SRI/USEPA-GHG-QAP-13
March 2001

Test and Quality Assurance Plan

Mariah Energy Corporation
Heat PlusPower^{TM} System

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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Mariah Energy Corp.
Heat PlusPower™ System

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This Test and Quality Assurance Plan has been reviewed and approved by the Greenhouse Gas Technology Center Project Manager and Center Director, the Southern Research Institute Q/A Manager, the U.S. EPA Pilot Manager, and the U.S. EPA Pilot Q/A Manager.

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Test Plan Final: March 2001

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1.0 INTRODUCTION

1.1. BACKGROUND

The U.S. Environmental Protection Agency's Office of Research and Development (EPA-ORD) operates a program to facilitate the deployment of innovative technologies through performance verification and information dissemination. The goal of the Environmental Technology Verification (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 and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

The Greenhouse Gas Technology Center (the GHG Center) is one of several verification organizations operating under the ETV program. The GHG Center is managed by EPA's partner verification organization, Southern Research Institute, which conducts verification testing of promising GHG mitigation and monitoring technologies. The GHG Center's verification process consists of developing verification protocols, conducting field tests, collecting and interpreting field and other data, obtaining independent peer-review input, and reporting findings. Performance evaluations are conducted according to externally reviewed verification Test Plans 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 comprising 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 the wide distribution of verification results.

One technology of interest to some GHG Center's stakeholders was the use of microturbines as a distributed energy source. Distributed generation refers to power generation equipment, typically ranging from 5 to 1000 kilo-watts (kW) that provides 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 system. Examples of technologies available for distributed generation include gas turbine generators, internal combustion engine generators (gas, diesel, or other), photovoltaics, wind turbines, fuel cells, and microturbines. Distributed generation 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).

Microturbines coupled with heat recovery systems for cogeneration are a relatively new technology, and the availability of performance data is limited and in demand. The GHG Center's stakeholder groups and other organizations have expressed interest in obtaining verified field data on the technical, economic, emissions, and operational performance of the microturbine-based combined heat and power (CHP) systems. Mariah Energy Corporation (Mariah) has committed to participate in an independent verification of their Heat PlusPower™ system (Mariah CHP) at the Walker Court condominium project in Calgary, Alberta, Canada. The Mariah CHP system uses a Capstone MicroTurbine® for electricity generation. It also includes: (1) a specially designed and insulated microturbine enclosure, (2) a turbine exhaust waste heat recovery unit, and (3) an integrated building energy management system. All three components are designed, installed, and offered by Mariah. The Mariah CHP will provide most of the electricity and hot water required by Walker Court. It will also provide all space heating requirements, except during some of the coldest winter months in Calgary, during which 50 percent of the comfort heating will be provided by a back-up gas-fired boiler. The overall energy conversion efficiency is estimated to range from 70 to 80 percent, which is high enough to significantly reduce greenhouse gas emissions (estimated by 50 percent) and provide end users with high quality energy services at competitive prices.

The Mariah CHP at Walker Court is one of the first commercial installations of the Heat PlusPower™ System. According to Mariah, the system at Walker Court is representative of future applications the company plans to market to hotels, restaurants, office buildings, and other condominiums. The electricity generated by the system will be used on-site, and excess electrical energy will be interconnected to the Alberta electric utility grid for sale. The thermal energy generated by the system will be used to heat domestic hot water tanks and provide comfort heating for the facility. Mariah Energy has retained the services of the Alberta Research Council as a technical resource for this study. The GHG Center will be evaluating the performance of the CHP system at the Walker Court facility, in collaboration with Natural Resources Canada (NRCAN) and the Canada Center For Mineral and Energy Technology (CANMET). Field tests will be performed over a five week verification period to independently verify the electricity generation and use rate, thermal energy recovery and use rate, electrical power quality, energy efficiency, emissions, and GHG emission reductions for the Walker Court site. GHG emission reductions will also be estimated for CHP system installations at model sites in the U.S. and Canada.

This document is the Test/Quality Assurance Plan (Plan) for the Walker Court configuration. It contains rationale for the selection of verification parameters, verification approach, data quality objectives, and Quality Assurance/Quality Control (QA/QC) procedures to be implemented. This Plan will be, or has been, reviewed by Mariah, NRCAN/CANMET, the GHG Center's DG Stakeholder Panel, and the U.S. EPA QA team. Once approved, as evidenced by the signature sheet at the front of this document, it will meet the requirements of the GHG Center's Quality Management Plan (QMP) and thereby satisfy the ETV QMP requirements and conform with U.S. EPA's standard for environmental testing (E-4). This Plan has been prepared to guide implementation of the test and to document planned test operations. Once testing is completed, the GHG Center will prepare a Verification Report and Statement, which will be reviewed first by Mariah. Once all comments are addressed, the report will be peer-reviewed by the Stakeholders, NRCAN/CANMET, and the U.S. EPA QA team. Once completed, the GHG Center Director and the U.S. EPA Laboratory Director will sign the Verification Statement, and the final Report will be posted on the Web sites maintained by the GHG Center and the ETV program.

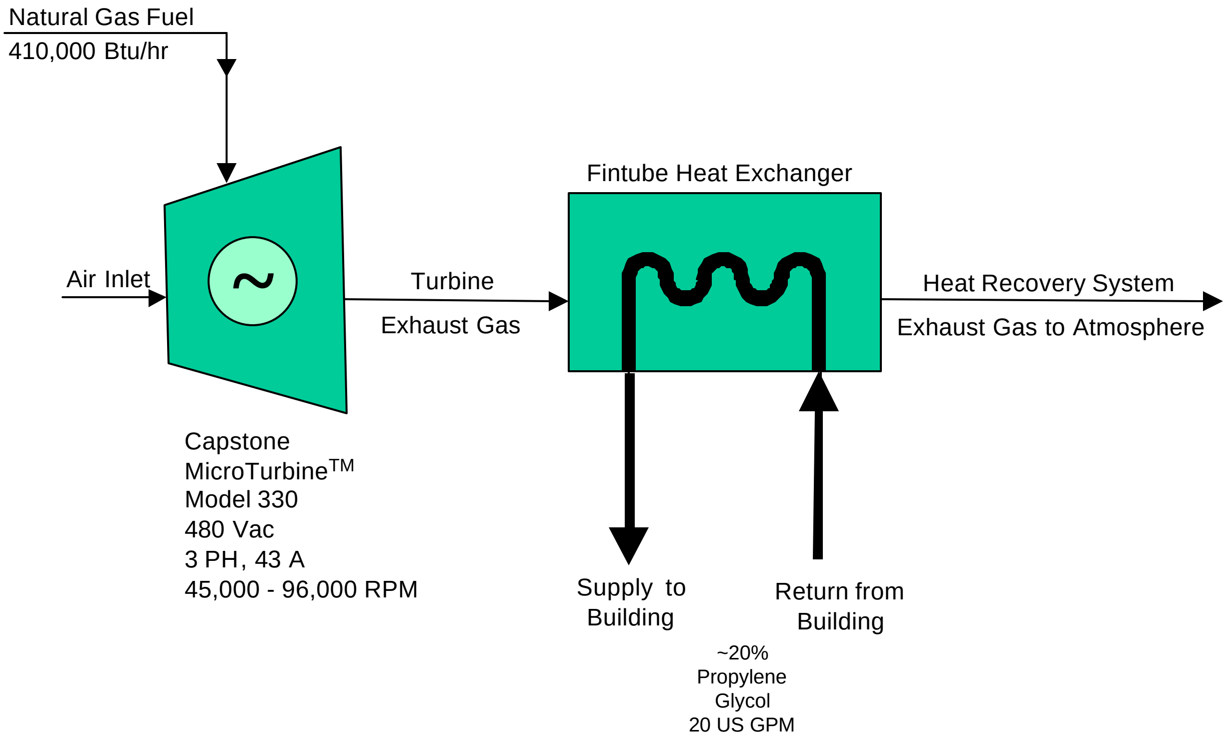
The remaining discussion in this section provides a description of the Mariah CHP technology and the Walker Court facility. This is followed by a list of performance verification parameters that will be quantified through independent testing at the Walker Court site. A discussion of key organizations participating in this verification, their roles, and the verification test schedule is provided at the end of this section. Section 2.0 describes the technical approach for verifying each parameter, including the sampling procedures, analytical procedures, and QA/QC procedures that will be followed to assess data quality. Section 3.0 identifies the data quality objectives for critical measurements, and states the accuracy, precision, and completeness goals for each measurement. Section 4.0 discusses data acquisition, validation, reporting, and auditing procedures.

1.2. MARIAH CHP TECHNOLOGY DESCRIPTION

Large- and medium-scale gas fired turbines have been used to generate electricity since the 1950s. Recently they have become more widely used to provide additional generation capacity because of their ability to be quickly deployed and provide electricity at the point of use. Technical and manufacturing developments during the last decade have enabled the introduction of microturbines, with generation capacity ranging from 30 to 200 kW. The Mariah CHP is one of the first cogeneration installations that integrate the microturbine technology to produce electric power, heat, and hot water (Figure 1-1). Figure 1-2 illustrates a simplified process flow diagram of the CHP sytem, and a discussion of key components is provided below.

Figure 1-1. The Mariah Combined Heat and Power System

Figure 1-2. Mariah CHP Process Diagram



Electric power is generated with a Capstone MicroTurbine™ Model 330 (76.5” high, 30” wide, 59.7” deep, and 891 pounds), with a nominal power output of 30 kW (60 °F, sea level). Table 1-1 summarizes the physical and electrical specifications reported by Capstone. The system incorporates an air compressor, recuperator, combustor, turbine and permanent magnet generator. In the compressor section, compressed air is mixed with fuel, and this compressed fuel/air mixture is burned in the combustor under constant pressure conditions. The resulting hot gas is allowed to expand through the turbine section to perform work, rotating the turbine blades to turn a generator which produces electricity. Because of the inverter based electronics that enable the generator to operate at high speeds and frequencies, the need for a gearbox and associated moving parts is eliminated. The rotating components are mounted on a single shaft, supported by patented air bearings that rotate at over 96,000 rpm (full load). The generator is cooled by air flow into the gas turbine. The exhaust gas exits the turbine and enters the recuperator, which captures some of the energy and uses it to pre-heat the air entering the combustor, improving the efficiency of the system. The exhaust gas then exits the recuperator through a muffler and into Mariah’s heat recovery unit. Mariah provides an optional muffler system to further reduce sound levels in sensitive installations.

The permanent magnet generator produces high frequency alternating current which is rectified, inverted, and filtered by the line power unit into conditioned alternating current at 480 volts. The unit supplies a variable electrical frequency of 50 or 60 Hertz (Hz), and is supplied with a control system which allows for automatic and unattended operation. An active filter in the turbine is reported by the turbine manufacturer to provide cleaner power, free of spikes and unwanted harmonics. All operations, including start-up, setting of programmable interlocks, grid synchronization, operational setting, dispatch, and shutdown, can be performed manually or remotely using an internal power controller system. The Walker Court CHP system runs parallel with the local power utility. If the power demand exceeds the available capacity of the turbine, additional power is drawn from the grid. In the event of a power grid failure, the system is designed to automatically disconnect from the grid and run stand-alone, which isolates the on-site electrical system from grid faults. Additionally, the control system is designed to automatically shed lower priority loads if necessary to ensure local loads never exceed stand-alone generator capacity. When grid failure does occur, Mariah's energy management control system allows automatic shedding of low priority loads to ensure the load at Walker Court never exceeds the generator capacity. When grid power is restored, the CHP system can either automatically reconnect, or await a manual command. When excess power is available, it is exported back to the grid. A bi-directional time-of-use meter records energy feeding into the grid.

Table 1-1. Mariah CHP Physical, Electrical, and Thermal Specifications

(Source: Mariah Energy Corp.)

Dimensions (Walker Court CHP system)	Width Length Height	30 in. 60 in. 84 in.
Weight	Turbine only	891 lb
Electrical Inputs	Power (start-up) Communications	Utility Grid or Black Start Battery Ethernet IP or Modem
Electrical Outputs	Power at ISO Conditions (59 ^{o}F @ sea level)	30 kW, 400-480 VAC, 50/60 Hz, 3-phase
Noise Level	Walker Court CHP system	55 dBA at 10 m; <70 dBA at 1 m in turbine room
Fuel Pressure Required	w/o Natural Gas Compressor (Walker Court CHP) w/ Natural Gas Compressor	52 to 55 psig 5 to 15 psig
Fuel Flow Rate	Higher heating value Volumetric flow rate	420,000 Btu/hr 7.06 scfm at full load
Electrical Efficiency (LHV basis)	w/o Natural Gas Compressor (ISO Conditions) w/ Natural Gas Compressor (ISO Conditions)	27 % (± 2 %) 26 % (± 2 %)
Thermal Efficiency (LHV basis)	Walker Court CHP (derated for elevation and ambient conditions)	59 %
Heat Rate	w/o Natural Gas Compressor: Electrical Thermal	12,600 Btu/kWh 235,000 Btu/h
Emissions (full load)	Nitrogen oxides (NOx) Carbon monoxide (CO) Total hydrocarbon (THC)	<9 parts per million volume (ppmv) at 15 % O_2 <40 ppmv @ 15 % O_2 <9 ppmv @ 15 % O_2

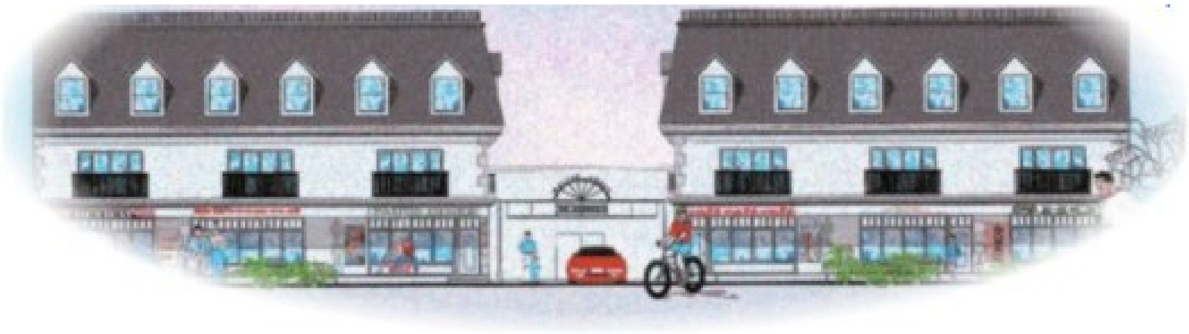
The turbine at the Walker Court facility uses natural gas supplied at about 52 to 60 psig. Capstone offers an optional booster compressor which is not required at the test site due to availability of high pressure gas. Based on manufacturer specifications, the use of a booster compressor can decrease overall electrical efficiency by about 1 percent. The Mariah CHP uses the Capstone Industrial Housing with modifications. This supports the weight of an over-head heat recovery unit. The housing was modified to alter the exhaust flow path, and for improved sound attenuation. The heat recovery system consists of a fin-and-tube heat exchanger, which circulates a 10 to 20 percent Propylene Glycol (PG) mixture through the heat exchanger at approximately 20 gallons per minute (gpm). The primary heating loop is driven by the main circulation pump, and no additional pumping is required. The recovered heat is circulated through the building's mechanical rooms, a domestic hot water system, and a secondary loop which provides comfort heat to the two L-shaped building structures. The resultant, cooler PG mixture is circulated back to the fin-and-tube heat exchanger, energy is exchanged between the PG mixture and the hot turbine exhaust gas, and the entire circulation loop is repeated. If the Walker Court heat load is significantly lower than the heat transferred with the CHP system, such that overheating of the glycol loop could occur, the system will automatically shut off.

The thermal control system is programmable for individual site requirements. Minimum settings may vary, but the maximum temperature may never exceed 203 °F. During the peak heating season, if necessary, supplementary heat may be provided by natural gas fired hot water heaters and a backup boiler (see Section 1.3 for further discussion). For periods when the heat generated cannot be consumed on site, Mariah has developed a proprietary method for eliminating and discarding excess heat. This method is currently undergoing internal testing, and will not be evaluated by the GHG Center. The exhaust gases leave the heat recovery unit at less than 212 °F, and are vented through the turbine/boiler room roof and a further acoustical damper. Future plans call for the warm air to be ducted to garages for more complete heat utilization; however, this will not be implemented during the ETV testing.

1.3. WALKER COURT TEST FACILITY DESCRIPTION

The Walker Court condominium site, shown in Figure 1-3, is located in Inglewood, an inner city community east of the downtown core of Calgary, Alberta, Canada. The site is a live/work arrangement consisting of 12 condominium units that combines a street-level retail or office space with basement, and a one or two-level residence above. Mariah operates the CHP system as a service provider under contract. Mariah retains all responsibility for operation and maintenance of the equipment. Condominium owners receive monthly statements indicating the amount of heat and light consumed as well as an estimate of emissions displaced in the previous month. Mariah has coined the term "Distributed Micro-Utility" to describe this model.

Figure 1-3. The Walker Court Condominium Project



The twelve unit condominium has two L-shaped buildings surrounding a courtyard. The back wall of the courtyard is formed by the common garages joining the two buildings. The central unit of the common garage block includes the main turbine/boiler room, electrical room, and garbage room. Each of the twelve units in the development have approximately 1800 square feet (ft^2) of living space, plus 750 ft^2 of commercial/storefront space and a full basement. Each unit also includes a roof-top patio/garden area.

The Commercial and Residential floors are heated using a hydronic radiant floor heating system embedded in a 2 inch “light-crete” concrete slab. All exterior walls except the front of each unit is constructed of “Blue-Maxx,” a system involving styrofoam blocks that create a form and are subsequently filled with 6 inches of concrete. The result is a high thermal mass wall with an R50 insulation factor. The front walls of each unit are constructed using steel studs and are insulated to an R22 rating. All walls between units are 6 inch poured concrete from foundation to parapet. This provides additional insulation between units, while contributing to the thermal storage capacity of the building structure.

Each unit has three zone controls with manual balancing between rooms within each zone. An injection pump draws heating fluid from the secondary loop to control the temperature of the water in each zone loop. The secondary loops circulate a portion of the heating medium from the primary loop through the length of each of the two L-shaped building structures.

Each of the two main buildings has a small mechanical room below the rear garage level. The primary loop circulates heating medium through both mechanical rooms, to the secondary loops via manifolds, and to the domestic hot water (DHW) systems. The DHW tanks are manifolded off the primary loop. These tanks have an internal heating coil, through which the turbine-heated medium can heat the DHW. When comfort heating is required, the dual-fired DHW tanks burn natural gas, freeing the heat from the Mariah CHP to be used for comfort heating. The “Combi-Cor™” DHW tanks have a storage capacity of 61 Imperial gallons (gal). There are three such tanks in each of the two buildings. Back-up and peaking heat, for use during prolonged extreme cold periods, is provided by a Raypack natural draft boiler rated at 1 million British Thermal Units per hour (MM Btu/h).

The Walker Court facility is located in an established inner-city community. Sensitivity to intrusion, such as odor or noise, is very high. Mariah does not expect the backup boiler system to be operated often. As a result, costly forced draft or high efficiency condensing boilers were not selected. The selected natural draft boiler required a 20 inch flue, resulting in substantial path for boiler room noise to reach the exterior of the building. To minimize the impact of this, and to increase comfort while working in the boiler room, substantial attenuation was added to the turbine housing and duct work. The air intake for both combustion and electronics cooling is drawn from an acoustically damped plenum. Further acoustic damping was added to the exterior exhaust duct which also provides a small amount of attenuation as the heat recovery unit itself acts as an acoustic damper. The sound level at the property line is required to be below 55 dBA to meet night-time municipal bylaw restrictions. The CHP is located only 6 feet from the line and easily meets this requirement.

1.4. PERFORMANCE VERIFICATION PARAMETERS

The verification test is scheduled to take place during the month of March 2001. It is expected that at least four of the 12 residential units will be occupied with three of the commercial spaces operational. The CHP system will be set to operate 24 hours per day at maximum electrical power output (30 kW). Excess electricity, not consumed by the site, will be exported back to the grid. The DHW loads are projected to be less than the maximum heat recoverable with the CHP system. However, combined thermal loads are expected to use all available heat. This is because the site will not be fully occupied during the test period, and the second phase of the building will be under construction. The majority of the heat recovered by the CHP system will offset comfort heating normally supplied by the boiler.

The verification factors selected for testing are intended to evaluate the performance of the combined heat and power system only, and not the overall building integration or specific management strategy. The factors are listed below, and detailed descriptions of testing and analysis methods are presented in Section 2.0.

Verification Factors

- Power and Heat Production Performance
- Electrical Power Quality Performance
- GHG and Conventional Air Pollutant Emission Performance

The verification test will include periods of load testing, in which the GHG Center will intentionally modulate the unit to operate at four electrical loads: 50, 75, 90, and 100 percent of the maximum 30 kW capacity. During load tests, simultaneous monitoring for power output, heat recovery rate, fuel consumption, ambient meteorological conditions, and exhaust emissions will be performed. Average electrical power output, heat recovery rate, energy conversion efficiency (electrical, thermal, and net), and exhaust stack emission rates will be reported for each load factor. The testing period for each load is expected to be 30 minutes in duration, and the entire load testing period will take about two days to complete. The turbine will be allowed to stabilize at each load for 15 to 30 minutes before starting the tests.

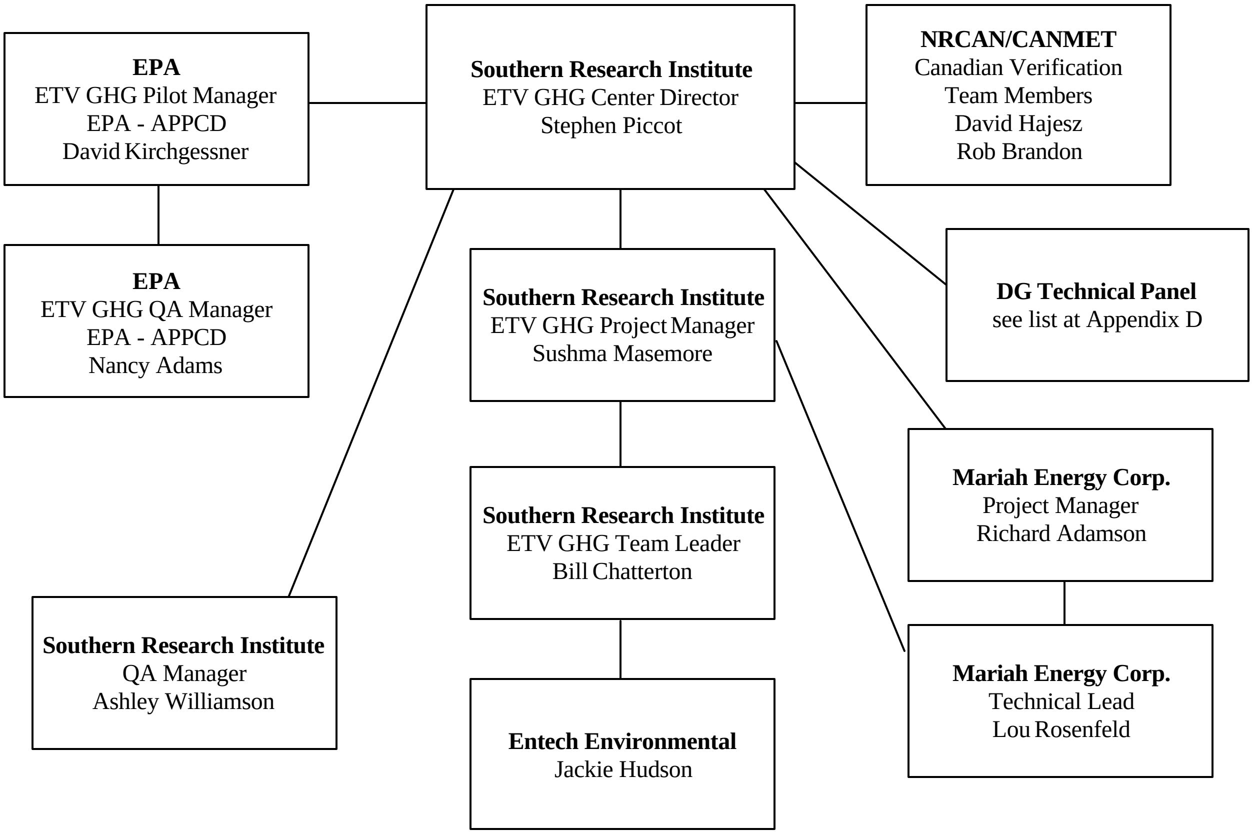
Following the load testing, daily performance of the CHP system will be characterized for a four week period. During this time, the GHG Center will continuously monitor and record electric power generated/consumed, heat recovered/used, fuel consumed, ambient meteorological conditions, and power quality. The continuous test results will report total electrical energy generated, total electrical energy used on-site, total thermal energy recovered, total thermal energy used on-site, GHG emission reductions, and power quality. Actual GHG emission reductions for Walker Court will be based on measured GHG emission rates, energy used on-site, and baseline GHG emissions for Alberta Power Pool and standard heating equipment. The measured data will also be used to report GHG emission reductions when maximum energy generated/recovered is consumed on-site (e.g., future Walker Court). GHG emission reductions will also be estimated for “model sites” similar to the Walker Court facility to account for emission reduction potentials across the U.S. and Canada. Further discussion of the verification strategy is provided in Section 2.0.

It should be noted that verification testing will occur at high altitude (3700 ft. above sea level) during late winter and early spring months. Relatively cool air temperatures, ranging between -21 to 45 ^{o}F, are expected. As a result, the test is not expected to provide information related to the system’s response to higher ambient temperatures that may be encountered in other regions. Operating microturbines at higher elevations and elevated temperatures can result in de-rating of these units, as efficiency levels decrease. In addition, as the unit attempts to operate at lower efficiencies, it is likely that environmental emissions introduced to the atmosphere may also increase. The GHG Center will make every effort to provide the reader with sufficient information to relate performance at site conditions relative to standard conditions.

1.5. ORGANIZATION

The project team organization chart is presented in Figure 1-4. A discussion of the functions, responsibilities, and lines of communication between the organizations and individuals associated with this verification test is provided below.

Figure 1-4. Project Organization



Southern Research Institute's Greenhouse Gas Technology Center has overall responsibly for planning and ensuring the successful implementation of this verification test. The GHG Center will ensure that effective coordination occurs, schedules are developed and adhered to, effective planning occurs, and high quality independent testing and reporting activities occur. The GHG Center's Ms. Sushma Masemore will have the overall responsibility as the project manager, under supervision of Mr. Stephen Piccot, the GHG Center Director. She will be responsible for quality assurance at the test site, including determination of DQOs prior to the completion of the test. Ms. Masemore will follow the procedures outlined in Sections 2.0 and 3.0 to make this determination, and will have full authority to repeat tests as determined necessary. Should a situation arise during the test that could affect the health or safety of any personnel, Ms. Masemore will have full authority to suspend testing. Ms. Masemore will be responsible for maintaining communication with Mariah, EPA, and NRCAN/CANMET

Mr. Bill Chatterton will serve as the Field Team Leader, and will support Ms. Masemore's data quality determination activities. Mr. Chatterton will provide field support activities related to all measurements data collected (e.g., fuel gas sampling, heat transfer fluid sampling, emissions testing, and efficiency determination). Mr. Chatterton has over 16 years experience in environmental testing with emphasis on emissions testing, flow measurements, field verifications, and project management. He will manage the emissions testing crew and ensure that QA/QC procedures outlined in Section 2.0 are followed. Mr. Chatterton will be responsible for ensuring that performance data, collected by continuously monitored instruments, are based on procedures described in Section 4.0 for data collection, storage, and retrieval practices. He will also coordinate with Mariah to ensure that the daily data stored by the Data Acquisition System (DAS) are submitted to the GHG Center's RTP office, as described in Section 4.0.

The GHG Center's Quality Assurance Manager, Mr. Ashley Williamson, will review and approve the Test Plan, and test results from the verification test. He will conduct an Audit of Data Quality, as required in the GHG Center's QMP. Further discussion of these audits is provided in Section 4.4. Results of the internal audits and corrective actions taken will be reported to the GHG Center Director, and used to prepare the final Verification Report.

As a member of the verification team, NRCAN will help ensure that the technical approach used to evaluate the CHP system performance and the methods used to verify carbon reductions are consistent with standard practices used by the Government of Canada. NRCAN will assist in defining three model sites in Canada for which emission reductions will be estimated, and will provide detailed review and input on the Test Plan and Verification Report.

EPA's APPCD is providing oversight and QA support for this verification. The EPA APPCD Pilot Manager, David Kirchgessner, is responsible for obtaining final approval of the project Test Plan and Test Report. The EPA QA Manager also reviews and approves the Plan and Final Report. The EPA QA Manager also reviews the Plan to ensure that it meets the ETV program's QMP requirements and represents sound scientific practices. At the discretion of the EPA QA Manager, an external audit of this verification may be conducted.

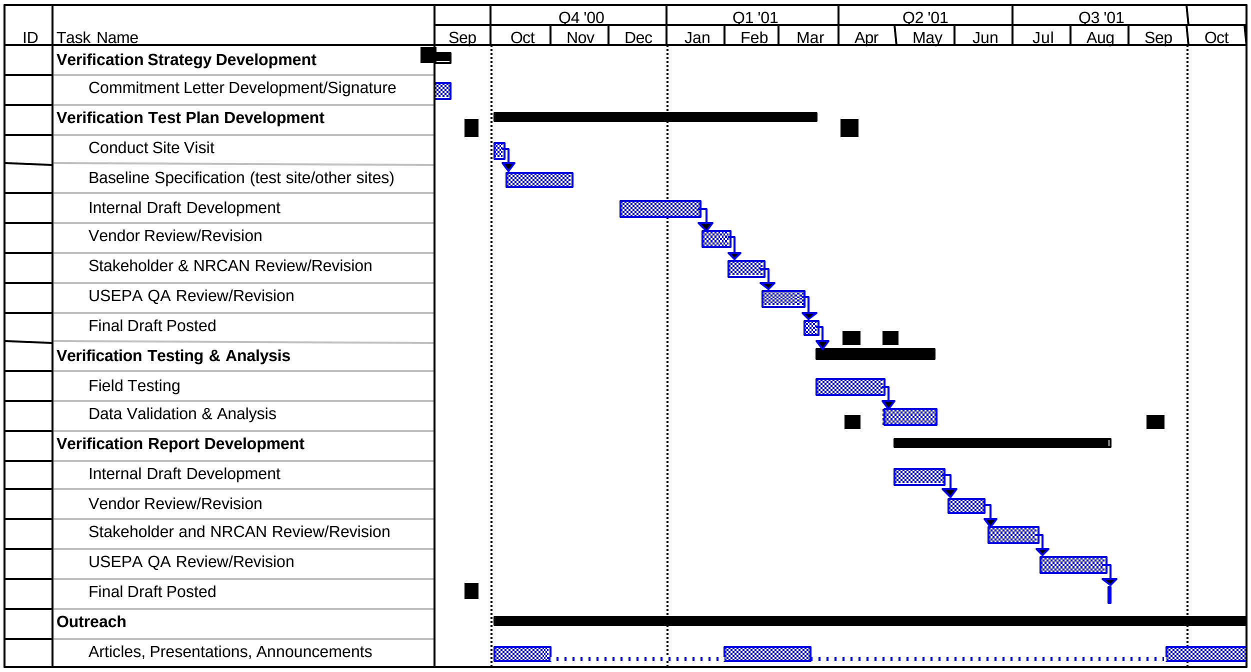
Mariah will ensure the unit and host site are available and accessible to the GHG Center for the duration of the test. Mariah will ensure the safe operation of the unit and demonstrate necessary safety features, be available to operate and adjust the unit's operation as specified in the Plan, and provide on-site support as needed to accomplish the goals of the verification testing. Mariah will review the Plan and will be present during the pre-test site visit and field test.

To support the planning, review, and the wide distribution of the verification results, a special Distributed Generation (DG) Technical Panel has been formed (see Appendix D for a complete list). The Panel members will advise on the selection of verification factors and provide guidance to ensure that the performance evaluation is based on recognized and reliable field measurement and data analysis procedures acceptable to stakeholders associated with this technology. The Panel members include members of trade organizations, potential purchasers, research groups, and regulatory organizations that have a national and international distributed generation focus. Individuals selected to serve on this Panel will be called upon to provide credible guidance and broad recognition of the verification, and will support the wide distribution of the final verification results.

1.6. SCHEDULE OF ACTIVITIES

Figure 1-5 presents the schedule of activities for verification testing of the Mariah CHP. A site survey visit has already been completed. Field testing is scheduled to begin on March 26, 2001. Although not expected, delays may occur for various reasons, including mechanical failures at the site, weather, permitting, and operational issues. Should significant delays occur, the schedule will be updated and all participants will be notified.

Figure 1-5. Verification Schedule



2.0 VERIFICATION APPROACH

2.1. OVERVIEW OF THE VERIFICATION STRATEGY

Microturbine CHP systems are a relatively new technology, and the availability of performance data is limited and in great demand. The GHG Center's Stakeholder groups and other organizations with interests in distributed generation 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 pollutants and greenhouse gases (GHG), GHG emission reductions, operational availability, maintenance requirements, and economic performance. The test approach described here focuses on assessing those performance parameters of significant interest to potential future customers of CHP systems. Long-term evaluations cannot be performed with available resources so economic performance and maintenance requirements will not be evaluated.

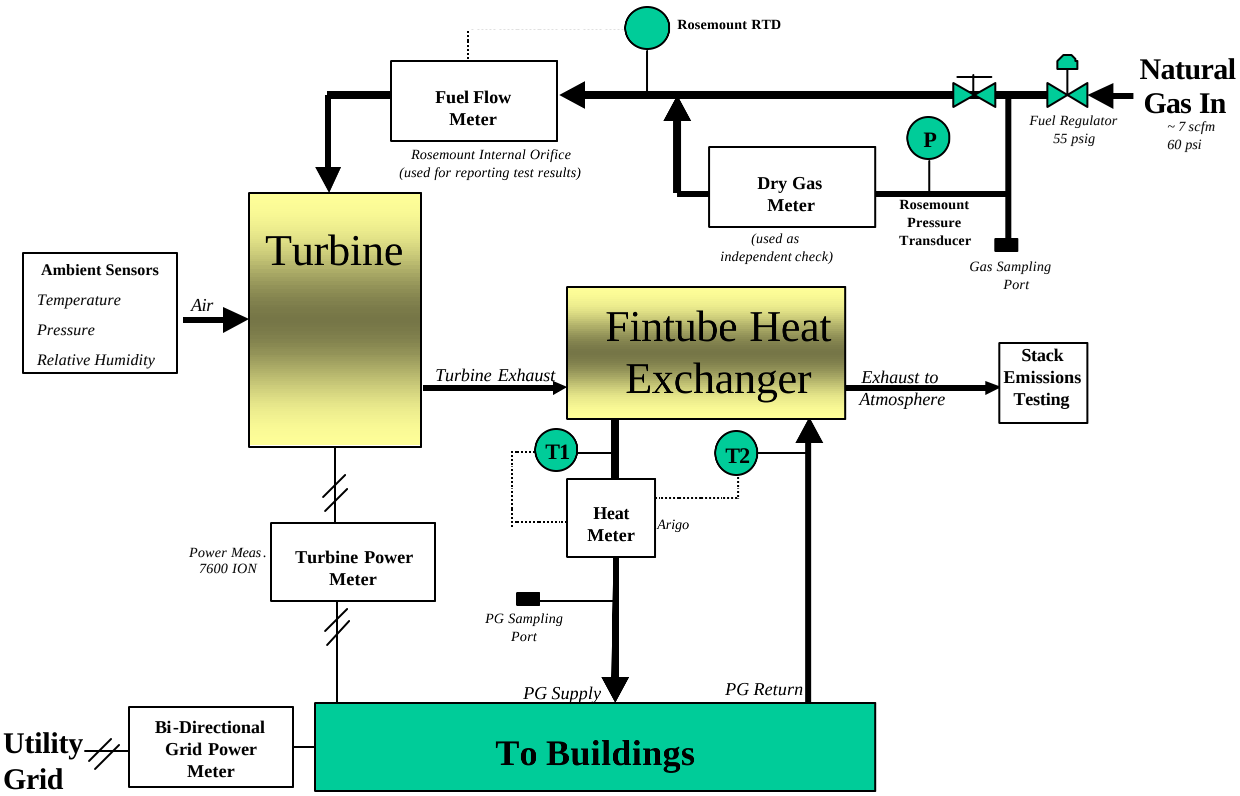
In developing the verification strategy, the GHG Center has applied existing standards for large gas-fired turbines, engineering judgement, and technical input from the verification team. Electrical power output and efficiency determination guidelines in the American Society of Mechanical Engineers (ASME) - *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. The strategy for determining thermal energy recovery was adopted from guidelines described in American National Standards Institute / American Society of Heating, Refrigeration and Air-Conditioning Engineers *Method of Testing Thermal Energy Meters for Liquid Streams in HVAC Systems* (ANSI/ASHRAE 125-1992). Exhaust stack emissions testing procedures, described in U.S. EPA's New Source Performance Standards (NSPS) for emissions from stationary gas turbines (40CFR60, Subpart GG), have been adopted for greenhouse gas and criteria pollutant emissions testing. Power quality standards used in this verification are based on the Institute of Electrical and Electronics Engineers' *Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* (IEEE 519).

Tests at four operating loads (50, 75, 90, and 100 percent) and continuous testing at full load for four weeks will be performed to address the following verification factors.

- Power and Heat Production Performance
- Electrical Power Quality Performance
- GHG and Conventional Air Pollutant Emission Performance

Figure 2-1 illustrates the measurement system to be employed. Following is a brief discussion of each verification factor and their method of determination. Detailed descriptions of testing and analyses methods and QA/QC procedures are provided sequentially in Sections 2.2 through 2.4.

Figure 2-1. Schematic of Measurement System



Power and Heat Production Performance

Power production performance represents a class of microturbine CHP operating characteristics that are of great interest to purchasers, operators, and users of these systems. Key parameters that will be characterized include:

- Electrical power output at selected loads (kW)
- Electrical efficiency at selected loads (%)
- Heat recovery rate at selected loads (Btu/hr)
- Thermal energy efficiency at selected loads (%)
- Combined heat and power production efficiency (%)
- Total electricity generated and used (kWh)
- Total thermal energy recovered and used (Btu)

The GHG Center will install a watt meter to measure the electrical power generated by the turbine. Excess power not consumed by the site and exported to the grid or additional power supplied by the grid during peak demand will be monitored with an existing electric meter. This meter is a bi-direction time-of-use revenue meter that is installed by the local power utility which allows the CHP system to be operated in parallel with the grid. Fuel input will be determined using a mass flow meter which monitors the natural gas flow rate. Fuel gas sampling and energy content analysis (via gas chromatograph) will be conducted to determine the lower heating value of the fuel.

Thermal heat recovery rate is defined as the amount of heat recovered from the turbine exhaust, and thermal heat use rate is defined as the amount of this heat that is actually consumed by the building. Thermal heat recovery and use rates will be verified by metering the flow, differential temperatures, and physical properties of the heat transfer fluid. PG mixture flow rate and temperatures will be measured with an existing heat meter (Figure 2-1). Manual samples of the PG mixture will be collected and analyzed to determine PG concentration. These results will be used to assign fluid density and specific heats, such that heat recovery and use rate can be calculated at actual conditions. The heat recovery rate measured at full load will represent maximum heat recovery potential of the CHP system. This rate will be used to compute GHG emission reductions for sites which are able to fully utilize all energy recoverable with the CHP system (discussed later in Section 2.4.2).

Fuel energy-to-electricity conversion efficiency will be determined by dividing the average electrical power output by the heat input. Similarly, thermal energy conversion efficiency will be determined by dividing the average heat recovered by the heat input. Combined heat and power production efficiency or net system efficiency will be reported as the sum of electrical and thermal efficiencies at each operating load. Ambient temperature, relative humidity, and pressure will be measured throughout the verification period to support determination of electrical conversion efficiency as required in PTC22.

To compute total electricity generated, the continuously logged power output data will be integrated over the duration of the four week verification period. Total electricity supplied to the grid will be computed in the same manner using the bi-directional meter. The difference between the electricity generated and transferred to the grid will represent the electricity used by the building.

To compute total thermal energy recovered by the CHP system, the continuously logged heat recovery rates will be summed over the four week verification period. During this period, the site is expected to use all the heat that can be recovered with the CHP system, provided unreasonably high ambient temperatures are not experienced in the field. The system will recover sufficient thermal energy to meet the site’s load demands, and if the demand reduces significantly such that the system is unable to maintain an optimum temperature difference in the glycol stream, the system will automatically shut down. Actual thermal energy used at Walker Court will be equivalent to thermal energy recovered.

Detailed discussion of sampling procedures, analytical procedures, and QA/QC procedures related to heat and power production performance parameters is provided in Section 2.2.

Power Quality Performance

The monitoring and determination of power quality performance is required to insure compatibility with the electrical grid, and to demonstrate that the electricity will not interfere with or harm microelectronics and other sensitive electronic equipment within the facility. Power quality data is used to report exceptions, which describe the number and magnitude of incidents that fail to meet or exceed a power quality standard chosen. The Institute of Electrical and Electronics Engineers’ Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems (IEEE 519) contains standards for power quality measurements that will be followed here. Power quality parameters will be determined over the four week continuous test period using the electric power meter installed by the GHG Center. The approach for verifying these parameters is described in Section 2.3. Power quality variables to be examined include the parameters listed below.

- Electrical frequency (Hz)
- Voltage transients (Volt)
- Voltage and current total harmonic distortion (%)
- Power factor (%)

Emissions Performance

The measurement of the emissions performance of the microturbine system is critical to the determination of the environmental impact of the technology. Emission rate measurements for nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), carbon dioxide (CO_2), and methane (CH_4) will be collected in the CHP system exhaust stack over a two day-long load testing. Exhaust stack emission testing procedures, described in U.S. EPA's NSPS for stationary gas turbines, will be adapted to verify the following verification parameters at the selected loads.

- NO_x Concentration (ppmv) and Emission Rates (lb/hr, lb/Btu, lb/kWh)
- CO Concentration (ppmv) and Emission Rates (lb/hr, lb/Btu, lb/kWh)
- VOC Concentration (ppmv) and Emission Rates (lb/hr, lb/Btu, lb/kWh)
- CO_2 and CH_4 Emission Rates (lb/hr, lb/Btu, lb/kWh)
- Estimated GHG emission reductions for Walker Court - Actual Conditions and Maximum energy utilization (tonnes CO_2)
- Estimated GHG emission reductions for model sites (tonnes CO_2)

For the conventional pollutants listed above, emission rates (e.g., mass/hour, mass/heat input, and mass/power output) will be measured and reported. CO_2 and CH_4 emission rates will also be measured. CO_2 emissions from the system will be calculated for the verification period using measured GHG emission rates, operating hours, and thermal/electrical generation and use data.

The verification will report two sets of GHG emission estimates: actual emissions and reductions for Walker Court; and estimated emissions and reductions for future Walker Court operation and for sites that can use all the energy produced with the CHP system. Mariah CHP emissions will be compared to emissions from a baseline system. The baseline system is that which would have been installed to meet the site's energy needs in the absence of the CHP system. The baseline system defined for Walker Court consists of electricity supplied by the local utility grid and thermal energy supplied by a new standard natural gas-fired boiler. Subtraction of the annual Mariah CHP emissions from the baseline emissions yield an estimate of the emission reduction for the facility.

Emissions for the utility grid will be computed using methodology adopted by the KEFI-Exchange, and will also account for transmission and distribution line losses. Detailed procedures for estimating emission reduction from electricity production is provided in Section 2.4.2.2. GHG emissions for a standard gas-fired boiler will be determined by estimating fuel needed to generate equivalent amounts of heat with a baseline boiler. The gas-fired boiler is assumed to be new, and provide heat at an 83 percent efficiency. Detailed procedures for estimating annual emission reduction from thermal energy production is provided in Section 2.4.2.3.

Different locations across the U.S. and Canada will experience emission reductions that could vary significantly depending on the region's specific electrical and heat systems, mix of local power supplies (i.e., coal vs. hydropower), and other factors. To estimate the effect of these regional differences, emissions will be estimated for model regions across North America which use different electricity and heat production strategies and technologies. The procedures used to select regions and estimate emission reductions relies on baseline systems and historical data described in U.S.EPA, U.S.DOE, and CANMET publications and other input. This is discussed in Section 2.4.3. Extrapolation procedures and assumptions used will be fully documented in the final report, allowing readers to make alternate assumptions and assessments for their regions as desired.

2.2. POWER AND HEAT PRODUCTION PERFORMANCE

The CHP system will be evaluated for the performance factors above at four operating loads: 50, 75, 90, and 100 percent of the turbine's rated capacity (30 kW). The loads selected bound the range expected by Mariah to occur at Walker Court. A step-by-step procedure for conducting the tests is provided in Appendix A-1, and a log form associated with this activity is provided in Appendix A-2. The test period at each load is expected to be 30 minutes in duration, and will be repeated 3 times. The triplicate measurement design is based on U.S. EPA NSPS guidelines for measuring emissions from stationary gas turbines.

Simultaneous measurement of electric power output, heat recovery rate, heat use rate, fuel consumption, ambient meteorological conditions, and exhaust emissions will be performed during testing at each load. The time-synchronized measurements data will be used to compute electrical efficiency as specified in PTC 22. The PTC 22 mandates using electric power data collected over time intervals of not less than 4 minutes and not greater than 30 minutes (PTC 22, Section 3.4.3 and 4.12.3) to compute electrical efficiency. This restriction minimizes the uncertainty in electrical efficiency determination due to varying changes in operating conditions (e.g., engine speed, ambient conditions). Within this time period, the PTC 22 specifies the maximum permissible limits in power output, power factor, fuel input, and atmospheric conditions to be less than the values shown in Table 2-1. The GHG Center will use only those time periods that meet these requirements to compute performance parameters. Should the variation in power output, power factor, fuel flow, or ambient conditions exceed the levels, the load test will be considered invalid and the test will be repeated.

Table 2-1. Permissible Variations in Power, Fuel, and Atmospheric Conditions

Measured Parameter	Maximum Permissible Variation
Power output	± 2 %
Power factor	± 2 %
Fuel flow	± 1 %
Barometric pressure	± 0.5 %
Ambient air temperature	± 4 ^{o}F

Sections 2.2.1.1 through 2.2.1.5 provide descriptions of measurement instruments that will be used to verify electrical power output and efficiency. Also included in these sections are instrument sampling, calibration, and QA/QC procedures that will be followed by GHG Center field test personnel.

The power production performance evaluation will verify:

- Electrical power output at selected loads (kW)
- Electrical efficiency at selected loads (%)
- Total electricity generated and used (kWh)

Heat recovery and use rate will be measured with an existing heat meter that was installed by Mariah. Manual sampling of PG mixture will be collected at a specially installed sampling port. The samples will be analyzed by a certified laboratory to report PG concentration in the mixture. Using the measured concentrations, the density and specific heat of the PG mixture will be selected from published ASHRAE tables.

The heat production performance evaluation will verify:

- Heat recovery rate at selected loads (Btu/hr)
- Thermal energy efficiency at selected loads (%)
- Combined heat and power production efficiency (%)
- Total thermal energy recovered and used (Btu)

2.2.1. Electrical Power Output and Efficiency Determinations

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

$$\eta_E = \frac{3412.14\ kW}{HI} \qquad (1)$$

where :

η_E = electrical efficiency (%)

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

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

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

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

where :

kW = average electrical power output (kW)

kWi = instantaneous reading of the kW sensor at each minute (kW)

nr = number of one minute readings logged by the kW sensor

Using the fuel flow rate data and the LHV results, average heat input will be computed as shown in Equation 3.

$$HI = 60\ F_m\ LHV \tag{3}$$

where :

HI = average heat input using LHV (Btu/hr)

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

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

Corrections for Standard Conditions:

The above calculations reflect power output and efficiency results at actual site conditions (i.e., temperature, pressure, and relative humidity observed during testing and site elevation of 3000 ft above sea level). To assess the performance of this technology in different geographic regions, it is useful to correct the actual test data to rated or standard conditions. A standard temperature of 60 ^{o}F, barometric pressure of 14.7 psia, and a relative humidity of 60 percent, as defined by the International Standards Organization (ISO 2314: 1989), is often used to correct for standard conditions. For turbines, standard conditions also represent sea level elevation.

Because it is unlikely ISO conditions will be encountered during the verification, directly verified performance results will not be obtainable at standard conditions. For readers interested in such data, Mariah will use derate performance curves to report the verified data to standard conditions. This data will be presented in a separate section of the final report, and because the charts were not developed by the GHG Center readers of this section will be informed that the results have not been verified by the GHG Center.

2.2.1.1. The 7600 ION Electrical Meter

The electric power output will be measured by a digital power meter, manufactured by Power Measurements Ltd. (Model 7600 ION). The 7600 ION will continuously monitor the kilowatts of real power at a rate of one reading per second, averaged at one-minute intervals. It will be installed after the 280 volt transformer (Figure 2-1), such that the electricity measured is the electricity that is ultimately used by the site or supplied to the utility grid. The power output measured with the 7600 ION will be slightly less than actual power generated by the turbine, and will account for losses in the transformer. The real-time data collected by the 7600 ION will be 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 will continuously operate unattended, and will not require further adjustments. QA/QC procedures associated with instrument setup, calibration, and sensor function checks are discussed below.

The meter will be factory calibrated to IEC687 SO.2 and ANSI C12.20 CAO.2 standards for accuracy. A certificate of compliance will be issued which certifies the instrument met or exceeded published specifications. Consistent with ISO 9002-1994 requirements, the manufacturer will supply documents illustrating calibration and traceability to national standards. The GHG Center will review the certificate and traceability records to ensure that the ± 0.2 percent accuracy goal was achieved. The 7600 ION is manufactured for electric utility applications, and its calibration records are reported to be valid for a minimum of 1 year of use, provided the manufacturer-specified installation and setup procedures are followed. QC checks related to this activity are listed in Appendix B-1, and will be performed by Center personnel. Factory calibration will be repeated at the end of the test to insure that instrument accuracy has remained within the specified limits.

Reasonableness checks will be performed by comparing the 7600 ION power output readings with the power generation output recorded by Capstone software. At full load, the power meter must read between 27 and 30 kW at Standard Conditions and after derated for elevation differences.

Due to the nature of the closed electrical system, independent field verification with a second meter cannot be conducted to verify the accuracy of the 7600 power readings in the field. However, QC checks will be performed in the field for two key measurements (voltage and current output) which are directly related to the power output measurement. The sensor diagnostics will be performed at the beginning, middle, and end of the verification period using a digital multimeter (DMM). The DMM will be used to check that the phase and polarity of the AC voltage inputs are correct and measure each of the three-phase voltage and currents and compare them to the readings obtained with the 7600 ION. The procedures for conducting these checks are provided in Appendix B-2. A minimum of five individual voltage and current readings will be obtained at the lowest recommended operational load (50 percent) and full load (100 percent). The specified voltage and current accuracy for the 7600 ION is ± 0.1 percent, while the DMM is ±1 percent. The percent difference between the DMM reading and the 7600 ION reading will be computed to determine it is within ± 1.1 percent. In these cases, the 7600 ION will be confirmed to be functioning properly.

2.2.1.2. The Rosemount 3095 Mass Flow Meter

The mass flow rate of the fuel supplied to the Turbine will be determined using an integral orifice meter (Rosemount Model 3095). The meter will contain a 0.150 inch orifice plate which will enable flow measurements to be conducted at the ranges expected during testing (3 to 8 scfm natural gas). The meter will be temperature- and pressure-compensated, providing mass flow output at standard conditions (60 ^{o}F, 14.7 psia). The meter will continuously monitor flows at a rate of one instantaneous reading per minute, and will be capable of providing an accuracy of ± 1 percent of reading. The meter will be fitted with a transmitter providing a 4 to 20 mA output over the meter's range. This output will be wired to an A/D module attached to a dedicated personal computer.

Prior to testing, the Rosemount meter will be factory calibrated, and a calibration certificate traceable to the National Institute for Standards and Technology (NIST) will be obtained and reviewed to ensure the ± 1 percent accuracy was satisfied. The factory certified calibration data are reported to be valid for three years, provided manufacturer-specified installation and set-up procedures are followed. The transmitter electronics are programmed in the field to enable the meter to calculate mass flow from differential pressure across an orifice. Rosemount's Engineering Assistant (EA) Software, which is interfaced to the transmitter via a HART protocol serial modem, is used to input information about gas properties and operating conditions. Specific setup parameters required in the EA and installation/setup checks and log forms for this meter are provided in Appendix B-3. The GHG Center testing personnel will maintain field logs of all data entered into the EA, and subsequently transmitted to the instrument. An electronic copy of the configuration file will be maintained.

To validate the performance of the meter in the field, two forms of QC checks will be performed: sensor diagnostic checks; and independent verification with a second meter. Sensor diagnostic checks consist of zero flow verification by isolating the meter from the flow, equalizing the pressure across the differential pressure (DP) sensors using a crossover valve on the orifice assembly, and reading the pressure differential and flow rate. The sensor output must read zero flow during these checks. Transmitter analog output checks will also be conducted at the beginning, middle, and end of the test. In this loop test, a current of known amount will be checked against a DMM to ensure that 4 mA and 20 mA signals are produced. The procedures for conducting sensor diagnostic checks and log forms are provided in Appendix B-4.

During testing, independent performance checks will be made using a secondary dry gas meter installed in series with the Rosemount test meter. During this check, natural gas will flow through both meters while the turbine is operating, and the resulting gas flow rates will be recorded by the DAS. The dry gas meter is manufactured by American Meter Company (Model AL800 - diaphragm type meter). The AL800 has a maximum allowable working pressure of 100 psig, and can meter natural gas flow rates up to 1700 scfh. The meter visually displays gas flow in units of actual cubic feet (acf). The meter will be factory calibrated using a NIST traceable volume prover (primary standard).

In order to compare Rosemount 3095 readings with the dry gas meter readings, the acf values must be converted to standard conditions. This will be accomplished by correcting the acf values for actual temperature and pressure. Measurements of gas temperature will be obtained from the Rosemount 3095 RTD (Figure 2-1). Gas pressures will be measured with a Rosemount pressure transducer installed upstream of the dry gas meter (Figure 2-1).

Both meters are certified with an accuracy of ± 1.0 percent (reading). Meter performance will be assessed during testing by comparing a minimum of two one-hour flow readings collected by both meters during the 50 and 100 percent load tests. For each hourly period, accuracy will be computed as the difference between the dry gas meter reading and the test meter reading divided by the dry gas meter reading. Average accuracy will be computed as the half-width of the 95 percent confidence interval of the mean, divided by the mean. If the computed average accuracy is determined to be greater than ± 2.0 percent, all testing will be stopped and the performance of each meter will be evaluated following procedures outlined in Appendices B-3 through B-5.

2.2.1.3. Fuel Heating Value Measurements

Fuel heating value measurements will be conducted to determine the actual lower heating value of natural gas, such that electrical and thermal efficiency calculations can be performed. Fuel gas samples will be collected no less than once per test load condition. Samples will be collected at an access port in the fuel line located prior to the flow meter (Figure 2-1). The port is downstream of a ball valve and consists of ¼-inch NPT union. At this point, fuel pressure is regulated by the facility at approximately 55 psig. Gas samples will be manually collected in stainless steel canisters provided by an analytical laboratory (Core Laboratories, Inc. of Calgary, Alberta). The canisters are 600 ml vessels with valves on the inlet and outlet sides. Prior to sample collection, canister pressure will be checked using a vacuum gauge to document that the canisters are leak free. Canisters that are not fully evacuated upon receipt from the laboratory will not be used for testing. During testing, the connections between the canisters and the fuel sampling port will be screened with a hand-held hydrocarbon analyzer to check for leaks in the system. In addition, the canisters will be purged with fuel for approximately 5 seconds to ensure that a pure fuel sample is collected. Appendix A-3 contains detailed procedures that will be followed, and Appendix A-4 and A-5 contains sampling log and chain of custody forms.

A minimum of one gas sample will be collected during each of the 50, 75, 90, and 100 percent load tests. Following EPA standard procedures, replicate samples will be collected during every third sampling procedure to quantify potential errors introduced by manual gas sampling. These samples will be collected simultaneously to eliminate variability in results due to small changes in natural gas quality over time. The canisters are designed such that they can be configured in series, allowing the replicates to be collected simultaneously.

The collected samples will be returned to the laboratory for compositional analysis in accordance with ASTM Specification D1945 for quantification of methane (C1) to hexanes plus (C6+), nitrogen, oxygen, and carbon dioxide. Sample gas is injected into a Hewlett Packard 589011 gas chromatograph (GC) equipped with a silicon and molecular sieve column. Components are physically separated on the columns and the resultant areas compared to the corresponding calibration data. Data acquisition is handled by an HP 339611 integrator. The useful range of the detectable concentrations (mole percent) is specified in Table 1 of the method (D1945). The GC is calibrated weekly as a continuing calibration verification check using a certified natural gas standard. Instrument accuracy is 0.02 percent full scale, but allowable method errors vary among gas constituents according to the following list.

Gas Constituent	Repeatability (% Diff.)
nitrogen	2.0
methane	0.2
CO_2	3.0
ethane	1.0
propane	1.0
isobutane, n-butane	2.0
isopentane, n-pentane	3.0

The instrument is re-calibrated whenever its performance is outside of any of the acceptance limits listed. Calibration records will be obtained and reviewed by the GHG Center. Records of the natural gas calibration standard will also be obtained. Sample collection canisters are leak checked at the laboratory prior to shipment to the test site.

Compositional 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. The accuracy of the LHV determinations using the method is related to the repeatability and reproducibility of the analysis. Specification D3588 provides procedures for calculating repeatability for duplicate analyses that will be used by Core Labs. The repeatability expected for duplicate samples is approximately 1.2 Btu/1000 ft^3, or about 0.1 percent.

As a quality assurance check on the fuel gas sampling and analyses, a blind audit sample will be submitted to the laboratory along with one lot of samples. The gas will be procured from a calibration gas manufacturer and will contain a certified concentration of methane in nitrogen (approximately 95 percent CH_4 in N_2). The laboratory will be requested to conduct duplicate analyses on the audit gas, and the reported values will be compared to the gas manufacturers certified methane concentration to determine if the average difference is within 0.2 percent of the allowable level.

2.2.1.4. Ambient Conditions Measurements

Meteorological data will be collected to determine if the maximum permissible limits for determination of electrical efficiency are satisfied (Table 2-1). The ambient meteorological conditions (temperature, relative humidity and barometric pressure) will be monitored using a pressure sensor and an integrated temperature / humidity unit located in close proximity to the air intake of the turbine. The integrated temperature / humidity unit uses a platinum 100 Ohm, 1/3 DIN RTD (resistance temperature detector) 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 which 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 relative humidity varies, and this change in capacitance is detected and converted by internal electronic circuitry which provides a linear DC (4-20mA) output signal. This sensor features electronic compensation to maintain accuracy over a broad range of temperature conditions. The barometric pressure is measured by a variable capacitance sensor. As pressure increases, the capacitance decreases. This change in capacitance is detected and converted by internal electronic circuitry which provides a linear DC (4-20mA) output signal. The range and accuracy of each sensor are given in Table 3-2. The response time of the temperature and humidity sensors is 0.25 seconds and the response time of the pressure sensor is under 2 seconds. The output of these units will be wired to an A/D module attached to a dedicated personal computer.

Electrical efficiency determinations require variability in ambient temperature and barometric pressure to be less than ± 4 °F and ± 0.5 percent, respectively. The instruments selected for the verification are capable of providing ± 2 °F for temperature and ± 0.06 percent and barometric pressure, which exceed the PTC22 requirements for meteorological data. The measurement equipment will be factory calibrated to NIST traceable standards for accuracy. Calibration certificates indicating conformance to these standards will be obtained from the laboratory, and reviewed to ensure the stated data quality indicator goal will be achieved. QA/QC procedures for the installation and operation of this equipment in the field are provided in Appendix B-6. In addition, reasonableness checks will be performed by comparing the test instrument readings with the values reported by the nearest national weather station.

2.2.1.5. Rosemount Fuel Gas Pressure Sensor

Fuel gas pressure will be monitored with a pressure transducer at a rate of one reading per minute. The readings collected by this instrument are used to correct dry gas readings from actual conditions to standard conditions (60 °F, 14.7 psi). This data is also a key indicator of fuel pressure required to operate the CHP system (i.e., the turbine is specified to operate at 52 to 55 psig gas pressure). A Rosemount model 3051 smart pressure transmitter will be used, which has a high degree of stability over time (0.25 percent in five years).

Prior to installation in the field, the meter will be laboratory calibrated by the manufacturer, and the calibration results will be reviewed to ensure the manufacturer specified accuracy goal is met. Similar to other continuous monitoring equipment, the pressure transmitter is designed to operate continuously and unattended. Manufacturer specified startup checks and reasonableness checks will be performed in the field (e.g., fuel pressure should be about 55 psig during turbine operating periods). Routine quality control consists of daily checks for reasonableness, trends, spikes, or other changes in operation that could indicate a system or sensor problem.

2.2.2. Total Electricity Generated and Used

After the load testing, the turbine is expected to be operated at full load for the remainder of the test period. The electrical power output data for the turbine will be continuously monitored and one minute average readings will be recorded throughout this period. In addition to the one minute power output measurements, the 7600 ION also has the capacity to compute and store 15 minute average electrical energy generation data. The 15 minute interval is the most common time period used in reporting electricity transfer records, and will be summed to develop hourly electricity generation rates for the turbine, as shown in Equation 5.

Actual electricity used at Walker Court will be determined as the difference between electricity generated and excess electricity supplied to the utility grid, as shown in Equation 4. The electricity supplied to the grid will be assigned using ENMAX bi-directional time-of-use meter. This meter logs 15 minute electricity transfer records to the Alberta Power Pool. A positive value indicates the electricity transferred from the grid to Walker Court, and a negative value indicates excess electricity supplied to the grid. An hourly estimate of electricity supplied to grid will be computed as shown in Equation 6.

$$Total\ Electricity\ Used\ (kWh) = Total\ Electricty\ Generated - Total\ Electricity\ Supplied\ to\ Grid \qquad (4)$$

$$Total\ Electricity\ Generated\ (kWh) = \sum_{i=1}^{i=hr} kWh_i \qquad (5)$$

$$Total\ Electricity\ Supplied\ to\ Grid\ (kWh) = \sum_{i=1}^{i=hr} kWh_{grid-i} \qquad (6)$$

where:

kWh_i = average electricity generated at 15 minute intervals (kWh)

kWh_{grid-i} = average electricity transferred between grid and Walker Court at 15 minute intervals (kWh)

hr = number of 15 minute records for the verification period

It is recognized that variations in ambient meteorological conditions, specifically temperature, pressure, and relative humidity, can significantly affect a gas turbine's ability to produce power and transfer heat. The electrical and thermal energy output discussed above represent site conditions. A review of average meteorological data near the test facility suggests that an average temperature of about 25 ^{o}F (range of 18 to 40 ^{o}F) is expected during the test period. Relative humidity ranges from 20 to 100 percent, with an average value of about 60 percent. The barometric pressure remains relatively constant at about 13 psia. The time series meteorological data will be examined with corresponding power output and heat rate data to identify potential trends in the data. Specifically, the data will be reviewed to determine the level of increase or decrease in electrical power output and heat recovery rate at different temperature, pressure, and relative humidity ranges.

Significant variations in fuel pressure or gas quality are not expected during the test because the fuel source is based on a relatively consistent natural gas supply. However, continuous monitoring for fuel pressure, fuel temperature, and fuel flow rate will be maintained to ensure that fuel inlet conditions are consistent with manufacturer specified ranges. In addition, gas samples and liquid samples will be collected a minimum of once per week to ensure correct values for LHV, PG-solution specific heat, and density are incorporated into the calculations.

2.2.3. Heat Recovery and Use Rate and Thermal Efficiency Measurements

The heat meter monitors and records the volume of PG mixture circulated through the heat exchanger and its temperatures at two locations. As shown earlier in Figure 2-1, the temperature readings at T1 and T2 can be used to compute heat recovered by the CHP system. The heat recovery rate will be computed according to ANSI/ASHRAE Standard 125, as follows:

$$\textit{\textbf{Heat Recovery Rate (Btu/min)}} = V\ r\ Cp\ (T1-T2) \qquad (7)$$

where:
V = total volume of liquid passing through the sensor during a minute (ft^3)
ρ = density of PG solution (lb/ft3), evaluated at the avg. temp. (T2+T1)/2
Cp = specific heat of liquid (Btu/lb F), evaluated at the avg. temp. (T2+T1)/2
T1 = temperature of heated liquid exiting heat exchanger, Figure 2-1 (^{o}F)
T2 = temperature of cooled liquid entering heat exchanger, Figure 2-1 (^{o}F)

The heat recovery performance of the CHP system will be a strong function of the building return water temperature and a weak function of the building water flow rate. Although not expected in March, low heat demand will result in a decrease in data across the heat exchanger significantly dropping the CHP system heat recovery rate. If the ambient temperatures are determined to be unseasonably high, a heat load will be imposed by manually dumping hot water, thus imposing a load on the DHW system. Mariah will also intentionally increase the thermostatic temperature settings in the building to maximize comfort heating demands. The maximum average heat recovery rate measured during full load testing will be used to represent maximum heat recovery potential of the CHP system. The measured data will also be used to report the performance of the heat recovery unit at different return water temperatures.

Maximum Heat Use Rate (Btu/min) = Maximum Heat Recovery Rate at 100 % Load Test (8)

The heat rate equations require physical properties of the heat transfer fluid at actual operating temperatures to be defined. To specify these properties, it is necessary to accurately characterize the composition of the PG solution, and select published density and specific heat data from reliable sources (ASHRAE publications). The fluid used in the heat recovery unit is a mixture of approximately 23 percent propylene glycol in water. Samples of this fluid will be collected and analyzed for propylene glycol content. Appendix A-9 and A-10 contains PG mixture density and specific heat data as a function of temperature, respectively. The GHG Center will use these ASHRAE published data to interpolate PG properties at the conditions encountered during testing, and to compute heat recovery and use rates.

For reporting average heat recovered and thermal efficiency at the selected loads, the metered data corresponding to time intervals used in computing electrical efficiency will be used to compute average heat recovered (Q_{avg}). The following equation will be used to compute thermal efficiency:

$$\boldsymbol{\eta_T = 60 * Q_{avg} / HI} \qquad (9)$$

where:
η_T = thermal efficiency (%)
Q_{avg} = average heat recovered (Btu/min)
HI = average heat input using LHV, Equation 3 (Btu/hr)

2.2.3.1. Arigo Heat Meter

The heat meter, currently in operation at Walker Court, is manufactured by Arigo Software GmbH (Model – Dialog WZ LON Multistream Electronic Heat Meter). The meter has the capability to measure PG solution temperature in the supply and return lines, with the use of two RTDs. The meter also measures volumetric flow rate with the use of a multi-impeller wheel contact water counter. It also has the capability to compute and record cumulative amount of heat transferred. All data are continuously monitored and recorded with a software supplied by the manufacturer. The meter is certified to meet Europe's custody transfer standards (CEN 1434-1).

The meter was factory calibrated prior to installation at Walker Court. The manufacturer guarantees the calibration validity period to be 5 years. The GHG Center does not plan to re-calibrate the meter prior to verification testing. However, calibration records will be obtained and reviewed to ensure that the manufacturer specified accuracy, precision, and other performance ratings are valid. The GHG Center plans to independently verify the performance of the RTD sensor output using a calibrated Type K thermocouple and readout device. The reference thermocouples will have an operating range of –300 to 800 ^{o}F and will be calibrated by the Center and documented to have an accuracy of 0.5 percent of reading or better. The independent verification of the temperature readings will be performed at the beginning and end of the test period. In this procedure, the RTDs will be removed from the fluid pipe and placed in an ice water bath along with thermocouples of known accuracy. Temperature readings from both sensors will be recorded for comparison. The procedure will then be repeated in a hot water bath. If the average differences in temperature readings are greater than 1.8 ^{o}F, the Arigo RTDs will be sent for re-calibration. Sampling procedures and QA/QC checks associated with this activity are provided in Appendix B-7.

The ANSI/ASHRAE Method 125 specifies requirements for the heat meter, which will be used as additional operational specifications or QC checks in the field.

- Instrument accuracy for temperature should be ± 0.9 ^{o}F, and precision should be ± 0.36 ^{o}F
- Volumetric flow rate should be within ± 1 percent over the test interval
- Density and specific heat should be taken from reliable material properties sources

2.2.3.2. PG Solution Sampling and Analysis

Samples will be collected from a fluid discharge spout located on the hot side of the heat recovery unit using pre-cleaned glass vials of 100 to 500 ml in capacity. Samples will be collected during each of the 50, 75, 90, and 100 percent load tests, and at least once per week during the extended verification period. Each sample collection event will be recorded on field logs (Appendix A-4) and shipped to Philip Analytical Laboratories along with completed chain-of-custody forms (Appendix A-5).

At the laboratory, samples will be analyzed for propylene glycol concentration (percent). The analyses will be conducted using gas chromatography/flame ionization detector (GC/FID). The GC/FID is calibrated with standards ranging from 10 to 1,000 ppm propylene glycol to establish instrument linearity and a calibration curve. Because the instrument is calibrated to 1,000 ppm and sample concentrations of propylene glycol are expected to be around 23 percent (230,000 ppm), appropriate sample dilution will be performed prior to direct injection into the instrument.

Instrument accuracy is 0.02 percent full scale, or ± 20 ppm. However, the nature of propylene glycol reactions in the GC column typically exhibit significant variability, and therefore the accuracy of the glycol content analyses is limited to approximately ± 10 percent (or ± 2.3 percent for a mixture of approximately 23 percent glycol). As a quality assurance check on the glycol fluid sampling and analyses, two blind audit samples will be submitted to the laboratory along with one lot of samples. The Center will procure pure ACS reagent grade propylene glycol from a qualified reagent manufacturer (J.T. Baker or equivalent). ACS reagent grade propylene glycol is minimum 99.5 percent pure, with actual purity reported per lot manufactured. Two mixtures of glycol in distilled water (in the range of 20 to 25 percent) will be mixed by Center personnel, recorded at the Center's laboratory, and submitted to the analytical laboratory for analysis. The analytical laboratory will be requested to conduct duplicate analyses on the audit samples, and the reported values will be compared to the mixture recorded by the Center to evaluate analytical accuracy.

2.2.4. Total Thermal Energy Recovered and Used

After the load testing, the CHP system will be operated to meet the site's daily heating load. The heat recovery rate will be continuously monitored and recorded throughout this period at a sampling rate of one measurement per minute. Time series plots of measured heat recovery and use rates will be generated, and analyzed to determine total thermal energy recovered, as follows:

$$\textit{Total Thermal Energy Recovered (Btu)} = \Sigma\, \textit{Heat Recovery Rate} \qquad (10)$$

$$\textit{Actual Thermal Energy Used at Walker Court (Btu)} = \textit{Total Thermal Energy Recovered} \qquad (11)$$

Where:
Heat Recovery Rate = amount of heat recovered by CHP system, Eqn. 7 (Btu/min)

During the four week continuous testing, it is expected the site will continue to consume all the heat that can be recovered with the CHP system, unless ambient temperatures increase to unseasonably high levels. In this case, the CHP system will strive to maintain a minimum temperature differential between the T1 and T2 locations to prevent the system from overheating. As the system operates to meet the actual thermal demands of the building, the use rate will be equivalent to the measured recovery rate. If the thermal demand continues to decrease and the CHP system is unable to discard the excess heat, the turbine will be forced to automatically shut off. Throughout the continuous test period, the GHG Center will continuously monitor and record heat recovery rates, and assign these rates as the actual heat used at Walker Court. Actual thermal energy used at Walker Court will simply be equal to the total thermal energy recovered during the test, as shown in Equation 11.

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 as the power grid. While in grid parallel mode, the turbine detects the utility voltage and frequency to ensure proper synchronization before actual grid connection occurs. This is accomplished by converting high frequency electrical output to match the grid frequency and voltage at constant current. The turbine power electronics contain circuitry to detect and react to abnormal conditions that, if exceeded, cause the unit to automatically disconnect from the grid. These out-of-tolerance operating conditions include overvoltages, undervoltages, and over/under frequency. For the test situation, out-of-tolerance conditions are defined as grid voltage outside the range of 480 volts ± 10 percent and electrical frequency of 60 Hz ± 0.01 percent.

The power factor delivered by the turbine must be of sufficient quality to allow successful operation of sensitive office equipment. 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 distortion have been established within which power generation equipment, such as the turbine, must operate within.

Power quality parameters such as electrical frequency, power factor, and THD cannot be isolated from the grid. The quality of power delivered by the turbine actually represents an aggregate of disturbances already present in the utility grid, and is a measure of how the turbine works to reduce the disturbances by compensating for extreme variations in power quality. In the case of the power factor, the turbine electronics follow the demand load (i.e., if there is an inductive demand, the turbine will provide a lower power factor). Similarly, THDs generated at the turbine represent improvements in THDs that are already present in the grid.

The power quality evaluation approach has been developed to account for these issues, and will report electrical frequency output, voltage output and voltage transients, power factor, and total harmonic distortion. Each parameter provides an understanding of the quality of electrical power produced by the turbine, and its ability to maintain synchronization with the power grid. To report power quality performance relative to the grid, baseline measurement data will be collected by shutting the turbine off each day for about 1 hour, and taking direct measurement of the grid power quality. The turbine will then be turned on, and additional data will be collected to determine improvements in quality of power generated by the turbine. The difference between before and after readings for a 1-week monitoring period will represent actual power quality delivered by the turbine. The same electrical meter (7600 ION) used for electrical power output measurements will be used to make these measurements. The methods for determining and reporting power quality parameters are discussed below.

2.3.1. Electrical Output Frequency

Electricity supplied in the U.S. and Canada is typically 60 Hz alternating current. Electrical frequency measurements will be monitored continuously, and average one-minute readings will be recorded. The data collected by the electrical meter will be analyzed to determine daily maximum frequency, minimum frequency, average frequency, variance, and standard deviation. In addition to daily results, the overall maximum frequency, minimum frequency, average frequency, and standard deviation in frequency will also be reported for the entire verification period. These parameters will be calculated while the microturbine is shut off for baseline data collection periods.

Equation 12 will be used to compute the average frequency.

$$F = \frac{\sum_{i=1}^{i=nr} Fi}{nr} \tag{12}$$

$where:$

$F =$ average frequency for baseline and turbine operating periods (Hz)

$Fi =$ instantaneous frequency reading of the electric meter (Hz)

$nr =$ number of one 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 (the mean). The following equations will be used to compute the variance and standard deviation:

$$F\,\mathrm{var} = \frac{\sum_{i=1}^{i=nr} (F - Fi)^2}{nr - 1} \qquad Fstd = \pm\sqrt{F\,\mathrm{var}} \tag{13, 14}$$

$where:$

$F\,\mathrm{var} =$ variation in frequency for baseline and turbine operating periods (Hz)

$Fstd =$ standard deviation in frequency for baseline and turbine operating periods

$F =$ average frequency (Hz)

$Fi =$ instantaneous frequency reading of the electric meter (Hz)

$nr =$ number of one minute readings logged by the electric meter

The performance of electrical frequency output will be reported as the percent difference between baseline averages and averages during turbine operation.

2.3.2. Voltage Output and Transients

An internal transformer will provide 480 volt output. Traditionally, it is accepted that voltage output can vary within ± 10 percent of the standard voltage (480 volts) without causing significant disturbances to the operation of most end-use equipment. 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 alternating current (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 C62.41-1991, which is the standard for transients in facilities operating under 600 volts $_{\mathrm{RMS}}$. 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 will be continuously monitored and recorded throughout testing using the 7600 ION meter. The 7600 ION meter will be capable of measuring 0 to 600 Volts (AC) at a rate of one reading per minute, and detecting surges up to 8 kV at a rate of one reading per 60 microseconds. All voltage readings will be reported as root mean square (RMS) voltage, which is the most common approach for measuring AC voltage. The total number of transient occurrences and its magnitude (greater than 480 Volts ± 10 percent) will be analyzed to quantify the following disturbances. All data will be reported on a daily basis, as well as 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

The following equations will be used to compute the average, variance, and standard deviation of the voltage output.

$$V = \frac{\sum_{i=1}^{i=nr} Vi}{nr} \qquad V\,\mathrm{var} = \frac{\sum_{i=1}^{i=nr} (V - Vi)^2}{nr - 1} \qquad Vstd = \pm\sqrt{V\,\mathrm{var}} \qquad (15,\ 16,\ 17)$$

where :

$V =$ average voltage output (volts)

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

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

$V\,\mathrm{var} =$ variation in voltage output (volts)

$Vstd =$ standard deviation in voltage output

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 loads 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. The magnitude is determined by a harmonic analyzer. 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 Total Harmonic Distortion (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 Standard, the turbine's specified values for total harmonic voltage and current distortion, are as follows:

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

For the verification, harmonic distortion (up to the 63rd harmonic) will be recorded for all voltage and current inputs using the 7600 ION. The meter will report one minute average THD for voltage and current, and are computed internally as shown below. The results will be analyzed to compute the average, maximum, and minimum THD for the baseline period and during turbine operation. The current and voltage harmonics present in the grid will be subtracted with the harmonics present during turbine operation to determine true contributions from the turbine.

$$Voltage\,THD = \frac{\sum_{j=1}^{j=nr}\left[\frac{\sum_{i=1st\ Harmonic}^{i=63rd\ Harmonic} Volt_i}{Volt_1}\right]}{nr} \qquad (18,\ 19)$$

$$Current\ THD = \frac{\sum_{j=1}^{j=nr}\left[\frac{\sum_{i=1st\ Harmonic}^{i=63rd\ Harmonic} Current_i}{Current_1}\right]}{nr}$$

where :

$Voltage\,THD =$ average voltage total harmonic distortion for baseline and turbine and operating periods (%)

$Current\ THD =$ average current total harmonic distortion for baseline and turbine and operating periods (%)

$Volt_i$ = RMS voltage reading for each harmonic in a minute (Volts)

$Current_i$ = current reading for each harmonic in a minute (Amps)

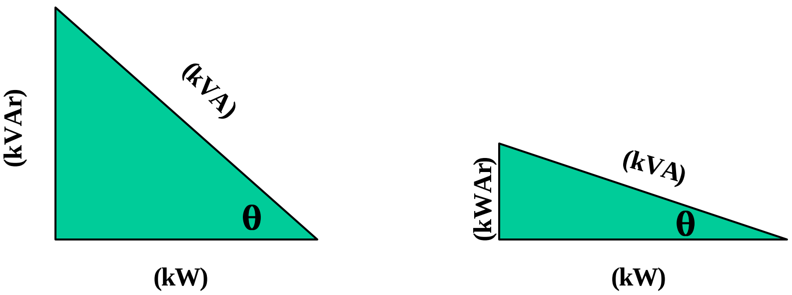
$Volt_1$ = RMS voltage reading for first harmonic in a minute (Volts)

$Current_1$ = current reading for first harmonic in a minute (Volts)

nr = number of one minute readings logged by an electric meter

2.3.4. Power Factor

Figure 2-2. Determination of Power Factor



Power Factor = cosine θ

Power factor is the phase relationship of current and voltage in AC electrical distribution systems. Under ideal conditions, current and voltage are in phase which results in a power factor equal to 1.0. If inductive loads (e.g., motors) are present, power factors are less than this optimum value. Although it is desirable to maintain the power factor at 1.0, the actual power factor of the electricity supplied by the utility may be much lower because of load demands of the different end users. Typical values ranging between 0.8 and 0.9 are common. Low power factor causes heavier current to flow in power distribution lines in order to deliver a given number of kilowatts to an electrical load.

Mathematically, electricity consists of three components which form a power triangle (Figure 2-2): Real Power (kW), Reactive Power (kVAr), and Apparent Power (kVA). Real Power (kW) is the part of the triangle which results in actual work being performed, in the form of heat and energy. This is the power that is verified in Section 2.2. Reactive Power, which accounts for electromagnetic fields produced by equipment, always acts at right angle or 90^o to Real Power. Reactive Power does not contribute to the work for which electricity was supplied, and the amount of current used to accomplish this work is increased, causing increased energy losses. The greater the Reactive Power, the worse the losses. Reactive Power can not be measured. Real Power and Reactive Powers create a right triangle where the hypotenuse is the Apparent Power, measured in kilovolt-amperes (kVA). The phase angle between Real Power and Apparent Power in the power triangle determines the size of the Reactive Power leg of the triangle. The cosine of the phase angle is called power factor, which is inversely proportional to the amount of Reactive Power that is being generated. In summary, the larger the amount of Reactive Power, the lower the power factor will be.

The turbine is specified by the manufacturer to operate at a power factor setting of 1.0. One minute average power factor measurements (before and after turning the turbine on) will be analyzed to determine if the unit maintained this setting. Maximum, minimum, average, standard deviation, and variance in the power factor will be reported for the test period.

2.4. EMISSIONS PERFORMANCE

2.4.1. Stack Emission Rate Determination

Exhaust stack emissions testing will be conducted to determine emission rates for criteria pollutants (NO_x, CO, and VOC) and greenhouse gases (CO_2 and CH_4). Stack emission measurements will be conducted at the same time as electrical power output measurements in the controlled test periods.

Following NSPS guidelines for evaluation of emissions from stationary gas turbines, CHP system exhaust stack emissions testing will be conducted at four loads within the normal operating range of the turbine, including the minimum load in the range and the peak load. As discussed earlier, the loads selected are 50, 75, 90, and 100 percent of the normal full load capacity (30 kW). The turbine will 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, will be conducted for each parameter at each load selected. The average results of three valid replicates will be reported.

The average emission rate measured during each test run will be reported in units of parts per million (ppmvd), for NO_X, CO, CH_4, and VOC, percent for O_2 and CO_2, pounds per hour (lb/hr), and pounds per kilowatt hour energy produced (lb/kWh). Reported concentrations will be corrected to 15 percent O_2 (using direct exhaust gas O_2 measurements). Appendix C-3 illustrates an example of the emissions test results. As with the power production and efficiency performance testing, Mariah operators will 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 will be used as a guideline to verify that the tests were conducted during steady operation. Variability in fuel flow to the turbine (limited to 1 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. Entech, an organization specializing in air emissions testing, will be contracted to perform all stack testing. Entech will provide all equipment, sampling media, and labor needed to complete the testing and will operate under the supervision of a GHG Center representative.

All of the emission test procedures to be utilized in this verification are U.S. EPA Federal Reference Methods. 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 2-2 summarizes the standard Test Methods that will 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 planned for use is discussed in more detail in the following sections. The entire Reference Method will not be repeated here, but will be available to site personnel during testing, and can be obtained and viewed using the Code of Federal Regulations (40CFR60, Appendix A).

Table 2-2. Summary of Emission Testing Methods

Air Pollutant	U.S. EPA Reference Method	Principle of Detection	Proposed Analytical Range[b]	Accuracy	Loads Tested (% nominal capacity 30kW)	No. of Test Replicates
O_2	3A	PARAMAGNETIC	0-25 %	± 5 %	50, 75, 90, and 100	3 per load (30 minutes)
CO_2	3A	NDIR	0-20 %	± 5 %		
NO_x	20[c]	Chemiluminescence	0-25 ppm	± 2 %		
CO	10	NDIR-Gas Filter Correlation	0-25 ppm	± 5 %		
CH_4	18	GC/FID	0-25 ppm	± 5 %		
THC[a]	25A	Flame ionization	0-25 ppm	± 5 %		

[a] VOC emissions will be determined as measured THC minus measured CH_4.

[b] Actual range will be determined prior to testing, with a portable analyzer.

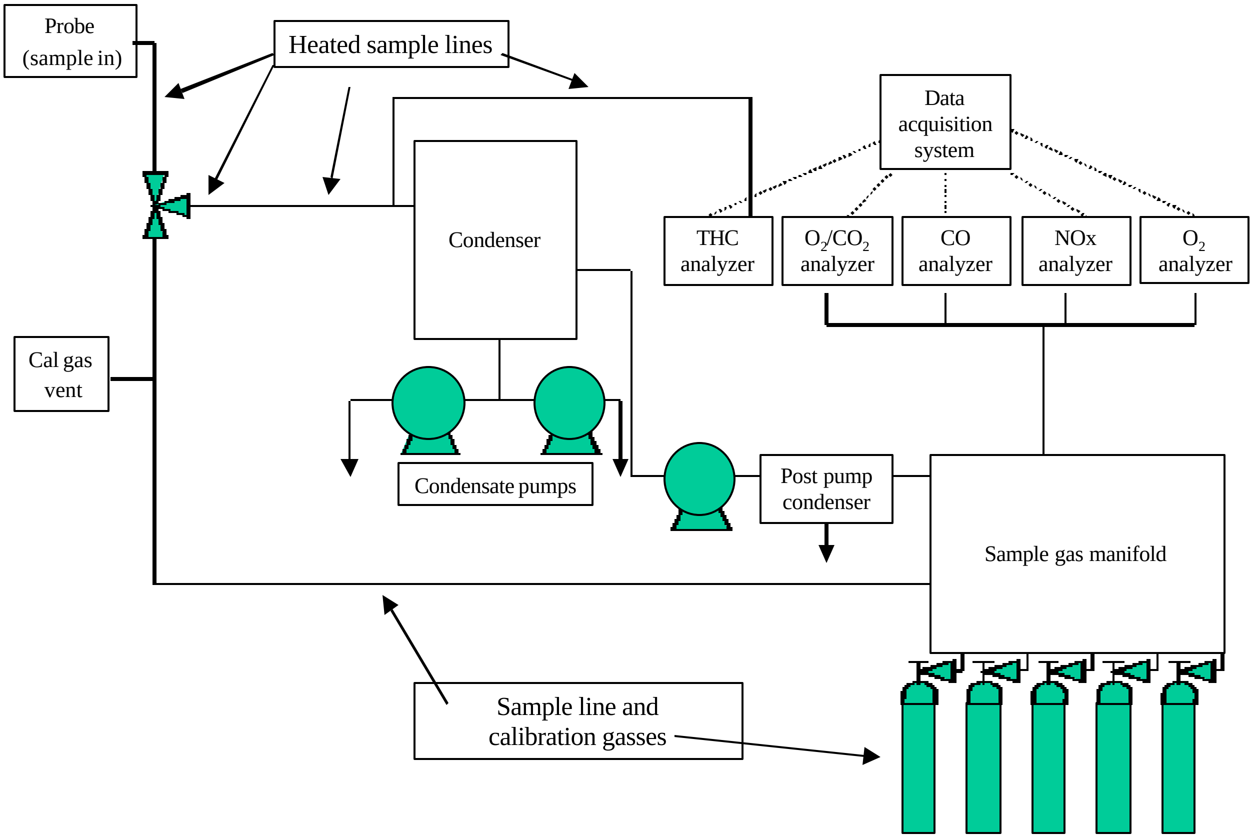
[c] Due to the small stack diameter (12 inches), Method 20 will be modified to incorporate single point sampling.

2.4.1.1. Gaseous Sample Conditioning and Handling

A schematic of the sampling system to be used to measure concentrations of CO_2, O_2, NO_x, CO, and VOC is presented in Figure 2-3. In order for the CO_2, O_2, NO_x, and CO instruments used 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. A Permapure permeation tube type moisture removal system will be used. This system exposes the extracted exhaust gases to a permeable membrane that has dried ambient air on the other side. The small amounts of water vapor in the exhaust gases permeate through the membrane to the dry air. This system eliminates the need to condense the moisture out of the gas and therefore minimizes the chance of 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 flame ionization detector (FIDs) 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 2-3. Gas Sampling and Analysis System



2.4.1.2. Gaseous Pollutant Sampling Procedures

For CO_2 and CO determinations, a continuous sample will be extracted from the emission source and passed through a California Analytical Model CA-300P non-dispersive infrared (NDIR) analyzer. For each pollutant, the NDIR analyzer measures the amount of infrared light that passes through the sample gas versus through the reference cells. Because CO_2 and CO absorb light in the infrared region, the degree of light attenuation is proportional to the CO_2/CO concentrations in the sample. The CO_2/CO analyzer ranges will be set at or near 0 to 20 percent for CO_2 and 0 to 25 ppm for CO at full load (0 to 50 ppm at reduced loads).

Oxygen content will also be analyzed with the California Analytical Model CA-300P analyzer using a paramagnetic reaction cell. This analyzer uses a measuring cell that consists of a dumbbell of diamagnetic material, which is temperature controlled electronically at 50^{o}C. The higher the sample O_2 concentration, the greater the dumbbell is deflected from its rest position. This deflection is detected by an optical system connected to an amplifier. Surrounding the dumbbell is a coil of wire with a current passed through the wire to return the dumbbell to its original position. The current applied is linearly proportional to the O_2 concentration in the sample. The O_2 analyzer range will be set at or near 0 to 25 percent.

Nitrogen oxides will be determined on a continuous basis using a Monitor Labs Model 8840 chemilumenescence analyzer or equivalent. This analyzer catalytically reduces nitrogen oxides in the sample gas to NO. The gas is then converted to excited NO_2 molecules by oxidation with O_3 (normally generated by ultraviolet light). The resulting NO_2 luminesces in the infrared region. The emitted light is measured by an infrared detector and reported as NO_x. The intensity of the emitted energy from the excited NO_2 is proportional to the concentration of NO_2 in the sample. The efficiency of the catalytic converter in making the changes in chemical state for the various nitrogen oxides is checked as an element of instrument set up and checkout (Section 2.4.1.3). The NO_x analyzer range will be operated on a range of 0 to 25 ppm at full load and 0 to 50 ppm at reduced loads.

Concentrations of VOC will be determined as THC less the methane content in the gas stream. Total hydrocarbons in the exhaust gas will be measured using a California Analytical Model 300 AD flame ionization analyzer which passes the sample through a hydrogen flame. The intensity of the resulting ionization is amplified, measured, and then converted to a signal proportional to the concentration of hydrocarbons in the sample. Unlike the other methods, the sample stream going to the analyzer does not pass through the condenser system, so it can be kept heated until analyzed. This is necessary to avoid loss of the less volatile hydrocarbons in the gas sample. Because many types of hydrocarbons are being analyzed, VOC results will be normalized and reported as methane equivalent. The calibration gas for THC will be propane. Concentrations of methane will be determined by collecting integrated gas samples in Tedlar bags and shipping samples to a certified laboratory for analysis. In the laboratory, samples will be directed to a Hewlett Packard 5890 gas chromatograph (GC) equipped with a flame ionization detector. Similar to the fuel sampling, the GC/FID will be calibrated with appropriate certified calibration gases. Sample collection bags will be leak checked prior to testing. In addition, one replicate sample will be collected and one duplicate analysis will be conducted for each turbine load tested.

2.4.1.3. Calibrations and Quality Control Checks

Analyzer and sampling system calibrations, and other QC check criteria specified in the Reference Methods for emissions determinations are identified later in Section 3.2.4 and Table 3-3. These QC procedures will be used to determine if overall Data Quality Objectives for emissions (discussed in Section 3.0), were met during the verification. All of these procedures are detailed in the corresponding Reference Methods and will not be repeated here in entirety. However, the specific procedures to be conducted during this test calibration ranges and other test specific data are outlined below.

NO_x Analyzer Interference Test

In accordance with Method 20, an interference test will be conducted on the NO_x analyzer once before the testing begins. This test is conducted by injecting the following calibration gases into the analyzer:

CO – 500 ± 50 ppm in balance nitrogen (N_2)
SO_2 – 200 ± 20 ppm in N_2
CO_2 – 10 ± 1 % in N_2
O_2 – 20.9 ± 1 %

For acceptable analyzer performance, the sum of the interference responses to all of the interference test gases must be $\leq$ 2 percent of the analyzer span value. Analyzers failing this test will be repaired or replaced.

NO_2 Converter Efficiency Test

The NO_x analyzer converts any NO_2 present in the gas stream to NO prior to gas analysis. An efficiency test on the converter must be conducted prior to beginning the testing. 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 will be stable at the highest peak value observed. If the response decreases by more than 2 percent from the peak value observed during the 30-minute test period, the converter is faulty. A NO_x analyzer failing the efficiency test will be either repaired or replaced prior to testing.

Sampling System Calibration Error and Drift

The sampling system calibration error test must be conducted prior to the start of the first test on each day of testing, it is performed 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 will be conducted on all analyzers using Protocol No. 1 calibration gases. Four calibration gases of NO_x, and THC are required including zero, 20 to 30 percent of span, 40 to 60 percent of span, and 80 to 90 percent of span. The maximum allowable error in response to any of the calibration gases is ± 2 percent of span for NO_x and ± 5 percent of span for THC.

At the conclusion of each test the zero and mid-level calibration gases are again introduced to the sampling systems at the probe and the response is recorded. System response is compared to the initial calibration error to determine sampling system drift. Drifts in excess of ± 2 percent for NO_x and ± 3 percent for THC are unacceptable and the test will be repeated.

Calibration Error, System Bias, and Calibration Drift Tests

These calibrations will be conducted to verify accuracy of CO, CO_2, and O_2 measurements. The calibration error test is conducted at the beginning of each day of testing. A suite of calibration gases is introduced directly to each analyzer and analyzer responses are recorded. EPA Protocol 1 calibration gases must be used for these calibrations. Three gases will be used for CO_2 and O_2 including zero, 40 to 60 percent of span, and 80 to 100 percent of span. Four gases will be used for CO including zero and approximately 30, 60, and 90 percent of span. The maximum allowable error in monitor response to any of the calibration gases is ± 2 percent of span.

Before and after each test, the zero and mid-level calibration gases will be introduced to the sampling system at the probe and the response recorded. System bias will then be calculated by comparing the responses to the calibration error responses recorded earlier. System bias must be less than ± 5 percent of span for each parameter for the sampling system to be acceptable. The pre- and post-test system bias calibrations will also be used to calculate drift for each monitor. Drifts in excess of ± 3 percent will be considered unacceptable and the test will be repeated.

Appendix C-5 provides an example calibration records sheet.

NO_x Audit Gas

The NO_x analyzer will be operated on a full-scale range of 0 to 25 ppm. It is possible that turbine emissions might be very low and on the low end of the analytical range (5 ppm or less). To evaluate the NO_x sampling system accuracy at the low end of the range, an audit sample will be provided by EPA. The audit gas will be introduced to the sampling system at the probe tip and a stable system response will be recorded. System error will be calculated as follows:

system error (percent full scale) = {(system response (ppm) / audit gas (ppm)) / 25} x 100

2.4.1.4. Determination of Emission Rates

The instrumental testing for CO_2, O_2, NO_x, CO, VOC, and CH_4 provides results of exhaust gas concentrations in units of percent for CO_2 and O_2 and ppmvd corrected to 15 percent O_2 for NO_x, CO, VOC, and CH_4. The THC and methane results are as ppmv on a wet basis, but will 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 will be conducted to determine the moisture content of the exhaust gases.

To convert measured pollutant concentrations to mass emissions, exhaust gas flow rate determinations will be conducted in accordance with each test run in accordance with EPA Method 2. Stack gas velocity and temperature traverses will be conducted using a calibrated thermocouple, a calibrated S-type pitot tube, and incline oil manometer. The number and location of traverse points sampled will be selected in accordance with EPA Method 1. At the conclusion of each test run, stack gas velocity will be calculated using the following equation:

$$V_s = 85.49 * C_p * [(P_{avg} * T_s) / (P_s * M_s)] \qquad (20)$$

Where:
V_s = Stack gas velocity, ft/sec
C_p = Pitot coefficient, unitless
P_{avg} = Average velocity head (delta P), in. water
T_s = Average stack temperature, ^oR
P_s = Absolute pressure in stack, in. Hg
M_s = Molecular weight of stack gas, lb/lb-mole

Measured gas velocities will be converted to volumetric flow rate in standard terms using the following equation:

$$Q_{std} = Vs * A * (P_s / P_{std}) * (T_s / T_{std}) * 60 \qquad (21)$$

Where:
Q_{std} = Volumetric flow rate, dscf/min
V_s = Stack gas velocity, ft/sec
A = Stack cross sectional area, ft^2
T_s = Average stack temperature, ^oR
P_s = Absolute pressure in stack, in. Hg
T_{std} = Standard temperature, 532^oR
P_{std} = Standard pressure, 29.92 in. Hg

After converting measured pollutant concentrations to mass units of lb/scf, emission rate values will be calculated in units of pounds per hour (lb/hr) using the standardized volumetric flow rates. Emissions will also be normalized to turbine heat input in units of pounds per million Btu (lb/MMBtu) using measured fuel consumption rates and fuel heating values. The emission rates will also be normalized to turbine output and reported as lb/kW-hr using measured turbine power output data collected during each test.

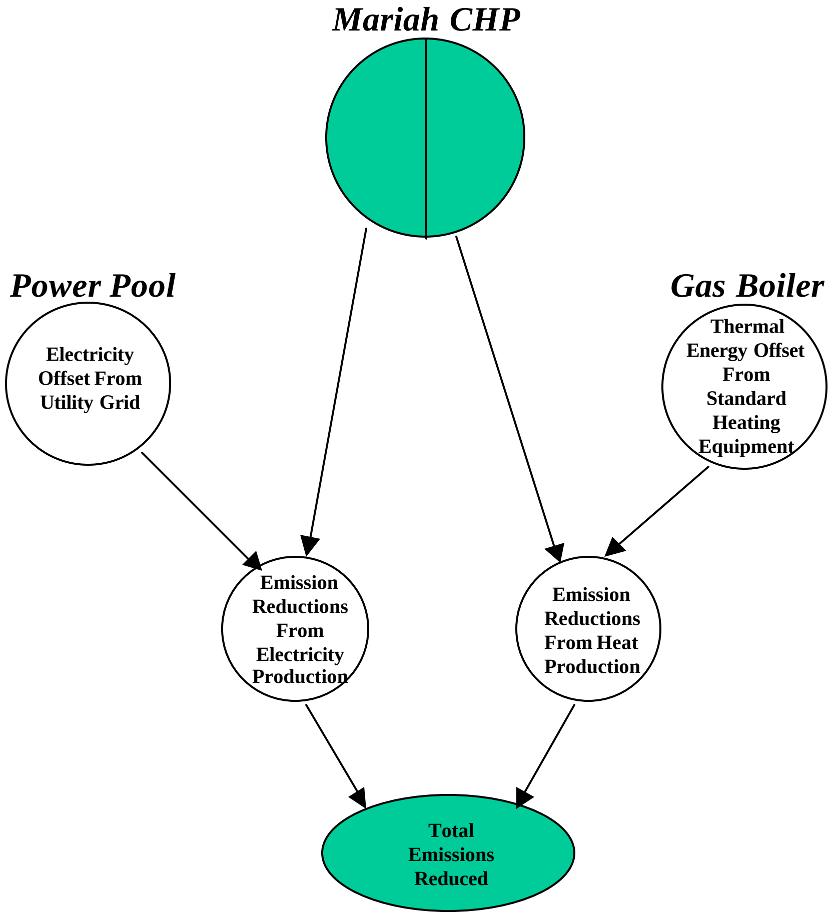
2.4.2. GHG Emission Reductions for Walker Court

This section presents the approach for determining GHG emission reductions for the Mariah CHP. The methodology to be employed is illustrated in Figure 2-3. In the first step, emission estimates for the CHP system will be developed using directly measured GHG emission rates, electricity generation/use rates, and heat recovery/use rates. The CHP system emissions will be compared to emissions from a baseline system. The baseline system is that which would have been used to meet the site's energy needs in the absence of the CHP system. The baseline system is electricity supplied by the local utility grid and thermal energy supplied by a new standard natural gas fired boiler. Subtraction of the Mariah CHP emissions from the baseline emissions will yield an estimate of net emission reductions.

$$\text{GHG Emission Reductions (tonnes CO}_2\text{)} = \text{Mariah CHP Emissions} - (\text{Grid Emissions} + \text{Boiler Emissions}) \qquad (22)$$

Emission reductions will be reported for carbon dioxide because it is the primary greenhouse gas emitted from combustion processes and reliable emission factors for electric utility and natural gas boilers are available for this greenhouse gas only. The following three subsections describe the approach for computing emissions for the CHP system, utility grid, and the natural gas boiler.

Figure 2-4. Walker Court Emission Reduction Estimation Methodology



2.4.2.1. Mariah CHP Emissions

During the verification, the Walker Court complex will not be fully occupied, and demand for electricity and heat may be lower than what the unit is capable of producing. As such, the electricity and heat used may be lower than the electricity generated and heat recovered (discussed in Sections 2.2.3). This expected under-occupancy, combined with the unique energy efficient design of the complex, will result in electricity and heat usage rates that are lower than the system's potential. Consequently, full emission reduction potentials of the CHP system are unlikely to occur during verification testing, even though they will likely increase in the future, as usage rates increase as additional tenants occupy the building. It is recognized that many potential CHP applications (e.g., hotels, swimming pools, car/truck washing facilities), have the electrical and thermal demand to use all the energy produced with the CHP system. It is also recognized that data to help such sites determine full GHG reductions would be a useful output from the verification. Mariah intends to market these sites by operating the CHP system continuously (i.e., base loaded), and use all the energy that can be produced/recovered with the system.

To provide readers the flexibility to examine CHP system emissions with maximum electricity and heat use rates, and to report emissions associated with actual conditions encountered at Walker Court, the verification will report two sets of GHG emissions estimates: (1) actual emissions and reductions for Walker Court and (2) estimated emissions and reductions for sites that can use all the energy produced by the CHP system. The following paragraphs describe the approach that will be followed to compute CHP system emissions for these two scenarios.

Total emissions over the verification period will be computed from hourly measurements data, as shown below.

$$\text{CHP System Emissions (tonnes } CO_2\text{)} = \text{Emissions}_{Elect} + \text{Emissions}_{Heat} \qquad (23)$$

$$\text{Emissions}_{Elect}\text{(tonnes } CO_2\text{)} = MW_{generated} \times 1\ \text{Hr} \times CO_2\ \text{Emission Factor}$$
$$\text{Emissions}_{Heat}\text{ (tonnes } CO_2\text{)} = 0$$

Walker Court Actual:
$MW_{generated}$ = hourly average power output measured with electric meter (MW)
CO_2 Emission Factor = measured emission rate corresponding to each hour's operating load (tonnes/MWh)

Maximum Energy Utilization:
$MW_{generated}$ = average power output measured at full load (MW)
CO_2 Emission Factor = measured emission rate at full load (tonnes/MWh)

Actual Walker Court emissions from electricity production will be computed as the hourly electrical energy generated times a load-specific CO_2 emission factor. The hourly electricity generated will be determined from the power meter data collected during the verification period, and the CO_2 emission factor will be assigned based on emissions test results that corresponds to the average electrical load at which the turbine was operating. There are no GHG emissions associated with heat recovered from the Mairah CHP, thus $Emissions_{Heat}$ will be assigned 0 tonnes of CO_2. Table 2-3 illustrates an example calculation.

Emission estimates will also be prepared assuming that the maximum energy output from the CHP system is used at Walker Court or other sites. Maximum output will be based on the electrical power output and heat recovery rates measured during 100 percent load testing at Walker Court (discussed in Sections 2.2.2 and 2.2.3). It should be noted that the Center is not verifying that the test site is capable of achieving this, but is simply extrapolating the measured data for sites which are able to utilize maximum energy output. To compute emissions from maximum electricity generation as shown above in Equation 23, the average electrical power measured during full load testing will be multiplied with the CO_2 emission factor at this load.

Table 2-3. Example Mariah CHP Emission Calculations

Walker Court - Actual

Hour	Electricity Generation				Heat Recovery			Total Emissions
	Electricity Generated[a]	Electricity Used[a]	Emission Factor[a,b]	Emissions	Heat Recovered [a]	Heat Used [f]	Emissions	
	(MWh)	(MWh)	(tonnes CO_2/MWh)	(tonnes CO_2)	**(Btu)**	**(Btu)**	(tonnes CO_2)	(tonnes CO_2)
1	0.029	0.015	0.60	0.0174	200,000	200,000	0	0.0174
2	0.029	0.015	0.60	0.0174	205,000	205,000	0	0.0174
3	0.029	0.016	0.60	0.0174	201,000	201,000	0	0.0174
4	0.028	0.015	0.60	0.0168	198,000	198,000	0	0.0168
5	0.030	0.015	0.60	0.0180	202,000	202,000	0	0.0180
Total	*0.145*	*0.076*		*0.0870*	*1,006,000*	*1,006,000*		*0.0870*

Maximum Energy Usage

	Electricity Generation				Heat Recovery			Total Emissions
Total Oper-Ating Hours	Maximum Electricity Generated[c]	Electricity Used	Emission Factor[d]	Emissions	Heat Recovered[e]	Heat Used[e]	Emissions	
	(MWh)	(MWh)	(tonnes CO_2/MWh)	(tonnes CO_2)	**(Btu)**	**(Btu)**	(tonnes CO_2)	(tonnes CO_2)
1	0.030	0.030	0.60	0.0180	235,000	235,000	0	0.0180
2	0.030	0.030	0.60	0.0180	235,000	235,000	0	0.0180
3	0.030	0.030	0.60	0.0180	235,000	235,000	0	0.0180
4	0.030	0.030	0.60	0.0180	235,000	235,000	0	0.0180
5	0.030	0.030	0.60	0.0180	235,000	235,000	0	0.0180
Total	*0.150*	*0.150*		*0.0900*	*1,175,000*	*1,175,000*	*0*	*0.0900*

[a] Measured by Center during continuous testing

[b] Corresponds to electrical load at which the unit was operating

[c] Corresponds to average power output measured during 100 % load test, this examples assumes 30 kW

[d] Corresponds to emission factor measured during 100 % load test

[e] Corresponds to maximum heat recovery rate during 100 % load test, this example assumes 235,000 Btu/hr

[f] Assigned as equivalent to actual heat recovered during continuous testing

During the verification, it is expected the CHP system will supply all the heat demand of the building. As a result, the natural gas fired boiler will not be needed, and will not operate to supply additional thermal load. For these periods, the CHP system is displacing the heating boiler such that it is off for long periods and the extra standby losses are zero. Emissions from the heat recovery unit will be assigned as 0 tonnes CO_2.

However, if unseasonably cold temperatures are encountered, the natural gas boiler will be operating in conjunction with the CHP system to supply comfort heating. Under these circumstances, the boiler will likely operate at a lower efficiency than its rated efficiency of 82 percent. The boiler operating at lower duty cycle while the CHP system is operating will result in GHG emissions (i.e., more natural gas will be used in the boiler at a lower efficiency than if the CHP was switched off). Mariah expects this scenario to be highly unlikely to occur during the March/April verification period. Nevertheless, the Center will make every effort to monitor boiler operating hours and fuel consumption rates. Boiler emissions associated with this fuel consumption will be computed, and subtracted from emissions at full load (discussed in Section 2.4.2.3) to estimate actual emission reductions with the heat recovery system. Computational procedures associated with this routine are not discussed in the Plan, but will be described fully if the boiler is verified to be operating during the test.

2.4.2.2. Utility Grid Emissions

For each kilo-watt hour of electrical energy produced and used with the Mariah CHP, an equivalent amount of electricity is no longer required from the utility grid. The electricity offset is defined as the energy used plus additional energy that must be generated at central stations to account for transmission and distribution line and transformer losses between the plant fence-line and the end-user. Based on data reported by CANMET, the average line losses between power plant fence-line and end-user is 7.87 percent for the Alberta grid. This means that for every MWh electricity produced and used on-site with the Mariah CHP system, 1.0787 MWh of electricity will not be produced at central power plants.

When some of the electricity generated with the CHP system is not used on site, the excess energy is supplied to the distribution grid. CANMET has suggested that the excess electricity injected would be such a small quantity (i.e., less than 30 kW) that it would likely be distributed to local end-users, and would not be transmitted long distances. As a result, step-down transformers would not be required as needed for central power generation. Line losses between electricity generated on-site and distributed to the power grid are estimated to be about 2 percent. This means that for every MWh excess electricity generated with the CHP system, 0.98 MWh will actually reach the grid. This means that 1.0375 MWh of electricity will not be produced at central power plants.

The following equation will be used to compute utility grid emissions:

$$\textit{Grid Emissions (tonnes } CO_2\textit{)} = MW_{offset} \text{ x } 1\ Hr \text{ x } Grid\ CO_2\ Emission\ Factor \qquad (24)$$

$$MWh_{offset} = (MW_{used} * 1.0787) + (MW_{excess} * 1.0375)$$

Walker Court Actual:

MW_{excess} = hourly avg. power measured with existing grid meter (MW)

MW_{used} = hourly avg. power measured with electric meter minus power measured with grid meter (MW)

Maximum Energy Utilization:

MW_{used} = average power output measured with electric meter at full load (MW)

MW_{excess} = 0 MW

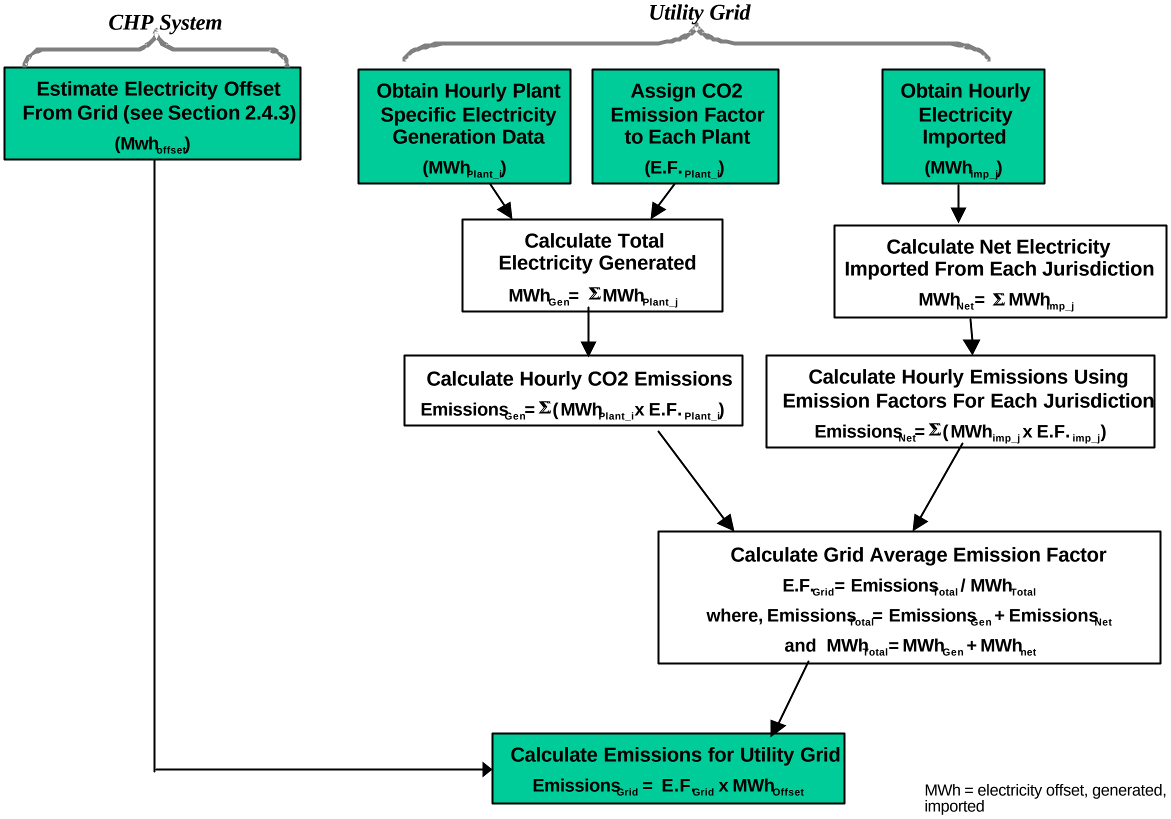
1.0787 = average line losses between central power plants and end user

1.0375 = average line losses between central power plants and distribution grid

CO_2 Emission Factor = hourly average utility emission factor for electricity generated and imported in Alberta, Figure 2-5a

The approach for assigning hourly average utility grid CO_2 emission factor is based, in part, on guidelines developed by the Emissions Quantification Working Group, which allows emission estimates to be developed for power generation plants operating in Alberta and importing power into the Alberta grid. The Working Group, which consists of representatives from major production, marketing and distribution utilities, independent power producers, Environment Canada, Alberta Energy, the Power Pool of Alberta and a major accounting firm, developed a protocol for quantifying CO_2 emissions from electrical generation facilities in the Alberta pool (EQWG 1999). The Group also recommended procedures for quantifying emission reductions from initiatives undertaken by individual companies to lower emissions. The protocol was prepared for the Power Pool of Alberta, the Federal and Alberta governments, the Greenhouse Gas Emissions Trading Pilot (GERT) and other parties exploring mechanisms for emissions trading. The Center has used components of this protocol to develop a procedure for computing emissions for the utility grid. The methodology is illustrated in Figure 2-5a, and an example calculation is shown in Table 2-4. The following describes key steps.

Figure 2-5a. Emissions For Electricity Utility Grid



MWh = electricity offset, generated, or imported
E.F. = CO2 emission factor (tonnes/MWh)
Emissions = CO2 emissions (tonnes)
i = individual generating plants
j = jurisdiction from where electricity was imported

Step 1. Calculate Emissions Associated with Electricity Generated

The Working Group recommended using publicly available electricity generation data from the Power Pool of Alberta to identify specific generation units that are operating during a given hour, and specify the amount of electricity produced by each. The Power Pool is a not-for-profit corporation that was established under Alberta's Electric Utilities Act of 1995. All electricity that flows onto the Alberta electrical grid is dispatched via the Power Pool. Over 95 percent of all electric energy transactions occurring in the region are dispatched through the Power Pool, including the Mariah CHP system at Walker Court.

The Power Pool maintains an on-line Energy Trading System (ETS) which is an internet based electricity exchange system. The ETS contains hourly, plant specific electricity generation data (MWh) that is derived from actual custody transfer electricity metering records. The Center plans to use the ETS database to identify individual plants and their electricity generation rates for all hours corresponding to Mariah CHP production periods. This task will be performed jointly with the KEFI-Exchange. KEFI-Exchange is a privately owned, industry sponsored, commodity exchange, which operates under an order from the Alberta Securities Commission. The KEFI-Exchange routinely processes the ETS data to offer emissions reduction certificates, and has agreed to provide this data to the Center. The Center will quality assure this data by selecting random electricity production periods, and verify the accuracy and completeness of the submitted data with the on-line ETS reports.

Table 2-4. Example Emission Reduction Calculations

For Walker Court

Hour	**CHP System**		**Utility Grid**			**Natural Gas Boiler**			**Emissions Reduced**
	Emissions From Electricity Prod.	Emissions From Heat Prod.	Electricity Offset	Average Emission Factor (generation + imports)	Emissions	Heat Used	Estimated Fuel Needed To Generate Equivalent Heat	Emissions	
	(tonnes CO_2)		(MWh)	(tonnes CO_2/MWh)	(tonnes CO_2)	(Btu)	(Btu natural gas)	(tonnes CO_2)	(tonnes CO_2)
1	0.0174	0	0.0307	0.94	0.0290	200,000	268,000	0.0141	0.0257
2	0.0174	0	0.0307	0.95	0.0293	205,000	274,700	0.0145	0.0264
3	0.0174	0	0.0308	0.91	0.0281	201,000	269,340	0.0142	0.0249
4	0.0168	0	0.0297	0.90	0.0268	198,000	265,320	0.0140	0.0240
5	0.0180	0	0.0318	0.89	0.0284	202,000	270,680	0.0143	0.0247
Total	*0.0870*	*0*			*0.1416*			*0.0711*	*0.1257*

Maximum Energy Usage

Total Oper-ating Hours	**CHP System**		**Utility Grid**			**Natural Gas Boiler**			**Emissions Reduced**
	Emissions From Electricity Prod.	Emissions From Heat Prod.	Maximum Electricity Offset	Average Emission Factor (generation + imports)	Emissions	Heat Used	Estimated Fuel Needed To Generate Equivalent Heat	Emissions	
	(tonnes CO_2)		(MWh)	(tonnes CO_2/MWh)	(tonnes CO_2)	(Btu)	(Btu natural gas)	(tonnes CO_2)	(tonnes CO_2)
1	0.0180	0	0.0324	0.94	0.0305	235,000	314,900	0.0166	0.0291
2	0.0180	0	0.0324	0.95	0.0308	235,000	314,900	0.0166	0.0294
3	0.0180	0	0.0324	0.91	0.0295	235,000	314,900	0.0166	0.0281
4	0.0180	0	0.0324	0.90	0.0292	235,000	314,900	0.0166	0.0278
5	0.0180	0	0.0324	0.89	0.0288	235,000	314,900	0.0166	0.0274
Total	*0.0900*	*0*	*0.1620*		*0.1488*	*1,175,000*	*1,574,500*	*0.0831*	*0.1418*

To assign emission factors to each power generating plant, the Working Group recommended using publicly available emission factors for each plant. A summary table listing CO_2 emission factors is presented in the EQWG report (Appendix Item 2), and is not repeated here. These factors were developed based on the latest publicly available data from the 1999/2000 General Rate Application to the Alberta Energy and Utilities Board, which contained plant specific heat rate and heating value data. The emissions factors presented in the EQWG protocol have been derived from these values, and used by other organizations to estimate emission reductions from alternative power generation technologies (GERT 1999). The KEFI-Exchange uses the same emission factors, given in tonnes CO_2 per MWh, and when multiplied by electricity generated, yield hourly CO_2 emissions for power stations in Alberta. The sum of emissions from all plants represents the total CO_2 emitted from Alberta generation units.

Step 2. Calculate Emissions Associated with Electricity Imported

During 2000, net imports (imports minus exports) represented approximately 1.1 percent of the total consumption in the province, making imports a very small portion of the Alberta energy transactions. In addition, due to changing market conditions and the availability of excess capacity, exports to the Pacific Northwest and California, during January and February 2001, outweighed imports by 2.5:1. It is expected that during the test period this net export situation will continue true and therefore imports will not be an issue during the test.

However, if net imports do occur during the test, KEFI-Exchange will record the hourly net imports from Saskatchewan and British Columbia and multiply them by the respective emissions factor for that jurisdiction, as listed below:

British Columbia - Using published data from BC Hydro (1997) KEFI-Exchange has assumed that 7.5 percent of all BC Hydro generation is via a natural gas fired thermal plant (Emission Factor = 0.59 tonnes/MWh). The remaining 92.5 percent is from hydro generation (Emission Factor = 0 tonnes/MWh). KEFI-Exchange has therefore calculated a weighted-average CO_2 emission factor of 0.44 tonnes/MWh for the import of electricity from B.C..

Saskatchewan - Using published data from SaskPower (1997) KEFI-Exchange has calculated that 70.9 percent of all Saskatchewan generation is via coal-fired thermal units, 5.4 percent via natural gas-fired thermal units, and the remaining 23.7 percent is from hydro generation. KEFI-Exchange has therefore calculated a weighted average CO_2 emission factor of 0.79 tonnes/MWh for the import of electricity from Saskatchewan.

Step 3. Calculate Average Hourly Emission Factor for the Utility Grid

The Working Group also recommended using the average or aggregate method for reporting emissions for the grid on a hourly basis. In this method, an average emission factor for the grid is determined for each hour electricity was generated and net electricity imported. As shown in Figure 2-4a, the average emission factor for the utility grid is defined as the sum of hourly CO_2 emissions from generation plants and imports, divided by the total electricity generated and imported. The average method was recommended because it met the criteria set by the Canadian Environment Ministers for establishing the Credit For Early Action program (simple to use, robust, transparent, predictable, and low cost).

The grid average emission factor will be computed for each hour the Mariah CHP was determined to be generating electricity. This emission factor will be multiplied with electricity offset, discussed earlier, to compute total emissions for the utility grid. Table 2-4 illustrates example calculations for Walker Court-Actual scenario and maximum utilization scenario.

2.4.2.3. Natural Gas Boiler Emissions

For each Btu of thermal energy recovered and used with the Mariah CHP, equivalent amount of energy is no longer needed from the baseline gas fired boiler. The approach for computing emissions associated with a baseline natural gas boiler consists of first estimating the fuel that would have to be combusted to produce an amount of heat that is equivalent to the heat recovered by the CHP system and used at Walker Court. Figure 2-5b illustrates the approach, and an example calculation was illustrated in Table 2-4. GHG emissions from baseline natural gas boiler will be computed as follows:

$$\textit{Boiler Emissions (tonnes } CO_2\textit{)} = \textit{Fuel} \times \textit{Boiler } CO_2 \textit{ Emission Factor} \qquad (25)$$

$$\textit{Fuel} = \textit{Heat}_{used} \times 1.34$$

Walker Court Actual:

Heat $_{used}$ = hourly total heat used during continuous testing, see Equations 10 and 11 (Btu)

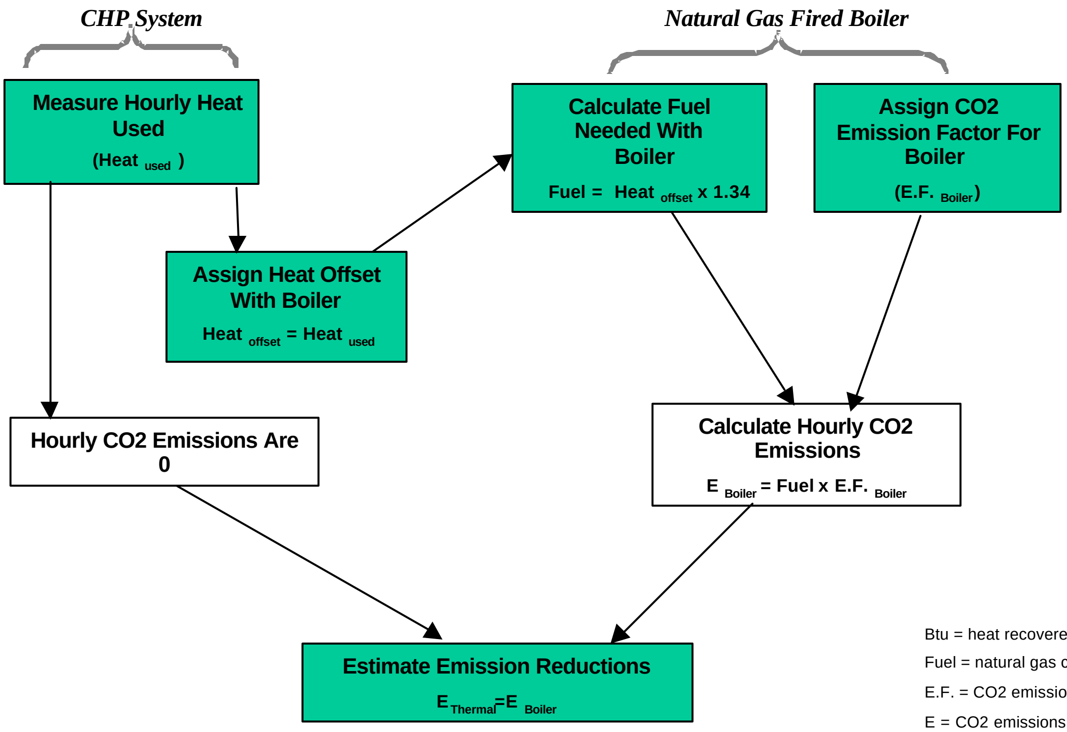
Maximum Energy Utilization:

Heat $_{used}$ = maximum heat recovery rate measured during full load testing times 60 minutes, see Equations 7 and 8 (Btu)

1.34 = ratio of fuel consumed by the boiler divided by heat produced

Boiler CO_2 Emission Factor = estimated using measured fuel carbon content and estimated oxidation rates, see Equation 26

Figure 2-5b. Walker Court Emission Reductions From Thermal Energy Production



Btu = heat recovered, used, or offset

Fuel = natural gas consumed, Btu

E.F. = CO2 emission factor (tonnes/MWh)

E = CO2 emissions, tonnes

The baseline comfort heating and hot water system is a new natural gas fired boiler system, manufactured by Raypack (Model 1826). The boiler is sized for peak consumption, with heat output of 1515.2 MBtu/hr and an efficiency of 83 percent. This standard system is consistent with a baseline gas boiler selected by CANMET as representative of this region. Due to test site elevation of 3000 ft above sea level, the manufacturer specifies the efficiency rating to be derated by 10 percent. As a result, the unit produces 1363.7 MBtu/hr heat with energy input of 1825.6 MBtu/h. The amount of fuel needed for the boiler to generate an equivalent amount of CHP-based heat used at Walker Court is actual heat used times 1.34 (ratio of fuel in over heat out).

CO_2 emission factor for the boiler will be computed using measured fuel carbon content and published oxidation rates, as shown below.

$$\textbf{Boiler Emission Factor (tonnes } \mathbf{CO_{2}/_{Btu\ Fuel}}\textbf{) = (44/12) (CC) (FO) / (2204.6 tonne/lb)} \qquad (26)$$

where:
CC = measured carbon content of the fuel (expected value is about 31.9 lb C/10^6 Btu)
FO = fraction of initial carbon content oxidized during combustion, according to U.S. EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1997, fraction oxidized is 0.995 for natural gas

2.4.3. GHG Emission Reductions for Model Sites

Different locations across the U.S. and Canada will experience emission reductions that could vary significantly from Walker Court. These locations are likely to employ alternative electrical energy and thermal energy systems that are typical of locations in the U.S. and Canada. The verification methodology will estimate emissions associated with the use of standard electricity and thermal energy system and Mariah CHP system at selected model sites in North America. The emission estimates between the standard and CHP system will be compared, and an estimate of the total CO_2 reduction potential will be reported for each model site. To enable this, model sites must be defined which include: the type of building (e.g., office, restaurant, hotel), size (ft^2), geographic location, electrical and thermal demand (base and peak), and end-use equipment. The Center has developed a preliminary list of model sites based on two comprehensive studies performed for the U.S. DOE Office of Building Equipment and NRCAN. The following paragraphs discuss how these studies have been used to define model sites for this verification.

2.4.3.1. Model Sites In the U.S.

The DOE project estimated total heating and cooling loads in U.S. buildings which are attributable to different shell components such as windows, roofs, walls, internal processes, and space-conditioning systems. The study defined prototypical commercial and residential buildings for the U.S. The building characteristics data were combined with Energy Information Administration residential and commercial energy consumption surveys to execute the DOE-2 building energy simulation program (Winkelmann et al., 1993). The prototypical building descriptions and DOE-2 input files, which consisted of hourly building loads, were developed for 112 single-family, 66 multi-family, and 481 commercial building prototypes. The commercial building prototypes were based on a previous GRI study which examined the market applicability of cogeneration systems for 13 building types in 4 geographic regions (Huang et al. 1991). The building types and regions were selected for their favorable factors for cogeneration (e.g., constant thermal loads and high ratio of electricity to gas prices), and covered an estimated 24 percent all U.S. commercial buildings. In a more recent study, whose results are not yet available, the DOE made changes to the building types and added small offices, small retail, and warehouses which covered an estimated 70 percent of all U.S. commercial buildings. The Center has elected to use the 1991 GRI report because it specifically examined market potential of cogeneration systems.

Table 2-5 summarizes the regions and cities selected for the model sites. The GHG Center has selected the Northeast (Boston), South (Houston), and West (San Francisco) as the locations for model sites. These locations were selected because (1) their corresponding states have or are in the process of undergoing electricity deregulation, (2) regulatory impetus exists for using distributed generation technologies, and (3) region specific CO_2 emission factors are available.

Table 2-5. Locations of Prototype Buildings

Region	City	Heating Deg. Days (base 65 F)	Cooling Deg. Days (base 65 F)	Selected As Model Site Location
Northeast	Boston	5775	695	X
	New York	5022	834	
	Philadelphia	4923	1065	
North Central	Chicago	6151	1015	
	Detroit	5997	922	
	St. Louis	4860	1467	
South	Miami	185	4045	
	New Orleans	1392	2578	
	Houston	1346	2891	X
West	Los Angeles	1494	472	
	San Diego	1275	662	
	San Francisco	3238	73	X
	Phoenix	1382	3647	

The GRI study ranked the market potential of cogeneration systems for different buildings. Table 2-6 shows the building types identified with medium to high market potential. Based on this ranking, the GHG Center has selected three model building types for the analysis of Mariah CHP system. These include: multi-family residential building (similar to Walker Court), restaurant, and hotel.

Table 2-6. Cogeneration Market Potential For Commercial Buildings
(Huang et al. 1991)

	Medium	High	Selected As Model Sites For Verification
RESIDENTIAL			
Multi-family	X		Yes
COMMERCIAL			
Food Services			
Supermarket	X		
Sitdown Restaurant		X	Yes
Fast-food Restaurant		X	
Hotel			
<60,000 ft^2	X		
>60,000 ft^2		X	Yes
Office			
20 to 60,000 ft^2	X		
>60,000 ft^2		X	
Hospital		X	

Table 2-7 provides a description of the prototype hotel building. The hotel model is used as an example to illustrate the verification approach. The methodology for the remaining two model building types will be developed during the verification period, and is not discussed in the Test Plan.

Table 2-7. Description of the Hotel Model

Building Parameter	North-east / Boston	South / Houston	West / San Francisco
Floor Area (1000 ft^2)	144	244	359
No. of Floors	6	7	10
ft^2/person	200		
Lights Watt/ft^2	1.2		
Equipment Watt/ft^2	0.6		
Hot Water Btu/ft^2h	5.0		
Process Btu/ft^2h	0.8		
Heat Schedule	70 F day, 65 F night		
Cool Schedule	78 F all day		
Electricity	Supplied by grid	Supplied by grid	Supplied by grid
Heating Plant	Gas Boiler	Gas Boiler	Gas Boiler
Chiller	Hermetic Centrif.	Hermetic Centrif.	Hermetic Centrif.
Hot Water Plant	Gas Boiler (TBD)	Electric Boiler (TBD)	Gas Boiler (TBD)

Based on the building characteristics, the standard system for a hotel located in Boston is defined to have electricity supplied by the utility grid and thermal energy generated by an on-site gas fired boiler (efficiency of 85 percent). The peak demand for hot water alone is about 720,000 Btu/hr in Boston, and the peak demand for electricity is about 259 kW. Table 2-8 summarizes the hourly load profiles for domestic hot water use and lights. This data shows that, on average, 40 percent of the heat demand is base loaded (i.e., 288,000 Btu/hr heat is needed on a continuous basis), and about 62 kW of electricity is needed on a continuous basis.

Table 2-8 Hourly Electricity and Hot Water Load Profiles for Hotels (% of Peak Demand)

Hour	DHW	Lights		Hour	DHW	Lights
1	0.21	0.20		13	0.45	0.25
2	0.20	0.15		14	0.40	0.25
3	0.20	0.10		15	0.35	0.25
4	0.20	0.10		16	0.35	0.25
5	0.22	0.10		17	0.33	0.25
6	0.20	0.20		18	0.45	0.25
7	0.51	0.40		19	0.60	0.60
8	0.61	0.50		20	0.65	0.80
9	0.59	0.40		21	0.55	0.90
10	0.48	0.40		22	0.50	0.80
11	0.42	0.25		23	0.48	0.60
12	0.48	0.25		24	0.20	0.30

Mariah intends to operate the CHP system base loaded singly or in multi-packs with up to ten units. Thus, installation of the CHP system at the hotel model building would offset daily electrical and heating demands. As shown earlier, the load profiles for the hotel model reveal that constant demand for electricity (lighting, fans, etc.) and thermal energy exists for this building. Therefore, one CHP system installed at this facility would offset GHG emissions associated with electricity supplied from the utility grid, and heat generated with a gas fired boiler.

Annual emissions for the Mariah CHP will be calculated as the maximum electricity that can be generated in a year multiplied with the unit's CO_2 emission factor at full load. The annual electricity generation figure will require (1) efficiency derating to account for site elevation and average annual temperatures, and (2) annual operating hours - 90 percent system availability will be assumed. For this example, power output with the Mariah CHP will be about 29 kW in Boston, which equates to annual electricity production of 228,636 kWh (29kW multiplied by 7884 hours per year). The annual heat recovered will be computed using the same heat recovery rate assigned as maximum achievable with the CHP system. For example, if the CHP system was verified to recover 235,000 Btu/hr thermal heat, annual heat generation will be computed as 235,000 Btu/hr times 7884 hours, or 1,853 MMBtu. The Center will coordinate with Mariah to develop a reasonable estimate of electricity and heat generation potentials for each model building. Emissions for the Mariah CHP will be computed in the same manner as discussed in Section 2.4.2.

Emissions associated with the standard system (utility grid and natural gas fired boiler) will be computed as follows:

Electricity Supplied By Grid:

- Select CO_2 emission factors for the model site (see Table 2-9 for U.S. DOE/U.S. EPA published system average emission factors by census region)
- Estimate transmission and distribution line losses for the model region (see discussion below)
- Calculate CO_2 emissions for generating the same amount of electricity generated by the Mariah CHP and consumed at the site
- Emissions = (annual electricity generated) (CO_2 emission factor) (1+ percent line losses)

Thermal Heat Supplied By Gas Fired Boiler:

- Estimate natural gas fuel needed to generate the same amount of heat with an 85 percent efficient natural gas boiler (Section 2.4.2.3, Equation 25)
- Calculate CO_2 emissions (Section 2.4.2.3., Equation 26)

Net emission reductions will be computed as the difference between the standard system emissions (electricity plus thermal heat) and Mariah CHP emissions.

Table 2-9. CO_2 Emission Factors for U.S. Utility Grid (US EPA 2000)

National Average

	CO_2 Emission Rate (tonne / MWh)
Coal	0.960
Petroleum[c]	0.869
Gas[a]	0.596
Other Fuels[b]	0.625
Average	0.624

Regional Average

CO_2 Emission Rate (tonne / MWh)

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific Contiguous	Pacific Noncontiguous
Coal	0.877	0.935	0.958	1.026	0.919	0.934	1.004	0.988	0.979	1.011
Petroleum	0.900	0.855	0.462	0.798	0.826	0.687	1.794	1.271	1.087	0.744
Gas	0.550	0.550	0.539	0.560	0.753	0.505	0.842	0.624	0.570	0.584
Other[a]	0.607	0.681	0.510	1.099	0.625	1.471	0.068	0.002	0.971	0.753
Total	0.480	0.486	0.762	0.802	0.605	0.661	0.666	0.713	0.189	0.659

[a] Includes natural gas, waste heat, waste gas, butane, methane, propane, and other gas

[b] Includes municipal solid waste, landfill gases, and other fuels that emit anthropogenic CO_2 when burned to generate electricity

[c] Includes petroleum, petroleum coke, diesel, kerosene, liquid butane, liquid propane, oil waste, and tar oil

Transmission and Distribution Line Losses

The electricity generated by central power station is delivered through electrical transmission and distribution 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 kV 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.

To identify transmission and distribution losses, the "Annual Electric Utility Report, Form EIA-861", published by the U.S. Department of Energy, Energy Information Administration will be used (EIA 2000b). Form EIA-861, 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. Based on this data, national average electricity loss from transmission, distribution, and/or unaccounted electricity losses is estimated to be 5.1 percent (averaged from about 3100 electric utilities records). For the verification, the EIA data will be used to compute average line losses for the region in which model sites are located.

2.4.3.2. Model Sites In Canada

Similar to the DOE and GRI studies, NRCAN/CANMET investigated the potential of packaged cogeneration, microturbines, and fuel cells for applications in Canadian buildings. This study, whose results are not yet publicly available, analyzed the performance of distributed generation technologies in five commercial/institutional building types in five cities. It also examined environmental benefits compared to central power plants using three scenarios (current average generation mix, short-term and long-term generation mix on the margin). A total of 175 cases were analyzed using DOE-2 energy analysis program. The authors used electricity demand as opposed to thermal energy demand to compare different systems, because it was assumed that DG units would be sized to meet either the building base or average electrical load. As a result, thermal heat demand data are not available. As part of this verification, CANMET will be requested to provide estimates of thermal demand for the building types examined.

Five building types were selected in the NRCAN/CANMET study. These include long term care, hospital, office, mult-unit residential, and hotel buildings. The study concluded that economics of DG systems were best at hotels, followed by hospital, multi-unit residential building, and long-term care. Based on this, the GHG Center has selected the following building types for the verification (office building, hotel, and multi-unit residential units), located in Vancouver, Toronto, and Montreal. Table 2-10 provides description of the buildings, and Table 2-11 summarizes each building's electricity requirements.

Table 2-10 Building Types Simulated In the CANMET Study

Building Type	Size (ft^2)	HVAC System	Selected As Model Sites For Verification
Office Building	260,000	Central VAV hydronic zone/DX cooling, Heating system – gas fired boiler	X
Hotel	113,000	Suites: PTHPs/elect Comm: rooftop/hyd, Heating system – gas fired boiler	X
Multi-unit residential	130,000 (130 units)	PSZ/hydronic heating, Heating system – gas fired boiler	X
Hospital	150,000	Central VAV/constant volume reheat, Heating system – gas fired boiler	
Long term care	43,000	Packaged cooling with hydronic heating, Heating system – gas fired boiler	

Table 2-11. Standard System Electrical Energy Consumption

Building Type	Location	Electricity Load (kW)		Electricity Consumption (kWh)
		Peak	Base	
Office Building	Vancouver	1,094	189	3,843,029
	Toronto	1,197	189	4,028,309
	Montreal	1,239	189	4,033,399
Hotel	Vancouver	375	47	1,616,977
	Toronto	592	47	1,899,768
	Montreal	610	47	1,902,351
Multi-unit residential	Vancouver	281	45	945,692
	Toronto	336	45	1,025,415
	Montreal	302	45	987,491

The standard system is defined as electricity supplied by the utility grid and thermal energy supplied by a gas-fired boiler. The model site energy consumption data, shown in Table 2-11, indicate that a single CHP system can provide between 15 to 65 percent of the building electrical needs. With CANMET and Mariah's assistance, annual electricity and thermal energy production estimates will be developed for each building type. Annual GHG emissions will be computed using the strategy discussed earlier in Section 2.4.2.

Emissions associated with the standard system will be computed as follows:

Electricity Supplied By Grid:

- Select CO_2 emission factors for model sites (Table 2-12)

Table 2-12. Emission Characteristics of Average Energy Mix

	Average Energy Mix	
	% fossil	**CO_2 Emission Factor* (lb/kWh)**
Vancouver	5.5	1.770
Toronto	13.7	2.180
Montreal	2.4	1.094

* Includes contributions from transmission and distribution line losses
Vancouver = 8.86 %
Toronto = 7.71 %
Montreal = 8.56 %

The GHG Center recognizes that baseline emission characterizations schemes are evolving in Canada, and proposes to use the average system emission factor method. This method assumes the power displaced is simply the average electricity generation in the region of interest, and is consist with the approach selected for Walker Court.

- Calculate CO_2 emissions for generating the same amount of electricity generated by the Mariah CHP and consumed at the site

  Emissions = (annual electricity generated) (CO_2 emission factor, corrected for line losses)

Thermal Heat Supplied With Gas Fired Boiler:

- CANMET will be requested to provide heat demand for each model facility. Based on this, an estimate of heat recovery rate with the Mariah CHP will be generated, and its emissions will be calculated. With CANMET's assistance, average combustion efficiency will be assigned for the standard system. Fuel consumption and emission factor for the standard gas boiler will be computed as discussed earlier.

Net emission reductions will be computed as the difference between the baseline system emissions (electricity plus thermal energy) and Mariah CHP emissions.

3.0 DATA QUALITY

3.1. DATA QUALITY OBJECTIVES AND DATA QUALITY INDICATORS

In verifications conducted by the GHG Center and EPA's Office of Research and Development, measurement methodologies and instrumentation are selected to ensure that desired level of data quality occurs in the final results. Data quality objectives (DQO) are stated for key verification parameters before testing commences. These objectives must be achieved in order to draw conclusions from the measurements with the desired level of confidence. This section presents the DQOs for critical verification parameters, followed by a discussion of the Data Quality Indicators (DQIs) that will be used to determine if the DQOs were met.

The process of establishing data quality objectives starts with determining the desired level of confidence in the verification parameters. The next step is to identify all measured values which affect the verification parameters, and determine the levels of error which can be tolerated. In most cases the error associated with the measurement variable is also the error associated with the verification parameter (e.g., electrical power output). For a selected group of verification parameters, the errors associated with multiple measurements must be accounted for to determine the cumulative effect of all measured variables on the data quality objectives. For example, electrical efficiency determination requires measurements for power output, fuel flow rate, and fuel heating value. The errors associated with each measurement must be accounted for to satisfy the DQO for electrical efficiency. The technique used to determine if data quality objectives are met is to satisfy the DQI goals. For this verification, DQI goals have been established for accuracy and completion, where completeness is defined as the number of valid determinations expressed as a percent of the total tests or readings conducted.

Quantitative DQOs are established for the verification parameters: electrical power output, electrical efficiency, heat recovered, thermal efficiency, net efficiency, and exhaust stack emission rates. Table 3-1 lists the DQOs for these parameters. Table 3-2 summarizes the DQI goals corresponding to physical measurements, which are be used to compute DQOs. All independent measurements specified with DQI goals are considered critical measurements, and are essential to forming valid conclusions about the performance of the CHP system.

Table 3-1. Data Quality Objectives

Verification Parameter	Accuracy
Electrical Power Output	± 0.2 %
Electrical Efficiency	± 0.38 %
Heat Recovered/Used	± 2.18 %
Thermal Efficiency	± 1.86 %
Net CHP System Efficiency	± 1.11 %
Concentration	
NO_x	± 0.50 ppm
CO, CO_2, and CH_4	± 1.25 ppm
VOC	± 2.50 ppm

Table 3-2. Measurement Instrument Specifications and Data Quality Indicator Goals

Measurement Variable		Operating Range Expected in Field	Instrument Type / Manufacturer	Instrument Range	Instrument Rated Accuracy	Frequency of Measurements	Data Quality Indicator Goals Accuracy*	Data Quality Indicator Goals Completeness	How Verified / Determined
Electrical Power Output and Quality	Power	0 to 30 kW	Electric Meter/ Power Measurements 7600 ION	0 to 260 kW	± 0.20 % reading	once per min	± 0.20 % reading	Load tests – 100 % Continuous test – 90 %	Review manufacturer calibration certificates, Perform sensor function checks in field ***
	Voltage**	0 to 480 V (3-phase)		0 to 600 V	± 0.1 % reading		± 0.1 % reading		
	Voltage Transients**	600 to 8000 V		0 to 8000 V	not available	once per 60 mili-sec	not defined		
	Frequency**	60 Hz		57 to 63 Hz	± 0.01 % reading	once per min	± 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	once per sec	± 1 % FS		
	Current THD**	0 to 100 %		0 to 100 %	± 1 % FS		± 1 % FS		
	Power Factor**	0 to 1.0		0 to 1.0	± 0.5 % reading		± 0.5 % reading		
Heat Recovery Rate	Temperature	TBD	Arigo Thermal Meter	37 to 356 ° F	± 0.1 % reading	once per min	± 0.9 ° F		
	Liquid Flow	TBD		3.53 to 5.89 cfm	± 1 %		± 1 %		
	PG Concentration	10 to 20 %	GC/FID	10 to 1000 ppm	± 0.02% FS	3 times per load test, repeated weekly	± 3 % for 23 % PG mixture		Independent check with blind sample
Bi-Directional Time of Use Meter	Electricity Supplied to Grid	0 to 20 Amps 120 Volts	Schlumberger Type ST-Q300	0 to 20 Amps 120 Volts	TBD	15 min averages	TBD	Load tests - 100% Continuous test - 90%	Review ENMAX utility meter certifications
Ambient Meteorological Conditions	Ambient Temperature**	50 to 110 °F	RTD / Vaisala Model HMP 35A	-4 to 140 °F	± 0.2 °F	once per min	± 0.2 ° F	Load tests – 100 % Continuous test – 90 %	Review manufacturer calibration certificates
	Ambient Pressure**	30 to 31 in Hg	SETRA Model 280E or equiv.	0 to 51 in Hg	± 0.11 % FS		± 0.11 % FS		
	Relative Humidity**	0 to 100 %	Vaisala Model HMP 35A	0 to 100 %	± 2 % (0 to 90 % RH,) ± 3 % (90 to 100 % RH)		± 3 %		

(continued)

Table 3-2. Measurement Instrument Specifications and Data Quality Indicator Goals (continued)

							Data Quality Indicator Goals		
Measurement Variable		**Operating Range Expected in Field**	**Instrument Type / Manufacturer**	**Instrument Range**	**Instrument Rated Accuracy**	**Frequency of Measurements**	**Accuracy***	**Completeness**	**How Verified / Determined**
Fuel Input	Mass Flow Rate	7 scfm	Mass Flow Meter / Rosemount 3095	3 to10 scfm	± 1.0 % reading	once per min	± 1.0 % reading	Load tests – 100 % Continuous test – 90 %	Review manufacturer calibration certificates, Perform sensor function checks in field
	Gas Pressure	50 to 55 psi	Pressure Transducer / Rosemount or equiv.	0 to 150 psig	± 0.075 % FS	once per min	± 0.075 % FS		
	Gas Temperature**	-20 °F to 80 °F	RTD / Rosemount Series 68	-58 to 752 °F	± 0.09 % reading	twice per week	± 0.09 % reading		
	LHV	94 to 98 % CH$_4$ (20,000 to 22,400 Btu/lb)	Gas Chromatograph / HP 589011	0 to 100 % CH$_4$	± 0.2 % accuracy for CH$_4$ ± 0.1 % repeatably for LHV	min. 1 sample at each load test, replicates every 3rd collection	± 0.2 % for LHV		
Exhaust Stack Emissions	NO$_x$ Levels	0 to 50 ppm	Chemilumunescene / Monitor Labs Model 8840	0 to 25 ppm (full load), 0 to 50 ppm (reduced loads)	± 1 % FS	three 30 minute replicates per load	± 2 % FS	Load tests - 100 %	Follow EPA Reference Method calibration and QC criteria
	CO Levels	0 to 50 ppm	California Analytical CA-300P	0 to 25 ppm (full load), 0 to 50 ppm (reduced loads)	± 1 % FS		± 5 % FS		
	O$_2$ Levels	0 to 25 %	California Analytical CA-300P	0 to 25 %	± 1 % FS		± 5 % FS		
	CO$_2$ Levels	0 to 20 %	California Analytical CA-300P	0 to 20 %	± 1 % FS		± 5 % FS		
	CH$_4$ content	0 to 50 ppm	GC / FID HP Model 5890	0 to 25 ppm (full load), 0 to 50 ppm (reduced loads)	± 0.1 % FS		± 5 % FS		
	THC Levels	0 to 50 ppm %	California Analytical 300 FID	0 to 25 ppm (full load), 0 to 50 ppm (reduced loads)	± 1 % FS		± 5 % FS		
	Temperature	400 to 600 °F	Thermocouple / Omega Type K	up to 2100 °F	± 1 % reading	twice per week	± 1 % reading		

FS: full scale

* Accuracy goal represents the maximum error expected at the operating range. It is defined as the sum of instrument and sampling errors.

** These variables are not directly used to assess data quality objectives, but are used to determine if data quality indicator goals for key measurements are met. They are also used to form conclusions about the CHP system performance.

*** Performance checks as a means of verification implies that we will use the manufacturer's specification for accuracy unless quality control performance checks indicate a problem.

Table 3-3. Summary of QA/QC Checks

Measurement Variable	QA/QC Check	When Performed/Frequency	Expected or Allowable Result	Response to Check Failure or Out of Control Condition
Power Output	Instrument Calibration by Manufacturer	Beginning and end of test	± 0.20 % reading	Identify cause of any problem and correct, or replace meter
	Sensor Diagnostics in Field	Beginning and end of test	Voltage and current checks within ± 1 % reading	Identify cause of any problem and correct, or replace meter
	Reasonableness checks	Throughout test	Readings should range between 27 and 30 kW at full load	Identify cause of any problem and correct or replace meter
Mass Flow Rate	Instrument Calibration by Manufacturer	Beginning and end of test	± 1.0 % reading	Identify cause of any problem and correct, or replace meter
	Sensor Diagnostics	Beginning and end of test	Pass	Identify cause of any problem and correct, or replace meter
	Independent performance check with a dry gas meter	Beginning and end of test	average accuracy between the two meters should be less than ± 1.0 %	Identify cause of discrepancy, perform sensor diagnostics, recalculate DQO for electrical efficiency
	Reasonableness checks	Throughout test	Readings should be about 7 scfm at full load	Perform sensor diagnostic checks
Fuel Heating Value	Replicate samples collected in field	Once during each load testing	Average accuracy between replicates should be less than ± 0.2 %	Recalculate DQO for electrical efficiency
	Calibration with gas standards by laboratory	Prior to analysis of each lot of samples submitted	± 0.2 % for CH_4 concentration	Repeat analysis
	Independent performance check with blind sample	Two times	± 0.2 % for CH_4 concentration	Recalculate accuracy
	Duplicate analyses performed by laboratory	Every sample	± 0.1 % for LHV	Repeat analysis
Heat Recovery Rate	Review manufacturer's calibration records for heat meter	Prior to testing	Temp: ± 0.9 °F Flow: ± 1 %	Recalibrate heat meter
	Independent performance check of temperature readings	Beginning and end of test	Difference in temperature readings should be < 0.18 °F	Identify cause of discrepancy and recalibrate heat meter
	Independent performance check of PG analysis with blind sample	Two times	PG concentration should be accurate to within ± 3 %.	Recalculate DQO for heat recovered and thermal efficiency
Electricity Supplied to Grid	Review ENMAX calibration records/certificates	Prior to testing	± 0.50 % reading	Recalibrate electric meter
	Reasonableness checks	Prior to testing	Reading should be similar to power output measurements by 7600 ION meter when no electricity is consumed on site	Identify cause of discrepency

(continued)

Table 3-3. Summary of QA/QC Checks (continued)

Measurement Variable		QA/QC Check	When Performed/Frequency	Expected or Allowable Result	Response to Check Failure or Out of Control Condition
Ambient Meteorological Conditions		Instrument calibration by manufacturer or certified laboratory	Beginning and end of test	Temp: ± 0.2 ^oF Pressure: ± 0.11 % FS RH: ± 3 %	Identify cause of any problem and correct, or replace meter
		Reasonableness checks	Throughout test	Recording should be comparable with airport data	Identify cause of any problem and correct, or replace meter
Fuel Gas Pressure		Instrument calibration by manufacturer	Beginning and end of test	± 0.75 % FS	Identify cause of any problem and correct, or replace meter
		Reasonableness checks	Throughout test	Readings should be about 60 psig	Identify cause of any problem and correct, or replace meter
Emission Rates	NO_x	Analyzer interference check NO_2 converter efficiency	Once before testing begins	± 2 % of analyzer span 98 % efficiency	Repair or replace analyzer
		NO_x Audit gas	Once before testing begins	Less than 30 seconds ± 0.5 ppm	Modify or repair sampling system
		Sampling system calibration error and drift checks	Before and after each test run	± 2 % of analyzer span	Repeat test
	CO, CO_2, O_2	Analyzer calibration error test	Daily before testing	± 2 % of analyzer span	Repair or replace analyzer
		System bias checks	Before each test	± 5 % of analyzer span	Correct or repair sampling system
		Calibration drift test	After each test	± 3 % of analyzer span	Repeat test
	THC	System calibration error test	Daily before testing	± 5 % of analyzer span	Correct or repair sampling system
		System calibration drift test	After each test	± 3 % of analyzer span	Repeat test
	CH_4	Calibration with gas standards by certified laboratory	Prior to analysis of each lot of samples submitted	± 2 % for CH_4 concentration	Repeat analysis

Achieving the DQI goals will require Center personnel to follow the QA/QC procedures discussed in Section 2.0. A summary of QA/QC check list is provided in Table 3-3, and will serve as the basis for determining if the DQI goals were met. Determination of completeness, accuracy, and precision (emission testing only) calculations will be performed by the GHG Center Field Team Leader during load testing. Completeness will be calculated as the number of valid determinations divided by the total number of determinations. The GHG Center Field Team Leader will have the specific responsibility for quality assurance of the on-site field testing. If the DQI goals are not met, the Field Team Leader will have the authority to halt testing until the measurement system is corrected and proved to meet the required DQI goals.

3.2. DETERMINATION OF DATA QUALITY INDICATORS AND DATA QUALITY OBJECTIVES

3.2.1. Electrical Power Output and Electrical Efficiency

Precise determination of the electric power generated is required because it is a key performance parameter for the turbine. The data quality objective for this parameter is set to be ± 0.2 percent. Given a rated maximum power output of 30 kW for the system, this will yield a maximum error of ± 0.06 kW, which is sufficient for determining the suitability of the unit for demand control, emergency power backup, and other applications for which it may be considered. This level of accuracy will also exceed the typical uncertainty as set forth in PTC22 (Section 1.3.2 – typical uncertainty for power output using gas fuel is 1.8 percent). It also exceeds the maximum permissible variation (± 2 percent) allowed in PTC22 to determine electrical efficiency (Section 2.2.1). The data quality indicator goal required to meet the DQO will consist of assessing the accuracy of the electric power meter.

The data quality objective for electrical efficiency is to achieve an accuracy of ± 0.38 percent. Given a specified target efficiency of 28 percent for the microturbine, this will yield a maximum error of ± 0.38 percent efficiency (i.e., for a calculated efficiency of 28 percent, the actual value could range from 27.62 to 28.38 percent). This level of accuracy will also meet the typical uncertainty as set forth in PTC22 (Section 1.3.1 – typical uncertainty for efficiency using gas fuel is 1.7 percent). The data quality indicator goals required to meet the DQO will consist of achieving a ± 0.2 percent accuracy goal for the power meter (discussed above), ± 1.0 percent accuracy goal for a mass flow meter, and ± 0.2 percent accuracy goal for fuel heating value. The GHG Center will make every effort to meet these accuracy goals. However, if unplanned circumstances or excessive variabilities in the measurements are encountered, the DQO for electrical efficiency will be computed using Equation 1.

The 7600 ION electric meter accuracy determination will require that the instrument is factory calibrated prior to installation in the field. The GHG Center will review its calibration certificate and NIST tracability records to ensure that the ± 0.2 percent accuracy goal was achieved. In addition, manufacturer specified installation and set-up procedures and QC checks will be followed in the field. Sensor function checks (discussed in Section 2.2.2.1) will be performed by comparing the meter's voltage and current output with digital multimeter readings. The specified voltage and current accuracy for the 7600 ION is ± 0.1 percent, while the DMM is ± 1 percent. Thus, if the percent difference between the two meters is computed to be within ± 1.5 percent, the two meters will be determined to be in agreement. During testing, reasonableness checks will be performed by comparing the 7600 ION power output readings with the output recorded by the turbine software. At full load, the power meter must read between 28 to 30 kW at Standard conditions. Routine quality control consists of daily checks for trends, spikes, or other changes in operation that could indicate a system problem. The data quality indictor goals will be determined to be met, provided the routine QC checks do not indicate sensor function failure.

Similar to the electric meter, the mass flow meter will be factory calibrated prior to installation in the field, and its calibration record will be reviewed to ensure the instrument rated ± 1 percent accuracy was satisfied. The factory calibration is reported to be valid for three years, and thus will not require re-calibration over the duration of the test, provided manufacturer-specified installation and set-up procedures are followed. These procedures, discussed in Section 2.2.1.2, consists of following specific installation and software set up procedures, and maintaining written records of user-supplied input parameters. In addition to these checks, QC checks will be performed immediately prior to testing; sensor diagnostic checks; and independent verification with a second meter. Sensor diagnostic checks consist of zero flow verification by isolating the meter from the flow, equalizing the pressure across the differential pressure (DP) sensors, and reading the pressure differential and flow rate. The sensor output must read zero flow during these checks. A transmitter analog output check, known as the loop test consists of checking a current of known amount against a DMM to ensure that 4 mA and 20 mA signals are produced. Finally, a dry gas meter, installed in series, will be used to independently verify the Rosemount flow meter output. During this check, natural gas will flow through both meters while the turbine is operating. For each paired reading, if the average accuracy is determined to be less than the propagated error of the two meters (± 2 percent), the data quality objective for electrical efficiency will be met. The accuracy achieved will be reported as the accuracy certified by the manufacturer.

QA/QC procedures for assessing data quality of lower heating values consists of extracting replicate samples, reviewing Core Laboratories' calibration records to ensure instrument errors are less than Method D1945 specifications, and repeating the lab analysis to ensure the LHV repeatability is 0.1 percent. To compute accuracy achieved, replicate sampling results will be used (i.e., standard error of the mean will be multiplied by the student-t value and divided by the mean). If the computed accuracy is determined to be less than the DQI goal (± 0.2 percent), the data quality objective for electrical efficiency will be satisfied. Conversely, if the accuracy goal was not met, the DQO for electrical efficiency will be recalculated using Equation 1.

The bi-directional time-of-use meter is used to measure electricity supplied to the utility grid. This meter was provided by the local electrical utility operator, ENMAX, and is consistent with meters used to conduct electricity transfer transactions within the utility grid. The GHG Center will obtain and review ENMAX's calibration records to ensure accuracy ratings were achieved. In addition, reasonableness checks will be performed in the field by comparing the 7600 ION power output readings with the ENMAX meter. The two meters should read the same electricity values for a given 15 minute period, corresponding to times when 100 percent of the electricity generated by the CHP system is supplied to the utility grid.

3.2.2. Thermal Recovery Rate, Use Rate, and Efficiency

Precise determination of thermal heat recovery/use rate is required because it is a key performance parameter for the CHP system. Based on accuracy ratings for PG solution flow rate, temperature, and concentration measurement, the data quality objective for this parameter is set to be ± 2.18 percent. Given a nominal heat recovery rate of 235,000 Btu/hr, this will yield a maximum error of ± 5,123 Btu/hr. The data quality indicator goals required to meet this objective consist of assessing Arigo heat meter's temperature and flow rate accuracy. It also consists of assessing the accuracy of measured PG concentrations.

Thermal efficiency is defined as the amount of heat recovered divided by heat input. With a 2.18 percent error in heat recovery rate, 1 percent error in fuel flow rate, and 0.2 percent error in LHV, the maximum uncertainty in thermal efficiency is expected to be ± 1.86 percent.

To ensure the Arigo flow meter's accuracy requirements are met, the GHG Center will obtain recent calibration and traceability records from Mariah and determine if the accuracy of the RTDs and flow sensor are within the specified limits. Quality assurance checks in the field will also be performed. This will consist of independently verifying the performance of the Arigo RTDs. In this procedure, the RTDs will be removed from the fluid pipe and placed in an ice water bath along with thermocouples of known accuracy. Temperature readings from both sensors will be recorded for comparison. The procedure will then be repeated in a hot water bath. If the average differences in temperature readings are greater than 0.18 °F, the Arigo heat meter will be sent for re-calibration.

A final quality assurance check consists of laboratory analysis of the propylene glycol mixture (see Section 2.2.2.1 for further detail). The lab will quantify volume percent of PG and provide instrument calibration records. In addition, blind/audit samples of known PG concentration will be submitted to the laboratory for analysis, and results will be used to determine errors between laboratory reported values and the true concentration of the audit samples. The GHG Center will select density and specific heat values from ASHRAE publications (Appendix A-9 and A-10). Interpolation between data sets may be required, and procedures used to select density and specific heat will be transparent in the final report. The error associated with interpolating for density and specific heat is estimated to be about ± 1 percent, with a 3 percent error in PG content measurements.

3.2.3. Net CHP System Efficiency

Given a ± 0.38 percent accuracy in electrical efficiency measurements and a ± 1.86 percent accuracy in thermal efficiency measurement, the net efficiency of the CHP system is expected to be accurate within ± 1.11 percent. For example, if the electrical efficiency and thermal efficiency are determined to be 27.09 percent and 54.36 percent, respectively, the CHP system net efficiency will be 81.45 ± 1.11 percent. If the accuracy goals for electrical efficiency or thermal efficiency are not met, actual system accuracy achieved will be re-computed using equations shown in Sections 2.2.1 and 2.2.3.

3.2.4. Exhaust Stack Emissions

EPA Reference Methods, listed earlier in Table 2-1, will be used to quantify emission rates of criteria pollutants and greenhouse gases. The Reference Methods clearly specify the sampling methods, calibration methods, and data quality checks that must be followed to achieve a data set that meets the required objectives. These Methods ensure that run-specific quantification of instrument and sampling system drift and accuracy occurs, and that runs are repeated if specific performance goals are not met. Based on the requirements of the Reference Methods, the DQOs for emission rate measurements are ± 2 percent for NO_x, ± 5 percent for CO_2, CH_4, CO, and THC measurements, and ± 10 percent for VOC. The data quality indicator goals required to meet the DQO will consist of assessing the sampling system accuracy, precision, and drift.

Assessment of the emissions data quality, integrity, and accuracy with respect to the DQOs and DQIs will be performed using a series of measurement system calibrations and QC checks. The QC checks required by the EPA Reference Methods, as summarized in Table 3-3, vary between methods and are pollutant specific. Table 3-3 lists the QC procedures required for each pollutant, the frequency of the calibrations and checks, the maximum allowable result, and corrective measures for failed checks. Satisfaction and documentation of each of the calibrations and QC checks conducted will verify the accuracy and integrity of the measurements with respect to the DQI's listed in Table 3-2, and subsequently the DQOs for each pollutant. QC requirements for each of the pollutants are described below. Section 2.4 of this plan provides details regarding sampling system components, sampling procedures, and specific calibration and QC check procedures.

In accordance with Method 20 for determination of NO_x emissions, QC requirements include an analyzer interference response check, an NO_2 converter efficiency test, system response time determination, sampling system calibration error, and sampling system drift tests. The interference and NO_2 converter efficiency tests are conducted once prior to the start of testing to verify proper analyzer function. The response time test is conducted on-site and prior to testing to verify that the system response time (i.e., the time required to route sample gas from the stack to the analyzer and obtain stable analyzer readings) is 30 seconds or less. The calibration error and drift tests are direct assessments of system accuracy conducted before and after each test run using EPA Protocol 1 gas standards.

In accordance with Method 25A for determination of THC emissions, QC requirements include sampling system calibration error and drift tests before and after each test conducted. The calibrations are direct assessments of sampling system accuracy using EPA Protocol 1 gas standards. Methane samples will be collected and analyzed using a GC/FID following the guidelines of EPA Draft Method 0040. The GC will be calibrated prior to sample analysis using certified methane standards, and the accuracy of the methane analysis is ± 2 percent. The THC and methane test results for each test period will be used to calculate VOC concentrations as THC less methane. Therefore, the DQO for VOC is 10 percent because two separate measurements are involved. Actual calibration data from the THC sampling system calibrations and the GC/FID calibrations for the methane analyses will be used to propagate error in the calculated VOC concentrations.

Emissions of CO will be determined in accordance with Method 10, and emissions of O_2 and CO_2 in accordance with Method 3A. QC criteria for CO measurements are not well defined in Method 10. Method 3A references EPA Method 6C (determination of sulfur dioxide emissions) for QC criteria, and these criteria will be followed for this testing. The criteria specified in Method 6C include determination of analyzer calibration error, sampling system bias, and calibration drift. The calibration error checks are conducted once per day of testing to verify proper instrument function. The system bias checks are conducted before and after each test run to determine overall sampling system accuracy. These pre- and post-test system calibrations are also used to determine sampling system drift during each test period.

3.2.5. Power Quality Measurements

The DQI accuracy goal for voltage output is ± 0.1 percent. Given a voltage output of 480 volts, an uncertainty of ± 0.48 volts is expected for readings ranging between 0 to 600 volts. This level is sufficient to determine when the turbine has exceeded the industry accepted ± 10 percent threshold. The accuracy for power factor is ± 0.5 percent, which is sufficient to meet the ± 2 percent maximum permissible variation allowed for electrical efficiency determination by the PTC 22 method. The accuracy goal for total harmonic distortion is ± 2 percent, which is sufficient to meet the ± 5 percent level defined in the IEEE 519 standard. The 7600 ION electric meter, selected for electrical power output measurement, is capable of meeting the above stated accuracy requirements. The same installation/setup procedures, calibration checks, and sensor diagnostic checks discussed in Section 2.2.1.1 will apply here.

3.3. INSTRUMENT TESTING, INSPECTION, AND MAINTENANCE REQUIREMENTS

The equipment used to collect verification data will be subject to the pre-and post-test QC checks discussed earlier. Before the equipment leaves the GHG Center or emission testing contractor laboratories, it will be assembled exactly as anticipated to be used in the field and fully tested for functionality. For example, all pumps, controllers, flow meters, computers, instruments, and other sub-components of the entire stack testing measurement system will be operated and calibrated as required by the reference methods. Any faulty sub-components will be repaired or replaced before being transported to the test site. A small amount of consumables and frequently needed spare parts will be maintained in the testing trailer. Major sub-component failures will be handled on a case-by-case basis (e.g., by renting replacement equipment or buying replacement parts).

The instruments used to make electric power measurements are new, having been purchased for this verification. They will be inspected at the GHG Center's laboratory prior to installation in the field to ensure all parts are in good condition. The equipment used to make flow measurements and ambient measurements are maintained by the Center's Environmental Studies Group. The mass flow meters, temperature/humidity sensors, gas pressure sensor, and barometric pressure sensors will be shipped to the manufacturer for calibration prior to being transported to the test site.

3.4. INSPECTION/ACCEPTANCE OF SUPPLIES AND CONSUMABLES

EPA Protocol gases will be used to calibrate the gaseous pollutant measurement system. Calibration gas concentrations meeting the levels stated in Section 2.4 will be generated from high concentration gases for each target compound using a dilution system. Per EPA Protocol gas specifications, the actual concentration must be within ± 2 percent of the certified tag value. Copies of the EPA Protocol gas certifications will be available on-site.

The calibration gases used to calibrate the hydrocarbon analyzer used for leak detection are instrument grade gases including pure nitrogen for zero, pure methane for full scale, and methane in nitrogen mixtures for mid-range checks (2.5 percent methane in N_2 and 50 percent methane in N_2). All gases and gas mixtures are analyzed and certified by the gas supplier.

4.0 DATA ACQUISITION, VALIDATION, AND REPORTING

4.1. DATA ACQUISITION AND STORAGE

4.1.1. Continuous Meters

All sensors to be used for continuous monitoring will provide an electrical signal which can be interfaced to a computerized data acquisition system (DAS). Figure 4-1 lists the instruments that will be employed, and Table 4-1 summarizes the measurement that will be continuously logged.

Figure 4-1. Data Acquisition System Diagram

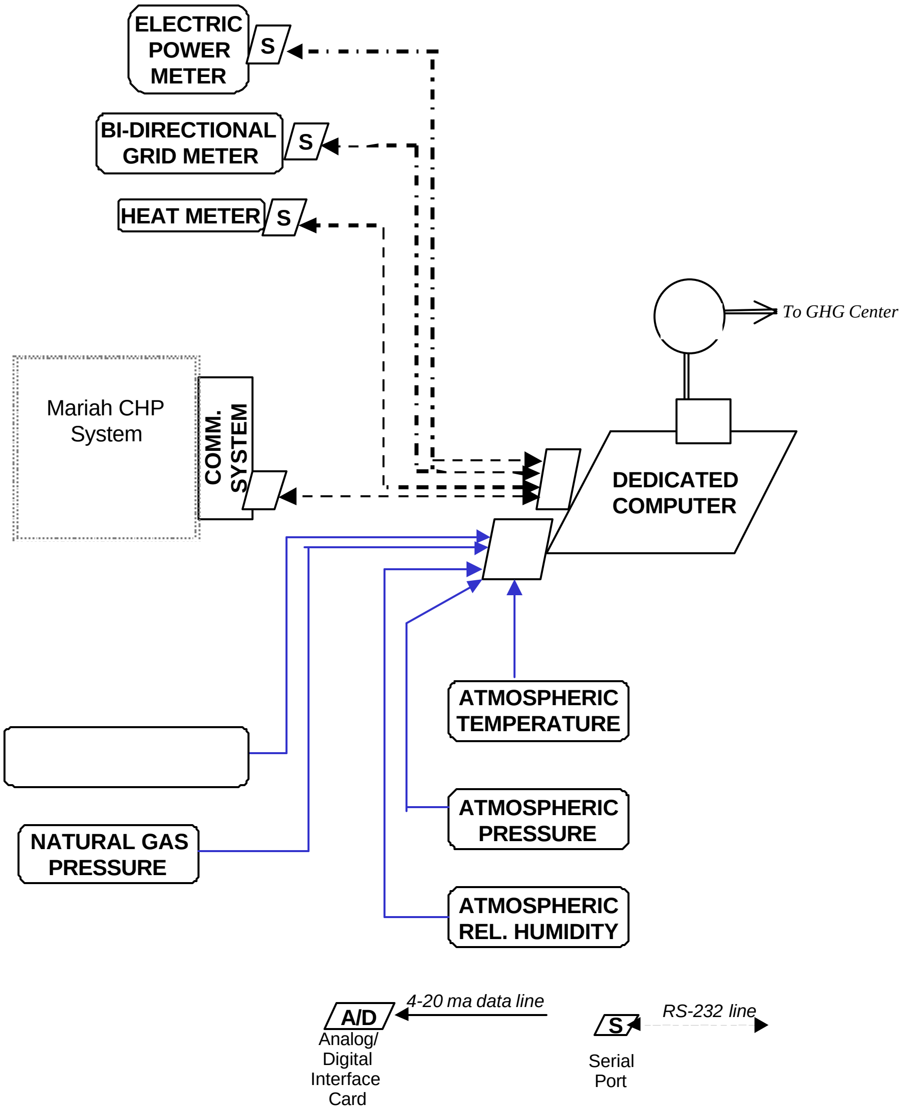


Table 4-1 Continuous Data to be Collected for Turbine Evaluation

Sensor / Source	Measurement Parameter	Purpose[1]	Significance
Rosemount 3095 Flow Meter	Natural gas flow rate (scfm)	P	System performance parameter
	Natural gas temperature (°F)		
Rosemount pressure transducer	Natural gas pressure (psi)	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
Electric Meter 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
	Power Output (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
CHP Communication system (Input)	Power Command (kW)	P	User input parameter
	Start / Stop schedule	P	User input parameter
CHP Communication System (Output)	Date, time	D/S	System operational parameter
	Engine speed (rpm)	D/S	System operational parameter
	Compressor inlet temperature (°C)	D/S	System operational parameter
	Ambient pressure (psi)	D/S	System operational parameter
	Power supply voltage (volt)	D/S	System operational parameter
	Fuel inlet pressure (psi)	D/S	System operational parameter
	Electrical frequency (Hz)	D/S	System operational parameter
	Current – Phase A (amps)	D/S	System operational parameter
	Current – Phase B (amps)	D/S	System operational parameter
	Current – Phase C (amps)	D/S	System operational parameter
	Current – Neutral (amps)	D/S	System operational parameter
	Voltage RMS - Phase A	D/S	System operational parameter
	Voltage RMS - Phase B	D/S	System operational parameter
	Voltage RMS - Phase C	D/S	System operational parameter
	Average power - Phase A (kW)	D/S	System operational parameter
	Average power - Phase B (kW)	D/S	System operational parameter
	Average power - Phase C (kW)	D/S	System operational parameter
	Total average power (kW)	D/S	System operational parameter
Arigo Heat Meter	Temperature of heated liquid exiting heat exchanger (°F)	P	System performance parameter
	Temperature of cooled liquid entering heat exchanger (°F)	P	System performance parameter
	Liquid flow rate (ft^3/min)	P	System performance parameter
	15 min. average electricity transferred (kWh)	P	System performance parameter
Bi-directional Grid Meter	15 min. average electricity transferred (kWh)	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 will be made available at the test site, and used as the accumulation point for all of the data being continuously monitored. A storage directory will be assigned on the DAS computer which will maintain delimited ASCII files. Three separate data files will store the following measurement groups of data. All data will be time synchronized with the computer clock. (Note: the electric meters have built-in features to synchronize clocks every 2 hours.)

- 4 to 20 mA output (fuel flow rate, fuel pressure, fuel temperature, ambient temperature, relative humidity, and barometric pressure)
- 7600 ION Pegasus software output (power, voltage, current, power factor, frequency, and voltage/current THD)
- CHP communication system output Arigo Heat Meter Output, and Grid Meter Power reading

The natural gas flow meter, pressure, temperature, and meteorological sensors consist of a signal conditioner/transmitter that produces a 4 to 20 mA linear output over the full scale of the sensors. These signals are transmitted to circuitry installed in the DAS computer which provides 12 bit analog to digital (A/D) conversion of the 4 to 20 mA signals. Each minute, the software associated with the A/D interface will log to the hard drive the input from each sensor. Raw data will be converted to actual measurements as shown below.

- natural gas mass flow: lbm/hr = (mA - 4)/16 * FS
- natural gas pressure: $psig = (mA - 4)/16 * FS$
- natural gas temperature: $°F = (mA - 4)/16 * FS$
- atmospheric pressure: in. Hg = (mA - 4)/16 * FS
- atmospheric temperature: $°F = (mA - 4)/16 * FS$
- atmospheric relative humidity: $\% R.H. = (mA - 4)/16 * FS$

where, mA is the mA output from the meter electronics and FS is the full-scale reading

The remaining verification instruments (7600 ION electrical power) and the CHP communication system will be connected to the DAS via an RS-232 line to three separate serial ports. Communication with the 7600 ION electrical power meter will be conducted via the PEGASYS® software supplied by the manufacturer. The software will convert, scale, and format the sensor inputs into the meter's microprocessor and electronics. Therefore, the readings of voltage, amperage, power factor, kilowatts, kilovolt-amps reactive, current, frequency, and harmonics will be directly contained as such in a standard data format file transferred from the electrical power meter to the computer DAS. The 7600 ION has an on-board data memory which stores about 48 hours of one minute data. The 1 minute collected data are queried every hour and downloaded automatically to the DAS computer.

Daily performance data files will be retrieved and stored in the hard drive of a dedicated computer at the GHG Center's RTP office. The GHG Center staff will review, validate, and verify the data, and generate summary statistics and trend plots to assess the CHP system performance as discussed in Section 2.0 and check for unusual or changing conditions. The site will be notified for potential malfunctions of measurement instruments. Each week, hard copies of the daily data files will be stored onto a disk or CD. Record keeping procedures, document control procedures, and data storage/retrieval procedures outlined in the GHG Center's QMP will be followed.

During field testing, the Field Team Leader will retrieve, review, and validate the electronically collected data at the end of each load testing. To determine if the criteria for electrical efficiency determinations are met, time series power output, power factor, gas flow rate, ambient temperature, and ambient pressure will be processed using the statistical analysis tool in Microsoft Excel®. If it is determined that maximum permissible limits for each variable, calculated at a 95 percent confidence level, are satisfied, the electrical efficiency measurement goal will be met. Conversely, the load testing will be repeated until maximum permissible limits are attained. Data for this task will be maintained by computer and by handwritten entries. Observations and test run sheets will be recorded manually in a log form developed exclusively for this task (Appendix A-2). Disk copies of the Excel spreadsheet results will be made at the end of each day. The Field Team Leader will report the following results to the Project Manager:

- Electrical power generated at selected loads
- Fuel flow rate at selected loads
- Electrical efficiency at selected loads (estimated until gas analyses results are submitted)
- Heat recovery and use rate at selected loads (estimated until PG analyses results are submitted)
- Thermal efficiency at selected loads
- Net CHP system efficiency

Data quality assurance checks for the instruments illustrated in Figure 2-1 were discussed in Sections 2.0 and 3.0. Manual and electronic records (as required) resulting from these checks will be maintained by the Field Team Leader.

After the completion of the control test, the manually recorded information will be maintained in labeled three ring binders. The binders and electronic copies of data output and statistical analyses will be stored at the GHG Center's RTP office per guidelines described in the GHG Center's QMP.

4.1.2. Emission Measurements

Data measurement and collection activities will consist of initial pretest QA steps to the passing of the data to the Field Team Leader. The emissions contractor may use software, such as the Strawberry Tree STRATA Data Acquisition System (STRATA®) or equivalent system, to record the concentration signals from the individual monitors. The data acquisition system records instrument output at one-second intervals, and will average those signals into 1-minute averages. At the conclusion of a test run, the pre- and post-test calibration results and test run values will be electronically transferred from DAS into a Microsoft Excel spreadsheet for data calculations and averaging.

The emissions contractor will report emission measurements results to the Field Team Leader as:

- Parts per million by volume (ppmv)
- ppmv connected to 15 percent O_2
- Emission rate (lb/hr)

Upon completion of the field test activities, the emissions contractor will provide copies of records of calibration, pre-test checks (stratification, system response time, and NO_2 converter), and field test data to Field Team Leader prior to leaving the site. A formal report will be prepared by the contractor and submitted to Center Field Team Leader within three weeks of completion of the field activities. The report will describe the test conditions, documentation of all QA/QC procedures, including copies of calibrations, certificates of calibration gases, and the results of the testing. Field data will be included as an appendix and an electronic copy of the report will be submitted. The submitted information will be stored at the GHG Center's RTP office per guidelines defined in the QMP.

4.1.3. Fuel Gas Sampling and PG Mixture Sampling

Fuel gas and PG solution sampling and QA/QC procedures are discussed in Section 2.0. The Field Team Leader will maintain manual fuel sampling logs and chain of custody records. After the field test, the laboratory will submit results for each sample, calibration records, and repeatability test results to the Field Team Leader. The information submitted will be stored in labeled three ring binders. The binders and electronic copies of data output and statistical analyses will be stored at the GHG Center's RTP office per guidelines described in the GHG Center's QMP. The Field Team Leader will compute the actual electrical and thermal efficiency at each load tested. The results will be reported to the Project Manager.

4.2. DATA REVIEW, VALIDATION, AND VERIFICATION

Data review and validation will primarily occur at the following stages:

- On-site following each test run – by the Field Team Leader
- On-site following completion of each load testing – by the Field Team Leader
- After fuel gas analyses results are submitted by Core Laboratories - by the Field Team Leader
- After PG liquid analyses results are submitted by laboratory - by the Field Team Leader
- At GHG Center Office each week – by the Field Team Leader
- Before writing the draft verification test report – by the Project Manager
- During QA review of the draft report and audit of the data – by Center QA Manager

Upon review, all data collected will be classed as either valid, suspect, or invalid. The criteria used to review and validate the data will be QA/QC criteria specified in Table 3-3 and determination of DQI goals discussed in Section 3.2. In general, valid results are based on measurements meeting data quality objectives, and that were 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 will be investigated in the field for load testing and weekly for continuous testing. Anomalous data may be considered suspect if no specific operational cause to invalidate the data are found. All data, valid, invalid, and suspect will be included in the final report. However, report conclusions will be based on valid data only. The reasons for excluding any data will be justified in the report. Suspect data may be included in the analyses, but may be given special treatment as specifically indicated. If the DQI goals cannot be met due to excessive data variability (e.g., ambient temperature), the data will be presented to the Project Manager and QA Manager. Based on this, a decision will be made to either continue the test or collect additional data or terminate the test and report the data obtained.

Those individuals responsible for onsite data review and validation are noted above. The QA Manager reviews and validates the data and the draft report using the Test/QA Plan and test methods. The data review and data audit will be conducted in accordance with Center's QMP. The procedures that will be followed are summarized in Section 4.5.

4.3. RECONCILIATION WITH DATA QUALITY OBJECTIVES

DQOs were defined in Section 3.1. The reconciliation of the results with the DQO will be evaluated using the DQI process. When the primary data is collected, the data will be reviewed to ensure that they are valid and are consistent with what was expected. In addition, the data will be reviewed to identify patterns, relationships, and potential anomalies. The quality of the data will be assessed in terms of accuracy and statistical significance as they relate to the stated DQI goals. Attainment of the DQI accuracy goals will be confirmed by analyzing the test data as described in Section 3.2. The statistical analysis will be done by the Field Team Leader at the conclusion of each load testing as described in Sections 2.2 through 2.4 and Section 3.0. If the accuracy goals were satisfied, it will be concluded that DQOs are met. Conversely, if the test is found to not meet the DQI goals, the DQO for electrical and thermal efficiency will be re-computed. Accuracy determinations for electrical and thermal efficiency will be based on accuracy of one of more measurement instruments used in reporting these verification parameters. For example, electrical efficiency is computed using measured power output, fuel flow rate, and fuel lower heating value (Equation 1). Section 3.0 identifies methods for determining accuracy achieved for individual instruments (e.g., manufacturer calibrations, independent verification, and reasonableness checks) used in reporting the performance of this verification parameter. If the accuracy achieved is determined to be different than the pre-specified DQI goals, the DQO for electrical efficiency will be recomputed using Equation 1. For example, independent performance check of the Rosemount flow meter must be performed by comparing its readings with a dry gas meter. Accuracy achieved is computed as the average of the percent difference between the two measurements. If the computed accuracy is determined to be less than the stated DQI goal for fuel flow rate measurement (± 1 percent), the DQO for electrical efficiency will be recomputed.

Emissions testing DQOs will be met because tests will be repeated until DQI goals are achieved.

Results from verification testing of the CHP system will be presented in a Verification Statement and a Verification Report as described in Section 4.5.4. All data and analyses performed will be transparent in the Final Report and the statement. Potential limitations on the use of the data resulting from reconciliation issues will be identified during the test by the Field Team Leader, and corrective actions will be taken in the field after consultation with the Project Manager. Results of corrective actions and re-computation of the DQOs will be made transparent in the Verification Report and the Statement.

4.4. ASSESSMENTS AND RESPONSE ACTIONS

The quality of the project and associated data are assessed within the project by the Field Team Leader, Project Manager, QA Manager, Center Director, and technical peer reviewers. Assessment and oversight of the quality for 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/QA Plan are assessed through project reviews, in-phase inspections, audits, and data quality assessment.

4.4.1. Project reviews

The review of project data and the writing of project 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 and assessed to determine that the data meet the measurement quality objectives, it is the Project Manager who must assure that overall the project activities meet the measurement and data quality objectives. The second review of the project is performed by the GHG Center Director, who is responsible for ensuring that the project's activities adhere to the requirements of the program. The GHG Center Director's review of the project will also include an assessment of the overall project operations to ensure that the Field Team Leader has the equipment, personnel, and resources to complete the project as required and to deliver data of known and defensible quality. The third review is that of the QA Manager, who is responsible for assuring that the program management systems are established and functioning as required by the QA Manual and corporate policy. The QA Manager is the final reviewer within the Southern Research Institute organization, and is responsible for assuring that contractual requirements have been met.

The draft document is then reviewed by Mariah, followed by an independent review by NRCAN/CANMET and selected Stakeholders (minimum of two industry experts). The external peer reviews are conducted by technically competent persons who are familiar with the technical aspects of the project, but 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. Further details on project review requirements can be found in the GHG Center's QMP.

The draft report will then be submitted to EPA QA personnel, and all comments will be addressed by the project Manager. Following this review, the Verification Report and Statement will undergo various EPA management reviews, including EPA Pilot Manager, EPA ORD Laboratory Director, and EPA Technical Editor.

4.4.2. Inspections

Inspections may be conducted by the Field Team Leader, Project Manager, or QA Manager. Inspections assess activities that are considered important or critical to key activities of the project. These critical activities may include, but are not limited to, pre- and post-test calibrations, the data collection equipment, sample equipment preparation, sample analysis, or data reduction. Inspections are assessed with respect to the Test Plan or other established methods, and are documented in the field records. The results of the inspection are reported to the Project Manager and QA Manager. Any deficiencies or problems found during the inspections must be investigated and the results and responses or corrective actions reported in a Corrective Action Report (CAR). This report is discussed later in Section 4.5.3.

4.4.3. Audits

Independent systematic checks to determine the quality of the data will be performed on the activities of this project. These checks will consist of a performance evaluation audit and data audit as described below. In addition, the internal quality control measurements will 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 this project.

The QA Manager is responsible for ensuring the audits are conducted as required by the Test/QA 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. A summary report of the findings and corrective actions is prepared and distributed to the Project Manager and Center Director.

4.4.3.1. Performance Evaluation Audit

The performance evaluation audit (PEA) is designed to check the operation of the Entech emissions testing analytical system. The method of performance will be based on internal audits performed by the Field Team Leader. As discussed in Section 2.4, performance samples, obtained from the gas supplier, will contain analytes at a known (determined) concentration and will be presented to the Entech 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 will evaluate the performance data for compliance with the requirements of the project. The PEA will occur on-site during the field test. The specific measurement and data quality objectives for method performance samples have been described earlier.

The PEA will also require checking the operation of the mass flow meter (i.e., comparison of Rosemount Integral Orifice meter with the dry gas meter). The natural gas heating value and PG concentration measurements will also be audited by providing each laboratory with blind samples of natural gas and PG solution with known quality.

4.4.3.2. Audit of Data Quality

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

The ADQ, as part of the system audit, is not an evaluation of the reliability of the data presentation. The review of the data presentation is the responsibility of the Project Manager and the technical peer reviewer.

4.5. DOCUMENTATION AND REPORTS

During the different activities on this project, documentation and reporting of information to management and project personnel is critical. To insure the complete transfer of information to all parties involved in this project, the following field test documentation, QC documentation, corrective action/assessment report, and verification report/statements will be prepared.

4.5.1. Field Test Documentation

The Field Team Leader will record all field activities. The Test Leader reviews all data sheets and maintains them in an organized file. The required test information was described earlier in Section 6.1. The Field Team Leader will 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. This person will also maintain documentation for the continuos operation of the turbine, after the field test is completed. Any problems found during testing requiring corrective action will be reported immediately by the field test personnel to the Field Team Leader through a Corrective Action Report. The Field Team Leader will document this in the project files and report it to the Project Manager and QA Manager.

Following each test run, the Project Manager will check the test results with the assistance of the Field Team Leader to determine whether the run met the method QA criteria. Following this review and confirmation that the appropriate data were collected and DQOs were satisfied, the GHG Center Director will be notified.

At the end of each test day, the Field Team Leader will collect all of the data from the field team members, which will include data sheets, data printouts, back-up copies of electronic files stored on computer, and field notebook. A copy of the field test documentation will be submitted to the Project Manager, and originals will be stored in the project records, as required by the QMP.

4.5.2. QC Documentation

After the completion of verification tests, test data, sampling logs, calibration records, certificates of calibration, and other relevant information will be stored in the project file in Center's RTP office. Calibration records will include information about the instrument being calibrated, raw calibration data, calibration equations, analyzer identifications, calibration dates, calibration standards used and their traceabilities, calibration equipment, and staff conducting the calibration. These records will 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 data quality objectives 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 is required on all corrective actions (Figure 4-2).

Since the tasks of this study involve a validations process to ensure data quality for the technology being verified, predetermined limits for the data acceptability have been established in the measurement and data quality objectives. Therefore, data determined to deviate from these objectives require evaluation through immediate corrective action process. Immediate corrective action responds quickly to improper procedures, indications of malfunctioning equipment, or suspicious data. The analyst, as a result of calibration checks and internal quality control sample analyses, will most frequently identify the need for such an action. The Field Team Leader will be notified of the problem immediately. The Field Team Leader will then notify the Project Manager, who will take and document appropriate action. The Project Manager is responsible for and is authorized to halt the work if it is determined that a serious problem exists.

The Field Team Leader is responsible for implementing corrective actions identified by the Project Manager, and is authorized to implement any procedures to prevent the recurrence of problems.

After technical assessments, the QA Manager will submit the Assessment Report to the Project Manager and Center Director. The Project Manager will submit the Assessment Report to the EPA Pilot Manager and QA Manager for information purposes.

The results of TSAs, inspections, PEAs, and ADQs conducted by the QA Manager will be routed to the Project Manager for review, comments, and corrective action. The results will be documented in the project records. The Project Manager will take any necessary corrective action needed and will respond via the Corrective Action Report to the QA Manager. Inspections conducted by the QA Manager will be reported to the Project Manager in the same manner as other audits. The results of all assessments, audits, inspections, and corrective actions for the task will be summarized and used in the Data Quality section in the final report.

Figure 4-2. Corrective Action Report

Corrective Action Report

Verification Title: ______________________________

Verification Description: ________________________

Description of Problem: _______________________________

____

____

____

Originator: _______ **Date:** ________

Investigation and Results: ____________________________

____

____

____

Investigator: _______ **Date:** ________

Corrective Action Taken: ______________________________

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____

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Originator: _______ **Date:** ________
Approver: _______ **Date:** ________

Carbon copy: Project Manager, Center Director, Center QA Manager, Pilot Manager

4.5.4. Verification Report and Verification Statement

A draft Verification Report and Statement will be prepared within 6 weeks of completing the field test by the Project Manager. The Project Manager will submit the draft verification report and statement to the QA Manager and Center Director for review. The final Verification Report will contain a Verification Statement, which is a 3 to 4 page summary of the Turbine system, the test strategy used, and the verification results obtained. The Verification Report will summarize the results for each verification parameter discussed in Section 2.0 and will contain sufficient raw data to support findings and allow others to assess data trends, completeness, and quality. Clear statements will be provided which characterize the performance of the verification parameters. A preliminary outline of the report is shown below.

Preliminary Verification Report Outline

Verification Statement

Section 1: *Verification Test Design and Description*
Description of the ETV program
Turbine 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 Mariah*

Appendices: *Raw Verification and Other Data*

The report will then be submitted to Mariah for review, and after modifications are made, will be submitted simultaneously to at least two representatives of the GHG Center's DG Technical Panel and the U.S. EPA Quality Assurance Team. When the final draft is prepared, officials from U.S. EPA's Office of Research and Development and the GHG Center will sign the Verification Statement. The report and statement will be posted on the GHG Center's and ETV web sites, and copies will be distributed to the reviewers.

4.6. TRAINING AND QUALIFICATIONS

The GHG Center's Field Team Leader has extensive experience (+15 years) in field testing of air emissions from gas turbines, and the Field Support person has over +20 years experience conducting power measurements. They are familiar with the requirements of all of the test methods and standards that will be used in the verification test. The Project Manager has performed numerous field verifications under the ETV program, and is familiar with requirements mandated by the EPA and Center QMPs. The

QA Manager is an independently appointed individual whose responsibility is to ensure the GHG Center's activities are performed according to the EPA approved QMP. The participants working on behalf of the GHG Center in support of this verification are selected by the GHG Center and evaluated by EPA. Evaluation criteria include relevant education, work experience, and experience in quality management. These qualifications are documented in project personnel resumes and files, as required by the GHG Center's QMP. Each field crew member will be thoroughly familiar with this Test Plan, the measurement equipment, procedures, and method for their assigned jobs. All field test personnel will receive a safety briefing by the GHG Center Field Team Leader.

The nature of the tests to be performed do not require formal certifications by state, federal, or local authorities. However, special software training was obtained from Rosemount, Power Measurements, and Rochester to install, configure, and operate their instruments. The GHG Center has used the Rosemount mass flow meter in past verifications, and is familiar with its operation and QA/QC requirements.

4.7. HEALTH AND SAFETY

This Section applies to Center personnel only. Other organizations involved in the project have their own health and safety plans specific to their roles in the project.

All work conducted as a part of this verification test will conform to applicable OSHA safety standards. All contractors and sub-contractors which may be used to perform such work must agree to meet or exceed these standards in their project work.

All electrical installations and connections will be performed by a licensed electrician. All electrical equipment and connections installed, as a part of this test will be conducted in accordance with the National Electrical Code (NEC) or state and local electrical codes, whichever are most stringent. All mechanical and gas installation and connections will conform to applicable ASME and ANSI codes, or applicable state and local codes, whichever are most stringent.

5.0 REFERENCES

American National Standards Institute / American Society of Heating, Refrigeration And Air-Conditioning Engineers, *Method of Testing Thermal Energy Meters for Liquid Streams in HVAC Systems* – ANSI/ASHRAE 125, Atlanta, Georgia, 1992.

American Society of Heating, Refrigeration And Air-Conditioning Engineers. *Physical Properties of Secondary Coolants (Brines),* F20IP, Chapter 20, Atlanta, Georgia, 1997.

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Code of Federal Regulations, Title 40, Part 60 (Subpart GG), *Standards of Performance for Stationary Gas Turbines*, United Environmental Protection Agency, Washington, D.C. 1999.

Emissions Quantification Working Group. *Final Report of the Emissions Quantification Working Group*, September 1999.

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Greenhouse Gas Emission Reduction Trading Pilot (GERT). Project Documentation, Green Power Sale by Enmax, and Purchase by Her Majesty in Right of Canada, with Assignment and Transfer of CO2 Emission Reductions, http://www.gert.org, August 2, 1999.

Huang, Y.J., H. Akbari, L. Rainer, and R. Ritschard. 481 Prototypical Commercial Buildings for Twenty Urban Market Areas, Gas Research Institute, GRI-90/0326, Chicago, IL, Lawrence Berkeley Laboratory, LBL-29798. Berkeley, CA, 1991.

Institute of Electrical and Electronics Engineers, *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*, IEEE Std 519-1992, New York, New York, April 1993.

Southern Research Institute. *Environmental Technology Verification Greenhouse Gas Technology Verification Quality Management Plan, Research Triangle Park*, NC, October 1998.

U.S. Department of Energy and U.S. Environmental Protection Agency. *Carbon Dioxide Emissions from the Generation of Electric Power in the United States*, http://www.eia.doe.gov/cneaf/electricity, July 2000.

APPENDIX A
Test Procedures and Field Log Forms

Appendix A-1. Load Testing Procedures

1. In the CHP System Communications Software, select 100 percent 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 CHP 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. Obtain a minimum of one PG sample from the fluid return line. Follow procedures outlined in Appendix A-6.

6. 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)	± 2 %
Power factor	± 2 %
Fuel heating value	± 1 %
Fuel flow	± 1 %
Barometric pressure	± 0.5 %
Ambient air temperature	± 4 ^{o}F

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

8. Repeat Steps 1 through 7 by changing the operating load to 90, 75, and 50 percent. 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 .... _______ %

Heat Recovery Rate _________ Btu/min

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 .... _______ %

Heat Recovery Rate _________ Btu/min

Heat Use Rate _________ Btu/min

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

Load Testing Duration Time __________ minutes *(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 Core Laboratories along with completed chain-of-custody form.
   Core Laboratories' Analytical Procedures:

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

Appendix A-4. Fuel Sampling Log (Cont'd)

Project: ____________________

Location: ____________________

Source: ____________________

Sampler: ____________________

Ambient Pressure: ____________________________

Ambient Temperature: ____________________________

____

____

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

Appendix A-5. Fuel Sampling Chain of Custody Record

Project: Mariah Energy Corp. Microturbine CHP
Location: Calgary, Alberta
Sampler:
Source ID: Fuel Header
Matrix: Natural Gas

Sampling Date(s):
Shipping Date:
Laboratory: Core Laboratories
Ship to:
Calgary, Alberta

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. Propylene Glycol Sampling Procedures

1) Connect pre-cleaned, 100 to 500 ml glass vials to the fluid discharge spout located on the hot side of the heat recovery unit.

2) Open fluid discharge spout, collect sample until vials are at least 1/2 full.

3) Close the spout. Record date, time, and vial ID number (Appendix A-7) on proper chain-of-custody form (Appendix A-8).

4) Return collected samples to Philip Analytical Laboratories along with completed chain-of-custody form.

   Philip Laboratories' Analytical Procedures:

   a) Samples are received with proper chain-of-custody form and logged into the laboratory system for analysis.
   b) Samples are injected and analyzed. The GC determines concentrations based on the areas of the chromatograph peaks relative to the gas standard.
   c) Duplicate analysis is conducted on one sample per lot.
   d) Hard copies of calibration records, fluid concentration, and fluid density will be submitted to the GHG Center.
   e) Determine accuracy based on the replicates.

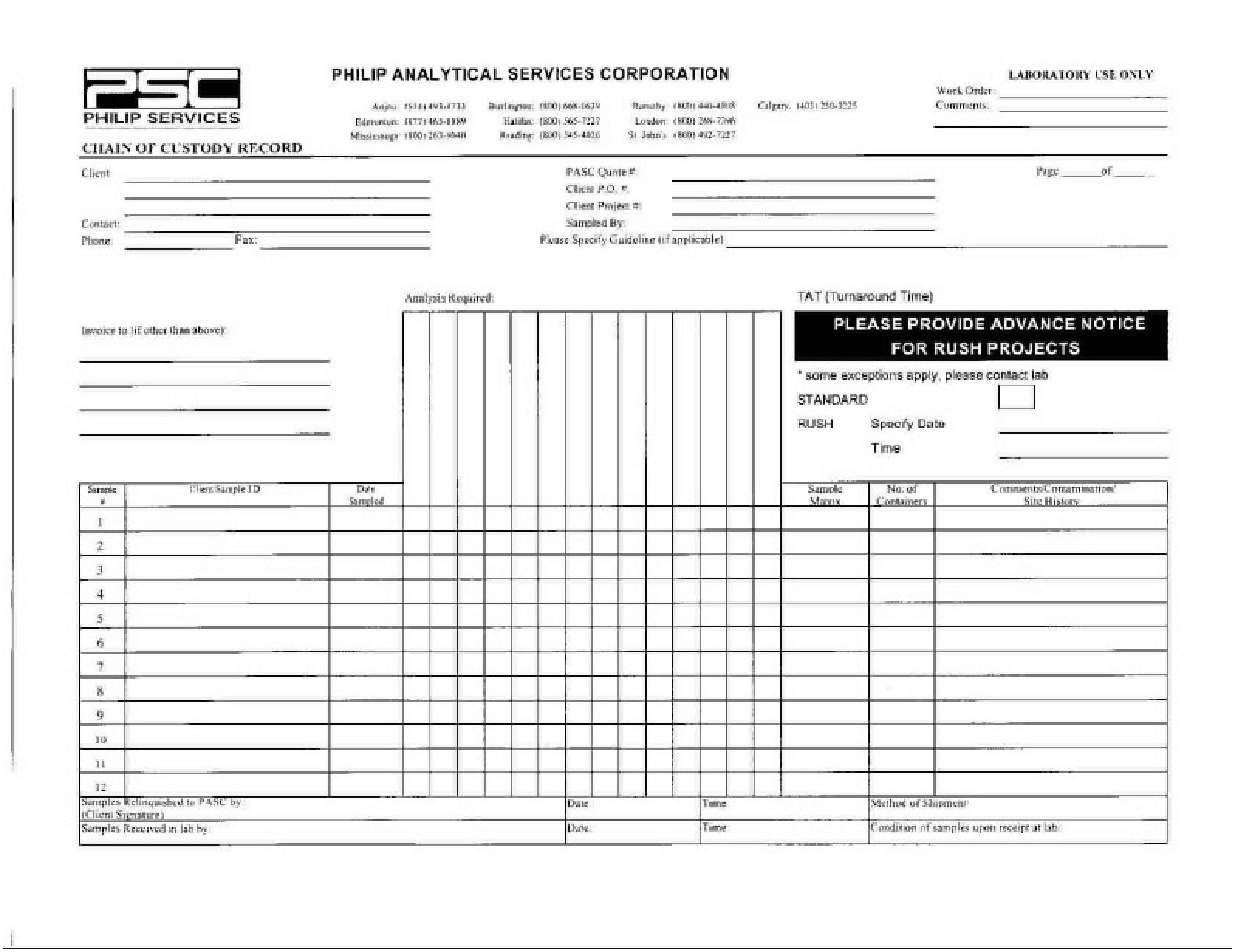
Appendix A-7. Propylene Glycol Sampling Log

Project: ____________________
Location: ____________________
Source: ____________________
Sampler: ____________________

Ambient Pressure: ____________________
Ambient Temperature: ____________________
____
____

Sample ID	Date	Time	Fluid Temp. (^oC)	Sample size (ml)

Appendix A-8. Propylene Glycol Sampling Chain of Custody Record



PSC
PHILIP SERVICES

PHILIP ANALYTICAL SERVICES CORPORATION

Anjou: (514) 493-4733	Burlington: (800) 668-1639	Burnaby: (800) 440-4808	Calgary: (403) 250-3225
Edmonton: (877) 463-8889	Halifax: (800) 565-7227	London: (800) 268-7396	
Mississauga: (800) 263-9040	Reading: (800) 345-4026	St. John's: (800) 492-7227	

LABORATORY USE ONLY
Work Order: ____________
Comments: ____________

CHAIN OF CUSTODY RECORD

Client ____________
Contact: ____________
Phone: ________ Fax: ________

PASC Quote #: ____________
Client P.O. #: ____________
Client Project #: ____________
Sampled By: ____________
Please Specify Guideline (if applicable) ____________

Page ______ of ______

Invoice to (if other than above):

Analysis Required:

TAT (Turnaround Time)

PLEASE PROVIDE ADVANCE NOTICE FOR RUSH PROJECTS

* some exceptions apply, please contact lab

STANDARD ☐

RUSH Specify Date ____________
Time ____________

Sample #	Client Sample ID	Date Sampled															Sample Matrix	No. of Containers	Comments/Contamination/ Site History
1																			
2																			
3																			
4																			
5																			
6																			
7																			
8																			
9																			
10																			
11																			
12																			

Samples Relinquished to PASC by: (Client Signature)	Date:	Time:	Method of Shipment:
Samples Received in lab by:	Date:	Time:	Condition of samples upon receipt at lab:

Appendix A-9. Density of Propylene Glycol (lb/ft^3)

Concentrations in Volume Percent Propylene Glycol

Source: ASHRAE 1997 (pg. 20.8)

Temp (F)	10%	20%	30%	40%
-30				
-20				
-10				
0				65.71
10			65	65.6
20		64.23	64.9	65.48
30	63.38	64.14	64.79	65.35
40	63.3	64.03	64.69	65.21
50	63.2	63.92	64.53	65.06
60	63.1	63.79	64.39	64.9
70	62.98	63.66	64.24	64.73
80	62.86	63.52	64.08	64.55
90	62.73	63.37	63.91	64.36
100	62.59	63.2	63.73	64.16
110	62.44	63.03	63.54	63.95
120	62.28	62.85	63.33	63.74
130	62.11	62.66	63.12	63.51
140	61.93	62.46	62.9	63.27
150	61.74	62.25	62.67	63.02
160	61.54	62.03	62.43	62.76
170	61.33	61.8	62.18	62.49
180	61.11	61.56	61.92	62.22
190	60.89	61.31	61.65	61.93
200	60.65	61.05	61.37	61.63
210	60.41	60.78	61.08	61.32
220	60.15	60.5	60.78	61
230	59.89	60.21	60.47	60.68
240	59.61	59.91	60.15	60.34
250	59.33	59.6	59.82	59.99

Appendix A-10. Specific Heat of Propylene Glycol (Btu/lb F)

Concentrations in Volume Percent Propylene Glycol
Source: ASHRAE 1997 (pg. 20.8)

Temp (F)	10%	20%	30%	40%
-30				
-20				
-10				
0				0.855
10			0.898	0.859
20		0.936	0.902	0.864
30	0.966	0.938	0.906	0.868
40	0.968	0.941	0.909	0.872
50	0.97	0.944	0.913	0.877
60	0.972	0.947	0.917	0.881
70	0.974	0.95	0.92	0.886
80	0.976	0.953	0.924	0.89
90	0.979	0.956	0.928	0.894
100	0.981	0.959	0.931	0.899
110	0.983	0.962	0.935	0.903
120	0.985	0.965	0.939	0.908
130	0.987	0.967	0.942	0.912
140	0.989	0.97	0.946	0.916
150	0.991	0.973	0.95	0.921
160	0.993	0.976	0.953	0.925
170	0.996	0.979	0.957	0.929
180	0.998	0.982	0.961	0.934
190	1	0.985	0.964	0.938
200	1.002	0.988	0.968	0.943
210	1.004	0.991	0.971	0.947
220	1.006	0.994	0.975	0.951
230	1.008	0.996	0.979	0.956
240	1.011	0.999	0.982	0.96
250	1.013	1.002	0.986	0.965

APPENDIX B
Quality Assurance/Quality Control Checks and Log Forms

Appendix B-1. 7600 ION Installation and Setup Checks

Date ___________ Lead installer name _________________________________

Initial all items after they have been completed.

NOTE: In all events, conformance to applicable local codes will supercede the instructions in this log sheet or the installation manual.

_____ Prior to commencement of installation, **obtain and read the *7600 ION INSTALLATION & BASIC SETUP MANUAL*.** The points outlined here were developed as a guideline using the instructions in the *7600 ION INSTALLATION & BASIC SETUP MANUAL,* but should any information or instructions in the manual not be listed here, those steps should not be skipped or ignored. A reference page number listed as [*x*] will be included for each point, as appropriate.

_____ Verify that the meter enclosure is mounted in a location to provide ventilation around the case in an area free of oil, moisture, excessive dust and corrosive vapors. All wiring will conform to applicable NEC standards.

_____ Connect to power supply to the 7600 ION (**85 to 240 VAC**) via a **switch or circuit breaker** using **AWG 12** to **AWG 14 wire**. Connect the line supply wire to the L/+ terminal and the neutral supply wire to the N/- using a compatible plug. [7]

_____ Connect the ground terminal of the 7600 ION to the switchgear earth ground using AWB 12 wire or larger. [8]

_____ Make voltage and current transformer (CT) connections to the 7600 ION according to the type of electrical connection according to the directions in the Manual [pages 8-14]. To provide a maximum input of 20 amps for a current flow of 200 amps, 10:1 ratio CTs should be used.

AWG 12 to 14 wire is recommended for all phase voltage and current connections.

_____ Use a digital multimeter (DMM) to check that the phase and polarity of the AC voltage inputs are correct.

_____ Connect the DAS to the DB9 serial connector on the back of the 7600 ION via a **null modem**. [18]

_____ Set-up the 7600 ION according to the instructions in the Manual [pages 24-29].

_____ Verify the operation of the 7600 ION according to the instructions in the Manual [30].

_____ Using a DMM measure each of the phase voltage and currents and compare them to the readings on the display of the 7600 ION. The readings on the DMM should agree (within the tolerance of the meters) with the readings from the 7600 ION. If they do not agree, modify the connections to the 7600 ION until they are correct. Also check both readings for reasonability.

_____ The readings of the 7600 ION agree with the DMM readings and are reasonable for this connection.

_____ Confirm that the readings on the 7600 ION agree with the corresponding readings on the DAS. If they do not agree, troubleshoot the communications link until proper readings are obtained by the DAS.

_____ The readings of the 7600 ION agree with the DAS readings.

_____ Verify that the readings are being properly stored on the DAS harddisk or other non-volatile memory

Appendix B-2. 7600 ION Sensor Function Checks

Date ___________

QA/QCTest leader name _________________________________

Initial all items after they have been completed.

_____ 7600 ION calibration certificates and supporting data are on-hand.

_____ Check power supply voltage with a DMM (should be between **85 to 240 VAC.**)

_____ Check the 7600 ION ground terminal connection for continuity with the switchgear earth ground.

_____ Use a digital multimeter (DMM) to check that the phase and polarity of the AC voltage inputs are correct.

_____ Verify the operation of the 7600 ION according to the instructions in the *7600 ION INSTALLATION & BASIC SETUP MANUAL* [page 30].

_____ Using a DMM measure each of the phase voltage and currents and compare them to the readings on the display of the 7600 ION. The readings on the DMM should agree (within the tolerance of the meters) with the readings from the 7600 ION. If they do not agree, note the readings from each source on the back of this sheet, along with the date and time of the readings.

_____ The readings of the 7600 ION agree with the DMM readings.

_____ Confirm that the readings on the 7600 ION agree with the corresponding readings on the DAS. If they do not agree, troubleshoot the communications link until proper readings are obtained by the DAS.

_____ The readings of the 7600 ION agree with the DAS readings.

_____ Verify that the readings are being properly stored on the DAS harddisk or other non-volatile memory.

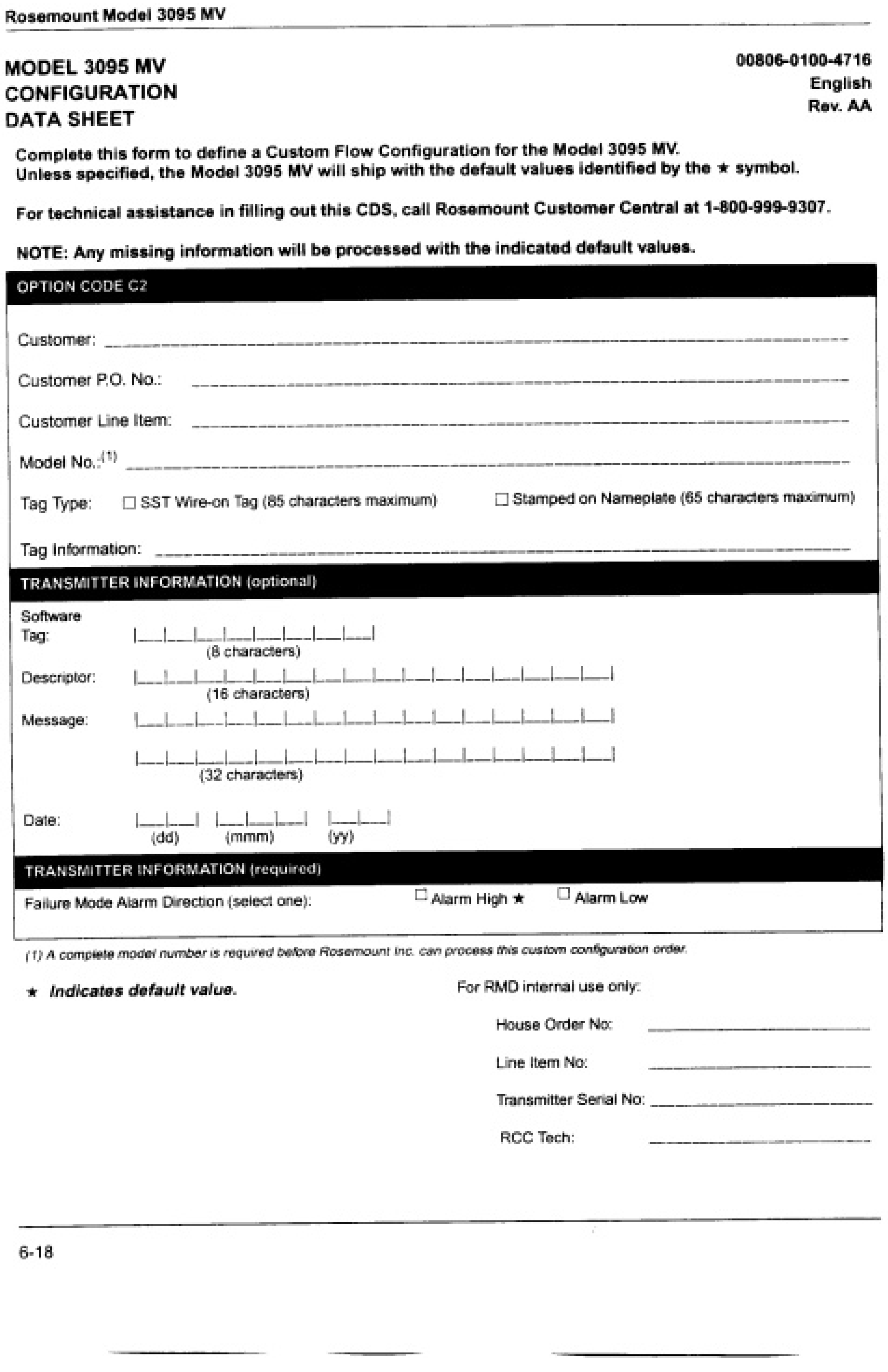
Appendix B-3. Rosemount 3005 Installation and Setup Checks/Log Form

Manufacturer's installation checks: Field installation procedures are well documented in Rosemount's "Model 3095 MV Product Manual", and will not be repeated here in entirety. Center testing personnel will follow all required procedures to ensure that checks for process connections, leaks, field wiring, and ground wiring are conducted properly. The Product Manual will be made available during installation. Following manual specifications, meter installation will be conducted using the following considerations:

1. The meter will be installed vertically in the 1-inch diameter fuel line in a safe, accessible, and vibration free section of pipe.
2. Installation will include sufficient straight run of pipe (no less than 20 diameters) upstream and downstream of the meter.
3. Temperature sensors will be installed in the piping and wired to the transmitters for continuous temperature compensation.
4. All mechanical connections will be leak checked.
5. All electrical connections will be made following manufacturer specifications and tested.

Manufacturer's setup and start-up checks: In each flow sensor element, a transmitter calculates mass from differential pressure across an integral orifice element. To perform this calculation, the transmitter electronics must be programmed with information on the gas being metered and the operating conditions. This is accomplished using Rosemount's Engineering Assistant (EA) Software, which is interfaced to the transmitter via a HART protocol serial modem. Specific setup parameters required in the EA are listed in the following pages. The GHG Center testing personnel will maintain field logs of all data entered into the EA, and subsequently transmitted to the instrument. An electronic copy of the configuration file will be maintained. Detailed guidelines are provided in the Product Manual.

Appendix B-3. Rosemount 3005 Installation and Setup Checks/Log Form (Continued)



Rosemount Model 3095 MV

MODEL 3095 MV
CONFIGURATION
DATA SHEET

00806-0100-4716
English
Rev. AA

Complete this form to define a Custom Flow Configuration for the Model 3095 MV.
Unless specified, the Model 3095 MV will ship with the default values identified by the ★ symbol.

For technical assistance in filling out this CDS, call Rosemount Customer Central at 1-800-999-9307.

NOTE: Any missing information will be processed with the indicated default values.

OPTION CODE C2

Customer: ____________________

Customer P.O. No.: ____________________

Customer Line Item: ____________________

Model No.:(1) ____________________

Tag Type: ☐ SST Wire-on Tag (85 characters maximum) ☐ Stamped on Nameplate (65 characters maximum)

Tag Information: ____________________

TRANSMITTER INFORMATION (optional)

Software Tag: |__|__|__|__|__|__|__|__| (8 characters)

Descriptor: |__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__| (16 characters)

Message: |__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|
|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__| (32 characters)

Date: |__|__| (dd) |__|__|__| (mmm) |__|__| (yy)

TRANSMITTER INFORMATION (required)

Failure Mode Alarm Direction (select one): ☐ Alarm High ★ ☐ Alarm Low

(1) A complete model number is required before Rosemount Inc. can process this custom configuration order.

★ ***Indicates default value.***

For RMD internal use only:

House Order No: ____________________

Line Item No: ____________________

Transmitter Serial No: ____________________

RCC Tech: ____________________

6-18

LCD Meter Configuration

Process Variables displayed on LCD:

☐ Absolute Pressure
☐ Analog Output Current
☐ Differential Pressure
☐ Flow
☐ Flow Total
☐ Gauge Pressure
☐ Percent of Range
☐ Process Temperature

Number of seconds to display each variable:______________________
(available ranges from 2–10 seconds, in one second increments)

FLOW CONFIGURATION (required)

Select units for each Process Variable, then enter *sensor* Lower Trim Value (LTV) and *sensor* Upper Trim Value (UTV).
Note: LTV and UTV must be within the range limits stated in the Range Limits Table (see page 6-26).

Differential Pressure:

DP Units	☐ inH$_2$O–68 °F★	☐ inHg–0 °C	☐ ftH$_2$O–68 °F	☐ mmH$_2$O–68 °F	☐ mmHg–0 °C	☐ psi
	☐ bar	☐ mbar	☐ g/SqCm	☐ Kg/SqCm	☐ Pa	☐ kPa
	☐ torr	☐ Atm	☐ inH$_2$O–60 °F			

Trim Values LTV:______________________(0 ★)__ UTV:______________________(URL inH$_2$O–68 °F ★)

Static Pressure:

Static Units	☐ inH$_2$O–68 °F	☐ inHg–0 °C	☐ ftH$_2$O–68 °F	☐ mmH$_2$O–68 °F	☐ mmHg–0 °C	☐ psi ★
	☐ bar	☐ mbar	☐ g/SqCm	☐ Kg/SqCm	☐ Pa	☐ kPa
	☐ torr	☐ Atm	☐ MPa	☐ inH$_2$O–60 °F		

Trim Values(2) LTV:______________________(0 ★)__ UTV:______________________(URL psi ★)

Process Temperature:

PT Units ☐ °F ★ ☐ °C

Trim Values LTV:______________________(–300 ★) UTV:______________________(1500 °F ★)

Flow Rate:

Flow Units:	☐ StdCuft/s	☐ StdCuft/min	☐ StdCuft/h	☐ StdCuft/d	☐ StdCum/h
	☐ StdCum/d	☐ lbs/sec	☐ lbs/min	☐ lbs/hour ★	☐ lbs/day
	☐ grams/sec	☐ grams/min	☐ grams/hour	☐ kg/sec	☐ kg/min
	☐ kg/hour	☐ NmlCuM/hour	☐ NmlCuM/day	☐ Special (see Flow Rate Special Units)	

Flow Rate Special Units (use if "Special" is checked in Flow Rate above):

NOTE: Flow Rate Special Units = Base Flow Unit multiplied by Conversion Factor.

Base Flow Units (select from above Flow Rate units): ______________________________

Conversion Factor: ______________________________

Display As: |___|___|___|___|___| *(available units A–Z, 0–9)*

Flow Rate Output:

Low PV (4 mA) ______________________________(0.00 ★) High PV (20 mA)______________________________

FLOW CONFIGURATION CONT. (required)

Flow Total:

Flow Units: ☐ Grams ☐ Kilograms ☐ Metric Tons ☐ Pounds ☐ Short Tons
☐ Long Tons ☐ Ounces ☐ NmlCuM ☐ Normal Liters ☐ StdCuM
☐ StdCuFt ☐ Special (see Flow Total Special Units)

Flow Total Special Units (use this section if "Special" is checked in Flow Total above):

NOTE: Flow Rate Special Units = Base Flow Unit multiplied by Conversion Factor.

Base Flow Units (select from above Flow Total units): ______________________________

Conversion Factor: ______________________________

Display As: |___|___|___|___|___| *(available units A–Z, 0–9)*

Flow Total Output:

Low PV (4 mA) ___________________________(0.00 ★) High PV (20 mA)_______________________________

Damping: Enter a damping value for each variable (valid range: 0.1 – 29 seconds).
(Transmitter will round to nearest available damping value.)

Differential Pressure = _______________(0.864★) Temperature = _______________(0.864★)

Static Pressure = _______________(0.864★)

(2) If absolute pressure module, then lower static pressure values must be ≥ 0.5 psia (3.45 kPa).

★ ***Indicates default value.***

NOTE ***The information on Pages 6-21–6-25 can be sent in on a floppy disk by creating a .MFL file with the EA Software or EA Demo Disk. Call 1-800-999-9307 for more information.***

PRIMARY ELEMENT INFORMATION

Select Differential Producer (Select One)
☐ 1195 Integral Orifice
☐ Annubar® Diamond II+/Mass ProBar+
☐ Nozzle, Long Radius Wall Taps, ASME
☐ Nozzle, Long Radius Wall Taps, ISO
☐ Nozzle, ISA 1932, ISO
☐ Orifice, 2½D & 8D Taps
☐ Orifice, Corner Taps, ASME
☐ Orifice, Corner Taps, ISO
☐ Orifice, D & D/2 Taps, ASME
☐ Orifice, D & D/2 Taps, ISO
☐ Orifice, Flange Taps, AGA3
☐ Orifice, Flange Taps, ISO
☐ Small Bore Orifice, Flange Taps, ASME
☐ Venturi Nozzle, ISO
☐ Venturi, Rough Cast/Fabricated Inlet, ASME
☐ Venturi, Rough Cast Inlet, ISO
☐ Venturi, Machined Inlet, ASME
☐ Venturi, Machined Inlet, ISO
☐ Venturi, Welded Inlet, ISO

Selecting Area Averaging Meter or V-Cone® requires a constant value for discharge coefficient: ____________________
☐ Area Averaging Meter ☐ V-Cone

Primary Element Minimum Diameter (d) ________________ ☐ in. ☐ mm at ___________ ☐ °F ☐ °C in. at 68 °F ★
or
Diamond II Sensor Series No. ______ (see table on page 6-26)

Differential Producer Material (Select One) ☐ Carbon Steel ☐ SST 304 ☐ SST 316★ ☐ *Hastelloy C* ☐ *Monel*

Pipe Tube Diameter (Pipe ID) (D) ______________ ☐ in. ☐ mm at ___________ ☐ °F ☐ °C in. at 68 °F ★
Pipe Tube Material: ☐ Carbon Steel★ ☐ SST 304 ☐ SST 316 ☐ *Hastelloy C* ☐ *Monel*

PROCESS OPERATING CONDITIONS

Operating Pressure Range ___________ to ____________ ☐ psia ☐ psig ☐ kPa (absolute) ☐ kPa (gage) ☐ bar

Operating Temperature Range ___________ to ____________ ☐ °F ☐ °C

For fixed process temperatures (Model Code = 0), enter value ____________________.
Valid range: –459 to 3500 °F (–273 to 1927 °C)

NOTE: For steam applications, temperatures must be equal to or greater than the saturation temperature at the given pressures.

ATMOSPHERIC PRESSURE

Atmospheric Pressure = ___________ ☐ psia ☐ kPa(absolute) ☐ bar 14.696 psia ★

STANDARD REFERENCE CONDITIONS

NOTE: This information is only required if any of the following flow units were selected: StdCuft/s, StdCuft/min, StdCuft/h, StdCuft/d, StdCum/h, StdCum/d

Standard Reference Conditions:
Standard Pressure = ________________ ☐ psia ☐ bar ☐ kPa(absolute) 14.696 psia ★
(gas/steam only)

Standard Temperature = _____________ ☐ °F ★ ☐ °C 60 °F ★ (For Steam, 212 °F ★)

★ *Indicates default value.*

FLUID TYPE (Select One)

☐ Gas ☐ Liquid

FLUID INFORMATION (Complete one section only)

☐ **Steam (ASME) Saturated and/or Superheated**

☐ **Natural Gas**

NOTE: If you selected Natural Gas, complete the information on page 6-23.

☐ **Gas or Liquid from AIChE database**: Circle **ONE** fluid name below:

Acetic Acid
Acetone
Acetonitrile
Acetylene
Acrylonitrile
Air
Allyl Alcohol
Ammonia
Argon
Benzene
Benzaldehyde
Benzyl Alcohol
Biphenyl
Carbon Dioxide
Carbon Monoxide
Carbon Tetrachloride
Chlorine
Chlorotrifluoroethylene
Chloroprene
Cycloheptane
Cyclohexane
Cyclopentane
Cyclopentene
Cyclopropane
Divinyl Ether
Ethane
Ethanol
Ethylamine
Ethylbenzene
Ethylene
Ethylene GlycolEthylene
Oxide
Fluorene
Furan
Helium–4
Hydrazine
Hydrogen
Hydrogen Chloride
Hydrogen Cyanide
Hydrogen Peroxide
Hydrogen Sulfide
Isobutane
Isobutene
Isobutylbenzene
Isopentane
Isoprene
Isopropanol
Methane
Methanol
Methyl Acrylate
Methyl Ethyl Ketone
Methyl Vinyl Ether
m–Chloronitrobenzene
m–Dichlorobenzene
Neon
Neopentane
Nitric Acid
Nitric Oxide
Nitrobenzene
Nitroethane
Nitrogen
Nitromethane
Nitrous Oxide
n–Butane
n–Butanol
n–Butyraldehyde
n–Butyronitrile
n–Decane
n–Dodecane
n–Heptadecane
n-Heptane
n–Hexane
n–Octane
n–Pentane
Oxygen
Pentafluorothane
Phenol
Propane
Propadiene
Pyrene
Propylene
Styrene
Sulfer Dioxide
Toluene
Trichloroethylene
Vinyl Acetate
Vinyl Chloride
Vinyl Cyclohexane
Water
1–Butene
1–Decene
1–Decanal
1–Decanol
1-Dodecene
1–Dodecanol
1–Heptanol
1–Heptene
1–Hexene
1–Hexadecanol
1–Octanol
1–Octene
1–Nonanal
1–Nonanol
1–Pentadecanol
1–Pentanol
1–Pentene
1–Undecanol
1,2,4–Trichlorobenzene
1,1,2–Trichloroethane
1,1,2,2–Tetrafluoroethane
1,2–Butadiene
1,3–Butadiene
1,3,5–Trichlorobenzene
1,4–Dioxane
1,4–Hexadiene
2–Methyl–1–Pentene
2,2–Dimethylbutane

☐ **Custom Gas or Liquid**

Enter your custom fluid name ______________________________

NOTE: If you are defining a custom fluid, complete the density and viscosity information on page 6-25.

★ ***Indicates default value.***

NOTE ***Only fill out this page if you selected natural gas.***

COMPRESSIBLITY FACTOR INFORMATION:

Choose desired characterization method, and only enter values for that method:

☐ Detail Characterization Method, (AGA8 1992)

		Mole	Valid Range
CH4	Methane mole percent	____ %	0–100 percent
N2	Nitrogen mole percent	____ %	0–100 percent
CO2	Carbon Dioxide mole percent	____ %	0–100 percent
C2H6	Ethane mole percent	____ %	0–100 percent
C3H8	Propane mole percent	____ %	0–12 percent
H2O	Water mole percent	____ %	0–Dew Point
H2S	Hydrogen Sulfide mole percent	____ %	0–100 percent
H2	Hydrogen mole percent	____ %	0–100 percent
CO	Carbon Monoxide mole percent	____ %	0–3.0 percent
O2	Oxygen mole percent	____ %	0–21 percent
C4H10	i-Butane mole percent	____ %	0–6 percent (1)
C4H10	n-Butane mole percent	____ %	0–6 percent (1)
C5H12	i-Pentane mole percent	____ %	0–4 percent (2)
C5H12	n-Pentane mole percent	____ %	0–4 percent (2)
C6H16	Hexane mole percent	____ %	0–Dew Point
C7H16	n-Heptane mole percent	____ %	0–Dew Point
C8H18	n-Octane mole percent	____ %	0–Dew Point
C9H20	n-Nonane mole percent	____ %	0–Dew Point
C10H22	n-Decane mole percent	____ %	0–Dew Point
He	Helium mole percent	____ %	0–3.0 percent
Ar	Argon mole percent	____ %	0–1.0 percent

(1) The summation of i-Butane and n-Butane cannot exceed 6 percent.

(2) The summation of i-Pentane and n-Pentane cannot exceed 4 percent.

☐ Gross Characterization Method, Option 1 (AGA8 Gr-Hv-CO2)

		Valid Range
Specific gravity at 14.73 psia and 60 °F	____	0.554–0.87
Volumetric Gross Heating Value at Base Conditions	____ BTU/SCF	477–1150 BTU/SCF
Carbon dioxide mole percent	____ %	0–30 percent
Hydrogen mole percent	____ %	0–10 percent
Carbon monoxide mole percent	____ %	0–3 percent

☐ Gross Characterization Method, Option 2 (AGA8 Gr-CO2-N2)

		Valid Range
Specific Gravity at 14.73 psia and 60 °F	____	0.554–0.87
Carbon dioxide mole percent	____ %	0–30 percent
Nitrogen mole percent	____ %	0–50 percent
Hydrogen mole percent	____ %	0–10 percent
Carbon monoxide mole percent	____ %	0–3 percent

★ ***Indicates default value.***

NOTE ***Only fill out this page if you selected a custom gas.***

GAS COMPRESSIBLITY AND VISCOSITY INFORMATION

1. Fill in the following operating pressures and operating temperatures.
(Min and max values must match values entered on 6-21.)

Operating Pressures

(1)__________ min

(2)__________ [$^1/_3$(max–min)]+min

(3)__________ [$^2/_3$(max–min)]+min

(4)__________ max

Operating Temperatures

(5)__________ min

(6)__________ [½ (max–min)]+min

(7)__________ max

(8)__________ [$^1/_3$(max–min)]+min

(9)__________ [$^2/_3$(max–min)]+min

2. **Transfer the values from the above section to the numbered lines below.**
3. Check one Density/Compressibility box, then enter the 12 values for each pressure/temperature range.
4. Check one Viscosity box, then enter values for each temperature. (At least one viscosity value is required.)
5. Enter values for molecular weight, isentropic exponent, and standard density (or standard compressibility).

Pressure	Temp.	☐ Density in Kg/CuM ☐ Density in Lbs/CuFt ☐ Compressibility
(1)__________	(5)______	__________________
(2)__________	(5)______	__________________
(3)__________	(5)______	__________________
(4)__________	(5)______	__________________
(1)__________	(6)______	__________________
(2)__________	(6)______	__________________
(3)__________	(6)______	__________________
(4)__________	(6)______	__________________
(1)__________	(7)______	__________________
(2)__________	(7)______	__________________
(3)__________	(7)______	__________________
(4)__________	(7)______	__________________

Temp.	☐ Viscosity in Centipoise ☐ Viscosity in Lbs/Ft sec ☐ Viscosity in Pascal sec
(5)______	____________________
(8)______	____________________
(9)______	____________________
(7)______	____________________

Molecular Weight ______________

Isentropic Exponent ____________ 1.4 ★

Standard density/compressibility ____________________
(at standard reference conditions specified on page 4)

★ ***Indicates default value.***

NOTE: Custom Gas Configuration order will be delayed if any fields on this page are left blank.

NOTE ***Only fill out this page if you have selected a custom liquid.***

LIQUID DENSITY AND VISCOSITY INFORMATION

1. Fill in the following operating temperatures. (Min and max values must match values entered on 6-21.)

Operating Temperatures

(a)___________ min

(b)___________ [$^{1}/_{3}$(max–min)] + min

(c)___________ [$^{2}/_{3}$(max–min)] + min

(d)___________ max

2. **Transfer the values from the above section to the numbered lines below.**
3. Check one Density box, then enter values for each temperature and the standard density.
4. Check one Viscosity box, then enter values for each temperature. (At least one viscosity value is required.)

Temp.	☐ Density in Lbs/CuFt ☐ Density in Kg/CuM	Temp.	☐ Viscosity in Centipoise ☐ Viscosity in Lbs/Ft sec ☐ Viscosity in Pascal sec
(a)_______	_____________________	(a)______	__________________________
(b)_______	_____________________	(b)______	__________________________
(c)_______	_____________________	(c)______	__________________________
(d)_______	_____________________	(d)______	__________________________

Standard density _____________________
(at standard reference conditions specified on page 4)

Note: Custom Liquid Configuration order will be delayed if any fields on this page are left blank.

Appendix B-4. Rosemount 3095 Sensor Function Checks/Log Form

Sensor function checks: A series of meter and transmitter function checks will be conducted before the verification period begins and again at the end of the testing. The following checks will be included.

- Power supply test to document that the facility DAS is supplying sufficient power (no less than 11 vDC) to the tranmitter.
- Analog output checks where a current of known amount will be checked against a secondary device to ensure that 4 mA and 20 mA signals are produced.
- Reasonableness checks will be performed by ensuring that the mA signal produced at the transmitter is recorded correctly in the DAS.
- Zero checks will be conducted by isolating the transmitter from the differential pressure taps using valves built into the meter, and recording the transmitter output. The sensor output must read 0 flow during these checks.

Procedures for performing these checks are documented in the Product Manual. All records will be logged in the following form.

Appendix B-4. Rosemount 3095 Sensor Function Checks/Log Form (Continued)

SENSOR FUNCTION CHECKS

1) Analog Loop Test

Date ___________

Time ___________ ___________ ___________ ___________

Meter Output (mA) ___________ ___________ ___________ ___________

Master Reading mA) ___________ ___________ ___________ ___________

% Difference ___________ ___________ ___________ ___________

Corrective Action ____

2) Analog Output to DAS Terminal

Date ___________

Time ___________ ___________

Meter Output (mA) ___________ ___________

Meter "raw data" reading at DAS terminal (mA) ___________ ___________

% Difference ___________ ___________

Corrective Action ____

CALIBRATION CHECKS

1) Bench Calibration

Date ___________ Time ___________

Absolute Pressure Offset Trim Point (psi) ________________________

Absolute Pressure Slope Trim Point (psi) ________________________

Absolute Temperature Offset Trim Point (°F) ________________________

Absolute Temperature Slope Trim Point (°F) ________________________

Corrective Action ____

2) Zero Check

Date ___________

Time ___________

Initial reading ___________mA ___________lbs/hr

Reading after adjustment ___________mA ___________lbs/hr (should be 0, enter n/a if no adjustment)

Corrective Action ____

Appendix B-5. Rosemount 3095 Independent Performance Check

The Rosemount Model 3095 orifice plate gas flow meter will be compared to the American Meter Model AL800 as an independent meter performance check. Gas flow rates measured by each of the meters will be recorded during each of the load tests to determine if the meters agree within 2 percent of reading. Data will be recorded on field logs such as the example on the following page using the procedures outlined below.

1. Review current flow data to confirm functionality of both flow meters.

2. Confirm that the Rosemount metering data (flow in scfm) are properly logging on the DAS.

3. Identify and record the Load Testing start time.

4. Read and record the AL800 meter reading at the start of the test.

5. Manually record the line pressure and temperature from the Rosemount meter at 2-minute intervals for the duration of the test on the field log.

6. Manually record the line pressure at the outlet of AL800 meter at 2-minute intervals for the duration of the test on the field log.

7. Record the final AL800 meter reading at the end of the test period.

8. Calculate the total volume recorded by the AL800 in units of actual cubic feet.

9. Correct the meter volume to standard conditions (60^{o}F and 14.78 psia) using the average temperature and pressure recorded during the test, and calculate the average gas flow during the test period as scfm.

10. Retrieve the Rosemount data and determine the average gas flow for the test period as scfm.

11. Determine the percent difference between the two meters. If greater than 2 percent, take corrective action to identify and correct the metering error.

Appendix B-5. Rosemount 3095 Independent Performance Check (Continued)

Flow Meter Independent Performance Test Log

Project:
Primary Meter ID:
Test Meter ID:
Date:

Ambient Pressure:
Ambient Temperature:
Technician:

Control Test Start Time:
Initial Gas Meter Reading:

Control Test No.

	Gas Meter AL800		**Rosemount 3095**	
Time	Meter Reading (acf)	Inlet Gas Pressure (psig)	Gas Temp. (^{o}F)	Gas Pressure (psig

Control Test Start Time:
Initial Gas Meter Reading:

Appendix B-6. Ambient Monitor Installation, Setup, and Sensor Function Checks

Installation and Setup Checks:

Field installation procedures are detailed in the documentation provided for the integrated temperature/ humidity unit by Vaisala and for the pressure sensor by Setra and will not be discussed here. Center testing personnel will follow all required procedures to ensure that checks for appropriate installation locations, length of cable, process connections, leaks, field wiring and ground wiring are conducted properly, including:

1. All wires will not be located near motors, power supply calbles, or other such electrically "noisy" equipment

2. No hand-held radios will be used near the instruments

In each of these sensors, the parameter monitored creates a small electrical change in capacitance or resistance which corresponds to the variation in the monitored parameter. This change is measured, amplified and converted by the electronics package associated with each sensor. Unless catastrophic damage (which should be visible) has occurred to the sensors, their accuracy at setup should correspond precisely to the initial factory calibration performed before shipping. Visual checks for damage both before and after installation will be performed, and appropriateness checks of the outputs will be performed at start-up.

The signal inputs into the A/D module in the data acquisition computer are scaled and converted into the proper units and logged on the computer hard drive by a program provided by the A/D module manufacturer. The GHG Center testing personnel will maintain field logs of all data entered into this program. An electronic copy of the configuration file will be maintained. Detailed guidelines are provided in the software Programming Manual.

Sensor function checks:

Analog output checks will be conducted a minimum of 2 times during the test. In this loop test, a current of known quantity will be checked against a secondary device to ensure that 4 mA and 20 mA signals are produced. Reasonableness checks will also be performed by ensuring that the signal produced at the transmitter is recorded correctly by the A/D module and the DAS computer.

Reasonableness checks will be performed by examining the ambient temperature, pressure, and relative humidity recorded by the test instruments with those reported by the nearest national Weather Station at the Calgary International Airport. All suspect data will be flagged, and the measurement instruments will be examined for damage or failure.

Appendix B-7. Heat Exchanger RTD Performance Testing

The Arigo heat meter used at the test site to monitor heat recovery receives temperature signals from two resistance temperature devices (RTDs), mounted upstream and downstream of the heat recovery unit. The accuracy of the RTDs will be determined by comparing RTD signals to temperatures measured by the Center using a calibrated Type K thermocouple. Prior to this evaluation, the thermocouple will be calibrated in the laboratory using an ice bath and boiling water at or near sea level conditions. A thermocouple that is determined to be accurate within 0.5 percent of reading or better will be used for the performance check. The performance check will be conducted a minimum of three times during the verification period using the procedures outlined below. Data will be recorded on field logs such as the example on the following page using the procedures outlined below.

Laboratory calibration of reference thermocouple (TC):

1. Insert TC into ice bath while stirring the bath. Record the stable reading in degrees Kelvin. Calculate the percent error as ((TC response (^{o}K))/273.15] * 100.
2. Insert TC into boiling water while stirring the bath. Record the stable reading in degrees Kelvin. Calculate the percent error as ((TC response (^{o}K))/373.15] * 100.
3. Use the higher of the two errors to determine if the TC accuracy is within 0.5% of reading.

Performance testing of Arigo RTDs:

1. Remove the two RTDs from the pipe and immerse in an ice-water bath.
2. Simultaneously immerse the reference thermocouple and, while stirring, obtain and record stable readings from the three devices.
3. Repeat the process in a hot-water bath.
4. Compare the RTD readings to the reference reading at each of the two calibration points. If the RTD readings differ by more than 1.8^{o}F, the RTDs should be submitted for recalibration.

Appendix B-7. Heat Exchanger RTD Performance Testing (Continued)

Heat Exchanger RTD Performance Test

Project: ____________________

Inlet RTD ID: ____________________

Outlet RTD ID: ____________________

Reference TC ID: ____________________

Date: ______________________________

Ambient Temperature: ________________

Technician: ____________________________

Date of Reference Cal: ________________

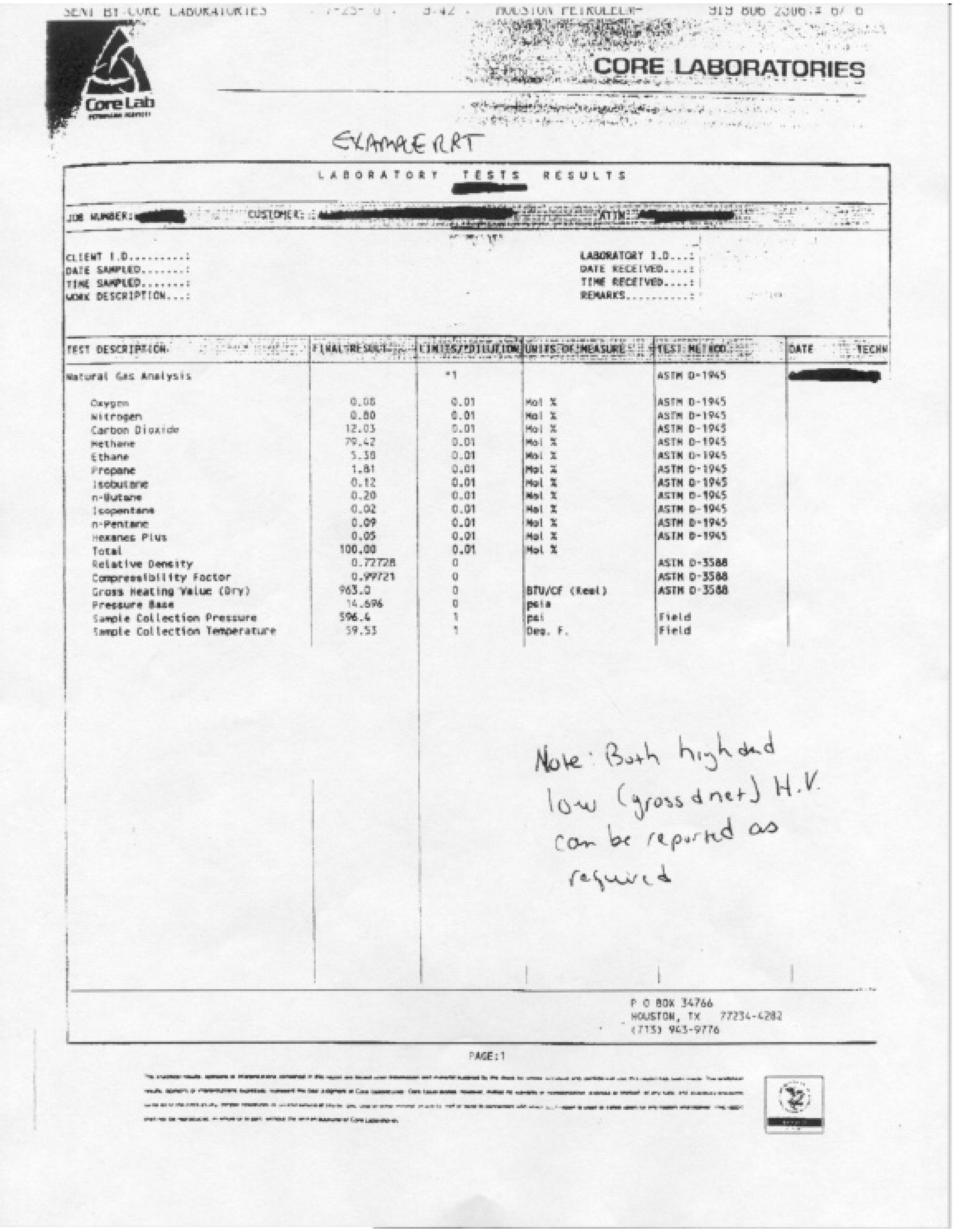
Reference Temp. (°F)

Inlet RTD Reading (°F)	Difference (°F)

Outlet RTD Reading (°F)	Difference (°F)

APPENDIX C
Example Test and Calibration Data

Appendix C-1. Example of Core Laboratories Gas Analysis Results



SENT BY:CORE LABORATORIES ; 7-25- 0 ; 3:42 ; HOUSTON PETROLEUM- 519 806 2306;# 6/ 6

CORE LABORATORIES

EXAMPLE RPT

LABORATORY TESTS RESULTS [redacted]

JOB NUMBER: [redacted] CUSTOMER: [redacted] ATTN: [redacted]

CLIENT I.D.........:	LABORATORY I.D...:
DATE SAMPLED.......:	DATE RECEIVED....:
TIME SAMPLED.......:	TIME RECEIVED....:
WORK DESCRIPTION...:	REMARKS..........:

TEST DESCRIPTION	FINAL RESULT	LIMITS/*DILUTION	UNITS OF MEASURE	TEST METHOD	DATE	TECHN
Natural Gas Analysis		*1		ASTM D-1945	[redacted]	
Oxygen	0.06	0.01	Mol %	ASTM D-1945		
Nitrogen	0.80	0.01	Mol %	ASTM D-1945		
Carbon Dioxide	12.03	0.01	Mol %	ASTM D-1945		
Methane	79.42	0.01	Mol %	ASTM D-1945		
Ethane	5.30	0.01	Mol %	ASTM D-1945		
Propane	1.81	0.01	Mol %	ASTM D-1945		
Isobutane	0.12	0.01	Mol %	ASTM D-1945		
n-Butane	0.20	0.01	Mol %	ASTM D-1945		
Isopentane	0.02	0.01	Mol %	ASTM D-1945		
n-Pentane	0.09	0.01	Mol %	ASTM D-1945		
Hexanes Plus	0.05	0.01	Mol %	ASTM D-1945		
Total	100.00	0.01	Mol %			
Relative Density	0.72728	0		ASTM D-3588		
Compressibility Factor	0.99721	0		ASTM D-3588		
Gross Heating Value (Dry)	963.0	0	BTU/CF (Real)	ASTM D-3588		
Pressure Base	14.696	0	psia			
Sample Collection Pressure	596.4	1	psi	Field		
Sample Collection Temperature	59.53	1	Deg. F.	Field		

Note: Both high and low (gross & net) H.V. can be reported as required

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HOUSTON, TX 77234-4282
(713) 943-9776

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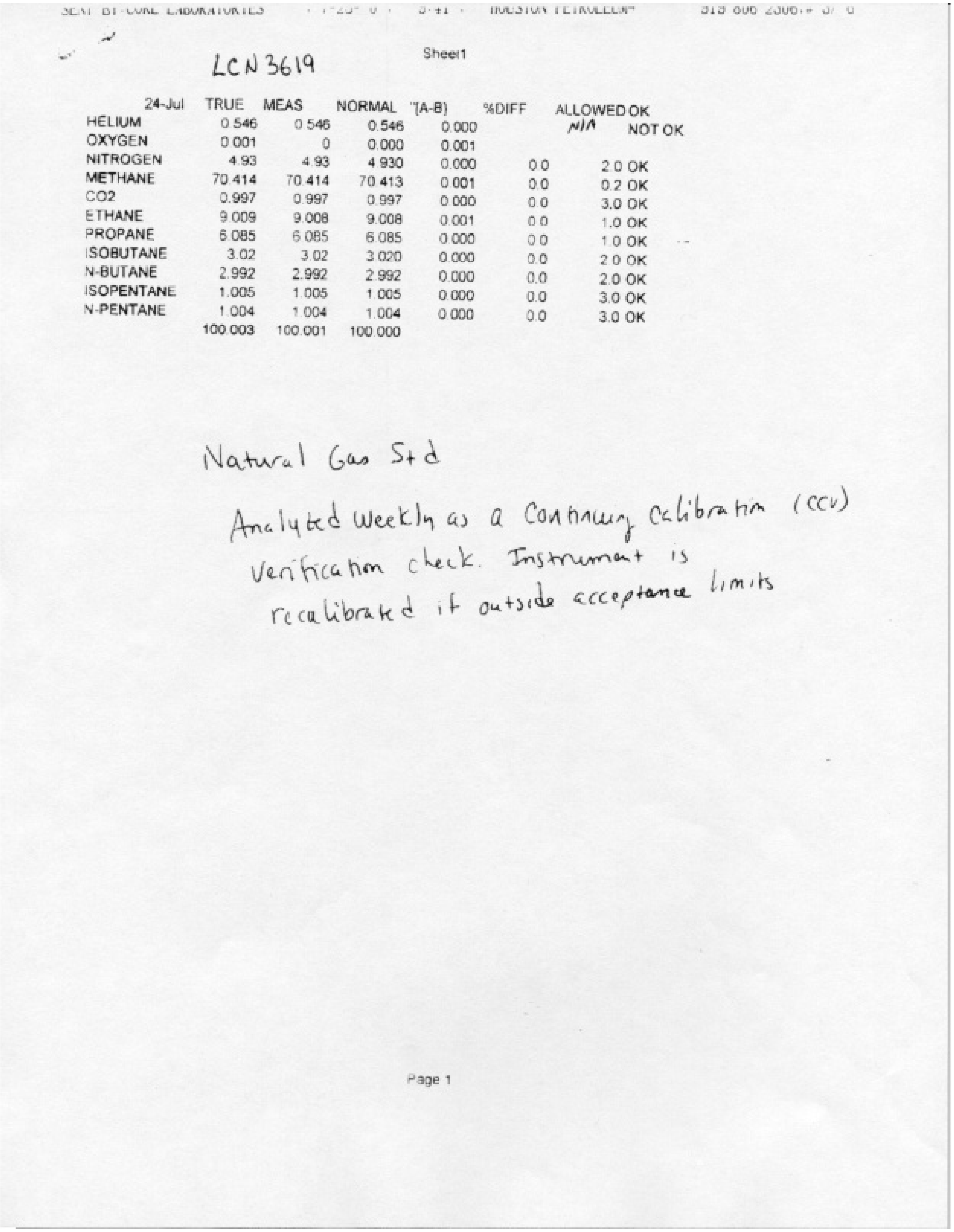
Appendix C-2. Example of Core Laboratories Calibration Data



SENT BY:CORE LABORATORIES ; 7-25- 0 ; 3:41 ; HOUSTON PETROLEUM→ 318 606 2306;# 3/ 6

LCN 3619

Sheet1

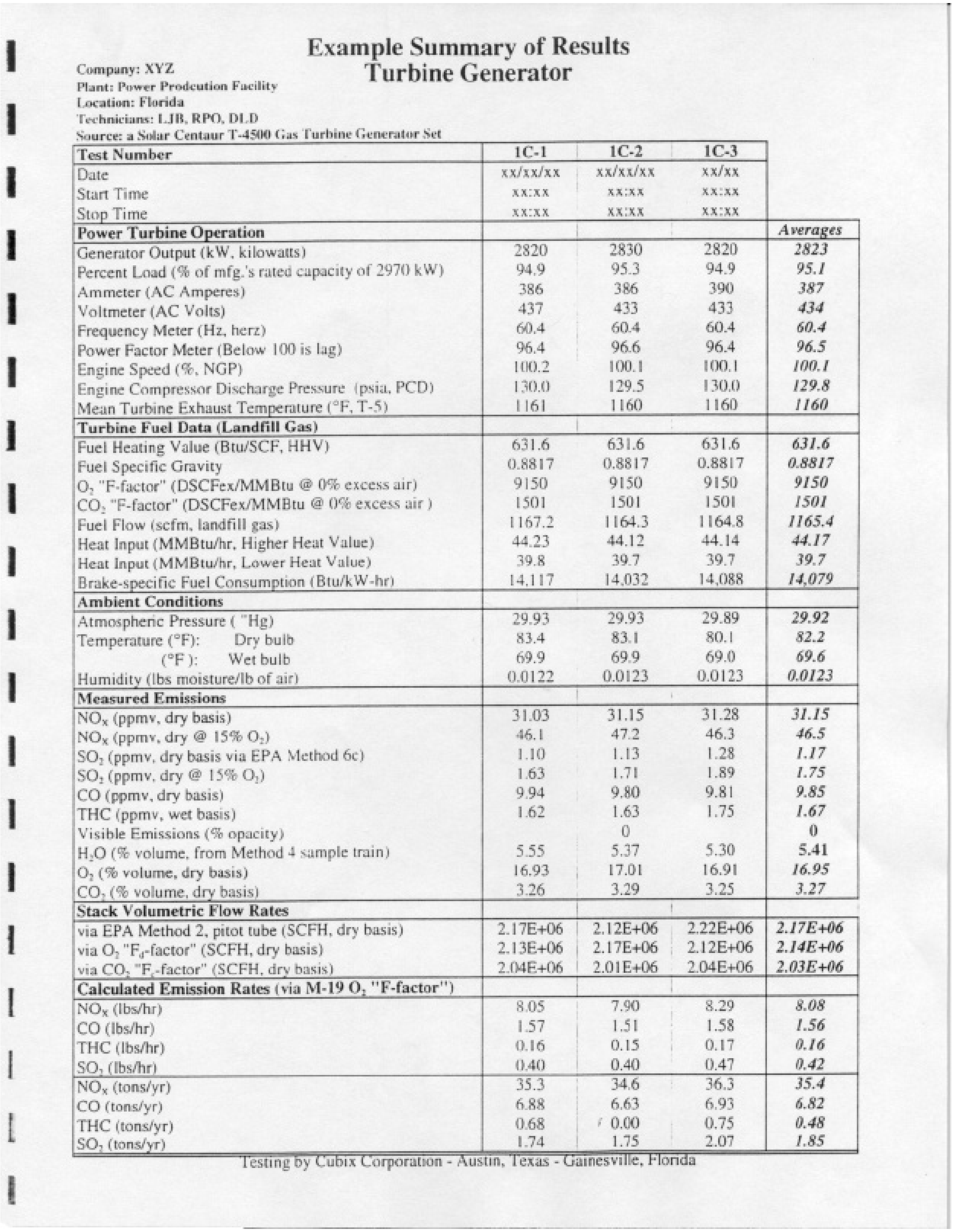
24-Jul	TRUE	MEAS	NORMAL	[A-B]	%DIFF	ALLOWED	OK NOT OK
HELIUM	0.546	0.546	0.546	0.000		N/A	
OXYGEN	0.001	0	0.000	0.001			
NITROGEN	4.93	4.93	4.930	0.000	0.0	2.0	OK
METHANE	70.414	70.414	70.413	0.001	0.0	0.2	OK
CO2	0.997	0.997	0.997	0.000	0.0	3.0	OK
ETHANE	9.009	9.008	9.008	0.001	0.0	1.0	OK
PROPANE	6.085	6.085	6.085	0.000	0.0	1.0	OK
ISOBUTANE	3.02	3.02	3.020	0.000	0.0	2.0	OK
N-BUTANE	2.992	2.992	2.992	0.000	0.0	2.0	OK
ISOPENTANE	1.005	1.005	1.005	0.000	0.0	3.0	OK
N-PENTANE	1.004	1.004	1.004	0.000	0.0	3.0	OK
	100.003	100.001	100.000				

Natural Gas Std

Analyzed weekly as a continuing calibration (CCV) verification check. Instrument is recalibrated if outside acceptance limits

Page 1

Appendix C-3. Example of Exhaust Stack Emission Rate Results



Example Summary of Results
Turbine Generator

Company: XYZ
Plant: Power Prodcution Facility
Location: Florida
Technicians: LJB, RPO, DLD
Source: a Solar Centaur T-4500 Gas Turbine Generator Set

Test Number	**1C-1**	**1C-2**	**1C-3**	
Date	xx/xx/xx	xx/xx/xx	xx/xx	
Start Time	xx:xx	xx:xx	xx:xx	
Stop Time	xx:xx	xx:xx	xx:xx	
Power Turbine Operation				***Averages***
Generator Output (kW, kilowatts)	2820	2830	2820	***2823***
Percent Load (% of mfg.'s rated capacity of 2970 kW)	94.9	95.3	94.9	***95.1***
Ammeter (AC Amperes)	386	386	390	***387***
Voltmeter (AC Volts)	437	433	433	***434***
Frequency Meter (Hz, herz)	60.4	60.4	60.4	***60.4***
Power Factor Meter (Below 100 is lag)	96.4	96.6	96.4	***96.5***
Engine Speed (%, NGP)	100.2	100.1	100.1	***100.1***
Engine Compressor Discharge Pressure (psia, PCD)	130.0	129.5	130.0	***129.8***
Mean Turbine Exhaust Temperature (°F, T-5)	1161	1160	1160	***1160***
Turbine Fuel Data (Landfill Gas)				
Fuel Heating Value (Btu/SCF, HHV)	631.6	631.6	631.6	***631.6***
Fuel Specific Gravity	0.8817	0.8817	0.8817	***0.8817***
O_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	9150	9150	9150	***9150***
CO_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	1501	1501	1501	***1501***
Fuel Flow (scfm, landfill gas)	1167.2	1164.3	1164.8	***1165.4***
Heat Input (MMBtu/hr, Higher Heat Value)	44.23	44.12	44.14	***44.17***
Heat Input (MMBtu/hr, Lower Heat Value)	39.8	39.7	39.7	***39.7***
Brake-specific Fuel Consumption (Btu/kW-hr)	14,117	14,032	14,088	***14,079***
Ambient Conditions				
Atmospheric Pressure ("Hg)	29.93	29.93	29.89	***29.92***
Temperature (°F): Dry bulb	83.4	83.1	80.1	***82.2***
(°F): Wet bulb	69.9	69.9	69.0	***69.6***
Humidity (lbs moisture/lb of air)	0.0122	0.0123	0.0123	***0.0123***
Measured Emissions				
NO_X (ppmv, dry basis)	31.03	31.15	31.28	***31.15***
NO_X (ppmv, dry @ 15% O_2)	46.1	47.2	46.3	***46.5***
SO_2 (ppmv, dry basis via EPA Method 6c)	1.10	1.13	1.28	***1.17***
SO_2 (ppmv, dry @ 15% O_2)	1.63	1.71	1.89	***1.75***
CO (ppmv, dry basis)	9.94	9.80	9.81	***9.85***
THC (ppmv, wet basis)	1.62	1.63	1.75	***1.67***
Visible Emissions (% opacity)		0		***0***
H_2O (% volume, from Method 4 sample train)	5.55	5.37	5.30	***5.41***
O_2 (% volume, dry basis)	16.93	17.01	16.91	***16.95***
CO_2 (% volume, dry basis)	3.26	3.29	3.25	***3.27***
Stack Volumetric Flow Rates				
via EPA Method 2, pitot tube (SCFH, dry basis)	2.17E+06	2.12E+06	2.22E+06	***2.17E+06***
via O_2 "F_d-factor" (SCFH, dry basis)	2.13E+06	2.17E+06	2.12E+06	***2.14E+06***
via CO_2 "F_c-factor" (SCFH, dry basis)	2.04E+06	2.01E+06	2.04E+06	***2.03E+06***
Calculated Emission Rates (via M-19 O_2 "F-factor")				
NO_X (lbs/hr)	8.05	7.90	8.29	***8.08***
CO (lbs/hr)	1.57	1.51	1.58	***1.56***
THC (lbs/hr)	0.16	0.15	0.17	***0.16***
SO_2 (lbs/hr)	0.40	0.40	0.47	***0.42***
NO_X (tons/yr)	35.3	34.6	36.3	***35.4***
CO (tons/yr)	6.88	6.63	6.93	***6.82***
THC (tons/yr)	0.68	0.00	0.75	***0.48***
SO_2 (tons/yr)	1.74	1.75	2.07	***1.85***

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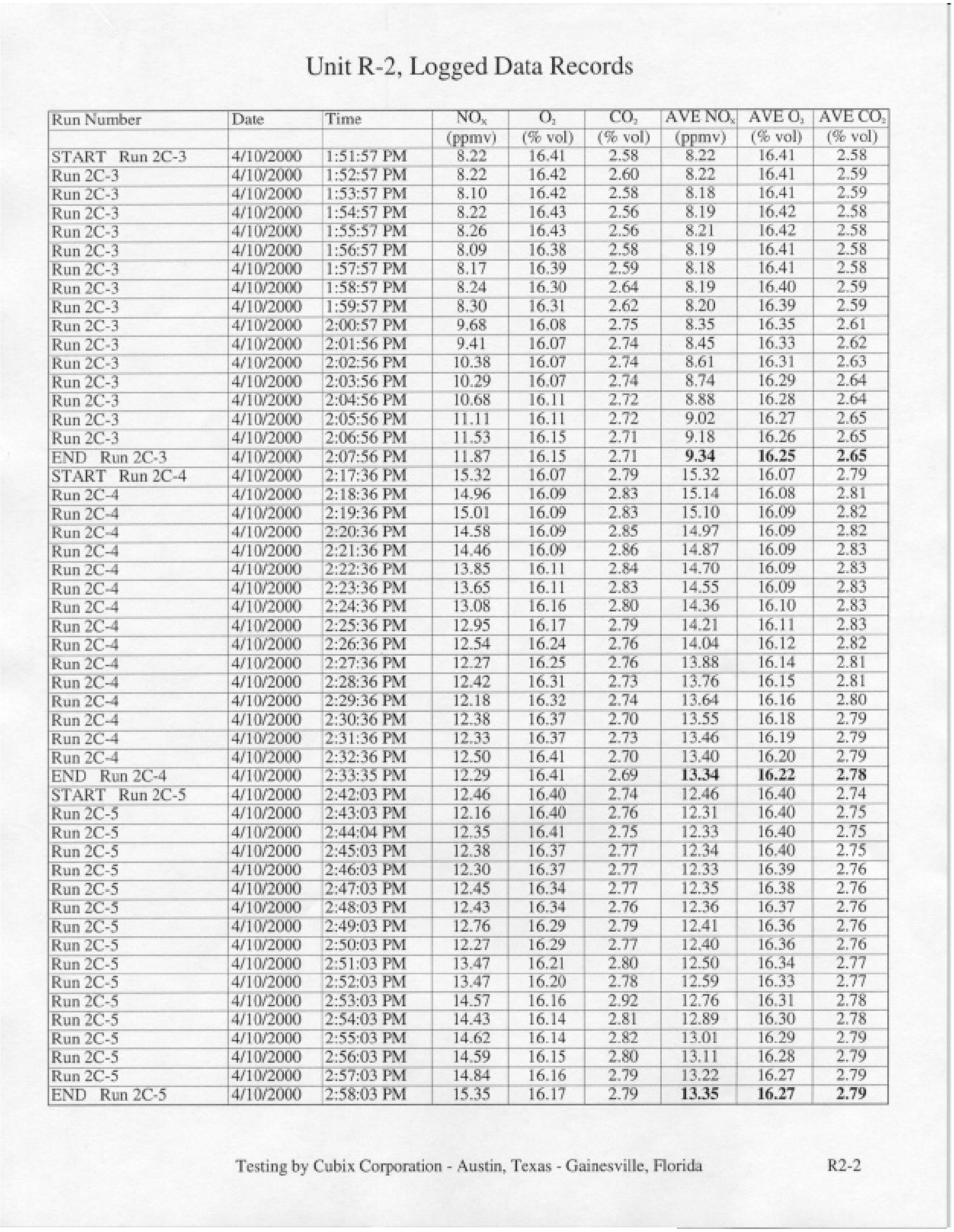
Appendix C-4. Example of Exhaust Stack Raw Emission Measurements Data



Unit R-2, Logged Data Records

Run Number	Date	Time	NO$_x$	O$_2$	CO$_2$	AVE NO$_x$	AVE O$_2$	AVE CO$_2$
			(ppmv)	(% vol)	(% vol)	(ppmv)	(% vol)	(% vol)
START Run 2C-3	4/10/2000	1:51:57 PM	8.22	16.41	2.58	8.22	16.41	2.58
Run 2C-3	4/10/2000	1:52:57 PM	8.22	16.42	2.60	8.22	16.41	2.59
Run 2C-3	4/10/2000	1:53:57 PM	8.10	16.42	2.58	8.18	16.41	2.59
Run 2C-3	4/10/2000	1:54:57 PM	8.22	16.43	2.56	8.19	16.42	2.58
Run 2C-3	4/10/2000	1:55:57 PM	8.26	16.43	2.56	8.21	16.42	2.58
Run 2C-3	4/10/2000	1:56:57 PM	8.09	16.38	2.58	8.19	16.41	2.58
Run 2C-3	4/10/2000	1:57:57 PM	8.17	16.39	2.59	8.18	16.41	2.58
Run 2C-3	4/10/2000	1:58:57 PM	8.24	16.30	2.64	8.19	16.40	2.59
Run 2C-3	4/10/2000	1:59:57 PM	8.30	16.31	2.62	8.20	16.39	2.59
Run 2C-3	4/10/2000	2:00:57 PM	9.68	16.08	2.75	8.35	16.35	2.61
Run 2C-3	4/10/2000	2:01:56 PM	9.41	16.07	2.74	8.45	16.33	2.62
Run 2C-3	4/10/2000	2:02:56 PM	10.38	16.07	2.74	8.61	16.31	2.63
Run 2C-3	4/10/2000	2:03:56 PM	10.29	16.07	2.74	8.74	16.29	2.64
Run 2C-3	4/10/2000	2:04:56 PM	10.68	16.11	2.72	8.88	16.28	2.64
Run 2C-3	4/10/2000	2:05:56 PM	11.11	16.11	2.72	9.02	16.27	2.65
Run 2C-3	4/10/2000	2:06:56 PM	11.53	16.15	2.71	9.18	16.26	2.65
END Run 2C-3	4/10/2000	2:07:56 PM	11.87	16.15	2.71	**9.34**	**16.25**	**2.65**
START Run 2C-4	4/10/2000	2:17:36 PM	15.32	16.07	2.79	15.32	16.07	2.79
Run 2C-4	4/10/2000	2:18:36 PM	14.96	16.09	2.83	15.14	16.08	2.81
Run 2C-4	4/10/2000	2:19:36 PM	15.01	16.09	2.83	15.10	16.09	2.82
Run 2C-4	4/10/2000	2:20:36 PM	14.58	16.09	2.85	14.97	16.09	2.82
Run 2C-4	4/10/2000	2:21:36 PM	14.46	16.09	2.86	14.87	16.09	2.83
Run 2C-4	4/10/2000	2:22:36 PM	13.85	16.11	2.84	14.70	16.09	2.83
Run 2C-4	4/10/2000	2:23:36 PM	13.65	16.11	2.83	14.55	16.09	2.83
Run 2C-4	4/10/2000	2:24:36 PM	13.08	16.16	2.80	14.36	16.10	2.83
Run 2C-4	4/10/2000	2:25:36 PM	12.95	16.17	2.79	14.21	16.11	2.83
Run 2C-4	4/10/2000	2:26:36 PM	12.54	16.24	2.76	14.04	16.12	2.82
Run 2C-4	4/10/2000	2:27:36 PM	12.27	16.25	2.76	13.88	16.14	2.81
Run 2C-4	4/10/2000	2:28:36 PM	12.42	16.31	2.73	13.76	16.15	2.81
Run 2C-4	4/10/2000	2:29:36 PM	12.18	16.32	2.74	13.64	16.16	2.80
Run 2C-4	4/10/2000	2:30:36 PM	12.38	16.37	2.70	13.55	16.18	2.79
Run 2C-4	4/10/2000	2:31:36 PM	12.33	16.37	2.73	13.46	16.19	2.79
Run 2C-4	4/10/2000	2:32:36 PM	12.50	16.41	2.70	13.40	16.20	2.79
END Run 2C-4	4/10/2000	2:33:35 PM	12.29	16.41	2.69	**13.34**	**16.22**	**2.78**
START Run 2C-5	4/10/2000	2:42:03 PM	12.46	16.40	2.74	12.46	16.40	2.74
Run 2C-5	4/10/2000	2:43:03 PM	12.16	16.40	2.76	12.31	16.40	2.75
Run 2C-5	4/10/2000	2:44:04 PM	12.35	16.41	2.75	12.33	16.40	2.75
Run 2C-5	4/10/2000	2:45:03 PM	12.38	16.37	2.77	12.34	16.40	2.75
Run 2C-5	4/10/2000	2:46:03 PM	12.30	16.37	2.77	12.33	16.39	2.76
Run 2C-5	4/10/2000	2:47:03 PM	12.45	16.34	2.77	12.35	16.38	2.76
Run 2C-5	4/10/2000	2:48:03 PM	12.43	16.34	2.76	12.36	16.37	2.76
Run 2C-5	4/10/2000	2:49:03 PM	12.76	16.29	2.79	12.41	16.36	2.76
Run 2C-5	4/10/2000	2:50:03 PM	12.27	16.29	2.77	12.40	16.36	2.76
Run 2C-5	4/10/2000	2:51:03 PM	13.47	16.21	2.80	12.50	16.34	2.77
Run 2C-5	4/10/2000	2:52:03 PM	13.47	16.20	2.78	12.59	16.33	2.77
Run 2C-5	4/10/2000	2:53:03 PM	14.57	16.16	2.92	12.76	16.31	2.78
Run 2C-5	4/10/2000	2:54:03 PM	14.43	16.14	2.81	12.89	16.30	2.78
Run 2C-5	4/10/2000	2:55:03 PM	14.62	16.14	2.82	13.01	16.29	2.79
Run 2C-5	4/10/2000	2:56:03 PM	14.59	16.15	2.80	13.11	16.28	2.79
Run 2C-5	4/10/2000	2:57:03 PM	14.84	16.16	2.79	13.22	16.27	2.79
END Run 2C-5	4/10/2000	2:58:03 PM	15.35	16.17	2.79	**13.35**	**16.27**	**2.79**

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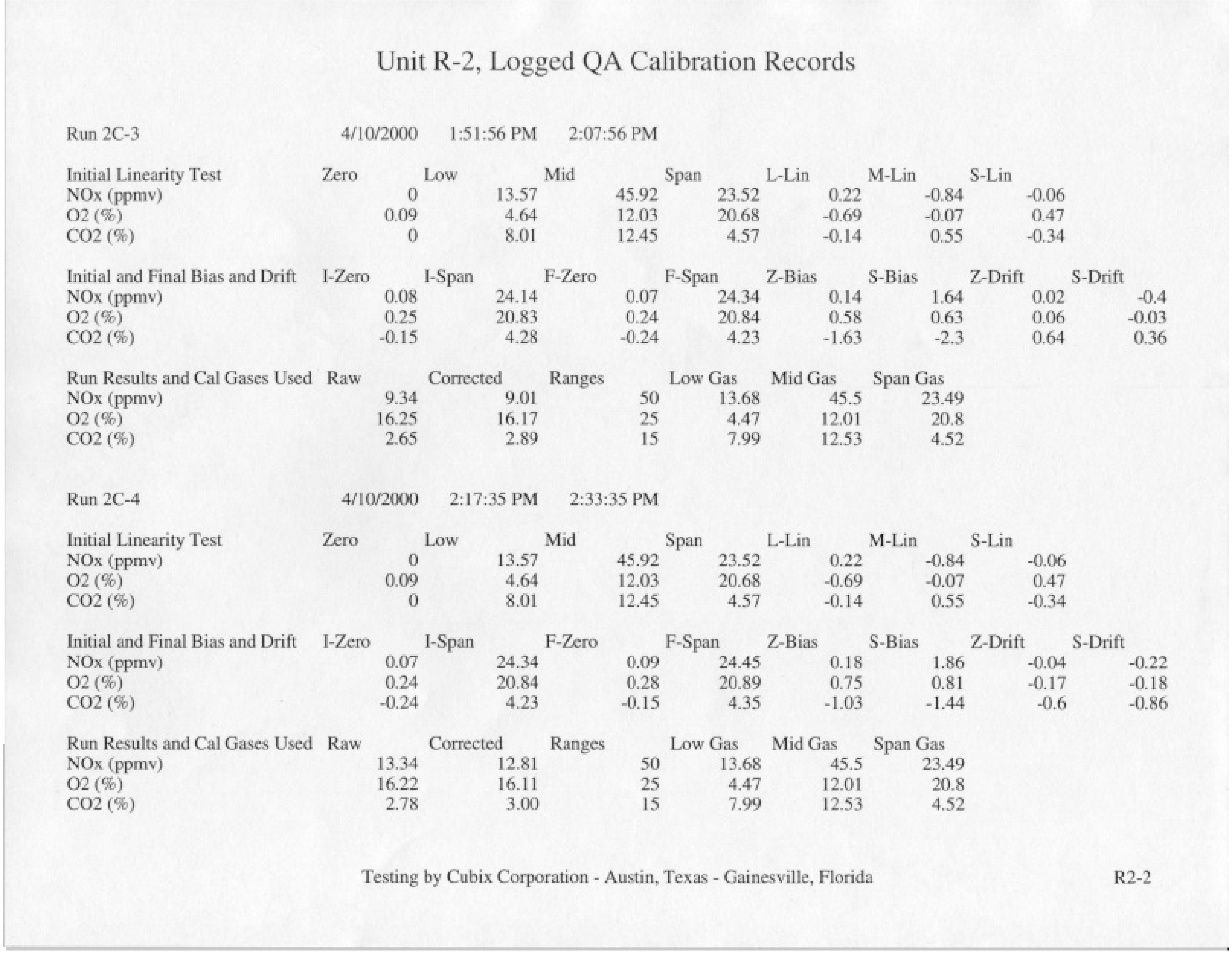
Appendix C-5. Example of Exhaust Stack Emission Measurements Calibration Data



Unit R-2, Logged QA Calibration Records

Run 2C-3 4/10/2000 1:51:56 PM 2:07:56 PM

Initial Linearity Test	Zero	Low	Mid	Span	L-Lin	M-Lin	S-Lin
NOx (ppmv)	0	13.57	45.92	23.52	0.22	-0.84	-0.06
O2 (%)	0.09	4.64	12.03	20.68	-0.69	-0.07	0.47
CO2 (%)	0	8.01	12.45	4.57	-0.14	0.55	-0.34

Initial and Final Bias and Drift	I-Zero	I-Span	F-Zero	F-Span	Z-Bias	S-Bias	Z-Drift	S-Drift
NOx (ppmv)	0.08	24.14	0.07	24.34	0.14	1.64	0.02	-0.4
O2 (%)	0.25	20.83	0.24	20.84	0.58	0.63	0.06	-0.03
CO2 (%)	-0.15	4.28	-0.24	4.23	-1.63	-2.3	0.64	0.36

Run Results and Cal Gases Used	Raw	Corrected	Ranges	Low Gas	Mid Gas	Span Gas
NOx (ppmv)	9.34	9.01	50	13.68	45.5	23.49
O2 (%)	16.25	16.17	25	4.47	12.01	20.8
CO2 (%)	2.65	2.89	15	7.99	12.53	4.52

Run 2C-4 4/10/2000 2:17:35 PM 2:33:35 PM

Initial Linearity Test	Zero	Low	Mid	Span	L-Lin	M-Lin	S-Lin
NOx (ppmv)	0	13.57	45.92	23.52	0.22	-0.84	-0.06
O2 (%)	0.09	4.64	12.03	20.68	-0.69	-0.07	0.47
CO2 (%)	0	8.01	12.45	4.57	-0.14	0.55	-0.34

Initial and Final Bias and Drift	I-Zero	I-Span	F-Zero	F-Span	Z-Bias	S-Bias	Z-Drift	S-Drift
NOx (ppmv)	0.07	24.34	0.09	24.45	0.18	1.86	-0.04	-0.22
O2 (%)	0.24	20.84	0.28	20.89	0.75	0.81	-0.17	-0.18
CO2 (%)	-0.24	4.23	-0.15	4.35	-1.03	-1.44	-0.6	-0.86

Run Results and Cal Gases Used	Raw	Corrected	Ranges	Low Gas	Mid Gas	Span Gas
NOx (ppmv)	13.34	12.81	50	13.68	45.5	23.49
O2 (%)	16.22	16.11	25	4.47	12.01	20.8
CO2 (%)	2.78	3.00	15	7.99	12.53	4.52

Testing by Cubix Corporation - Austin, Texas - Gainesville, Florida

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