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September 2003

Environmental Technology Verification Report

Combined Heat and Power at a Commercial Supermarket - Capstone 60 kW Microturbine CHP System

Prepared by:

Greenhouse Gas Technology Center
Southern Research Institute

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

and

Under Agreement With
New York State Energy Research and Development Authority

ETV ETV ETV

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

NYSERDA

SOUTHERN RESEARCH INSTITUTE

ETV Joint Verification Statement

TECHNOLOGY TYPE:	Natural-Gas-Fired Microturbine Combined With Heat Recovery System
APPLICATION:	Distributed Electrical Power and Heat Generation
TECHNOLOGY NAME:	Capstone 60 Microturbine CHP System
COMPANY:	Capstone Microturbine Corporation
ADDRESS:	Chatsworth, CA
WEBSITE:	www.microturbine.com

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. The GHG Center has collaborated with the New York State Energy and Development Authority (NYSERDA) to evaluate the performance of a combined heat and power system (CHP system) designed and installed by CDH Energy Corporation. The primary components of the CHP system tested are a Capstone 60 MicroTurbine™ and a Unifin International heat exchanger. This verification statement provides a summary of the test results for the CHP system.

TECHNOLOGY DESCRIPTION

Large- and medium-scale gas-fired turbines have been used to generate electricity since the 1950s. Technical and manufacturing developments during the last decade have enabled the introduction of microturbines with generation capacities ranging from 30 to 200 kW. The CHP system tested here is a cogeneration installation that integrates microturbine technology with a heat-recovery system. The following description of the CHP system tested is based on information provided by CDH Energy and the equipment vendors and does not represent verified information.

Electric power is generated by a Capstone 60 microturbine with a nominal power output of 60 kW (59 °F, sea level). The system operates on natural gas and consists of an air compressor, recuperator, combustor, turbine, and a permanent magnet generator. Preheated air is mixed with fuel and this compressed fuel/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 rotate at over 96,000 revolutions per minute (rpm) at full load. The exhaust gas exits the turbine and enters the recuperator that pre-heats the air entering the combustor to improve the efficiency of the system. The exhaust gas is then directed to the Unifin heat-recovery unit.

The Unifin is a fin-and-tube heat exchanger (Model MG2) suitable for up to 700 °F exhaust gas. A nominal 25-percent mixture of propylene glycol (PG) in water is used as the heat-transfer media to recover energy from the microturbine exhaust gas stream. The PG fluid is circulated at a rate of up to 50 gallons per minute (gpm). A digital controller monitors the PG fluid outlet temperature and, 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 PG fluid 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 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 that is free of spikes and unwanted harmonics. All operations, including startup, setting of programmable interlocks, grid synchronization, operational setting, dispatch, and shutdown, can be performed either manually or remotely using an internal power controller system. This CHP system also incorporates a Copeland-Scroll Model SZN22C1A gas booster compressor with a nominal volume capacity of 29 standard cubic feet per minute (scfm) and the capability of compressing natural gas from inlet pressures of 0.25 to 15 pounds per square inch gauge (psig) to outlet pressures of 60 to 100 psig.

The verification of the Capstone 60 microturbine system was conducted at a 57,000-sq ft Waldbaums Supermarket constructed in 2002. The store uses energy-efficient T4 light fixtures so the load in the sales area is about 1.2 watts per square foot. The facility electric demand is never expected to drop below 200 kW in this store. The three-phase 480 volt power generated by the microturbine is wired directly into the store's 480-volt main panel. This CHP unit was integrated with a 20,000-cfm Munters Drycool air-handling unit previously installed at the Waldbaums. The Munters is the primary source of space heating, air conditioning, and air-dehumidification at the store. Recovered heat from the Capstone 60 CHP System is used to supplement the Munters' primary functions of heating the main sales areas of the store, and air dehumidification. The CHP system can provide heat to either the PG coil in the supply air stream that provides space heating in the winter or the PG coil that preheats the air entering the direct-fire burner that regenerates the desiccant wheel.

VERIFICATION DESCRIPTION

Testing commenced on June 4, 2003, and was completed on June 20, 2003. The testing included 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, 30, 45, and 60 kW. Demand for space heating and dessicant regeneration was low during the testing period due to the mild weather. The PG was, therefore, manually directed to the Munter's space-heating coil during each of the controlled test periods. This was done to maximize the heat demand on the CHP system and verify CHP performance under periods of high heat demand. The controlled tests at the 30 and 60 kW power command points were also repeated with the Unifin heat exchanger damper open (heat recovery bypass mode) to evaluate the impact of heat exchanger back-pressure on microturbine performance. The controlled test periods were followed by 14 days of extended monitoring to verify electric power production, heat recovery, power quality performance, and efficiency during an extended period of normal site operations. The classes of verification parameters evaluated were:

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

Evaluation of heat and power production performance includes 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) and tests consisted of direct measurements 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 tests consisted of direct measurements of heat-transfer fluid flow rate, differential temperatures, and specific heat of the heat transfer fluid. Ambient temperature, barometric pressure, and relative humidity measurements were also collected to characterize the condition of the combustion air used by the turbine.

The evaluation of emissions performance occurred simultaneously with efficiency testing conducted during the controlled test period. Pollutant concentration and emission rate measurements for nitrogen oxides (NO_X), carbon monoxide (CO), total hydrocarbons (THC), carbon dioxide (CO_2), and methane (CH_4) 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 Register (CFR). Pollutant emissions are reported in two sets of units – 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 turbine power output and reported as pounds per kilowatt hour (lb/kWh).

Annual NO_X and CO_2 emissions reductions for the CHP system at the test site are estimated by comparing measured lb/kWh emission rates with corresponding emission rates for the baseline power and heat-production systems (i.e., systems that would be used if the CHP system were not present). The baseline systems at this site include electricity supplied from the local utility grid and heat from the facility's natural gas-fired burners. Baseline emissions for the electrical power were determined following Ozone Transport Commission (OTC) guidelines. Baseline emissions from heat production are based on EPA emission factors for commercial-scale gas-fired burners.

Electrical power quality parameters, including electrical frequency and voltage output, were also measured during the 14-day extended test. 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). EPA personnel conducted an on-site technical systems audit during the testing program. The GHG Center staff conducted two performance evaluation audits and an audit of data quality on at least 10 percent of the data generated during this verification. The GHG Center field team leader and project manager have reviewed the data from the verification testing and have concluded that the data have attained the data quality objectives that are specified in the Test and Quality Assurance Plan.

VERIFICATION OF PERFORMANCE

Heat and Power Production Performance

- The average gross power output at full load was 59.6 kW at these test conditions (corresponding gross electrical efficiency was about 28.4 percent). The gross power output would be available to potential users not needing sources of significant parasitic load such as the gas compressor and glycol circulation pump.

- Considering parasitic loads from the gas compressor and glycol circulation pump, the net power delivered at full load averaged 54.9 kW. Net electrical efficiency during the controlled test periods ranged from 26.2 percent at full load to 13.1 percent at the lowest load tested (25 percent of capacity). Electrical efficiency was not impacted by changes in operation of the heat recovery system.

HEAT AND POWER PRODUCTION							
Test Condition	Electrical Power Generation				Heat Recovery Performance		Total CHP System Efficiency (%)
	Gross Power Output (kW_e)	Gross Efficiency (%)	Net Power Delivered (kW_e)	Net Efficiency (%)	Heat Recovery (10^3Btu/hr)	Thermal Efficiency (%)	
Full load, heat recovery maximized	59.6	28.4	54.9	26.2	373.0	52.2	78.4

<table>
<tr><th colspan="8">HEAT AND POWER PRODUCTION</th></tr>
<tr><th rowspan="2">Test Condition</th><th colspan="4">Electrical Power Generation</th><th colspan="2">Heat Recovery Performance</th><th rowspan="2">Total CHP System Efficiency (%)</th></tr>
<tr><th>Gross Power Output (kW_e)</th><th>Gross Efficiency (%)</th><th>Net Power Delivered (kW_e)</th><th>Net Efficiency (%)</th><th>Heat Recovery (10^3Btu/hr)</th><th>Thermal Efficiency (%)</th></tr>
<tr><td>75-percent load, heat recovery maximized</td><td>44.5</td><td>27.0</td><td>39.9</td><td>24.2</td><td>317.0</td><td>56.4</td><td>80.7</td></tr>
<tr><td>50-percent load, heat recovery maximized</td><td>29.5</td><td>23.8</td><td>24.8</td><td>20.0</td><td>239.6</td><td>56.7</td><td>76.7</td></tr>
<tr><td>25-percent load, heat recovery maximized</td><td>14.4</td><td>19.3</td><td>9.8</td><td>13.1</td><td>148.5</td><td>58.0</td><td>71.1</td></tr>
<tr><td>Full load, normal operation</td><td>59.6</td><td>28.4</td><td>54.9</td><td>26.2</td><td>51.4</td><td>7.2</td><td>33.3</td></tr>
<tr><td>50-percent load, normal operation</td><td>29.5</td><td>23.7</td><td>24.9</td><td>20.0</td><td>68.6</td><td>16.2</td><td>36.2</td></tr>
</table>

- Total CHP efficiency during the controlled test periods with operation configured to maximize heat recovery ranged from 71.1 percent at 25-percent load to 80.7 percent at 75-percent load. CHP efficiency was 33.3 percent at full load during normal heat recovery controlled tests because of low space heating and dehumidification demand during testing.

- Electrical, thermal, and CHP efficiencies during the 14-day extended monitoring period averaged 25.7, 8.0, and 33.7 percent, respectively. Low space heating and dehumidification demand was evident throughout the period.

Emissions Performance

- NO_X emissions at full load were 0.00015 lb/kWh and increased as power output decreased. Changes in operation of the heat exchanger did not produce a significant impact on NO_X emissions.

- Emissions of CO, THC, and CH_4 were also lower at full load and increased slightly as power output was reduced. Changes in operation of the heat exchanger did not produce a significant impact on emissions of these pollutants.

- NO_X emissions per unit electrical power output at full load were 0.00015 lb/kWh, well below the average levels reported for the regional grid (0.0024 lb/kWh). The average CO_2 emissions for the regional grid are estimated at 1.53 lb/kWh which is nearly identical to the emission rate for the Capstone 60 (which had 1.54 lb/kWh_e). These values, along with emission reductions attributed to the CHP system heat recovery performance, yield an average annual emission reduction of 1,064 lbs (17 percent) for NO_X and 328,478 lbs (8 percent) for CO_2.

CRITERIA POLLUTANT AND GREENHOUSE GAS EMISSIONS									
Test Condition	**(ppmvd at 15% O_2)**				**(lb/kWh$_e$)**				
	NO_X	CO	THC	CH_4	NO_X	CO	THC	CH_4	CO_2
Full load, heat recovery maximized	3.13	3.53	1.06	< 0.9	1.49×10^{-4}	1.03×10^{-4}	1.77×10^{-5}	$< 1.58 \times 10^{-5}$	1.54
75-percent load, heat recovery maximized	3.30	154	70.3	43.5	1.71×10^{-4}	4.86×10^{-3}	1.27×10^{-3}	7.84×10^{-4}	1.61
50-percent load, heat recovery maximized	4.26	582	1194	721	2.67×10^{-4}	2.26×10^{-2}	2.61×10^{-2}	1.57×10^{-2}	1.87
25-percent load, heat recovery maximized	6.56	338	327	198	6.31×10^{-4}	1.98×10^{-2}	1.09×10^{-2}	6.65×10^{-3}	2.89
Full load, normal operation	3.05	3.90	0.69	Not tested	1.47×10^{-4}	1.14×10^{-4}	1.14×10^{-5}	Not tested	1.49
50-percent load, normal operation	4.50	586	1154	678	2.83×10^{-4}	2.25×10^{-2}	2.53×10^{-2}	1.48×10^{-2}	1.87

Power Quality Performance

- The CHP system maintained continuous synchronization with the utility grid throughout the 14-day test period. Average electrical frequency was 60.000 Hz and average voltage output was 494.48 volts.
- The power factor remained relatively constant for all monitoring days with an average of 99.98 percent.
- The average current THD was 5.66 percent and the average voltage THD was 1.98 percent. The THD threshold specified in IEEE 519 is ± 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 Combined Heat and Power at a Commercial Supermarket, Capstone 60 kW Microturbine* (SRI 2002). Detailed results of the verification are presented in the Final Report titled *Environmental Technology Verification Report for Combined Heat and Power at a Commercial Supermarket, Capstone 60 kW Microturbine* (SRI 2003). 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: Hugh W. McKinnon, 9-2003

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Greenhouse Gas Technology Center

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

Environmental Technology Verification Report

Combined Heat and Power at a Commercial Supermarket— Capstone 60 kW Microturbine CHP System

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ACKNOWLEDGMENTS

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ACRONYMS AND ABBREVIATIONS

Abs Diff.	absolute difference
AC	alternating current
acf	actual cubic feet
ADER	average displaced emission rate
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 feet
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
DHW	domestic hot water
DMM	digital multimeter
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
^oF	degrees Fahrenheit
FERC	Federal Energy Regulatory Commission
FID	flame ionization detector
fps	feet per second
ft^3	cubic feet
gal	U.S. Imperial gallons
GC	gas chromatograph
GHG Center	Greenhouse Gas Technology Center
gpm	gallons per minute
GU	generating unit

(continued)

ACRONYMS/ABBREVIATIONS
(continued)

Hg	Mercury (metal)
HHV	higher heating value
hr	hour
Hz	hertz
IC	internal combustion
IEEE	Institute of Electrical and Electronics Engineers
IPCC	Intergovernmental Panel on Climate Change
ISO	International Standards Organization and Independent System Operator
ISO NE	ISO New England
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
LIPA	Long Island Power Authority
10^3Btu/hr	thousand British thermal units per hour
10^6Btu/hr	million British thermal units per hour
10^6cf	million cubic feet
mol	molecular
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
NY ISO	New York ISO
NYSERDA	New York State Energy Research and Development Authority
O_2	oxygen
O_3	ozone
ORD	Office of Research and Development
OTC	Ozone Transport Commission

(continued)

ACRONYMS/ABBREVIATIONS
(continued)

PEA	Performance Evaluation Audit
PG	propylene glycol
PJM	Pennsylvania/New Jersey/Maryland
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
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
TEI	Thermo Environmental Instruments
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) gneration).

The GHG Center and the New York State Energy Research and Development Authority (NYSERDA) recently agreed to collaborate and share the cost of verifying several new DG technologies operating throughout the state of New York under NYSERDA-sponsored programs. This verification evaluated the performance of a Capstone 60 kW Microturbine Combined Heat and Power System (CHP System) installed and integrated by CDH Energy Corporation (CDH). The test unit is currently in use at the Waldbaums Supermarket in Hauppauge, New York. The CHP System uses a natural gas-fired 60 kW microturbine for electricity generation, and a heat recovery unit to provide space heating or desiccant regeneration at the supermarket. Facility electrical and thermal demand exceeds the CHP capacity, so the facility can operate the system continuously at full load. The system is interconnected to the electric utility grid, but the facility does not anticipate exporting power for sale.

The GHG Center evaluated the performance of the CHP system by conducting field tests over a seventeen-day verification period (June 4-20, 2003). 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 Waldbaums Supermarket. This report presents the results of these verification tests.

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 the Combined Heat and Power at a Commercial Supermarket, Capstone 60 Microturbine System*™ [10]. 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 NYSERDA, system integrators at the supermarket (CDH Energy), 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 CHP system technology and test facility and outlines the performance verification procedures that were followed. Section 2 presents test results, and Section 3 assesses the quality of the data obtained. Section 4, submitted by CDH Energy, presents additional information regarding the CHP system. Information provided in Section 4 has not been independently verified by the GHG Center.

1.2. CHP TECHNOLOGY DESCRIPTION

Natural gas-fired turbines have been used to generate electricity since the 1950s. Technical and manufacturing developments in the last decade have enabled the introduction of microturbines, with generation capacity ranging from 30 to 200 kW. Microturbines have evolved from automotive and truck turbocharger technology and small jet-engine technology. A microturbine consists of a compressor, combustor, power turbine, and generator. They have a small number of moving parts and their compact size enables them to be located on sites with limited space. A waste heat-recovery system can be integrated with a microturbine to achieve higher efficiencies for sites with thermal demands.

The microturbine system verified at Waldbaums Supermarket is shown in Figure 1-1. It consists of a Capstone 60 MicroTurbine (developed by Capstone Turbine Corporation) and a heat-recovery system (developed by Unifin International). The CHP system also includes a Copeland-Scroll natural gas compressor which is needed to boost the delivered gas pressure from approximately 5 to 90 psig. The compressed gas is regulated at 75 psig as required by the Capstone. 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.

Figure 1-1. The Waldbaum's Capstone 60 Microturbine System

Electric power is generated from a high-speed, single-shaft, recuperated, air-cooled turbine generator with a nominal power output of 60 kW net (59 ^{o}F, sea level). Table 1-1 provides Capstone 60 microturbine specifications. Table 1-2 summarizes the physical and electrical specifications for the Capstone 60, which is designed to operate on natural gas 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/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 into a Unifin heat-recovery unit.

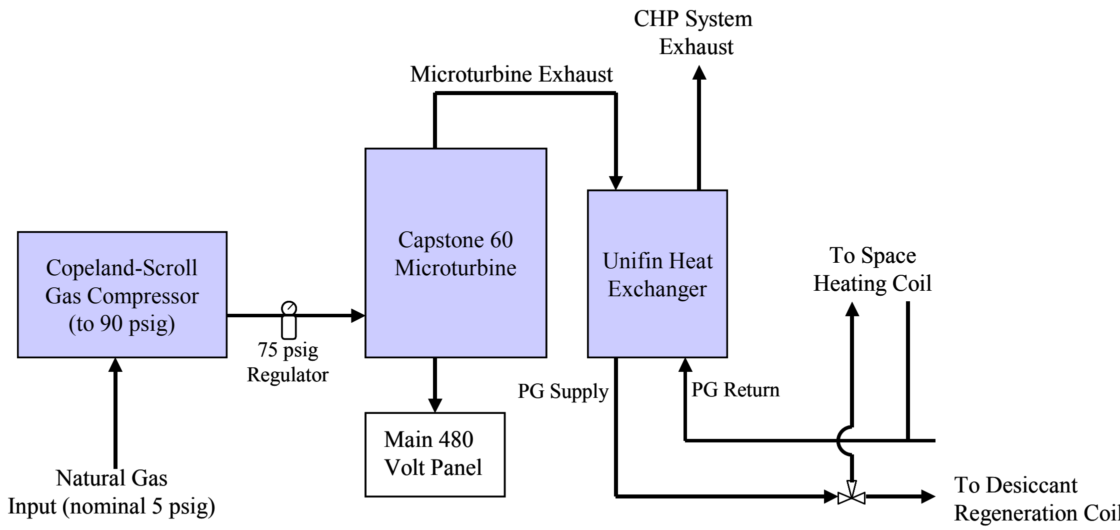

Figure 1-2. Capstone Microturbine System Process Diagram

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 cleaner 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 Copeland-Scroll Model SZN22C1A with a nominal volume capacity of 29 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 5 to 90 psig in this application. A regulator is located downstream of the compressor to control and maintain gas pressure to the microturbine at 75 psig. The compressor imposes a parasitic load of approximately 3.9 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 Unifin International and integrated by Capstone. It is an aluminum fin-and-tube heat exchanger (Model MG2) suitable for up to 700 °F exhaust gas. A nominal 25-percent mixture of PG in water (designated as "PG fluid" for the remainder of this document) is used as the heat-transfer media to recover energy from the microturbine exhaust gas stream. The PG fluid is circulated at a rate of up to 50 gallons per minute (gpm). A digital controller monitors the PG fluid 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 PG fluid 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 60 Microturbine Specifications
(Source: Capstone Turbine Corporation)

Dimensions	Width Depth Height	30 in. 77 in. 83 in.
Weight	Microturbine only	1,671 lb
Electrical Inputs	Power (startup) Communications	Utility grid Ethernet IP or modem
Electrical Outputs	Power at ISO conditions 60 °F at sea level	60 kW, 400-480 VAC, 50/60 Hz, 3-phase
Noise Level	Typical reported by Capstone	70 dBA at 33 ft
Fuel Pressure Required	w/o natural gas compressor w/ natural gas compressor	75 psig 0.5 to 15 psig
Fuel Heat Content	Higher heating value	970 to 2615 Btu/scf
Electrical Performance at Full Load (natural gas)	Heat input Power output Efficiency - with natural gas compressor Heat rate	811,000 Btu/hr, Natural gas-HHV 60 kW ± 1 kW 28% ± 2%, ISO conditions, LHV basis 12,200 Btu/kWh, LHV basis
Heat Recovery Potential at Full Load	Exhaust gas temperature Exhaust energy available for heat recovery	580 °F 541,000 Btu/hr, LHV basis
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

Table 1-2. Unifin MG2 Heat Exchanger Specifications
(Source: Unifin International, Inc.)

Weight	820 lb
Dimensions	34.75"(W) x 48.5"(D) x 70.1875"(H)
Heat Exchanger Efficiency	> 90% (at full load at water inlet temperature = 120 °F)
Exhaust Design Temperature	700 °F for C60
Tubeside Design Temperature	220 or 275 °F, closed-loop
Tubeside Design Pressure	150 psig
Design Heat Input	541,000 Btu/hr
Output	375,000 Btu/hr at 180 °F return fluid temperature

1.3. TEST FACILITY DESCRIPTION

The verification of the Capstone 60 microturbine system was conducted at the Waldbaums' Supermarket (constructed in 2002) and pictured in Figure 1-3. This new supermarket was originally a 35,000-sq. ft. retail facility. It was gutted to the block walls, expanded, and totally rebuilt into a 57,000-sq. ft. supermarket. It recently opened in July 2002. The store uses energy-efficient T4 light fixtures, so the load in the sales area is about 1.2 watts per square foot. The facility electric demand is never expected to drop below 200 kW in this store. The 480-volt power generated by the microturbine is wired directly into the store's 480-volt main panel. This unit was integrated in July 2002 with a 20,000-cfm Munters Drycool air-handling unit previously installed at Waldbaums in order to use the available heat from the Capstone 60 kW microturbine CHP system. The Munters unit provides cooling and heating to the main sales areas of the store. The unit also includes a desiccant section to provide dehumidification. The

Munters air-handling unit was configured to be capable of using recovered heat when it is available or reverting back to the conventional natural gas-fired burners otherwise.

Figure 1-3. Waldbaums Supermarket in Hauppauge, NY

1.3.1. Integration of CHP System with Facility Operations

The facility electric load remains above the 60 kW microturbine generating capacity at all times and the unit normally operates "base-loaded" at full generating capacity. The unit is designed to shut down during power outages. The local utility currently does not require any interconnect protections other than those integrated into the Capstone 60 system. The heat demands of the facility will vary on a daily and seasonal basis and, although well-matched on the average to the heat generated and recoverable from the unit, will not generally represent a constant load or use the maximum available heat from the microturbine. The specific design of the CHP system in this application is unique in using two different heat-recovery pathways to optimize overall annual heat use at the facility.

The single large 20,000-cfm central air handler for the facility (the Munters unit) makes it easier to use waste heat from the turbine to meet the space-heating loads. The space-heating loads are expected to be significant in this application due to the year-round space cooling load imposed by the refrigerated display cases. The need for heat to provide desiccant regeneration also adds significant heating loads in the summer.

PG fluid from the Capstone Unifin heat-recovery unit provides heat to two hot coils that have been added to the Munters air-handling unit: (1) a PG coil in the supply air stream that provides space heating in the winter, and (2) a PG coil that preheats the air entering the direct-fire burner that regenerates the desiccant wheel. This arrangement with the Unifin heat exchanger was selected because it provides the greatest amount of year-round heat recovery which is required because of the large space-heating loads common to this climate (Note: An alternate configuration was also considered that would have used turbine exhaust directly for desiccant regeneration, but it was not implemented because it precluded the use of heat recovery for space heating.) The Unifin heat exchanger recovers heat from the microturbine exhaust that is used by the Munters unit to provide either space heating or desiccant regeneration. The PG fluid piping from the Unifin is directly connected to hot PG fluid coils in the Munters unit. The microturbine skid, which includes the Capstone turbine, Unifin heat exchanger, and natural gas compressor module, is installed on the roof adjacent to the Munters air-handling unit (approximately 35 feet apart).

1.4. PERFORMANCE VERIFICATION OVERVIEW

This verification test design was developed to evaluate only the performance of the CHP system—not the overall building 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, 30, 45, and 60 kW. Demand for space heating and desiccant regeneration was low during the testing period due to the mild weather. The PG was, therefore, manually directed to the Munter's space-heating coil during each of the controlled test periods (the store was heated for short periods of time). This was done in an attempt to maximize the heat demand on the CHP system and demonstrate CHP performance under periods of high heat demand. These tests are identified herein as controlled test periods with heat recovery maximized.

The Test Plan also specified that controlled tests at the 30 and 60 kW power command points be repeated with the Unifin heat exchanger damper open (heat recovery bypass mode) to evaluate the impact of heat exchanger back-pressure on microturbine performance. However, problems with the Unifin control panel precluded the GHG Center from manually locking open the damper. Instead, these tests were conducted under normal CHP and Munters system operations such that the Unifin damper was automatically opened in response to the low heat demand of the store during the test periods. This allowed these tests to be conducted with operations similar to those planned because the Unifin would go into heat-recovery mode (that is, with the damper closed) only long enough to maintain PG temperatures above 170 ^{o}F under these conditions. The heat exchanger damper was open for approximately 25 minutes and then closed to heat recovery mode for the remainder of time during each of the 30-minute test replicates conducted under these conditions. These tests are identified herein as controlled test periods under normal conditions.

The controlled test periods were followed by a period of extended monitoring to evaluate power and heat production and power quality over a range of ambient conditions and store operations. The microturbine was allowed to operate continuously at full load during the extended monitoring period.

The specific verification factors associated with the test are listed below. Brief discussions of each verification factor 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 full load
- Electrical, thermal, and total system efficiency at full load
- Combined heat and power efficiency (total efficiency)

Power Quality Performance

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

Emissions Performance

- Nitrogen oxides (NO_X) concentrations and emission rates

- Carbon monoxide (CO) concentrations and emission rates
- Total hydrocarbon (THC) concentrations and emission rates
- Carbon dioxide (CO_2) and methane (CH_4) concentrations and emission rates
- Estimated greenhouse gas emission reductions

Each of the verification parameters listed were evaluated during the controlled or extended monitoring periods as summarized in Table 1-3. This table also specifies the dates and time periods during which the testing was conducted.

<table>
<tr><th colspan="4">Table 1-3. Controlled and Extended Test Periods</th></tr>
<tr><th colspan="4">Controlled Test Periods</th></tr>
<tr><th>Date</th><th>Time</th><th>Test Condition</th><th>Verification Parameters Evaluated</th></tr>
<tr><td>06/04/03</td><td>13:05 - 14:55</td><td>Power command of 60 kW in maximum heat-recovery mode, three 30-minute test runs</td><td rowspan="6">NO_X, CO, THC, CH_4, CO_2 emissions, and electrical, thermal, and total efficiency</td></tr>
<tr><td>06/04/03</td><td>15:40 - 17:30</td><td>Power command of 60 kW in current (low) heat-recovery mode, three 30-minute test runs</td></tr>
<tr><td>06/05/03</td><td>10:15 - 12:10</td><td>Power command of 45 kW in maximum heat-recovery mode, three 30-minute test runs</td></tr>
<tr><td>06/05/03</td><td>12:35 - 14:25</td><td>Power command of 30 kW in maximum heat-recovery mode, three 30-minute test runs</td></tr>
<tr><td>06/05/03</td><td>14:45 - 16:35</td><td>Power command of 30 kW current (low) heat-recovery mode, three 30-minute test runs</td></tr>
<tr><td>06/05/03</td><td>16:45 - 18:35</td><td>Power command of 15 kW in maximum heat-recovery mode, three 30-minute test runs</td></tr>
<tr><td>06/06/03</td><td>07:40 - 09:30</td><td>Emissions profile test over range of power commands from 15 to 60 kW in 5 kW increments</td><td>NO_X, CO, THC, CH_4, CO_2 emissions</td></tr>
<tr><th colspan="4">Extended Test Periods</th></tr>
<tr><th>Start Date, Time</th><th>End Date, Time</th><th colspan="2">Verification Parameters Evaluated</th></tr>
<tr><td>06/06/03, 12:00</td><td>06/20/03, 12:00</td><td colspan="2">Total electricity generated; total heat recovered; electrical, thermal, and total efficiency; power quality; and emission offsets</td></tr>
</table>

Simultaneous monitoring for power output, heat recovery rate, fuel consumption, ambient meteorological conditions, and exhaust emissions were performed during each of the controlled test periods. Manual samples of natural gas and PG solution were collected to determine fuel lower heating value and specific heat of the heat transfer fluid. 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.

Daily performance of the CHP system was characterized over the 14-day extended monitoring period following the controlled test periods. The CHP system was operating 24 hours per day at maximum electrical power output. The facility's heat demand was generally low due to the warm weather conditions during this period. There was some demand for desiccant regeneration, so the heat recovery performance measured during the period is representative for this facility during early summer conditions. It is likely that seasonal changes in space heating and regeneration demand for this facility will have a significant impact on the system's heat-recovery performance.

Results from the extended test are used to report total electrical energy generated and used on site, total thermal energy recovered, greenhouse gas emission reductions, and electrical power quality. Greenhouse gas emission reductions are estimated using measured greenhouse gas emission rates, emissions estimates for electricity produced at central station power plants, and emissions estimates for the Munters unit gas-fired burners.

1.4.1. Heat and Production Performance

Electrical efficiency determination was based upon guidelines listed in ASME PTC-22 [5], and was calculated using the average measured net power output, fuel flow rate, and fuel lower heating value (LHV) during each 30-minute test period. The CHP system has two primary parasitic loads at this facility: (1) the gas-pressure booster compressor, and (2) the PG fluid circulation pump. This verification includes measurement of these two parasitic loads to report the net system efficiency. For potential users with access to has high-pressure gas and/or PG circulation facilities, the gross power output and electrical efficiencies are also reported here.

The electrical power output (in kW) was measured continuously throughout the verification period with a 7600 ION Power Meter (Power Measurements Ltd.). A second power meter (7500 ION) was used to simultaneously monitor parasitic power consumption by the gas compressor. The power consumed by the PG circulation pump was not independently monitored by the GHG Center, but is continuously logged by site operators at one-minute intervals. The corresponding one-minute data logged by the operators were used to determine pump draw. The accuracy of the pump draw data was not verified but is stated by the manufacturer to be within ± 1 percent of reading. The reported parasitic load, at approximately 0.75 kW during all test periods, represents a small portion of total CHP system heat and power production. Therefore, a true assessment of watt-meter accuracy is not expected to impose a significant impact on the net efficiency determination.

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

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

where:

η = efficiency (%)
kW = average net electrical power output measured over the 30-minute interval (kW), (Capstone 60 power output minus power consumed by gas compressor and PG circulation pump)
HI = average heat input using LHV over the test interval (Btu/hr); determined by multiplying the average mass flow rate of natural gas 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

Heat recovery rate was measured simultaneous with electrical power measurements using an in-line PG flow meter (Onicon Model F-1110) and PG supply and return temperatures (Controlotron Model 1010EP). The meters enabled one-minute averages of differential heat exchanger temperatures and PG mixture flow rates to be monitored. Manual samples of the PG solution were collected to determine PG concentration, fluid density, and specific heat such that heat recovery rates could be calculated at actual conditions per ANSI/ASHRAE Standard 125 [4].

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

where:

V = total volume of liquid passing through the heat meter flow sensor during a minute (ft^3)
ρ = density of PG solution (lb/ft^3), evaluated at the avg. temp. (T2 plus T1)/2
C_p = specific heat of PG 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 extended 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:

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

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 natural gas to the system (converted to scfh) times the gas LHV (Btu/scf)

1.4.2. Measurement Equipment

Figure 1-4 illustrates the location of measurement instruments that were used in the verification.

The ION electrical power meters continuously monitored the kilowatts of power generated by the Capstone 60 and consumed by the compressor at a rate of approximately one reading every 8 to 12 milliseconds. These data are averaged every minute using the GHG Center's data acquisition system (DAS). The generator meter was located in the main switchbox connecting the CHP to the host site and represented power delivered to Waldbaums. The real-time data collected by the meters were downloaded and stored on a data acquisition computer using Power Measurements' PEGASYS software. The logged one-minute average kW readings were averaged over the duration of each controlled test period to compute electrical efficiency. The kW readings were integrated for the extended test period over the duration of the verification period to calculate total electrical energy generated in units of kilowatt hours (kWh).

The mass flow rate of the fuel was measured using an integral orifice meter (Rosemount Model 3095/1195). The orifice meter contained a 0.512-inch orifice plate to enable flow measurements at the ranges expected during testing (10 to 15 scfm natural gas). The Rosemount orifice meter includes gas pressure and temperature sensors for flow rate compensation to provide mass flow output at standard conditions (60 °F, 14.696 psia). Note that the Rosemount was located upstream of the gas compressor, and, therefore, the measured gas pressures and temperatures were not indicative of fuel conditions entering the microturbine. Gas pressure into the microturbine were not independently verified, but indicated by a pressure gauge to be 75 psig. The meter was configured to continuously monitor the average flow rate at one-minute intervals. The meter components (orifice plate and differential pressure sensors) were calibrated prior to testing using NIST-traceable instruments. Additional QA/QC checks for this meter were performed routinely in the field, including reasonableness and zero checks.

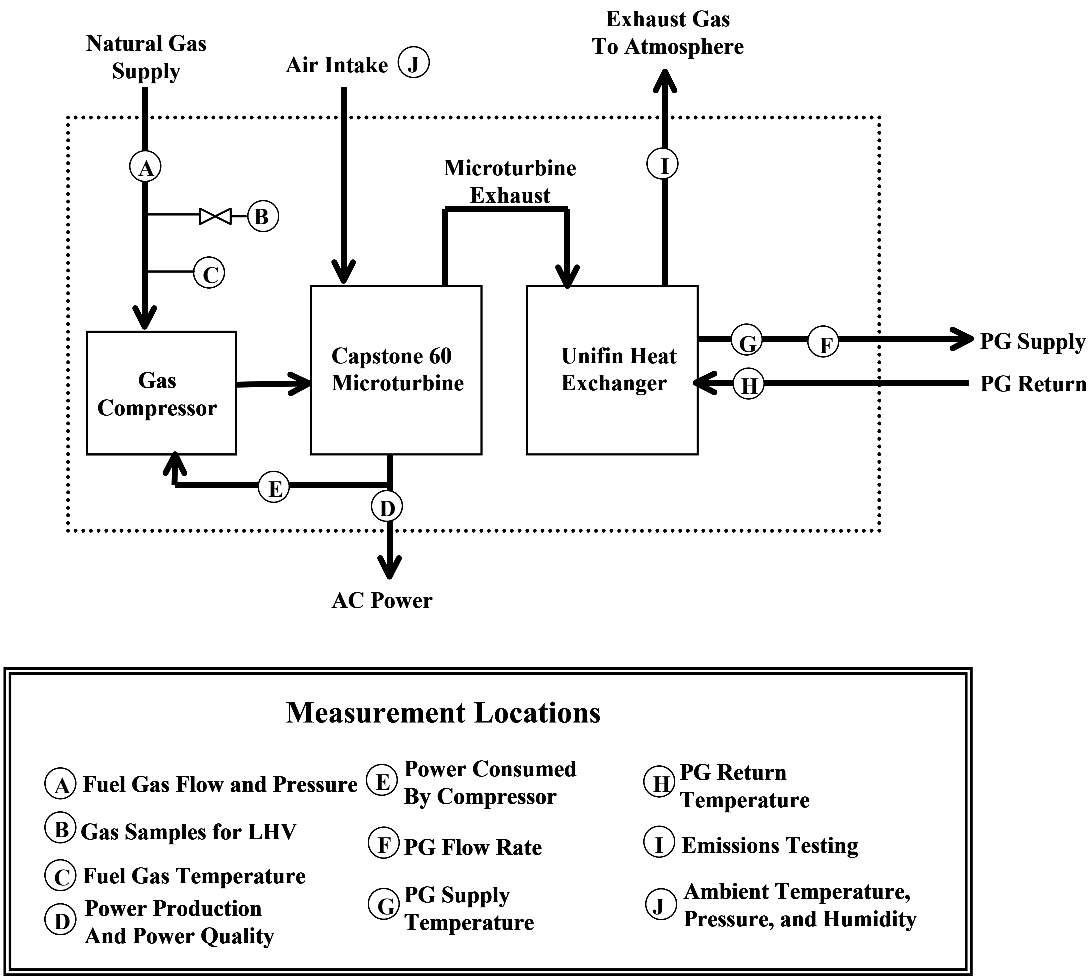

Figure 1-4. Schematic of Measurement System

Natural gas samples were collected and analyzed to determine gas composition and heating value. A total of six samples were collected—four during the control test periods and another two during the extended monitoring. The collected 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 [7]. The compositional data were then used in conjunction with ASTM Specification D3588 to calculate LHV and the relative density of the gas [8]. Duplicate analyses were performed by the laboratory on two of the samples to determine the repeatability of the LHV results.

A Controlotron Model 1010EP1 energy meter was used to monitor PG 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 fluid flow rate component failed intermittently during some of the field testing, so the meter was used only to monitor PG temperatures and to confirm the accuracy of a replacement meter used to monitor PG flow rates. An Onicon Model F-1110 turbine meter was used to continuously monitor PG fluid flow rate. The meter has an overall rated accuracy of ± 0.5 percent of reading and provides a continuous 4-20 mA output signal over a range of 0 to 80 gpm. The meter was installed in the 2-inch Type-L copper PG supply line by CDH Energy.

The PG flow rate and supply and return temperature data were logged as one-minute averages throughout all test periods and used in Equation 2 to determine CHP system recovery rates. The two other variables in Equation 2—fluid density and specific heat—were determined by collecting PG samples during the test periods and submitting the samples to Energy Laboratories of Billings, MT, for compositional analyses. The PG samples were collected from a fluid discharge spout located on the hot side of the heat-recovery unit using 250-mL capacity sample containers. A total of six PG samples were collected, including one per day during the controlled test periods, and four during the extended monitoring period. Each sample collection event was recorded on field logs and shipped to the laboratory along with completed chain-of-custody forms. Samples were analyzed at the laboratory for PG concentration and fluid density using gas chromatography with a flame ionization detector (GC/FID). Specific heat of the PG solution was selected using published PG properties data [6] using the measured concentrations.

1.4.3. Power Quality Performance

There are a number of issues of concern when an electrical generator is connected in parallel and operated simultaneously with the utility grid. The voltage and frequency generated by the power system must be aligned with the power grid. The units must detect grid voltage and frequency while in grid parallel mode to ensure proper synchronization before actual grid connection occurs. The Capstone 60 system electronics contain circuitry to detect and react to abnormal conditions that, if exceeded, cause the unit to automatically disconnect from the grid. These out-of-tolerance operating conditions include overvoltages, undervoltages, and over/under frequency. With stakeholder input, the GHG Center has defined grid voltage tolerance as the nominal voltage ± 10 percent for previous verifications. Frequency tolerance is 60 ± 0.6 Hz (1.0 percent).

Another issue is the generator's effects on electrical frequency, power factor, and total harmonic distortion (THD)—they cannot be completely isolated from the grid. The quality of power delivered actually represents an aggregate of disturbances already present in the utility grid. An example is that local CHP power with low THD will tend to dampen grid power with high THD in the test facility's wiring network. This effect will drop off with distance from the CHP generator.

The GHG Center and its stakeholders developed the following power quality evaluation approach to account for these issues. Two documents [1,2] 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 extended monitoring period:

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

The 7600 ION power meter used for power output determinations was used to perform these measurements as described below and detailed in the Test Plan. The factory calibrated the ION power meter to ANSI C12.20 CAO.2 standards prior to field installation. Electricity supplied in the U.S. and Canada is typically 60 Hz AC. The ION power meter continuously measured electrical frequency at the generator's distribution panel. The DAS was used to record one-minute averages throughout the extended period. 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 [3]. 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 extended 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. The ION power meter applies Fourier Analysis algorithms to quantify THD. Fourier showed that any wave form can be analyzed as one sum of pure sine waves with different frequencies and that each contributing sine wave is an integer multiple (or harmonic) of the lowest (or fundamental) frequency. The fundamental is 60 Hz for electrical power in the U.S. The 2nd harmonic is 120 Hz, the 3rd is 180 Hz, and so on. Certain harmonics, such as the 5th or 12th, can be strongly affected by the types of devices (that is, capacitors, motor control thyristors, inverters) connected to the distribution network.

The magnitude of the distortion can vary for each harmonic. Each harmonic's magnitude is typically represented as a percentage of the rms voltage of the fundamental. The aggregate effect of all harmonics is called THD. THD is the sum of the rms voltage of all harmonics divided by the rms voltage of the fundamental, converted to a percentage. 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 [2].

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 and, similar to voltage THD, can be quantified by Fourier Analysis. 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. The standard's recommendations for a small CHP unit connected to a large-capacity grid, for example, are more forgiving than those for a large CHP unit connected to a small-capacity 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 recommendation. The ION power meter, as with voltage THD, continuously measured current THD for each phase and reported the average.

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.

1.4.4. Emissions Performance

Pollutant concentration and emission rate measurements for NO_X, CO, THCs, CH_4, and CO_2 were conducted on the turbine exhaust stack during all of the controlled test periods. Emissions testing coincided with the efficiency determinations described earlier. All of 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 1-4 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 1-4. Summary of Emissions Testing Methods

Exhaust Stack			
Pollutant	**EPA Reference Method**	**Analyzer Type**	**Instrument Range**
NO_X	20	TEI Model 42LS (chemiluminescense)	0 - 25 ppm
CO	10	TEI Model 48 (NDIR)	0 - 25 ppm at high load, 0 - 1,000 ppm at reduced loads
THC	25A	TEI Model 51 (FID)	0 - 18 ppm at high load, 0 - 500 ppm at reduced loads
CH_4	18	Hewlett-Packard 5890 GC/FID	0 - 500 ppm
CO_2	3A	Servomex Model 1440 (NDIR)	0 - 10%
O_2	3A	Servomex Model 1440 (electrochemical)	0 - 25%

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 instrumental testing are reported in units of parts per million volume dry (ppmvd) and ppmvd corrected to 15-percent O_2. The emissions testing was conducted by ENSR International of East Syracuse, NY, 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.

EPA Method 19 was followed to convert measured pollutant concentrations into emission rates in units of pounds per hour (lb/hr). The fundamental principle of Method 19 is based upon F-factors. F-factors are the ratio of combustion gas volume to the heat content of the fuel and are calculated as a volume/heat input value, (e.g., standard cubic feet per million Btu). This method specified all calculations required to compute the F-factors and provides guidelines for their use. The published F-factor of 8,710 dry standard cubic feet per million Btu (dscf/10^6Btu) was used to determine emission rates for each controlled test period. Pollutant concentrations were converted from a ppmvd basis to lb/dscf. The emission rates were then calculated using the measured heat input to the turbine [10^6Btu/hr based on the higher heating value (HHV) of the gas] and stack gas O_2 concentration (dry basis) in terms of lb/hr as follows:

$$Mass\ Emission\ Rate\ (lb/hr) = HI * Concentration * F\text{-}factor * [20.9 / (20.9 - \%\ O_{2,d})] \qquad \text{(Eqn. 4)}$$

where:

HI	=	average measured heat input, HHV based (10^6Btu/hr)
Concentration	=	measured pollutant concentration (lb/dscf)
F-factor	=	calculated exhaust gas flow rate (dscf/10^6Btu)
$O_{2,d}$	=	measured O_2 level in exhaust stack, dry basis (%)
20.9	=	oxygen concentration in air (%)

The mass emission rates as lb/hr were then normalized to electrical power output by dividing the mass rate by the average power output measured during each controlled test and are reported as pounds per kilowatt-hour electrical (lb/kWh$_e$).

1.4.5. Estimated Annual Emission Reductions for Waldbaums

All of the Waldbaums' electrical power and heat demand is met by the local utility, LIPA, and the gas-fired Munters unit when on-site generation of electricity and heat with the CHP is unavailable. Electricity generation from central power stations and heat production from the Munters' gas burners then defines the baseline power and heat scenario for this facility. Emissions of NO_X and CO_2 generated by these systems represent the baseline emissions in the absence of the CHP system. Some of the power and heat demand of the facility is met through on-site generation with the CHP system operating. Less power is purchased from the utility grid under this scenario and less heat is generated by the gas-fired burners. A reduction in emissions is realized under the CHP system scenario if CHP emissions of CO_2 and NO_X are lower than the emissions associated with the generation of energy displaced from the baseline scenario.

Emissions from the CHP scenario for this verification are compared with the baseline scenario to estimate annual NO_X and CO_2 emission levels and reductions (lb/yr). Reliable emission factors for electric utility grid and burners are available for both gases. Emission reductions were computed as follows:

Annual Emission Reductions (lb/yr) = [Baseline Scenario Emissions] – [CHP Scenario Emissions]

Annual Emission Reductions (%) = Annual Emission Reductions (lb/yr) / [Baseline Scenario Emissions] 100*

The following 4 steps describe the methodology used.

<u>Step 1 - Determination of Waldbaum's Annual Electrical and Thermal Energy Profiles</u>

The first step in estimating emission reductions was to estimate the supermarket's annual electrical (kWh$_e$) and thermal energy demand (kWh$_{th}$) for a typical calendar year. System integrators (CDH Energy Systems) are monitoring these data as part of a long-term demonstration of CHP performance for NYSERDA [14]. The data span the first year of the supermarket's operation beginning in August 2002 and ending in June 2003. Demand data for the month of July are projected. The monthly electrical demand (power consumption) and Munters' air-handling system gas use (heat demand) were made available to the GHG Center for this analysis and are summarized in Table 1-5.

Table 1-5. Annual Electrical and Thermal Demand for the Hauppauge Waldbaums (Provided by CDH Energy Corporation)			
Month	**Electrical Demand (kWh_e)**	**Heat Demand (kWh_{th})**	
		Space Heating	**Desiccant Regeneration**
August 2002	239,441	0	53,398
September 2002	225,634	0	52,401
October 2002	194,258	21,684	21,257
November 2002	166,075	75,973	4,167
December 2002	164,062	113,774	1,671
January 2003	167,012	143,898	0
February 2003	152,592	123,463	0
March 2003	172,600	89,261	932
April 2003	164,823	70,370	0
May 2003	187,295	45,458	1,292
June 2003	204,690	14,160	12,353
July 2003	222,066	0	32,883
Totals	**2,260,548**	**698,045**	**180,354**

The utility grid and Munters unit provide all power and heat necessary to meet these demand values under the baseline scenario. The average electrical generating rate measured during the extended test period is used to estimate electrical offsets (55.08 kW) for the CHP scenario. Estimation of heat offsets for the CHP scenario is beyond the scope of this verification. Therefore, heat offsets are estimated using projected CHP heat recovery rates developed by CDH during system design (see Test Plan Section 2.5.3). The total annual projected useable heat from the CHP system is 394,513 kWh for space heating and 95,257 kWh for desiccant regeneration.

Step 2 – Emissions Estimate for the CHP

Emissions associated with this system were estimated using the energy production data for the CHP as follows:

$$E_{CHP} = kWhe_{\ CHP} * ER_{CHP} \qquad \text{(Eqn. 5)}$$

where:

E_{CHP} = CHP emissions (lb/yr)
$kWh_{e,CHP}$ = Annual electrical energy generated by CHP (kWh/yr)
ER_{CHP} = CHP emission rate (lb/kWh)

The CO_2 and NO_X emission rates defined above are equivalent to the average full load emission rate determined during the verification test (see Section 2).

Step 3 - Emissions Estimate for the Utility Grid

Emissions associated with electricity generation at central power stations is defined by the following equation:

$$E_{Grid} = kWh_{e,Grid} * 1.078 * ER_{Grid} \quad \text{(Eqn. 6)}$$

where:

E_{Grid}	=	grid emissions (lb/yr)
$kWh_{e,Grid}$	=	electricity supplied by the grid (kWh)
1.078	=	transmission and distribution system line losses (%)
ER_{Grid}	=	NY ISO-displaced emission rate (lb/kWh$_e$)

The $kWh_{e,Grid}$ variable shown above represents the estimated electricity supplied by the utility grid under either the baseline or CHP scenario. These values are increased by a factor of 1.078 to account for line losses between central power stations and the end user.

Defining the grid emission rate (ER_{Grid}) is complex and the methodol for estimating this parameter is continuously evolving. The discussion presented in Appendix B-1 provides a brief background on the concept of displaced emissions and presents the strategy employed by the GHG Center to assign ER_{Grid} for this verification.

Step 4 - Emissions Estimate For the Gas Burners

Combustion of the carbon in natural gas will form CO_2. The resulting CO_2 emission rate for each of the Munters' gas burners is then calculated as follows:

$$ER_{BurnerCO2} = \frac{44}{12} * (CC) * (FO) * \frac{3412.1}{1{,}000{,}000} * \frac{1}{(Eff_{Burner} / 100)} \quad \text{(Eqn. 7)}$$

where:

$ER_{BurnerCO2}$	=	burner CO_2 emission rate (lb/kWh$_{th}$)
44	=	molecular weight of CO_2 (lb/lb-mol)
12	=	molecular weight of carbon (lb/lb-mol)
CC	=	measured fuel carbon content (35.04 lb/10^6Btu)
FO	=	0.995; fraction of natural gas carbon content oxidized during combustion
3412.1	=	1 kW$_{th}$/Btu
1,000,000	=	1 10^6Btu/Btu
Eff_{Burner}	=	Combustion efficiency of gas burners (69.5% for the space heating coil, 95% for the desiccant regeneration burner)

The carbon content of natural gas sampled at the test site by the GHG Center is used to determine the CO_2 emission rates for the space heating and regeneration burners. These values are 0.628 and 0.459 lb/kWh$_{th}$, respectively. These emission rates assume that the burner efficiency is the same at all heat output levels; that is, the units are not derated for part-load operating conditions. Efficiency profiles at various heat output levels were not available for this unit to allow such corrections to be made. NO_X emission factors for gas-fired burners were obtained from AP-42 [13]. Burners such as those used in the Munters unit are categorized as similar to commercial boilers under 100 10^6Btu/hr heat input. The NO_X emission factor for such units is listed as 100 lb/10^6 scf of natural gas. The average measured LHV for the natural gas used at the host facility was approximately 903 Btu/scf. This means that 10^6 scf of natural gas will supply approximately 903 10^6Btu of heat to the burners. The resulting NO_X emission rate is expected to be approximately 100/903, or 0.1107 lb/10^6Btu (or 0.000378 lb/kWh).

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2.0 VERIFICATION RESULTS

The verification period started on June 4, 2003, and continued through June 20, 2003. The controlled tests were conducted on June 4 and 5, and were followed by an extended fourteen-day period of continuous monitoring to examine heat and power output, power quality, efficiency, and emission reductions.

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 (for example, gas flow, gas pressure, gas temperature, power output and quality, heat recovery rate, and ambient conditions)
- Fuel gas compositional data
- Emissions testing data
- PG compositional analyses
- 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 fuel LHV and PG 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.

The days listed above include periods when the unit was operating normally. The GHG Center has made every attempt to obtain a reasonable set of data to examine daily trends in atmospheric conditions, electricity and heat production, and power quality. It should be noted that these results may not represent performance over longer operating periods or at significantly different operating conditions (especially the severe winter weather conditions that can be experienced at this site).

Test results are presented in the following subsections:

Section 2.1 – Heat and Power Production Performance
(short-term controlled testing and extended monitoring)
Section 2.2 – Power Quality Performance
(extended 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 48 and 56 kW of net electrical power depending on ambient temperature (51 to 84 ^{o}F) during the extended monitoring period. The highest heat recovery rate measured during normal operations during the extended monitoring period was approximately 318,700 Btu/hr under normal site operation (approximately 370,700 Btu/hr was the maximum heat recovery rate measured during the controlled test periods with heat recovery manually maximized). Electrical efficiency averaged 26.2 percent. Thermal efficiency averaged 51.6 percent (7.1 percent under normal heat-recovery operations) at full load with forced heat recovery. Corresponding total CHP system efficiency at full load was 77.8 percent (33.3 percent under normal heat recovery operations). NO_X emissions at full load were 4 ppmvd or less (corrected to 15-percent O_2). NO_X and CO_2 emission reductions are estimated to be at least 17 and 8 percent, respectively.

In support of this verification, QA staff from EPA-ORD's Technical Services Branch conducted an on-site Technical Systems Audit (TSA) of the GHG Center's testing activities and procedures. Based on the verification approaches and testing procedures specified in the Test Plan, the overall conclusion of the audit was that the GHG Center performed well during this verification. Certain deviations from planned activities and other items of concern were documented in the TSA report, and each is addressed in this report. The primary items noted are listed below along with the location in this report where each item is addressed (in parentheses).

- How the "heat exchanger damper full open" test condition was conducted (Section 1.4).
- The determination of the parasitic load associated with the glycol pump and its consideration for the overall heat-recovery efficiency of the CHP system (Section 1.4.1).
- The actual gas pressure of the fuel gas entering the Capstone 60 (Section 1.4.2).
- The absence of a true flow-through calibration of the fuel gas meter system (Section 3.2.2.3).
- Calibration of the Vaisala ambient temperature and relative humidity sensor (Section 3.2.2.2).
- The circumstances surrounding the expansion of the calibration ranges for the CO and THC analyzers (Section 3.2.5).
- Substitution of the faulty Controlotron glycol flow meter with the Onicon turbine meter (Sections 1.4.2 and 3.2.3).
- The impact that questionable insulation around the surface-mounted RTDs may have imposed on the glycol delta-temperature readings (Section 3.2.3).
- The final condition of the Tedlar bags samples shipped to the analytical laboratory for determination of methane in exhaust gases (Section 3.2.5).

In addition to the TSA, the GHG Center conducted two performance evaluation audits (PEAs) and 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 is then used to demonstrate whether the data quality objectives (DQOs) introduced in the Test Plan were met for this verification.

2.1. HEAT AND POWER PRODUCTION PERFORMANCE

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

2.1.1. 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 54 to 71 ^{o}F, relative humidity ranged from 62 to 97 percent, and barometric pressure was between 14.47 and 14.74 psia during the controlled testing periods. The conditions encountered during testing were similar to standard conditions defined by the International Standards Organization (59 ^{o}F, 60 percent RH, and 14.696 psia). The results shown in Table 2-1 and the discussion that follows are representative of conditions encountered during testing and are not intended to indicate performance at other operating conditions such as cooler temperatures and different elevations. Supporting natural gas fuel input characteristics and heat recovery unit operation data corresponding to the test results are summarized in Table 2-2.

The average net electrical power delivered to the supermarket was 54.9 kW_e at full load. The average electrical efficiency corresponding to these measurements was 26.2 percent. The average gross power output at full load was 59.6 kW at these test conditions (corresponding gross electrical efficiency was about 28.4 percent). The gross power output would be available to potential users not needing sources of significant parasitic load such as the gas compressor and glycol circulation pump. Electric power generation heat rate, which is an industry-accepted term to characterize the ratio of heat input to electrical power output, averaged 13,025 Btu/kWh_e at full power.

The average heat-recovery rate at full power with heat demand maximized was 373.0 10^3Btu/hr, or 109.3 kW_{th}/hr, and thermal efficiency was 52.2 percent. Results of three runs indicated that the total efficiency (electrical and thermal combined) was 78.4 percent at this condition. The net heat rate, which includes energy from heat recovery, was 4,354 Btu/kWh_{tot}.

Table 2-1. Heat and Power Production Performance

Test ID	Test Condition	Heat Input 10^3Btu/hr)	Electrical Power Generation Performance				Heat Recovery Performance		Total CHP System Efficiency (%)	Ambient Conditions [c]	
			Net Power Delivered [a] (kW_e)	Net Efficiency (%)	Gross Power Output (kW_e)	Gross Efficiency (%)	Heat Recovery Rate [b] (10^3Btu/hr)	Thermal Efficiency (%)		Temp (^oF)	RH (%)
Run 1	100% Load – Heat recovery maximized	715.6	54.94	26.2	59.59	28.4	370.0	51.7	77.9	55.5	97
Run 2		715.2	54.92	26.2	59.56	28.4	374.6	52.4	78.6	54.7	97
Run 3		714.6	54.91	26.2	59.56	28.4	374.4	52.4	78.6	54.5	96
Avg.		**715.1**	**54.93**	**26.2**	**59.57**	**28.4**	**373.0**	**52.2**	**78.4**	**54.9**	**97**
Run 4	100% Load – Normal	716.0	54.91	26.2	59.54	28.4	62.8	8.8	34.9	54.3	97
Run 5		716.7	54.92	26.2	59.55	28.4	39.8	5.6	31.7	54.7	96
Run 6		717.3	54.93	26.1	59.56	28.3	51.4	7.2	33.3	54.9	97
Avg.		**716.7**	**54.92**	**26.2**	**59.55**	**28.4**	**51.4**	**7.2**	**33.3**	**54.6**	**97**
Run 7	75% Load – Heat recovery maximized	558.8	39.87	24.4	44.52	27.2	318.3	57.0	81.3	58.1	92
Run 8		562.9	39.88	24.2	44.52	27.0	315.2	56.0	80.2	60.4	88
Run 9		563.6	39.89	24.2	44.53	27.0	317.6	56.4	80.5	62.9	83
Avg.		**561.8**	**39.88**	**24.2**	**44.52**	**27.0**	**317.0**	**56.4**	**80.7**	**60.4**	**88**
Run 10	50% Load – Heat recovery maximized	423.0	24.84	20.0	29.49	23.8	239.6	56.7	76.7	63.0	81
Run 11		423.0	24.83	20.0	29.49	23.8	239.7	56.7	76.7	62.3	83
Run 12		422.3	24.83	20.0	29.48	23.8	239.4	56.7	76.8	62.2	84
Avg.		**422.8**	**24.83**	**20.0**	**29.49**	**23.8**	**239.6**	**56.7**	**76.7**	**62.5**	**83**
Run 13	50% Load – Normal	423.7	24.85	20.0	29.49	23.8	79.9	18.7	38.7	64.0	79
Run 14		425.0	24.85	20.0	29.49	23.7	63.7	15.0	35.0	66.8	72
Run 15		424.9	24.86	20.0	29.49	23.7	62.8	14.8	34.7	70.6	62
Avg.		**424.5**	**24.85**	**20.0**	**29.49**	**23.7**	**68.6**	**16.2**	**36.2**	**67.1**	**71**
Run 16	25% Load – Heat recovery maximized	254.5	9.80	13.1	14.46	19.4	154.3	60.6	73.8	70.7	63
Run 17		258.0	9.80	13.0	14.46	19.1	145.2	56.3	69.2	67.0	75
Run 18		255.4	9.79	13.1	14.46	19.3	146.1	57.2	70.3	66.8	73
Avg.		**256.0**	**9.80**	**13.1**	**14.46**	**19.3**	**148.5**	**58.0**	**71.1**	**68.1**	**70**

[a] Represents actual power available for consumption at the test site (power generated less parasitic loads of gas compressor and PG circulation pump).
[b] Divide by 3412.14 to convert to equivalent kilowatts (kW_{th}).
[c] Barometric pressure remained relatively consistent throughout the test runs (14.47 to 14.74 psia).

Table 2-2. Fuel Input and Heat Recovery Unit Operating Conditions

	Test Condition		Natural Gas Fuel Input				PG Fluid Conditions				
			Gas Flow Rate	LHV [a]	Gas Pressure	Gas Temp	PG Comp. [b]	Fluid Flow Rate	Outlet Temp.	Inlet Temp.	Temp. Diff.
	% of Rated Power	Site Operations	(scfm)	(Btu/ft^3)	(psig)	(^{o}F)	(% volume)	(gpm)	(^{o}F)	(^{o}F)	(^{o}F)
Run 1			13.2	902.4	5.06	58.3		50.6	137.7	122.5	15.2
Run 2		Heat recovery maximized	13.2	--	5.09	57.8		50.6	137.3	121.9	15.4
Run 3	100		13.2	--	5.08	57.9		50.5	137.2	121.8	15.4
Avg.			**13.2**	**--**	**5.08**	**58.0**	**25.5**	**50.5**	**137.4**	**122.1**	**15.3**
Run 4			13.2	--	5.09	56.6		44.6	174.7	171.2	2.9
Run 5			13.2	901.9	5.11	56.9		44.4	175.3	173.4	1.9
Run 6	100	Normal	13.3	--	5.11	57.5		44.9	176.6	174.2	2.4
Avg.			**13.2**	**902.2**	**5.10**	**57.0**		**44.6**	**175.5**	**172.9**	**2.4**
Run 7			10.3	902.3	5.12	63.8		50.4	128.3	115.2	13.1
Run 8		Heat recovery maximized	10.4	--	5.15	69.3		50.6	127.9	115.0	13.0
Run 9	75		10.4	--	5.10	72.9		50.6	129.5	116.4	13.0
Avg.			**10.4**		**5.12**	**68.7**		**50.5**	**128.6**	**115.5**	**13.0**
Run 10			7.81	--	5.12	72.1		50.3	116.3	106.4	9.9
Run 11		Heat recovery maximized	7.81	--	5.14	69.8		50.4	115.7	105.8	9.9
Run 12	50		7.79	--	5.16	70.0		50.3	115.5	105.7	9.9
Avg.			**7.80**		**5.14**	**70.6**	**25.0**	**50.3**	**115.8**	**106.0**	**9.9**
Run 13			7.82	--	5.17	72.4		44.9	177.3	173.7	3.7
Run 14			7.84	--	5.20	77.5		44.9	178.1	175.1	3.0
Run 15	50	Normal	7.84	--	5.15	84.9		44.6	179.8	176.9	2.9
Avg.			**7.84**		**5.17**	**78.3**		**44.8**	**178.4**	**175.2**	**3.2**
Run 16			4.70	--	5.10	84.5		50.2	107.8	101.4	6.4
Run 17		Heat recovery maximized	4.76	--	5.07	75.6		50.2	103.9	97.9	6.0
Run 18	25		4.71	903.7	5.15	73.8		50.2	103.4	97.3	6.1
Avg.			**4.72**	**903.0**	**1.89**	**78.0**		**50.2**	**105.0**	**98.9**	**6.2**

[a] Represents results of gas samples collected during each day (average of two samples taken during runs 1-6, and two samples from runs 7-18).
[b] Represents results of PG samples collected once each day.

The average full-power heat-recovery rate during normal site operations (low heat demand under these test conditions) was 51.4 10^3Btu/hr, or 15.1 kW_{th}/hr, and thermal efficiency was 7.2 percent. Results of three runs showed that the total efficiency was 33.3 percent. Net heat rate, which includes energy from heat recovery, was 10,236 Btu/kWh_{tot} under normal operations.

Results of the reduced load tests are also included in the tables. Results show that electrical efficiency decreases as the power output is reduced. Thermal efficiency, however, remains high throughout the range of operation with the heat recovery operations maximized and increases slightly as electrical power output is reduced. These trends are illustrated in Figures 2-1 and 2-2 which display the power and heat production and CHP system efficiency for each of the controlled test conditions.

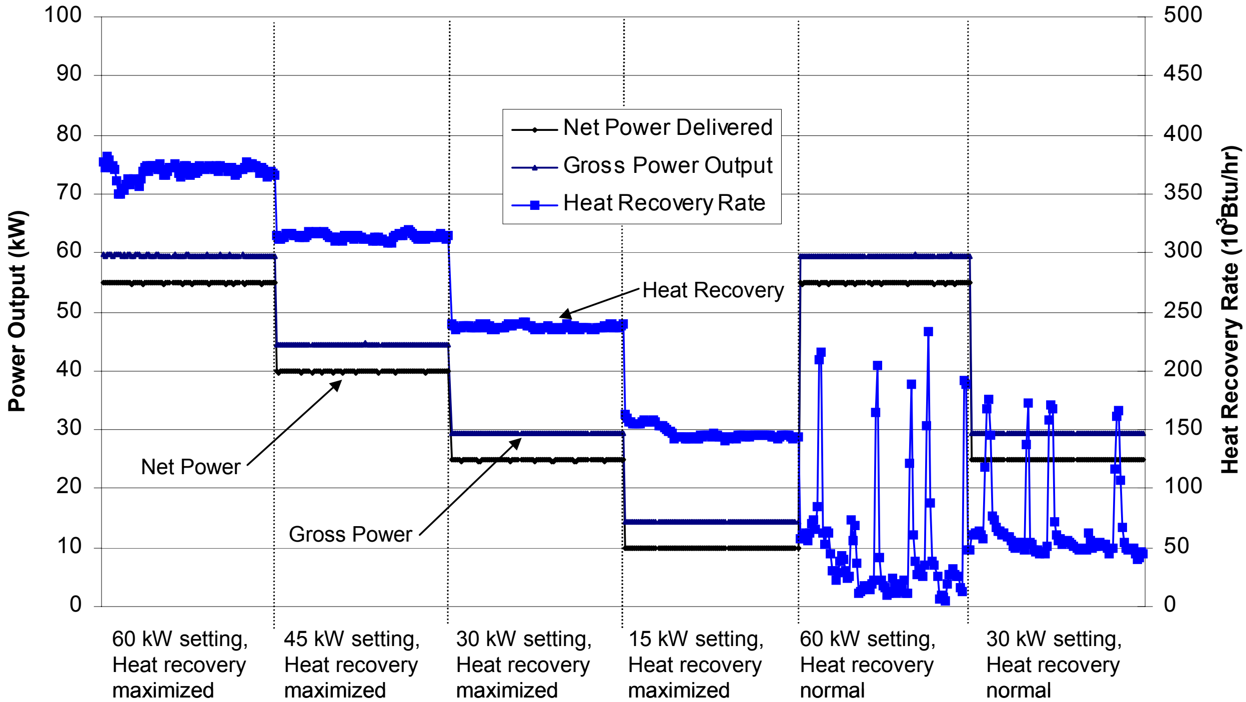

Figure 2-1. Heat and Power Production During Controlled Test Periods

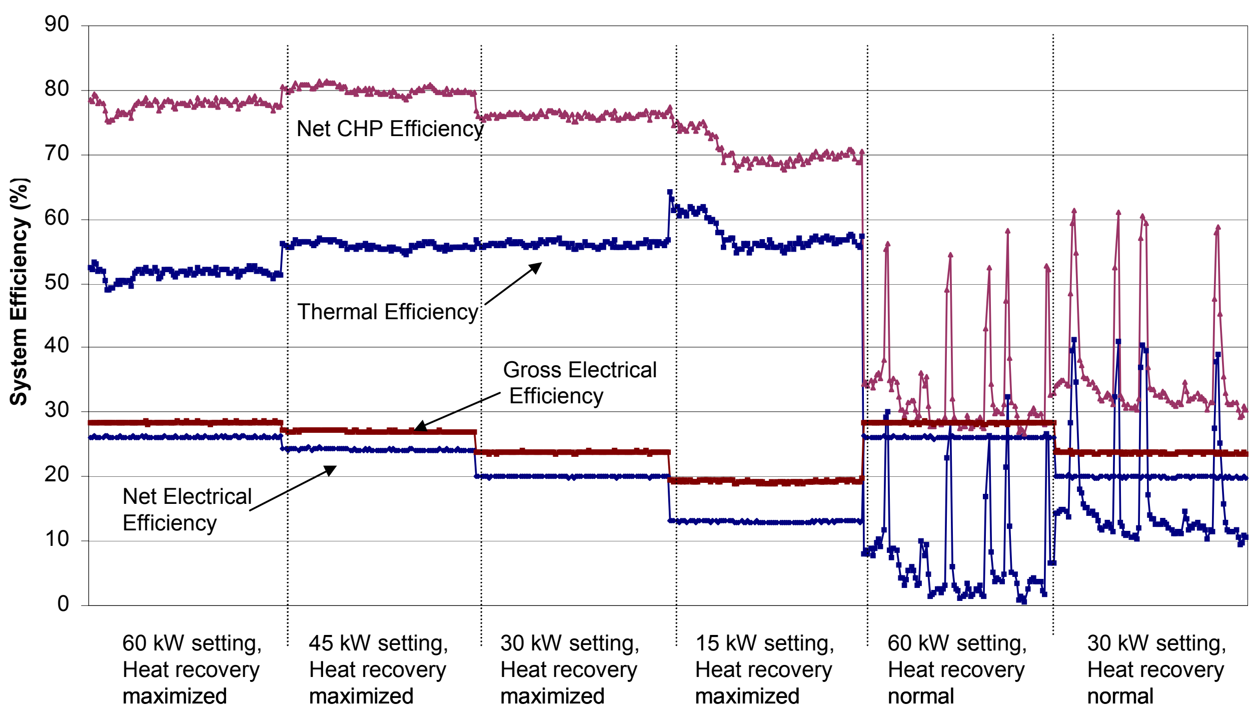

Figure 2-2. CHP System Efficiency During Controlled Test Periods

2.1.2. Electrical and Thermal Energy Production and Efficiencies Over the Extended Test

Figure 2-3 presents a time series plot of power production and heat recovery during the 14-day extended verification period. The system was operating 24 hours per day and was producing as much electrical power as possible depending on ambient conditions. Heat recovery rates were dictated by store demand. The warm temperatures caused generally low heat demand for the unit during the period. A total of 18,447 kWh_e electricity and 5,730 kWh_{th} of thermal energy were generated over an operating period of 336 hours. All of the electricity and heat generated were used by the facility. Electrical, thermal, and total system efficiencies during the extended period averaged 25.7, 8.0, and 33.7 percent, respectively, and were consistent with the efficiencies measured during the controlled test period.

The average power generated over the extended period was 55.1 kW_e and the average heat recovery rate was 17.1 kW_{th} (58.2 10^3Btu/hr). The power output trace shows several depressions where output dropped below 54 kW to as low as 50 kW. Review of the data indicate that each of these decreases occurred during afternoon hours when ambient temperatures were above 70 ^oF. The effect of ambient temperature on power output is further illustrated in Figure 2-4. The figure clearly shows that power output decreases as the ambient temperature (intake air) rises above 60 ^oF. This trend is consistent with industry knowledge of turbine performance (i.e., electrical power output generally decreases with increasing temperatures).

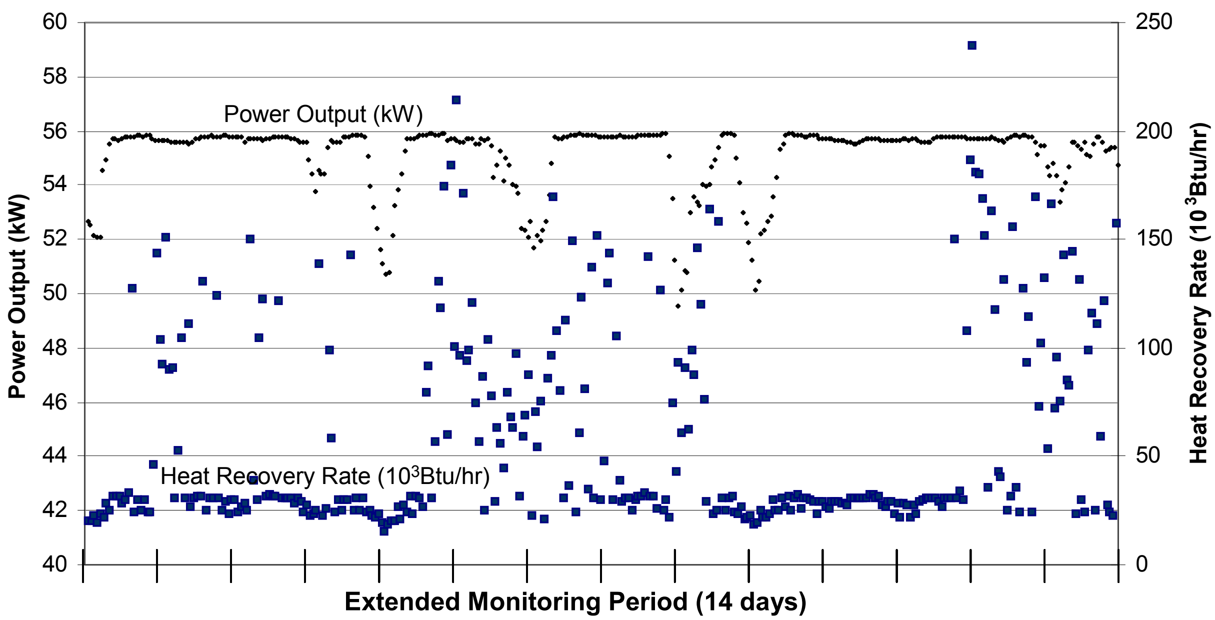

Figure 2-3. Heat and Power Production During the Extended Monitoring Period (1-hour averages)

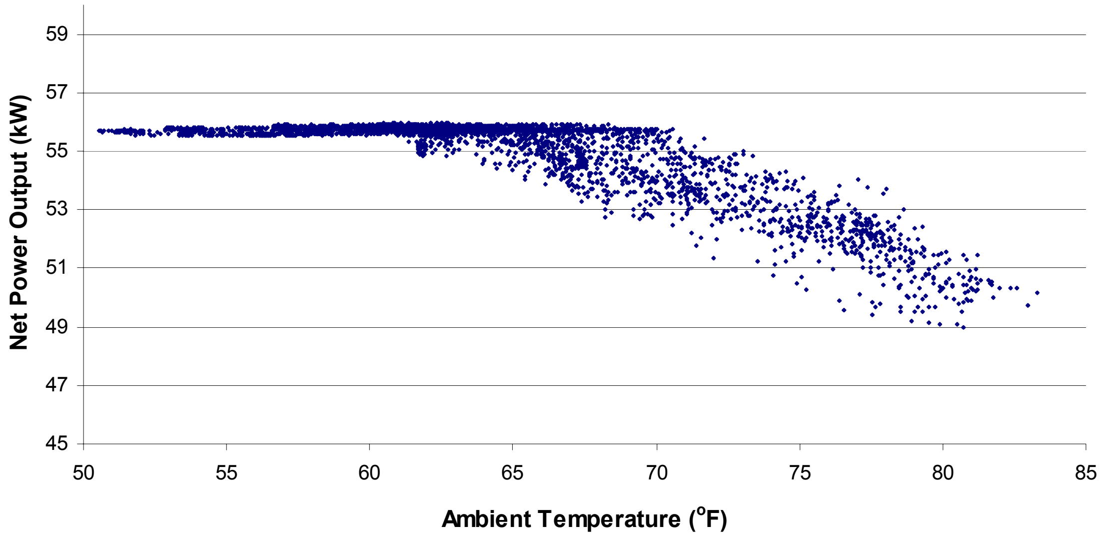

Figure 2-4. Ambient Temperature Effects on Power Production During Extended Test Period

Figure 2-5 plots electrical efficiency over the extended monitoring period as a function of ambient temperature and shows a linear relationship. Electrical efficiency ranged from 23.8 to 27.0 percent across the temperature range of 50.5 to 83.7 ^{o}F. Thermal and total system efficiencies are better illustrated during the control test periods in Figure 2-2 since heat demand was low throughout the period.

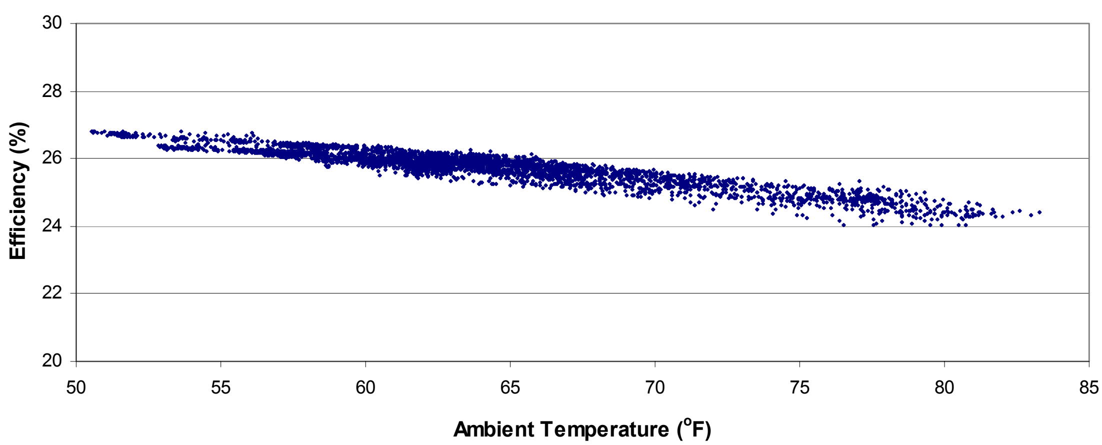

Figure 2-5. Ambient Temperature Effects on Electrical Efficiency During Extended Test Period

2.2. POWER QUALITY PERFORMANCE

2.2.1. Electrical Frequency

Electrical frequency measurements (voltage and current) were monitored continuously during the extended 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 2-6 and summarized in Table 2-3. The average electrical frequency measured was 60.000 Hz and the standard deviation was 0.014 Hz.

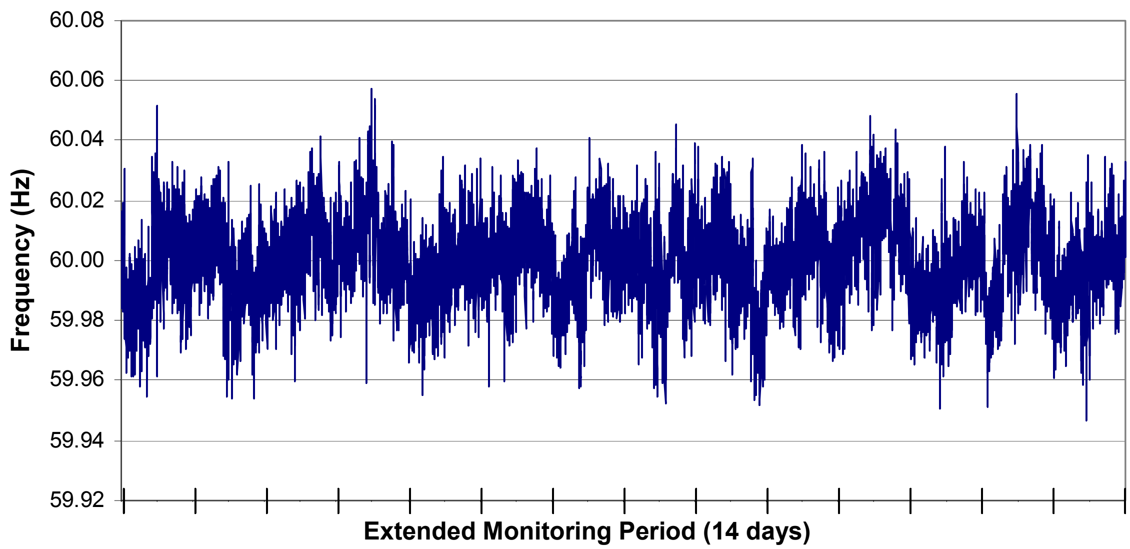

Figure 2-6. Capstone 60 Frequency During Extended Test Period

Table 2-3. Electrical Frequency During Extended Period

Parameter	Frequency (Hz)
Average Frequency	60.000
Minimum Frequency	59.946
Maximum Frequency	60.057
Standard Deviation	0.014

2.2.2. 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 7600 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 2-7 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.

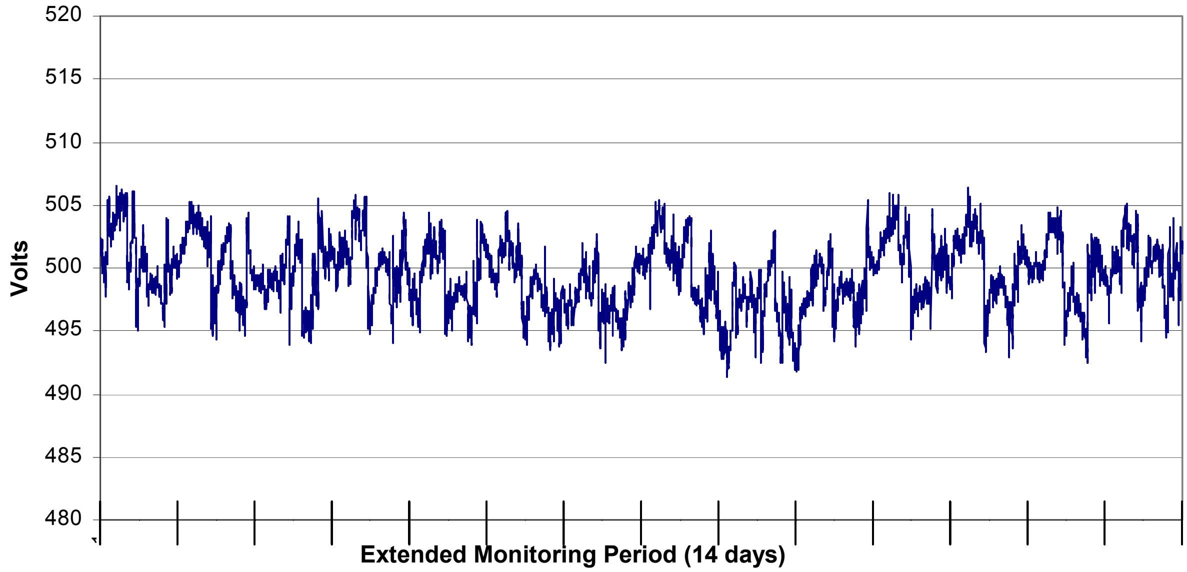

Figure 2-7. Capstone 60 Voltage During Extended Test Period

Table 2-4. Capstone 60 Voltage During Extended Period	
Parameter	**Volts**
Average Voltage	499.48
Minimum Voltage	491.38
Maximum Voltage	506.46
Standard Deviation	2.65

2.2.3. Power Factor

Figure 2-8 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. Test results show that the power factor was very stable throughout the period.

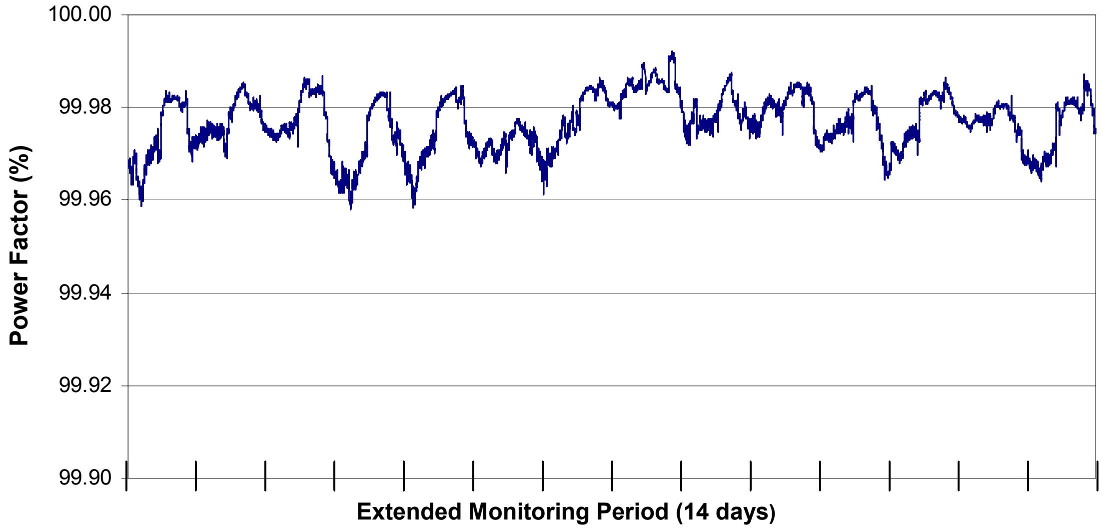

Figure 2-8. Capstone 60 Power Factor During Extended Test Period

Table 2-5. Power Factors During Extended Period	
Parameter	**%**
Average Power Factor	99.98
Minimum Power Factor	99.96
Maximum Power Factor	99.99
Standard Deviation	0.006

2.2.4. 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 7600 ION. The average current and voltage THD were measured to be 5.66 percent and 1.98 percent, respectively (Table 2-6). Figure 2-9 plots the current and voltage THD throughout the 14-day extended verification period. Results indicate that the average current THD exceeds the IEEE 519 specification of ± 5 percent. Figure 2-9 also shows numerous occurrences of current THD in excess of 7 percent.

Table 2-6. Capstone 60 THD During Extended Period		
Parameter	**Current THD (%)**	**Voltage THD (%)**
Average	5.66	1.98
Minimum	2.35	1.29
Maximum	12.11	2.83
Standard Deviation	1.24	0.31

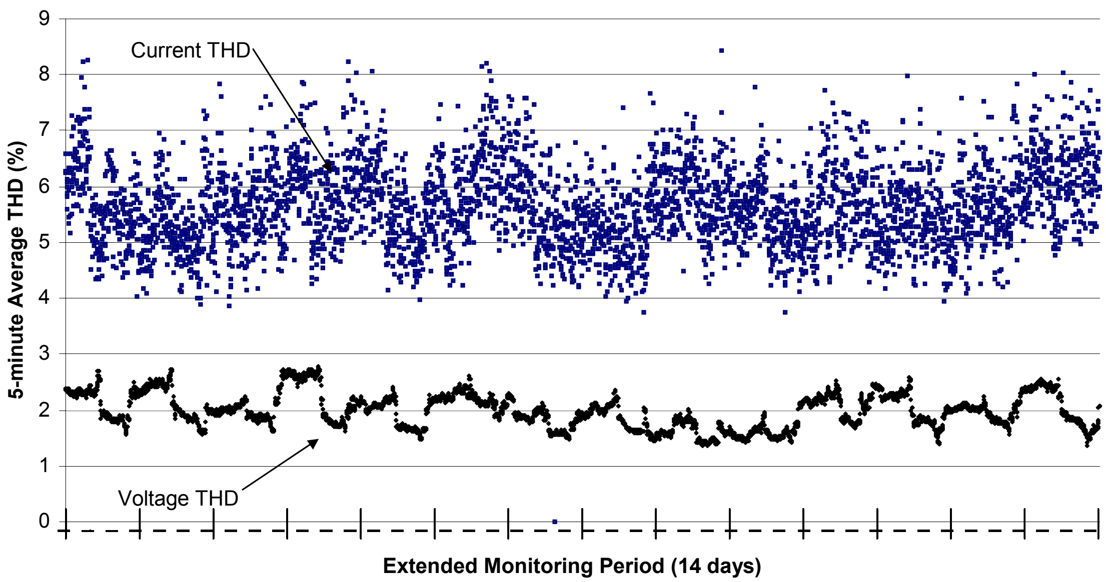

Figure 2-9. Capstone 60 Current and Voltage THD During Extended Test Period

2.3. EMISSIONS PERFORMANCE

2.3.1. CHP System Stack Exhaust Emissions

CHP System emissions testing was conducted to determine emission rates for NO_X, criteria pollutants (CO and THC), and greenhouse gases (CO_2 and CH_4). Stack emission measurements were conducted during each of the controlled test periods summarized in Table 1-3. Three replicate test runs were conducted at each operating condition each approximately 30 minutes in duration. All testing was conducted in accordance with the EPA reference methods listed in Table 1-4. The CHP system was maintained in a stable mode of operation during each test run using PTC-22 variability criteria.

Emissions results are reported in units of parts per million volume dry, corrected to 15-percent O_2 (ppmvd at 15-percent O_2) for NO_X, CO, and THC. Emissions of CO_2 are reported in units of volume percent. These concentration and volume percent data were converted to mass emission rates using computed exhaust stack flow rates following EPA Method 19 procedures and are reported in units of pounds per hour (lb/hr). The emission rates are also reported in units of pounds per kilowatt hour electrical output (lb/kWh_e). They were computed by dividing the mass emission rate by the electrical power generated.

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. The results show that DQOs for all gas species met the reference method requirements. A complete summary of emissions testing equipment calibration data is presented in Appendix A. Table 2-7 summarizes the emission rates measured during each run and the overall average emissions for each set of tests.

NO_X concentrations (corrected to 15-percent O_2) averaged 3.09 ppmvd at full load, and increased to 6.56 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 0.000148 lb/kWh$_e$. The data in Table 2-7 also show that changes in operation of the heat-recovery unit did not significantly impact emissions of NO_X or any of the other pollutants evaluated. The benefits of lower NO_X emissions from the CHP system are further enhanced when exhaust heat is recovered and used. Annual published data by EIA reveal that the measured CHP system emission rate is well below the average rate for coal and natural gas-fired power plants in the U.S. The rates are 0.0074 lb/kWh for coal-fired plants and 0.0025 lb/kWh for natural gas-fired plants. The emission reductions are further increased when transmission and distribution system losses are accounted for.

Table 2-7. Capstone 60 CHP System Emissions During Controlled Test Periods

	Site Operations	Electrical Power Delivered (kW_e)	Exhaust O_2 (%)	CO Emissions (ppm at 15% O_2)	CO lb/hr	CO lb/kWh_e	NO_x Emissions (ppm at 15% O_2)	NO_x lb/hr	NO_x lb/kWh_e	THC Emissions (ppm at 15% O_2)	THC lb/hr	THC lb/kWh_e	CH_4 Emissions (ppm at 15% O_2)	CH_4 lb/hr	CH_4 lb/kWh_e	CO_2 Emissions %	CO_2 lb/hr	CO_2 lb/kWh_e
Run 1	Heat recovery maximized using continuous space heating	54.9	17.8	4.45	7.14E-03	1.30E-04	3.14	8.26E-03	1.50E-04	1.20	1.10E-03	2.01E-05	<0.955	<8.75E-04	<1.59E-05	1.76	84.7	1.54
Run 2		54.9	17.8	3.82	6.12E-03	1.12E-04	3.12	8.12E-03	1.48E-04	1.19	1.09E-03	1.99E-05	<0.946	<8.66E-04	<1.58E-05	1.78	84.8	1.55
Run 3		54.9	17.8	2.31	3.70E-03	6.74E-05	3.14	8.11E-03	1.48E-04	0.789	7.22E-04	1.32E-05	<0.939	<8.60E-04	<1.57E-05	1.78	84.2	1.53
AVG		**54.9**	**17.8**	**3.53**	**5.65E-03**	**1.03E-04**	**3.13**	**8.16E-03**	**1.49E-04**	**1.06**	**9.72E-04**	**1.77E-05**	**<0.947**	**<8.67E-04**	**<1.58E-05**	**1.77**	**84.6**	**1.54**
Run 7		39.9	18.1	157	0.197	4.93E-03	3.34	6.89E-03	1.73E-04	75.8	5.42E-02	1.36E-03	45.7	3.27E-02	<8.20E-04	1.55	63.4	1.59
Run 8		39.9	18.1	161	0.205	5.13E-03	3.25	6.74E-03	1.69E-04	74.7	5.39E-02	1.35E-03	45.9	3.31E-02	<8.28E-04	1.56	64.5	1.62
Run 9		39.9	18.0	143	0.180	4.51E-03	3.32	6.89E-03	1.73E-04	60.5	4.36E-02	1.09E-03	38.9	2.81E-02	<7.04E-04	1.58	64.3	1.61
AVG		**39.9**	**18.1**	**154**	**0.194**	**4.86E-03**	**3.30**	**6.84E-03**	**1.71E-04**	**70.3**	**5.06E-02**	**1.27E-03**	**43.5**	**3.13E-02**	**7.84E-04**	**1.56**	**64.1**	**1.61**
Run 10		24.8	18.4	596	0.565	2.28E-02	4.27	6.66E-03	2.69E-04	1206	0.653	2.63E-02	767	0.415	<1.67E-02	1.36	47.1	1.90
Run 11		24.8	18.4	601	0.570	2.30E-02	4.31	6.71E-03	2.71E-04	1229	0.665	2.68E-02	nd	nd	nd	1.35	47.1	1.90
Run 12		24.8	18.3	579	0.548	2.21E-02	4.19	6.52E-03	2.63E-04	1147	0.620	2.50E-02	676	0.365	<1.47E-02	1.34	44.9	1.81
AVG		**24.8**	**18.3**	**592**	**0.561**	**2.26E-02**	**4.26**	**6.63E-03**	**2.67E-04**	**1194**	**0.646**	**2.61E-02**	**721**	**0.390**	**1.57E-02**	**1.35**	**46.4**	**1.87**
Run 16		9.8	18.8	318	1.81E-01	1.85E-02	6.63	6.21E-03	6.34E-04	288	9.38E-02	9.58E-03	nd	nd	nd	1.11	27.8	2.84
Run 17		9.8	18.8	345	1.99E-01	2.03E-02	6.41	6.09E-03	6.22E-04	345	1.14E-01	1.16E-02	213	7.04E-02	7.18E-03	1.10	28.2	2.88
Run 18		9.8	18.9	352	2.01E-01	2.06E-02	6.63	6.23E-03	6.36E-04	347	1.14E-01	1.16E-02	183	5.99E-02	6.11E-03	1.11	29.0	2.96
AVG		**9.8**	**18.8**	**338**	**1.94E-01**	**1.98E-02**	**6.56**	**6.18E-03**	**6.31E-04**	**327**	**1.07E-01**	**1.09E-02**	**198**	**6.51E-02**	**6.65E-03**	**1.11**	**28.4**	**2.89**
Run 4	Low heat demand, heat exchanger damper primarily open	54.9	17.7	3.52	5.64E-03	1.03E-04	3.05	8.05E-03	1.47E-04	0.782	7.17E-04	1.31E-05	nd	nd	nd	1.77	83.1	1.51
Run 5		54.9	17.7	3.27	5.25E-03	9.56E-05	3.01	7.96E-03	1.45E-04	0.712	6.54E-04	1.19E-05	nd	nd	nd	1.74	80.3	1.46
Run 6		54.9	17.7	4.91	7.89E-03	1.44E-04	3.10	8.19E-03	1.49E-04	0.560	5.14E-04	9.37E-06	nd	nd	nd	1.74	82.1	1.50
AVG		**54.9**	**17.7**	**3.90**	**6.26E-03**	**1.14E-04**	**3.05**	**8.07E-03**	**1.47E-04**	**0.685**	**6.28E-04**	**1.14E-05**	nd	nd	nd	**1.75**	**81.8**	**1.49**
Run 13		24.9	18.3	572	0.543	2.19E-02	4.27	6.66E-03	2.68E-04	1162	0.631	2.54E-02	670	0.364	1.46E-02	1.33	44.4	1.79
Run 14		24.9	18.4	596	0.568	2.29E-02	4.54	7.11E-03	2.86E-04	1155	0.628	2.53E-02	729	0.397	1.60E-02	1.34	47.2	1.90
Run 15		24.9	18.4	591	0.563	2.26E-02	4.70	7.36E-03	2.96E-04	1146	0.624	2.51E-02	635	0.345	1.39E-02	1.35	47.5	1.91
AVG		**24.9**	**18.3**	**586**	**0.558**	**2.25E-02**	**4.50**	**7.04E-03**	**2.83E-04**	**1154**	**0.628**	**2.53E-02**	**678**	**0.369**	**1.48E-02**	**1.34**	**46.3**	**1.87**

nd: No data for these tests. Bag samples from Runs 11 and 16 were deflated upon arrival at laboratory. No samples were collected during Runs 4 through 5 because the real time THC concentrations were less than 1 ppm.

Emissions of CO, THC, and CH_4 were all dramatically impacted by changes in power output. Table 2-7 shows that emissions of each pollutant were low at full load, but increased greatly as power output was reduced. Emissions peaked at 50 percent of load (30 kW) and then decreased again at the lowest set-point. The variation in emissions as power output changed was further illustrated during the emissions profile test conducted at the conclusion of the controlled test periods. Results of the NO_X, CO, and THC emissions measured during the profile test are shown in Figure 2-10.

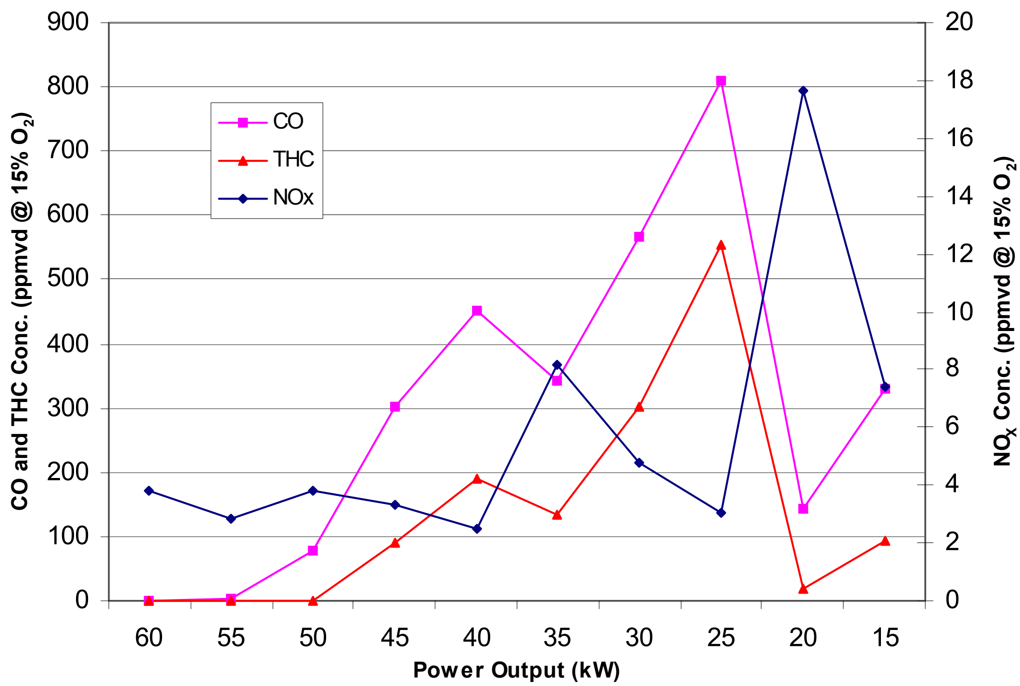

Figure 2-10. Capstone 60 Emissions as Function of Power Output

The profile test showed that emissions of each pollutant were variable and generally increased as power output decreased. Emissions of CO and THC showed an inverse relationship to NO_X emissions which is typical with most combustion sources.

Concentrations of CO_2 in the CHP system exhaust gas averaged 1.76 percent at full load and decreased as power output was reduced to a low of 1.11 percent. These concentrations correspond to average CO_2 emission rates of 1.54 lb/kWh$_e$ and 2.89 lb/kWh$_e$, respectively. The CHP system CO_2 emission rate at full load is well below the average rate for coal-fired power plants in the U.S. (2.26 lb/kWh) and slightly higher than natural gas-fired power plants (1.41 lb/kWh). Emissions of CO_2 were also not significantly affected by changes in operation of the heat-recovery unit.

2.3.2. Estimation of Annual Emission Reductions for Waldbaums

The electricity and heat generated by the CHP system will offset electricity supplied by the utility grid and heat supplied by the Munters' gas-fired burners. Section 1.4.5 states that annual emission reductions are estimated for the Waldbaums with two key assumptions: (1) all energy (power and heat) produced by the CHP system is consumed on site and, (2) the unit will have a 98-percent availability rate.

Table 2-8 summarizes estimated NO_X and CO_2 emissions and emission reductions from on-site electricity production. The table shows that electricity production under the CHP scenario results in annual NO_X emission reductions of 879 lbs. The reductions are favorable for both ozone and non-ozone season periods because the emission rate for the NY ISO is significantly higher than the emission rate for the CHP. The CO_2 emission rate for the NY ISO is similar to the emission rate for the CHP. CO_2 emission reductions are estimated to be small on a percentage basis (about 1 percent), but significant as an absolute value. About 37,000 lbs CO_2 may be reduced annually.

CHP emission rates for on-site heat production are assigned as zero because emissions are accounted for in electricity generation. In other words, the heat recovered is otherwise waste heat and no emissions are associated with this process. Section 1.4.5 shows that approximately 394,513 kWh of energy from the space-heating burner and 95,257 kWh of energy from the regeneration burner are eliminated. An annual NO_X reduction of 185 lbs is estimated using the burner NO_X emission factor of 0.000378 lb/kWh_{th}. An annual CO_2 emission reduction of 291,477s lb may be realized through heat recovery and use using the CO_2 emission factors of 0.628 and 0.459 lb/kWh for the two different burners.

Table 2-9 summarizes the annual emissions and emission reductions for both electrical and thermal energy production systems. It is estimated that 17-percent reductions in NO_X emissions may occur with the CHP system compared to the baseline scenario. The highest reduction is due to the displacement of emissions from the electric utility. An annual CO_2 emission reduction of 8 percent may occur. Over 88 percent of these reductions (291,477 lbs) are due to the displacement of emissions from on-site heat recovery. In conclusion, DG systems operated in combined power and heat recovery mode results in the most reductions in greenhouse gas emissions.

Table 2-8. Emissions Offsets From On-Site Electricity Production

NY ISO Emission Rates (lb/kWh$_e$)

	NO_X	CO_2
ozone wkday	0.0021	1.37
ozone night/wkend	0.0028	1.67
non-ozone wkday	0.0021	1.46
non-ozone night/wkend	0.0028	1.61

CHP System Emission Rates (lb/kWh$_e$)

	NO_X	CO_2
full load	0.000148	1.52

Emission Reduction Estimates From Electricity Production

	Baseline Scenario		CHP Scenario					
			Energy From CHP		Makeup Energy			
	Electricity From Grid (kWhe)	Grid Emissions (lbs)	Electricity From CHP (kWhe)	CHP Emissions (lbs)	Electricity From Grid (kWhe)	Grid Emissions (lbs)	Total Emissions (lbs)	Emission Reductions (lbs)
NO_X								
ozone season wkday	512,033	1,159	94,138	14	417,894	946	960	199
ozone season night/wkend	567,093	1,712	59,160	9	507,933	1,533	1,542	170
non-ozone season wkday	565,006	1,279	131,275	19	433,731	982	1,001	278
non-ozone season night/wkend	616,416	1,861	80,752	12	535,664	1,617	1,629	232
Annual Total	**2,260,548**	**6,011**	**365,326**	**54**	**1,895,222**	**5,078**	**5,132**	**879**
CO_2								
ozone season wkday	512,033	756,201	94,138	143,090	417,894	617,172	760,262	(4,061)
ozone season night/wkend	567,093	1,020,915	59,160	89,924	507,933	914,411	1,004,335	16,580
non-ozone season wkday	565,006	889,252	131,275	199,539	433,731	682,641	882,179	7,073
non-ozone season night/wkend	616,416	1,069,839	80,752	122,743	535,664	929,687	1,052,430	17,408
	-							
Annual Total	**2,260,548**	**3,736,207**	**365,326**	**555,295**	**1,895,222**	**3,143,911**	**3,699,206**	**37,001**

Table 2-9. Estimated Annual Emission Reductions using the CHP System at Waldbaums

	Baseline Scenario			CHP System Scenario					Estimated Reductions	
				Energy From CHP		Makeup Energy				
	Electricity From Grid (lbs)	Heat from Burners (lbs)	Total Baseline (lbs)	Electricity From CHP (lbs)	Heat/DHW From CHP (lbs)	Electricity From Grid (lbs)	Heat from Burners (lbs)	Total CHP Case (lbs)	(lbs)	(%)
Annual Total NO_X Emissions	6,011	332	6,343	54	-	5,078	147	5,279	1,064	17
Annual Total CO_2 Emissions	3,736,207	521,155	4,257,362	555,295	-	3,143,911	229,678	3,928,884	328,478	8

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 and they are summarized in the Test Plan. 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)	± 1.50% / 0.90 kW	± 1.0% / 0.56 kW
Electrical efficiency (%)	± 1.81% / 0.51%[c]	± 1.43% / 0.37%[c]
Heat recovery rate (10^3Btu/hr)	± 2.50% / 8.75 10^3Btu/hr[c]	± 0.55 / 2.05 10^3Btu/hr[c]
Thermal energy efficiency (%)	± 2.24% / 1.07%[c]	± 1.16% / 0.61%[c]
CHP production efficiency (%)	± 2.04% / 1.38%[c]	± 0.9% / 0.71%[c]
Power Quality Performance		
Electrical frequency (Hz)	± 0.01% / 0.006 Hz	± 0.01% / 0.006 Hz
Voltage	1.01 / 1.21 V[c]	1.01 / 4.99 V[c]
Power factor (%)	± 0.50% / 0.50%	± 0.50% / 0.50%
Voltage and current total harmonic distortion (THD) (%)	± 1.00% / 0.05%	± 1.00% / 0.05%
Emissions Performance		
NO_X concentration accuracy	± 2.0% of span[d]	± 0.9% of span / 0.23 ppmvd
CO concentration accuracy	± 2.0% of span[d]	± 0.6% of span / 0.15 ppmvd at full load, ± 0.9% of span / 9.0 ppmvd at reduced loads
O_2 and CO_2 concentration accuracy	± 2.0% of span[d]	± 1.1% of span / 0.1% CO_2 ± 0.6% of span / 0.2% O_2
THC and CH_4 concentration accuracy	± 5.0 % of span[d]	± 2.4% of span/ 0.43 ppmvd at full load, 12.0 ppmvd at reduced loads
CO, NO_X, and CO_2 emission rates (lb/kWh)	± 5.59%[c]	± 1.66%[c]
THC and CH_4 emission rates (lb/kWh)	± 7.22%[c]	± 2.69%[c]

[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] Determined by evaluating sampling system bias.

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.

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 the six different load conditions. This completeness goal was achieved.

Completeness goals for the extended tests were to obtain 90 percent of 14 days of power quality, power output, fuel input, and ambient measurements. This goal was exceeded—14 complete days of valid data were collected (a total of 10 minutes of data were invalidated when the microturbine shut down momentarily). These data were useful in establishing trends in power and heat performance capability at varying ambient temperatures as discussed in Section 2.

Table 3-2 also includes accuracy goals for measurement instruments. Actual measurement accuracy achieved are also reported based on instrument calibrations conducted by manufacturers, field calibrations, reasonableness checks, and/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 / Manufacturer	Instrument Range	Range Observed in Field	Accuracy [a]			Completeness	
					Goal	Actual	How Verified / Determined	Goal	Actual
CHP System Power Output and Quality	Power	Electric Meter/ Power Measurements 7600 ION	0 to 100 kW	14.4 to 59.9 kW	± 1.50% reading[b]	± 1.50% reading[b]	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 14 days.	Controlled tests: six valid runs at each load. Extended test: 99.9 % of one-minute readings for 14 days.
	Voltage		0 to 600 V	491 to 506 V	± 1.01% reading	± 1.01% reading			
	Frequency		49 to 61 Hz	59.95 to 60.06 Hz	± 0.01% reading	± 0.01% reading			
	Current		0 to 100A	40 to 71 A	± 1.01% reading	± 1.01% reading			
	Voltage THD		0 to 100%	1.3 to 2.8%	± 1% FS[C]	± 1% FS			
	Current THD		0 to 100%	2.4 to 12.1%	± 1% FS	± 1% FS			
	Power Factor		0 to 100%	99.96 to 99.99%	± 0.5% reading	± 0.5% reading			
	Compressor power draw	7500 ION	0 to 100 kW	3.9 to 4.1 kW	± 1.50% reading[b]	± 1.50% reading[b]			
CHP System Heat Recovery Rate	Inlet Temperature	Controlotron Model 1010EP	37 to 356 °F	97 to 198 °F	Temps must be ± 1.5°F of ref. Thermocouples	± 0.4 °F for outlet, ± 0.5 °F for inlet	Independent check with calibrated thermocouple		
	Outlet Temperature		37 to 356 °F	103 to 199 °F					
	PG Flow	Onicon Model F-1110 turbine meter	1 to 80 gpm	40 to 55 gpm	± 1.0% reading	± 0.1% reading	Instrument calibration from manufacturer prior to testing		
	PG Concentration and Specific Heat	GC/FID	PG Conc: 0 to 100%	PG Conc: 25-26 %	PG Conc: ± 3% relative error	PG Conc: ± 3.6% relative (1.7% absolute)	Independent check with one blind sample		
Ambient Conditions	Ambient Temperature	RTD / Vaisala Model HMD 60YO	-50 to 150 °F	51 to 84 ° F	± 0.2 °F	± 0.2 °F	Instrument calibration from manufacturer prior to testing		
	Ambient Pressure	Setra Model 280E	13.80 to 14.50 psia	14.47 to 14.74 psia	± 0.1% FS	± 0.05% FS			
	Relative Humidity	Vaisala Model HMD 60YO	0 to 100% RH	31 to 98% RH	± 2%	± 0.2%			

(continued)

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

Measurement Variable		Instrument Type / Manufacturer	Instrument Range	Measurement Range Observed	Accuracy			Completeness	
					Goal	Actual	How Verified / Determined	Goal	Actual
Fuel Input	Gas Flow Rate	Mass Flow Meter / Rosemount 3095 w/ 1195 orifice	0 to 20 scfm	0 to 15 scfm	1.0% of reading	± 1.0% of reading	Factory calibration of differential pressure sensor and orifice plate bore	Controlled tests: three valid runs per load meeting PTC 22 criteria. Extended test: 90 % of one-minute readings for 14 days.	Controlled tests: six valid runs at each load. Extended test: 99.9 % of one-minute readings for 14 days.
	Gas Pressure	Rosemount Model 3095	0 to 100 psia	18 to 20 psia	± 0.75% FS	± 0.75% FS	Instrument calibration from manufacturer prior to testing		
	Gas Temperature	RTD / Rosemount Series 68	-58 to 752 °F	50 to 100 °F	± 0.10% reading	± 0.09% reading			
	LHV	Gas Chromatograph / HP 589011	0 to 100% CH_4	95 to 96% CH_4	± 3.0% accuracy, ± 0.2% repeatability	± 0.5% accuracy, ± 0.2% repeatability	Duplicate analysis of NIST-traceable CH_4 audit gas	controlled tests: two valid samples per day	Controlled tests: two valid samples per day
				901 to 906 Btu/ft^3	0.1% repeatability	± 0.04% repeatability	Conducted duplicate analyses on 2 samples		
Exhaust Stack Emissions	NO_X Levels	Chemiluminescent/ TEI Model 42	0 to 25 ppmvd	1 to 3 ppmvd	± 2% FS or	≤ 0.9% FS [d]	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 25 ppmvd full load, 0 to 1,000 ppmvd reduced loads	1 to 3 ppmvd full load, 70 to 257 ppmvd reduced loads	± 2% FS or	≤ 0.9% FS [d]			
	THC and CH_4 levels	FID / TEI Model 51, HP 5890 for CH_4	0 to 18 ppmv full load, 0 to 500 ppmvd reduced loads	0 to 2 ppmv full load, 29 to 525 ppmvd reduced loads	± 5% FS or	≤ 0.6% FS [d] THC, ± 2.4 % CH_4			
	CO_2 Levels	NDIR / IR Model 703	0 to 10%	1.1 to 1.8%	± 2% FS or	≤ 1.1% FS [d]			
	O_2 Levels	NDIR / IR Model 2200	0 to 25%	17 to 19%	± 2% FS or	≤ 0.6% FS [d]			

[a] Accuracy goal represents the maximum error expected at the operating range. It is defined as the sum of instrument and sampling errors.
[b] Includes instrument, 1.0% current transformer (CT), and 1.0% potential transformer (PT) errors.
[c] FS: full scale
[d] Values represent the maximum system bias observed throughout the controlled test periods.

3.2.1. Power Output

Instrumentation used to measure power was introduced in Section 1.0 and included a Power Measurements Model 7600 ION. The data quality objective for power output is ± 1.5 percent of reading, which is lower than the typical uncertainty set forth in PTC-22 of ± 1.8 percent. The power output DQO was also applied to the ION 7500 power meter used to monitor gas compressor power consumption. The Test Plan specified factory calibration of the ION meters 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 meters were factory calibrated by Power Measurements within one year of being used at the test site (July 2002 for the 7600 ION and April 2003 for the 7500 ION). 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 and potential transformers, met the ± 1.5-percent DQO. Using the manufacturer-certified calibration results and the average power output measured during the full-load testing, the error during all testing is determined to be ± 0.56 kW.

Additional QC checks were performed on the 7600 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 7600 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 7600 ION was installed and operating properly during the verification test. The ± 1.50-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	± 0.03% voltage ± 0.0% current
	Reasonableness checks	Throughout test	Readings should be between 47 and 57 kW net power output at full load	Readings were 49 to 56 kW
Fuel Flow Rate	Sensor diagnostics	Beginning and end of test	Pass	Passed all diagnostic checks
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 check with blind audit sample	One time during test period	± 3.0% for each major gas constituent	
Heat Recovery Rate	Meter zero check	Prior to testing	Reported heat recovery < 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 0.4 °F of reference.

3.2.2. Electrical Efficiency

The DQO for electrical efficiency was to achieve an uncertainty of ± 1.8 percent at full electrical load or less. This is consistent with the typical uncertainty levels set forth in PTC-22 of 1.7 percent. 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 and, in some cases, they were exceeded. 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 7600 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 measured to be 56 kW and the measurement error is determined to be ± 0.56 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 orifice plate and the differential pressure sensors with a NIST-traceable standard and through performing reasonableness checks in the field. The manufacturer certifies an accuracy of ± 1 percent of reading if the pressure sensors and orifice bore specifications are met. The specifications were satisfied in this case, and the ±1 percent of reading DQI was met. The average flow rate at full load was 13.2 scfm and the measurement error is then determined to be ± 0.13 scfm. Complete documentation of data quality results for fuel flow rate is provided in Section 3.2.2.3.

The Test Plan specified using the results of duplicate analyses on at least two samples to reconcile the accuracy of LHV determination. Duplicate analyses were conducted on two samples collected during the load tests and a blind audit sample. The average LHV repeatability for the three duplicate analyses was 0.09 percent. As such, the LHV goal of ± 0.2 percent was met.

Results of the blind audit sample analysis indicated that methane results were within 0.51-percent relative error of the certified concentration. The percent difference between the original and duplicate methane analyses for the audit was ± 0.19 percent (Section 3.2.2.4). The average LHV during testing was verified to be 903 Btu/ft^3 and the measurement error corresponding to this heating value is ± 1.8 Btu/ft^3. The heat input compounded error then is:

$$Error\,in\,Heat\;Input = \sqrt{(flowmetererror)^2 + (LHV error)^2} \qquad \text{(Eqn. 8)}$$

$$= \sqrt{(0.01)^2 + (0.002)^2} = 0.0102$$

The measurement error amounts to approximately ± 730 Btu/hr, or 1.02 percent relative error at the average measured heat input of 715.9 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 ± 1.02 percent relative. Therefore, compounded relative error for the electrical efficiency determination is:

$$Error\,in\,Elec.\;Power\;Efficiency = \sqrt{(powermetererror)^2 + (heatinputerror)^2} \qquad \text{(Eqn. 9)}$$

$$= \sqrt{(0.010)^2 + (0.0102)^2} = 0.0143$$

Electrical efficiency for the controlled test periods at full load was 26.2 ± 0.37 percent, or a relative compounded error of 1.43 percent.

3.2.2.1. PTC-22 Requirements for Electrical Efficiency Determination

PTC-22 guidelines state that efficiency determinations were to be performed within time intervals in which maximum variability in key operational parameters did not exceed specified levels. This time interval could be as brief as 4 minutes or as long as 30 minutes. Table 3-4 summarizes the maximum permissible variations observed in power output, power factor, fuel flow rate, barometric pressure, and ambient temperature during each test run. The table shows that the requirements for all parameters were met for all test runs. Thus the PTC-22 requirements were met and the efficiency determinations are representative of stable operating conditions.

Table 3-4. Variability Observed in Operating Conditions

	Maximum Observed Variation[a] in Measured Parameters				
	Power Output (%)	Power Factor (%)	Fuel Flow Rate (%)	Inlet Air Press. (%)	Inlet Air Temp. (^{o}F)
Maximum Allowable Variation	**± 2**	**± 2**	**± 2**	**± 0.5**	**± 4**
Run 1	0.1	0.0	0.6	0.0	0.4
Run 2	0.1	0.0	0.6	0.0	0.4
Run 3	0.1	0.0	0.7	0.0	0.2
Run 4	0.1	0.0	0.7	0.0	0.2
Run 5	0.1	0.0	0.7	0.0	0.4
Run 6	0.1	0.0	0.6	0.0	0.1
Run 7	0.1	0.0	0.7	0.0	0.5
Run 8	0.1	0.0	0.8	0.0	1.1
Run 9	0.1	0.0	0.7	0.0	1.4
Run 10	0.1	0.0	0.7	0.0	0.8
Run 11	0.1	0.0	1.1	0.0	0.2
Run 12	0.2	0.0	1.1	0.0	0.9
Run 13	0.1	0.0	0.9	0.0	1.9
Run 14	0.1	0.0	0.8	0.0	2.1
Run 15	0.2	0.0	0.9	0.0	1.2
Run 16	0.2	0.0	1.0	0.1	3.0
Run 17	0.2	0.0	1.1	0.0	0.9
Run 18	0.2	0.0	1.5	0.0	1.1

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

3.2.2.2. Ambient Measurements

Ambient temperature, relative humidity, and barometric pressure at the site were monitored throughout the extended 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 pre-test temperature and relative humidity sensor calibration had expired two months prior to the testing, so a post-test calibration of the instrument was also performed. Both pre- and post-test factory calibrations verified that the ± 2 °F accuracy goal for temperature and ± 2 percent accuracy goal for relative humidity were met.

3.2.2.3. Fuel Flow Rate

The Test Plan specified the use of an integral orifice meter (Rosemount Model 3095) to measure the flow of natural gas supplied to the CHP system. The two major components of the integral orifice meter (the differential-pressure sensor and the orifice plate bore) were factory-calibrated prior to installation in the field. Calibration records were reviewed to ensure that the ± 1.0-percent instrument accuracy goal was satisfied. QC checks (sensor diagnostics) listed in Table 3-4 were conducted to ensure proper function in the field.

Sensor diagnostic checks consisted of zero-flow verification by isolating the meter from the flow, equalizing the pressure across the differential pressure (DP) sensors, and reading the pressure differential and flow rate. The sensor output must read zero flow during these checks. Transmitter analog output checks—known as the loop test—consist of checking a current of known amount from the sensor against a Fluke multimeter to ensure that 4 mA and 20 mA signals are produced. These results were found to be within ± 0.01 mA. Reasonableness checks revealed that measured flow rates were within the range specified by the CHP Operator's Manual.

The Test Plan also specified that gas flow rates recorded by the Rosemount meter would be compared to the site's rotary positive-displacement meter. Problems with the function of the facility meter prevented this additional QC check. The site meter had very poor index resolution and was not pressure-compensated. Therefore, a true flow-through comparison between meters was not conducted. The same Rosemount meter (meter components include precision bore spool, orifice plate and housing, pressure sensors, temperature sensor, and transmitter) was calibrated during a previous verification on a similar microturbine in August 2002. During this test, a true flow-through comparison with a calibrated displacement-type meter was performed [11]. The two meters were confirmed to agree be within ± 0.3 percent over the same range of gas flows as those experienced during this verification.

3.2.2.4. Fuel Lower Heating Value

Fuel gas samples were collected twice per day during the controlled test periods. Two additional samples were collected during the extended monitoring period. Full documentation of 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 (ASTM 2001a) and D3588 (ASTM 2001b), 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. Both DQIs were met with the methane accuracy at ± 0.51 percent and the LHV repeatability at ± 0.09 percent.

Results of analysis of the audit sample are summarized in Table 3-5 and show acceptable accuracy for all major gas components.

Table 3-5. Results of Natural Gas Audit Sample Analysis

Gas Component	Certified Component Concentration (%)	Analytical Result for Initial Analysis (%)	Analytical Result for Initial Analysis (%)	Combined Sampling and Analytical Error (%)[a]	Analytical Repeatability (%)
Nitrogen	5.00	5.17	5.17	3.4	0.0
Carbon dioxide	1.01	1.00	0.99	1.0	1.0
Methane	70.41	70.05	70.18	0.5	0.2
Ethane	9.01	9.06	9.05	0.6	0.1
Propane	6.03	6.07	6.07	0.7	0.0
n-butane	3.01	3.03	3.03	0.7	0.0
Iso-butane	3.01	2.99	2.99	0.7	0.0
Iso-pentane	1.01	1.02	0.98	1.0	3.9
n-pentane	1.01	1.01	0.98	0.0	3.0

[a] Calculated as: Error =(certified conc. – initial analytical result / certified conc.) * 100

Duplicate analyses, in addition to the blind audit samples, were conducted on two of the samples collected during the control test periods (the sample collected during Runs 1 and 18). 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 0.07 percent for methane and 0.09 percent for LHV. The results demonstrate that the ± 0.2 percent LHV accuracy goal was achieved.

3.2.3. Heat Recovery Rate and Efficiency

Several measurements were conducted to determine CHP system heat-recovery rate and thermal efficiency. These measurements include PG fluid flow rate, fluid supply and return temperatures, fluid composition, 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 Onicon Model F-1110 turbine meter was used to continuously monitor PG fluid flow rate. This meter has a NIST-traceable factory-calibrated accuracy of ± 0.1 percent of reading (the calibration was conducted on June 11, 2002). This certification serves as the primary DQI. An additional field check on the meter included the GHG Center comparing readings from the Onicon turbine meter to fluid flow readings generated by the GHG Center's Controlotron ultrasonic meter. The two meters agreed within 0.2 percent of reading while operating the CHP system at full load. A zero check was also performed on the turbine meter. The turbine meter reading was -0.06 gpm with the CHP system shut down and the circulation pump off.

Tables 3-2 and 3-3 showed that the DQI for supply and return temperatures (delta T) was achieved. The error in the fluid supply and return temperatures were 0.4 and 0.5 ^{o}F, respectively, for an overall delta T uncertainty of 0.9 ^{o}F. This absolute error equates to a relative error of 0.5 percent at the highest average fluid temperatures measured during the full-load testing. To address concerns regarding the amount of insulation surrounding the GHG Center's surface-mounted RTDs, an additional QC check was conducted. The facility uses a calibrated set of thermocouples immersed into thermowells in each glycol line to monitor delta T. A total of 12 one-minute average delta T readings were recorded for the two sets of temperature sensors to obtain delta T comparisons over a PG-supply temperature range of 104 to 183 ^{o}F. The average absolute difference between the two RTD sets was 0.25 ^{o}F. This indicates that the thermal paste used as a surface contact medium, along with the insulation that was used, was sufficient to provide reliable delta T data.

The error in the glycol analysis was determined to be 3.6 percent based on results of the blind audit sample. This analytical error translates to uncertainties in the fluid density and specific heat equal to 0.21 percent (see Test Plan Section 3.2.5). The 3.6 percent error exceeds the DQI goal of 3.0 percent, but the composite error in heat recovery rate is still well within the DQO goal for that parameter.

The overall error in heat recovery rate is then the combined error in PG temperature, flow rate, and compositional measurements. This error compounds multiplicatively as follows:

$$Overall\ Heat\ Meter\ Error = \sqrt{(Flow\,rate\,error)^2 + (compositional\ \ error)^2 + (temperature\,error)^2} \quad \text{(Eqn. 10)}$$

$$= \sqrt{(0.0010)^2 + (0.0021)^2 + (0.005)^2} = 0.0055$$

The heat recovery rate determination, therefore, has a relative compounded error of ± 0.55 percent.

The errors in heat-recovery rate and heat input for the heat-recovery efficiency determination compound similarly to Equation 10 as follows:

$$Error\,in\,Heat\,Recovery\;\;Efficiency = \sqrt{(0.0055)^2 + (0.0102)^2} = 0.0116 \qquad \text{(Eqn. 11)}$$

Average heat recovery rate (thermal) efficiency was 52.2 ± 0.61 percent, or a relative compounded error of 1.16 percent for the full-load tests with maximized heat recovery. This compounded relative error meets the data quality objective for this verification parameter.

3.2.4. Total Efficiency

Total efficiency is the sum of the electrical power and heat-recovery efficiencies. Total efficiency is defined as 26.2 ± 0.37 percent (± 1.43-percent relative error) plus 52.2 ± 0.61 percent (± 1.16-percent relative error). This is based on the determined errors in electrical and thermal efficiency at full load. The absolute errors compound as follows:

$$err_{c,abs} = \sqrt{err_1^{\;2} + err_2^{\;2}} \qquad \text{(Eqn. 12)}$$

$$= \sqrt{0.37^2 + 0.61^2} = 0.71 \text{-percent absolute error}$$

Relative error, is:

$$err_{c,rel} = \frac{err_{c,abs}}{Value_1 + Value_2} \qquad \text{(Eqn. 13)}$$

$$= \frac{0.71}{26.2 + 52.2} = 0.91 \text{-percent relative error}$$

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 efficiency with heat recovery maximized is then 78.4 ± 0.71 percent, or 0.9-percent relative error. This compounded relative error meets the data quality objective for this parameter.

3.2.5. Exhaust Stack Emission Measurements

EPA reference methods were used to quantify emission rates of criteria pollutants and greenhouse gases. The reference methods specify the sampling and calibration procedures and data quality checks that must be followed to collect data that meets the methods required performance objectives. These methods ensure that run-specific quantification of instrument and sampling system drift and bias occur throughout the emissions tests. The DQOs specified in the Test Plan were based on an assessment of sampling system error (bias) and calibration drift for each pollutant. Specifically, they are ± 2 percent for NO_X, CO, CO_2, and O_2 concentrations, and ± 5 percent for THC and CH_4 concentrations.

The Plan also specified DQOs for emission rates in units of lb/kWh that were ± 5.59 percent for NO_X, CO, CO_2, and ± 7.22 percent for THC and CH_4. These composite error estimates were calculated using statistical propagation of error formulae and the DQOs for the concentrations, flue gas O_2 content, and power output. Although these calculations are not statistically correct because the QC check requirements substitute standard deviations in the formulae, they provide an estimate of the uncertainty of the emission rate determinations.

NO_X and THC Concentrations

The NO_X and THC sampling system calibration error test was conducted prior to the start of each test run. The calibration was conducted by sequentially introducing a suite of calibration gases into the sampling system at the sampling probe and recording the system responses. Calibrations were conducted on all analyzers using Protocol No. 1 calibration gases. The four calibration gas concentrations of NO_X and THC used were zero, 20 to 30 percent of span, 40 to 60 percent of span, and 80 to 90 percent of span. The results of sampling system error tests are summarized in Appendix A. It should be noted that, at reduced loads, the higher THC emissions required the analyst to use a higher instrument range of 1 to 500 ppm. The highest-concentration Protocol 1 calibration gas available on short notice was 150 ppm. Measured concentrations exceeded this calibration level during all tests conducted at 50 and 25 percent of load. The accuracy of the THC concentrations reported at reduced loads could be an issue even though the instrument had excellent calibration linearity at the lower levels.

Table 3-2 shows that the maximum actual-measured error for NO_X was ±0.9 percent of full scale (± 0.23 ppmvd), which indicates the goal was met. The maximum system error for THC was determined to be ± 0.6 percent of full scale (± 0.11 ppm at full load, ± 3.0 ppm at reduced loads), which indicates the goal was met for the higher load settings.

Zero- and mid-level calibration gases were again introduced to the sampling systems at the probe and the response recorded at the conclusion of each test. System response was compared to the initial system calibration error to determine sampling system drift. The maximum sampling system drift was determined to be 0.16 ppmvd for NO_X and 0.07 ppmvw for THC (3.0 ppmvw at reduced loads), which were all below the method's maximum allowable drift. Sampling system calibration error and drift results for all runs conducted during the verification are summarized in Appendix A.

An additional QC check was conducted on the NO_X analyzer. The check consisted of determining NO_2 converter efficiency prior to beginning of testing. This was done by introducing to the analyzer a mixture of mid-level calibration gas and air. The analyzer response was recorded every minute for 30 minutes. The response will be stable at the highest peak value observed if the NO_2 to NO conversion is 100-percent efficient. The converter is faulty and the analyzer must be either repaired or replaced prior to testing if the response decreases by more than 2 percent from the peak value observed during the 30-minute test period. Table 3-6 shows that the converter efficiency was measured to be 100 percent.

Table 3-6. Additional QA/QC Checks for Emissions Testing

Parameter	QA/QC Check	When Performed/Frequency	Expected or Allowable Result	Maximum Results Measured[a]
NO_X	NO_2 converter efficiency	Once before testing begins	98% efficiency or greater	100.0%
	Sampling system drift checks	Before and after each test run	± 2% of analyzer span or less	0.64% of span or 0.16 ppmvd
CO, CO_2, O_2	Analyzer calibration error test	Daily before testing	± 2% of analyzer span or less	CO: 0.6% of span or 0.15 ppmvd at full load, and 0.7% of span or 7.0 ppmvd at reduced loads CO_2: 1.6% of span or 0.16% absolute O_2: 0.4% of span or 0.1% absolute
	Calibration drift test	After each test	± 3% of analyzer span or less	CO: 2.0% of span or 0.50 ppmvd at full load, and 2.0% of span or 20.0 ppmvd at reduced loads CO_2: 0.8% of span or 0.08% absolute O_2: 0.8% of span or 0.20% absolute
THC	System calibration drift test	After each test	± 3% of analyzer span or less	0.4% of span or 0.07 ppmvd at full load, and 0.6% of span or 3.0 ppmvd at reduced loads

[a] See Appendix A for individual test run results

CO, CO_2, and O_2

Analyzer calibrations were conducted to verify the error in CO, CO_2, and O_2 measurements relative to calibration gas standards. The calibration error test was conducted at the beginning of each day of controlled test periods. A suite of calibration gases were introduced directly to the analyzer and analyzer responses were recorded. Three gases were used for CO_2 and O_2: (1) zero, (2) 40 to 60 percent of span, and (3) 80 to 100 percent of span. Four gases were used for CO: (1) zero and approximately (2) 30, (3) 60, and (4) 90 percent of span. The analyzer calibration errors for all gases were below the allowable levels, as shown in Table 3-7. It was necessary to operate the CO analyzer on a higher range during these tests (0 to 1,000 ppm) similar to the THC testing problem encountered at the reduced loads. Two additional Protocol 1 calibration gases were obtained that had concentration levels of 303 and 898 ppm. A mid-level gas of around 600 ppm could not be procured to complete the calibration suite required by the method. This is not believed to have any impact on the accuracy of the reported CO concentrations because the instrument was linear throughout the range of operation and measured concentrations never exceeded the 898-ppm level calibration gas.

Zero-and mid-level calibration gases were introduced to the sampling system at the probe and the response was recorded before and after each test run. System bias was calculated by comparing the system responses to the calibration error responses recorded earlier. Table 3-2 shows that the system bias goal for all gases was achieved and, consequently, the DQO was satisfied. The pre- and post-test system bias calibrations were also used to calculate sampling system drift for each pollutant and, as shown in Table 3-7, the drift goals were also met for all pollutants.

Collected bag samples for CH_4 were shipped to the laboratory for analysis. The laboratory reported that all samples were received in good condition and with sufficient volume for analysis other than the samples collected during Runs 11 and 16. These bags were deflated and, therefore, voided. The Test Plan specified calibration of the GC/FID with a certified gas standard and duplicate analyses of each sample as the means to evaluate accuracy. Instrument calibrations were properly performed, but the duplicate analyses were conducted on only three of the samples due to incorrect analytical instructions on the sample chain-of-custody form. Results of the duplicate analyses, shown in Table 3-2, indicate an average analytical repeatability for CH_4 of 2.4 percent, which meets the DQO. Another evaluation of sampling and analytical error was conducted that uses a sample spike and recovery analysis for CH_4. A bag was spiked with a known concentration of methane and several other hydrocarbons and then analyzed following the same instrumentation, procedures, and personnel as the samples. The results of this test was 99.8 percent recovery for CH_4.

Determination of Error in Emission Rate Determinations

Worst-case estimates of the uncertainty of the emission rate determinations were calculated from the estimated maximum uncertainties for each of the contributing measurements (that is, pollutant concentrations, O_2 concentrations, and power output). The largest observed bias in the NO_X, CO, and CO_2 measurements was 1.1 percent of full scale and the largest bias in the THC and CH_4 measurements was 2.4 percent of full scale. The corresponding maximum observed bias in the O_2 measurement was 0.6 percent of full scale. Based on the NIST-traceable factory calibration of the power meter, the estimated uncertainty in the power output measurements was 1.0 percent. Using the propagation of error formulae to combine these three estimates, the worst-case estimates in emission rate uncertainty are 1.7 percent for the NO_X, CO, and CO_2, and 2.7 percent for THC and CH_4. Both are well within the Test Plan DQO goals of ± 5.59 percent for NO_X, CO, and CO_2, and ± 7.22 percent for THC and CH_4.

4.0 TECHNICAL AND PERFORMANCE DATA SUPPLIED BY CDH ENERGY

Note: This section provides an opportunity for CDH Energy to provide additional comments concerning the CHP System and its features not addressed elsewhere in the Report. The GHG Center has not independently verified the statement made in this section.

This section compares the rated performance data from Capstone to the measured data presented in this report. Capstone provides thermal performance data on page 44 of the Installation and Start-up Manual (Part Number 511519-003). The measured performance data for the microturbine alone are compared to the published data in Figures 4-1 and 4-2 below.

The measured efficiency and power data in figures below are slightly different than the values reported in Section 2, which were net values that include the impact of parasitic loads such as the gas compressor and pump. The efficiency data shown in Figure 4-1 are the 1-minute data records for Runs 1 through 6 when the turbine provided the full rated output. The lines represent rated performance. The measured efficiency is based on a measured LHV of 903 Btu/ft^3. The rated ISO conditions correspond to 59 °F at sea level (a barometric pressure of 14.7 psia). The measured data were collected when the barometric pressure was 14.52 psia. Therefore, the Capstone-recommended adjustment factor of 1.0% was applied to the rated performance curves[1] (shown as dotted lines on the plot). Figure 4-2 compares the measured and rated turbine power output, with and without similar barometric pressure corrections applied.

[1] Capstone states that the altitude adjustment for efficiency and power is 3% for each 1000 ft of altitude above sea level, or 5.76% for each 1 psia drop in barometric pressure. Therefore, (14.7 psia – 14.52 psia) x 5.76% is equivalent to a 1.0% decrease in performance.

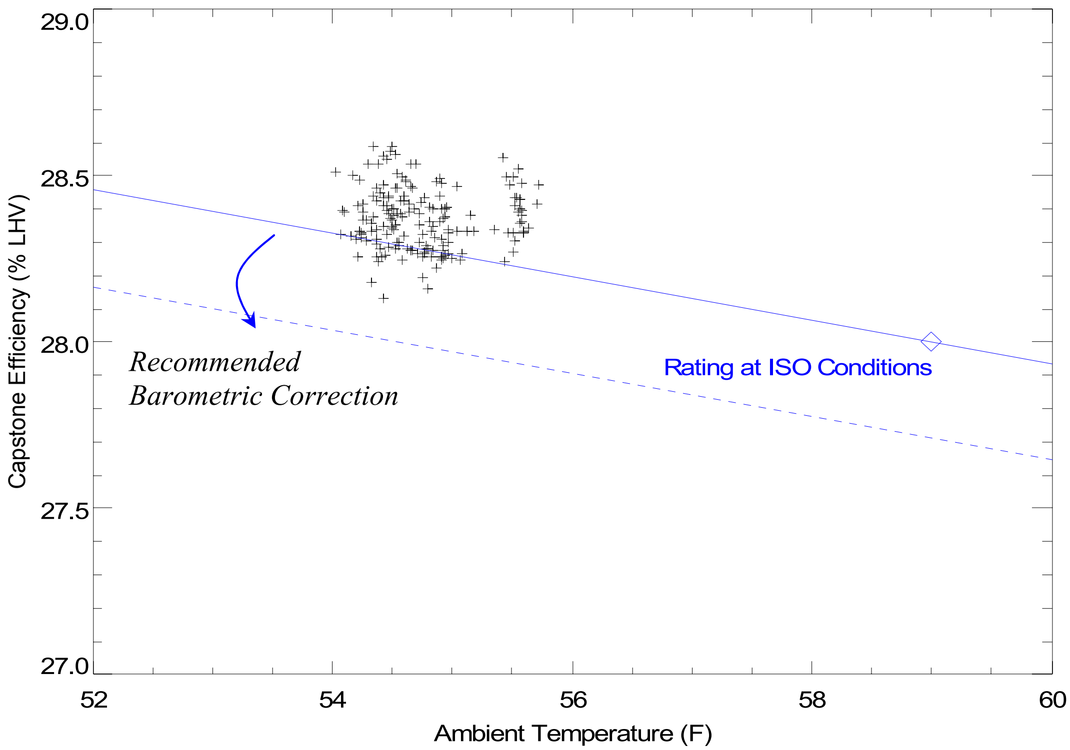

Figure 4-1. Comparing Measured and Rated Efficiency for the Capstone C60 at Full Load

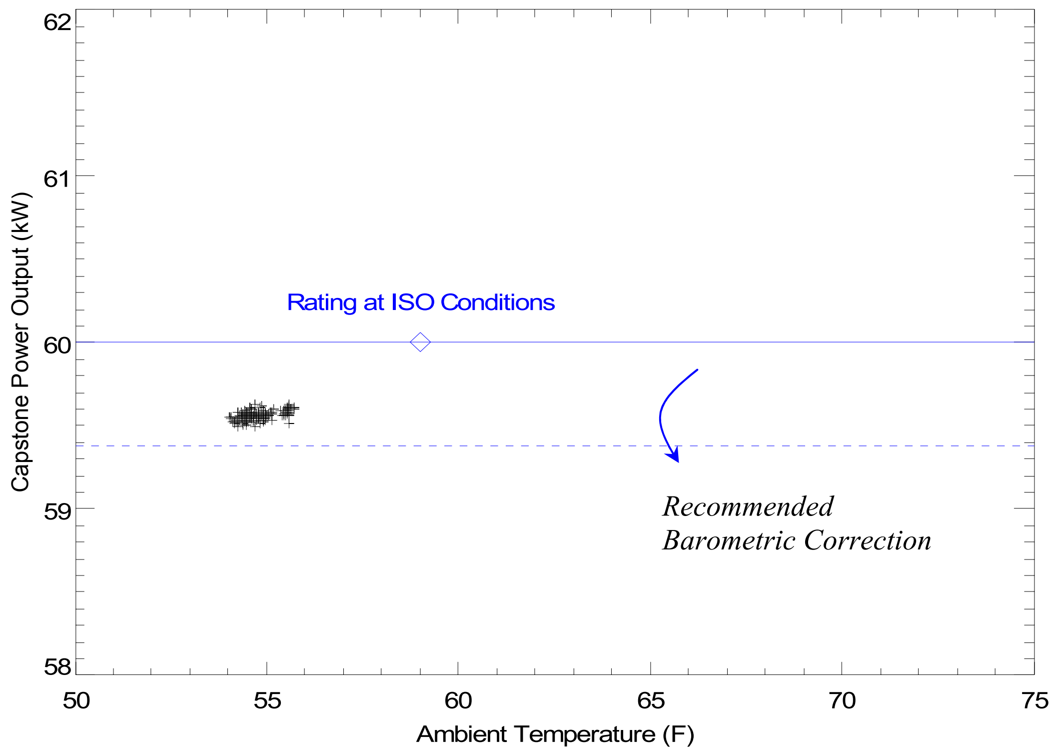

Figure 4-2. Comparing Measured and Rated Power Output for the Capstone C60 at Full Load

The measured efficiency slightly exceeds the rated performance for the turbine after correcting for both temperature and barometric pressure. The measured efficiency is 0.3-0.5% higher than expected based on the Capstone performance curves.

The barometric correction does a good job of explaining the slightly lower power output of 59.5 kW measured for the unit on that day. The measured power output is within 0.1-0.2 kW of the expected output.

The thermal performance of the Capstone microturbine installed at this site is generally in line with expectations. The emissions performance, summarized in Table 4-1, significantly exceed the published expectations for the microturbine.

Table 4-1. Comparing Measured and Rated Emissions For Capstone C60 at Full Load.		
	Capstone Rated Performance	Measured Performance
Nitrogen Oxides - NO_x (ppmv at 15% O_2)	< 9	3.1
Carbon Monoxide - CO (ppmv at 15% O_2)	< 40	3.7
Total Hydrocarbons - THC (ppmv at 15% O_2)	< 9	0.9

Note: Measured data are average of Runs 1-6.

5.0 REFERENCES

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[4] American National Standards Institute / American Society of Heating, Refrigeration, and Air-conditioning Engineers, *Method of Testing Thermal Energy Meters for Liquid Streams in HVAC Systems,* ANSI/ASHRAE 125-1992, Atlanta, GA. 1995.

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[7] American Society for Testing and Materials, *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*, ASTM D1945-98, West Conshohocken, PA. 2001.

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[12] U.S. Environmental Protection Agency, Code of Federal Regulations, Title 40, Part 60, *New Source Performance Standards, Appendix A*, U.S. EPA, Washington, DC, 1999.

[13] U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume 1. Stationary Point and Area Sources*, U.S. EPA, Washington, DC, 1999.

[14] CDH Energy Corporation, *Waldbaums CHP Demonstration Data Summary - June 2003,* CDH Energy Corp., Cazenovia, NY 2003.

APPENDIX A

Emissions Testing QA/QC Results

Appendix A-1 presents instrument calibration error and linearity checks for each of the analyzers used for emissions testing. These calibrations are conducted once at the beginning of each day of testing and after any changes or adjustments to the sampling system are conducted (changing analyzer range, for example). All of the calibration error results are within the specifications of the reference methods.

Appendix A-2 summarizes the system bias and drift checks conducted on the sampling system for each pollutant quantified. These system calibrations are conducted before and after each test run. Results of all of the calibrations are within the specifications of the reference methods.

Appendix A-1. Summary of Daily Reference Method Calibration Error Determinations

Date	Gas	Measurement Range	Cal Gas Value	Analyzer Response	Absolute Difference	Calibration Error (% of Span)*
		(ppm for NO_x, CO, and THC; % for O_2 and CO_2)				
6/4/03	NO_x	25	0.00	0.04	0.04	0.16
(Runs 1 - 6)			6.26	6.22	0.04	0.16
			12.09	12.19	0.10	0.40
			24.10	23.80	0.30	1.20
	CO	25	0.00	0.01	0.01	0.04
			6.04	6.07	0.03	0.12
			13.30	13.42	0.12	0.48
			24.36	24.21	0.15	0.60
	CO_2	10	0.00	0.16	0.16	1.60
			4.45	4.45	0.00	0.00
			9.23	9.25	0.02	0.20
	O_2	25	0.00	0.03	0.03	0.12
			11.18	11.17	0.01	0.04
			21.70	21.75	0.05	0.20
	THC	18	0.00	0.02	0.02	0.11
			3.07	3.11	0.04	0.22
			7.76	7.76	0.00	0.00
			15.89	15.91	0.02	0.11

Appendix A-1. Summary of Daily Reference Method Calibration Error Determinations (Continued)

Date	Gas	Measurement Range	Cal Gas Value	Analyzer Response	Absolute Difference	Calibration Error (% of Span)*
		(ppm for NO_x, CO, and THC; % for O_2 and CO_2)				
6/5/03	NO_x	25	0.00	0.01	0.01	0.04
(Runs 7 - 18)			6.26	6.24	0.02	0.08
			12.09	12.01	0.08	0.32
			24.10	24.32	0.22	0.88
	CO	1000	0.00	0.96	0.96	0.10
			303.00	303.30	0.30	0.03
			898.00	893.00	5.00	0.50
	CO_2	10	0.00	0.13	0.13	1.30
			4.45	4.46	0.01	0.10
			9.23	9.21	0.02	0.20
	O_2	25	0.00	0.02	0.02	0.08
			11.18	11.20	0.02	0.08
			21.70	21.73	0.03	0.12
	THC	18	0.00	0.02	0.02	0.11
			3.07	3.11	0.04	0.22
			7.76	7.76	0.00	0.00
			15.89	15.91	0.02	0.11
	THC	500	0.00	-1.3	1.30	0.26
			15.89	14.5	1.39	0.28
			150.00	149.9	0.10	0.02

Allowable calibration error is 2% span.

Appendix A-1. Summary of Daily Reference Method Calibration Error Determinations (Continued)

Date	Gas	Measurement Range	Cal Gas Value	Analyzer Response	Absolute Difference	Calibration Error (% of Span)*
		(ppm for NO_x, CO, and THC; % for O_2 and CO_2)				
6/6/03 (Profile Test)	NO_x	25	0.00	-0.04	0.04	0.16
			6.26	6.12	0.14	0.56
			12.09	12.23	0.14	0.56
			24.10	24.31	0.21	0.84
	CO	1000	0.00	-1.70	1.70	0.17
			303.00	298.00	5.00	0.50
			898.00	891.00	7.00	0.70
	CO_2	10	0.00	0.03	0.03	0.30
			4.45	4.46	0.01	0.10
			9.23	9.25	0.02	0.20
	O_2	25	0.00	0.02	0.02	0.08
			11.18	11.27	0.09	0.36
			21.70	21.73	0.03	0.12
	THC	500	0.00	-2.1	2.10	0.42
			7.76	5.68	2.08	0.42
			15.89	14.21	1.68	0.34
			150.00	149.5	0.50	0.10

Allowable calibration error is 2% span.

Appendix A-2. Summary of Reference Method System Bias and Drift Checks

Analyzer Spans: NO_x = 25, CO = 10, THC = 18 ppm, CO_2 = 10%, O_2 = 25%

		Initial Cal	Run Number 1	2	3	4	5	6
NO_x Zero	**System Response (ppm)**	0.04	-0.03	-0.01	-0.03	-0.04	-0.03	-0.04
0.04	**System Bias (% span)**	0.00	-0.28	-0.20	-0.28	-0.32	-0.28	-0.32
	Drift (% span)	na	0.28	0.08	0.08	0.04	0.04	0.04
NO_x Mid	**System Response (ppm)**	6.22	6.17	6.17	6.19	6.18	6.11	6.20
6.22	**System Bias (% span)**	0.00	-0.20	-0.20	-0.12	-0.16	-0.44	-0.08
	Drift (% span)	na	0.20	0.00	0.08	0.04	0.28	0.36
CO Zero	**System Response (ppm)**	-0.01	-0.11	-0.13	-0.09	-0.13	-0.12	0.02
0.01	**System Bias (% span)**	-0.08	-0.48	-0.56	-0.40	-0.56	-0.52	0.04
	Drift (% span)	na	1.00	0.20	0.40	0.40	0.10	1.40
CO Mid	**System Response (ppm)**	6.19	5.99	6.10	5.99	6.10	6.13	6.11
6.07	**System Bias (% span)**	0.48	-0.32	0.12	-0.32	0.12	0.24	0.16
	Drift (% span)	na	2.00	1.10	1.10	1.10	0.30	0.20
CO_2 Zero	**System Response (ppm)**	0.16	0.09	0.07	0.07	0.07	0.12	0.11
0.16	**System Bias (% span)**	0.00	-0.70	-0.90	-0.90	-0.90	-0.40	-0.50
	Drift (% span)	na	0.70	0.20	0.00	0.00	0.50	0.10
CO_2 Mid	**System Response (ppm)**	4.41	4.41	4.43	4.39	4.47	4.47	4.40
4.45	**System Bias (% span)**	-0.40	-0.40	-0.20	-0.60	0.20	0.20	-0.50
	Drift (% span)	na	0.00	0.20	0.40	0.80	0.00	0.70
O_2 Zero	**System Response (ppm)**	0.25	0.04	0.02	0.01	0.02	0.05	0.02
0.03	**System Bias (% span)**	0.88	0.04	-0.04	-0.08	-0.04	0.08	-0.04
	Drift (% span)	na	0.84	0.08	0.04	0.04	0.12	0.12
O_2 Mid	**System Response (ppm)**	11.22	11.15	11.18	11.15	11.25	11.22	11.16
11.17	**System Bias (% span)**	0.20	-0.08	0.04	-0.08	0.32	0.20	-0.04
	Drift (% span)	na	0.28	0.12	0.12	0.40	0.12	0.24
THC Zero	**System Response (ppm)**	-0.04	0.01	0.04	0.02	0.03	0.01	0.02
0.02	**System Bias (% span)**	-0.33	-0.06	0.11	0.00	0.06	-0.06	0.00
	Drift (% span)	na	0.28	0.17	0.11	0.06	0.11	0.06
THC Mid	**System Response (ppm)**	3.12	3.19	3.09	3.08	3.12	3.18	3.10
3.11	**System Bias (% span)**	0.06	0.44	-0.11	-0.17	0.06	0.39	-0.06
	Drift (% span)	na	0.39	0.56	0.06	0.22	0.33	0.44

Allowable system bias is 5% span, allowable drift is 3% span.

Appendix A-2. Summary of Reference Method System Bias and Drift Checks (Continued)

Analyzer Spans: NO_x = 25, CO = 1000, THC = 500 ppm, CO_2 = 10%, O_2 = 25%

		Initial	Run Number											
		Cal	7	8	9	10	11	12	13	14	15	16	17	18
NO_x Zero	System Response (ppm)	-0.04	-0.01	0.03	-0.01	0.02	0.01	0.02	0.04	0.01	0.00	0.02	0.07	0.03
0.01	System Bias (% span)	-0.20	-0.08	0.08	-0.08	0.04	0.00	0.04	0.12	0.00	-0.04	0.04	0.24	0.08
	Drift (% span)	na	0.12	0.16	0.16	0.12	0.04	0.04	0.08	0.12	0.04	0.08	0.20	0.16
NO_x Mid	System Response (ppm)	6.18	6.19	6.03	6.01	6.07	6.08	6.09	6.11	6.13	6.13	6.14	6.14	6.16
6.24	System Bias (% span)	-0.24	-0.20	-0.84	-0.92	-0.68	-0.64	-0.60	-0.52	-0.44	-0.44	-0.40	-0.40	-0.32
	Drift (% span)	na	0.04	0.64	0.08	0.24	0.04	0.04	0.08	0.08	0.00	0.04	0.00	0.08
CO Zero	System Response (ppm)	-1.31	-1.44	-0.56	-0.24	-0.49	-0.44	-0.31	-1.39	-0.28	-0.77	-0.81	-0.77	-0.44
0.96	System Bias (% span)	-0.23	-0.24	-0.15	-0.12	-0.15	-0.14	-0.13	-0.24	-0.12	-0.17	-0.18	-0.17	-0.14
	Drift (% span)	na	0.01	0.09	0.03	0.03	0.01	0.01	0.11	0.11	0.05	0.00	0.00	0.03
CO Mid	System Response (ppm)	300.37	296.04	297.93	297.82	298.66	296.20	295.79	294.89	294.91	296.25	294.60	296.80	296.89
303.30	System Bias (% span)	-0.29	-0.73	-0.54	-0.55	-0.46	-0.71	-0.75	-0.84	-0.84	-0.71	-0.87	-0.65	-0.64
	Drift (% span)	na	0.43	0.19	0.01	0.08	0.25	0.04	0.09	0.00	0.13	0.16	0.22	0.01
CO_2 Zero	System Response (ppm)	0.10	0.10	0.09	0.07	0.07	0.07	0.09	0.09	0.08	0.09	0.12	0.08	0.12
0.13	System Bias (% span)	-0.30	-0.30	-0.40	-0.60	-0.60	-0.60	-0.40	-0.40	-0.50	-0.40	-0.10	-0.50	-0.10
	Drift (% span)	na	0.00	0.10	0.20	0.00	0.00	0.20	0.00	0.10	0.10	0.30	0.40	0.40
CO_2 Mid	System Response (ppm)	4.48	4.43	4.43	4.37	4.39	4.39	4.38	4.39	4.37	4.33	4.36	4.40	4.35
4.46	System Bias (% span)	0.20	-0.30	-0.30	-0.90	-0.70	-0.70	-0.80	-0.70	-0.90	-1.30	-1.00	-0.60	-1.10
	Drift (% span)	na	0.50	0.00	0.60	0.20	0.00	0.10	0.10	0.20	0.40	0.30	0.40	0.50
O_2 Zero	System Response (ppm)	-0.02	0.03	0.01	0.01	0.02	0.04	-0.01	-0.01	0.01	0.01	0.00	0.01	0.03
0.02	System Bias (% span)	-0.16	0.04	-0.04	-0.04	0.00	0.08	-0.12	-0.12	-0.04	-0.04	-0.08	-0.04	0.04
	Drift (% span)	na	0.20	0.08	0.00	0.04	0.08	0.20	0.00	0.08	0.00	0.04	0.04	0.08
O_2 Mid	System Response (ppm)	11.13	11.06	11.11	11.09	11.11	11.09	11.11	11.08	11.08	11.07	11.14	11.07	11.09
11.20	System Bias (% span)	-0.28	-0.56	-0.36	-0.44	-0.36	-0.44	-0.36	-0.48	-0.48	-0.52	-0.24	-0.52	-0.44
	Drift (% span)	na	0.28	0.20	0.08	0.08	0.08	0.08	0.12	0.00	0.04	0.28	0.28	0.08
THC Zero	System Response (ppm)	-0.01	-0.01	-0.05	0.01	-1.77	-1.66	-1.97	-2.21	-2.10	-1.98	-2.03	-2.13	-1.92
0.02	System Bias (% span)	-0.01	-0.01	-0.01	0.00	-0.36	-0.34	-0.40	-0.45	-0.42	-0.40	-0.41	-0.43	-0.39
	Drift (% span)	na	0.00	0.01	0.01	na	0.02	0.06	0.05	0.02	0.02	0.01	0.02	0.04
THC Mid	System Response (ppm)	7.85	7.76	7.76	7.78	152.70	153.10	150.82	150.09	147.12	148.65	148.87	151.95	150.87
7.76	System Bias (% span)	0.02	0.00	0.00	0.00	0.56	0.64	0.18	0.04	-0.56	-0.25	-0.21	0.41	0.19
149.90	Drift (% span)	na	0.02	0.00	0.00	na	0.08	0.46	0.15	0.59	0.31	0.04	0.62	0.22

Allowable system bias is 5% span, allowable drift is 3% span.

Appendix A-2. Summary of Reference Method System Bias and Drift Checks (Continued)

Analyzer Spans: NO_x = 25, CO = 1000, THC = 500 ppm, CO_2 = 10%, O_2 = 25%

		Initial Cal	Profile Test
NO_x Zero	**System Response (ppm)**	-0.04	-0.02
-0.04	**System Bias (% span)**	0.00	0.08
	Drift (% span)	na	0.08
NO_x Mid	**System Response (ppm)**	6.13	6.07
6.12	**System Bias (% span)**	0.04	-0.20
	Drift (% span)	na	0.24
CO Zero	**System Response (ppm)**	-0.42	-1.58
-1.70	**System Bias (% span)**	0.13	0.01
	Drift (% span)	na	0.12
CO Mid	**System Response (ppm)**	298.02	298.69
298.00	**System Bias (% span)**	0.00	0.07
	Drift (% span)	na	0.07
CO_2 Zero	**System Response (ppm)**	0.07	0.04
0.03	**System Bias (% span)**	0.40	0.10
	Drift (% span)	na	0.30
CO_2 Mid	**System Response (ppm)**	4.40	4.38
4.46	**System Bias (% span)**	-0.60	-0.80
	Drift (% span)	na	0.20
O_2 Zero	**System Response (ppm)**	0.06	0.08
0.02	**System Bias (% span)**	0.16	0.24
	Drift (% span)	na	0.08
O_2 Mid	**System Response (ppm)**	11.20	11.19
11.27	**System Bias (% span)**	-0.28	-0.32
	Drift (% span)	na	0.04
THC Zero	**System Response (ppm)**	-2.11	-2.63
-2.10	**System Bias (% span)**	0.00	-0.11
	Drift (% span)	na	0.10
THC Mid	**System Response (ppm)**	149.52	149.01
149.50	**System Bias (% span)**	0.00	-0.10
	Drift (% span)	na	0.10

Allowable system bias is 5% span, allowable drift is 3% span.

APPENDIX B-1

Estimation of Regional Grid Emissions

EPA has long recognized that clean energy technologies have the potential for significant emission reductions through displaced generation. However, a robust and analytically sound method to quantify the potential of displaced emissions has yet to be developed. Displaced generation is defined as the total electrical output (measured in kWh) from conventional electricity sources that is either displaced by or avoided through the implementation of energy-efficient measures. Displaced emissions is defined as the change in emissions (measured in lb) that results when conventional electrical generation is displaced by energy-efficient measures. On-site power generation with a distributed energy technology is an example of a clean energy source, provided its emissions are less than conventional sources. DG-CHP systems can result in displaced generation and ultimately displace emissions.

Several different methods have been developed and employed by various organizations to estimate emissions displaced by on-site electricity generation. There are many variations of such methodologies and they are all derived from the average emission rate method—the marginal unit method—or historical emissions-generation data.

- The average emission rate method uses the average emission rate of electricity generating units in a particular region or nationally. It is usually based on the average emission characteristics of all electricity-generating units or fossil-fired units only. It is often derived from historic generation and emissions data or projections of future generation and fuel use patterns. This approach is most widely used due to its simplicity and wide availability of average rates for many U.S. regions. Unfortunately, there is little or no correlation between the average emission rate and the emission rate at which the emissions are displaced by energy-efficient measures. The result is that estimates of emissions impacts can be inaccurate and may not adequately reflect the realities of power markets.

- The marginal-unit method is an attempt to improve on the average emission rate approach by identifying a particular unit or type of unit that may be displaced. Similar to the average emission rate method, the average emission characteristics of the displaced units are applied to total electricity saved to estimate displaced emissions. The marginal unit method assumes that at any point in time the marginal unit, by virtue of being the most expensive generating unit to operate, will be the unit that is displaced. Although this approach conceptually appears to be more reasonable than simply using an average emission rate, identifying the marginal unit is difficult, particularly in regions with large and frequent variations in hourly electricity demand.

- Displaced emissions are also estimated using statistical techniques based on historical data. This approach seeks to forecast how displaced emissions arise from observed changes in electricity demand/supply instead of identifying the average or marginal emission rate of particular units. This approach requires statistical modeling, and data such as regional generation, emissions, and electricity demand. Its primary limitation is that actual site-specific and electricity control area specific data must be available.

EPA has been developing a newer approach that utilizes region/time specific parameters to represent average displaced emission rate (ADER). The ADER methodology accounts for the complexities of electricity markets in assessing how displaced emissions result from changes in electric demand or supply and produces regional, national, short-term, and long-term estimates of displaced emissions of CO_2, NO_X, SO_2, and mercury (Hg) from electric generation. The results of the ADER analysis are not yet available; as such, the GHG Center is unable to apply this methodology for this verification. However, at the suggestion of the EPA project officer leading this effort, a similar approach developed by the Ozone Transport Commission (OTC), has been adopted for this verification to estimate displaced emissions and is described below.

OTC is a multi-state organization focused on developing regional solutions to the ground-level ozone problem in the Northeast and Mid-Atlantic region of the U.S. with special emphasis on the regional transport of ground-level ozone and other related pollutants. OTC was created by Congress in 1990 and consists of the jurisdictions within Connecticut, Delaware, D.C., Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. OTC has recently developed an Emission Reduction Workbook (workbook) to provide a method of assessing the emissions impacts of a range of energy policies affecting the electric industry [9]. The geographic focus of the workbook is the three northeastern electricity control areas: Pennsylvania/New Jersey/Maryland (PJM), the New York Independent System Operator (NY ISO), and Independent System Operator of New England (ISO NE).

The three energy programs evaluated by the workbook are programs that (1) displace generation (e.g., DG-CHP systems), (2) alter the average emission rate of the electricity used in a state or region (e.g., emissions performance standard), and (3) reduce emission rates of specific generating units (e.g., multi-pollutant regulations applied to existing generating units). The Workbook contains default displaced emission rates for the three northeastern control areas to evaluate these programs. The default displaced emission rates are divided into three time periods: near-term (2002-2005), medium-term (2006-2010), and long-term (2011-2020). The short-term default emission rates for the NY ISO control area have been used to represent the ER_{Grid} variable shown in Equation 8 for this verification.

The near-term rates for the NY ISO are summarized in Table B-1. These rates were compiled using the PROSYM electricity dispatch model and are reported to be representative of actual operations because the identity of generating units that constitute each regional power system are known with a relatively high level of certainty.

Table B-1. Displaced Emission Rates For the NY ISO (2002)

	NOx (lb/kWh$_e$)	CO_2 (lb/kWh$_e$)
Ozone season weekday [a]	0.0021	1.37
Ozone season night/weekend [b]	0.0028	1.67
Non-ozone season weekday [c]	0.0021	1.46
Non-ozone season night/weekend [d]	0.0028	1.61

[a] Average of all hourly marginal emission rates during weekdays, May through September, 7:00 am through 10:59 pm
[b] Average of all hourly marginal emission rates during all nights, May through September, 11:00 pm through 6:59 am, and all weekend days during this period
[c] Average of all hourly marginal emission rates during weekdays, October through April, 7:00 am through 10:59 pm
[d] Average of all hourly marginal emission rates during all nights, October through April, 11:00 pm through 6:59 am, and all weekend days during this period

PROSYM is a chronological, multi-area electricity market simulation model that is often used to forecast electricity market prices, analyze market power, quantify production cost and fuel requirements, and estimate air emissions. It simulates system operation on an hourly basis by dispatching generating units each hour to meet load. The simulation is based on unit-specific information on the generating units in multiple interconnection areas (unit type and size, fuel type, heat-rate curve, emission and outage rates, and operating limitations) and on detailed data on power flows and transmission constraints within and between ISOs. Actual constraints on system operation (such as unit-ramp times and minimum up and down times) are taken into account because the simulation is done in chronological order. The resulting emission rates in one control region take into account emission changes in neighboring regions. PROSYM has been used by many organizations, including the EPA and Department of Justice, to pursue New Source Review violations and by DOE, numerous utility companies, Federal Energy Regulatory Commission (FERC), and the Powering the South organization to simulate the electric power system in the Southern U.S.

OTC generated the displaced emission rates for the Northeast control areas by first performing a “base case” model run simulating plant dispatch across all three control areas for the year. OTC then performed three “decrement” model runs. In one decrement run, all hourly loads in PJM were reduced by 1 percent; loads in ISO NE and NY ISO were not reduced. In another decrement run, loads in ISO NE were reduced by 1 percent and in the third, NY ISO loads were reduced. The total difference in kWhs generated between the base case and decrement case and the total difference in emissions was calculated and the emissions were divided by kWhs to derive the marginal emission rate for the time period OTC calculated marginal emission rates for different periods. Marginal rates shown in Table B-1 takes into account changes in generation in all areas resulting from the load reductions in the target DG-CHP use area. This includes analysis of emissions changes across six interconnected control areas: PJM, NY ISO, ISO NE, Canada’s Maritime Provinces, Ontario, and Quebec.