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Environmental Technology Verification Report

Ingersoll-Rand Energy Systems IR PowerWorks™ 70 kW Microturbine System

Prepared by:

Greenhouse Gas Technology Center
Southern Research Institute

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

and

Under Agreement With
New York State Energy Research and Development Authority

EPA REVIEW NOTICE

THE ENVIRONMENTAL TECHNOLOGY VERIFICATION PROGRAM

U.S. Environmental Protection Agency

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:	IR Power Works™ 70 kW Microturbine System
COMPANY:	Ingersoll-Rand Energy Systems
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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 substantially 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 the IR PowerWorks™ 70 kW Microturbine System offered by Ingersoll-Rand Energy Systems. This verification statement provides a summary of the test results for the IR PowerWorks 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 IR PowerWorks System is one of the first cogeneration installations that integrates microturbine technology with a heat recovery system.

The following description of the IR PowerWorks System was provided by the vendor and does not represent verified information.

Electric power is generated with an integrated Ingersoll-Rand microturbine with a nominal power output of 70 kW (59 °F, sea level). The system incorporates a gas generator compressor, recuperator, combustor, power turbine, and electric generator. Air enters the unit and is compressed to about 35 psig in the gas generator compressor and then heated to around 1,000 °F in the recuperator. A screw compressor type fuel booster is used to compress the natural gas fuel, the compressed air is 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 power turbine section to perform work, rotating the turbine blades to turn a generator that produces electricity. The rotating components are of a two-shaft design with the power turbine connected to a gearbox and supported by oil lubricated bearings. The generator is cooled by air flow into the gas turbine. The exhaust gas exits the turbine and enters the recuperator, which captures some of the thermal energy and uses it to pre-heat the air entering the combustor, improving the efficiency of the system. The exhaust gas then exits the recuperator through a muffler and into the integrated IR heat recovery unit.

The integral heat recovery system consists of a fin-and-tube heat exchanger, which circulates a mixture of approximately 16 percent propylene glycol (PG) in water through the heat exchanger at approximately 20 gallons per minute (gpm). The heating loop is driven by an internal circulation pump and no additional pumping is required. The thermal control system is programmable for individual site requirements. Minimum settings may vary, but the maximum fluid temperature entering the PowerWorks may never exceed 200 °F.

The IR PowerWorks system includes an induction generator that produces high-frequency alternating current (AC) at 480 volts. 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 turbine is reported by the turbine manufacturer to provide clean power, free of spikes and unwanted harmonics. The power unit operates at 44,000 revolutions per minute (rpm), and the generator operates at 3,260 rpm regardless of load.

VERIFICATION DESCRIPTION

Verification of the IR PowerWorks was conducted at the Crouse Community Center in Morrisville, New York. The facility is a 60,000-square foot skilled nursing facility providing care for approximately 120 residents. The IR PowerWorks system was installed to provide electricity to the facility and to provide heat for domestic hot water (DHW) and space heating. During normal occupancy and facility operations, electrical demand exceeds the IR PowerWorks generating capacity, and additional power is purchased from the grid. On rare occasions, when facility electrical demand is below 70 kW (demand can drop as low as 50 kW in some instances), the excess power is exported to the grid. In the event of a power grid failure, the system is designed to automatically shut down to isolate system from grid faults. When grid power is restored, the IR PowerWorks system can be restarted manually.

Prior to installation of the IR PowerWorks, the facility used two gas-fired boilers to generate hot water for space heating and DHW throughout the complex. The two boilers are Weil-McLain Model Number BG-688 units, installed in 1996. Each boiler has a rated heat input of 1,700 thousand British thermal units per hour (MBtu/hr), gross output capacity of 1,358 MBtu/hr, and a net hot water production rate of 1,181 MBtu/hr. The IR PowerWorks is configured in-line with the boiler supply and return fluid (PG) lines (working fluid is a mixture of 16-percent propylene glycol in water).

Testing commenced on August 14, 2002, and was completed on August 21, 2002. It consisted of a series of short periods of "controlled tests" in which the unit was operated at full load (the IR PowerWorks unit tested did not have the capability of intentionally modulating power output). Three test replicates were conducted during normal site operations regarding heat recovery and use. During these tests, the facility boilers were thermostatically controlled to maintain desired supply PG temperature. A second set of three tests was conducted at full power with the boilers turned off to demonstrate the unit's ability to produce more heat. These controlled test periods were followed by six days of extended monitoring to verify electric power production, heat recovery, power quality performance, and efficiency during an extended period of normal site operations. During this period, the IR PowerWorks System operated 24 hours per day at full electrical power output and normal heat recovery rate.

The classes of verification parameters evaluated are:

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 heating value, 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 determination at both normal site conditions and with site conditions altered to enhance heat recovery. 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 Federal Reference Methods. Pollutant concentrations in the exhaust gas are reported in two sets of units-parts per million volume, dry (ppmvd) corrected to 15 percent oxygen (O_2), and 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 IR PowerWorks 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 IR PowerWorks System were not present). At this site the baseline systems include electricity supplied from the local utility grid and heat from the facility's standard natural gas boilers. Baseline emissions for the electrical power were determined following Ozone Transport Commission guidelines. Baseline emissions from heat production are based on EPA emission factors for commercial-scale gas-fired boilers.

Electrical power quality parameters, such as electrical frequency and voltage output, were also measured during the six-day extended test. Other performance parameters, including current and voltage total harmonic distortions (THD) and power factor, were monitored to characterize the quality of electricity supplied to the end user. The guidelines listed in the Institute of Electrical and Electronics Engineers' Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems were used to perform power quality testing.

Quality Assurance (QA) oversight of verification testing was provided by Southern Research Institute (SRI). Following specifications of the ETV Quality Management Plan (QMP), SRI staff conducted three performance evaluation audits and an audit of data quality on at least 10 percent of the data generated during this verification.

VERIFICATION OF PERFORMANCE

Heat and Power Production Performance

- All controlled tests occurred at similar operating conditions (ambient temperatures defined on S-2: 76 to 86 ^{o}F; barometric pressure: 14.01 to 14.07 psia; relative humidity: 45 to 68 percent).

- During the controlled test period, 50.62±0.84 kW of electric power was generated at full load. Heat recovery rate during normal facility operations was 143.5±1.82 MBtu/hr. Corresponding efficiencies were 25.3±0.46 percent for electrical generation, 21.0 ± 0.31 percent for heat production, and 46.3±0.55 percent for total combined heat and power (CHP) efficiency.

- During controlled test periods with the boilers turned off, enhanced heat recovery rate was 173.2±1.82 MBtu/hr. Corresponding heat production efficiency was 24.9±0.35 percent during these tests. These results demonstrate that heat recovery performance of the IR PowerWorks can be improved by reducing the heating loop temperature. These results represent the highest heat recovery rate achievable at this facility under current heating loop design and operation, but do not represent the maximum heat recovery potential of the IR PowerWorks where lower loop temperatures are evident.

HEAT AND POWER PRODUCTION					
Test Condition	Electrical Power Generation		Heat Recovery Performance		Total IR PowerWorks System Efficiency (%)
	Power Delivered (kW_e)	Electrical Efficiency (%)	Heat Recovery Rate (MBtu/hr)	Thermal Efficiency (%)	
Full Power, Normal Site Operations	50.62	25.3	143.5	21.0	46.3
Full Power, Heat Recovery Potential Enhanced	52.34	25.7	173.2	24.9	50.6

- Heat input at full load was 684.1 MBtu/hr, or 12.5 standard cubic feet per minute (scfm) natural gas. Heat rate at full load was 13,487 Btu/kWh_e.

Emissions Performance

- During normal site operations, average NO_X concentration was 0.86 ppmvd @ 15 percent O_2. This equates to a mass emission rate of 0.0024 lb/hr and a power normalized emission rate of 4.67 x 10^{-5} lb/kWh$_e$. Mass emissions of CO_2 averaged 82.9 lb/hr (1.60 lb/kWh$_e$).

- CO concentrations averaged 0.62 ppmvd @ 15 percent O_2 during normal site operations. This equates to a mass emission rate of 0.0011 lb/hr and a power normalized emission rate of 2.09 x 10^{-5} lb/kWh$_e$.

- Emissions of THC were near the sensitivity of the sampling system, averaging 2.38 ppmvd @ 15-percent O_2 during normal site operations. Methane concentrations were not detected during any of the test periods (< 1 ppmvd).

- At full load, NO_X emissions per unit electrical power output were 4.67E-05 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 slightly lower than the emission rate for the IR PowerWorks (1.60 lb/kWh). These values, along with emission reductions attributed to the IR PowerWorks heat recovery performance yield an average annual emission reduction of 1,333 lbs (34 percent) for NO_X, and 211,744 lbs (7 percent) for CO_2. Calculated emission reductions include 7.8 percent line losses across the regional grid.

CRITERIA POLLUTANT AND GHG EMISSIONS									
Test Condition	**(ppmvd @ 15% O_2)**				**(lb/kWh$_e$)**				
	NO_X	CO	THC	CH_4	NO_X	CO	THC	CH_4	CO_2
Full Power, Normal Site Operations	0.86	0.62	2.38	< 1.0	4.67 x 10^{-5}	2.09 x 10^{-5}	4.48 x 10^{-5}	< 4.93 x 10^{-5}	1.60
Full Power, Heat Recovery Potential Enhanced	1.07	0.65	0.54	< 1.0	5.84 x 10^{-5}	2.14 x 10^{-5}	1.04 x 10^{-6}	< 4.87 x 10^{-5}	1.78

Power Quality Performance

- Throughout the six-day test period, the IR PowerWorks System maintained continuous synchronization with the utility grid. Average electrical frequency was 60.001 Hz and average voltage output was 494.75 volts.
- The power factor remained relatively constant for all monitoring days with an average of 67.5 percent and a range of 62.7 to 73.9 percent.
- The average current THD was 4.76 percent and the average voltage THD was 2.05 percent, both lower than the ±5 percent threshold specified in IEEE 519.

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 Ingersoll-Rand Energy Systems, IR PowerWorks™ 70 kW Microturbine System* (SRI 2002). Detailed results of the verification are presented in the Final Report titled Environmental Technology Verification Report *for the Ingersoll-Rand Energy Systems, IR PowerWorks™ 70 kW Microturbine System* (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).

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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.

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Greenhouse Gas Technology Center

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

Environmental Technology Verification Report

Ingersoll-Rand Energy Systems
IR PowerWorks™ 70 kW Microturbine System

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ACRONYMS/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 cubit feet
C1	quantification of methane
CCC	Crouse Community Center
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/MMBtu	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
Hg	Mercury (metal)

(continued)

ACRONYMS/ABBREVIATIONS
(continued)

HHV	higher heating value
hr	hours
Hz	hertz
IC	internal combustion
IEEE	Institute of Electrical and Electronics Engineers
IPCC	Intergovernmental Panel on Climate Change
IR PowerWorks	Ingersoll-Rand PowerWorks™ 70 kW microturbine system
ISO	International Standards Organization and Independent System Operation
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
ISO	International Standards Organization and Independent System Operation
LHV	lower heating value
MBtu/hr	thousand British thermal units per hour
MMBtu/hr	million British thermal units per hour
MMcf	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
NOX	nitrogen oxides
NSPS	New Source Performance Standards
NY ISO	New York ISO
NYSEG	New York State Electric and Gas Corporation
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
PEA	Performance Evaluation Audit
PG	propylene glycol
PJM	Pennsylvania/New Jersey/Maryland
ppmv	parts per million volume
ppmvw	Parts per million volume wet

ACRONYMS/ABBREVIATIONS
(continued)

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
SRI	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 substantially 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 (SRI), which conducts verification testing of promising GHG 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-review 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 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 closer to customers than central station generation. A distributed power unit can be connected directly to the customer and/or to a utility's transmission and distribution system. Examples of technologies available for DG include gas turbine generators, internal combustion (IC) engine generators (e.g., gas, diesel), photovoltaics, wind turbines, fuel cells, and microturbines. DG technologies provide customers one or more of the following main services: stand-by generation (i.e., emergency backup power), peak shaving capability (generation during high demand periods), baseload generation (constant generation), or cogeneration (combined heat and power (CHP) generation).

Recently, the GHG Center and the New York State Energy Research and Development Authority (NYSERDA) 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 the Ingersoll-Rand (IR) PowerWorks™ 70 kW microturbine system offered by Ingersoll-Rand Energy Systems (IR PowerWorks). The test unit is currently in use at the Crouse Community

Center (CCC) in Morrisville, New York which includes an adult care assisted living facility. The IR PowerWorks system uses a natural-gas-fired 70 kW microturbine for electricity generation and a heat recovery unit to provide domestic hot water (DHW) and space heating at the CCC complex. Facility electrical and thermal demand exceeds the IR PowerWorks 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 overall energy conversion efficiency is estimated to range from 70 to 80 percent, which is high enough to significantly reduce greenhouse gas emissions and provide end users with high-quality energy services at competitive prices.

The GHG Center evaluated the performance of the IR PowerWorks by conducting field tests over a seven-day verification period (August 14 through 21, 2002). 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 GHG emission reductions for the Crouse Community Center. 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 Ingersoll-Rand Energy Systems, IR PowerWorks^{TM} 70 kW Microturbine System* (SRI 2002). 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 operators at the Crouse Community Center, Ingersoll-Rand, 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. In some cases, deviations from the Test Plan were required. These deviations, and the alternative procedures selected for use, are discussed in this report.

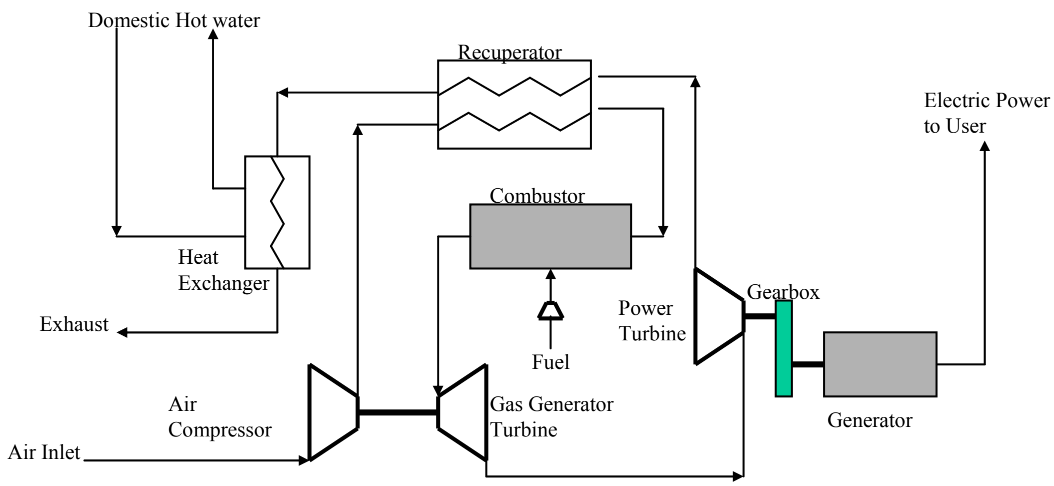
The remainder of Section 1.0 describes the IR PowerWorks System technology and test facility and outlines the performance verification procedures that were followed. Section 2 presents test results, and Section 3 assesses the quality of the data obtained. Section 4, submitted by Ingersoll-Rand, presents additional information regarding the IR PowerWorks System. Information provided in Section 4 has not been independently verified by the GHG Center.

1.2. IR POWERWORKS TECHNOLOGY DESCRIPTION

Large- and medium-scale gas-fired turbines have been used to generate electricity since the 1950s. Recently they have become more widely used to provide additional generation capacity because of their ability to be quickly and economically deployed. Technical and manufacturing developments during the last decade have enabled the introduction of microturbines, with generation capacities ranging from 30 to 200 kW. The IR PowerWorks is one of the first microturbine (CHP) units that integrates microturbine and heat recovery technologies to produce electric power, heat, and hot water all in a single package (Figure 1-1). Figure 1-2 illustrates a simplified process flow diagram of the IR PowerWorks system, and a discussion of key components is provided below.

Figure 1-1. IR PowerWorks CHP System

Figure 1-2. IR PowerWorks Process Diagram



Electric power is generated with an integrated Ingersoll-Rand microturbine with a nominal power output of 70 kW (59 ^oF, sea level). Table 1-1 summarizes the physical and electrical specifications reported by IR. The system incorporates a gas generator compressor, recuperator, combustor, power turbine, and electric generator. Air enters the unit and is compressed to about 35 psig in the gas generator compressor and then heated to around 1,000 ^oF in the recuperator. A screw-compressor type fuel booster is used to compress the natural gas fuel, the compressed air is 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 power turbine section to perform work, rotating the turbine blades to turn a generator that produces electricity. The rotating components are of a two-shaft design with the power turbine connected to a gear box and supported by oil lubricated bearings. The generator is cooled by air. The exhaust gas exits the turbine and enters the recuperator, which captures some of the thermal energy and uses it to pre-heat the air entering the combustor, improving the efficiency of the system. The exhaust gas then exits the recuperator through a muffler and into the integrated IR heat recovery unit.

The IR PowerWorks system includes an induction generator that produces high frequency alternating current (AC) at 480 volts. 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 turbine is reported by the turbine manufacturer to provide clean power, free of spikes and unwanted harmonics. The power unit operates at 44,000 revolutions per minute (rpm), and the generator operates at 3,260 rpm regardless of load. The Crouse Community Center IR PowerWorks system runs parallel with the local power utility. If the power demand exceeds the available capacity of the turbine, additional power is drawn from the grid. In the event of a power grid failure, the system is designed to automatically shut down to isolate the system from grid faults. When grid power is restored, the IR PowerWorks system can be restarted manually.

Table 1-1. IR PowerWorks Physical, Electrical, and Thermal Specifications
(Source: Ingersoll-Rand Energy Systems)

Electrical Efficiency (Lower heating value (LHV) basis)	28% (±2%)
Power (start-up) Communications	Utility grid or black start battery Ethernet IP or modem
Electrical Outputs (Power at ISO Conditions (59 ^oF @ sea level))	70 kW, 480 VAC, 60 Hz, 3-phase
Full Load Emissions Nitrogen oxides (NOX) Full Load Emissions Carbon monoxide (CO) Full Load Emissions Total hydrocarbon (THC)	< 9 ppmv @ 15% O_2 < 9 ppmv @ 15% O_2 < 9 ppmv @ 15% O_2
Natural gas Fuel Consumption Rate	832,230 Btu/hr
Maximum Fuel Supply Pressure Minimum Fuel Supply Pressure	5 psig 0.29 psig
Total Exhaust Heat Output	119,400 Btu/hr
Heat Recovery Rate – Inlet water temperature Heat Recovery Rate – Inlet water flow rate	40 to 160 ^oF 5 to 20 gallons per minute
Crouse Community Center IR Powerworks Noise Level	73 dbA at 1 m
Length Width Weight	69 in. 42 in. 4100 lbs

The turbine at the Crouse Community Center facility uses natural gas supplied at about 2 pounds per square inch gauge (psig). The IR PowerWorks system boosts the fuel pressure to about 50 psig using the fuel booster compressor.

The integral heat recovery system consists of a fin-and-tube heat exchanger, which circulates a mixture of approximately 16 percent propylene glycol (PG) in water through the heat exchanger at approximately 20 gallons per minute (gpm). The heating loop is driven by an internal circulation pump, with no additional pumping required. The recovered heat is circulated through the facility's mechanical room to offset or supplement heat generated by two gas-fired boilers. The resulting, cooler PG mixture is circulated back to the heat exchanger, energy is exchanged between the PG mixture and the hot turbine exhaust gas, and the entire circulation loop is repeated. If overheating of the glycol loop should occur due to the Crouse Community Center heat load being significantly lower than the heat transferred with the IR PowerWorks system, the system will automatically shut off.

The thermal control system is programmable for individual site requirements. Minimum settings may vary, but the maximum fluid temperature entering the PowerWorks may never exceed 200 ^{o}F. Section 1.3 below contains further discussion regarding the use of recovered heat.

1.3. TEST FACILITY DESCRIPTION

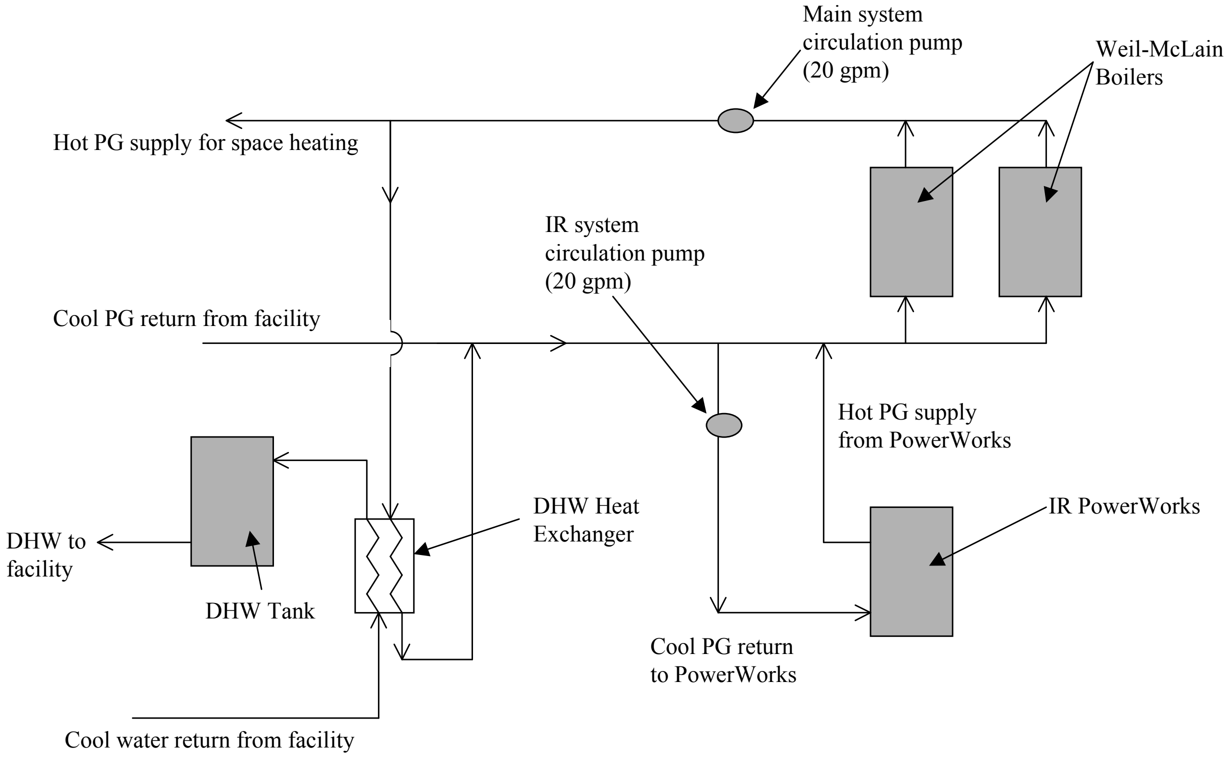
The Crouse Community Center is located in Morrisville, New York. The facility is a 60,000 square foot skilled nursing facility providing care for approximately 120 residents. Similar to a hospital, the facility includes private residential rooms, social and recreational areas, industrial-scale laundry facilities, and cafeterias. The IR PowerWorks system was installed to provide electricity to the facility and to provide heat for DHW and space heating.

During normal occupancy and facility operations, electrical demand exceeds the IR PowerWorks generating capacity, and additional power is purchased from the grid. On rare occasions, when facility electrical demand is below 70 kW (demand can drop as low as 50 kW in some instances), the excess power is exported to the grid.

Prior to installation of the IR PowerWorks, the facility used two gas-fired boilers to generate hot water for space heating and DHW throughout the complex. The two boilers are Weil-McLain Model Number BG-688 units, installed in 1996. Each boiler has a rated heat input of 1,700 thousand British thermal units per hour (MBtu/hr) and a net hot water production rate of 1,181 MBtu/hr. (rated efficiency of 69.5%). The IR PowerWorks is configured in-line with the facilities existing boiler supply and return PG lines (Figure 1-3).

During normal facility occupancy and operation, the IR PowerWorks system provides enough heat to supply all of the facility's DHW needs throughout the year. Space heating demand at the facility varies greatly by season. During warm seasons, the IR PowerWorks system usually provides all of the heat for space heating as well as DHW. The boilers remain idle unless DHW demand is high, at which time one boiler may operate for short periods of time. This system is thermostatically controlled such that supply PG fluid temperature to the DHW and space heating loops is maintained at 185 ^{o}F or higher. Should the fluid temperature drop below this set-point (e.g., cold weather periods or times of high DHW demand), one or both of the gas-fired boilers will turn on as needed to supplement the heat generated by the IR PowerWorks and maintain the desired 185 ^{o}F PG supply temperature. At times when the space heating and DHW demand is low, the return PG fluid temperature becomes elevated. Should this temperature reach 200 ^{o}F, the PowerWorks will automatically shut down.

Figure 1-3. Crouse Community Center Space Heating and Hot Water System



1.4. PERFORMANCE VERIFICATION OVERVIEW

This verification test design was developed to evaluate only the performance of the combined heat and power system and not the overall building integration or specific management strategy. The Test Plan specified that the verification would include a series of controlled test periods in which the GHG Center would intentionally modulate the unit to produce electricity at 50, 75, 90, and 100 percent of rated capacity (70 kW nominal), followed by a period of extended monitoring. However, after development of the Test Plan, IR informed the Center that the PowerWorks unit at this facility does not have the capability of modulating power command or output. Instead, the System operates at full capacity during all operations. The power delivered can vary only slightly in response to natural changes in ambient conditions. Therefore, the controlled test periods were conducted only at full load. During the extended monitoring period, the PowerWorks unit was allowed to operate continuously at full load.

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 1.4.3. Detailed descriptions of testing and analysis methods are not provided here but can be found in the Test Plan.

Power and Heat 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 (NOX) 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 GHG emission reductions

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

Table 1-2. Controlled and Extended Test Periods

Controlled Test Periods

Date	Time	Test Condition	Verification Parameters Evaluated
08/14/02	09:20 - 11:30	Official Controlled Test Period, three 15 to 30-minute test runs	NOX, CO, THC, CH_4, CO_2 emissions, and electrical, thermal, and total efficiency
08/15/02	09:30 - 13:00	Additional Controlled Test Period - Enhanced recovery potential with boiler turned off, three 30-minute test runs	

Extended Test Periods

Date	Time	Verification Parameters Evaluated
8/15/02	20:30 - 23:59	Total electricity generated; total heat recovered; electrical, thermal, and total efficiency; power quality; and emission offsets
8/16/02	00:00 - 23:59	
8/17/02	00:00 - 23:59	
8/18/02	00:00 - 23:59	
8/19/02	00:00 - 23:59	
8/20/02	00:00 - 23:59	
8/21/02	00:00 - 09:00	

With the PowerWorks at full load and under normal facility operations, three test runs were executed to constitute the official controlled tests. During the controlled and extended test periods, facility heat demand exceeded the heat recovery capacity of the PowerWorks, and therefore one of the facility boilers was operating intermittently. Under this condition, the facility's heat demands were satisfied, but it was suspected that the elevated PG fluid return temperatures to the IR PowerWorks that are inherent to this facility may affect heat recovery performance. To assess any such effects, a second series of controlled tests were conducted with the boiler control system manually turned off. With the boiler off and the IR PowerWorks operating at full load, PG fluid return temperatures dropped considerably (and facility DHW demand was not being fully met). This series of tests (shown in Table 1-2) allowed the GHG Center to report enhanced heat recovery potential for this system in addition to the performance measured during normal site operations. More detail regarding justification of these additional controlled tests, and the Center's findings, is provided along with the official test results in Section 2.1.1.

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

Following the controlled test periods, daily performance of the IR PowerWorks System was characterized over the six-day extended monitoring period. The IR PowerWorks System was operating 24 hours per day at maximum electrical power output. During this period, the facility's heat demand exceeded the heat recovery capacity of the IR PowerWorks at all times, and therefore the test results represent the heat recovery performance for this facility under normal operations. During the first day of extended monitoring (8/15/02), the boiler was turned off for a period of approximately 13 hours (0700 to 2000 hours), and the PG loop temperature dropped through the evening hours (period of highest DHW demand). Although data collected during this period does not represent normal facility operations, it was used to further evaluate the enhanced potential heat recovery of the IR PowerWorks at this site.

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

1.4.1. Power and Heat Production Performance

Electrical efficiency determination was based upon guidelines listed in ASME PTC-22 (ASME 1997), and was calculated using the average measured power output, fuel flow rate, and fuel lower heating value (LHV) during each 30-minute test period. The electrical power output in kW was measured with a 7600 ION Power Meter (Power Measurements Ltd.). 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 electrical power output measured over the 30-minute interval (kW)
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)

Simultaneous with electrical power measurements, heat recovery rate was measured using an in-line heat meter (Controlotron Model 1010EP). The meter enabled 1-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 (ANSI 1992).

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

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+T1)/2
C_p = specific heat of PG solution (Btu/lb ^oF), evaluated at the avg. temp. (T2+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 IR PowerWorks System. Thermal energy conversion efficiency was computed as the average heat recovered divided by the average energy input (Equation 3).

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

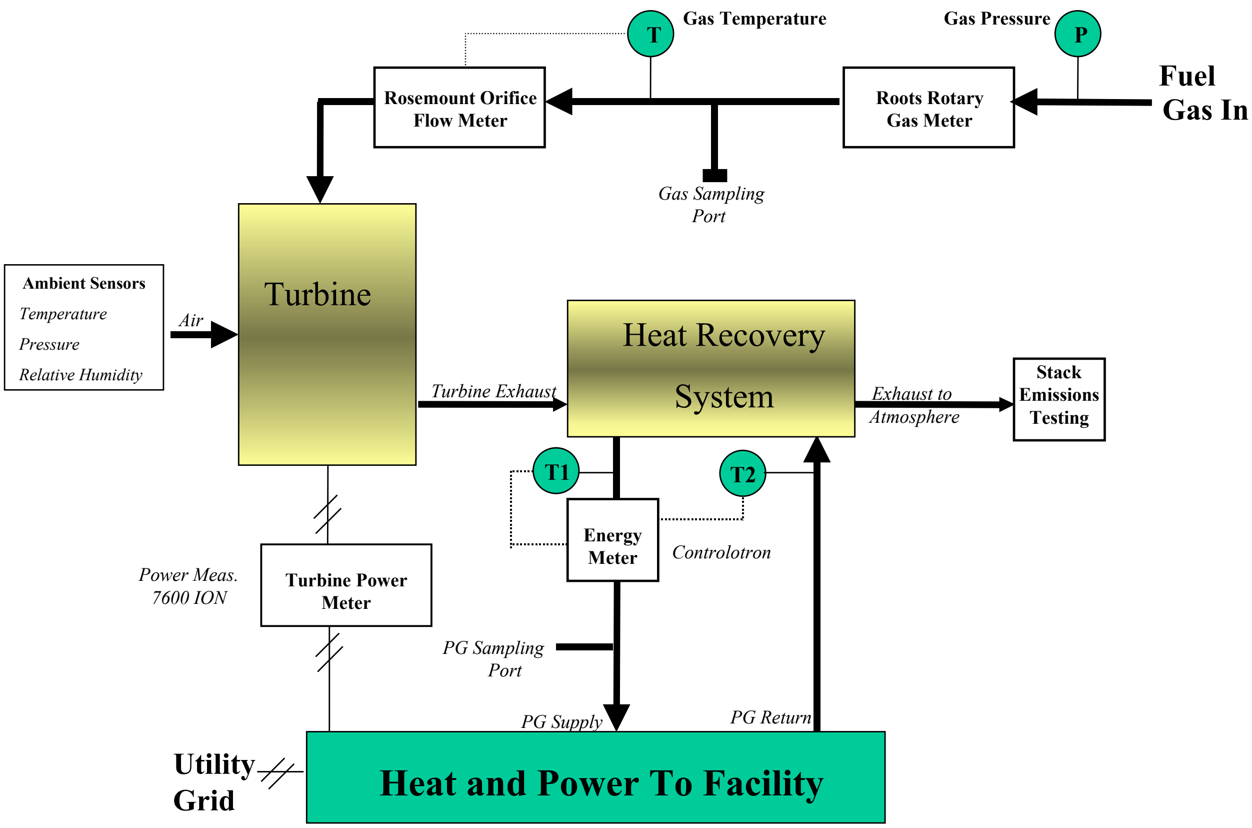
where:

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.

Figure 1-4. Schematic of Measurement System



The 7600 ION electrical power meter continuously monitored the kilowatts of power at a rate of approximately one reading every 8 to 12 milliseconds. These data were averaged every minute using the GHG Center's data acquisition system (DAS). The 7600 ION was factory calibrated by Power Measurements, complies with ISO 9002 requirements (ISO 9002: 1999), and is traceable to National Institute of Standards and Technology (NIST) standards. The electric meter was located in the main switchbox connecting the IR PowerWorks to the host site and represented power delivered to Crouse Community Center. The real-time data collected by the 7600 ION were downloaded and stored on a data acquisition computer using Power Measurements' PEGASYS software. The logged 1-minute average kW readings were averaged over the duration of each controlled test period to compute electrical efficiency. For the extended test period, kW readings were integrated 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 standard cubic feet per minute natural gas). The orifice meter was temperature- and pressure-compensated to provide mass flow output at standard conditions (60 ^{o}F, 14.696 pound per square inch absolute (psia)). The meter was configured to continuously monitor the average flow rate per minute. Prior to testing, the meter components (orifice plate and differential pressure sensors) were calibrated using NIST-traceable instruments. QA/QC checks for this meter were performed routinely in the field using an in-line positive displacement rotary type gas meter. As shown in

Figure 1-4, the two meters were installed in series to allow natural gas to flow through both meters while the turbine was operating. The rotary gas meter, manufactured by Dresser/DMD Roots (Series B3, Model 11C175), was capable of metering flow rates up to 20 acfm. This meter, owned by the local gas utility (New York State Electric and Gas (NYSEG)), was calibrated prior to testing using a NIST-traceable volume prover (primary standard) at the range of flows expected during the verification test.

Natural gas samples were collected and analyzed to determine gas composition and heating value. A total of four samples were collected, three during the control test periods and another after four days of monitoring. Collection of daily samples were planned, but several samples were invalidated after analysis due to obvious air contamination (sample collection error). This error is not expected to affect results due to the consistency in gas composition observed in the four valid samples and the four additional gas analyses obtained from NYSEG (see Section 3.2.2 for more detail on gas composition). The collected samples were submitted to a qualified laboratory (Core Laboratories, Inc. of Houston, Texas) for compositional analysis in accordance with ASTM Specification D1945 for quantification of methane (C1) to hexanes plus (C6+), nitrogen, oxygen, and carbon dioxide (ASTM 2001a). The compositional data were then used in conjunction with ASTM Specification D3588 to calculate LHV, and the relative density of the gas (ASTM 2001b). 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 heat recovery rates. 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 system has an overall rated accuracy of ±1 to ±2 percent of reading depending on the application characteristics described below. The system can be used on pipe sizes ranging from 0.25 to 360 inches in diameter with fluid flow rates ranging from 0 to 60 feet per second (fps) (bi-directional).

The energy meter's software contains lookup tables that provide the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) working fluid density and specific heat values corrected to the average fluid temperature measured by the RTDs. In order for these values to be correct, the fluid composition must be known or determined, and programmed into the computer. Fluid composition testing was conducted before and during testing as described below to ensure proper system programming.

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. Samples were collected once per day during the testing period. Each sample collection event was recorded on field logs and shipped to Enthalpy Analytical Laboratories in Durham, NC along with completed chain-of-custody forms. At the laboratory, samples were analyzed for PG concentration and fluid density using gas chromatography with a flame ionization detector (GC/FID). Using the measured concentrations, specific heat of the PG solution was selected using published PG properties data (ASHRAE 1997).

1.4.3. Power Quality Performance

When an electrical generator is connected in parallel and operated simultaneously with the utility grid, there are a number of issues of concern. The voltage and frequency generated by the power system must be aligned with the power grid. While in grid parallel mode, the units must detect grid voltage and frequency to ensure proper synchronization before actual grid connection occurs. The PowerWorks 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. For previous verifications, the GHG Center has defined grid voltage tolerance as the nominal voltage ±10 percent. Frequency tolerance is 60±0.6 Hz (1.0 percent).

The generator's effects on electrical frequency, power factor, and total harmonic distortion (THD) cannot be completely isolated from the grid. The quality of power delivered actually represents an aggregate of disturbances already present in the utility grid. For example, 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 IR PowerWorks incorporates an induction generator, and therefore always requires reactive power from the grid and operates at less than unity power factor. The generator's power factor effects will also change with distance from the CHP generator as the aggregate grid power factor begins to predominate.

The GHG Center and its stakeholders developed the following power quality evaluation approach to account for these issues. Two documents (IEEE 519, ANSI/IEEE 1989) 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 6-day extended period:

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

The ION power meter (7600 ION) used for power output determinations was used to perform these measurements as described below and detailed in the Test Plan. Prior to field installation, the factory calibrated the ION power meter to ANSI C12.20 CAO.2 standards (ANSI/IEEE 1989). 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 frequency, maximum, minimum, and standard deviation are reported.

The CHP unit generates power at 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. 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 voltage, maximum, minimum, and standard deviation for the average of the three phases are reported.

THD results from 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. For electrical power in the US, the fundamental is 60 Hz. 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 (i.e., capacitors, motor control thyristors, inverters) connected to the distribution network.

For each harmonic, the magnitude of the distortion can vary. Typically, each harmonic's magnitude is represented as a percentage of the rms voltage of the fundamental. The aggregate effect of all harmonics is called THD. THD amounts to 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. Based on "recommended practices for individual customers" in the IEEE 519 Standard (IEEE 519), the specified value for total voltage harmonic is a maximum THD of 5.0 percent.

The ION meter continuously measured voltage THD up to the 63^{rd} 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 (IEEE 1992) 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. For example, the standard's recommendations for a small CHP unit connected to a large capacity grid 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. As with voltage THD, the ION power meter continuously measured current THD for each phase and reported the average.

Power factor is the phase relationship of current and voltage in AC electrical distribution systems. Under ideal conditions, current and voltage are in phase, which results in a unity (100 percent) power factor. If reactive loads are present, power factors are less than this optimum value. Although it is desirable to maintain unity power factor, the actual power factor of the electricity supplied by the utility may be much lower because of load demands of different end users. Typical values ranging between 60 and 90 percent are common. Low power factor causes heavier current to flow in power distribution lines for a given number of real kilowatts delivered to an electrical load.

The ION power meter 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 averaged over all three phases.

1.4.4. Emissions Performance

Pollutant concentration and emission rate measurements for NOX, CO, THCs, and CO_2 were conducted on the turbine exhaust stack during the full load controlled test periods. Emissions testing coincided with the efficiency determinations described earlier. All of the test procedures used are U.S. EPA Federal Reference Methods, which are well documented in the Code of Federal Regulations. The Reference Methods include procedures for selecting measurement system performance specifications and test procedures, quality control procedures, and emission calculations (40CFR60, Appendix A). Table 1-3 summarizes the standard test methods that were followed. A complete discussion of the data quality requirements (e.g., NOX analyzer interference test, nitrogen dioxide (NO_2) converter efficiency test, sampling system bias and drift tests) is presented in the Test Plan.

Table 1-3. Summary of Emissions Testing Methods

Exhaust Stack			
Pollutant	**EPA Reference Method**	**Analyzer Type**	**Instrument Range**
NOX	20	TEI Model 10 (chemiluminescense)	0 - 25 ppm
CO	10	TEI Model 481 (NDIR)	0 - 25 ppm
THC	25A	TEI Model 51 (FID)	0 - 25 ppm
CH_4	18	Hewlett-Packard 5890 GC/FID	0 - 25 ppm
CO_2	3A	Infrared Industries Model 703D (NDIR)	0 - 10%
O_2	3A	Infrared Industries Model 2200 (electrochemical)	0 - 25%

During each test, sampling was conducted for approximately 30 minutes at a single point near the center of the 12-inch diameter stack. Results of the instrumental testing are reported in units of parts per million by volume dry (ppmvd) and ppmvd corrected to 15 percent O_2. The emissions testing was conducted by ENSR International of East Syracuse, New York, under the on-site supervision of the GHG Center Field Team Leader. A detailed description of the sampling system used for criteria pollutants, GHGs, and O_2 is provided in the Test Plan and is not repeated in this report. A brief description of key features is provided below.

In order for the CO_2, O_2, NOX, and CO instruments to operate properly and reliably, the flue gas must be conditioned prior to introduction into the analyzers. The gas conditioning system used for this test was designed to remove water vapor and/or particulate from the sample. Gas was extracted from the turbine exhaust gas stream through a stainless steel probe and heated sample line and transported to ice-bath condensers, one on each side of a sample pump. The condensers removed moisture from the gas stream. The clean, dry sample was then transported to a flow distribution manifold where sample flow to each analyzer was controlled. Calibration gases were routed through this manifold to the sample probe to perform bias and linearity checks.

NOX concentrations were determined using a Thermo Environmental Instruments (TEI) Model 10. This analyzer catalytically reduces NO_2 in the sample gas to nitric oxide (NO). The gas is then catalytically converted to excited NO_2 molecules by oxidation with ozone (O_3) (normally generated by ultraviolet light). The resulting NO_2 emits light (luminesces) in the infrared region. The emitted light is measured by an infrared detector and reported as NOX. The intensity of the emitted energy from the excited NO_2 is proportional to the concentration of NO_2 in the sample. The efficiency of the NO to NO_2 catalytic converter is checked as an element of instrument setup and checkout. The NOX analyzer was calibrated to a range of 0 to 25 ppmvd.

A TEI Model 48 gas filter correlation analyzer with an optical filter arrangement was used to determine CO concentrations. This method provides high specificity for CO. Gas filter correlation uses a constantly rotating filter with two separate 180-degree sections (much like a pinwheel.) One section of the filter contains a known concentration of CO, and the other section contains an inert gas without CO. The sample gas is passed through the sample chamber containing a light beam in the spectral region absorbed by CO. The sample is then measured for CO absorption with and without the CO filter in the light path. These two values are correlated, based upon the known concentrations of CO in the filter, to determine the concentration of CO in the sample gas. The CO analyzer was operated on a range of 0 to 25 ppmvd.

THC concentrations in the exhaust gas were measured using a TEI Model 51 flame ionization analyzer and quantified as methane. This detector analyzes gases on a wet, unconditioned basis. Therefore, a second heated sample line was used to deliver unconditioned exhaust gases directly to the THC analyzer. All combustible hydrocarbons were analyzed. Emission rates are reported on an equivalent methane basis.

For determination of CO_2 concentrations, an Infrared Industries Model 703D analyzer equipped with a non-dispersive infrared (NDIR) detector was used. NDIR measures the amount of infrared light that passes through the sample gas versus through a reference cell. Because CO_2 absorbs light in the infrared region, the degree of light attenuation is proportional to the CO_2 concentration in the sample. The CO_2 analyzer range was set at 0 to 10 percent. A Infrared Industries Model 2200 electrochemical cell analyzer was used to monitor O_2 concentrations. The O_2 analyzer range was set at 0 to 25 percent.

The instrumental testing for CO_2, O_2, NOX, CO, and THC yielded concentrations in units of ppmvd and ppmvd corrected to 15 percent O_2. 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. For this verification, the published F-factor of 8,710 dry standard cubic feet per million Btu (dscf/MMBtu) was used to determine emission rates for each controlled test period. After converting the pollutant concentrations from a ppmvd basis to lb/dscf, emission rates were calculated using the measured heat input to the turbine [MMBtu/hr based on the higher heating value (HHV) of the gas] and stack gas O_2 concentration (dry basis), in terms of lb/hr using Equation 4.

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

where:

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

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 Crouse Community Center

Without on-site generation of electricity and heat with the IR PowerWorks, all of the Crouse Community Center's electrical power and heat demand is met by the local utility, NYSEG, and two on-site gas-fired boilers, respectively. Electricity generation from central power stations and heat production from gas boilers is defined as the baseline power and heat scenario for this facility, and emissions of NOX and CO_2 generated by these systems represent the baseline emissions in the absence of the IR PowerWorks CHP system. With the IR PowerWorks system operating, some of the power and heat demand of the facility is met through on-site generation. Under this scenario, less power is purchased from the utility grid, and less heat is generated by the gas-fired boilers. If emissions of CO_2 and NOX with the IR PowerWorks scenario are lower than the emissions associated with the baseline scenario, then a reduction in emissions would be realized under the CHP system scenario.

For this verification, emissions from the IR PowerWorks scenario are compared with the baseline scenario to estimate annual NOX and CO_2 emission levels and reductions (lb/yr). These pollutants were considered because CO_2 is the primary greenhouse gas emitted from combustion processes, and NOX is a primary pollutant of regulatory interest. Reliable emission factors for electric utility grid and boilers are available for both gases. Emission reductions were computed as follows:

Annual Emission Reductions (lb/yr) = [Baseline Scenario Emissions] – [IR PowerWorks 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 Crouse Community Center Annual Electrical and Thermal Energy Profiles</u>

The first step in estimating emission reductions was to determine the facility's annual electrical (kWh_e) and thermal energy demand (kWh_{th}). This was done by obtaining the monthly electricity and natural gas utility bills from the facility operator and reviewing the information to estimate the energy demand for each month of 2002. The IR PowerWorks was operating during this fiscal year; therefore, the electrical demand was simply the sum of electricity purchased from the utility (obtained from the utility bills) and the electricity supplied by the IR PowerWorks CHP (obtained from site's data records). Table 1-4 summarizes the site's electrical energy demand.

The site operators also provided utility bills which contained monthly natural gas consumption records for both the on-site boilers and the IR PowerWorks CHP. Since these records indicate fuel input levels, thermal energy delivered was estimated by multiplying heat input levels by the efficiency of each system. For the gas fired boilers, manufacturer's efficiency rating of 69.5% was used, which accounts for radiation losses and normal piping and pickup losses. For the IR PowerWorks CHP, the efficiency rating as measured during full load testing by the GHG Center was used. The sum of energy delivered by the boilers and the IR PowerWorks CHP represented the monthly thermal energy demand of the site. Table 1-4 summarizes the site's thermal energy demand.

Table 1-4 also shows the distribution of energy demand as supplied by the systems in the baseline and IR PowerWorks scenarios. Note, based on the site operator's observations, the operational availability of the IR PowerWorks is assigned to be 98%. Also, the electrical and thermal energy supplied by the IR PowerWorks are derated using average monthly air temperatures for the site. This was accomplished by using the trends observed during the verification test. Specifically, as discussed later in Section 2, the heat and power production performance of the IR PowerWorks was monitored when ambient temperatures ranged between 47 and 93 ^oF. Using this verification data, electrical and thermal energy efficiency curves were developed as a function of ambient temperatures, and the efficiency levels at the average monthly temperatures in 2002 were used to estimate electrical energy and thermal energy generation potential with the IR PowerWorks system (Table 1-4). The average monthly temperatures for 8 months were characterized using the efficiency observed during the verification period. For the remaining months (the four coldest), the de-rate curves were extrapolated to the lowest average monthly temperature of 18 ^oF.

Table 1-4 Electrical and Thermal Energy Profiles of the Crouse Community Center

	Estimated Energy Demand of the Facility		Baseline Scenario: Energy Supplied By Utility Grid	Baseline Scenario: Energy Supplied By Gas Boilers	IR PowerWorks Scenario: Energy Suplied By IR		IR PowerWorks Scenario: Makeup Energy Supplied By Grid and Gas Boilers	
	Electric kWh_e	Thermal kWh_{th}	Electric $kWh_{e,Grid}$	Thermal $kWh_{e,Boiler}$	Electric $kWh_{e,IR}$	Thermal $kWh_{th,IR}$	Electric $kWh_{e,Grid}$	Thermal $kWh_{th,Boiler}$
Jan	114,710	177,662	114,710	177,662	46,204	23,919	68,506	153,743
Feb	90,833	183,189	90,833	183,189	41,774	21,836	49,059	161,353
Mar	94,007	165,096	94,007	165,096	44,263	25,333	49,744	139,763
Apr	86,251	130,643	86,251	130,643	38,216	26,132	48,035	104,511
May	86,066	116,370	86,066	116,370	35,884	28,545	50,182	87,825
June	99,260	86,351	99,260	86,351	33,304	28,743	65,956	57,608
July	112,824	74,310	112,824	74,310	32,157	30,215	80,667	44,095
Aug	112,770	84,705	112,770	84,705	33,191	29,958	79,579	54,747
Sept	95,335	93,924	95,335	93,924	34,530	27,997	60,805	65,927
Oct	86,451	131,030	86,451	131,030	38,177	27,517	48,274	103,513
Nov	88,677	146,155	88,677	146,155	40,466	25,386	48,211	120,769
Dec	104,540	191,566	104,540	191,566	44,820	24,819	59,720	166,747
Annual Total	1,171,724	1,581,001	1,171,724	1,581,001	462,987	320,400	708,737	1,260,601

Step 2 – Emissions Estimate For the IR PowerWorks CHP

Using the energy production data for the IR PowerWorks, emissions associated with this DG-CHP system were estimated as follows:

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

where:

E_{IR} = IR PowerWorks emissions, lb/yr
$kWh_{e,IR}$ = Electrical energy generated by IR PowerWorks, Table 1-4, $kWh_{e,IR}$
ER_{IR} = IR PowerWorks emission rate, lb/kWh_e

The CO_2 and NOX 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 Gas Boiler(s)

The host facility's baseline heating units, (two identical natural gas-fired Weil-McLain boilers), have a manufacturer's specified gross combustion efficiency of 81.4 percent. The units are designed to provide 1.181 MMBtu/hr of hot water from 1.703 MMBtu/hr natural gas fuel input. After accounting for boiler insulation, heat transfer, and other losses, the rated net boiler efficiency reported by the manufacturer for hot water production is 69.5 percent. This means that, for every Btu of heat required, 1/0.695, or 1.439 Btu, of fuel would have been supplied to the boilers. The carbon in the natural gas, when combusted, will form CO_2. The resulting CO_2 emission rate can be calculated as follows:

$$ER_{BoilerCO2} = \frac{44}{12} * (CC) * (FO) * \frac{3412.1}{1{,}000{,}000} * \frac{1}{(Eff_{Boiler} / 100)} \quad \text{(Eqn. 6)}$$

where:

$ER_{BoilerCO2}$ = boiler 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/MMBtu
FO = 0.995; fraction of natural gas carbon content oxidized during combustion
3412.1 = 1 kW$_{th}$/Btu
1,000,000 = 1 MMBtu/Btu
Eff_{Boiler} = Combustion efficiency of gas boiler, 69.5%

Using the carbon content of natural gas sampled at the test site by the GHG Center, the CO_2 emission rate for the boiler is 0.627 lb/kWh$_{th}$. Note, this emission rate assumes that the boiler efficiency is the same at all heat output levels (i.e., the unit is 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.

For NOX, emission factor for commercial boilers was obtained from AP-42 (EPA 1995). For boiler sizes ranging between 0.3 and 10 MMBtu/hr of heat input, 100 lb NOX/10^6 scf of natural gas is emitted. Using the measured LHV of the natural gas used at the facility, the NOX emission rate for the boilers is 0.000538 lb/kWh$_{th}$.

The CO_2 and NOX emission rates, combined with the energy supplied by the boilers, yields the following equation for estimating boiler emissions:

$$E_{Boiler} = kWh_{th,Boiler} * ER_{Boiler} \quad \text{(Eqn. 7)}$$

where:

E_{Boiler} = boiler emissions, lb/yr
$kWh_{th,Boiler}$ = thermal energy supplied by the boilers, kWh$_{th}$
ER_{Boiler} = boiler emission rate, lb/kWh$_{th}$

Step 4 - Emissions Estimate For the Utility Grid

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

$$E_{Grid} = kWh_{e,Grid} * 1.078 * ER_{Grid} \quad \text{(Eqn. 8)}$$

where:

E_{Grid} = grid emissions (lb/yr)
$kWh_{e,Grid}$ = electricity supplied by the grid, Table 1-4 (kWh$_e$)
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 (EIA 2000b) the utility grid under the baseline scenario and the IR PowerWorks scenario (Table 1-4). 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 methodology for estimating this parameter is continuously evolving. The following discussion 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.

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 heat and power generation with a distributed energy technology (e.g., IR PowerWorks) 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 methodologies have been developed and employed by various organizations to estimate emissions displaced by on-site electricity generation. Although there are many variations of such methodologies, 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, and 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. As a result, 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, NOX, SO_2, and mercury (Hg) from electric generation. The results of the ADER analysis are not currently 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. It 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 (OTC 2002). The geographic focus of the Workbook is the three northeastern electricity control areas: Pennsylvania/New Jersey/Maryland (PJM), the New York Independent System Operation (NY ISO), and Independent System Operation 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). To evaluate these programs, the Workbook contains default displaced emission rates for the three northeastern control areas. The default displaced emission rates are divided into three time periods: near term (2002-2005), medium term (2006-2010), and long term (2011-2020). For this verification, 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.

The near-term rates for the NY ISO are summarized in Table 1-5. 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 1-5. 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. Because the simulation is done in chronological order, actual constraints on system operation (such as unit ramp times and minimum up and down times) are taken into account. 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 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. To calculate marginal emission rates for different periods, OTC calculated the total difference in kWhs generated between the base case and decrement case and the total difference in emissions and then divided the emissions by kWhs to derive the marginal emission rate for the time period. It should be noted that marginal rates shown in Table 1-5 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 Provences, Ontario, and Quebec.

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2.0 VERIFICATION RESULTS

The verification period started on August 14, 2002, and continued through August 21, 2002. The controlled tests at full load were conducted on August 14 and repeated on August 15 with the boiler shut down to enhance heat recovery. This was followed by an extended six-day period of continuous monitoring to examine heat and power output, power quality, efficiency, and emission reductions.

During the controlled and extended verification test periods, 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 (i.e., 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
- IR PowerWorks and facility operating data

The Field Team Leader reviewed, verified, and validated some data (e.g., DAS file data, reasonableness checks) while on site. In the field, the Team Leader reviewed collected data for reasonableness and completeness. The data from each of the controlled test periods was reviewed on-site to verify that PTC 22 (ASME 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 glycol solution analysis results, were reviewed, verified, and validated after testing had ended. Upon review, all collected data was classed as valid, suspect, or invalid 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. In general, all 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. Although 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, the reader is cautioned 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).

With the verification testing occurring in August and the IR PowerWorks System and its intake air located outdoors, the high summer air temperatures encountered must be considered when evaluating the results. During the test period, temperatures generally ranged from 65 ^{o}F at night to highs approaching 95 ^{o}F in afternoons (the lowest temperature recorded was 47 ^{o}F on the last night of the test period). Therefore, the test results do not provide information related to the system's response to lower ambient temperatures that are encountered in this and other regions.

Test results are presented in the following subsections:

Section 2.1 – Heat and Power Production Performance
(short-term controlled testing and six days of extended testing)
Section 2.2 - Power Quality Performance
(six days of extended testing)
Section 2.3 - Emissions Performance and Reductions
(controlled test periods)

The results show that the quality of power generated by the IR PowerWorks System is generally high, and that the unit is capable of operating in parallel with the utility grid. The unit produced between 50 and 69 kW of electrical power depending on ambient temperature (47 to 95 ^{o}F). The highest heat recovery rate measured was approximately 173,600 Btu/hr under normal site operation (approximately 178,000 Btu/hr with the boiler turned off). During normal operations, electrical efficiency averaged 25.3 percent and thermal efficiency averaged 21.0 percent (24.9 percent with the boilers turned off). Total IR PowerWorks System efficiency at full load was 46.3 percent (50.6 percent with the boilers turned off). NOX and CO emissions at full load were 1 ppmvd or less (corrected to 15 percent O_2). NOX and CO_2 emission reductions are estimated to be at least 99 and 61 percent, respectively.

An 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. POWER AND HEAT 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 IR PowerWorks System. All controlled testing occurred during relatively consistent atmospheric conditions: 81 ^{o}F average ambient temperature, 56 percent average RH, and 14.0 psia average barometric pressure. Actual conditions encountered during testing were warmer than standard conditions defined by the International Standards Organization (59 ^{o}F, 60 percent RH, and 14.696 psia), and as a result, some deration of the electrical power and efficiency should be expected in the verification results. The reader is cautioned that 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 (e.g., cooler temperatures, different elevations). Natural gas fuel input characteristics and heat recovery unit operation data corresponding to these efficiency results are summarized in Table 2-2.

Table 2-1. Heat and Power Production Performance

	Test Condition		Heat Input	Electrical Power Generation Performance		Heat Recovery Performance		Total IR Power-Works System Efficiency	Ambient Conditions [b]	
				Power Delivered [a]	Electrical Efficiency	Heat Recovery Rate [c]	Thermal Efficiency			
	% of Rated Power	Site Operations	(M Btu/hr)	(kW_e)	(%)	(M Btu/hr)	(%)	(%)	Temp (°F)	RH (%)
Run 1	100	Normal	691.5	51.69	25.5	142.9	20.7	46.2	76.1	69
Run 2			677.3	49.80	25.1	142.1	21.0	46.1	80.9	58
Run 3			683.4	50.37	25.2	145.6	21.3	46.5	86.0	45
Avg.			**684.1**	**50.62**	**25.3**	**143.5**	**21.0**	**46.3**	**81.0**	**57**
Run 4	100	Boiler off	691.6	51.95	25.6	171.0	24.7	50.4	80.4	55
Run 5			690.0	51.76	25.6	173.0	25.1	50.7	84.5	46
Run 6			705.2	53.31	25.8	175.7	24.9	50.7	79.1	63
Avg.			**695.6**	**52.34**	**25.7**	**173.2**	**24.9**	**50.6**	**81.3**	**55**

[a] Represents actual power available for consumption at the test site.
[b] To convert to equivalent kilowatts (kW_{th}), divide by 3412.14.
[c] Barometric pressure remained relatively consistent throughout the test runs (14.01 to 14.07 psia).

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

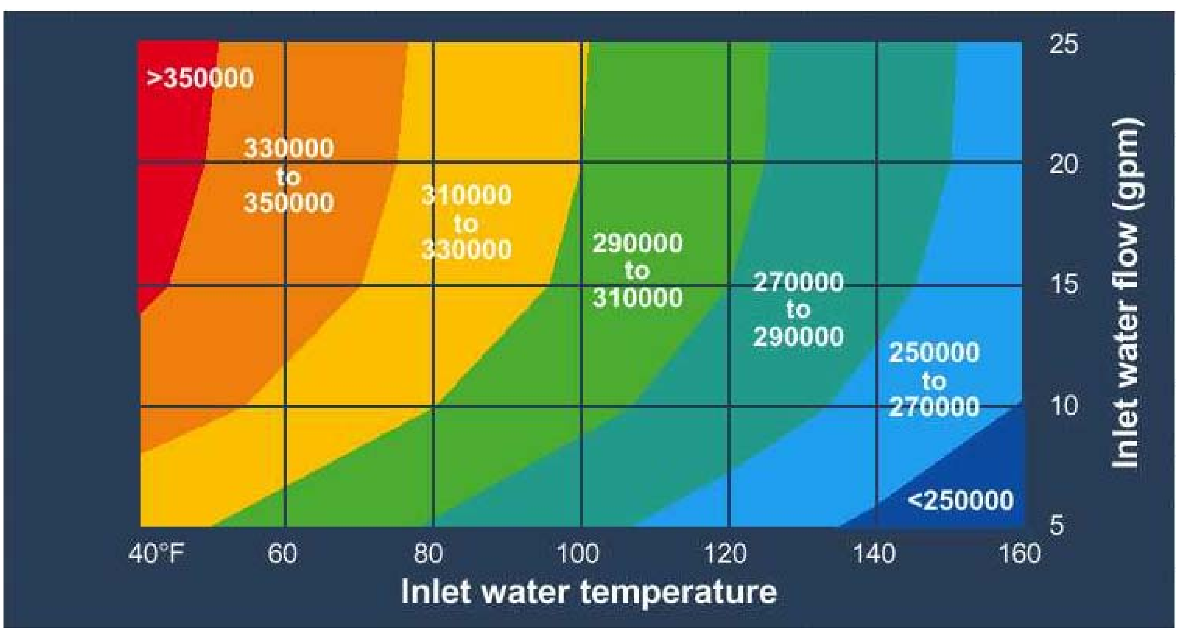
	Test Condition		Natural Gas Fuel Input				PG Fluid Conditions				
			Gas Flow Rate	LHV [a]	Gas Pressure	Gas Temp	PG Comp.[b]	Fluid Flow Rate	Outlet Temp.	Inlet Temp.	Temp. Diff.
	% of Rated Power	Site Operations	(scfm)	(Btu/ft^3)	(psig)	(°F)	(% volume)	(gpm)	(°F)	(°F)	(°F)
Run 1	100	Normal	12.6	913.4	1.89	76.8	15.4	16.2	188.5	170.4	18.1
Run 2			12.4	--	1.89	80.6	--	16.2	189.0	171.0	18.0
Run 3			12.5	911.7	1.89	84.5	--	16.2	189.6	171.1	18.5
Avg.			**12.5**	**912.6**	**1.89**	**80.6**	**15.4**	**16.2**	**189.0**	**170.8**	**18.2**
Run 4	100	Boiler off	12.7	--	1.89	79.9	15.3	16.0	157.9	136.0	21.9
Run 5			12.7	906.9	1.89	82.7	--	16.0	156.8	134.6	22.2
Run 6			13.0	--	1.89	83.8	--	16.0	159.5	137.0	22.5
Avg.			**12.8**	**906.9**	**1.89**	**82.1**	**15.3**	**16.0**	**158.1**	**135.9**	**22.2**

[a] Represents results of actual gas samples collected during each day (average of two samples for runs 1 - 3, one sample for runs 4 - 6)
[b] Represents results of actual PG samples collected during each day

During normal site operations, the average electrical power delivered was 50.62 kW_e at full load, and the average electrical efficiency corresponding to these measurements was 25.3 percent. Electric power generation heat rate, which is an industry accepted term to characterize the ratio of heat input to electrical power output, was measured to be 13,487 Btu/kWh_e at full power. Net heat rate, which includes energy from heat recovery, was 7,370 Btu/kWh_{tot} at full power. The average heat recovery rate during normal site operations was 144.5 MBtu/hr, or 42.35 kW_{th}/hr, and thermal efficiency was 21.0 percent. Based on results of three runs, the total efficiency (electrical and thermal combined) was 46.3 percent.

As briefly discussed in Section 1.4, the return PG temperature averaged 170.8 ^oF during normal operations at this facility, which is higher than design specifications for the IR PowerWorks (the unit is designed for return temperatures in the range of 40 to 160 ^oF). To evaluate if the elevated return temperatures at this site impacted heat recovery performance, the second series of controlled tests were conducted at full load with the boilers turned off to reduce return temperature (enhanced heat recovery tests). During these tests, average electrical power output and efficiency were 52.34 kW_e and 25.7 percent. The average heat recovery rate increased to 173.2 MBtu/hr, or 50.78 kW_{th}/hr, and thermal efficiency was 24.9 percent. Based on results of three runs, the total system efficiency was 50.6 percent with the reduced PG loop temperature. Table 2-2 shows that this increase was due to a greater difference between supply and return temperature, indicating that the IR System transferred more heat to the PG loop once the inlet temperature was reduced. After the PG return temperature dropped from 170.8 to 135.9 ^oF, the temperature differential increased from 18.2 to 22.2 ^oF. This trend is consistent with data published by IR that show anticipated heat recovery rates as a function of inlet fluid temperature (Figure 2-1). Heat recovery potential of the IR PowerWorks may be greater for facilities with lower fluid loop temperatures, but the Crouse Community facility cannot operate for extended periods at these reduced loop temperatures and still meet the critical DHW requirements of the facility. It is expected that major heating loop design modifications would be necessary at this site in order to minimize the return loop temperature and realize the maximum heat recovery potential of the IR PowerWorks.

Figure 2-1. Anticipated IR PowerWorks Heat Recovery Rates as a Function of Inlet Water Temperature (Btu/hr) (figure provided by Ingersoll Rand)



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

Figure 2-2 presents a time series plot of power production and heat recovery during the six-day extended verification period. The system was operating 24 hours per day and was producing as much electrical power and heat as possible depending on ambient conditions. A total of 7,472 kWh_e electricity and 6,070 kWh_{th} of thermal energy were generated over an operating period of 132 hours. All of the electricity and heat generated were used by the facility. Electrical, thermal, and total system efficiencies during the extended period averaged 25.8, 21.0, and 46.8 respectively, percent and were consistent with the efficiencies measured during the controlled test period.

The average power generated over the extended period was 56.6 kW_e, and average heat recovery rate was 46.3 kW_{th}. Power production showed variation that coincides with diurnal temperature variations. The effect of ambient temperature on power output (and fuel consumption) is further illustrated in Figure 2-3. The figure clearly shows that power output increases as the ambient temperature (intake air) drops below 75 ^oF. This trend is consistent with industry knowledge of turbine performance (i.e., electrical power output generally decreases with increasing temperatures). Facility operators have reported power output as high as 80 kW from this unit during periods of very cold weather.

Figure 2-2. Power and Heat Production During the Verification Periods

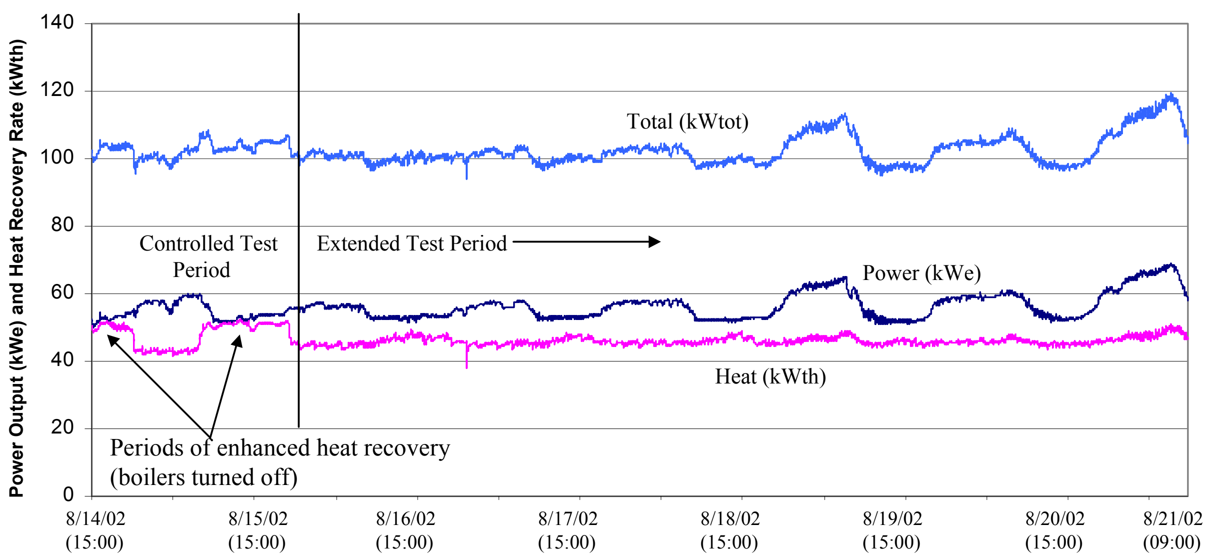


Figure 2-3. Ambient Temperature Effects on Power Production During Extended Test Period

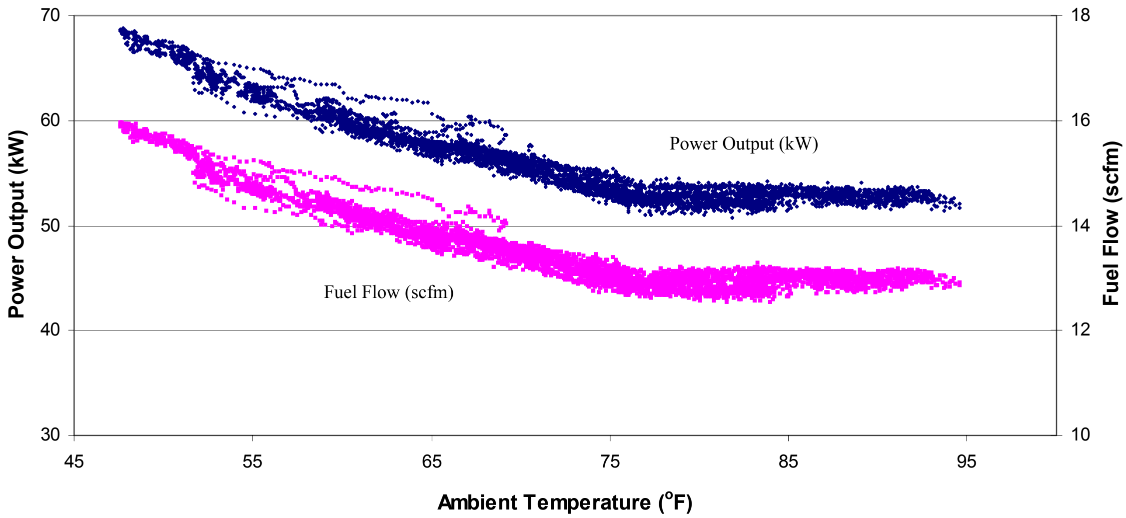
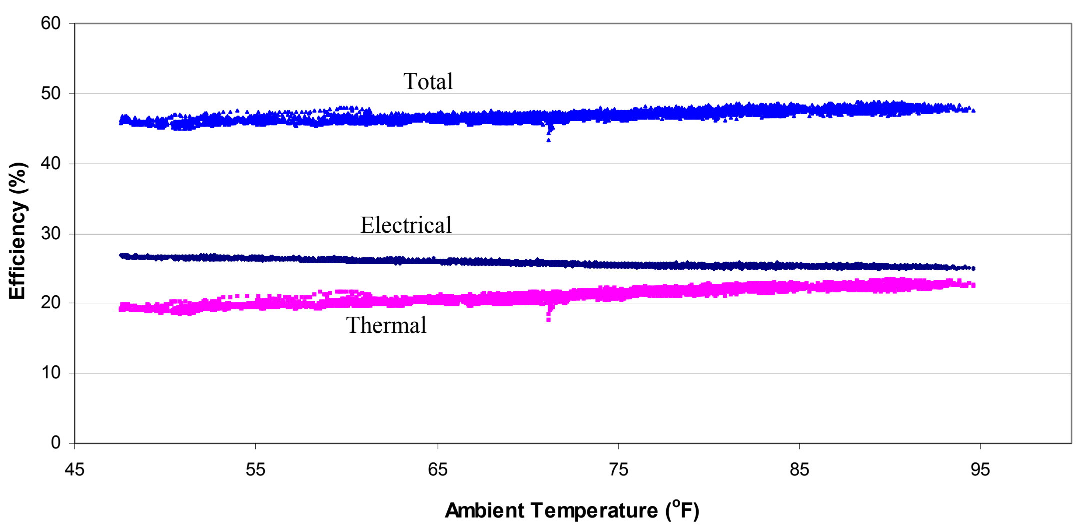


Figure 2-4 plots electrical, thermal, and total system efficiency over the extended monitoring period as a function of ambient temperature. Although electrical power production increased at lower temperatures, electrical efficiency did not change significantly because fuel input increased proportionately to power output, as shown in Figures 2-3 and 2-4. The change in electrical efficiency over the range of temperatures (47 to 95 °F) observed during the extended period was less than 1.5 percent, with the highest efficiencies occurring at the lowest ambient temperatures. Heat production did not change significantly during the period (Figure 2-2), but Figure 2-4 shows that heat recovery efficiency increased slightly during periods of higher ambient temperature.

Figure 2-4. Ambient Temperature Effects on System Efficiency During Extended Test Period



2.2. POWER QUALITY PERFORMANCE

2.2.1. Electrical Frequency

Electrical frequency measurements (voltage and current) were monitored simultaneously for the IR PowerWorks System. The 1-minute average data collected by the electrical meter were analyzed to determine maximum frequency, minimum frequency, average frequency, and standard deviation for the verification period. These results are illustrated in Figure 2-5 and summarized in Table 2-3. The average electrical frequency measured was 60.001 Hz, and the standard deviation was 0.014 Hz.

Figure 2-5. IR PowerWorks System Electrical Frequency During Extended Test Period

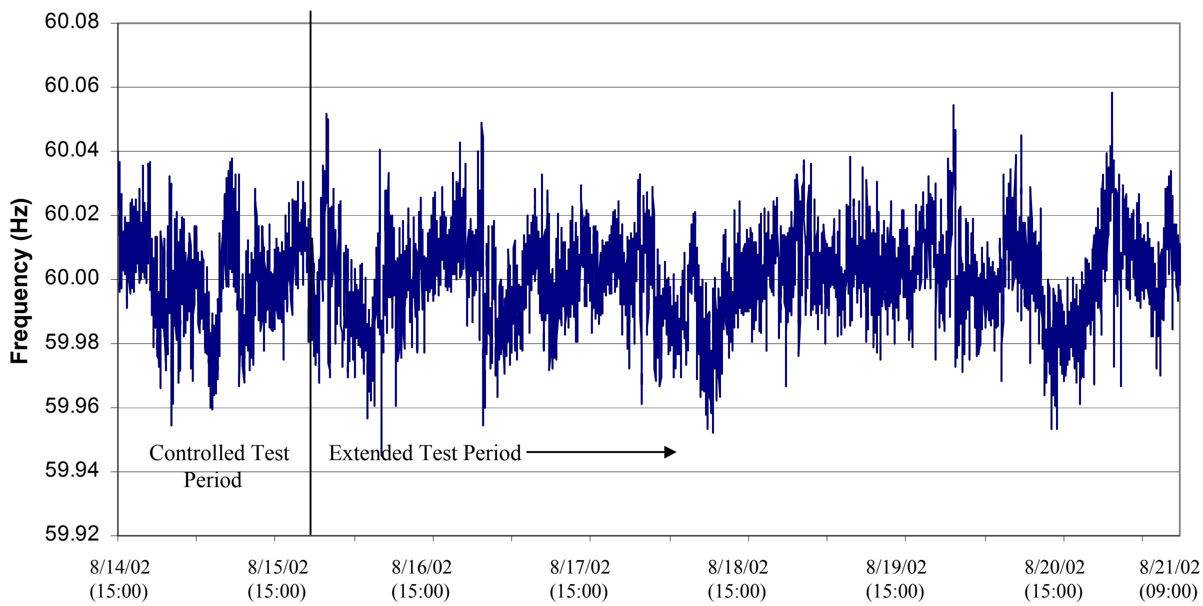


Table 2-3. IR PowerWorks Electrical Frequency During Extended Period	
Parameter	**Frequency (Hz)**
Average Frequency	60.001
Minimum Frequency	59.945
Maximum Frequency	60.058
Standard Deviation	0.014

2.2.2. Voltage Output

Traditionally, it is 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).

Voltage was monitored on the turbine using the 7600 ION electric meter. The meter was configured to measure 0 to 600 VAC. The turbine was grid connected and operated as a voltage-following current source. As a result, the voltage levels measured are more indicative of the grid voltage levels that the IR PowerWorks tried to mimic (typically around 490 volts at the specific location).

Figure 2-6 plots 1-minute average voltage readings, and Table 2-4 summarizes the statistical data for the voltages measured on the turbine throughout the verification period. The voltage levels were well within the normal accepted range of ±10 percent.

Figure 2-6. IR PowerWorks System Voltage Output During Extended Test Period

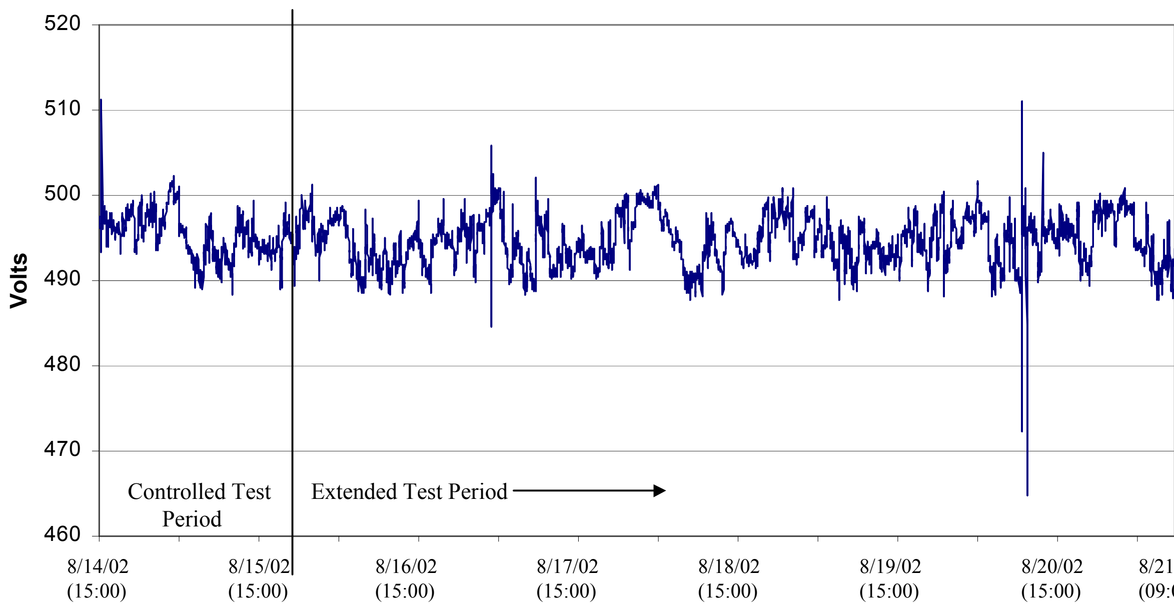


Table 2-4. IR PowerWorks Voltage During Extended Period

Parameter	Volts
Average Voltage	494.64
Minimum Voltage	464.82
Maximum Voltage	510.98
Standard Deviation	2.86

2.2.3. Power Factor

Having an induction generator, the IR PowerWorks power factors were expected to be in the range of 60 to 90 percent, as is common for this type of equipment. Figure 2-7 plots one-minute average power factor readings, and Table 2-5 summarizes the statistical data for power factors measured on the turbine throughout the verification period. It is clear that the variation in power factor follows the variations seen in the power output results shown earlier in Figure 2-2. During cooler periods, both power output and power factor increased, particularly during the diurnal cycles that peaked during the evenings of the 18th, 19th, and 20th.

Figure 2-7. IR PowerWorks System Power Factors During Extended Test Period

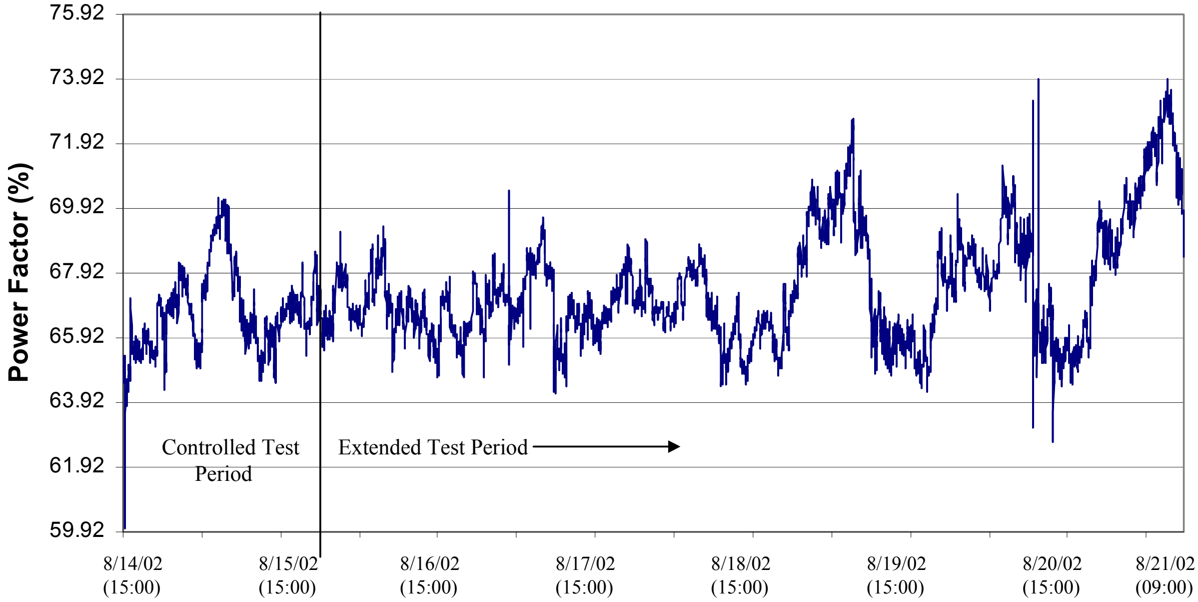


Table 2-5. IR PowerWorks Power Factors During Extended Period

Parameter	%
Average Power Factor	67.49
Minimum Power Factor	62.71
Maximum Power Factor	73.91
Standard Deviation	1.76

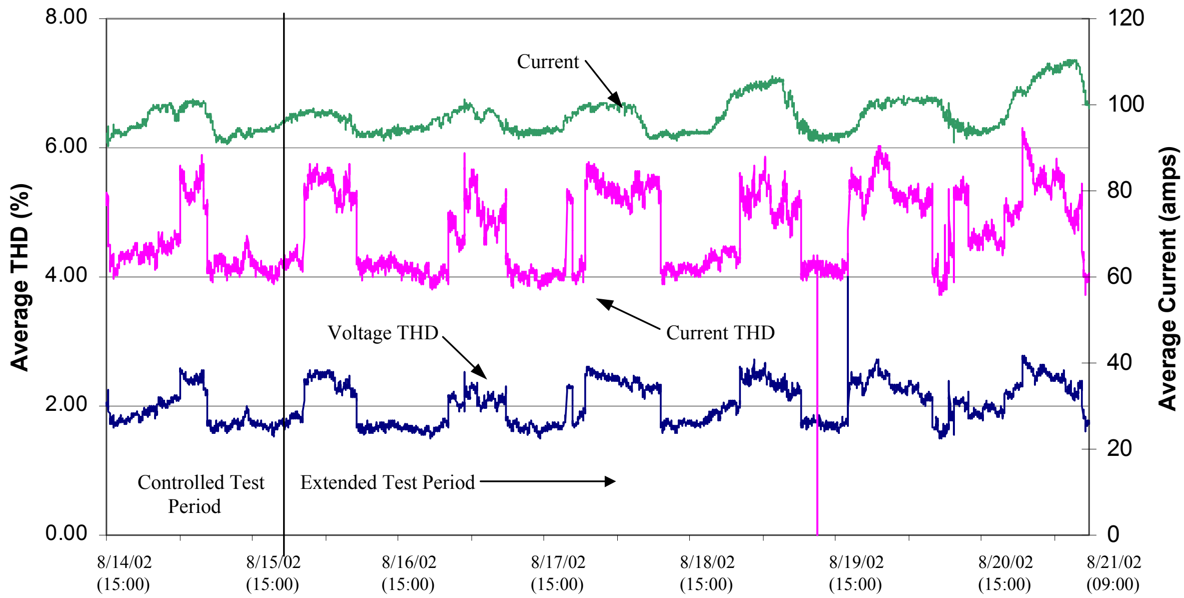
2.2.4. Current and Voltage Total Harmonic Distortion

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 THDs were measured to be 4.76 percent and 2.05 percent, respectively (Table 2-6). Figure 2-8 plots the current and voltage THDs throughout the six day extended verification period.

Table 2-6. IR PowerWorks THDs During Extended Period

Parameter	Current THD (%)	Voltage THD (%)
Average	4.76	2.05
Minimum	3.71	1.50
Maximum	6.30	4.36
Standard Deviation	0.61	0.33

Figure 2-8. IR PowerWorks System Current and Voltage THD During Extended Test Period



As shown in Figure 2-8, THDs for both current and voltage exhibited a diurnal trend in variation, with the higher values occurring during the cool evening hours. These trends are consistent with the same diurnal trends in power output and other monitored variables. The periods of higher current and power output had higher levels of THDs.

2.3. EMISSIONS PERFORMANCE

2.3.1. IR PowerWorks System Stack Exhaust Emissions

IR PowerWorks System emissions testing was conducted to determine emission rates for criteria pollutants (NOX, CO, and THC) and greenhouse gases (CO_2 and CH_4). Stack emission measurements coincided with electrical power output and efficiency measurements. At each operating condition, three replicate test runs were conducted, each approximately 30 minutes in duration. All testing was conducted in accordance with EPA Reference Methods listed in Table 1-3. The IR PowerWorks System was maintained in a stable mode of operation during each test run using PTC-22 variability criteria (Sections 2.1 and 3.2.2.1).

Emissions results are reported in units of parts per million corrected to 15 percent O_2 (ppmvd @ 15 percent O_2) for NOX, 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.

To ensure the collection of adequate and accurate emissions data, sampling system QA/QC checks were conducted in accordance with Test Plan specifications. These included analyzer linearity tests, sampling system bias and drift checks, interference tests, and use of audit gases. 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.

As described in the system efficiency performance discussion, the original set of IR PowerWorks System performance tests were conducted on August 14, 2002 and were then repeated on August 15 after shutting down the existing boiler. Table 2-7 summarizes the emission rates measured during each run and the overall average emissions for each set of tests. In general, emissions of NOX, CO, and THCs were very low during all test periods.

NOX emissions under normal system operations averaged less than 1 ppmvd corrected to 15 percent O_2 and remained around 1 ppmvd after shutting down the existing boiler. The overall average NOX emission rate, normalized to power output, was 0.000047 lb/kWh$_e$. The benefits of lower NOX emissions from the IR PowerWorks System are further enhanced when exhaust heat is recovered and used. Based on annual published data by EIA, the measured IR PowerWorks System emission rate is well below the average rate for coal and natural-gas-fired power plants in the U.S.-0.0074 and 0.0025 lb/kWh, respectively. The emission reductions are further increased when transmission and distribution system losses are accounted for providing electricity to the end user.

Emissions of CO were also very low during all six test runs, averaging 0.64 ppmvd @ 15 percent O_2, or 0.000021 lb/kWh$_e$. It should be noted that these levels of NOX and CO emissions are below what is typically considered to be the level of sensitivity of the sampling system (i.e., 2 percent of span, or about 1.28 ppmvd @ 15 percent O_2). However, the average sampling system errors for NOX and CO (determined using pre- and post-test calibrations) were 0.17 and 0.20 percent of span, respectively, during these tests. This indicates that the sampling system sensitivity was lower than measured concentrations, and therefore, the concentrations are reported as measured.

Emissions of THC were also very low during all test periods, averaging 1.46 ppm @ 15 percent O_2, or 0.00028 lb/kWh$_e$ during the six tests conducted. Methane samples collected during these tests were analyzed at the laboratory and results were below the detection limit (1 ppmvd) for all samples collected. Concentrations of CO_2 in the IR PowerWorks System exhaust gas averaged 1.21 percent during the three normal site operation tests and 1.32 percent during the enhanced heat recovery tests. These concentrations correspond to average CO_2 emission rates of 1.60 lb/kWh$_e$ and 1.78 lb/kWh$_e$, respectively. The IR PowerWorks System CO_2 emission rate 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). The U.S. average emission factors reported here account for an estimated line loss of 5.1 percent between power plant fence line to the end user.

Table 2-7. IR PowerWorks Emissions During Controlled Test Periods

	Site Operations	Electrical Power Delivered (kW_e)	Exhaust	CO Emissions			NO_x Emissions			THC Emissions			CH_4 Emissions			CO_2 Emissions		
			O_2 (%)	(ppm @ 15% O_2)	lb/hr	lb/kWh $_e$	(ppm @ 15% O_2)	lb/hr	lb/kWh $_e$	(ppm @ 15% O_2)	lb/hr	lb/kWh $_e$	(ppm @ 15% O_2)	lb/hr	lb/kWh $_e$	%	lb/hr	lb/kWh $_e$
Run 1		51.69	18.58	0.79	0.0014	2.62E-05	0.76	0.0021	4.14E-05	3.69	0.0036	6.99E-05	<1.00	< 0.0025	<4.82E-05	1.22	83.6	1.62
Run 2		49.8	18.59	0.64	0.0011	2.17E-05	0.79	0.0022	4.24E-05	2.60	0.0025	4.85E-05	<1.00	< 0.0025	<4.94E-05	1.19	80.6	1.56
Run 3	Normal	50.37	18.64	0.44	0.0007	1.48E-05	1.04	0.0029	5.62E-05	0.85	0.0008	1.60E-05	<1.00	< 0.0025	<5.03E-05	1.21	84.4	1.63
AVG		**50.62**	**18.60**	**0.62**	**0.0011**	**2.09E-05**	**0.86**	**0.0024**	**4.67E-05**	**2.38**	**0.0023**	**4.48E-05**	**<1.00**	**< 0.0025**	**<4.93E-05**	**1.21**	**82.9**	**1.60**
Run 4		51.95	18.61	0.70	0.0012	2.32E-05	1.03	0.0029	5.61E-05	0.38	0.0004	7.19E-06	<1.00	< 0.0025	<4.87E-05	1.31	91.3	1.76
Run 5		51.76	18.61	0.72	0.0012	2.39E-05	1.11	0.0031	6.03E-05	0.49	0.0005	9.25E-06	<1.00	< 0.0025	<4.88E-05	1.32	91.8	1.77
Run 6	Boilers Off	53.31	18.62	0.52	0.0009	1.71E-05	1.06	0.0031	5.88E-05	0.76	0.0008	1.47E-05	<1.00	< 0.0026	<4.86E-05	1.32	94.2	1.81
AVG		**52.34**	**18.61**	**0.65**	**0.0011**	**2.14E-05**	**1.07**	**0.0030**	**5.84E-05**	**0.54**	**0.0005**	**1.04E-05**	**1.00**	**< 0.0026**	**<4.87E-05**	**1.32**	**92.4**	**1.78**
Overall AVG		**51.48**	**18.61**	**0.64**	**0.0011**	**2.12E-05**	**0.97**	**0.0027**	**5.25E-05**	**1.46**	**0.0014**	**2.76E-05**	**<1.00**	**< 0.0025**	**<4.90E-05**	**1.26**	**87.7**	**1.69**

2.3.2. Estimation of Annual Emission Reductions for Crouse Community Center

The electricity and heat generated by the IR PowerWorks System will offset electricity supplied by the utility grid and heat supplied by standard gas-fired boilers. As discussed in Section 1.4.5, annual emission reductions are estimated for the Crouse Community Center with two key assumptions: first, that all energy (power and heat) produced by the IR PowerWorks System is consumed on site; and second, that the unit will have a 98 percent availability rate (the current availability rate quoted by site operators).

Table 2-8 summarizes estimated NOX and CO_2 emissions and emission reductions from on-site electricity production. As shown in the table, electricity production under the IR PowerWorks scenario results in annual NOX emission reductions of 1,160 lb. 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 IR PowerWorks. Conversely, the CO_2 emission rate for the NY ISO is lower or similar to the emission rate for the IR PowerWorks. As such, CO_2 emissions increase may result when the DG-CHP system is operated during ozone and non-ozone season weekdays. Annually, about 10,712 lb CO_2 may be reduced.

Table 2-9 summarizes estimated emissions and emission reductions for on-site heat production. IR PowerWorks emission rates are assigned as zero because the heat recovered is otherwise waste heat, and no emissions are associated with this process. As discussed in Section 1.4.5, boiler emission rates are 0.000538 lb/kWh_{th} for NOX and 0.627 lb/kWh_{th} for CO_2. Annually, NOX reductions of 172 lb and CO_2 reductions of 201,031 lb may be realized with the IR PowerWorks scenario.

Finally, Table 2-10 summarizes the annual emissions and emission reductions for both electrical and thermal energy production systems. It is estimated that 34% reductions in NOX emissions may occur with the DG-CHP system compared to the baseline scenario. The highest reduction is due to the displacement of emissions from the electric utility. For CO_2, an annual emission reduction of 7% may occur. Over 95 percent of these reductions (201,031 lb) 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

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

	NO_X	CO_2
Full Load	4.67E-05	1.60

Emission Reduction Estimates From Electricity Production

	Baseline Scenario		IR PowerWorks Scenario					
			Energy Supplied By IR		Makeup Energy			
	Electricity From Grid kWhe	Grid Emissions lb	Electricity From IR kWhe	IR Emissions lb	Electricity From Grid kWhe	Grid Emissions lb	Total Emissions lb	Emission Reductions lb
NO_X								
ozone season wkday	271,581	615	103,847	5	103,847	380	385	230
ozone season night/wkend	234,674	708	65,219	3	65,219	511	515	194
non-ozone season wkday	334,977	758	181,882	8	181,882	347	355	403
non-ozone season night/wkend	330,492	998	112,038	5	112,038	659	665	333
Annual Total	1,171,724	3,079	462,987	22	462,987	1,897	1,919	1,160
CO_2								
ozone season wkday	271,581	401,087	103,847	166,156	103,847	247,719	413,875	(12,788)
ozone season night/wkend	234,674	422,474	65,219	104,351	65,219	305,063	409,413	13,061
non-ozone season wkday	334,977	527,214	181,882	291,012	181,882	240,953	531,964	(4,751)
non-ozone season night/wkend	330,492	573,595	112,038	179,261	112,038	379,144	558,405	15,190
	-							
Annual Total	1,171,724	1,924,370	462,987	740,779	462,987	1,172,879	1,913,658	10,712

Table 2-9. Emissions Offsets From On-Site Heat Recovery

On-Site Boiler Emission Rates (lb/kWh_{th})

	NO_X	CO_2
Full Load	0.000538	0.627

IR CHP System Emission Rates (lb/kWh_{th})

	NO_X	CO_2
Full Load	0	0

Emission Reduction Estimates From Heat Recovery

	Baseline Scenario		IR PowerWorks Scenario					
			Energy Supplied By IR		Makeup Energy			
	Heat From Boiler kWh_{th}	Boiler Emissions lbs	Heat From IR Cogen kWh_{th}	IR Emissions lb	Heat from Boiler kWh_{th}	Boiler Emissions lb	Total Emissions lb	Emission Reductions lb
NO_X								
ozone season	455,660	245	145,458	-	310,202	167	167	78
non-ozone season	1,125,341	605	174,942	-	950,399	511	511	94
Annual Total	1,581,001	851	320,400	-	1,260,601	678	678	172
CO_2								
ozone season	455,660	285,899	145,458	-	310,202	194,633	194,633	91,266
non-ozone season	1,125,341	706,083	174,942	-	950,399	596,318	596,318	109,765
Annual Total	1,581,001	991,982	320,400	-	1,260,601	790,950	790,950	201,031

Table 2-10. Estimated Annual Emission Reductions From DG-CHP System at Crouse Community Center

	Baseline Scenario			IR PowerWorks Scenario					Estimated Reductions	
				Energy Suplied By IR		Makeup Energy				
	Electricity From Grid lb	Heat/DHW from Boiler lb	Total Baseline lb	Electricity From IR lb	Heat/DHW From IR Cogen lb	Electricity From Grid lb	Heat/DHW from Boiler lb	Total IR Case lb	lb	%
Annual Total NO_X Emissions	3,079	851	3,930	22	-	1,897	678	2,597	1,333	34
Annual Total CO_2 Emissions	1,924,370	991,982	2,916,352	740,779	-	1,172,879	790,950	2,704,608	211,744	7

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3.0 DATA QUALITY ASSESSMENT

3.1. DATA QUALITY OBJECTIVES

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

The establishment of DQOs begins with the determination of the desired level of confidence in the verification parameters. The next step is to identify all measured values which affect the verification parameter and determine the levels of error which can be tolerated. The DQIs, most often stated in terms of measurement accuracy, precision, and completeness, are used to determine if the stated DQOs are satisfied. 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.

Table 3-1. Verification Parameter Data Quality Objectives

Verification Parameter	Original DQO Goal [a] Relative (%) / Absolute (units)	Achieved [b] Relative (%) / Absolute (units)
Power and Heat Production Performance		
Electrical power output (kW)	±1.5% / 1.05 kW	±1.5% / 0.84 kW
Electrical efficiency (%)	±1.8% / 0.51%[c]	±1.8% / 0.46%[c]
Heat recovery rate (MBtu/hr)	±2.2% / 7.50 MBtu/hr[c]	±0.9% / 1.37 MBtu/hr[c]
Thermal energy efficiency (%)	±2.4% / 1.00%[c]	±1.3% / 0.31%[c]
CHP production efficiency (%)	±1.6% / 1.12%[c]	±1.1% / 0.55%[c]
Power Quality Performance		
Electrical frequency (Hz)	±0.01% / 0.006 Hz	±0.01% / 0.006 Hz
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		
CO and NOX Concentration (ppmvd)	±2.0% of span / 0.5 ppmvd	±0.6% of span / 0.15 ppmvd
O_2 and CO_2 Concentration (%)	±2.0% of span / 0.2%	±0.6% of span / 0.1%
THC and CH_4 Concentration (ppmv)	±5.0 % of span / 2.50 ppmvw[d]	±1.4% of span / 0.70 ppmvw
CO, NOX , CO_2 and CH_4 Emission Rates	±12.7%[c]	±1.66%[c]
THC Emission Rates	±13.5%[c]	±2.09%[c]
Estimated NOX emission reductions for Crouse Community Center	±12.7%[c]	±1.66%[c]
Estimated GHG emission reductions for Crouse Community Center	±12.7%[c]	±1.66%[c]

[a] Absolute errors based on anticipated values where applicable
[c] Absolute errors based on average values measured during verification
[c] Calculated composite error described in text
[d] Parts per million by volume, wet (ppmvw)

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 discussion illustrates that all DQI goals were achieved and, thus, all DQOs were met or exceeded for all verification parameters.

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 and emission rate data for three test runs conducted at different load conditions. As stated earlier, the Test Plan specified a total of four loads. Since this was not possible, the only two conditions tested were full power turbine operation with normal site heat recovery operations and full power with enhanced heat recovery potential. Completeness results for controlled test periods are reported here based on these two operating conditions.

Completeness goals for the extended tests were to obtain 90 percent of 5 days of power quality, power output, fuel input, and ambient measurements. This goal was exceeded, and nearly six complete days of valid data were collected (a total of 10 minutes of data were invalidated when the microturbine shut down momentarily). As discussed in Section 2, these data were useful in establishing trends in power and heat performance capability at varying ambient temperatures.

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 Goals and Results

Measurement Variable		Instrument Type / Manufacturer	Instrument Range	Range Observed in Field	Accuracy [a]			Completeness	
					Goal	Actual	How Verified / Determined	Goal	Actual
IR PowerWorks System Power Output and Quality	Power	Electric Meter/ Power Measurements 7600 ION	0 to 100 kW	0 to 60 kW	±1.50% reading[b]	±1.50% reading[b]	Instrument calibration from manufacturer just prior to testing	controlled tests: three valid runs per load meeting PTC 22 criteria extended test: 90 % of one-minute readings for five days	controlled tests: six valid runs at full load only extended test: 99.9 % of one-minute readings for six days
	Voltage		0 to 600 V	0 to 220 V	±0.1% reading	±0.1% reading			
	Frequency		49 to 61 Hz	59.908 to 60.070 Hz	±0.0% reading	±0.01% reading			
	Current		0 to 100[A]	0 to 80 [A]	±0.1% reading	±0.1% reading			
	Voltage THD		0 to 100%	0 to 100%	±% FS[C]	±1% FS			
	Current THD		0 to 100%	0 to 100%	±1% FS	±1% FS			
	Power Factor		0 to 100%	0 to 100%	±0.5% reading	±0.5% reading			
IR PowerWorks System Heat Recovery Rate	Inlet Temperature	Controlotron Model 1010EP	37 to 356 °F	134 to 176 °F	Temps must be ±1.5°F of ref. Thermocouples	±0.4 °F	Independent check with calibrated thermocouples	controlled tests: three valid runs at each load extended test: 90 % of one-minute readings for five days	controlled tests: six valid runs at full load only extended test: 99.9 % of one-minute readings for six days
	Outlet Temperature		37 to 356 °F	156 to 195 °F					
	PG Flow		1 to 300,000 gpm	15.7 to 16.5 gpm	±1.0% reading	±0.33% reading	Instrument calibration from manufacturer just prior to testing		
	PG Concentration and Specific Heat	GC/FID	PG Conc: 10 to 20%	PG Conc: 15.7-16.5 %	PG Conc: ±3% relative error	PG Conc: ±2.6% relative (0.39% absolute)	Independent check with one blind sample		
Ambient Conditions	Ambient Temperature	RTD / Vaisala Model HMD 60YO	-50 to 150 °F	25 to 65 ° F	±0.2 °F	±0.2 °F	Instrument calibration from manufacturer just prior to testing	controlled tests: three valid runs at each load extended test: 90 % of one-minute readings for five days	controlled tests: six valid runs at full load only extended test: 99.9 % of one-minute readings for six days
	Ambient Pressure	Vaisala Model PTB220 Class B	13.80 to 14.50 psia	13.90 to 14.20 psia	±0.1% FS	±0.05% FS			
	Relative Humidity	Vaisala Model HMD 60YO	0 to 100% RH	27 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 13 scfm	1.0% of reading	±1.0% of reading	Factory calibration of differential pressure sensor and orifice plate bore	controlled tests: one minute readings for all runs extended test: 99.9 % of one-minute readings for six days	Controlled tests: one minute readings for all runs extended test: 99.9 % of one-minute readings for six days
	Gas Pressure	Pressure Transducer / Rosemount or equiv.	0 to 100 psig	69 to 71 psig	±0.75% FS	±0.75% FS	Instrument calibration from manufacturer prior to testing		
	Gas Temperature	RTD / Rosemount Series 68	-58 to 752 °F	30 to 70 °F	±0.10% reading	±0.09% reading			
	LHV	Gas Chromatograph / HP 589011	0 to 100% CH_4	90 to 95% CH_4	±0.2% for CH_4 concentration	±0.20% for CH_4 concentration	Analysis of NIST-traceable CH_4 audit gas	controlled tests: one valid sample per load	Controlled tests: one valid sample per load
				907 to 916 Btu/ft^3	± 0.2% for LHV	± 0.01% overall average LHV	Conducted duplicate analyses on 1 sample		
Exhaust Stack Emissions	NOX Levels	Chemiluminescent/ TEI Model 10	0 to 25 ppmvd	0 to 3 ppmvd	± 2% FS or ± 0.5 ppmvd	≤ 0.6% FS or ± 0.15 ppmvd [d]	Calculated following EPA Reference Method calibrations (Before and after each test run)	controlled tests: three valid runs per load	Controlled tests: six valid runs at full load only
	CO Levels	NDIR / TEI Model 48	0 to 25 ppmvd	0 to 5 ppmvd	± 2% FS or ± 0.5 ppmvd	≤ 0.6% FS or ± 0.15 ppmvd [d]			
	THC Levels	FID / TEI Model 51	0 to 50 ppmv	0 to 5 ppmvd	± 5% FS or ± 2.5 ppmvd	≤ 1.4% FS or ± 0.8 ppmvd [d]			
	CO_2 Levels	NDIR / IR Model 703	0 to 10%	1.0 to 1.5%	± 2% FS or ± 0.2%	≤ 0.6% FS or ± 0.06% [d]			
	O_2 Levels	NDIR / IR Model 2200	0 to 25%	18 to 19%	± 2% FS or ± 0.5%	≤ 0.4% FS or ± 0.10% [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 error observed throughout the controlled test periods.

3.2.1. Power Output

Precise determination of electric power generated by the IR PowerWorks System is required because it is a key verification parameter for the turbine. 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. To determine if the power output DQO was met, the Test Plan specified factory calibration of the ION 7600 with a NIST-traceable standard. The Test Plan also required the GHG Center to perform several reasonableness checks in the field to ensure that the meter was installed and operating properly. The following summarizes the results.

The meter was factory calibrated by Power Measurements approximately one month prior to being used at the test site. Calibrations were conducted in accordance with Power Measurements strict standard operating procedures (in compliance with ISO 9002:1994) and are traceable to NIST standards. The meter was 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 meter indicated that its 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, the error during all testing is determined to be ±0.84 kW.

After installation of the meters at the site and prior to the start of the verification test, additional QC checks were performed in the field to verify the operation of the electrical meter. 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.

Based on these results, it was concluded 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	±0.43% voltage ±1.2% current
	Reasonableness checks	Throughout test	Readings should be between 63 and 70 kW at full load	Readings were 50 to 60 kW, due to extremely warm weather
Fuel Flow Rate	Sensor Diagnostics	Beginning and end of test	Pass	Passed all diagnostic checks
	Comparison with in-line facility gas meter	During controlled tests	Difference of ±3% between the two meters differential pressures	Meters agreed within ±0.3%
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 gas constituent	
Heat Recovery Rate	Meter zero check	Prior to testing	Reported heat recovery < 0.5 Btu/min	Reported heat recovery was < 0.5 Btu/min
	Fluid index check	Each day of testing	±5.0% of reference value	Index check was within ±0.5% of reference value
	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 ±1.50 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 ±0.84 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. In this case, the specifications were satisfied, and therefore the ±1 percent of reading DQI was met. The average flow rate at full load was 12.49 scfm, and the measurement error is then determined to be ±0.12 scfm. A second assessment of measurement accuracy was conducted in the field by comparing the integral orifice meter reading with a calibrated, in-line, dry-gas meter. The comparison between the orifice meter and the dry-gas meter readings resulted in an overall average difference of ±0.3 percent during the test periods. Complete documentation of data quality results is provided in Section 3.2.2.3.

The Test Plan specified using the results of analysis of a blind audit gas and duplicate analysis to reconcile the accuracy of LHV determination. The primary gas composition DQI is the accuracy of the methane portion of the blind audit sample (methane represents about 95 percent of the gas composition). Methane results of the blind audit sample were within 0.2 percent of the certified concentration. The percent difference between the original and duplicate analyses was ±0.01 percent (Section 3.2.2.4). As such, the LHV goal of ±0.2 percent was met. During testing, the average LHV was verified to be 915 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:

$$Error\,in\,Heat\;Input = \sqrt{(flowmetererror)^2 + (LHV error)^2} \qquad \text{(Eqn. 9)}$$

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

At the average measured heat input of 683.7 MBtu/hr, the measurement error amounts to approximately ±697 Btu/hr, or 1.02 percent relative error.

For the electrical efficiency determination, the errors in the divided values compound similarly. The electrical power measurement error is ±1.5 percent relative (Table 3-2) and the heat input error is ±0.36 percent relative. Therefore, compounded relative error for the electrical efficiency determination is:

$$Error\,in\,Elec.\;Power\;Efficiency = \sqrt{(powermetererror)^2 + (heatinputerror)^2} \qquad \text{(Eqn. 10)}$$

$$= \sqrt{(0.015)^2 + (0.0102)^2} = 0.0181$$

This means that for the controlled test periods, electrical power efficiency was 25.3±0.46 percent, or a relative compounded error of 1.81 percent. This compounded relative error is the data quality objective for this verification parameter.

3.2.2.1. PTC-22 Requirements for Electrical Efficiency Determination

Per PTC-22 guidelines, 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. As shown in the table, the requirements for all parameters were met for all test runs. Thus, it can be concluded that 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. (°F)**
Maximum Allowable Variation	**±2**	**±2**	**±2**	**±0.5**	**±4**
Run 1	2.0	1.3	1.1	0.03	0.3
Run 2	1.3	1.3	1.2	0.08	2.0
Run 3	2.0	1.9	1.4	0.02	2.4
Run 4	1.0	0.9	0.8	0.02	2.3
Run 5	0.7	1.3	0.7	0.01	2.0
Run 6	0.8	1.4	0.5	0.01	1.2

[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 prior to the verification testing using reference materials traceable to NIST standards. Results of these calibrations indicate that the ±2 °F accuracy goal for temperature, ±0.1 percent for pressure, and ±2 percent 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 IR PowerWorks 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, and 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 IR PowerWorks Operators Manual.

Finally, a dry gas meter (Roots Model 2M175 SSM Series B3 rotary positive displacement meter manufactured by DMD-Dresser), installed in series with the GHG Center's orifice meter, was used to independently verify the Rosemount flow meter output. The dry gas meter was calibrated by the local utility (NYSEG) using a volume prover, and the meter calibration proof was within 99.0 percent at full scale. During the field testing, dry gas meter readings were obtained and compared with the Rosemount flow data. The dry gas meter flow rates were computed by taking manual dry gas meter readings over a period of time [in units of actual cubic feet (acf)], and then correcting the dry gas meter readings to standard conditions. Actual gas pressure and temperature measurements were used to make these corrections as shown in Equation 11.

$$\text{Dry Gas Meter Reading (scf)} = \text{Gas Volume Measured (acf)} * (T_{std}/T_g) * (P_g/P_{std}) * C_m \qquad \text{(Eqn. 11)}$$

where:

T_{std} = standard temperature (519.67 ^oR)
T_g = measured gas temperature (^oR)
P_g = measured gas pressure (psia)
P_{std} = standard pressure (14.696 psia)
C_m = meter calibration coefficient (1.00)

The standardized gas volume was then divided by the duration of the sampling interval to yield average gas flow in scfm. These values were then compared to the average gas flow rate recorded by the integral orifice meter during the same period. The results of these field comparisons between the integral orifice meter and the in-line dry gas meter are presented in Table 3-5. On average, the integral orifice flows were 0.3 percent lower than dry gas meter readings.

Table 3-5. Comparison of Integral Orifice Meter With Dry Gas Meter During Controlled Testing

Test Condition (% of Rated Power)	Run ID	Integral Orifice Meter (scfm)	Gas Pressure (psia)	Gas Temp. (^oF)	Dry Gas Meter (acfm)	Dry Gas Meter (scfm)	Absolute Difference[a] (scfm)	Relative Difference[b] (%)
100	1	12.59	15.92	77.30	11.97	12.62	-0.03	-0.27
	2	12.39	15.94	80.90	11.83	12.41	-0.02	-0.15
	3	12.48	15.94	84.50	12.03	12.54	-0.06	-0.44
						Overall Average	-0.04	-0.29

[a] Integral Orifice Reading – Dry Gas Reading
[b] (| Integral Orifice Reading - Dry Gas Reading |) / Dry Gas Reading] x 100

3.2.2.4. Fuel Lower Heating Value

Fuel gas samples were collected no less than once per test condition. 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 Core Laboratories of Houston for compositional analysis and determination of LHV per ASTM test methods D1945 (ASTM 2001a) and D3588 (ASTM 2001b), respectively. A total of four valid samples were collected and analyzed, three during the controlled test periods and one during the six-day extended monitoring period. The DQI goals were to measure methane concentration that was within ±0.2 percent of a NIST-traceable calibration gas and a certified audit gas and to achieve less than ±0.2 percent difference in LHV duplicate analyses results.

The GC/FID was calibrated daily using a continuous calibration verification standard (NIST-traceable) and upper and lower control limits maintained by Core Laboratory. Copies of the GC/FID calibration records are maintained at the GHG Center and indicate that instrument responses were well within the control limits for all analyses conducted. A certified natural gas audit sample was submitted to Core Laboratory, and its results were reviewed to determine analytical error and repeatability for major gas components. Results of the audit sample, summarized in Table 3-6, show acceptable accuracy for major gas components. High levels of error were evident only on components that were present in very low concentrations (e.g., n-butane and n-hexane) and carbon dioxide. The results also show that the ±0.2 percent goal for methane concentration was achieved.

Table 3-6. Results of Natural Gas Audit Sample Analysis

Gas Component	Certified Component Concentration (%)	Analytical Result (%)	Combined Sampling and Analytical Error (%)[a]
nitrogen	5.00	5.01	0.2
carbon dioxide	1.01	1.12	10.9
methane	70.41	70.27	0.2
ethane	9.01	8.87	1.6
propane	6.03	5.99	0.7
n-butane	3.01	2.95	2.0
Iso-butane	3.01	2.99	0.7
Iso-pentane	1.01	0.97	4.0
n-pentane	1.01	0.96	5.0

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

Duplicate analyses were conducted on one of the samples collected during the control test periods (the sample collected during Run 3 on August 14). Duplicate analysis is defined as the analyses performed by the same operating procedure and using the same instrument for a given sample volume. Results of the duplicate analyses showed an analytical repeatability of 0.06 percent for methane (results were 96.40 and 96.34 mol % CH_4), and 0.01 percent for LHV (results were 911.7 and 911.6 Btu/scf). The results demonstrate that the ±0.2 percent LHV accuracy goal was achieved.

3.2.3. Heat Recovery Rate

Heat recovery efficiency is the heat recovered divided by the turbine fuel heat input. Precise determination of the heat recovery rate is required because it is a key performance parameter for the CHP system. A Controlotron heat meter was used that determines the heat recovery rate by measuring the glycol solution heat exchanger temperature difference (delta T) and the flow rate. It then multiplies delta T, flow rate, glycol solution specific heat, and density to yield the heat recovery rate. Earlier, Tables 3-2 and 3-3 showed that the DQIs achieved for delta T and PG flow rate were achieved (0.4 ^{o}F temperature accuracy for each sensor (0.8 ^{o}F for temperature differential) and 0.33 percent accuracy for flow rate. For a given glycol concentration (volume percent), the manufacturer specifies an overall heat recovery rate accuracy of ±2.0 percent. The meter obtains specific heat and density data from an internal "look up" table, based on ASHRAE data (Appendices A-9, A-10; ASHRAE 1997) and the measured glycol solution volume percent as input by the Field Team Leader at the beginning of the test campaign.

The Test Plan specified that the GHG Center would collect and analyze glycol solution samples from the CHP system prior to and during the testing. Using results of the preliminary analyses, the Field Team Leader computed the average volume percent glycol and programmed this into the heat meter. As shown in Table 3-2, the laboratory's relative analytical error for the glycol concentration was ±2.6 volume percent. This means that, for the average percent glycol solution of 15.0 percent, actual concentration could range between 15.4 and 14.6 percent. This range is based on a measured absolute error of ±0.39 percent, which was determined using the analytical results of a blind audit sample submitted to the laboratory by the Center. Because specific heat and density vary with different glycol compositions, the laboratory analytical error will introduce additional error into the heat meter's heat recovery rate determination. However, example calculations in the Test Plan showed that an absolute PG analytical error of 3 percent contributed a combined density and specific heat error of only 0.79 percent. Since analytical accuracy was much better during this test (absolute error of only 0.39 percent on PG concentration), the error introduced into the heat recovery calculation is considered negligible and not included in propagation of the overall error in heat recovery rate.

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

$$Overall\ Heat\ Meter\ \ Error = \sqrt{(Flowrateerror)^2 + (temperatureerror)^2} \qquad \text{(Eqn. 12)}$$

$$= \sqrt{(0.0033)^2 + (0.008)^2} = 0.0087$$

Given this, the average heat recovery rate was 157,982±1374 Btu/hr, or a relative compounded error of ±0.87 percent.

For the heat recovery efficiency determination, the errors in heat recovery rate and heat input compound similar to Equation 10 as follows:

$$Error\ in\ Heat\ \mathrm{Re}\cos ery\ \ Efficiency = \sqrt{(0.0087)^2 + (0.0102)^2} = 0.0134 \qquad \text{(Eqn. 13)}$$

This means that for the controlled test periods, average heat recovery rate (thermal) efficiency was 23.0±0.31 percent, or a relative compounded error of 1.34 percent. This compounded relative error meets the quality objective for this verification parameter.

3.2.4. Total Efficiency

Total efficiency is the sum of the electrical power and heat recovery efficiencies. Continuing from the determined errors in electrical and thermal efficiency, average total efficiency is defined as 25.3±0.46 percent (±1.81 percent relative error) plus 23.0±0.31 percent (±1.34 percent relative error). For additive errors, the absolute errors compound as follows (EPA 1999):

$$err_{c,abs} = \sqrt{err_1^{\ 2} + err_2^{\ 2}} \qquad \text{(Eqn. 14)}$$

$$= \sqrt{0.46^2 + 0.31^2} = 0.55 \ \text{ percent absolute error}$$

Relative error, then, is:

$$err_{c,rel} = \frac{err_{c,abs}}{Value_1 + Value_2} \qquad \text{(Eqn. 15)}$$

$$= \frac{0.55}{25.3 + 23.0} = 1.14 \text{ percent relative error}$$

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 average total efficiency is 48.3±0.55 percent, or 1.1 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 accuracy occur throughout the emissions tests. The DQOs specified in the Test Plan were based on the requirements of the Reference Methods. Specifically, these include overall accuracies of ±0.50 ppmvd for NOX and CO, ±2.50 ppmvd for THC and CH_4, and ±0.4 percent for CO_2 and O_2. The data quality indicator goals required to meet the DQO consisted of an assessment of sampling system error (bias) and drift for NOX and THC and of bias and drift for CO, CO_2, and O_2.

<u>NOX and THC</u>

The NOX 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 NOX 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.

As shown in Table 3-2, the system calibration error goal for NOX was ±0.50 ppmvd, and the maximum actual measured error was ±0.15 ppmvd, which indicates the goal was met. For THC, the maximum system error was determined to be ±0.8 ppmvw, which is within the ±2.50 ppmvw goal. The system error and drift are calculated only for the mid-level calibration gas based on following Method 25A requirements.

The NOX analyzer used for all tests had a full-scale range of 0 to 25. The NOX analyzer was calibrated with certified concentrations 0, 6.26, 12.9, and 23.0 ppmvd NOX at the beginning of each day to establish linearity. Results of these calibrations (Appendix A-1) indicate excellent instrument linearity with calibration errors of 1.6 percent of span or less.

At the conclusion of each test, zero and mid-level calibration gases were again introduced to the sampling systems at the probe and the response recorded. System response was compared to the initial system calibration error to determine sampling system drift. The maximum sampling system drift was determined to be 0.1 ppmvd for NOX and 0.7 ppmvw for THC, which were both 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.

Two additional QC checks were performed to better quantify the NOX data quality. In accordance with Method 20, an interference test was conducted once on the NOX analyzer before the testing started. This test confirms that the presence of other pollutants in the exhaust gas do not interfere with the accuracy of the NOX analyzer. This test was conducted by injecting the following calibration gases into the analyzer and recording the response of the NOX analyzer, which must be zero ±2 percent of span (or 0.50 ppmvd).

- CO – 602 ppmvd in balance nitrogen (N_2)
- SO_2 – 251 ppmvd in N_2
- CO_2 – 9.9 percent in N_2
- O_2 – 20.9 percent in N_2

As shown in Table 3-7, the maximum measured value was well below the 0.50 ppmvd required by the Method.

The NOX analyzer converts any NO_2 present in the gas stream to NO prior to gas analysis. The second QC check consisted of determining NO_2 converter efficiency prior to beginning of emissions 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. If the NO_2 to NO conversion is 100 percent efficient, the response will be stable at the highest peak value observed. If the response decreases by more than 2 percent from the peak value observed during the 30-minute test period, the converter is faulty and the analyzer must be either repaired or replaced prior to testing. As shown in Table 3-7, the converter efficiency was measured to be 100 percent.

As an additional QC check for low-range NOX measurements, the GHG Center provided an EPA Protocol mixture of 2.49 ppmvd NOX in N_2 as an audit of ENSR International's sampling system. The gas was introduced to the sampling system as a blind audit, and the system response was recorded by Center personnel. A stable system response of 2.56 ppmvd was recorded, corresponding to a system error of 0.28 percent of span.

Table 3-7. Additional QA/QC Checks for Emissions Testing

Parameter	QA/QC Check	When Performed/Frequency	Expected or Allowable Result	Maximum Results Measured[a]
NOX	Blind audit sample	Once during testing	±2% of analyzer span or less	System error was 0.28% of span
	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	0.4% of span or 0.10 ppmvd
CO, CO_2, O_2	Analyzer calibration error test	Daily before testing	±2% of analyzer span or less	CO: 1.2% of span or 0.30 ppmvd CO_2: 1.2% of span or 1.2 % absolute O_2: 0.8% of span or 0.2 % absolute
	Calibration drift test	After each test	±3% of analyzer span or less	CO: 0.5% of span or 0.13 ppmvd CO_2: 0.9% of span or 0.09 % absolute O_2: 0.3% of span or 0.08 % absolute
THC	System calibration drift test	After each test	±3% of analyzer span or less	1.4% of span or 0.70 ppmvd

[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: zero, 40 to 60 percent of span, and 80 to 100 percent of span. Four gases were used for CO: zero and approximately 30, 60, and 90 percent of span. The analyzer calibration errors for all gases were below the allowable levels, as shown in Table 3-7.

Before and after each test run, zero and mid-level calibration gases were introduced to the sampling system at the probe, and the response was recorded. System bias was calculated by comparing the system responses to the calibration error responses recorded earlier. As shown in Table 3-2, the system bias goal for all gases was achieved: ±0.50 ppmvd for CO, ±0.40 percent (absolute) for CO_2, and ±0.15 percent (absolute) for O_2. Consequently, the DQO was satisfied.

The pre- and post-test system bias calibrations were also used to calculate sampling system drift for each pollutant. As shown in Table 3-7, the maximum drift measured was 0.5 percent of span for CO, 0.9 percent for CO_2, and 0.3 percent for O_2. In conclusion, the drift goals were also met for all pollutants.

Results of each of the analyzer and sampling system calibrations conducted, including linearity tests and sampling system bias and drift checks, are presented in Appendix A.

Determination of Error in Emission Rate Determinations

Error in determination of emission rates in units of lb/kWh is derived from the errors in each of the contributing measurements including pollutant concentrations, oxygen concentrations, and power output.

The Test Plan specified an emission rate DQO for NOX, CO, and CO_2 collectively of 12.7 percent relative error and a THC DQO of 13.5 percent relative error. The highest concentration error in the NOX, CO, and CO_2 measurements was 0.6 percent of full scale (0.15 ppmvd absolute,) and the error in THC concentration measurements was 1.4 percent of full scale, or 0.8 ppmv absolute. Compounding these errors with the error in measurement of O_2 concentrations (0.4 percent of full scale, or 0.10 percent absolute), and the power output error (1.50 percent), the emission rate compounded error then computed as:

$$Error\,in\,EmissionRates = \sqrt{(0.006)^2 + (0.004) + (0.0150)^2} = 0.0166 \qquad \text{(Eqn. 16)}$$

The error in NOX, CO, and CO_2 emission rate determinations is then 1.66 percent. The error in THC emission rates is 2.09 percent. Both are well within the goals set for emission rate determinations.

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4.0 TECHNICAL AND PERFORMANCE DATA SUPPLIED BY INGERSOLL-RAND ENERGY SYSTEMS

Ingersoll-Rand (IR) appreciates the comprehensive and thorough testing effort evident in this report and the well-qualified insights it yields into various aspects of the performance of the PowerWorks 70kW microturbine. As the report shows, the electrical generation and heat recovery performance of the unit under test do not match our production criteria, but other performance metrics such as emissions and electrical power quality are favorable.

4.1. SYSTEM CONFIGURATION

First we would like to note that the unit tested at the Crouse Community Center was an early pre-production model that has not been updated to the production units we manufacture today. As with its other industrial and commercial products, IR continues to improve its microturbine line and expand its capability to meet the needs of its customers. Therefore, a continuous program of improvements in capability, performance, and quality is always underway and this effort addresses the kinds of issues raised in the report as described below.

4.2. ELECTRICAL PERFORMANCE

During the ETV tests, the microturbine was producing about 53 to 50 kW of power under ambient conditions ranging from 76 to 86 °F. The tests also revealed an electricity generating efficiency in the range of 25.8 to 25.1 percent LHV. With a production machine we would expect typical ranges of 65 to 60 kW and 27.2 to 26.6 percent efficiency for ambient temperatures in this range (gas turbine power and efficiency drop with increased ambient temperature).

IR's production acceptance criteria for power output are ±5 kW and ±2 points efficiency respectively. Therefore, the measurements represent performance below the criteria we would normally allow. This was due to three factors.

- The testing occurred at ambient pressures that were measured at 14.01 to 14.07 psia. Gas turbine engine power varies directly in proportion to ambient pressure. Therefore, a comparison of measured power output to rated power output at ISO conditions must also account for ambient pressure. In this case, the ratio of the average value (14.035 versus 14.696) equates to a 0.955 drop in power or around 4.5 percent or 3 kW.

- The tested configuration included a compressor diffuser with substandard performance. IR has since switched to a new design whose net effect is to increase system power output by about 6 kW.

- We have found measurement errors of the Turbine Inlet Temperature (TIT) operating point in earlier machines. These errors would result in the microturbine producing up to 5 kW less power.

4.3. COGENERATION PERFORMANCE

The ETV test revealed that approximately 140 MMBtu/hr (170MMBtu/hr when the facility boilers were turned off) of heat was captured for cogeneration use. The higher heat capture rate reflects the expected additional gain when inlet water temperature lowers. With a production unit we would expect higher heat capture rates, more in the range of 200 MMBtu/hr at 170.8 °F entering water temperature and 240 MMBTU/hr at 136 °F.

The Heat Recovery Unit (HRU) used in the tested system had a supplier defect which allowed fin separation from the water passage tubes. This separation significantly reduced heat transfer capability from the exhaust to the water, which lead to less heat capture in the water. The HRUs now employed in our production units have resolved this issue.

4.4. ELECTRICAL POWER QUALITY

Since this machine employs an induction generator, it completely relies on the utility grid to regulate frequency and voltage. Therefore, the variations shown in the test data are completely controlled by the power quality of the electrical power in the facility.

With regards to power factor and Total Harmonic Distortion (THD), the measured values fall within the typical range expected in this kind of application.

4.5. EMISSIONS AND THE FUEL SYSTEM

The ETV report shows that PowerWorks NOX, CO, and THC emissions are quite low both from an input basis (ppmv corrected to 15% O_2) and an output basis (lbs/kWh). For example, the average measured full load NOX values of 0.000047 lb/kWh are an order of magnitude below the newly enacted California Air Resources Board (CARB) limits of 0.0005 lbs/kWh (2003 limits) for Distributed Generation systems, even without accounting for NOX reduction when operating in part load conditions.

Another important element of the PowerWorks design is the fully integrated fuel gas booster. As noted in the report, the booster design is based on a fully sealed industrial screw compressor. Since the fuel booster system is included in the microturbine enclosure, no high-pressure gas lines are required between the microturbine and an outside component. This enhances safety and eliminates potential sources of leaks. In addition, special attention has been paid to the ventilation design of the microturbine enclosure and the venting design of the fuel system to avoid potentially dangerous concentrations of fuel gas. Therefore, the PowerWorks microturbine is fully qualified for indoor use.

5.0 REFERENCES

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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	System Response	Calibration Error (% of Span)
		(ppm for NO_x, CO, and THC; % for O_2 and CO_2)				
8/14/02	NO_x	25	0.00	na	0.01	0.04
(Runs 1 - 3)			6.26	na	6.27	0.04
			12.90	na	13.2	1.2
			23.00	na	23.4	1.6
	CO	25	0.00	0.02	na	0.08
			6.00	5.85	na	0.6
			14.00	14.00	na	0.0
			24.30	24.60	na	1.2
	CO_2	10	0.00	0.12	na	1.2
			4.42	4.40	na	0.2
			9.11	9.05	na	0.6
	O_2	25	0.00	0.03	na	0.1
			11.09	11.07	na	0.08
			20.90	20.70	na	0.8
	THC	50	0.00	na	0.14	na
			14.82	na	15.6	2.96
			23.94	na	24.2	1.06
			48.00	na	48.9	na
8/15/02	NO_x	25	0.00	na	0.02	0.08
(Runs 4 - 6)			6.26	na	6.22	0.02
			12.90	na	13.2	1.2
			23.00	na	23.3	1.2
	CO	25	0.00	0.03	na	0.1
			6.00	5.92	na	0.3
			14.00	13.90	na	0.4
			24.30	24.50	na	0.8
	CO_2	10	0.00	0.11	na	1.1
			4.42	4.43	na	0.1
			9.11	9.04	na	0.7
	O_2	25	0.00	0.04	na	0.16
			11.09	11.12	na	0.1
			20.90	20.70	na	0.8
	THC	50	0.00	na	0.14	na
			14.82	na	14.55	2.02
			23.94	na	23.3	2.62
			48.00	na	47.8	na

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

Analyzer Spans: NO_x = 25 ppm, CO = 25 ppm, THC = 50 ppm, CO_2 = 10%, O_2 = 25%

		Initial	Run Number			
		Cal	1	2	3	4, 5, 6
NO_x Zero	System Response (ppm)	0.01	0.03	0.00	0.03	0.03
	System Error (% span)	0.00	0.10	-0.10	0.00	0.10
	Drift (% span)	na	0.10	-0.10	0.10	0.00
NO_x Mid	System Response (ppm)	6.27	6.24	6.24	6.14	6.20
	System Error (% span)	-0.10	-0.20	-0.20	-0.60	-0.30
	Drift (% span)	na	-0.10	0.00	-0.40	-0.10
CO Zero	System Response (ppm)	0.10	-0.30	0.00	-0.02	-0.07
	System Error (% span)	0.30	-0.20	-0.10	-0.10	-0.40
	Drift (% span)	na	-0.50	0.10	-0.10	-0.30
CO Mid	System Response (ppm)	5.84	5.86	5.78	5.70	5.91
	System Error (% span)	0.00	0.00	-0.30	-0.60	0.00
	Drift (% span)	na	0.10	-0.30	-0.40	0.40
CO_2 Zero	System Response (ppm)	0.11	0.15	0.11	0.12	0.11
	System Error (% span)	-0.20	0.20	-0.20	0.00	-0.20
	Drift (% span)	na	0.40	-0.40	0.10	-0.20
CO_2 Mid	System Response (ppm)	4.35	4.38	4.43	4.34	4.34
	System Error (% span)	-0.40	-0.20	0.30	-0.60	-0.60
	Drift (% span)	na	0.30	0.50	-0.90	0.00
O_2 Zero	System Response (ppm)	0.10	0.10	0.06	0.11	0.15
	System Error (% span)	0.30	0.20	0.10	0.30	0.40
	Drift (% span)	na	0.00	-0.10	0.20	0.20
O_2 Mid	System Response (ppm)	11.15	11.14	11.12	11.09	11.19
	System Error (% span)	0.30	0.20	0.20	0.00	0.30
	Drift (% span)	na	-0.10	-0.10	-0.20	0.30
THC Zero	System Response (ppm)	0.14	0.19	0.15	0.12	0.15
	System Error (% span)	0.30	0.40	0.30	0.20	0.30
	Drift (% span)	na	0.10	-0.10	-0.10	0.10
THC Mid	System Response (ppm)	15.64	15.62	15.62	15.51	14.61
	System Error (% span)	1.60	1.60	1.60	1.40	0.00
	Drift (% span)	na	-0.10	0.00	-0.20	-1.40