SRI/USEPA-GHG-GD-03
March 2002

Greenhouse Gas (GHG) Verification Guideline Series

Natural Gas-Fired Microturbine Electrical Generators

Prepared by:

Greenhouse Gas Technology Center
Southern Research Institute

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

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Greenhouse Gas Technology Center

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

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FOREWORD

The U.S. Environmental Protection Agency (EPA) has created the Environmental Technology Verification (ETV) program to facilitate the deployment of promising environmental technologies. Under this program, third-party performance testing of environmental technology is conducted by independent verification organizations under strict EPA quality assurance guidelines. Southern Research Institute (SRI) is one of six independent verification organizations operating under ETV, and operates the Greenhouse Gas Technology Center (GHG Center). With full participation from technology providers, purchasers, and other stakeholders, the GHG Center develops testing protocols and conducts technology performance evaluation in field and laboratory settings. The testing protocols are developed and peer-reviewed with input from a broad group of industry, research, government, and other stakeholders. After their development, the protocols are field-tested, often improved, and then made available to interested users via Verification Guidelines such as this. Typically, verifications conducted by the GHG Center involve substantial measurements, so an effort is made here to recommend only the most important measurements for the guideline.

This document provides guidelines for verifying the performance of natural gas-fired microturbines as a source of distributed generation (DG). These guidelines are based upon two verification tests conducted by the GHG Center on commercially available microturbines. Microturbines as a DG source of power typically range from 5 to 1,000 kilowatts (kW) and provide electric power at a site closer to customers than central station generation. A distributed power unit can be connected directly to the customer or to a utility's transmission and distribution (T&D) system. This guideline is based on the verifications conducted by the GHG Center where performance evaluations addressed the following parameters:

- Power production performance – Actual power generated at various power command settings and ambient conditions, and electricity offset from baseline power generating systems (e.g., utility grid)
- Electrical efficiency – Energy conversion efficiency based on power output, fuel consumption, and fuel heating value
- Electrical power quality performance – Quality of electricity generated and supplied to the end user
- Operational performance – Cold start time and system availability
- Emissions performance – Criteria pollutant and GHG emissions generated at various power command settings
- Estimated emission reductions compared to baseline electricity production equipment

The purpose of this guideline is to describe specific procedures for evaluation and verification of natural gas-fired microturbines. It is not the intention of the GHG Center that these guidelines become accepted as a national or international standard. Rather, a significant effort has been devoted to their development, field trial, and improvement; and this experience and data are recognized as potentially valuable to others. Instrument descriptions and recommendations presented in this document do not constitute an endorsement by the GHG Center or the EPA. Readers should be aware that use of this guideline is voluntary, and that the GHG Center is not responsible for liabilities that result from its use.

Finally, the GHG Center continues to conduct verifications, and will update this guideline with new findings as warranted. Updates can be obtained online at the GHG Center (www.sri-rtp.com) or ETV (www.epa.gov/etv) Web sites.

ACKNOWLEDGEMENTS

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ACRONYMS/ABBREVIATIONS

AC	alternating current
acf	actual cubic feet
ADQ	audit of data quality
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASTM	ASTM International
Btu/ft^3	British thermal units per cubic foot
Btu/lb	British thermal units per pound
Btu/scf	British thermal units per standard cubic foot
CH_4	methane
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
DAS	data acquisition system
DC	direct current
DG	distributed generation
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
EGRID	Emissions and Generation Resource Integrated Database (U.S. EPA)
EIA	Energy Information Administration
EQWG	Emissions Quantification Working Group (Canada)
EPA	U.S. Environmental Protection Agency
ETV	Environmental Technology Verification
^oF	degrees Fahrenheit
FERC	Federal Energy Regulatory Commission
FID	flame ionization detector
GC	gas chromatograph
GHG	greenhouse gas
GHG Center	Greenhouse Gas Technology Center
GU	generating unit
HI	heat input
hrs	hours
Hz	hertz
IEEE	Institute of Electrical and Electronics Engineers
in.	inches
IPCC	Intergovernmental Panel on Climate Change
IPM	Integrated Planning Model
ISO	International Standards Organization
kV	kilovolt
kVA	kilovolt-amps
kVAR	reactive kilovolt-amps
kW	kilowatts
kWh	kilowatt hours

(continued)

ACRONYMS/ABBREVIATIONS
(continued)

lb/dscf	pounds per dry standard cubic foot
lb/hr	pounds per hour
lb/kWh	pounds per kilowatt hour
lb/MMBtu	pounds per million British thermal units
lb/yr	pounds per year
LHV	lower heating value
min	minutes
N_2	nitrogen
N_2O	nitrous oxide
NDIR	nondispersive infrared spectroscopy
NIST	National Institute for Standards and Technology
NO	nitrogen oxide
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O_2	oxygen
ORD	Office of Research and Development
PEA	performance evaluation audit
Pf	power factor
ppmvd	parts per million volume dry
psia	pounds per square inch absolute
psig	pounds per square inch gauge
QA/QC	quality assurance and quality control
QMP	Quality Management Plan
RH	relative humidity
RMS	root mean square
RTD	resistance temperature detector
scfm	standard cubic feet per minute
SRI	Southern Research Institute
Test Plan	Test and Quality Assurance Plan
T&D	transmission and distribution
THCs	total hydrocarbons
THD	total harmonic distortion
TSA	technical systems audit
U.S.	United States
VOC	volatile organic compound
WRAP	Western Regional Air Partnership
WRI	World Resources Institute

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 the ETV program is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. The ETV program is funded by Congress 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 (U.S.) 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 measurements 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 offer advice on specific technologies most appropriate for testing, help disseminate results, and review Test Plans and Verification Reports. 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 Executive Stakeholder Group is one such group that helps identify industries where GHG verification is most needed. The GHG Center's activities are also guided by industry specific stakeholders comprised of technology purchasers, manufacturers, environmental regulatory groups, and other government and non-government organizations. The stakeholders help identify and select technology areas for verification, and support the planning, review, and wide distribution of verification results.

One technology of interest to GHG Center stakeholders was the use of microturbines as a distributed energy 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 or to a utility's transmission and distribution (T&D) system. Examples of technologies available for DG include gas turbine generators, internal combustion engine generators (e.g., gas, diesel), photovoltaics, wind turbines, fuel cells, and microturbines. DG technologies provide customers one or more of the following main services: stand-by generation (i.e., emergency backup power), peak shaving capability (generation during high demand periods), baseload generation (constant generation), or cogeneration (combined heat and power generation).

To pursue verification testing of microturbines, the GHG Center placed formal announcements in the Commerce Business Daily and industry trade journals, and invited vendors of commercial products to participate in independent testing. Recently, the GHG Center has conducted performance verifications on two microturbine technologies. Systems tested include a Honeywell Power Systems, Inc. Parallon® 75 kW Turbogenerator and a Capstone 30 kW MicroTurbine®. The Capstone unit was a component of a combined heat and power (CHP) system developed by Mariah Energy Corporation in Calgary, Alberta, Canada. Performance verifications of both units were carried out under the ETV program with specific Test and Quality Assurance Plans (Test Plan). In both cases, the Test Plans were reviewed by the GHG Center's Distributed Generation Stakeholder Panel, the technology vendors, and the EPA Quality Assurance team, and met the requirements of the GHG Center's Quality Management Plan (QMP), and ETV QMP requirements. Copies of the Test Plans, Verification Statements, and Verification Reports from both of these evaluations can be viewed or downloaded at the GHG Center (www.sri-rtp.com) or ETV (www.epa.gov/etv) Web sites.

1.2. VERIFICATION GUIDELINE SCOPE

The purpose of this guideline is to describe specific procedures for evaluation and verification of microturbine performance based on the GHG Center's experience gained during the two verifications described above. It is not the intention of the GHG Center that these guidelines become accepted as a national or international standard. Although the guidance has been field tested, it may not be applicable to all microturbine installations. This guideline should also be considered dynamic, because the GHG Center continues to conduct technology verifications, and this document may be updated regularly to include new findings and procedures as warranted. Updates of this document can be obtained online at the GHG Center or ETV Web sites referenced above. After the planning, execution, and post-test analysis phases of each field verification, the GHG Center identifies procedures that performed poorly or were marginally necessary, and then revises the protocol.

This guideline recommends an approach for evaluation of the performance of natural gas-fired microturbines in DG applications. The verification scope can vary depending on specific applications and site requirements, but energy conversion efficiency, power quality, and operational availability are always important performance characteristics. For applications where the primary function of a microturbine is to provide backup power or peak demand shaving capabilities, then cold start time is important as well. The verification approach recommended here identifies verification parameters that were identified by the GHG Center's stakeholders as important variables on any application. Detailed descriptions of test strategies and procedures, quality assurance and quality control (QA/QC) activities, calculation of results and reporting formats, and references are provided here for all of the verification parameters evaluated by the GHG Center during past verifications.

This document also provides guidance on verification planning. A site-specific Test Plan is recommended for each specific verification conducted. Specific guidance regarding preparation of a comprehensive and site-specific Test Plan are not provided here, but the Test Plan should address all key elements of a verification test that are discussed in this guideline including:

- Descriptions of the technology and test site
- Identification of verification parameters and measurements required for each
- Detailed measurements methods, procedures, and calculations
- Data quality objectives (DQOs) and quality assurance and control activities
- Data validation and reporting

All of these elements are discussed in detail in this guideline document. The remainder of this guideline presents a brief description of the microturbine technology and provides detailed procedures for performance evaluations of these technologies. The document is organized as follows:

- The remainder of Section 1 provides an overview of the microturbine technology
- Section 2 presents the verification guideline and details Test Plan preparation, selection of verification parameters, and verification methodologies
- Section 3 describes data quality assessment guidelines
- Section 4 presents data acquisition, validation, and reporting guidelines
- Section 5, the Bibliography, provides references relevant to this guideline, including references to detailed, step-by-step procedures for the recommended Reference Methods

1.3. DESCRIPTION OF THE MICROTURBINE TECHNOLOGY

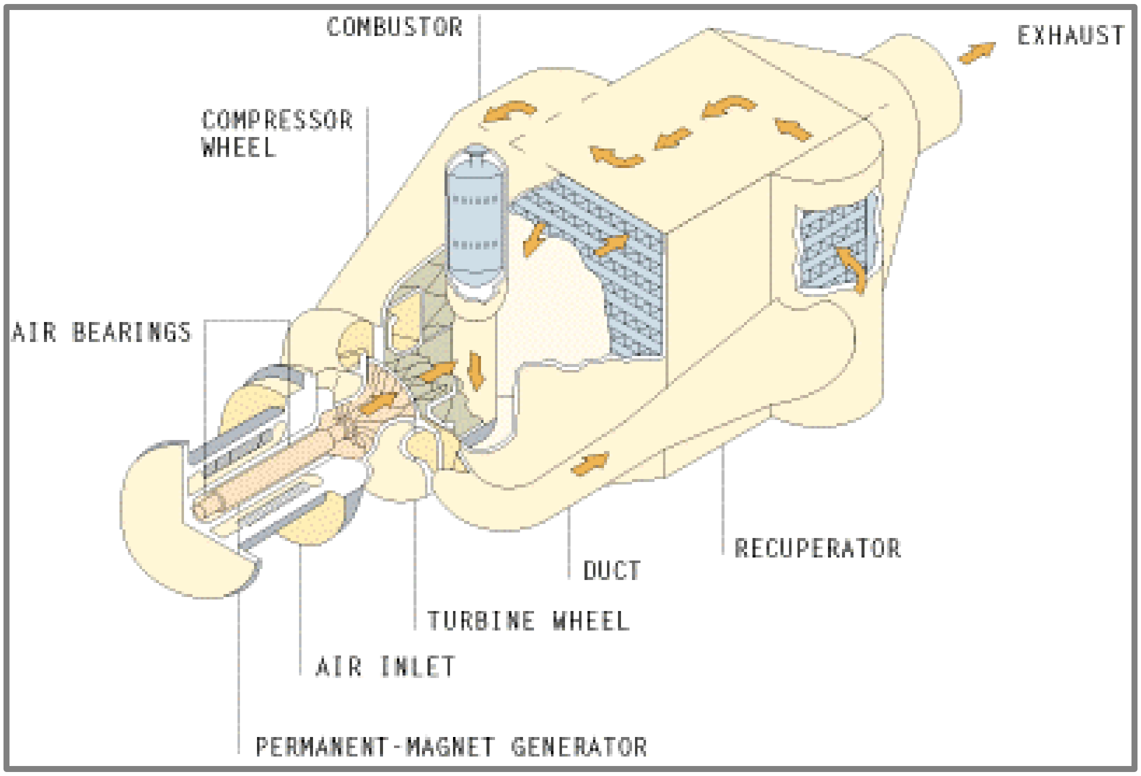
Large- and medium-scale natural gas-fired turbines have been used to generate electricity since the 1950s. Technical and manufacturing developments have occurred in the last decade that have enabled the introduction of microturbines, with generation capacity ranging from 30 to 200 kW, that provide electricity at the point of use as DG power sources. DG technologies can provide customers one or more of the following main services:

- stand-by generation (i.e., backup power)
- peak shaving capability (generation during high demand periods)
- baseload generation (generation at constant power setting)
- or cogeneration (combined heat and power generation)

Most systems also have the capability to fire waste gas or diesel, but the GHG Center's verification and this guideline address natural gas applications only. The units can be operated in stand-alone mode or in parallel. When a microturbine is interconnected with the utility grid, it can supply electrical power to the facility where it is installed, or to the grid during periods when its generation exceeds the needs of the facility. When configured to operate isolated, a microturbine supplies electricity to specific equipment dedicated to consume the power generated.

Most microturbines operate on natural gas at a fuel pressure ranging from 50 to 125 pounds per square inch gauge (psig) depending on manufacturer differences. Those units requiring pressurized gas are offered with optional booster compressors that allow low-pressure natural gas supplies to be pressurized to the required operating conditions. Specific design characteristics among different microturbines vary, but each type is comprised of four main sections: a compressor, a recuperator, a combustor, and a power generator (Figure 1-1). In the compressor section, combustion air is drawn into the microturbine and compressed. Normally, the compressed combustion air is passed through a recuperator where the air is preheated using exhaust gases from the combustor. Use of the recuperator results in significantly improved electrical efficiency. In applications where high temperature microturbine exhaust gases are desirable (e.g., certain cogeneration applications), the recuperator can be removed or bypassed. The compressed and preheated air is then mixed with fuel, and this mixture of compressed air and fuel is burned in the combustor under constant pressure conditions. The resulting hot gas is allowed to expand through the turbine section to perform work, rotating the turbine blades to run a generator that produces electricity. On most microturbines, the compressor is mounted on the same shaft as the electrical generator, and consists of only one rotating part. Other units have a dual shaft design.

Figure 1-1. Components of a Typical Microturbine



Because of the inverter-based electronics inherent to these systems, the generator can operate at high speeds and frequencies, and the need for a gearbox and associated moving parts is eliminated. On some systems, the high-speed rotating shaft is supported by air-foil bearings and does not require lubrication, although some designs do use oil-lubricated bearings. The exhaust gas exiting the recuperator passes through a muffler before being discharged to the atmosphere. The exhaust from units using a recuperator typically contain sufficient thermal energy for cogeneration applications, making microturbines good candidates for cogeneration.

The permanent magnet generators supplied with microturbines produce high-frequency alternating current which is rectified, inverted, and filtered by the line power unit into conditioned alternating current at various voltage levels, depending on the manufacturer. The output can be converted to the voltage level required by the facility using either an internal transformer or external transformer for distribution, offered by most suppliers. Most units are equipped with sophisticated control systems that allow for automatic and unattended operation. Normally, all operations including startup, synchronization with the grid, dispatch, and shutdown, can be performed manually or remotely using these control systems.

2.0 VERIFICATION GUIDELINE

2.1. OVERVIEW OF THE VERIFICATION STRATEGY

The GHG Center's stakeholder groups, and other organizations with interests in DG, have a specific interest in obtaining verified field data on the emissions, and technical and operational performance of microturbine systems. Performance parameters of greatest interest include electrical power output and quality, thermal-to-electrical energy conversion efficiency, exhaust emissions of conventional air pollutants and greenhouse gases (GHG), GHG emission reductions, operational availability, maintenance requirements, and economic performance. The test approach used in the verifications previously conducted by the GHG Center focused on assessing those performance parameters of significant interest to potential future customers of microturbines. As a practical matter, long-term evaluations could not be performed, and economic performance and maintenance requirements were not evaluated during the studies conducted by the GHG Center.

In developing the verification strategies, the GHG Center has applied existing standards for large gas-fired turbines, engineering judgement, and technical input from industry experts. Performance testing guidelines listed in the American Society of Mechanical Engineers (ASME) - Performance Test Code for Gas Turbines (PTC22-1997) have been adopted to evaluate electric power production and energy conversion efficiency performance. Some variations in the PTC22 requirements were made to reflect the small scale of the microturbine. Exhaust stack emissions testing procedures, described in EPA's New Source Performance Standards (NSPS) for emissions from stationary gas turbines (40CFR60, Subpart GG), have also been adopted for GHG and criteria pollutant emissions testing. Power quality standards used for these verifications are based on the Institute of Electrical and Electronics Engineers' Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems (IEEE 519).

Using these reference materials, and strategies and procedures developed by the GHG Center during past verifications, a site-specific verification approach can be developed. Development of a microturbine verification strategy can be outlined in four primary steps:

1. Identification of verification parameters applicable to the unit being evaluated and its installation specifics
2. Identification of detailed measurement requirements including instrumentation, test procedures, and DQOs
3. Development of a site-specific Test Plan that addresses each of the verification parameters based on the reference materials described above and guidelines presented here
4. Field evaluation of the test unit, data analysis and interpretation, and results reporting

Identification of verification parameters should address all performance aspects of a microturbine that are applicable to the installation and intended use of the unit. This guideline is based on the verifications previously conducted by the GHG Center where both units evaluated were baseloaded systems and were interconnected to the grid (one with cogeneration capabilities). Evaluation of the units' performance addressed the following parameters:

- Power production performance – Actual power generated at various power command settings and ambient conditions, and electricity offset from baseline power generating systems (e.g., utility grid)
- Electrical efficiency – Energy conversion efficiency based on power output, fuel consumption, and fuel heating value
- Electrical power quality performance – Quality of electricity generated and supplied to the end user
- Operational performance – Cold start time and system availability
- Emissions performance – Criteria pollutant and GHG emissions generated at various power command settings
- Estimated emission reductions compared to baseline electricity production equipment

These parameters can be evaluated using a two-phase test approach. The first phase is a series of controlled test periods. During each controlled test period, a specific power command (kW) or load (percent of rated power output) is specified into the system control software, and a series of tests are conducted during stable system operation. Accurate measurements of power output, fuel input, and emission rates are obtained throughout the controlled test periods. Since gas turbine performance can vary according to site conditions such as altitude and temperature, it is recommended that these tests are conducted during the upper and lower temperature extremes for the site, and emission test results be corrected to standard temperature and altitude.

The controlled test periods can be followed by an extended period of continuous monitoring. Continuous monitoring of actual electrical power delivered, fuel consumed, power quality parameters, ambient conditions, and other operational parameters can be performed to evaluate performance of the unit over time as system demand and ambient conditions change. The duration of the extended monitoring will depend on the operating schedule of the unit. For a unit operating continuously, the GHG Center has used a target of four weeks of data collection in past verifications. This period may be extended for units that operate on a demand based schedule, but in any case should provide a reasonable data capture of different daily electricity demands and environmental conditions at the test site. The time series performance data are analyzed to report net electricity generated, the variability observed in electrical efficiency during changing ambient conditions, the quality of power generated, and the unit's availability over a period of time.

Following is a brief discussion of each verification parameter and their method of determination. Detailed descriptions of testing and analyses methods are provided sequentially in Sections 2.2 through 2.6. Each of these subsections first details the approach and procedures used to verify each parameter, and then provides guidance for each of the measurements and instrumentation required to evaluate the parameters.

Power Production Performance

Power production performance is an operating characteristic that is of great interest to purchasers, operators, and users of electricity generating systems. Key parameters that should be characterized include:

- Electrical power output and efficiency at selected loads within normal operating range
- Total electrical energy generated over an extended monitoring period

All microturbines are equipped with an electrical meter that measures and displays power generated. However, if an independent measurement of this key variable is required, a separate electric meter may be required. The GHG Center used a Power Measurements, Ltd. 7600 ION Power Meter to determine actual power delivered to the end user. The power output measurements with such a meter allow for determination of power losses from external voltage transformers, which is often not included in the power output displays of the manufacturer's control system. Power output can be continuously logged and averaged or integrated over the duration of the monitoring period to calculate average power output or total electrical energy generated, respectively.

Electrical efficiency determinations are based upon guidelines listed in ASME PTC22. This requires direct measurement of electrical power output (kW), fuel flow rate [standard cubic feet per minute (scfm) or pounds per hour (lb/hr)], and fuel heating value [British thermal units per cubic foot (Btu/ft^3) or British thermal units per pound (Btu/lb)]. Energy to electricity conversion efficiency is determined by dividing the electrical energy output by the fuel energy input. Natural gas fuel flow measurements can be conducted using a mass flow, displacement, or rotary type gas meter. Fuel gas heating values may be obtained from a local gas distribution company that supplies natural gas to the site. Independent determination of fuel energy content can be performed by obtaining actual fuel samples during testing, and by performing laboratory analysis to determine lower heating value (LHV) of the fuel. Detailed verification approaches for power production performance and electrical efficiency evaluations are provided in Section 2.2.

Power output and electrical efficiency of gas turbines can vary depending on inlet air conditions. For this reason, most microturbine performance specifications are stated relative to standard conditions [59 ^{o}F, 14.7 pounds per square inch absolute (psia), and 60 percent relative humidity (RH)], as identified by the International Standards Organization (ISO). For performance at other conditions, manufacturers often supply a series of performance curves that illustrate expected power output and efficiency levels at different ambient conditions. These curves may not be available for all microturbine models, and in some cases they may be generated using computer modeling. Thus, independent verification of power output and efficiency is recommended to determine performance at actual site conditions. The GHG Center recommends direct measurements of ambient temperature, RH, and atmospheric pressure, which is consistent with PTC22 requirements.

Power Quality Performance

The monitoring and evaluation of power quality performance is required to measure the quality of electrical power delivered by the microturbine. In some cases, the data can be used to demonstrate that the electricity does or does not interfere with or harm microelectronics and other sensitive electronic equipment within a facility that uses a microturbine. Power quality data is used to report "exceptions", which are the number and magnitude of incidents that fail to meet or exceed a power quality standard chosen. Such standards are developed by the American National Standards Institute (ANSI) and the IEEE, some of which have been adopted by the GHG Center to verify power quality parameters. Specifically, the IEEE's Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems were adopted to verify voltage and current total harmonic distortion (THD). Power quality parameters are determined over the verification period using the power meter (7600 ION or equivalent). The approach for verifying these parameters is described in Section 2.3. Power quality variables to be examined include the following parameters:

- Electrical frequency
- Voltage transients
- Voltage and current THD
- Power factor (Pf)

Operational Performance

The microturbine's operational performance should also be evaluated. The unit's ability to produce power when called upon is documented with the following performance parameters:

- Cold start time
- Operational availability

Microturbine start time is useful in knowing the time required to achieve a desired power setting when backup power is needed or when electrical power is needed during peak demand periods. Cold start time is defined as the number of seconds required to obtain full power after a start command is sent to the unit's control system, after a minimum shutdown period of 4 hours. The data can also be used to determine the number of successful starts achieved for each start opportunity provided.

Microturbine availability represents the percentage of time the unit is available to serve the load when called upon. Microturbine availability accounts for unscheduled downtimes due to failures of the unit, and is defined as the percentage of time the unit was operating relative to the total available operating hours. The approach for verifying these parameters is described in Section 2.4.

Emissions Performance

The measurement of the emissions performance of the microturbine system is critical to the determination of the environmental impact of the technology. Consistent with EPA's NSPS for stationary gas turbines, emission rates for nitrogen oxides (NO_x), carbon monoxide (CO), total hydrocarbons (THCs), carbon dioxide (CO_2), and methane (CH_4) should be determined at four different operating loads within the normal range of operation of the test unit. The reference method emissions testing procedures are adapted to verify emission rates of the following verification parameters at each load:

- NO_x emission rates
- CO emission rates
- THC emission rates
- CO_2 and CH_4 emission rates
- Estimated GHG emission reductions

For the conventional pollutants listed above, emission rates (e.g., mass/hour, mass/heat input, and mass/power output) are determined and reported. CO_2 and CH_4 emission rates are also determined in the exhaust stack. Using measured GHG emission rates and projections of operating hours, the total GHG emissions from the system can estimated. The total emissions are then compared with "baseline" emission levels. To accomplish this, it is assumed that in the absence of the microturbine, electricity would be supplied to the user by the utility grid. Subtraction of the microturbine emissions from the baseline emissions will yield an estimate of the emission reduction for the facility. Section 2.5 describes the sampling and analytical approach for verifying emissions performance, and Section 2.6 provides guidelines for estimating emission reductions.

2.2. POWER PRODUCTION PERFORMANCE

The power production performance evaluation reports electrical power output and efficiency at selected loads and total electric energy generated. The approach for determining these parameters is discussed below.

2.2.1. Electrical Power Output and Efficiency at Selected Loads

For the controlled test periods, the microturbine is modulated at four power commands within the normal range of operation (testing at four loads is a requirement of the emissions testing procedures specified in Section 2.5). Most commercially available units are designed to operate at full capacity, but lower operating points are achievable. The four load points selected for verification should include full load, and three additional load points that include the lowest operating load anticipated during normal use of the unit. During the GHG Center's verifications, testing was conducted at 50, 75, 90, and 100 percent of rated capacity. Electrical power output is determined with the use of a power meter, and fuel consumption rates are measured using a gas meter. Both meters can be programmed to measure 1-minute average readings that can be used to satisfy PTC22 requirements. Fuel heating value is determined using nationally published natural gas quality data, local gas quality reported by the distribution company, or preferably by collecting a minimum of one gas sample at each load condition for analysis. A detailed discussion of each measurement instrument is provided in Section 2.3. A step-by-step procedure for conducting the tests and an example log form are provided in Appendices A-1 and A-2. The time synchronized measurements data are used to compute average electrical power output and efficiency at a given load condition.

Per PTC22 guidelines, efficiency determinations must be performed for continuous time periods in which maximum variability in key operational parameters do not exceed specified levels. The time intervals can be as brief as 4 minutes or as long as 30 minutes. During verifications conducted by the GHG Center, testing at each of the four loads was conducted in triplicate (this is also a requirement of the emissions testing procedures specified in Section 2.5). Table 2-1 summarizes the maximum permissible variations specified for power output, Pf, fuel flow rate, barometric pressure, and ambient temperature during each load condition. The GHG Center has conducted load tests for 30 minutes, which is also consistent with those used to report average emission rates. Thus, efficiency and emission performance data correspond to identical operating conditions.

Table 2-1. Variability Allowed in Key Operating Conditions

Measured Parameter	Maximum Permissible Variation[a]
Power output	$\pm$ 2 %
Power factor	$\pm$ 2 %
Fuel flow	$\pm$ 2 %
Barometric pressure	$\pm$ 0.5 %
Ambient air temperature	$\pm$ 4 ^{o}F

[a] Maximum (average of test run – 1-minute observed value) / average of test run * 100

Continuous monitoring for these measurements is conducted throughout the controlled test periods to ensure the above criteria are satisfied. Should the variation in power output, ambient pressure, or temperature exceed the required levels, the controlled test should be invalidated and repeated. Variability in these measurements must be documented and reported for each individual test run conducted.

Electrical efficiency at the selected loads is computed as shown in Equation 1 (per ASME PTC22, Section 5.3).

$$h = \frac{3412.14\ kW}{HI} \qquad (Eqn.\ 1)$$

where :

ς = *efficiency (%)*

3412.14 = Conversion of Btu/hr to kW

kW = average electrical power output, Eqn. 2 (kW)

HI = average heat input based on LHV, Eqn. 3 (Btu/hr)

Average electrical power output is computed as the mathematical average of the 1-minute average readings over the sampling period (4 to 30 minutes), as shown in Equation 2.

$$kW = \frac{\sum_{i=1}^{i=nr} kWi}{nr} \qquad (Eqn.\ 2)$$

where :

kW = average electrical power output (kW)

kWi = power output reading of the electric meter for each minute (kW)

nr = number of 1 – minute readings logged by the electric meter

The average heat input (HI) is determined by measuring the amount of gas combusted by the microturbine and the LHV of the fuel. Using 1-minute average fuel flow rate data and the LHV results, average HI is computed, as shown in Equation 3.

$$HI = 60\ F_m LHV \qquad (Eqn.\ 3)$$

where :

HI = average HI based on LHV (Btu/hr)

F_m = average mass flow rate of natural gas to turbine (lbm/min)

LHV = average LHV of natural gas (Btu/lbm)

Electrical efficiency can then be summarized in tabular form as shown in the example data presented in Table 2-2.

Table 2-2. Example Results of Power Output and Electrical Efficiency Performance[a]

	Test Condition		Power Delivered	Fuel Input (Natural Gas)			Ambient Conditions		Electrical Efficiency
	% of Rated Power	Power Command (kW)	(kW)	Flow Rate (scfm)	LHV (Btu/ft^3)	HI (Btu/hr)	Temp. (^{o}F)	RH (%)	(%)
Run 1			71.28	18.19	950.30	1,037,157	61.78	65	23.45
Run 2			71.25	18.14	950.30	1,034,307	61.69	64	23.51
Run 3	100	75	71.24	18.23	950.30	1,039,438	62.71	61	23.39
Average			**71.26**	**18.19**	**950.30**	**1,036,967**	**62.06**	**63**	**23.45**
Run 4			64.63	16.58	950.30	945,358	64.44	58	23.33
Run 5			64.71	16.74	950.30	954,481	65.78	56	23.13
Run 6	90	68	64.78	16.72	950.30	953,341	67.13	55	23.19
Average			**64.71**	**16.68**	**950.30**	**951,060**	**65.78**	**56**	**23.22**
Run 7			53.40	14.12	946.60	801,960	66.68	56	22.72
Run 8			53.35	14.08	946.60	799,688	66.12	55	22.76
Run 9	75	56	53.33	14.14	946.60	803,095	65.63	56	22.66
Average			**53.36**	**14.11**	**946.60**	**801,581**	**66.14**	**56**	**22.71**
Run 10			35.91	10.93	946.10	620,452	67.79	57	19.75
Run 11			35.91	10.86	946.10	616,479	66.20	61	19.88
Run 12	50	38	35.88	10.88	946.10	617,614	64.76	62	19.82
Average			**35.90**	**10.89**	**946.10**	**618,182**	**66.25**	**60**	**19.82**

[a] Sampling time for each test run was 30 minutes

Electrical Efficiency with a Fuel Pressure Booster Compressor

Most commercial microturbines require a gas supply at a minimum pressure of 50 psig or more. For installations where gas supply is at lower pressures, a booster compressor is needed to pressurize the supplied gas to an acceptable level. Most microturbine manufacturers supply the units with optional booster compressors that are usually powered by the electricity generated by the microturbine. These internal electrical compressors are typically powered prior to the output transformer, directly from the primary output from the generator. In these cases, the efficiency determinations described above account for energy consumed by the booster compressor.

To make the results of a verification test applicable to installations where high-pressure gas may be available (e.g., gas transmission compressor stations), it is necessary to measure the power consumed by the electrical booster compressor. This enables efficiency and gross power output of the microturbine to be computed independent of the gas compressor. In addition, it enables readers to examine the microturbine efficiency ratings on the same basis as the ratings that are reported for similar technologies.

To measure the power requirements of the internal compressor, a separate meter is placed where the electrical motor powering the compressor is located. The power consumed (kW) is monitored at the same sampling rate as the power delivered by the unit (one reading per minute). The sum of the readings from the two power meters represent the gross power output without the booster compressor (Equation 4). Power consumed by a booster compressor may need to be corrected for transformer losses if electrical power is converted to a different voltage (e.g., 275 to 480 volts). Manufacturer specifications should be consulted to determine this. Based on the *American Electricians Handbook* (12^{th} Edition, pp 5-36 and 5-37), the average efficiency through a transformer in this application is around 98 percent or better. Using the gross power output readings, electrical efficiency is calculated in the same manner, as shown in Equation 4.

$$Gross\ \ Power\ \ Output\ \ (kW) = kW + (kW_{comp} * TE) \qquad (Eqn.\ 4)$$

where :

kW = *average electrical power output (kW)*

kW_{comp} = *power consumed by the booster compressor (kW)*

TE = *transformer efficiency (98%), if present*

Table 2-3 provides an example of the impact that a booster compressor can have on the overall electrical efficiency of the system.

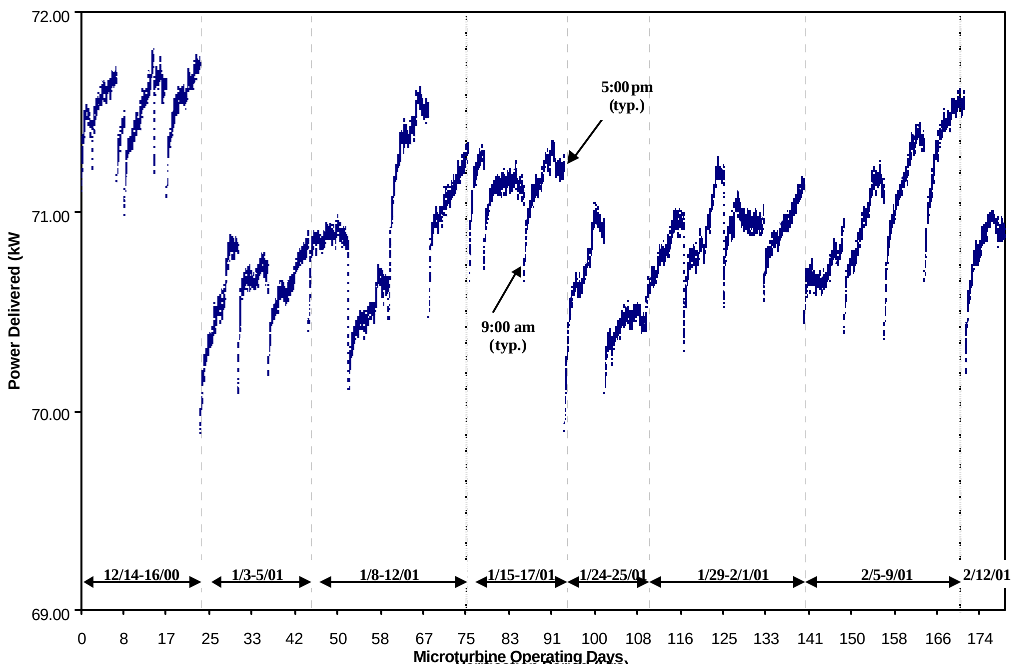
Table 2-3. Example Booster Compressor Power Requirements and Effects on Electrical Efficiency

		With Compressor		**Without Compressor**		
Test Condition		**Average Power Delivered (480 volts)**	**Average Electrical Efficiency**	**Power Consumed by Compressor (275 volts)**	**Estimated Total Power Delivered (480 volts)**	**Estimated Electrical Efficiency**
% of Rated Power	Power Command (kW)	(kW)	(%)	(kW)	(kW)	(%)
100	75	71.26	23.45	4.36	75.53	24.85
90	68	64.71	23.22	4.15	68.78	24.68
75	56	53.36	22.71	3.77	57.05	24.28
50	38	35.90	19.81	3.28	39.11	21.58

2.2.2. Total Electrical Energy Generated

After the controlled testing at selected loads, the microturbine should be operated as planned for the specific installation for the selected duration of the extended monitoring period. The electrical power output is continuously monitored and recorded throughout this period. Continuous monitoring of ambient meteorological conditions and gas flow rate must also be performed. Using these data, a time series plot of power output can be prepared and analyzed to determine total electricity generated. Measurement periods corresponding to the controlled tests, and unscheduled downtimes unrelated to the microturbine (i.e., intentional shutdowns by site operators) should be excluded from this analysis. Figure 2-1 provides an example taken from a microturbine that was operated on an 8-hour per day basis. These data are useful in evaluating the consistency and reliability of a unit's power output.

Figure 2-1. Example Microturbine Power Output at Full Power Command



Total electricity generated is computed from the measured power output and the operating time (Equation 5), and is reported in units of kWh.

$$Total\ \ Electrical\ \ Energy\ \ Generated\ \ (kWh) = \sum_{i-1}^{i=nr} kWi\ Time_i \qquad (Eqn. 5)$$

where :

kWi = *power output reading of the electric meter per minute (kW)*

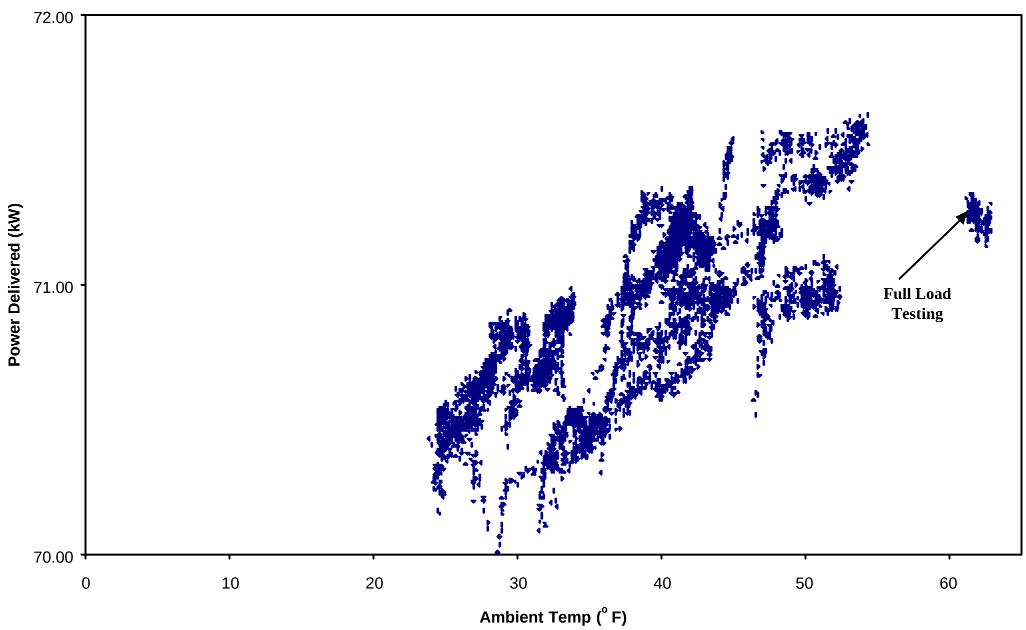
$Time_i$ = *sampling interval (min)*

nr = *number of 1 – minute readings logged by the electric meter*

It is recognized that variations in ambient meteorological conditions, specifically temperature, pressure, and RH, can significantly affect a gas turbine's ability to produce power. The electrical energy computation discussed above represent the combined effects of changes in such conditions, and does not provide insight on the microturbine's performance during specific ambient conditions.

Throughout verification testing, continuous measurements for temperature, pressure, and RH should be collected. The ambient monitors should be located in a close vicinity to the microturbine inlet air area, such that the true condition of the combustion air can be determined. The time series meteorological data can be examined with corresponding power output data to identify potential trends in the data. Figure 2-2 provides an example of this. The data should be reviewed to determine if significant increases or decreases in electrical power output occur at specific temperature, pressure, and RH ranges.

Figure 2-2. Example of Power Output vs. Ambient Temperature at Full Power Command

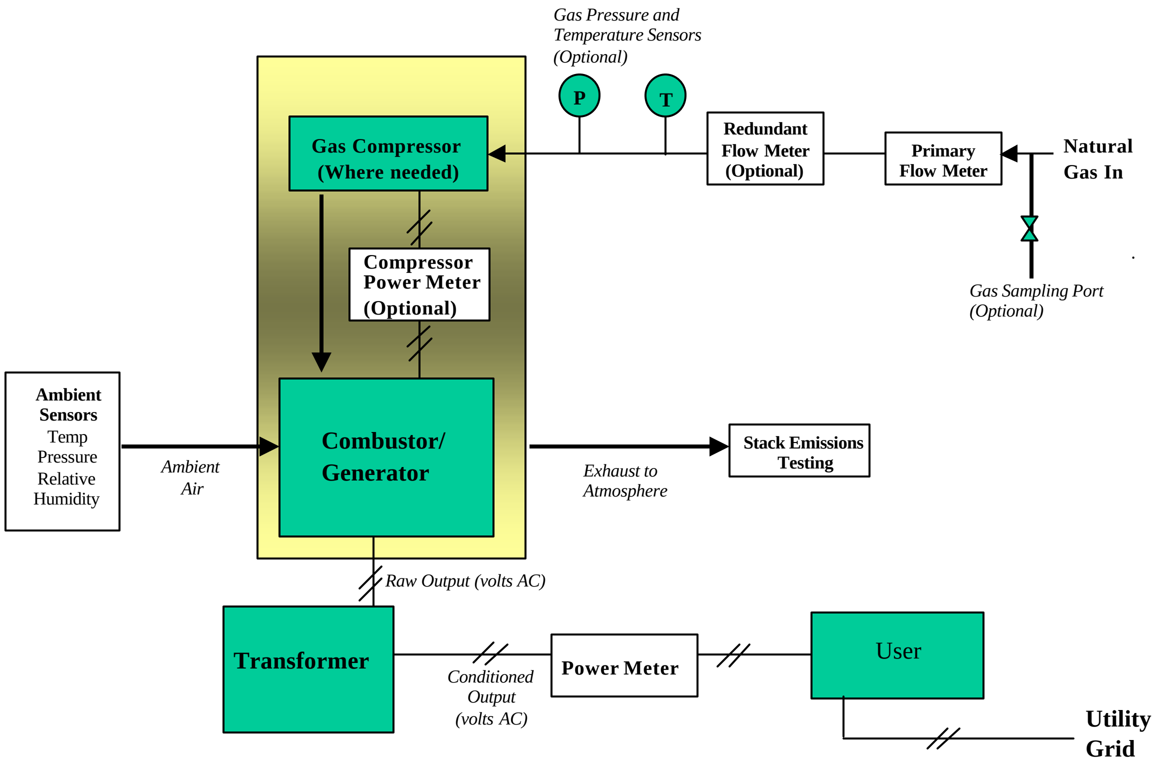


2.2.3. Instrumentation and Measurement Requirements

To reach sound conclusions regarding the power production performance evaluations described above, several key measurements must be conducted. Measurements including microturbine power output, fuel flow rate to the unit, LHV, and ambient conditions must be measured with a level of completeness and accuracy that satisfies the DQOs developed during planning of the verification (Section 3.0). Figure 2-3 provides a schematic of a typical measurement system.

The following subsections provide guidelines for these measurements and describe the instrumentation and measurement procedures employed by the GHG Center during past microturbine verifications. Section 3.0 of this guideline presents the DQOs that were specified for each of these measurements, the procedures that were used to evaluate measurement accuracy, and examples of the accuracy achieved during the GHG Center's verifications.

Figure 2-3. Schematic of a Typical Microturbine Verification Measurement System



2.2.3.1. Power Output Meter

Most power systems are equipped with power output metering instrumentation. These meters often measure power generated, not power delivered after voltage transformer losses occur. Determination of actual power delivered to the end user may be required at sites where after voltage transformers are required. Any suitable wattmeter that meets the desired accuracy criteria can be installed downstream of the transformer for this monitoring. The meter must be properly sized and equipped with suitable power and current transformers that are specified based on the output specifications for the test unit.

In addition to power output monitoring, this guideline specifies evaluation of power quality. A simple wattmeter is therefore not suitable when power quality is to be evaluated. A number of power meters are available commercially that have the capacity to simultaneously monitor power output and power quality parameters.

During verifications conducted by the GHG Center, electric power output was measured using a digital power meter manufactured by Power Measurements, Ltd. (Model 7600 ION). The 7600 ION continuously monitored the kW of real power at a rate of one reading per second, averaged at 1-minute intervals. This meter provided the desired level of accuracy in power measurements and also allowed the GHG Center to continuously monitor all of the desired power quality parameters. The meter also had the ability to monitor all three phases of power separately. It was installed after the voltage transformer (Figure 2-3), such that the electricity measured was the electricity that was ultimately used by the site. The real-time data collected by the 7600 ION was downloaded and stored using Power Measurements' PEGASYS software. Further discussion of the communication and data acquisition is provided in Section

4.0. After installation, the meter can operate continuously and unattended, and did not require further adjustments during the GHG Center's verifications. QA/QC procedures associated with instrument setup, calibration, and sensor function checks are discussed in Section 3.2.1.

If the verification includes evaluation of power consumed by a gas pressure booster compressor, a second power meter is needed (Figure 2-3). This meter should be capable of monitoring the power consumed by the booster compressor (kW), with the same level of accuracy as the power output meter.

2.2.3.2. Fuel Gas Conditions

The mass flow rate of the fuel supplied to the microturbine must be accurately measured and recorded. Some microturbine systems have built-in fuel metering capabilities that can be used for this measurement. In addition, most industrial or commercial facilities where a microturbine might be installed also have gas-metering capabilities, although the microturbine might not be isolated from other sources of gas use. Such meters measure volumetric flow rates and require measurement of gas temperature and pressure to correct actual flow rate to standard conditions. For the verifications conducted by the GHG Center, an independent metering system was required. Whatever metering system is selected, verification of meter accuracy is critical.

Many different types and sizes of gas flow meters are available commercially which include orifice type differential pressure (DP) meters, displacement type (diaphragm) dry gas meters, rotary and turbine meters, and coriolis type meters. Selection and proper installation of an appropriate gas meter is critical to any verification. In addition, more than one meter may be required where a wide range of gas flow rates and/or pressures are expected to enable accurate measurements over a wide range. Each meter type has certain advantages, disadvantages, and application criteria that should be carefully researched during verification planning. Considerations when selecting the best meter include:

- Expected range of fuel flow rates
- Desired accuracy (DQOs)
- Gas pressure and line size
- Fuel delivery system configuration
- Data acquisition and recording requirements
- Permanent gas pressure drop created by the meter (won't impede gas flow to microturbine)
- Cost

During the GHG Center's verifications, gas flow to the microturbines was determined using integral orifice meters (Rosemount Model 3095). Properties of these meters satisfied the GHG Center's metering requirements and were selected for the following reasons:

- Meter accuracy met the DQOs (± 1 percent of reading)
- Meters were adaptable to changing conditions/applications (orifice size is selectedable depending on metering conditions such as range of gas flow, gas pressure, and line size)
- The meters were internally temperature- and pressure-compensated, providing mass flow output at standard conditions (60 ^{o}F, 14.7 psia)
- The meters were programmable to continuously monitor flow at a rate of one reading per minute

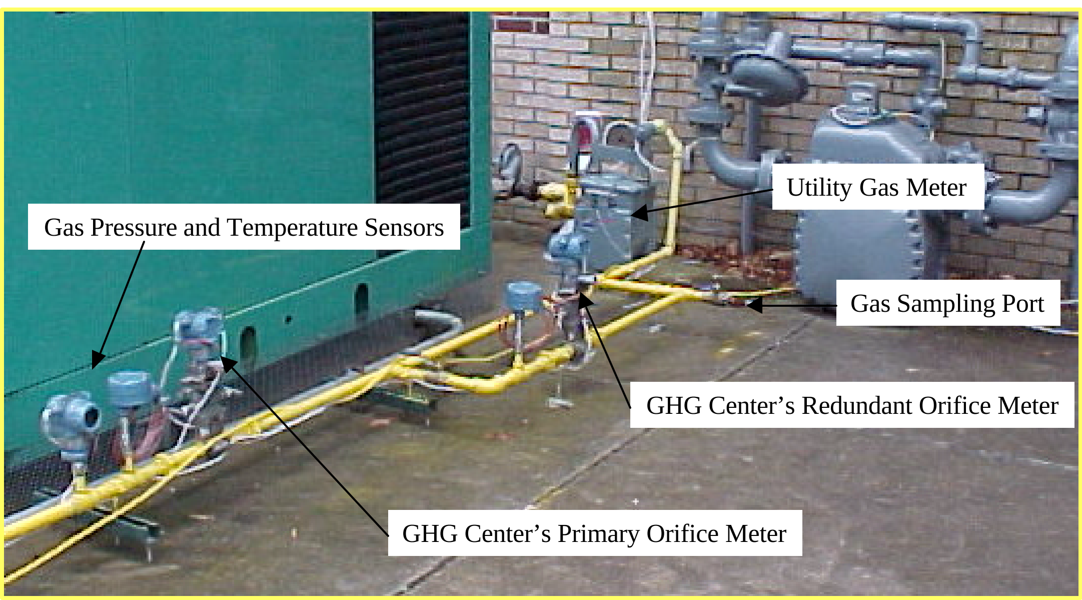
- The meters were fitted with a transmitter providing a 4 to 20 mA output over the metering range

Meter output was wired to an A/D module attached to a dedicated personal computer. Gas flow rates were then measured, recorded at 1-minute intervals in units of scfm, and stored on the computer. The computer was configured so that the GHG Center had remote access to the flow data, and files could be retrieved on a daily basis for review. Section 3.2.1 describes how metering accuracy was confirmed and documented.

Figure 2-4 shows the fuel metering equipment that was installed at one test site, including the utility gas meter and the GHG Center's redundant orifice meters. The utility dry gas meter was used to verify the accuracy of the orifice meters. Fuel gas pressure and temperature must be monitored to correct gas meter readings from actual conditions to standard conditions (60 ^{o}F, 14.7 psia). Many metering systems, such as the Rosemount orifice meters used by the GHG Center, have internal pressure and temperature correction capabilities. For metering systems lacking this capability, these additional measurements are required. The GHG Center conducted these measurements to independently confirm the accuracy of the Rosemount orifice meter pressure and temperature readings, and to correct gas flow readings from the utility displacement meter used for the independent gas flow checks to standard conditions.

For these measurements, the GHG Center used a Rosemount Model 3051 pressure transmitter and a Rosemount Series 68 resistance temperature detector (RTD). Pressure and temperature sensors should be installed as near as possible to the meter that these measurements will be used to correct. Calibration and QA/QC procedures for these measurements are detailed in Tables 3-3 and 3-4.

Figure 2-4. Example Fuel Metering System



For verifications where a higher degree of accuracy is needed, or site conditions warrant use of a different type of meter, sufficient resources should be dedicated to meter selection. In such cases, use of a second (redundant) meter for independent accuracy verification in the field is recommended. Due to safety concerns, only technicians certified to work on pressurized gas lines should conduct installation of gas meters. In order to achieve the highest level of accuracy, all installation specifications provided by the meter manufacturer should be strictly followed. The GHG Center has learned that insufficient runs of straight pipe, flow disturbances, mismatched line sizes, or gas conditions out of instrument range nearly always introduce measurement error that might otherwise be avoided.

Several QA/QC procedures must be followed to document the accuracy of the fuel flow metering. These procedures, detailed in Section 3.2.1, include meter calibration against primary standards, and procedures for conducting independent field checks with redundant meters. Section 3.2.1 includes an example of field meter comparisons conducted by the GHG Center.

2.2.3.3. Fuel Heating Value Measurements

LHV measurements are required to calculate HI to the microturbine. Most gas suppliers can supply LHV estimates of gas distributed to the test site. Several days of data should be examined to determine if gas composition is uniform enough to meet the variability criteria in PTC22 (permissible variation is ± 1 percent during a test period). If it is determined that the gas composition is uniform, (that is, generally within ± 2 percent over several days), then gas quality data should be obtained from the supplier during the controlled test periods. If significant variability in gas composition exists, it is recommended that gas samples be collected at the test site during the controlled test periods. For verifications conducted by the GHG Center, accurate measurement of LHV was required during the test periods.

LHV determinations are conducted by analyzing fuel gas samples in accordance with ASTM International (ASTM) Specification D1945 for quantification of CH_4 (i.e., molecules with one carbon atom) to hexane plus (i.e., molecules with six or more carbon atoms), nitrogen (N_2), oxygen (O_2), and CO_2. The analytical data are then used in conjunction with ASTM Specification D3588 to calculate the gross (HHV) and net (LHV) heating value, and the relative density of the gas. Some industrial facilities, such as natural gas handling or processing facilities, have on-site capabilities for monitoring gas quality at frequent intervals. For other facilities, samples must be collected and either analyzed on-site or shipped to a qualified laboratory for analysis.

Sampling frequency should be specified according to variability in gas quality. Typically, gas LHV is not highly variable during the course of a day, so for the controlled test periods, one sample per test load is sufficient (approximately every 2 hours). Samples should be collected in pre-evacuated stainless steel canisters provided by a qualified analytical laboratory. Safety precautions should be taken to ensure that leak free sampling connections can be made and gas pressure concerns are addressed. Detailed gas sampling procedures and log forms used by the GHG Center during verifications are presented in Appendix A. Appendix A-3 contains detailed procedures that may be followed, and Appendices A-4 and A-5 contain sampling log and chain of custody forms.

Several QA/QC procedures must be followed to document the accuracy of fuel sampling and analysis. These procedures, detailed in Section 3.2.1, include collection of replicate samples, duplicate sample analyses, calibration of analytical instrumentation, and submittal of blind audit samples (either CH_4 or natural gas standards). Section 3.2.1 also provides examples of results of LHV QA/QC checks conducted by the GHG Center. If supplier based gas LHV data are used, the corresponding QA/QC results must be obtained from the supplier/analyst to document accuracy.

2.2.3.4. Ambient Conditions Measurements

Meteorological data (temperature, RH, and barometric pressure) are collected to determine if the maximum permissible limits for determination of electrical efficiency are satisfied (Table 2-1), and to evaluate the impact of ambient conditions on microturbine performance. Many industrial facilities have on-site monitoring facilities, or access to local monitoring stations. Ideally however, the measurements should be taken in close proximity to the air intake of the turbine. Numerous portable instruments and monitoring stations are available to do this.

For the GHG Center's verifications, meteorological conditions were monitored using a pressure sensor and an integrated temperature/humidity unit located within 10 meters of the test units. The integrated temperature/humidity sensor selected uses a platinum 100 Ohm, 1/3 DIN RTD for temperature measurement. As the temperature changes, the resistance of the RTD changes. This change in resistance is detected and converted by associated electronic circuitry that provides a linear DC (4-20mA)-output signal. The integrated unit uses a thin film capacitive sensor for humidity measurement. The dielectric polymer capacitive element varies in capacitance as the RH varies, and this change in capacitance is detected and converted by internal electronic circuitry that provides a linear DC (4-20mA)-output signal. This sensor features electronic compensation to maintain accuracy over a broad range of temperature conditions. A variable capacitance sensor measured the barometric pressure. As pressure increases, the capacitance decreases. This change in capacitance is detected and converted by internal electronic circuitry that provides a linear DC (4-20mA)-output signal. The outputs of these units were wired to an A/D module attached to a dedicated personal computer.

Calibration and QA/QC procedures for meteorological measurements are detailed in Section 3.2.1. Should existing instrumentation at the test site be selected for this monitoring, the instruments should be calibrated and ideally, independently audited to verify accuracy and reliability.

2.3. 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 the same with the power grid. While in grid parallel mode, a microturbine must have proper synchronization to maintain grid connection (matched voltage and frequency at constant current). Most microturbines have power electronics that 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. To characterize a microturbine's ability to provide power at a desired voltage and frequency setting, measurement data are collected on the microturbine output. Simultaneous power quality measurements on the electricity supplied by the grid can be performed to identify reasons for potential shutdowns, and assess synchronization with the grid.

Similar to Pf, harmonic distortions in voltage and current must also be minimized to reduce damage or disruption to electrical equipment such as lights, motors, and office equipment. Industry standards for harmonic distortions have been established by which power generation equipment, such as a microturbine, must deliver.

The power quality evaluation approach has been developed to account for these issues, and evaluates electrical frequency output, voltage output and voltage transients, Pf, and THDs. Each parameter provides an understanding of the quality of electrical power produced by a microturbine. The methods for determining these parameters are discussed below. Calibration and QA/QC procedures for these measurements are detailed in Section 3.2.1.

2.3.1. Electrical Frequency Output

Electricity supplied in the U.S. is typically 60 hertz (Hz) alternating current (AC). Electrical frequency measurements conducted by the GHG Center were monitored at a rate of one reading per minute. The data are analyzed to determine daily maximum frequency, minimum frequency, average frequency, and standard deviation. In addition to daily results, the overall maximum frequency, minimum frequency, average frequency, and standard deviation in frequency should be reported for the entire test period. These parameters should be calculated only for those periods when the microturbine is in operation and supplied with an electrical load.

Equation 6 is used to compute the average frequency.

$$F = \frac{\sum_{i=1}^{i=nr} Fi}{nr} \qquad (Eqn. 6)$$

where :

F = average frequency (Hz)

Fi = 1-minute frequency reading of the electric meter (Hz)

nr = number of 1 − minute readings logged by the electric meter

The variance and standard deviation are related measures of how widely values are dispersed from the average value (mean). These values provide an indication of how stable the frequency output of the test unit is maintained. Equations 7 and 8 are used to compute the variance and standard deviation.

$$F\,var = \frac{\sum_{i=1}^{i=nr} (F - Fi)^2}{nr - 1} \qquad Fstd = \pm\sqrt{F\,var} \qquad (Eqns. 7, 8)$$

where :

$F\,var$ = variation in frequency (Hz)

$Fstd$ = standard deviation in frequency

F = average frequency (Hz)

Fi = 1 − minute average frequency reading of the electric meter (Hz)

nr = number of 1 − minute readings logged by the electric meter

Figure 2-5 provides an example of electrical frequency measured during one of the GHG Center's verifications for the entire verification period. The data are summarized in Table 2-4.

Figure 2-5. Example of Electrical Frequency During Extended Test Period

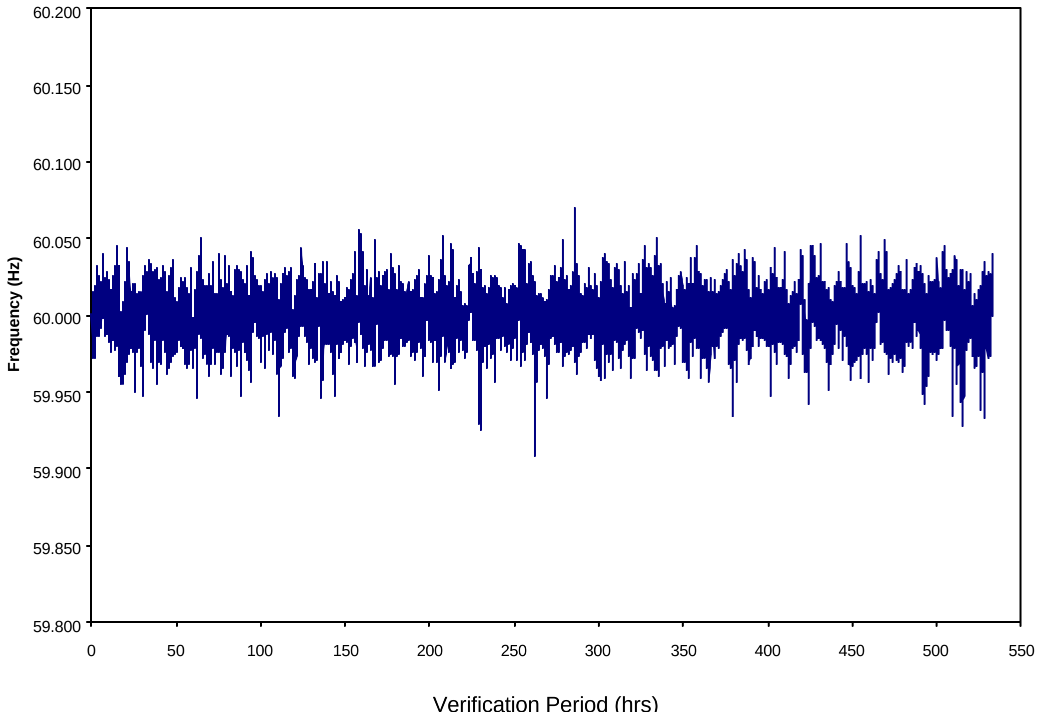


Table 2-4. Example Summary of Electrical Frequency Results

Parameter	Frequency (Hz)
Average Frequency	60.000
Minimum Frequency	59.908
Maximum Frequency	60.070
Standard Deviation	0.014

2.3.2. Voltage Output and Transients

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. Deviations from this range are often used to quantify voltage sags and surges. A voltage transient is a subcycle disturbance (typically an over-voltage) in the AC waveform. As defined by ANSI Standard 1100-1992, a transient is a subcycle disturbance that is evidenced by a sharp brief change in the system voltage. They are also known as spikes or surges that are normally on the line for only 1/1000th of a second or less (less than 1 millisecond). They can be from a few to 10,000 volts-peak above or below the voltage sinewave. Voltage transients normally last only about 50 microseconds according to the ANSI Standard C62.41-1991, which is the standard for transients in facilities operating under 600 volts$_{RMS}$. Transient overvoltages can result in equipment problems, and are caused by such events as electronic load switching, motor load switching, and lightning strikes.

Voltage output and voltage transients can be continuously monitored and recorded throughout the verification period using a power meter such as the 7600 ION meter used by the GHG Center, or other equivalent meter. The 7600 ION meter was capable of measuring 0 to 600 volts (AC) at a rate of one reading per minute, and identifying surges up to 8 kilovolt (kV). All voltage readings were reported as root mean square (RMS) voltage, which is the most common approach for measuring AC voltage. The total number of transient occurrences and the magnitude of each (greater than ± 10 percent of standard voltage) should be analyzed to quantify the following disturbances. All data should be reported on a daily basis, as well the cumulative results for the entire testing period.

- Total number of voltage disturbances exceeding ± 10 percent
- Maximum, minimum, average, and standard deviation of voltage exceeding ± 10 percent
- Maximum and minimum duration of incidents exceeding ± 10 percent

Equations 9, 10, and 11 can be used to compute the average, variance, and standard deviation of the voltage output.

$$V = \frac{\sum_{i=1}^{i=nr} Vi}{nr} \qquad V\,var = \frac{\sum_{i=1}^{i=nr} (V - Vi)^2}{nr - 1} \qquad Vstd = \pm\sqrt{V\,var} \qquad (Eqns.\ 9,\ 10,\ 11)$$

where :

V = *average voltage output (volts)*

Vi = *instantaneous voltage reading from the electric meter (volts)*

nr = *number of readings logged by the electric meter*

$V\,var$ = *variation in voltage output (volts)*

$Vstd$ = *standard deviation in voltage output*

Results of this testing can be summarized using figures and tables similar to those used to report verification results for frequency (Figure 2-5 and Table 2-4).

2.3.3. Voltage and Current Total Harmonic Distortion

Harmonic distortion of the voltage and current results from the operation of non-linear loads and devices on the power system. Harmonic distortions can damage or disrupt the proper operation of many kinds of industrial and commercial equipment. Voltage distortion is any deviation from the nominal sine waveform of AC line voltage. A similar definition applies for current distortion; however, voltage distortion and current distortion are not the same. Each affects load and power systems differently, and thus are considered separately.

In quantifying harmonic distortion, several parameters related to distortion are addressed, specifically the definition of a harmonic and how it is quantified. Fourier analysis breaks down a distorted waveform into a set of sine waves with two specific characteristics. The first characteristic deals with frequency of the waveform. The distorted waveform repeats itself with some basic frequency. The sine wave associated with this frequency, which is usually 60 Hz, is called the “fundamental.” Each successive sine wave, or harmonic of this particular set has a frequency that is an integer multiple of the fundamental. So, the 2nd harmonic has a frequency of 120 Hz, the 3rd is at 180 Hz, the 4th is at 240 Hz, and so on.

The second characteristic is the magnitude of the distortion, also called the harmonic distortion factor. Each of these sine waves may have a different magnitude from each other, depending on the actual distorted signal. A harmonic analyzer determines the magnitude. Typically, the magnitude of each harmonic is represented as a percentage of the RMS voltage of the fundamental, not the RMS voltage of the distorted waveform. The aggregate effect of all harmonics is called the THD. THD equals the RMS voltage of all harmonics divided by the RMS voltage of the fundamental, converted to a percentage.

Based on IEEE 519 Standards, microturbine manufacturers have specified values for total harmonic voltage and current distortion, as follows:

Maximum Voltage THD: 5 percent
Maximum Current THD: 5 percent

For the verification, harmonic distortion (up to the 63^{rd} harmonic) should be recorded for all voltage and current inputs using the selected power meter (7600 ION or equivalent). The meter should report 1-minute average THD for voltage and current, computed as shown in Equations 12 and 13. The results should be analyzed to report the average, maximum, and minimum THD for the test period.

$$Voltage\,THD = \frac{\sum_{i=1st\ Harmonic}^{i=63rd\ Harmonic} Volt_i}{Volt_1} \qquad (Eqns.\ 12,\ 13)$$

$$Current\ THD = \frac{\sum_{i=1st\ Harmonic}^{i=63rd\ Harmonic} Current_i}{Current_1}$$

where :

$Voltage\,THD$ = 1-minute average voltage THD (%)

$Current\ THD$ = 1-minute average current THD (%)

$Volt_i$ = RMS voltage reading for each harmonic (volts)

$Current_i$ = current reading for each harmonic (Amps)

Table 2-5 provides an example of summarized data for THDs measured during verification.

Table 2-5. Example Microturbine THDs During Verification Period

Parameter	Current THD (%)	Voltage THD (%)
Average	3.37	0.94
Minimum	2.84	0.64
Maximum	4.92	4.76
Standard Deviation	0.25	0.19

2.3.4. Power Factor

Power factor is the phase relationship of current and voltage in AC electrical distribution systems. It quantifies the reaction of AC electricity to various inductive loads that are found in motors, drives, and fluorescent lamp ballasts, and cause the voltage and current to shift out of phase. Additional power, measured in kilovolt-amps (kVA) must be generated to compensate for phase shifting. Mathematically, Pf is expressed as real power (kW) divided by apparent power (kVA). Under ideal conditions, current and voltage are in phase, which results in a Pf equal to 1.0 or 100 percent. If inductive loads are present, Pfs are less than this optimum value. In such instances, reactive components produce the magnetic field for the operation of a motor, drive, or other device that performs no useful work and does not register on measurement equipment such as the wattmeter. The reactive components, expressed as reactive kilovolt-amps (kVAR), contribute to undesirable heating of electrical generation and transmission equipment and real power losses to the source supplying electricity. Power factors ranging between 0.80 and 0.90 are common.

Most microturbines can be manually specified to deliver varying Pf. During the GHG Center's verification testing, a Pf setting of 1.0 was used because the test site operations required this operating condition. Continuous monitoring of Pf over the duration of the verification can be used to generate time series plots (similar to Figure 2-5), to assess the unit's ability to deliver power at a desired Pf setting. The data can also be summarized as shown in Table 2-4.

2.3.5. Power Quality Instrumentation and Measurement Requirements

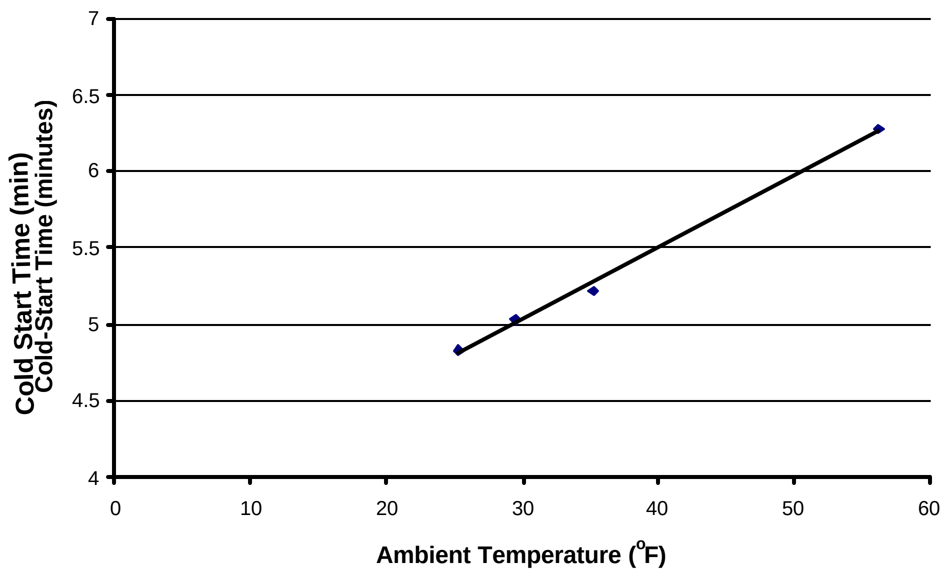
A power meter similar to the unit used during the GHG Center's verifications (7600 ION) is required to obtain all of the power quality measurements described here. The 7600 ION is extremely accurate and can provide the data in the desired time increments. Detailed specifications on this meter, or equivalent, should be obtained from the meter manufacturer to ensure that a power meter will provide sufficient performance. Accuracy specifications and QA/QC measures conducted during the verifications are discussed in Section 3.2.1.

2.4. OPERATIONAL PERFORMANCE

Operational performance evaluations document cold start time and operational availability. Microturbine start time is useful in knowing the time required to reach full power when backup power is needed or when electrical power is needed during peak demand periods. On most systems, the power system first undergoes a power-up sequence after a start command is received. The start-up system performs a self-diagnostic test to make sure the power system electronics are ready for operation and that the operator specified configuration values are correct, checks the grid voltage status, and checks the status of other processors. If all processors are functioning properly, the microturbine will begin operation and after some amount of time, the unit will stabilize to the maximum power that can be generated during that particular ambient condition.

For units used as emergency power providers or peak shaving units, it is useful to know the duration of the cold start sequence. The GHG Center verified cold start times after a minimum of 8 hours of shutdown period had occurred. To do this, the microturbine was specified to operate at full capacity. Cold start was measured from the time a start command was given until the time the unit reached full load. Documentation of cold start time should be conducted no less than four times and averaged for verification. An example log form for documenting cold start time is provided in Appendix A-6. It is recommended that these tests be conducted at several different ambient temperatures to document the impact of air temperature on start time. Figure 2-6 illustrates the impact that ambient temperature had on one of the units verified by the GHG Center.

Figure 2-6. Example Microturbine Cold Start Times



Operational availability represents the percentage of time the unit is available to serve the load when called upon. Availability is defined as the percentage of time the machine is unavailable due only to unscheduled downtimes. Unscheduled downtimes represent times during which the unit failed to produce electricity. Manual logs of unscheduled downtimes and reasons for each shutdown (e.g., Was the error operator related?, Would the error occur with unmanned operation? If so, how long could the unit be expected to be down until repairs can be made?) can be maintained throughout the verification period. These logs are combined with continuously monitored power output data used to calculate microturbine availability, as shown in Equation 14.

$$Availability\ (\%) = \frac{Period - UD}{Period} * 100 \qquad (Eqn.\ 14)$$

where :

$Period$ = *duration of testing period, excludes periods corresponding to controlled tests and other manual measurements (hrs)*

UD = *unscheduled downtime due to failure of the microturbine (hrs)*

2.5. EMISSIONS PERFORMANCE

Exhaust stack emissions testing is conducted to determine emission rates for criteria pollutants (NO_X, CO, and THC) and GHGs (CO_2 and CH_4). Stack emission measurements should be conducted in conjunction with the electrical power output and efficiency measurements in the controlled test periods. Following NSPS guidelines for evaluation of emissions from stationary gas turbines (40 CFR 60, Subpart GG), exhaust stack emissions testing is conducted at four points within the normal operating range of the test unit, including the minimum point in the range and peak load. During the GHG Center's verifications, these levels were selected at 50, 75, 90, and 100 percent of full load capacity. The microturbine should be allowed to stabilize at each load for 15 to 30 minutes before starting the tests. To verify testing precision, three replicate test runs (each approximately 30 minutes long) should be conducted for each parameter at each load selected. The average results of the three replicates are reported.

The average emission rate measured during each test run should be reported in units of parts per million volume dry (ppmvd), for NO_X, CO, CH_4, and THC, percent for O_2 and CO_2, pounds per hour (lb/hr), and pounds per kilowatt hour (lb/kWh) for energy produced. Consistent with Subpart GG requirements, reported pollutant concentrations are corrected to 15 percent O_2 (using direct exhaust gas O_2 measurements). Appendices B-3 and B-4 illustrate examples of the emissions test results. As with the power production and efficiency performance testing, microturbine operators must maintain steady unit operation and load for the duration of each emissions test. Variability in unit operation is not specified in the testing methods, but the variability criteria presented in Table 2-1 can be used as a guideline to verify that the tests are conducted during steady operation. Variability in fuel flow to the turbine (limited to 2 percent variability for the efficiency measurements) may exceed the limits specified in Table 2-1 slightly over the 30-minute test period, but small exceptions up to 2 percent are not expected to affect the emission rate measurements. An organization specializing in air emissions testing should perform all stack testing.

All of the emission test procedures used should be EPA Federal Reference Methods or equivalent. The Reference Methods are well documented in the Code of Federal Regulations, most often applied to determine pollutant levels, and include procedures for selecting measurement system performance specifications and test procedures, quality control procedures, and emission calculations (40CFR60, Appendix A). Table 2-6 summarizes the standard Test Methods that should be followed.

The Reference Methods generally address the elements listed below:

- Applicability and principle
- Range and sensitivity
- Definitions
- Measurement system performance specifications
- Apparatus and reagents
- Measurement system performance test procedures
- Quality control procedures
- Emission calculations
- Bibliography

Each of the selected methods utilizing an instrumental measurement technique includes performance-based specifications for the gas analyzer used. These performance criteria cover span, calibration error, sampling system bias, zero drift, response time, interference response, and calibration drift requirements.

Each test method is discussed in more detail in the following sections. The entire Reference Methods are not repeated here, but can be obtained and viewed using the Code of Federal Regulations (40CFR60, Appendix A).

Table 2-6. Summary of Emission Testing Methods

Air Pollutant	EPA Reference Method	Principle of Detection	Typical Analytical Range[a]	Accuracy	Typical Loads Tested (% nominal capacity)	No. of Test Replicates
O_2	3A	Paramagnetic or fuel cell	0 to 25 %	± 5 %	50, 75, 90, and 100	3 per load (30-minutes)
CO_2	3A	Nondispersive infrared spectroscopy (NDIR)	0 to 10 %	± 5 %		
NO_X	20	Chemiluminescence	0 to 25 ppmvd	± 2 %		
CO	10	NDIR-Gas Filter Correlation	0 to 25 ppmvd	± 5 %		
CH_4	18	Gas chromatograph/Flame ionization detector (GC/FID)	0 to 25 ppmvd	± 10 %		
THC[b]	25A	Flame ionization	0 to 25 ppmvd	± 5 %		

[a.] Actual range should be determined prior to testing, using a portable analyzer or manufacturer specifications
[b] Volatile organic compound (VOC) emissions can be determined as measured THC minus measured CH_4

2.5.1.1. Gaseous Sample Extraction, Conditioning, and Handling

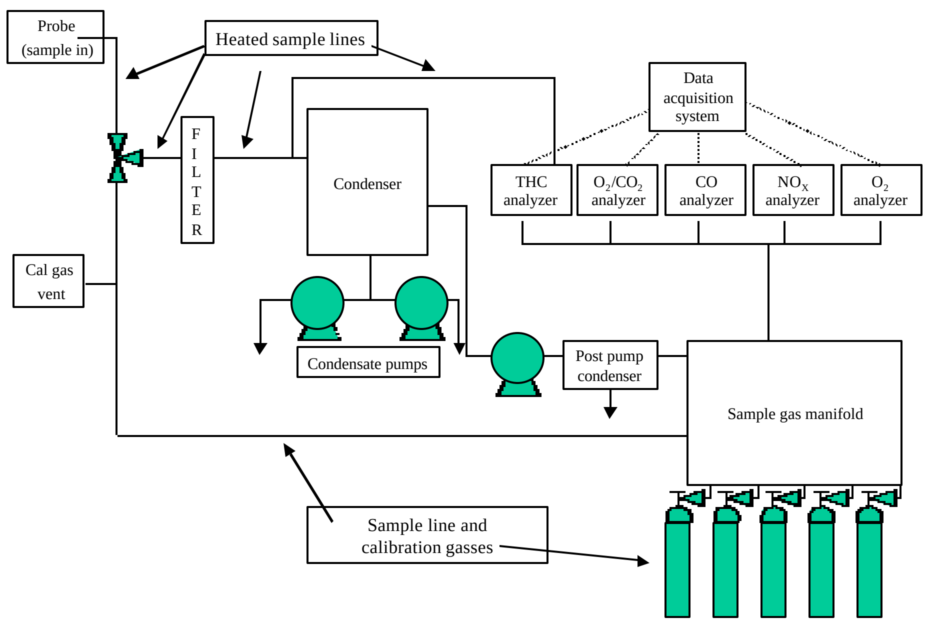
A schematic of a typical extractive sampling system used to measure concentrations of CO_2, O_2, NO_x, CO, and THC is presented in Figure 2-7. A continuous stream of microturbine exhaust gas is extracted and analyzed for pollutant concentrations. Most commercially available microturbines have an exhaust vent with little or no duct or stack. Method 20 for determination of NO_x emissions from stationary gas turbines requires a sampling traverse be conducted across the area of the exhaust stack or duct to collect integrated gas samples. To satisfy this requirement, a stack extension is recommended. The extension should be fabricated so that it provides sufficient straight run of duct (no less than three equivalent diameters) to allow for traversing with the probe. The extension should be secured to the microturbine exhaust vent in such a manner to minimize introduction of dilution air into the exhaust gas stream.

Due to the small diameter of the stack extensions used during the GHG Center's verifications, and the absence of gas stratification, the GHG Center employed single-point sampling procedures. Stratification tests were conducted on each verification and indicated no gas stratification, and therefore a stainless steel probe was fixed at a point near the center of each stack for sampling. It is recommended that an O_2 stratification test be conducted in accordance with Method 20 procedures to confirm the absence of stratification before adopting the single-point sampling strategy. If gas stratification is present in the exhaust gas stream, Method 20 procedures for selection of sampling traverse points should be followed.

In order for the CO_2, O_2, NO_x, and CO instruments to operate properly and reliably, the flue gas must be conditioned prior to introduction into the analyzer. The gas conditioning system is designed to remove water vapor from the sample. All interior surfaces of the gas conditioning system are made of stainless steel, Teflon™, or glass to avoid or minimize any reactions with the sample gas components. Gas is extracted from the turbine exhaust through a stainless steel probe and sample line. The gas is then transported using a sample pump to a gas conditioning system that removes moisture. Several types of moisture removal systems are available including permeation tube systems, and numerous types of condensers. The permeation tube systems are preferred for these low moisture sources because they eliminate the need to condense the moisture out of the gas and therefore minimize the chance of nitrogen dioxide (NO_2) scrubbing. The clean, dry sample is then transported to a flow distribution manifold where sample flow to each analyzer is controlled. Calibration gases can be routed through this manifold to the sample probe by way of a Teflon line. This allows calibration and bias checks to include all components of the sampling system. The distribution manifold also routes calibration gases directly to the analyzers, when linearity checks are made on each.

The THC analyzer is equipped with a FID as the method of detection. This detector analyzes gases on a wet, unconditioned basis. Therefore, a second heated sample line is used to deliver unconditioned exhaust gases from the probe to the THC analyzer.

Figure 2-7. Typical Exhaust Gas Sampling and Analysis System

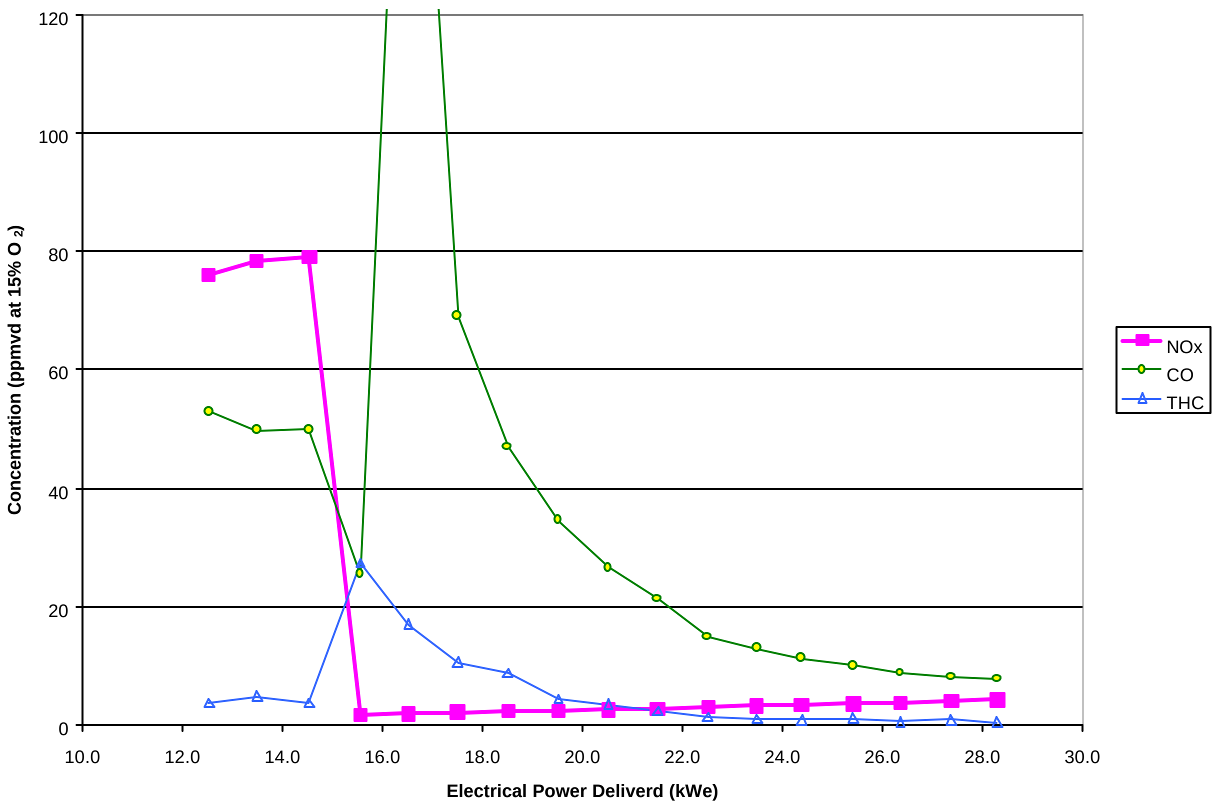


2.5.1.2. Gaseous Pollutant Sampling Procedures

Numerous emissions testing analyzers are available commercially to conduct these tests. The GHG Center does not endorse the use of any one analyzer over another, but the analytical principles of detection listed in Table 2-6 must be followed. Extracted and conditioned exhaust gas is directed to the analyzers for detection. Appropriate analyzer ranges expected at each load condition should be selected prior to testing. The analytical range of each analyzer should be selected such that no measurements during the verification are less than 30 percent of the range, or above the range. In some cases where microturbine emissions are extremely low or not detectable, readings will be less than 30 percent of the range. Preliminary screening is recommended prior to verification testing using a portable emissions analyzer on the test unit or by reviewing emissions data from a similar source. During the screening process, the test unit should be operated at each of the load points identified for verification because emissions can change dramatically as load points change, particularly for CO and THC emissions. In some cases, multiple analyzer ranges are needed to accommodate changes in emission rates at different loads.

To illustrate this, the GHG Center measured pollutant concentrations in the exhaust gas of a microturbine at intervals of 1 kW, starting at full load (30 kW) and ending at less than 50 percent capacity (13 kW). Figure 2-8 shows the results of these measurements and illustrates the dramatic changes in emissions that can occur as operating load is reduced. A test such as this (at multiple output levels) is not required for verification, but can provide useful information regarding the emissions characteristics of the unit as a function of power output. If these measurements are made, it is recommended that the unit be allowed to stabilize for at least 10 minutes after changing load command, and at least 10 minutes of data be collected and averaged at each set point. This sampling interval is less than that required in the Reference Methods, but this exercise is a useful screening technique as discussed earlier.

Figure 2-8. Example Microturbine Emissions at Various Power Outputs



Once a satisfactory sampling system is assembled and proper analyzers and ranges are selected, several QA/QC checks must be conducted prior to testing. These checks, detailed in Section 3.2.2, include system leak checks, analyzer performance tests, system response time tests, and analyzer calibrations. After all QA/QC checks are satisfied, verification testing can be conducted in conjunction with the power performance and efficiency testing.

Using an appropriate data acquisition system (DAS), analyzer outputs should be compiled as 1-minute averages throughout each test and averaged over the entire test period. Parameter concentrations are recorded in units of ppmvd for NO_X, CO, and THC, and percent for O_2 and CO_2. Concentrations of NO_X, CO, and THC are then reported as ppmvd corrected to 15 percent O_2 (ppmvd @ 15 % O_2) using Equation 15.

$$ppmvd\ @\ 15\ \%\ O_2 = ppmvd * [(20.9 - 15.0) / (20.9 - \text{exhaust gas } O_2)] \qquad (Eqn.\ 15)$$

Where:

ppmvd = average of 1-minute measurements for each pollutant
exhaust gas O_2 = average of 1-minute O_2 concentrations

Concentrations of CH_4 are determined in conjunction with each test run using a GC equipped with an FID (GC/FID). The analyses can be conducted using an on-site GC/FID by passing a slipstream of the extracted exhaust gas to the instrument. Alternately, integrated gas samples can be collected in Tedlar bags and shipped to a qualified laboratory for analysis. Following either procedure, samples are directed to the GC/FID after calibrating the instrument with appropriate certified calibration gases. Sample collection bags must be leak checked prior to testing. In addition, one replicate sample should be collected and one duplicate analysis should be conducted for each turbine load tested. The replicate samples can be used to demonstrate repeatability with regard to sample collection procedures, and the duplicate analyses can be used to demonstrate analytical repeatability.

2.5.1.3. Determination of Emission Rates

The instrumental testing for CO_2, O_2, NO_X, CO, THC, and CH_4 provides results of exhaust gas concentrations in units of percent for CO_2 and O_2 and ppmvd @ 15 percent O_2 for NO_X, CO, THC, and CH_4. The THC results are as ppmv on a wet basis, and must be corrected to ppmvd based on measured exhaust gas moisture measurements made in conjunction with the testing. No less than once at each load tested, an EPA Reference Method 4 test should be conducted to determine the moisture content of the exhaust gases.

Since turbine exhausts tend to be turbulent, EPA Method 19 is preferred for calculating emission rates instead of measuring the gas flow rate using EPA Method 2 procedures. Even on exhausts where stack extensions were used to straighten the flow of exhaust gases, the flow rates on some microturbines are extremely low and difficult to quantify using Method 2. EPA Method 19 provides procedures for converting the ppmvd concentration values of the exhaust gas pollutants to emission rate values in units of lb/hr). For these verifications, the lb/hr emission rates are normalized to turbine HI and reported as pounds per million British thermal units (lb/MMBtu), and to turbine output and reported as lb/kWh.

The fundamental principle of this method 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/HI value, (e.g., standard cubic feet per million Btu). This method applies only to combustion sources for which the heating value for the fuel can be determined. The F-factor can be calculated from either CO_2 or O_2 values, on either a wet or dry basis, as dictated by the measurement conditions for the gas concentration determinations. This method includes all calculations required to compute the F-factors and guidelines on their use. The F-factor for natural gas can be calculated from the fuel compositional analyses, or the published F-factor for natural gas [8,710 dry standard cubit feet per million British thermal units (dscf/MMBtu)] can be used as allowed by Method 19.

Measured pollutant concentrations as ppmvd will first be converted to pounds per dry standard cubic foot (lb/dscf) using the following unit conversion factors:

CO_2: 1 ppmvd = 1.142E-07 lb/dscf
NO_X: 1 ppmvd = 1.194E-07 lb/dscf
CO: 1 ppmvd = 7.264E-08 lb/dscf
THC: 1 ppmvd = 4.15E-08 lb/dscf (THC emissions are quantified as CH_4)
CH_4: 1 ppmvd = 4.15E-08 lb/dscf

Emission rates for each pollutant can then be calculated using Equation 16.

*Emission rate (lb/kWh) = [Ci * HI * F-factor * (20.9/(20.9-O_2))] / kW* *(Eqn. 16)*

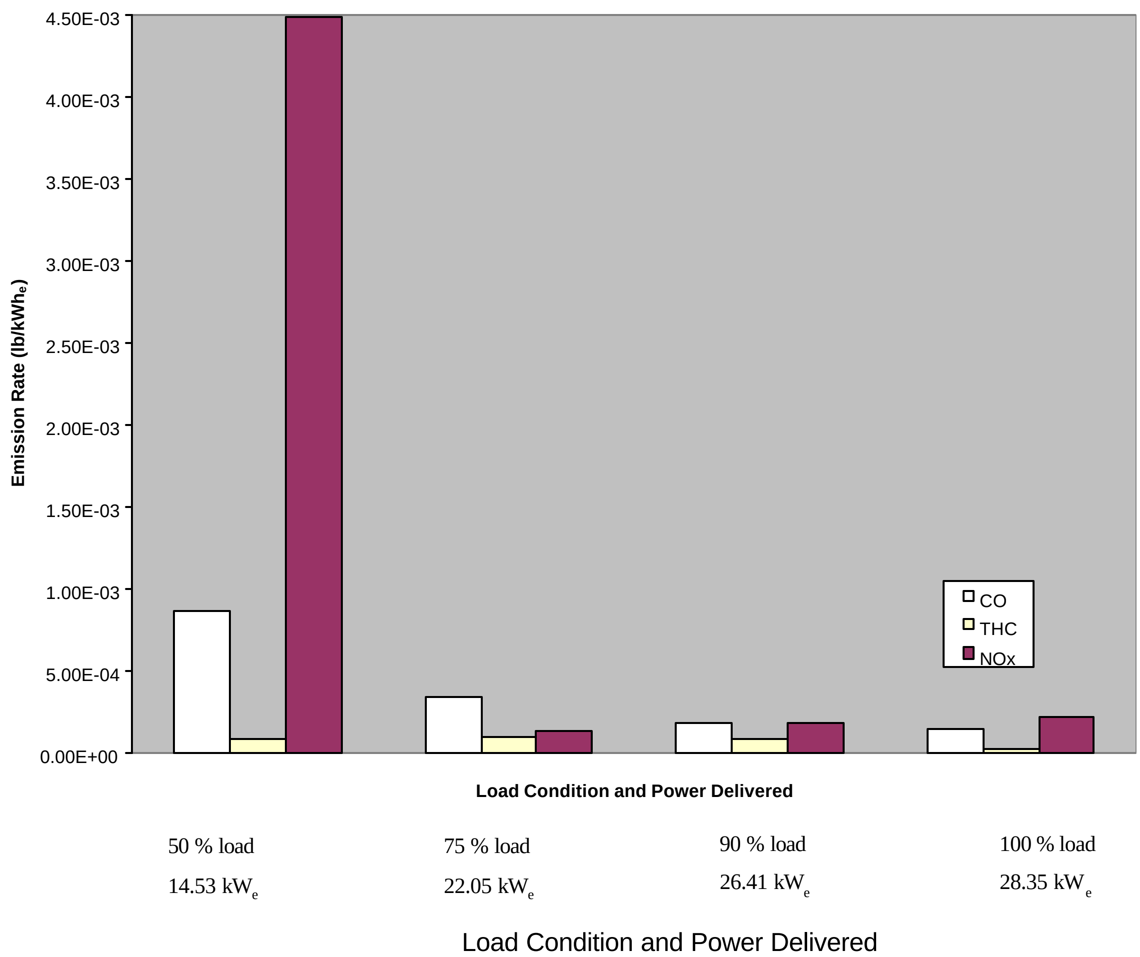
Where:
Ci = pollutant concentration (lb/dscf)
453.359 = units conversion lb to g
HI = average engine HI during test (Btu/hr)
F-factor = calculated fuel F-factor (dscf/MMBtu)
O_2 = average measured exhaust gas O_2 concentration (percent)
kW = average microturbine power output during test (kW)

Results of the testing can be summarized in tabular form as illustrated in Table 2-7. Figure 2-9 provides an example of graphic representation of measured emissions.

Table 2-7. Example Microturbine Emissions Testing Results

Test	Power Output (kW)	Ambient Temp. (°F)	Relative Humidity (%)	Exhaust O_2 (%)	CO Emissions (ppm @ 15% O_2)	CO Emissions lb/hr	CO Emissions lb/kWh	NO_x Emissions (ppm @ 15% O_2)	NO_x Emissions lb/hr	NO_x Emissions lb/kWh	THC Emissions (ppm @ 15% O_2)	THC Emissions lb/hr	THC Emissions lb/kWh	CO_2 Emissions %	CO_2 Emissions lb/hr	CO_2 Emissions lb/kWh
1	71.28	61.8	65.2	18.73	1.4	0.0031	4.34E-05	18.8	0.070	9.85E-04	< 2.00	< 7.07E-03	< 9.92E-05	1.27	123.55	1.73
2	71.25	61.7	63.7	18.71	1.6	0.0037	5.15E-05	18.4	0.068	9.59E-04	< 2.00	< 6.99E-03	< 9.81E-05	1.24	119.23	1.67
3	71.24	62.7	60.8	18.71	2.0	0.0043	6.04E-05	18.5	0.070	9.79E-04	< 2.00	< 7.02E-03	< 9.86E-05	1.26	121.76	1.71
AVG	**71.26**	**62.1**	**63.2**	**18.72**	**1.7**	**0.0037**	**5.18E-05**	**18.6**	**0.069**	**9.74E-04**	**< 2.00**	**< 7.03E-03**	**< 9.86E-05**	**1.26**	**121.51**	**1.71**
4	64.63	64.4	57.7	18.79	7.1	0.0151	2.33E-04	20.0	0.069	1.06E-03	< 2.00	< 6.63E-03	< 1.03E-04	1.21	110.36	1.71
5	64.71	65.8	56.1	18.80	7.8	0.0165	2.55E-04	19.6	0.068	1.05E-03	< 2.00	< 6.73E-03	< 1.04E-04	1.22	112.90	1.74
6	64.78	67.1	55.0	18.79	6.1	0.0129	1.99E-04	19.6	0.067	1.04E-03	< 2.00	< 6.68E-03	< 1.03E-04	1.21	111.25	1.72
AVG	**64.71**	**65.8**	**56.3**	**18.79**	**7.0**	**0.0148**	**2.29E-04**	**19.7**	**0.068**	**1.05E-03**	**< 2.00**	**< 6.68E-03**	**< 1.03E-04**	**1.21**	**111.51**	**1.72**
7	53.40	66.7	55.6	18.97	61.4	0.1082	2.03E-03	28.4	0.082	1.54E-03	< 2.00	< 6.15E-03	< 1.15E-04	1.13	95.63	1.79
8	53.35	66.1	55.1	18.94	54.1	0.0951	1.78E-03	27.7	0.080	1.50E-03	< 2.00	< 6.04E-03	< 1.13E-04	1.13	93.85	1.76
9	53.33	65.6	55.7	18.94	56.1	0.0993	1.86E-03	27.6	0.080	1.51E-03	< 2.00	< 6.06E-03	< 1.14E-04	1.13	94.29	1.77
AVG	**53.36**	**66.1**	**55.5**	**18.95**	**57.2**	**0.1008**	**1.89E-03**	**27.9**	**0.081**	**1.51E-03**	**< 2.00**	**< 6.08E-03**	**< 1.14E-04**	**1.13**	**94.59**	**1.77**
10	35.91	67.8	57.0	19.24	730.5	0.9951	2.77E-02	42.7	0.096	2.66E-03	40.20	3.13E-02	8.71E-04	1.00	76.17	2.12
11	35.91	66.1	60.8	19.24	780.3	1.0556	2.94E-02	42.4	0.094	2.62E-03	47.80	3.68E-02	1.03E-03	1.00	75.64	2.11
12	35.88	61.4	64.5	19.22	831.4	1.1274	3.14E-02	41.5	0.092	2.58E-03	59.90	4.66E-02	1.30E-03	0.99	74.16	2.07
AVG	**35.90**	**65.1**	**60.8**	**19.23**	**780.7**	**1.0594**	**2.95E-02**	**42.2**	**0.094**	**2.62E-03**	**49.30**	**3.82E-02**	**1.06E-03**	**1.00**	**75.32**	**2.10**

Figure 2-9. Example Graphic Presentation of Microturbine Emission Rates



2.6. ELECTRICITY OFFSETS AND ESTIMATION OF EMISSION REDUCTIONS

2.6.1. Introduction

Section 2 of this guidline defined the baseline system as electricity generated at central power stations and distributed to the end users via the utility grid. The electric energy generated by a microturbine will offset the electricity supplied by the grid whether the unit is operated in stand-alone mode or interconnected to the grid. Consequently, the reduction in electricity demand from the grid caused by this offset will result in changes in GHG (primarily CO_2) emissions associated with producing an equivalent amount of electricity at a central power plant. If the emissions per unit of electricity associated with the microturbine are less than the emissions per unit of electricity produced from an electric utility, it can be implied that a net reduction in emissions will occur at the site using the microturbine. Conversely, if the emissions from the microturbine are greater than the emissions from the grid, possibly due to the use of higher efficiency power generation equipment or zero emissions generating technologies (nuclear and hydroelectric) at the power plants, a net increase in emissions can occur. Electricity offsets will have an impact on other GHG pollutants and NO_X emissions as well.

To summarize, the verification approach for determining annual emission reductions (or increases) associated with the microturbine consists of the following steps:

1. Project annual electricity production potential of the microturbine and calculate its emissions (Section 2.6.2)
2. Estimate annual emissions for producing an equivalent amount of electricity using baseline emission factors (Section 2.6.3)
3. Estimate emission reductions by comparing the results from Steps 1 and 2, as shown in Equation 17.

$$\mathrm{Re}\,duction_{CO2} = (E_{microCO2} - (E_{baselineCO2} * LLoss)) * kWh_{DG} \qquad \textit{(Eqn. 17)}$$

Where: $Reduction_{CO2}$ *= Net reduction of* CO_2 *emissions, lb*

$E_{microCO2}$ *= Verified* CO_2 *emission rate of the microturbine at the load that represents actual operation, lb/kWh*

$E_{baselineCO2}$ *= Baseline system* CO_2 *emission rate, lb/kWh*

LLoss = line losses between central power stations and DG site (1 + assumed losses)

kWh_{micro} *= Site electricity generated by microturbine, kWh*

Note that Equation 17 assumes that all electricity generated by the microturbine will be consumed on-site and not exported to the grid. If excess electricity is exported, actual emission reductions will be lower due to lower line losses.

The more complex step is determination of the baseline emissions that are being displaced by the electricity generated by the microturbine. As shown in Table 2-8, each type of fuel contributes different amounts of total power to the national grid and emits different amounts of CO_2 and NO_X per kWh delivered. Currently, only CO_2 emissions data are published and readily available to the public. For this reason, the following text uses CO_2 as the primary GHG. It is recognized that displacement of CH_4 and nitrous oxide (N_2O) can occur, and the reader is encouraged to apply this approach if emission factors for these GHGs are available.

National averages may represent an oversimplified picture of the actual emissions displaced by a particular DG project. The inventory of grid connected generating units (GU) and their emission factors can vary widely by region. For example, regional CO_2 emission factors are higher in areas where generation is largely fossil-fuel based as opposed to nuclear and hydro. Appendix C summarizes fuel-based emission factors for the U.S. census divisions.

Table 2-8. 1999 U.S. Average Electricity Generation and Emission Factors			
Fuel	**Net Generation, 10^6 kWh**	**CO_2 Emission Factor, lb/kWh**	**NO_X Emission Factor, lb/kWh**
Coal	1,767,679	2.15	0.00741
Nuclear	725,036	0	0
Gas	296,381	1.34	0.00254
Net Hydroelectric[a]	293,932	0	0
Petroleum[b]	86,929	1.73	0.00283
Other[c]	3,716	0.464	0.00269
Total/Aggregate	3,173,673	1.38	0.00444

Source: EIA Electric Power Annual, 1999 (EIA 1999), Volume II, Tables 1 and 25
[a] Includes pumped storage hydroelectric minus energy used for pumping
[b] Includes petroleum coke
[c] Includes geothermal, biomass, wind, and photovoltaic

Another consideration when determining baseline emission factors is the intended use of the microturbine. A unit used primarily for backup power and peak shaving during periods of high demand will offset emissions generated by peak shaving units at the utility level (typically oil and gas fired units). Conversely, a microturbine that is designed to operate continuously regardless of grid demand might offset emissions generated by baseline GUs (typically coal, hydro, or nuclear).

Finally, since the microturbine's location is at or near the point of use, T&D system losses will be lower than the losses for power wheeled in from the grid. This means that the grid must create more power (and emissions) to compensate for the T&D losses.

In order to calculate the baseline emission factor, the following steps can be followed:

- Select the baseline fuel types which will be offset by the microturbine and justify the selection
- Calculate the baseline emission rate
- Estimate or calculate T&D losses
- Apply the calculations to the emission reduction determination

Section 2.6.3 presents a detailed discussion of these steps.

2.6.2. Determination of Microturbine GHG Emissions

The first step in estimating GHG emission reductions for the microturbine (or any DG source of emissions), is to estimate the emissions associated with generating electricity on-site over a given period of time (e.g. 1-year). Section 2.5 provided procedures for verifying microturbine emission rates at four operating loads. For a unit that is projected to operate only at full load, then the full load emission rate, along with projected annual operating hours, allows the calculation of annual emissions [pounds per year (lb/yr)], as shown in Equation 18.

$$Emissions_{microCO2} = E_{microCO2,100\%} * kWh_{micro} \qquad \textit{(Eqn. 18)}$$

Where: $Emissions_{microCO2}$ = *Total microturbine* CO_2 *emissions, lb/yr*
$E_{microCO2,100\%}$ = *Microturbine emission rate at full load, lb/kWh*
kWh_{micro} = *Projected (or proven) power generated, kWh/yr*

For units that will be operated at reduced loads, or multiple load levels, the annual emissions must be calculated using projected (or proven) power generated for each of the operating loads, as shown in Equation 19.

$$Emissions_{microCO2} = \sum_{1}^{n} \left(E_{microCO2,n} * kWh_{micro,n} \right) \qquad \textit{(Eqn. 19)}$$

Where: n = *Load designator (i.e., 70 percent, 90 percent)*

Equations 18 and 19 assume that all power generated by the site is consumed at the site. Where allowable, the DG operator will presumably export any excess electricity to the grid. In this case, the microturbine is likely to be operated at full load to maximum electricity sale to the grid. The equation must be modified to account for line losses for power going back to the grid, as shown in Equation 20.

$$Emissions_{microCO2} = \sum_{1}^{n} \left(E_{microCO2,100\%} * kWh_{micro,onsite} \right) + \left(E_{microCO2,100\%} * kWh_{micro,exported} * Lloss \right) \qquad \textit{(Eqn. 20)}$$

Where: $kWh_{on\text{-}site}$ = *Power consumed on-site, kWh*
$kWh_{exported}$ = *Power exported, kWh*
n = *Load designator, not including full load (i.e., 70 percent, 90 percent)*

Every effort should be made to provide reliable estimates of annual operating time. Over estimated operating time will result in over estimated emission reductions. The extended monitoring period described in Section 2.2.2 should be helpful in projecting annual operations. In all cases, the net microturbine emission rate is calculated, as shown in Equation 21.

$$E_{microCO2} = \frac{Emissions_{microCO2}}{kWh_{micro}} \qquad \textit{(Eqn. 21)}$$

2.6.3. Estimation of Baseline Annual GHG Emission Rates

Section 2.6.1 introduced the complexity in baseline emission factor estimation. Utility power systems and regional grids consist of an aggregate power supply typically generated by a wide variety of GU types. Each type of GU emits differing amounts of GHG (and other pollutants) per kWh generated. In the simplest case, for a single GU, total CO_2 emissions (lb) divided by the total power generated by that GU (kWh) yields the CO_2 emission rate for the selected GU (lb/kWh).

More complex analyses require determination of an aggregated baseline emission rate derived from multiple grid-connected GU. The method to develop an aggregate emission rate is to divide the total emission by the total power generated from the GU under consideration, as shown in Equation 22.

$$E_{baselineCO2} = \frac{\sum_{1}^{n} CO2_n}{\sum_{1}^{n} kWh_n} \qquad \text{(Eqn. 22)}$$

Where: $CO2_n$ = *Individual* GU_n CO_2 *emissions for the period, lb*
kWh_n = *Individual* GU_n *power generated for the period, kWh*
n = number of GU in the baseline selection set

The particular grid-connected GUs chosen for the baseline emission rate calculation have a strong effect on the potential microturbine emissions reductions. The microturbine power may offset generation from an individual grid-connected GU or from many GUs on a utility-side, regional, or national basis. Some considerations, which may confound the choice of GUs to be offset, are:

- The GU inventory in the geographic region, how they are connected to the grid, local utility fuel mix, and the local dispatch protocol can affect whether or not a particular GU is offset
- Microturbine operating schedules (i.e., in a baseload, peak shaving, or other mode) should be comparable to the offset GUs
- T&D line losses should be considered for the offset GUs and for the microturbine if it exports power to the grid
- Several different databases provide emission factor, power generation, cost, and other data in varying formats
- In most cases, real-time electrical production data is not publicly available

If the analyst proposes that GUs that operate on the margin (i.e., those dispatched last and offset first) are to be offset, then marginal fuel prices, dispatchability, and economics at the local and regional level may need to be considered.

Because of such complex issues, the GHG Center undertook a review of regulatory guidance and industrial community practice on how to choose the grid-connected emissions that would be offset by DG installations. The review included procedures used by EPA, U.S. Department of Energy (DOE), Western Regional Air Partnership (WRAP), World Resources Institute (WRI), Intergovernmental Panel on Climate Change (IPCC), and other emission trading organizations. The guidance provided by these organizations ranged from vague to explicit and the analyses ranged from simple to complex. Procedures included all levels of refinement from “generic” national or regional emission factors to detailed analysis of grid control area boundaries and the GUs therein, hourly operating data, peaks, peak shaving, and/or imports and exports.

After completing the reviews, it was concluded that the method used for choosing the baseline emissions to be offset is arbitrary; clear and consistent guidance does not exist at present. Judgment about whether or not a particular assumption (i.e., selection of a marginal GU to be offset) is reasonable or supportable is subject to opinion and case-by-case review. The best strategy may be to perform analyses using several baselines and allow the reader to rank their value according to preference or local administrative policy.

This document presents guidance for three emission factor calculation pathways with increasing levels of refinement:

- U.S. nationwide average baseline emission factors calculated from Electric Power Annual data
- Regional baseline emission factors calculated from Electric Power Annual data
- User specified emission factors for marginal fuel GUs based on local utility operating data

2.6.3.1. U.S. Nationwide Emission Factors

Table 2-8 presented the most recent nationwide CO_2 and NO_X emission factors for the entire U.S. utility grid and for individual fuel types. Volume II, Table 1 (Electric Power Industry Summary Statistics of the United States, 1998 and 1999) and Table 25 (Estimated Emission from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Fossil Fuel, Census Division, and State, 1999) of the Energy Information Administration (EIA) Electric Power Annual, 1999 (EIA 1999) provided the source data. Source data for other years may be obtained from EIA.

2.6.3.2. Regional Emission Factors

EIA data allow calculation of regional emission factors based on census division. Appendix C-1 provides average emission factors for all fossil fuels. Appendices C-2, C-3, and C-4 present emission factors for coal, petroleum, and natural gas, respectively.

Volume II, Table 24 (Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Census Division and State, 1998 and 1999) and Volume I Table A7 (Net Generation by Census Division and State, 1998 and 1999, Table A8 (Net Generation from Coal by Census Division and State, 1998 and 1999), Table A9 (Net Generation from Petroleum…), and Table A10 (Net Generation from Natural Gas…) of the Electric Power Annual, 1999 (EIA 1999) provided the source data. Source data for other years may be obtained from EIA.

2.6.3.3. User Specified Emission Factors

Development of user specified emission rates can take several approaches. Some analysts are applying a utility dispatch model [such as the Integrated Planning Model (IPM) or ECO™] and employing custom-designed regional grid or utility boundaries, and power dispatch protocols.

Figure 2-10 depicts the approach taken for one of the GHG Center's verifications, which is based on displacement of the highest cost, or marginal GU emissions for the local utility. It relies on the operating data from public Federal Energy Regulatory Commission (FERC) and EIA databases.

After identifying the local utility, the analyst develops a list of that utility's GUs from the FERC "Form 1" database (FERC 2000) which provides plant specific data. The Emission and Generation Resource Integrated Database [Emissions and Generation Resource Integrated Database (EGRID) (EPA 2001)] and EIA-767 data file (EIA 1998) are used to acquire plant-and/or GU specific power generation, emission, and costs by fuel type. Time series plots of these data, as shown by the examples in Figures 2-11 and 2-12, facilitate the selection of marginal GUs. Figure 2-11 shows monthly average data. Daily and hourly data are available from the EGRID if more detailed analysis is required.

Figure 2-10. User-Specified Emission Factor Development Schematic

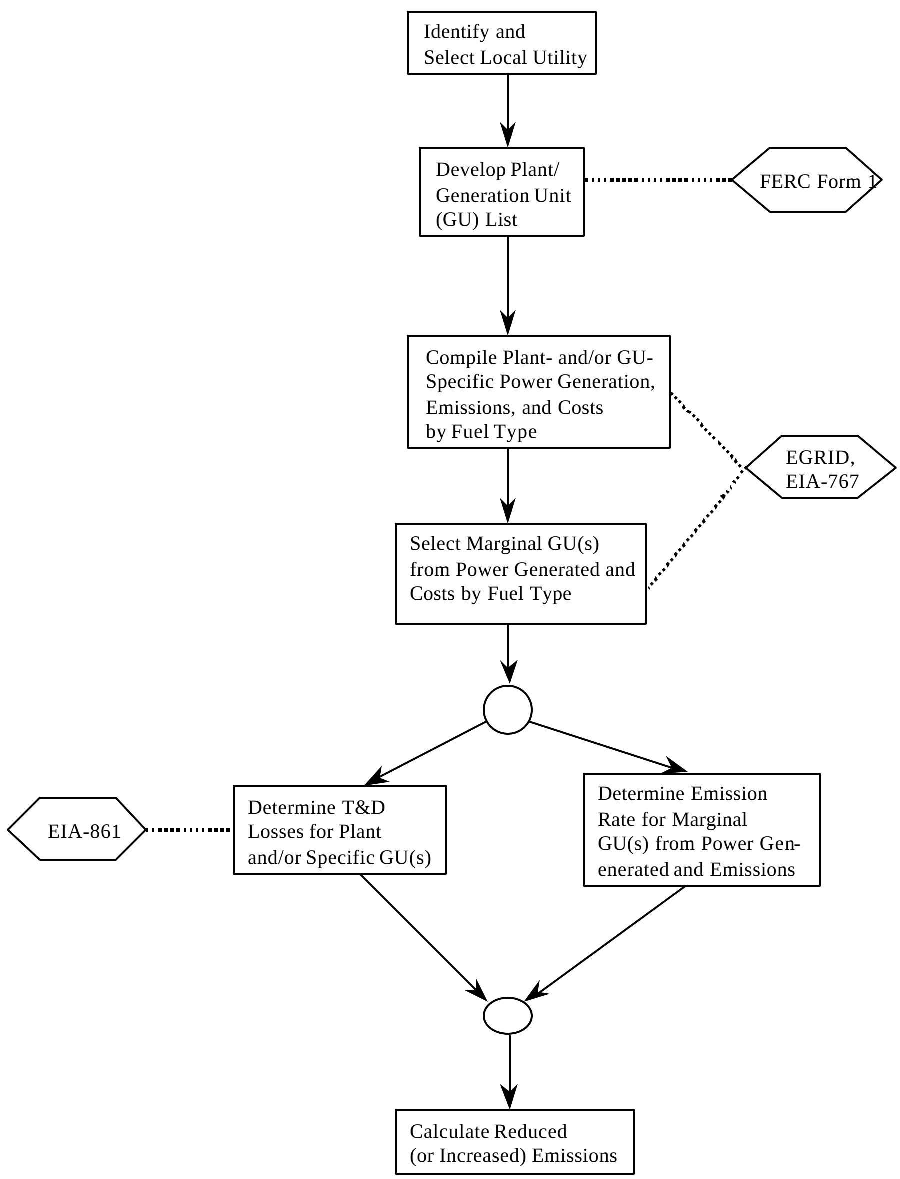


Figure 2-11. Example Monthly Electric Generation by Fuel Types for a Local Utility (Source: EPA EGRID and EIA-767 Databases)

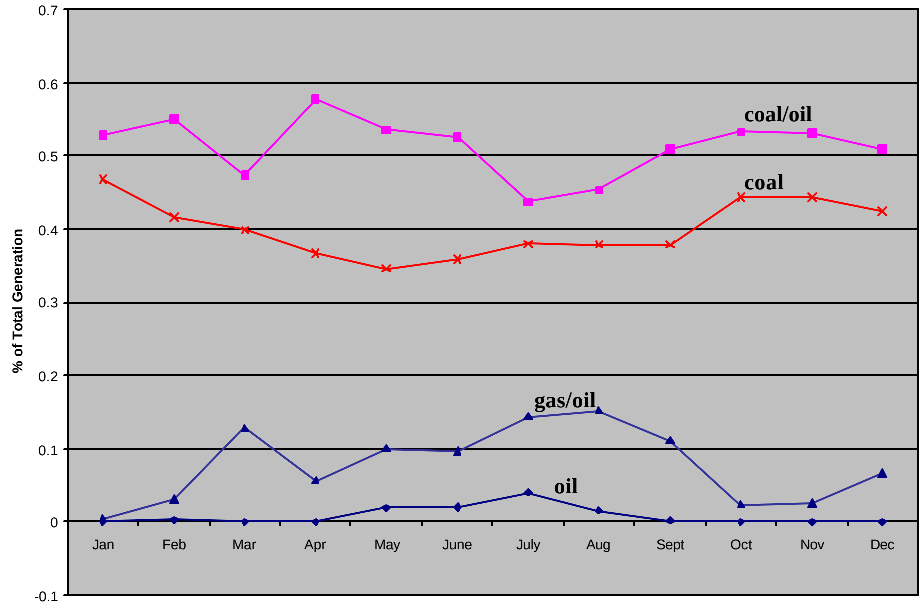
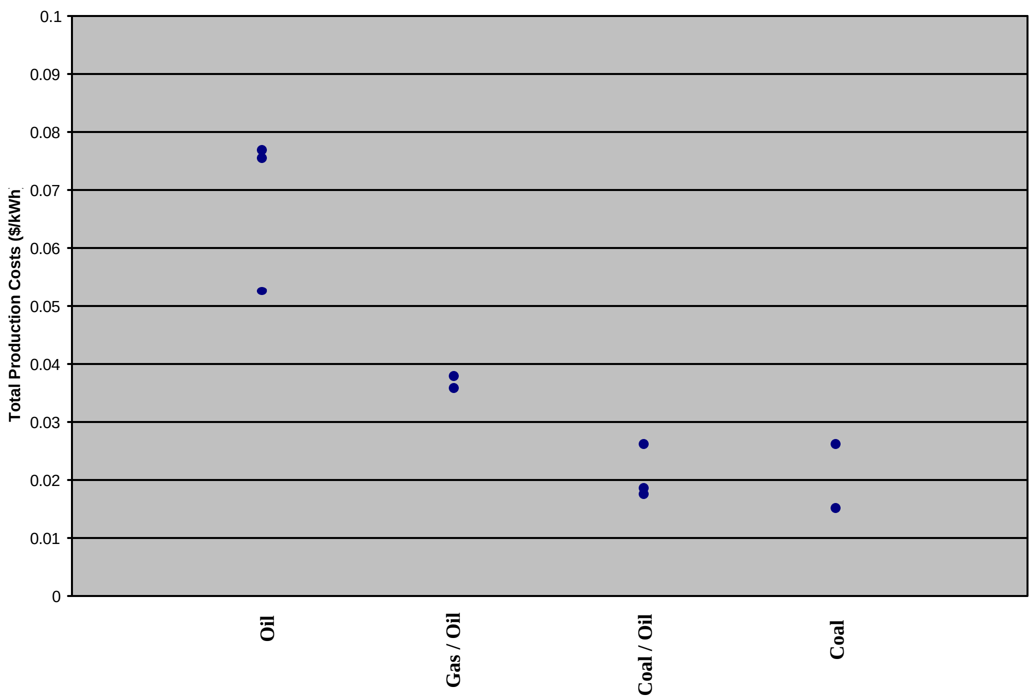


Figure 2-12. Example Generation Costs by Fuel Types for a Local Utility (Source: FERC Form 1)



The figures show that for this utility, coal- and coal/oil-fired units consistently generate the most power at the lowest cost. These units are unlikely to be displaced by a DG installation which, in this example, was intended to operate only during the business day. The utility operated the highest cost oil-fired units only during the summer. The most likely GUs to be offset are therefore those fired by gas/oil whose generation varies as demand changes from month to month. Once the GU(s) that will be offset are selected, the EGRID and EIA-767 databases provide total emissions and total power generated for the offset GU(s), and the emission factor can be calculated according to Equation 22.

The electricity generated by a central power station is delivered through an electrical T&D system. Electric energy losses in transformers, transmission wires, distribution wires, and other equipment are incurred as the electricity is distributed from the power plant to the end-user. Transmission lines and distribution lines are categorized by their voltage rating. Transmission lines operate at the highest voltage (generally defined as 115 to 765 kV), and carry electric energy from the power plants to the distribution system. Distribution systems operate between 25 to 69 kV and carry the electricity to the residential, commercial, and industrial customers. Power transformers are used to increase the voltage of the produced power from the generation voltage to transmission voltage, and in distribution substations to reduce the voltage of the power delivered to the distribution system. These system losses must be considered in calculating the true electricity savings and emission offset from the CHP system.

Data documenting T&D losses are not readily available. Some organizations assume a "rule of thumb" of 7 percent losses. This means that for each kWh used, the utility must generate 1.07 kWh to overcome the losses. EIA-861 data file (EIA 1998b), completed by each electric utility in the U.S., contains information on the status of electric utilities and their generation, transmission, and distribution of electric energy. T&D losses may be developed from EIA-861 by comparing total electricity generated with that actually sold. Based on these data, national average T&D losses were approximately 5.1 percent in 1998 (averaged from about 3,100 electric utility records). For the example in Figures 2-11 and 2-12, T&D losses were 4.7 percent. The T&D loss figure, the offset GU emission rate (from Equation 22), and the power generated by the microturbine are entered into Equation 17 to calculate total emission reductions.

During a verification conducted by the GHG Center in Calgary, Alberta a different approach was used. The Alberta Power Pool maintains actual electricity transfer metering records that are publicly available on the Internet. The KEFI-Exchange, a privately owned, industry-sponsored, commodity exchange firm that operates under an order from the Alberta Securities Commission, calculated hourly emission factors based on plant specific electricity production and emissions data. The methodology used was developed by Canada's Emissions Quantification Working Group (EQWG 1999) to estimate hourly emission factors for the Alberta grid. Briefly, the KEFI-Exchange collected the hourly Alberta Power Pool data and multiplied the plant-specific electricity generation data by published emission factors for that plant to derive total CO_2 emission for the plant for each hour corresponding to microturbine operation. The sum of emissions from all plants divided by the total electricity generated was the average grid emission factor. A similar approach was used for any electricity imported into Alberta. The overall average grid emission factor, T&D losses, microturbine emission factor, and microturbine power generated were entered in Equation 17 to calculate total emissions reductions.

3.0 DATA QUALITY

3.1. DATA QUALITY OBJECTIVES AND DATA QUALITY INDICATORS

In verifications conducted by the GHG Center and EPA-ORD, measurement methodologies and instruments are selected to ensure that a desired level of data quality occurs in the final results. DQOs are stated for key verification parameters before testing commences. These objectives must be achieved in order to draw conclusions with the desired level of confidence. The process of establishing DQOs starts with identifying the measurement variables that affect the verification parameter. For example, the electrical efficiency verification parameter requires measurement of three separate variables: fuel flow rate, fuel heating value (LHV), and microturbine power output. The errors associated with each measurement must be accounted for to determine their cumulative effect on this verification parameter. This is done by assuming that measurement errors are not random, and that these errors can be combined to produce a worst-case overall error in the verification parameter. The worst case error is determined through an assessment of measurement errors expected in the field when instrument and sampling errors are accounted for. The resulting error, propagated using maximum and minimum errors in the measurements, is used to establish the DQO for the verification parameter. Table 3-1 lists the DQOs developed by the GHG Center for key verification parameters based on the instruments selected for testing. Section 3.2 describes how these objectives are reconciled after a verification test was completed, and the actual errors achieved for a recent microturbine test are summarized in Table 3-1.

Table 3-1. Example Data Quality Objectives

Verification Parameter	Required (%)	Achieved (%)
Power Output	± 0.20 at full load	± 0.05 at full load
Electrical Efficiency	± 0.38 at full load	± 0.38 at full load
Emission Levels		
NO_X	Bias: ± 2 of span	NO_X: ≤ 2.0 of span
CO	Bias: ± 5 of span	CO: ≤ 2.0 of span
CO_2	Bias: ± 5 of span	CO_2: ≤ 1.0 of span
THCs	Bias: ± 5 of span	THCs: < 2.3 of span

A detailed look into the DQO for electrical efficiency (± 0.38 percent efficiency at full load) provides an example of how the DQOs were developed. Three measurements are used to determine efficiency including power output (kW), fuel flow (scfm), and fuel LHV [British thermal units per standard cubic foot (Btu/scf)]. The expected error in each of these measurements was ± 0.2, ± 1.0, and ± 0.2 percent, respectively. These errors were applied to the corresponding values expected in the field (i.e., 30 kW output, 6.7 scfm gas flow, and 940 Btu/scf LHV) to estimate measurement uncertainty in each parameter. The errors were applied on both the high and low end of the expected values, as illustrated in Table 3-2, and propagated into the electrical efficiency equation (Eqn. 1) to derive at an uncertainty of ± 0.38 percent.

Table 3-2. Error Propagation for Development of DQOs (Electrical Efficiency Determinations)				
	Measurements			**Calculated Electrical Efficiency (%)**
	Power Output (kW)	**Fuel Flow (scfm)**	**Fuel LHV (Btu/scf)**	
Expected measurement error	± 0.20 %	± 1.0 %	± 0.20 %	NA
Expected measurement value	30	6.7	940	27.09
Combinations of maximum error on both high and low end for each measurement	30.06	6.767	941.88	26.62
	29.94	6.633	938.12	27.36
	29.94	6.767	938.12	26.82
	29.94	6.767	941.88	26.71
	30.06	6.633	938.12	27.47
	30.06	6.767	938.12	26.93
	30.06	6.633	941.88	27.36
Maximum calculated efficiency				27.47
Minimum calculated efficiency				26.71
Maximum Uncertainty (max or min efficiency – expected efficiency)				± 0.38 efficiency, absolute

3.2. EVALUATION OF DATA QUALITY INDICATORS AND RECONCILIATION OF DQOs

To help ensure that the DQOs listed in Table 3-1 were met, data quality indicator (DQI) goals are established for critical measurements performed in the verification test. The DQI goals, specified in Table 3-3, 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, 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 checks are verified. The following discussion illustrates how the DQI goals were evaluated. By demonstrating that the DQI goals were met, the GHG Center was able to establish that the DQOs were satisfied for all verification parameters.

Table 3-3 provides an example of DQI goals established for each critical measurement including accuracy and completeness goals. The table also shows the range of measurements observed in the field during one of the GHG Center's verifications, and the procedures that were used to verify instrument accuracy.

The instrumentation summarized in Table 3-3 were selected such that the individual measurement errors and propagated measurement errors were small enough to satisfy the established DQOs. Once instrumentation and measurement methods or procedures are identified, procedures for evaluating measurement accuracy must be developed. The final column in Table 3-3 indicates how measurement accuracy was verified for each measurement conducted during the verification. Typically, measurement accuracy can be evaluated using instrument calibrations conducted by manufacturers, field calibrations, reasonableness checks, and/or independent performance checks with a second instrument of equal or better accuracy. The actual measurement accuracy achieved in the field is then used to reconcile the DQOs previously discussed. For verification parameters that require more than one measurement, the accuracy achieved values must be propagated to evaluate whether the DQOs were satisfied.

Table 3-3. Example Data Quality Indicator Goals and Results

Measurement Variable		Instrument Type / Manufacturer	Instrument Range	Operating Range Observed in Field	Accuracy			Completeness	
					Goal	Actual	How Verified / Determined	Goal	Actual
Microturbine Power Output and Quality	Power	Electric Meter/ Power Measurements 7600 ION	0 to 75 kW	0 to 73 kW	± 0.20 % reading	± 0.05 % reading	Instrument calibration certificates from manufacturer just prior to testing, sensor function checks in field	load tests: 100 % extended test: 90 %	load tests: 100 % extended test: 89 %
	Voltage		0 to 480 V (3-phase)	0 to 480 V (3-phase)	± 0.1 % reading	± 0.1 % reading			
	Voltage Transients		600 to 8,000 V	600 to 8,000 V	Not defined	NA			
	Frequency		49 to 61 Hz	59 to 60 Hz	± 0.01 % reading	± 0.01 % reading			
	Current		0 to 200 amps	0 to 200 amps	± 0.1 % reading	± 0.1 % reading			
	Voltage THD		0 to 100 %	0 to 100 %	± 1 % FS	± 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			
Booster Compressor Power Consumption	Power	Electric Meter/ Power Measurements 7600 ION	0 to 75 kW	3 to 4.5 kW	± 0.25 % reading	± 0.20 % reading		load tests: 100 %	load tests: 100 %
Fuel Input	Gas Flow Rate	Mass Flow Meter / Rosemount 3095 w/ 1195 orifice	0 to 20 scfm	0 to 20 scfm	1.0 % reading	± 1.1 % overall average for all loads, ± 1.4 % for full load	In-line comparison with calibrated dry gas meter in field	load tests: 100 % extended test: 90 %	load tests: 100 % extended test: 95 %
	Gas Pressure	Pressure Transducer / Rosemount or equiv.	0 to 20 psig	0 to 3 psig	± 0.75 % FS	± 0.75 % FS	Instrument calibration certificates from manufacturer just prior to testing, reasonableness checks in field		
	Gas Temperature	RTD / Rosemount Series 68	-58 to 752 °F	20 to 60 °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 ± 0.2 % for LHV for duplicate analyses	± 0.2 % for CH_4 concentration ± 0.09 % for LHV	Conducted duplicate analyses and compared analyses results with a single blind audit sample	load tests: 100 %	load tests: 100 %

(continued)

Table 3-3. Example 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
Ambient Conditions	Ambient Temperature	RTD / Vaisala Model HMP 35A	50 to 110 °F	25 to 65 ° F	± 0.2 °F	±-0.2 °F	Instrument calibration certificates from manufacturer just prior to testing	load tests: 100 % extended test: 90 %	load tests: 100 % extended test: 85 %
	Ambient Pressure	Vaisala Model PTB220 Class B	14.80 to 32.56 in. Hg	28 to 31 in. Hg	± 0.1 % FS	0.1 % FS			
	Relative Humidity	Vaisala Model HMP 35A	0 to 100 %	40 to 95 % RH	± 2 % (0 to 90 % RH) ± 3 % (90 to 100 % RH)	± 2 % (0 to 90 % RH) ± 3 % (90 to 100 % RH)			
Exhaust Stack Emissions	NO_X Levels	Chemiluminescence / TECO Model 10	0 to 100 ppmvd	7 to 12 ppmvd	± 2 % FS for system cal. Error and drift	≤ 1.6 % FS for calibration error and < 0.5 % for drift	Calculated following EPA Reference Method calibrations	load tests: Before and after each test run	load tests: Before and after each test run
	CO Levels	NDIR / TECO Model 48C	0 to 100 ppmvd/ 0 to 1000 ppmvd	0 to 240 ppmvd	± 5 % FS for system bias and ± 5 % FS for drift	Bias: ≤ 2.0 % FS Drift: ≤ 0.6 % FS			
	THC Levels	FID / JUM Model VE-7	0 to 100 ppmvd	0 to 20 ppmvd	± 5 % FS for system cal. error and ± 3 % FS for drift	≤ 2.3 % FS for calibration error and < 2.1 % for drift			
	CO_2 Levels	NDIR / Servomex Model 1400	0 to 20 %	1 to 1.3 %	± 5 % FS for system bias and ± 5 % FS for drift	Bias: ≤ 1.4 % FS Drift: ≤ 0.3 % FS			
	CH_4 Content	GC / FID HP Model 5890 Series II	0 to 100 ppmvd	0 to 13 ppmvd	± 10 % FS	± 10 % FS			
	O_2 Levels	Micro-fuel cell/ Servomex Model 1400	0 to 25 %	18 to 20 %	± 5 % FS for system bias and ± 5 % FS for drift	Bias: ≤ 1.1 % FS Drift: ≤ 0.2 % FS			
	H_2O Content	Gravimetric / NA	0 to 50 %	3 to 5 %	± 5 % FS	± 5 % FS			

NA - not applicable
FS - full scale

Propagation of the actual errors can be conducted as described above to obtain the worst-case conservative approach on uncertainty. Since it is unlikely that the maximum error in each measurement occurs in the same direction (i.e., always positive or negative), a procedure based on actual instrument performance in the field can be used to propagate the actual errors. The "square root of the sum of the squares" procedure (Harrison, et al.) examines the propagation of probable error.

Using this approach, the error bound (90 percent confidence half-width) associated with the product of two or more numbers is calculated using the absolute errors (DQIs) of the terms being multiplied. Using the example of electrical efficiency determinations, the efficiency is calculated using the power output (kW), fuel flow (scfm), and fuel LHV (Btu/scf) values. The actual error in each of these measurements as determined according to Table 3-3 was ± 0.05, ± 1.1, and ± 0.09 percent, respectively. Using these actual errors for each measurement, the overall achieved error for electrical efficiency is 1.10 percent, or an absolute uncertainty at full load (28.39 kW) ± 0.31 percent efficiency, computed as shown in Equation 23:

$$\text{Overall uncertainty} = \text{square root } (0.05^2 + 1.1^2 + 0.09^2) \qquad \text{(Eqn. 23)}$$

The following subsections present a detailed description of the data quality procedures that were conducted during the GHG Center's verifications and how the actual errors achieved were determined.

3.2.1. Power Output, Electrical Efficiency, and Power Quality Determination

The accuracy goals for each measurement required to evaluate power output, electrical efficiency, and power quality were evaluated using the primary DQI goals listed in Table 3-3. The following paragraphs summarize how the actual errors achieved were determined. In addition to the primary DQIs, other QA/QC checks were conducted during the GHG Center's verifications (as shown in the examples provided in Table 3-4). These additional checks are recommended to further confirm the accuracy of critical verification measurements.

Power Output and Power Quality: Precise determination of electric power generated is critical to these verifications. Most commercially available power meters are extremely accurate. Factory calibrations of the 7600 ION, used by the GHG Center, with National Institute for Standards and Technology (NIST) traceable standards resulted in ± 0.05 percent error in power measurements (current and voltage). The factory calibration should also provide accuracy ratings for each of the power quality parameters including frequency, voltage and current harmonic distortion, and Pf. Reasonableness checks can be performed in the field to ensure data quality. Comparisons of voltage and current output with a handheld digital multimeter, and comparisons with the microturbine's internal power output readings are suggested reasonableness checks.

Table 3-4. Examples of Additional QA/QC Checks				
Measurement Variable	**QA/QC Check**	**When Performed/Frequency**	**Allowable Result**	**Results Achieved**
Power Output	Reasonableness checks	Beginning of test	Readings should range between 90 and 100 % of the units rated kW output while at full load	7600 ION readings matched test unit's software output
	Sensor diagnostics in field – voltage and current comparisons with a digital multimeter	Beginning of test	Voltage and current checks within ± 1 % reading	± 0.49 % voltage ± 0.39 % current
Fuel Flow Rate	Instrument calibration by manufacturer	Beginning and end of test	± 1.0 % reading	Certified accuracy of ± 1.0 %
	Sensor diagnostics	Beginning of test	Pass	Passed all sensor diagnostic checks
	Reasonableness checks	Throughout test	Readings should be between 7 and 8 scfm at full load	All readings within specified range
Ambient Meteorological Conditions	Reasonableness checks	Throughout test	Recording should be comparable with airport data	Readings were consistent with airport data
Fuel Gas Pressure	Reasonableness checks	Throughout test	Readings should range between 55 and 65 psig	All readings were within specified range

Fuel Flow Rate: Procedures for determination of the accuracy of the fuel flow meter depend largely on the type of meter selected because the accuracy of certain meters (such as the orifice type meters used by the GHG Center) can be affected by installation configurations. All meters should be directly calibrated against a primary standard such as a volume prover or Roots meter before and after testing, or compared to readings from a second meter that was directly calibrated.

The integral orifice meters used by the GHG Center were factory calibrated prior to installation in the field, and calibration records were reviewed to ensure the ± 1.0 percent instrument accuracy was satisfied. QA/QC checks listed in Table 3-4 were conducted to ensure proper function in the field, and to reconcile ± 1.0 percent DQI goal. QC checks were performed immediately prior to load testing which included sensor diagnostic checks, and independent verification with a second meter.

A dry gas meter (Equimeter Model R-1600), installed in series with the orifice was used to independently verify the Rosemount flow meter output (Figure 2-4). This approach is recommended wherever possible when meters other than displacement type meters are used. The dry gas meter should be calibrated by the manufacturer or local utility using a volume prover or other primary standard. During the GHG Center's verifications, dry gas meter readings were obtained and compared with the flow data from the orifice meters. 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 the corrections using Equation 24.

*Dry gas meter reading (scf) = Gas Volume Measured (acf) * (T_{std}/T_g) * (P_g/P_{std}) * C_m* *(Eqn. 24)*

Where: T_{std} = *standard temperature (519.67 ^oR)*
T_g = *measured gas temperature (^oR)*
P_{std} = *standard pressure (14.696 psia)*
P_g = *measured gas pressure (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 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 1.07 percent higher than dry gas meter readings, which resulted in slightly missing the ± 1.00 percent DQI goal.

Table 3-5. Example Comparison of Integral Orifice Meter And Dry Gas Meter

Test Condition (% of Rated Power)	Power Delivered (kW)	Integral Orifice Meter Reading (scfm)	Gas Pressure (psia)	Gas Temperature (^{o}F)	Dry Gas Meter Reading (scfm)	Difference[a] (scfm)
100	28.45	7.16	52.77	46.65	7.15	0.01
	28.32	7.12	52.54	50.42	7.17	-0.05
	28.47	7.22	52.86	54.05	7.07	0.15
	28.45	7.20	52.62	54.73	7.08	0.12
	28.38	7.19	52.79	55.73	7.04	0.15
90	26.44	6.73	52.71	48.57	6.68	0.05
	26.47	6.71	52.86	49.38	6.64	0.07
	26.32	6.73	52.83	50.25	6.67	0.06
	26.46	6.75	52.78	54.18	6.64	0.11
75	22.04	5.76	53.24	50.63	5.73	0.03
	22.05	5.74	53.25	51.25	5.73	0.01
	22.02	5.79	53.09	54.38	5.75	0.04
50	14.54	4.19	53.76	52.46	4.13	0.06
	14.52	4.19	53.48	52.30	4.12	0.07
	14.54	4.19	53.63	55.00	4.14	0.05
Overall Average						± 0.69 scfm or ± 1.07 %

[a] = (Integral Orifice Reading – Dry Gas Reading)

Fuel LHV: Procedures for determination of the accuracy of the fuel LHV values depend on the source of these data. Whenever data is obtained from the gas supplier or other source and not directly measured, QA/QC documentation must be obtained from the data source to verify accuracy. If direct measurement of LHV is conducted, the data quality of the fuel analyses can be performed by comparing laboratory results with a NIST-traceable audit gas, conducting duplicate analysis of the same sample, and collecting replicate samples in the field.

The NIST-traceable audit gas can be purchased from gas standard suppliers and submitted to the laboratory as an independent check on analytical accuracy. The audit gas should be submitted to the lab in the same manner as the samples that are collected during testing (same type of sample container). As demonstrated in Table 3-6, the GHG Center was able to document excellent analytical accuracy by submitting these blind audit samples to the laboratories. Duplicate analyses of a number of samples provide another check on analytical accuracy and repeatability. The GHG Center also recommends collection of one or more replicate samples during testing. The replicates can be used to confirm the integrity of sample collection procedures.

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

Gas Component	Certified Component Concentration (%)	Analytical Result (%)	Combined Sampling and Analytical Error (%)[a]	Duplicate Analytical Result (%)	Analytical Repeatability (%)[b]
n-butane	0.386	0.43	11.4	0.40	7.0
carbon dioxide	3.01	3.20	6.3	3.18	0.6
ethane	3.52	3.52	0.0	3.50	0.6
n-heptane	0.020	0.02	0.0	0.02	0.0
n-hexane	0.049	0.05	2.0	0.06	20.0
Iso-butane	0.396	0.40	1.0	0.40	0.0
Iso-pentane	0.150	0.15	0.0	0.15	0.0
n-pentane	0.150	0.15	0.0	0.15	0.0
nitrogen	2.50	2.53	1.2	2.57	1.6
propane	1.00	1.01	1.0	1.01	0.0
methane	88.72	88.53	0.2	88.48	0.05

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

Ambient Measurements: Ambient temperature, pressure, and RH must be monitored at the site throughout the extended verification period and the load tests. The instrumentation used should be identified in the Test Plan (Table 3-3) along with instrument ranges, data quality goals, and data quality achieved. All of these sensors should be factory calibrated prior to the verification testing using reference materials traceable to NIST standards. After installation of the sensors at the test location, reasonableness checks should be conducted and recorded using an independent monitoring system, or another source of meteorological data such as a nearby airport or weather monitoring station.

3.2.2. Exhaust Stack Emission Measurements

EPA Reference Methods are used to quantify emission rates of criteria pollutants and GHGs. The Reference Methods specify the sampling and calibration procedures, and data quality checks that must be followed. These Methods ensure that run-specific quantification of instrument and sampling system drift and accuracy occurred throughout the emissions tests. The DQOs specified for these verifications are ± 2 percent for NO_X, ± 5 percent for CO_2, CO, and THC, and ± 10 percent for CH_4 emissions. The primary DQI goals required to meet these DQOs were summarized in Table 3-3 and consist of an assessment of: (1) sampling system calibration error and drift for NO_X and THC, and (2) sampling system bias and drift for CO, CO_2, and O_2. Additional QA/QC checks for emissions testing are summarized in Table 3-7.

Table 3-7. Additional Emissions Testing QA/QC Checks			
Parameter	**QA/QC Check**	**When Performed/Frequency**	**Expected or Allowable Result**
Sampling System	System leak check	Before and after each test run	$\leq$ 1.0 % O_2 while sampling pure N_2
NO_X	Analyzer interference check	Once before testing begins	± 2 % of analyzer span or less
	NO_2 converter efficiency	Once before testing begins	98 % efficiency or greater
	Audit gas (approximately 10 ppmvd NO in N_2)	Once before testing begins	± 2 % of analyzer span
CO, CO_2, O_2	Analyzer calibration error test	Daily before testing	± 2 % of analyzer span or less
CO	Audit gas (9.06 ppmvd CO in N_2)	At the end of test after low NO_X levels were measured	± 5 % of analyzer span
CH_4	Calibration with reference gas standard	Prior to analysis of each lot of samples submitted	± 2 % for CH_4 concentration

NO_X and THC

The sampling system calibration error test is conducted prior to the start of the first test run on the NO_X and THC sampling systems. The calibration is conducted by sequentially introducing a suite of calibration gases to the sampling system at the sampling probe, and recording the system response. Calibrations are conducted on all analyzers using Protocol No. 1 calibration gases. Four calibration gases of NO_X and THC are used, including 0, 20 to 30 percent of span, 40 to 60 percent of span, and 80 to 90 percent of span. As shown in Table 3-3, the system calibration error goal for NO_X is ± 2 percent., and the calibration goal for THC is ± 5 percent.

At the conclusion of each test run, the zero and mid-level calibration gases are again introduced to the sampling system at the probe and the response recorded. System response is compared to the initial calibration error to determine sampling system drift. The maximum allowable sampling system drift is $\pm$ 3 percent. An example of emissions sampling system calibration data is provided in Appendix B-4.

Two additional QA/QC checks must be performed to better quantify the NO_X data quality. In accordance with Method 20, an interference test is conducted on the NO_X analyzer once 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 NO_X analyzer. This test is conducted by injecting the following calibration gases into the analyzer and recording the response of the NO_X analyzer, which must be zero ± 2 percent of span.

- CO – 600 ppmvd in balance N_2
- O_2 – 255 ppmvd in N_2
- CO_2 – 10 percent in N_2
- O_2 – 22 percent in N_2

The second QA/QC check consists of determining NO_2 converter efficiency prior to beginning the emissions testing. The NO_X analyzer converts any NO_2 present in the gas stream to nitrogen oxide (NO) prior to gas analysis. This procedure is conducted by introducing to the analyzer a mixture of mid-level calibration gas and air. The analyzer response is recorded every minute for 30 minutes. If the NO_2-to-NO conversion is 100 percent efficient, the response is 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.

CO, CO_2, and O_2

Analyzer calibrations are conducted to verify the error in CO, CO_2, and O_2 measurements relative to calibration gas standards. The calibration error tests are conducted at the beginning of each test day, and repeated on any analyzers for which ranges are changed to accommodate low load testing. A suite of calibration gases is introduced directly to the analyzer, and analyzer responses are recorded. EPA Protocol 1 calibration gases are used for these calibrations. Three gases are used for CO_2 and O_2, including 0, 40 to 60 percent of span, and 80 to 100 percent of span. Four gases are used for CO, including 0 and approximately 30, 60, and 90 percent of span. The analyzer calibration error requirements for all gases are shown in Table 3-7.

Before and after each test run conducted, the zero and mid-level calibration gases are introduced to the sampling system at the probe, and the response are recorded. System bias is calculated by comparing the system responses to the calibration error recorded above. As shown in Table 3-3, the system bias goal for CO, CO_2, and O_2 is ± 5 percent of analyzer span. The pre- and post-test system bias calibrations are also used to calculate drift for each pollutant. The zero gas O_2 system bias checks can also be used to verify the absence of leaks in the sampling system. The highest O_2 value recorded during the zero gas system calibration checks was 0.04 percent.

NO_X Audit Gas Analysis

An additional QA/QC check that is recommended, but not required in the Reference Methods is analysis of an audit gas for NO_X. Most microturbines emit very low concentrations of NO_X. To further verify the accuracy of the sampling system at very low levels of NO_X, a low-level audit gas (less than 10 ppmvd NO_X in N_2) should be obtained and introduced into the sampling system as a blind audit. The audit gas must be EPA Protocol 1 certified. The system response is recorded and compared to the certified concentration. If the system response differs from the certified concentration by more than 2 percent of span, the system should be corrected or replaced prior to testing.

Sampling System Leak Checks

EPA Reference Methods for gaseous sampling systems do not specify leak checks or provide specific leak check procedures. However, leaks in the sampling system can present a significant error in the measurements, so care is needed to ensure that leaks are not present in the system. The most common method of detecting leaks in the sampling system is to introduce a zero calibration gas (common N_2) at atmospheric pressure into the sampling probe. The N_2 gas is run through the entire sampling system to the O_2 analyzer. Most sampling systems (including the system used for this test) use vacuum pumps to extract gas from the source, so any leaks in the sampling system will result in an elevated O_2 reading during the zero check.

These sampling system zero checks are conducted before and after every test during the sampling system bias checks. The GHG Center recommends that an additional leak check be conducted by plugging the tip of the sampling probe and pulling a vacuum on the system using the sampling pump. The sampling rate rotameter was observed until it reached a zero reading (not that most sampling pumps can create a vacuum on the system of greater than 15 in. Hg). Significant leaks in the system would result in a rotameter reading higher than zero. This test is a good indicator of sampling system integrity and should be repeated at the beginning of each day of testing. Any leaks detected in the sampling system must be repaired prior to testing.

4.0 DATA ACQUISITION, VALIDATION, AND REPORTING

4.1. DATA ACQUISITION AND STORAGE

4.1.1. Power and Fuel Meters

Data acquisition and data storage guidelines presented here describe procedures that were conducted during the GHG Center's verifications. These procedures are intended as an example of data acquisition procedures. Site conditions, specifications of measurement instrumentation, and test unit control systems must be investigated before a site-specific data acquisition system and approach can be developed. During the GHG Center's verifications, all sensors used for continuous monitoring provided an electrical signal that was interfaced with a computerized DAS. Table 4-1 summarizes the measurements that were continuously logged.

Table 4-1. Continuous Data Collected During Microturbine Evaluations

Sensor / Source	Measurement Parameter	Purpose[1]	Significance
Rosemount Integral Orifice Meter	Natural gas flow rate (scfm)	P	System performance parameter
Rosemount Pressure Transducer	Natural gas pressure (psi)	P	System performance parameter
Rosemount RTD	Natural gas temperature (°F)	P	System performance parameter
Vaisala Model HMP35A	Ambient temperature (°F)	P	System performance parameter
	Ambient relative humidity (% RH)	P	System performance parameter
Setra Model 280E	Ambient pressure (in. Hg)	P	System performance parameter
Power Measurement 7600 ION	Voltage output (volts)	P	System performance parameter
	Voltage transients (volts)	P	System performance parameters
	Amperage (Amps)	P	System performance parameter
	Power factor	P	System performance parameter
	Real power (kW)	P	System performance parameter
	Kilovolt-amps reactive	P	System performance parameter
	Frequency (Hz)	P	System performance parameter
	Voltage THD (%)	P	System performance parameter
	Current THD (%)	P	System performance parameter
Microturbine input	Power command (kW)	P	User input parameter
	Power factor command	P	User input parameter
	Start/stop schedule	P	User input parameter
Microturbine output	Actual total power (kW)	D/S	System operational parameter
	Max. power available (kW)	D/S	System operational parameter
	Power factor	D/S	System operational parameter
	Frequency (Hz)	D/S	System operational parameter
	Voltage (volts)	D/S	System operational parameter
	Actual engine speed (rpm)	D/S	System operational parameter
	Compressor inlet temp (°F)	D/S	System operational parameter
	Recuperator outlet temp (°F)	D/S	System operational parameter
	Turbine exit temp (°F)	D/S	System operational parameter
	Grid warning (over/under frequency, over/under voltage)	D/S	System operational parameter
	Runtime hours	D/S	System operational parameter
	Number of emergency stops	D/S	System operational parameter
	Number of protective shutdowns	D/S	System operational parameter
Booster Compressor Power Consumption	Power (kW)	P	System Performance Parameter

[1] D- Documentation/Diagnostic
P- Primary value, data points routinely evaluated
S- Secondary value, used as needed to perform comparisons and assess apparent abnormalities

A dedicated Pentium-class computer was made available at the test site, and was used as the accumulation point for all of the data being continuously monitored. A storage directory was assigned on the DAS computer which maintained storage of all data logged. Primary verification measurements such as power output, fuel flow, and power quality should be logged at 1-minute intervals, compiled, and stored in daily files. Other measurements that are not primary measurements (i.e., gas pressure, temperature, ambient conditions) can be logged less frequently to reduce the size of the daily data files. The GHG Center logged all parameters at 1-minute intervals.

Communication with the microturbine control system can typically be conducted through a serial (RS-232) connection. These data can be logged simultaneously with the verification measurements and can be very useful when evaluating data during the verification or during preparation of the Verification Report.

During field testing, the Field Team Leader should retrieve, review, and validate the electronically collected data at the end of each load test. To determine if the criteria for electrical efficiency determinations are met, time series power output, Pf, gas flow rate, ambient temperature, and ambient pressure, should be processed using the appropriate statistical analysis tools. If it is determined that maximum permissible limits for each variable is satisfied, the electrical efficiency measurement goal will be met. Conversely, the load testing should be repeated until maximum permissible limits are attained (Section 2.2). Data for this task should be maintained by both the DAS and by handwritten entries. Observations and test run sheets should be recorded manually in a log form developed exclusively for this task (Appendix A-1). The Field Team Leader should report the following results for each test conducted:

- Power delivered at selected load
- Fuel flow rate at selected load
- Efficiency at selected load

After the completion of the control tests, the manually recorded information should be maintained in a labeled field data log book.

4.1.2. Emission Measurements

Data measurement and collection activities will consist of initial pre-test QA/QC steps to the passing of the data to the Field Team Leader. Most qualified emissions testing contractors have satisfactory DAS in their mobile testing laboratories to record the concentration signals from the individual monitors. The DAS should be capable of recording instrument outputs at 5-second intervals, and averaging those signals into 1-minute averages. At the conclusion of a test run, the pre-and post-test calibration results and test run values are typically electronically transferred from the DAS into a Microsoft Excel spreadsheet for data calculations and averaging. Measurement system calibration and gaseous pollutant concentration measurements are normally recorded on forms similar to the examples shown in Appendices B-3 and B-4, or on strip charts.

The testing contractor should report emission measurement results for each test conducted to the Field Team Leader as:

- ppmvd
- ppmvd corrected to 15 percent O_2
- Emission rate (lb/hr, lb/kWh)

Upon completion of the field test activities, the contractor should provide copies of records for calibration, pre-test checks (stratification, system response time, and NO_2 converter), and field test data to the Field Team Leader prior to leaving the site.

4.1.3. Fuel Gas Sampling

Fuel gas sampling procedures were discussed in Section 2.2, and QA/QC procedures were discussed in Section 3.2. If field sampling for LHV is conducted, the Field Team Leader should maintain manual fuel sampling logs and chain of custody records. After the field test, the analytical laboratory conducting the analyses should submit LHV results for each sample, calibration records, and repeatability test results to the Field Team Leader.

4.1.4. Operational Performance Measurements

Procedures for determining operational availability and cold-start time were discussed in Section 2.4. Records for operational availability should be maintained by operators or on-site technicians in a labeled log book that is provided by the verification center (Appendix A-7). The verification team or Field Team Leader should initiate weekly communication with operators regarding the operation of the microturbine and measurement instrumentation.

4.2. DATA REVIEW, VALIDATION, AND VERIFICATION

A designated Field Team Leader and Project Manager should conduct data review and validation. The following summarizes the review stages executed by the GHG Center.

- On-site following each test run – by the Field Team Leader
- On-site following completion of each load tested – by the Field Team Leader
- After fuel gas analyses results are submitted by the laboratory - by the Field Team Leader
- At the office where continuous monitoring data are received each week – by the Field Team Leader
- Before writing the draft verification test report – by the Project Manager
- During QA/QC review of the draft report and audit of the data – by a designated QA Manager

Upon review, all data collected should be reviewed and subsequently classified as either valid, suspect, or invalid. The criteria used to review and validate the data are the QA/QC criteria specified in Table 3-2 and determination of DQI goals discussed in Section 3.2. In general, valid results are based on measurements meeting DQOs, and that are collected when an instrument was verified as being properly calibrated. Often anomalous data are identified in the process of data review. All outlying or unusual values should be investigated in the field during the control testing, and weekly during the continuous monitoring. Anomalous data can be considered suspect if no specific operational cause to invalidate the data are found. All data (valid, invalid, and suspect) should be included in the final report. However, report conclusions must be based on valid data only. The reasons for excluding any data should also be justified in the report. Suspect data may be included in the analyses, but may be given special treatment as specifically indicated.

Those individuals responsible for on-site data review and validation are noted above. A designated QA Manager reviews and validates the data and the draft report using the Test Plan and test methods. The procedures that should be followed are summarized in the following Sections.

4.3. RECONCILIATION WITH DATA QUALITY OBJECTIVES

DQOs were defined in Section 3.1. The reconciliation of the results with the DQOs should be evaluated using the DQI process. When the primary data is collected, the data is reviewed to ensure that they are valid and are consistent with what was expected. In addition, all data should be reviewed to identify patterns, relationships, and potential anomalies. The quality of the data can be assessed in terms of accuracy and statistical significance as they relate to the stated DQI goals. Attainment of the DQI accuracy goals should be confirmed by analyzing the test data as described in Section 3.2. If the accuracy goals were satisfied, it can be concluded that the DQOs were met. Conversely, if the test is found to not meet the DQI goals for fuel flow rate or LHV, the actual errors achieved should be computed. Emissions testing DQOs should always be met because tests should be repeated whenever the DQI goals are not achieved.

4.4. ASSESSMENTS AND RESPONSE ACTIONS

The Field Team Leader, Project Manager, and the designated QA Manager can assess the quality of the project and associated data within the project. Assessment and oversight of the quality of the project activities are performed through the review of data, memos, audits, and reports by the Project Manager ,and independently by the QA Manager.

The effectiveness of implementing the Test Plan should be assessed through project reviews, in-phase inspections, audits, and data quality assessment.

4.4.1. Project reviews

At the GHG Center, review of verification data and preparation of Verification Reports are the responsibility of the Project Manager, who also is responsible for conducting the first complete assessment of the project. Although the project's data are reviewed by the project personnel (Field Team Leader and other field personnel), and assessed to determine that the data meet the measurement quality objectives, it is the Project Manager who should confirm that, overall, the project activities meet the measurement and DQOs. The second review of the project is performed by the QA Manager, who is responsible for assuring that the program management systems are established and functioning as required by the Test Plan and other QA/QC requirements.

For all verifications conducted by the GHG Center, all draft documents are reviewed by the technology vendor, followed by an independent review by selected industry experts. These external peer reviews are conducted by technically competent persons who are familiar with the technical aspects of the project, but are not involved with the conduct of project activities. The peer reviewers present to the Project Manager an accurate and independent appraisal of the technical aspects of the project.

4.4.2. Inspections

The Field Team Leader, Project Manager, or QA Manager may conduct inspections. Inspections assess activities that are considered important or critical to key activities of the project. These activities may include, but are not limited to, pre- and post-test calibrations, the data collection equipment, sample equipment preparation, sample analysis, and data reduction. Inspections are assessed with respect to the

Test Plan or other established methods, and should be documented in field records. Results of inspections should be reported to the Project Manager and QA Manager. Any deficiencies or problems found during the inspections should be investigated, and the results and responses or corrective actions reported in a Corrective Action Report (Figure 4-1).

4.4.3. Audits

Independent systematic checks to determine the quality of the data should be performed on the activities of all verification projects. The guidelines recommended here include procedures specified in the Center's ETV Quality Management Plan. These checks can consist of a technical systems audit (TSA), performance evaluation audit (PEA), and audit of data quality (ADQ) as described below. In addition, the internal quality control measurements can be used to assess the performance of the analytical methodology. The combination of these audits and the evaluation of the internal quality control data allow the assessment of the overall quality of the data for a project.

The designated QA Manager should be responsible for ensuring the audits are conducted as required by the Test Plan. Audit reports that describe problems and deviations from the procedures are prepared and distributed to the Field Team Leader. Any problems or deviations need to be corrected. The Field Team Leader is responsible for evaluating Corrective Action Reports, taking appropriate and timely corrective actions, and informing the QA Manager of the action taken. The QA Manager is then responsible for ensuring that the corrective action was taken.

4.4.3.1. Technical System Audit

A TSA assesses the implementation of sampling and analytical procedures specified in the test plan. This type of audit should be conducted on a representative number of verifications that are similar in content. The TSA evaluates all components of the data gathering and management system to determine if these systems have been properly designed to meet the quality assurance objectives for the study. The TSA includes a careful review of the experimental design, the Test Plan, and procedures conducted during field operations. This review can include personnel qualifications, adequacy and safety of the facility and equipment, and the data management system.

The TSA begins with the review of verification requirements, procedures, and experimental design to ensure they can meet the DQOs. During the TSA, the QA Manager, or designee, can inspect the analytical activities and determine their adherence to the Test Plan. The QA Manager, or a designee, reports any area of nonconformance to the Field Team Leader through an audit report. The audit report may contain corrective action recommendations. If so, follow-up inspections may be required and should be performed to ensure corrective actions are taken.

4.4.3.2. Performance Evaluation Audit

PEAs are designed to check the operation of the analytical systems (emissions testing and fuel analyses for these verifications). Performance samples containing analytes of known (determined) concentration can be presented to the analyst in such a manner as to have the concentration of the PEA unknown (blind) to the analyst. Upon receiving the analytical data from the analyst, the Field Team Leader or Project Manager can evaluate the performance data for compliance with the requirements of the project. The PEA should occur on-site during the field test. The method performance can also be assessed using the internal quality control samples (inserted into the analytical scheme). The specific measurement and DQOs for method performance samples have been described earlier.

4.4.3.3. Audit of Data Quality

An ADQ is an important component of a total system audit and includes an evaluation of the measurement, processing, and evaluation steps to determine if systematic errors have been introduced. During the ADQ, the QA Manager, or designee, can randomly select approximately 10 percent of the data to be followed through the analysis and processing. The purpose of the ADQ is to verify that data-handling systems are correct and to assess the quality of the data generated.

4.5. DOCUMENTATION AND REPORTS

During the different activities on verification projects, documentation and reporting of information to management and project personnel is critical. To insure the complete transfer of information to all parties involved in a verification project, the following field test documentation, QA/QC documentation, corrective action/assessment report, and Verification Report/Statements should be prepared.

4.5.1. Field Test Documentation

The Field Team Leader should record all field activities. The Test Leader should review all data sheets and maintain them in an organized file. The Field Team Leader should also maintain a field notebook that documents the activities of the field team each day and any deviations from the schedule, Test Plan, or any other significant event. Any problems found during testing requiring corrective action should be reported immediately by the field test personnel or unit operators to the Field Team Leader through a Corrective Action Report (Figure 4-1). The Field Team Leader can then document this in the project files and report it to the Project Manager and QA Manager.

At the end of each test day, the Field Team Leader should collect all of the data from the field team members, which includes data sheets, data printouts, backup copies of electronic files stored on the DAS, and field notebooks. A copy of the field test documentation should be submitted to the Project Manager, and originals should be properly stored.

4.5.2. QA/QC Documentation

Upon completion of a verification test, test data, sampling logs, calibration records, certificates of calibration, and other relevant information should be stored in a safely maintained project file. Calibration records should include information about the instrument being calibrated, raw calibration data, calibration equations, analyzer identifications, calibration dates, calibration standards used and their traceability, calibration equipment, and staff conducting the calibration. These records can be used to prepare the Data Quality section in the Verification Report, and made available to the QA Manager during audits.

4.5.3. Corrective Action and Assessment Reports

A corrective action is the process that occurs when the result of an audit or quality control measurement is shown to be unsatisfactory, as defined by the DQOs or by the measurement objectives for each task. The corrective action process involves the Field Team Leader, Project Manager, and QA Manager. In cases involving the analytical process, the correction action will also involve the analyst. A written Corrective Action Report should be completed for all corrective actions (Figure 4-1).

Figure 4-1. Example Corrective Action Report

Corrective Action Report

Verification Title: ______________________________

Verification Description: ________________________

Description of Problem: _______________________________

____

____

____

Originator: _______ **Date:** ________

Investigation and Results: ____________________________

____

____

____

Investigator: _______ **Date:** ________

Corrective Action Taken: _____________________________

____

____

____

Originator: _______ **Date:** ________

Approver: _______ **Date:** ________

Carbon copy: GHG Center Project Manager, GHG Center Director, SRI QA Manager, GHG Center Program Manager

4.5.4. Verification Report and Verification Statement

A draft Verification Report and Statement should be prepared after completing all field testing, data collection, and data validation and review. The final Verification Report should contain a Verification Statement, which is a 3 to 4 page summary of the microturbine system, the test strategy used, and the verification results obtained. The Verification Report should summarize the results for each verification parameter discussed in Section 2.0 and include sufficient raw data to support findings and allow others to assess data trends, completeness, and quality. Clear statements should be provided which characterize the performance of the verification parameters identified in Sections 1 and 2. An example outline of the Verification Report is shown below.

Preliminary Verification Report Outline

Verification Statement

Section 1:	*Verification Test Design and Description* *Microturbine System and Site Description* *Overview of the Verification Parameters and Evaluation Strategies*
Section 2:	*Results* *Power Production Performance* *Power Quality Performance* *Operational Performance* *Emissions Performance*
Section 3:	*Data Quality*
Section 4:	*Additional Technical and Performance Data (optional) supplied by microturbine manufacturer*
Appendices	*Raw Verification and Other Data*

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APPENDIX A
Example Field Testing Procedures and Log Forms

Page

Appendix A-1. Load Testing Procedures

1. In the Microturbine Communications Software, select the desired test load in the Power Command box. Record these user specified settings in the log form (Appendix A-2).

2. Coordinate with emissions testing personnel to establish a start time. Record this time in the log form.

3. Continue operating the microturbine system at the selected load for a minimum of 4 minutes.

4. Obtain a minimum of one gas sample from the fuel supply line. Follow procedures outlined in Appendix A-3.

5. After 30 minutes of data are collected, review power output, ambient temperature, and barometric pressure to determine if all of the following criteria are satisfied:

Power output (kW)	$\pm$ 2 %
Power factor	$\pm$ 2 %
Fuel heating value	$\pm$ 1 %
Fuel flow	$\pm$ 2 %
Barometric pressure	$\pm$ 0.5 %
Ambient air temperature	$\pm$ 4 ^{o}F

6. If the above criteria are not satisfied, continue operating the turbine at the selected load. After each 15 minute interval, repeat Step 5 until the uncertainty criteria are met. Record the time intervals when valid data were obtained (minimum of 4 minutes and maximum of 30 minutes).

7. Repeat Steps 1 through 6 by changing the operating load to the remaining 4 desired operating loads. Data and calculations for each load test repetition will be maintained independently using the log forms provided in Appendix A-2.

Appendix A-2. Load Test Log

Date ________________________

Test technician name ____

Load Test Begin Time _________________ (*from DAS)*

Synchronize Emissions Test Equipment to DAS time _____________________ *(initial upon synchronization)*

Beginning of test

Turbine Load Setting. _______ %

Turbine Power Factor Setting _______ %

Power Output _______ kW

Power Factor _______ %

Fuel Flow _______ lbm/min

Barometric pressure _______ in Hg

Ambient air temp _______°F

Relative humidity _______ %

Emissions Test

First data point Date __________ Time __________

Final data point Date __________ Time __________

End of test

Turbine Load Setting _______ kW

Power Output _______ kW *(if > ± 2% from beginning test measurement, test is invalid)*

Power Factor _______ % *(if > ± 2% from beginning test measurement, test is invalid)*

Fuel Flow _______ lbm/min *(if > ± 1% from beginning test measurement, test is invalid)*

Barometric pressure _______ in. Hg *(if > ± 0.5% from beginning test measurement, test is invalid)*

Ambient air temp _______ °F *(if > ± 4°F from beginning test measurement, test is invalid)*

Relative humidity _______ %

Load Testing End Time _______________ *(from DAQ system)*

Load Testing Duration Time _______________ min *(if duration <4 or >30 minutes, test results are invalid)*

If for any reason the test is invalid, repeat the procedure.

Appendix A-3. Fuel Gas Sampling Procedures

1) Attach a leak free vacuum gauge to the inlet of two pre-evacuated stainless steel sample canisters. Open each canister inlet valve and verify that the canisters are fully evacuated. Record the absolute pressures.

2) Close the inlet valves, remove the vacuum gauge, and attach a canister to the sample port on the fuel line. Attach the inlet of the second canister to the outlet of the first to enable replicate sampling.

3) Open the fuel line valve upstream of the canisters, and open the inlet and outlet valves on the first canister and just the inlet valve on the second. Wait 5 seconds to allow the canisters to fill with fuel.

4) Open the second canister outlet valve and purge the canisters for 5 more seconds. Close the canister outlet valves, the canister inlet valves, and the fuel line valve.

5) Remove canister from port. Record date, time, canister ID number, and final canister pressure (Appendix A-4) on proper chain-of-custody form (Appendix A-5).

6) Return collected samples to laboratory along with completed chain-of-custody form.

Laboratories' Analytical Procedures:

1) Samples are received with proper chain-of-custody form and logged into the laboratory system for analysis.
2) Samples are injected and analyzed. The GC determines gas constituent concentrations based on the areas of the chromatograph peaks relative to the gas standard.
3) Duplicate analysis is conducted on one sample per lot.
4) Fuel LHV is calculated using results of each analysis and equations provided in ASTM D3588.
5) Hard copies of calibration records and LHV results will be submitted to the verification Center.
6) Determine accuracy based on the replicates.

Appendix A-4. Fuel Sampling Log

Project: ______________________ Ambient Pressure: ______________________

Location: ______________________ Ambient Temperature: ______________________

Source: ______________________ ______________________

Sampler: ______________________ ______________________

Sample ID	Date	Time	Canister ID	Initial Pressure (psig)	Final Pressure (psig)	Comments

Appendix A-5. Fuel Sampling Chain of Custody Record

Project: ______________________ Sampling Date(s): ______________________

Location: ______________________ Shipping Date: ______________________

Sampler: ______________________ Laboratory: ______________________

Source ID: ______________________ Ship to: ______________________

Matrix: Natural Gas ______________________

Sample ID	Date	Time	Canister ID	Initial Pressure (psig)		Final Pressure (psig)	Analytes	Method

Relinquished by: ______________________ Date/Time: ______________________

Received by: ______________________ Date/Time: ______________________

Relinquished by: ______________________ Date/Time: ______________________

Received by: ______________________ Date/Time: ______________________

Relinquished by: ______________________ Date/Time: ______________________

Received by: ______________________ Date/Time: ______________________

Appendix A-6. Microturbine Cold Start Test Procedure

Determination of cold start time is important in determining the suitability of this technology for use in peak shaving applications. To determine this parameter, the following procedures will be followed, and information will be logged in the forms shown in Appendix A-7.

1. The generator should be shut off at least eight (8) hours prior to the cold start test.

2. Immediately prior to the cold start test, the electrical load available at the facility will be determined to be greater than the 100 percent load capacity of the microturbine. If the available load is less than the 100 percent load capacity of the microturbine, the test will be postponed until a sufficient electrical load is available.

3. A stopwatch will be made ready to begin timing as soon as the microturbine start-up is commenced.

4. Microturbine start-up will be initiated when the start command is given by the user to the unit control system. The stopwatch will begin timing immediately at that point.

5. Standard microturbine start-up procedures will be followed (as detailed in the Operation Manual.)

6. As soon as the microturbine start-up parameters are fulfilled (as detailed in the Operation Manual), the electrical load will be automatically loaded onto the generator. The observer with the stopwatch should note this from the load reading of the electrical meter.

7. When the microturbine has supplied 100 percent of its rated load, the stopwatch timing is stopped and the length of the cold start-up time will be noted on the log sheet.

Appendix A-7. Microturbine Cold Start Log

Date __________ Time __________

Test technician name ______________________________

Barometric pressure .... _______ in Hg

Ambient air temp .... _______ °F

Relative humidity .... _______ %

End of last microturbine operation Date ___________ Time __________

______ Initial *to indicate that the microturbine has not operated within the past 8 hours.*

______ Initial *to indicate that the microturbine internal clock has been synchronized to DAQ clock.*

______ Initial *to indicate that the connected load is greater than 75 kW*

(to allow for full-power output operation.)

______ Initial *to indicate that the microturbine load setting is at 100%.*

______ Initial *to indicate that all necessary preparations have been made to start the microturbine.*

______ Initial *to indicate that stopwatch is ready to begin timing.*

Initiate microturbine **start-up and begin stopwatch timing.**

Time of commencement of start-up ..... __________ *(from microturbine display panel).*

Upon indication that power output is a full load, end stopwatch timing and note time of day.

Time of full power output _______________*(from microturbine display panel)*

Elapsed time from stopwatch ______________

Calculated elapsed time from microturbine display data ______________

Appendix A-8. Microturbine Start/Stop Log

Microturbine start: Date _____________ Time _____________

Microturbine stop: Date _____________ Time _____________
Unscheduled downtime..... Duration ________________days/hours Scheduled downtime

Reason for unscheduled downtime ____
____

Microturbine start: Date _____________ Time _____________

Microturbine stop: Date _____________ Time _____________
Unscheduled downtime..... Duration ________________days/hours Scheduled downtime

Reason for unscheduled downtime ____
____

Microturbine start: Date _____________ Time _____________

Microturbine stop: Date _____________ Time _____________
Unscheduled downtime..... Duration ________________days/hours Scheduled downtime

Reason for unscheduled downtime ____
____

Microturbine start: Date _____________ Time _____________

Microturbine stop: Date _____________ Time _____________
Unscheduled downtime..... Duration ________________days/hours Scheduled downtime

Reason for unscheduled downtime ____
____

Microturbine start: Date _____________ Time _____________

Microturbine stop: Date _____________ Time _____________
Unscheduled downtime..... Duration ________________days/hours Scheduled downtime

Reason for unscheduled downtime ____
____

Microturbine start: Date _____________ Time _____________

Microturbine stop: Date _____________ Time _____________
Unscheduled downtime..... Duration ________________days/hours Scheduled downtime

Reason for unscheduled downtime ____
____

APPENDIX B
Example Test Data Output and Reports

Appendix B-1. Example of Laboratory Gas Analysis Results

8210 Mosley Rd
Houston, TX 77075
713 943-9776 Telephone
713 943-3846 Facsimile

CORE LABORATORIES

BILL CHATTERTON
SOUTHERN RESEARCH
79 T W ALEXANDER DR
4401 BLDG SUITE 105
RESEARCH TRIANGEL PARK, NC 27709

Sample Number	111886-003
Sample Date	4/10/01 12:50:00 PM
Date Reported	4/20/01
Date Received:	4/18/01
Sample ID	Run# 6
Description	Natural Gas
	#1538

Analytical Report

Test	Result	Units	Method	Date	Analyst
Natural Gas Analysis					
Nitrogen	0.55	Mol %	GPA 2261-95	4/19/01	TH
Oxygen	0.06	Mol %	GPA 2261-95		
Carbon Dioxide	0.67	Mol %	GPA 2261-95		
Methane	93.47	Mol %	GPA 2261-95		
Ethane	4.08	Mol %	GPA 2261-95		
Propane	0.78	Mol %	GPA 2261-95		
Isobutane	0.10	Mol %	GPA 2261-95		
n-Butane	0.12	Mol %	GPA 2261-95		
Isopentane	0.04	Mol %	GPA 2261-95		
n-Pentane	0.03	Mol %	GPA 2261-95		
Hexanes Plus	0.10	Mol %	GPA 2261-95		
Total	100.00	Mol %	GPA 2261-95		
Molar Mass Ratio	0.59754		GPA 2172-96		
Relative Density	0.59850		GPA 2172-96		
Compressibility Factor	0.99771		GPA 2172-96		
Gross Heating Value (Dry)	1051.0	BTU/CF (Ideal	GPA 2172-96		
Gross Heating Value (Dry)	1053.4	BTU/CF (Real	GPA 2172-96		
Net Heating Value (Dry)	948.1	BTU/CF (Ideal	GPA 2172-96		
Net Heating Value (Dry)	950.3	BTU/CF (Real	GPA 2172-96		
Pressure Base	14.696	psia			

Approved By: HWatts
Dan Watts
Supervising Chemist

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Appendix B-2. Example of Laboratory Calibration Data

Core Lab

QA Report

Job No 111886

Date: 19-Apr

Components			CCVS TV	AV	% Rec	Sample Duplicate OV	DV	RPD
Identifier			10716			111886-1		
Oxygen	Mol%	PRE	0.001	0	0	4.74	4.72	0
Nitrogen	Mol%	PRE	5	5	100	18.28	18.15	1
Methane	Mol%	PRE	70.487	70.487	100	73.41	73.58	0
Ethane	Mol%	PRE	9.002	9	100	2.34	2.34	0
CO2	Mol%	PRE	0.998	0.998	100	0.49	0.49	0
Propane	Mol%	PRE	6.003	6	100	0.45	0.45	0
Iso-Butane	Mol%	PRE	3.001	3.02	101	0.06	0.06	0
N-Butane	Mol%	PRE	3.01	2.992	99	0.07	0.07	0
Isopentane	Mol%	PRE	0.998	1.005	101	0.02	0.02	0
N-Pentane	Mol%	PRE	1	1.004	100	0.02	0.02	0

CCVS Continuing calibration verification standard
TV True Value
AV Analyzed value
OV Original value
DV Duplicate value
RPD Relative Percent Difference

Appendix B-3. Example of Exhaust Stack Raw Emission Measurements Data

Parameter	: NOX25	: NO25	: CO	: CO2	: O2	: THC
Units	: PPM	: PPM	: PPM	: %	: %	: PPM
Date Time	Average	Average	Average	Average	Average	Average
4/2/2001 13:30	2.09	1.82	2.54	1.19	18.07	0.02
4/2/2001 13:31	2.05	1.76	2.52	1.21	18.08	0.01
4/2/2001 13:32	2.08	1.81	2.52	1.22	18.07	0.02
4/2/2001 13:33	2.16	1.87	2.53	1.23	18.05	0.02
4/2/2001 13:34	2.12	1.84	2.51	1.24	18.06	0
4/2/2001 13:35	2.15	1.86	2.5	1.24	18.06	-0.02
4/2/2001 13:36	2.12	1.84	2.52	1.25	18.05	-0.01
4/2/2001 13:37	2.14	1.85	2.51	1.25	18.05	-0.01
4/2/2001 13:38	2.13	1.84	2.47	1.25	18.05	-0.02
4/2/2001 13:39	2.12	1.83	2.46	1.25	18.06	-0.02
4/2/2001 13:40	2.12	1.83	2.47	1.25	18.05	-0.03
4/2/2001 13:41	2.09	1.8	2.43	1.25	18.06	-0.03
4/2/2001 13:42	2.07	1.77	2.47	1.25	18.06	-0.02
4/2/2001 13:43	2.06	1.76	2.48	1.25	18.05	-0.02
4/2/2001 13:44	2.09	1.78	2.43	1.25	18.06	-0.03
4/2/2001 13:45	2.08	1.77	2.35	1.25	18.07	-0.04
4/2/2001 13:46	2.06	1.74	2.39	1.25	18.05	-0.04
4/2/2001 13:47	2.07	1.77	2.35	1.25	18.05	-0.05
4/2/2001 13:48	2.05	1.74	2.41	1.25	18.07	-0.05
4/2/2001 13:49	2.07	1.75	2.38	1.25	18.06	-0.05
4/2/2001 13:50	2.06	1.73	2.31	1.25	18.06	-0.07
4/2/2001 13:51	2.06	1.72	2.29	1.24	18.07	-0.07
4/2/2001 13:52	2.06	1.72	2.3	1.24	18.06	-0.07
4/2/2001 13:53	2.08	1.75	2.31	1.25	18.06	-0.07
4/2/2001 13:54	2.06	1.72	2.31	1.25	18.07	-0.08
4/2/2001 13:55	2.05	1.71	2.32	1.25	18.06	-0.09
4/2/2001 13:56	2.06	1.72	2.29	1.25	18.06	-0.09
4/2/2001 13:57	2.07	1.72	2.31	1.25	18.07	-0.09
4/2/2001 13:58	2.08	1.73	2.31	1.25	18.06	-0.1
4/2/2001 13:59	2.06	1.71	2.32	1.25	18.05	-0.11
average	2.09	1.78	2.41	1.24	18.06	-0.04

Appendix B-4. Example of Exhaust Stack Emission Testing System Calibrations

CLIENT	SRI			**SITE**				**SOURCE**
DATE	April 2-3, 2001							**TEMP**
REFERENCE ANALYZER		ML 8840		**RESPONSE TIME**	1 min			**RANGE**
HIGH CAL VALUE		22.5	**+/- 2% FS:**	22 -	23			**MID CAL**
LOW CAL VALUE		7	**+/- 2% FS:**	6.5 -	7.5			

	TEST 1	**TEST 2**	**TEST 3**	**TEST 4**	**TEST 5**	**TEST 6**	**TEST 7**	**TEST 8**
INITIAL ZERO	0.00 PPM			0.00 PPM				
INITIAL LOW	6.95			7.00				
C.F. (2%) FS	1.007			1.000				
INITIAL HIGH	22.70 PPM			22.70 PPM				
C.F. (2%) FS	0.991			0.991				
INITIAL MID	12.05 PPM			12.00 PPM				
C.F. (2%) FS	0.996			1.000				
SYSTEM ZERO	0.00 PPM	0.00 PPM	0.00 PPM	0.00 PPM	0.00 PPM	0.00 PPM	0.00 PPM	0.00
SYSTEM SPAN	12.05 PPM	12.07 PPM	11.80 PPM	12.00 PPM	12.00 PPM	11.90 PPM	11.75 PPM	11.80
C.F. (5%) FS	0.996	0.994	1.017	1.000	1.000	1.008	1.021	1.017
FINAL ZERO	0.00 PPM	0.00 PPM	0.00 PPM	0.00 PPM	0.00 PPM	0.00 PPM	0.00 PPM	0.00
FINAL SPAN	12.07 PPM	11.80 PPM	11.70 PPM	12.00 PPM	11.90 PPM	11.75 PPM	11.80 PPM	11.75
C.F. (5%) FS	0.994	1.017	1.026	1.000	1.008	1.021	1.017	1.021
AVERAGE C.F.	0.995	1.006	1.021	1.000	1.004	1.015	1.019	1.019
AVERAGE ZERO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ZERO DRIFT <2%	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0
SPAN DRIFT <2%	-0.1 %	1.1 %	0.4 %	0.0 %	0.4 %	0.6 %	-0.2 %	0.2

APPENDIX C
Electricity Generation Emission Factors

Page

Appendix C-1. 1999 Census Division Average Electricity Generation and Emission Factors, (Average of All Fossil Fuels[a])			
Census Division (states)	**Net Generation, 10^6 kWh**	**CO_2 Emission Factor, lb/kWh**	**NO_X Emission Factor, lb/kWh**
New England (CT, ME, MA, NH, RI, VT)	44653	1.487380	0.002553
Middle Atlantic (NJ, NY, PA)	297473	0.913804	0.002098
East North Central (IL, IN, MI, OH, WI)	547482	1.647068	0.006353
West North Central (IO, KA, MN, MO, NE, ND, SD)	268491	1.746710	0.006875
South Atlantic (DE, DC, FL, GA, MD, NC, SC, VA, WV)	687223	1.345843	0.003740
East South Central (AL, KY, MI, TN)	317462	1.580485	0.005204
West South Central (AR, LA, OK, TX)	546311	1.246272	0.003580
Mountain (AZ, CO, ID, MT, NV, NM, UT, WY)	296479	1.592052	0.005451
Pacific Contiguous (CA, OR, WA)	251646	0.288055	0.000739
Pacific Non-contiguous (AK, HI)	10886	2.039317	0.005879

Source: EIA Electric Power Annual, 1999 (EIA 1999), Volume I, Tables A8, A9, A10; Volume II, Table 25

[a] Includes coal, gas, and petroleum

Appendix C-2. 1999 Census Division Average Electricity Generation and Emission Factors, (Average of Coal-Fired Plants Only)			
Census Division (states)	**Net Generation, 10^6 kWh**	**CO_2 Emission Factor, lb/kWh**	**NO_X Emission Factor, lb/kWh**
New England (CT, ME, MA, NH, RI, VT)	4402	6.486597	0.015902
Middle Atlantic (NJ, NY, PA)	102918	2.087371	0.005305
East North Central (IL, IN, MI, OH, WI)	409118	2.151365	0.008384
West North Central (IO, KA, MN, MO, NE, ND, SD)	201291	2.263052	0.009022
South Atlantic (DE, DC, FL, GA, MD, NC, SC, VA, WV)	395574	2.002295	0.005921
East South Central (AL, KY, MI, TN)	220023	2.167664	0.007299
West South Central (AR, LA, OK, TX)	214444	2.189933	0.007275
Mountain (AZ, CO, ID, MT, NV, NM, UT, WY)	207400	2.172517	0.007570
Pacific Contiguous (CA, OR, WA)	12354	2.179213	0.009552
Pacific Non-contiguous (AK, HI)	156	34.743590	0.230769
Source: EIA Electric Power Annual, 1999 (EIA 1999), Volume I, Tables A8, A9, A10; Volume II, Table 25			

Appendix C-3. 1999 Census Division Average Electricity Generation and Emission Factors, (Average of Petroleum-Fired Plants Only)

Census Division (states)	Net Generation, 10^6 kWh	CO_2 Emission Factor, lb/kWh	NO_X Emission Factor, lb/kWh
New England (CT, ME, MA, NH, RI, VT)	8285	n/a	0.004104
Middle Atlantic (NJ, NY, PA)	15330	1.891455	0.002087
East North Central (IL, IN, MI, OH, WI)	3163	1.976604	0.003162
West North Central (IO, KA, MN, MO, NE, ND, SD)	1488	1.817204	0.002688
South Atlantic (DE, DC, FL, GA, MD, NC, SC, VA, WV)	46527	1.880890	0.002665
East South Central (AL, KY, MI, TN)	3902	2.356740	0.003075
West South Central (AR, LA, OK, TX)	692	8.832370	0.014451
Mountain (AZ, CO, ID, MT, NV, NM, UT, WY)	244	1.573770	n/a
Pacific Contiguous (CA, OR, WA)	69	1.913043	n/a
Pacific Non-contiguous (AK, HI)	7227	1.826207	0.002767

Source: EIA Electric Power Annual, 1999 (EIA 1999), Volume I, Tables A8, A9, A10; Volume II, Table 25

Appendix C-4. 1999 Census Division Average Electricity Generation and Emission Factors, (Average of Gas-Fired Plants Only)			
Census Division (states)	**Net Generation, 10^6 kWh**	**CO_2 Emission Factor, lb/kWh**	**NO_X Emission Factor, lb/kWh**
New England (CT, ME, MA, NH, RI, VT)	2109	2.426743	0.004742
Middle Atlantic (NJ, NY, PA)	21218	1.320011	0.002074
East North Central (IL, IN, MI, OH, WI)	7876	1.946166	0.004063
West North Central (IO, KA, MN, MO, NE, ND, SD)	5899	1.535514	0.003390
South Atlantic (DE, DC, FL, GA, MD, NC, SC, VA, WV)	44914	1.091107	0.002360
East South Central (AL, KY, MI, TN)	10173	1.534651	0.003342
West South Central (AR, LA, OK, TX)	166899	1.229019	0.002325
Mountain (AZ, CO, ID, MT, NV, NM, UT, WY)	17198	1.223631	0.002675
Pacific Contiguous (CA, OR, WA)	17255	2.632976	0.003825
Pacific Non-contiguous (AK, HI)	2839	1.262416	0.002818
Source: EIA Electric Power Annual, 1999 (EIA 1999), Volume I, Tables A8, A9, A10; Volume II, Table 25			