% full scale	≤ 2% full scale	Calculated following EPA Reference Method calibrations (Before and after each test run)	Controlled tests: three valid runs per load.	Controlled tests: three valid runs per load.
	CO Levels	NDIR / TEI Model 48	0 to 300 ppmvd	50 to 160 ppmvd	± 2% full scale	≤ 2% full scale			
	CH_4 levels	HP 5890	0 to 300 ppmv	30 to 130 ppmv	± 5% full scale	≤ 5% reading			
	THC levels	HP 5890	0 to 300 ppmv	40 to 160 ppmv	± 5% full scale	≤ 5% full scale			
	SO_2 Levels	Bovar 721-AT	0 to 300 ppmvd	145 to 185 ppmvd	± 2% full scale	≤ 2% full scale			
	O_2 / CO_2 Levels	CAI 200	0 to 25%	10 to 20% O_2 2.0 to 2.5% CO_2	± 2% full scale	≤ 2% full scale			
	TRS Levels	Ametek 921	0 to 25 ppmvd	0 to 5 ppmvd	± 2% full scale	≤ 2% full scale			
	NH_3 Levels	Ion specific electrode	0 to 5 ug/ml	0 to 4.2 ug/ml	± 5% full scale	≤ 5% full scale			
	TPM concentrations	gravimetric	Not specified	0.01 to 0.04 g	± 1 mg	± .05 mg			
	Stack gas velocity	Pitot and thermocouple	Not specified	3552 to 3753 fpm	± 5% reading	≤ 5% reading			

3.2.1. Power Output

Instrumentation used to measure power was introduced in Section 1.0 and included a Power Measurements Model 7500 ION. The data quality objective for power output was ± 1.5 percent of reading, which includes compounded error of the instrument and the current transformers (CTs). The test plan specified factory calibration of the ION meter with a NIST-traceable standard to determine if the power output DQO was met. The Test plan also required the GHG Center to perform several reasonableness checks in the field to ensure that the meter was installed and operating properly. The following summarizes the results.

The meter was factory calibrated by Power Measurements in April 2003. Calibrations were conducted in accordance with Power Measurements' standard operating procedures (in compliance with ISO 9002:1994) and are traceable to NIST standards. The meters were certified by Power Measurements to meet or exceed the accuracy values summarized in Table 3-2 for power output, voltage, current, and frequency. NIST-traceable calibration records are archived by the GHG Center. Pretest factory calibrations on the meters indicated that accuracy was within ± 0.05 percent of reading and this value, combined with the 1.0-percent error inherent to the current transformers resulted in an overall error of ± 1.01 percent. Using the manufacturer-certified calibration results and the average power output measured during the full-load testing, the absolute error during all testing is ± 0.20 kW.

Additional QC checks were performed on the 7500 ION to verify the operation after installation of the meters at the site and prior to the start of the verification test. The results of these QC checks (summarized in Table 3-3) are not used to reconcile the DQI goals, but to document proper operation in the field. Current and voltage readings were checked for reasonableness using a hand-held Fluke multimeter. These checks confirmed that the voltage and current readings between the 7500 ION and the Fluke were within the range specified in the test plan as shown in Table 3-3.

These results led to the conclusion that the 7500 ION was installed and operating properly during the verification test. The ± 1.0-percent error in power measurements, as certified by the manufacturer, was used to reconcile the power output DQO (discussed above) and the electrical efficiency DQO (discussed in Section 3.2.2).

Table 3-3. Results of Additional QA/QC Checks				
Measurement Variable	**QA/QC Check**	**When Performed/Frequency**	**Expected or Allowable Result**	**Results Achieved**
Power Output	Sensor diagnostics in field	Beginning and end of test	Voltage and current checks within ± 1% reading	± 0.1% voltage ± 0.9% current
	Reasonableness checks	Throughout test	Readings should be around 22 kW net power output at full load	Readings were 20 to 24 kW at full load
Fuel Heating Value	Calibration with gas standards by laboratory	Prior to analysis of each lot of samples submitted	± 1.0% for each gas constituent	Results satisfactory, see Section 3.2.2.4
	Independent performance checks with blind audit sample	Twice during previous year	± 3.0% for each major gas constituent (methane, CO_2)	
Heat Recovery Rate	Meter zero check	Prior to testing	Reported water flow rate < 0.1 gpm	–0.06 gpm recorded
	Independent performance check of temperature readings	Beginning of test period	Difference in temperature readings should be < 1.5 °F	Temperature readings within 0.8 °F of reference.

3.2.2. Electrical Efficiency

The DQO for electrical efficiency was to achieve an uncertainty of ± 1.52 percent at full electrical load or less. Recall from Equation 1 (Section 1.4.1) that the electrical efficiency determination consists of three direct measurements: power output, fuel flow rate, and fuel LHV. The accuracy goals specified to meet the electrical efficiency DQO consisted of ± 1.5 percent for power output, ± 1.0 percent for fuel flow rate, and ± 0.2 percent for LHV. The accuracy goals for each measurement were met. The following summarizes actual errors achieved and the methods used to compute them.

Power Output: As discussed in Section 3.2.1, factory calibrations of the 7500 ION with a NIST-traceable standard and the inherent error in the current and potential transformers resulted in ± 1.0-percent error in power measurements. Reasonableness checks in the field verified that the meter was functioning properly. The average power output at full load was approximately 20 kW with a measurement error of ± 0.20 kW.

Heat Input: Heat input is the product of measured fuel flow rate and LHV. The DQI goal for fuel flow rate was reconciled through calibration of the gas meter and the gas temperature and pressure sensors used to correct measured gas volumes to standard conditions. All three components were calibrated with NIST-traceable standards. As shown in Table 3-2, the individual instruments errors were 0.3, 0.25, and 0.1 percent for flow, pressure, and temperature respectively. The overall error in biogas flow rate on a wet basis then is 0.40 percent of reading.

Since biogas flow rate was metered on a wet and low pressure basis, but combusted by the microturbine on a dry, high pressure basis, measured flow rates were corrected for moisture content (Section 1.4.2). Since the actual moisture content of the as-fired biogas was not directly measured, the assumption that the gas was completely dry introduced additional error into the heat input determination. The center conducted an analysis of this assumption and, knowing the temperature and pressure of the gas as fired, determined that the worst case error introduced by the assumption that the gas is totally dry is 0.7 percent. Combining that uncertainty with the heat input wet basis error of 0.40 percent, the overall error on determination of biogas flow rate on a dry basis is then 0.81 percent of reading.

The average flow rate at full load was 8.81 scfm with an associated measurement error of ± 0.07 scfm. Complete documentation of data quality results for fuel flow rate is provided in Section 3.2.5.

Uncertainty in the biogas LHV results was within the 0.2 percent DQI goal (Section 3.2.6). The average LHV during testing was 630 Btu/ft^3 and the measurement error corresponding to this heating value is ± 1.3 Btu/ft^3. The heat input compounded error then is:

$$Error\ in\ Heat\ Input = \sqrt{(flowmetererror)^2 + (LHVerror)^2} \qquad \text{(Equation. 5)}$$

$$= \sqrt{(0.0081)^2 + (0.002)^2} = 0.0083$$

The measurement error amounts to approximately ± 2.7 x 10^{3}Btu/hr, or 0.83 percent relative error at the average measured heat input of 332 x 10^{3}Btu/hr.

The errors in the divided values compound similarly for the electrical efficiency determination. The electrical power measurement error is ± 1.0 percent relative (Table 3-2) and the heat input error is ± 0.83 percent relative. Therefore, compounded relative error for the electrical efficiency determination is:

$$Error\ in\ Elec.\ Power\ Efficiency = \sqrt{(powermetererror)^2 + (heatinputerror)^2} \qquad \text{(Equation. 6)}$$

$$= \sqrt{(0.010)^2 + (0.0083)^2} = 0.0130$$

Electrical efficiency for the controlled test periods at full load was 20.4 ± 0.27 percent, or a relative compounded error of 1.3 percent.

3.2.3. PTC-22 Requirements for Electrical Efficiency Determination

PTC-22 guidelines state that efficiency determinations were to be performed within 60 minute test periods in which maximum variability in key operational parameters did not exceed specified levels. Table 3-4 summarizes the maximum permissible variations observed in power output, ambient temperature, ambient pressure, biogas pressure at the meter, and biogas temperature at the meter for each test run. The table shows that the requirements for all parameters were met for all test runs and the efficiency determinations were representative of stable operating conditions.

Table 3-4. Variability Observed in Operating Conditions					
	Maximum Observed Variation[a] in Measured Parameters				
	Power Output (%)	Ambient Temp. (^oF)	Ambient Pressure (%)	Biogas pressure (psia)	Power Factor (%)
Maximum Allowable Variation	**± 2**	**± 4**	**± 0.5**	**± 1**	**± 2**
Run 1	0.6	1.1	0.03	0.2	0.2
Run 2	1.7	0.7	0.03	0.1	0.1
Run 3	1.8	0.6	0.02	0.1	0.1
Run 4	0.3	2.2	0.01	0.2	0.1
Run 5	0.3	0.9	0.01	0.2	0.1
Run 6	0.4	2.5	0.02	0.2	0.2
Run 7	0.3	0.3	0.01	0.3	0.1
Run 8	0.4	0.7	0.01	0.1	0.1
Run 9	0.2	0.8	0.01	0.2	0.1
Run 10	0.4	0.5	0.02	0.1	0.1
Run 11	0.4	0.4	0.03	0.2	0.1
Run 12	0.3	0.4	0.02	0.3	0.1

[a] Maximum (Average of Test Run – Observed Value) / Average of Test Run · 100

3.2.4. Ambient Measurements

Ambient temperature, relative humidity, and barometric pressure at the site were monitored throughout the verification period and the controlled tests. The instrumentation used is identified in Table 3-2 along with instrument ranges, data quality goals, and data quality achieved. All three sensors were factory-calibrated using reference materials traceable to NIST standards. The pressure sensor was calibrated prior to the verification testing, confirming the ± 0.1 percent accuracy. The temperature and relative humidity sensors were also calibrated within a year prior to testing which verified that the ± 0.2 °F accuracy goal for temperature and ± 2 percent accuracy goal for relative humidity were met.

3.2.5. Fuel Flow Rate

The Dresser-Roots Model 2M175 rotary displacement gas meter was factory-calibrated prior to installation in 1999. Calibration records were obtained and reviewed to ensure that the ± 1.0-percent instrument accuracy goal was satisfied. The original calibration for the Roots meter, indicating an accuracy of ± 0.32 percent, is a permanent calibration. This error combines with the errors in the gas temperature, pressure, and moisture determinations for an overall biogas flow rate measurement error of ± 0.81 percent.

3.2.6. Fuel Lower Heating Value

Biogas sample collection date, time, run number, and canister ID were logged along with laboratory chain of custody forms and were shipped along with the samples. Copies of the chain of custody forms and results of the analyses are stored in the GHG Center project files. Collected samples were shipped to Empact Analytical Laboratories of Brighton, CO, for compositional analysis and determination of LHV per ASTM test Methods D1945 [6] and D3588 [7], respectively. The DQI goals were to measure methane concentrations within ± 3.0 percent of a NIST-traceable blind audit sample and to achieve less than ± 0.2 percent difference in LHV duplicate analyses results. Blind audits were submitted to Empact on two similar verifications within the past year to evaluate analytical accuracy on the methane analyses [13, 14]. Both audits indicated analytical accuracy within 0.5 percent, and repeatability of within ± 0.2 percent. Since the same sampling and analytical procedures were used here by the same analyst, the audit was not repeated a third time.

Duplicate analyses, in addition to the blind audit samples, were conducted on three of the samples collected during the controlled test periods. Duplicate analysis is defined as the analysis performed by the same operating procedure and using the same instrument for a given sample volume. Results of the duplicate analyses showed an average analytical repeatability of 0.06 percent for methane and 0.06 percent for LHV. The results demonstrate that the ± 0.2 percent LHV accuracy goal was achieved. As such, both DQIs were met with the methane accuracy at ± 0.5 percent and the LHV repeatability at ± 0.06 percent.

3.2.7. Heat Recovery Rate and Efficiency

Several measurements were conducted to determine CHP system heat-recovery rate and thermal efficiency. These measurements include water flow rate, water supply and return temperatures, and CHP system heat input. The individual errors in each of the measurements is then propagated to determine the overall error in heat-recovery rate and efficiency. The Controlotron ultrasonic heat meter was used to continuously monitor water flow rate. This meter has a NIST-traceable factory-calibrated accuracy of ± 1.0 percent of reading (this flow through calibration was conducted on October 9, 2002). This certification serves as the primary DQI. A zero check was also performed on the flow meter. The meter reading was -0.06 gpm with the CHP system shut down and the circulation pump off.

Table 3-2 showed that the DQI for supply and return temperatures (delta T) was achieved. Each temperature sensor was calibrated against a reference thermocouple with NIST-traceable accuracy. The error in the two temperature sensors resulted in an overall delta T uncertainty of 0.8 ^oC. This absolute error equates to a relative error of 2.2 percent at the average fluid temperatures measured during the full-load testing (about 36.1 ^oC). The overall error in heat recovery rate is then the combined error in flow rate and temperature differential. This error compounds multiplicatively as follows:

$$\text{Overall Heat Meter Error} = \sqrt{(\text{Flow rate error})^2 + (\text{compositional error})^2} \qquad \text{(Equation. 7)}$$

$$= \sqrt{(0.010)^2 + (0.022)^2} = 0.024$$

The heat recovery rate determination, therefore, has a relative compounded error of ± 2.4 percent. The absolute error in the average heat recovery rate at full load (111 x 10^3Btu/hr) then is ± 2.7 x 10^3Btu/hr.

This error in heat-recovery rate and the heat input error (0.83 percent) compound similarly to determine the overall uncertainty in the thermal efficiency determination as follows:

$$\text{Error in Heat Recovery Efficiency} = \sqrt{(0.024)^2 + (0.0083)^2} = 0.025 \qquad \text{(Equation. 8)}$$

Average heat recovery rate (thermal) efficiency at full load then is 33.3 ± 0.83 percent, or a relative compounded error of 2.5 percent. This compounded relative error exceeds the data quality objective slightly, but the absolute error is within the goal for this verification parameter (measured values were lower than anticipated).

3.2.8. Total Efficiency

Total efficiency is the sum of the electrical power and heat-recovery efficiencies. Total efficiency is defined as 20.4 ± 0.27 percent (± 1.30-percent relative error) plus 33.3 ± 0.63 percent (± 1.9-percent relative error). This is based on the determined errors in electrical and thermal efficiency at full load. The absolute errors compound as follows:

$$err_{c,abs} = \sqrt{err_1^{\,2} + err_2^{\,2}} \qquad \text{(Equation. 9)}$$

$$= \sqrt{0.27^2 + 0.83^2} = 0.87$$

Relative error, is:

$$err_{c,rel} = \frac{err_{c,abs}}{Value_1 + Value_2} \qquad \text{(Equation. 10)}$$

$$= \frac{0.87}{20.4 + 33.3} = 0.016$$

where:

$err_{c,abs}$	=	compounded error, absolute
err_1	=	error in first added value, absolute value
err_2	=	error in second added value, absolute value
$err_{c,rel}$	=	compounded error, relative
$value_1$	=	first added value
$value_2$	=	second added value

The total CHP efficiency at full load is then 53.7 ± 0.87 percent, or 1.6 percent relative error. Again, this compounded relative error exceeds the data quality objective slightly.

3.2.9. Exhaust Stack Emission Measurements

EPA reference method requirements form the basis for the qualitative DQIs specified in the Test plan and listed in Tables 3-1 and 3-2. Each method specifies sampling and calibration procedures and data quality checks. These specifications, when properly implemented, ensure the collection of high quality and representative emissions data. The specific sampling and calibration procedures vary by method and class of pollutants, and are summarized in Table 3-5. The table lists the method quality requirements, the acceptable criteria, and the results for the test conducted here. It is generally accepted that conformance to the reference method quality requirements demonstrates that the qualitative DQIs have been met.

All of the emissions testing and reference method quality control procedures were conducted by Cubix Corporation either in the field during testing or in their calibration and analytical laboratories in Austin, Texas. All of the field sampling procedures and calibrations were closely monitored by GHG Center personnel. In addition, documentation of all sampling and analytical procedures, data collection, and calibrations have been procured, reviewed, and filed by the GHG Center. Table 3-5 is followed by a brief explanation of the QA/QC procedures implemented for each class of pollutant quantified during this verification.

Table 3-5. Summary of Emissions Testing Calibrations and QC Checks

Measurement Variable	Calibration or QC Check	When Performed and Frequency	Expected or Allowable Result	Result of Calibration(s) or Check(s)
NO_X, CO, CO_2, SO_2, TRS, and O_2 concentrations	Analyzer calibration error test	Daily before testing	± 2% of analyzer span	All within allowable level for each day
	System bias checks	Before each test run	± 5% of analyzer span	All within allowable level for each test run
	Calibration drift test	After each test run	± 3% of analyzer span	
THC concentrations	System calibration error test	Daily before testing	± 5% of analyzer span	All within allowable level for each day
	System calibration drift test	After each test run	± 3% of analyzer span	All within allowable level for each test run
CH_4 concentrations	Triplicate injections	Each test run	± 5% difference	All within allowable level for each test run
	Calibration of GC with gas standards by certified laboratory	Immediately prior to sample analyses and/or at least once per day	± 5% for each compound	All within allowable level for each day
TPM emissions	Pre and post test sampling system leak checks	Before and after each test run	Sampling system leak rate < 0.02 cfm	All checks < 0.02 cfm
	Minimum sample volume	After each test run	Corrected Vol. ≥ 60.0 dscf	Volumes ranged from 69.4 to 79.6 dscf
	Percent isokinetic sampling rate (I)	After each test run	90 % ≤ I ≤ 110%	91 % ≤ I ≤ 102%
	Analytical balance calibration	Once before analysis	± 0.0001 g	Within allowable level
	Filter and reagent blanks	Once during testing after first test run	< 10% of particulate catch for first test run	Blank weights < 10% of each sample catch
	Dry gas meter calibration	Once before and once after testing	± 5%	Pre and post test calibrations within 1%
	Thermocouple calibration	Once after testing	± 1.5% of average stack temperature	Within 0.3% of reference TC
NH_3 concentrations	Calibration of instrument with NH_3 standards	Immediately prior to sample analyses at least once a day	± 5 %	Pre test calibrations within 1% of working standards
	Dry gas meter calibration	Once before and once after testing	± 5%	Pre and post test calibrations within 1%
Exhaust gas volumetric flow rate	Pitot tube dimensional calibration / inspection	Once before and once after testing	See 40CFR60 Method 2, Section 10.0	Calibration criteria met
	Thermocouple calibration	Once after testing	± 1.5% of average stack temperature	Within 0.3% of reference TC

3.2.9.1. NO_X, CO, CO_2, SO_2, TRS, and O_2 Concentrations

Test personnel performed sampling system calibration error tests prior to each test run. All calibrations employed a suite of three EPA Protocol No. 1 calibration gases (four for CO) that spanned the instrument ranges. Appropriate calibration ranges were selected for each pollutant based on exhaust gas screening (ranges are summarized in Table 3-2). The daily analyzer calibration error goal for each instrument was ± 2.0 percent of span. It was met for each analyzer during each day of testing.

Sampling system bias was evaluated for each parameter at the beginning of each test run using the zero and mid-level calibration gases. System response to the zero and mid-level calibration gases also provided a measure of drift and bias at the end of each test run. The maximum allowable sampling system bias and drift values were ± 5 and ± 3 percent of span, respectively. These specifications were met for each parameter and for each test run. Testers also performed a NO_X converter efficiency test as described in Section 3.5 of the test plan. The converter efficiency was 99.98 percent, which meets the 98-percent goal specified in the method.

3.2.9.2. THC Concentrations

Following Method 25A criteria, the analyzer calibration error test is not performed on the THC analyzer. Instead, a 4-point system bias test is conducted at the beginning of each test day. System response must be within ± 5 percent of the calibration standard at each point. System response to the zero and mid-level calibration gases also provided a measure of drift and bias at the end of each test run. The maximum allowable sampling system bias and drift values were ± 5 and ± 3 percent of span, respectively. These specifications were met for test run.

3.2.9.3. CH_4 Concentrations

The test plan specified EPA Method 18 for determining stack gas methane concentrations. This testing was conducted on-site, eliminating the need to collect bag samples for transport to a laboratory. Test operators injected calibration gas standards into the gas chromatograph (GC) to establish a concentration standard curve prior to sample analysis. The operator repeated the injections until the average of all desired compounds from three separate injections agreed to within 5.0 percent of the certified value. The acceptance criterion was met for all runs.

The analysts injected the mid-range standard to quantify instrument drift at the completion of each test. The analyst would repeat the calibration process used for the average of the two calibration curves to determine concentrations if he observed a variance larger than 5.0 percent.

3.2.9.4. Total Particulate Matter and Exhaust Gas Volumetric Flow Rate

Reference Methods 1 through 5, used for determination of exhaust gas volumetric flow rate and total particulate emissions, include numerous quality control and quality assurance procedures that are required to ensure collection of representative data. The most important of these procedures are listed in Table 3-5 along with the results for these tests. These methods do not specify overall uncertainties, but it is generally accepted that conformance to the control and quality assurance procedures will result in an overall method uncertainty ranging from 5 to 30 percent, depending on the mass of the particulate catch, the quality of the sampling system, and the length of the sampling probe [15]. For these tests, TPM catches were in the range of 10 to 20 mg, the sampling system surfaces contacting the exhaust gases were constructed entirely of glass or Teflon, and the probe was less than 3-feet in length. In addition, testers documented that all of the key method criteria were met. It is therefore expected that the overall error for tests conducted here is ± 10 percent of reading. This exceeds the original goal of ± 5 percent, but this deviation from the plan is not believed to impact results significantly because TPM emissions were very low.

3.2.9.5. NH_3 Concentrations

Ammonia samples were collected in the back-half of the total particulate sampling train and therefore all of the sampling system criteria are the same as for TPM measurements. Sampling error for the NH_3 samples should be the same as sampling error for the TPM samples. In the laboratory, analytical instrumentation was calibrated using nine working standards. A calibration curve for the instrument was developed using this nine-point calibration. The R^2 for the calibration curve was 0.9997, indicating excellent analytical linearity. Based on this, the same uncertainty used for the TPM determination (±10 percent) is assigned. Again, this level of uncertainty exceeds the original goal of ± 5 percent, but as with the TPM emissions, this deviation from the plan is not believed to impact results significantly because NH_3 emissions were also very low.

4.0 REFERENCES

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