SRI/USEPA-GHG-GVP-04
September 2005

Generic Verification Protocol

Distributed Generation and Combined Heat and Power Field Testing Protocol

Version 1.0

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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This Generic Verification Protocol has been reviewed and approved by the Greenhouse Gas Technology Center director and quality assurance manager, the U.S. EPA APPCD project officer, and the U.S. EPA APPCD quality assurance manager.

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GVP Version 1.0: September 2005

Foreword

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

Distributed generation (DG) technologies are emerging as a viable supplement to centralized power production. Many DG systems can be utilized in combined heat and power (CHP) applications, in which waste heat from the generator unit is used to supply local heating, cooling, or other services. This provides improved energy efficiency, reduced energy costs, and reduced use of natural resources. Current and developing DG technologies include microturbines (MTGs), internal combustion generators, small turbines, and Stirling engines. Independent evaluations of DG technologies are required to assess performance of systems, and, ultimately, the applicability and efficacy of a specific technology at any given site. A current barrier to the acceptance of DG technologies is the lack of credible and uniform information regarding system performance. Therefore, as new DG technologies are developed and introduced to the marketplace, methods of credibly evaluating the performance of a DG system are needed. This GVP was developed to meet that need.

In December 2004 the Association of State Energy Research and Technology Transfer Institutions (ASERTTI) issued the Interim Distributed Generation and Combined Heat and Power Performance Protocol for Field Testing. This GVP is based largely on the ASERTTI protocol, with some additional quality assurance/quality control procedures included as required by ETV. The ASERTTI protocol was developed as part of the *Collaborative National Program for the Development and Performance Testing of Distributed Power Technologies with Emphasis on Combined Heat and Power Applications*, co-sponsored by the U.S. Department of Energy and members of ASERTTI. The ASERTTI sponsoring members are the California Energy Commission, the Energy Center of Wisconsin, the New York State Energy Research and Development Authority, and the University of Illinois-Chicago. Other sponsors are the Illinois Department of Commerce and Economic Opportunity and the U.S. Environmental Protection Agency Office of Research and Development.

The protocol development program was directed by several guiding principles specified by the ASERTTI Steering Committee:

- The development of protocols uses a stakeholder driven process.
- The protocols use existing standards and protocols wherever possible.
- The protocols are cost-effective and user-friendly, and provide credible, quality.
- The interim protocols will become final protocols after review of validation efforts and other experience gained in the use of the interim protocols.

The field protocol was developed based on input and guidance provided by two stakeholder committees, the ASERTTI Stakeholder Advisory Committee (SAC) and the ETV program's Advanced Energy Stakeholder Group, managed by the Southern Research Institute (Southern). The SAC consisted of 27 stakeholders representing manufacturers, end-users, research agencies, regulators, trade organizations, and public interest groups.

This GVP addresses the performance of MTG and reciprocating internal-combustion engine generators in field settings. The protocol is not intended for small turbines. The purpose of this GVP is to describe specific procedures for evaluation and verification of DG/CHP systems. A significant effort has been devoted to their development, field trial, and improvement; and this experience and data are recognized as potentially valuable to others. Instrument descriptions and recommendations presented in this document do not constitute an endorsement by the GHG Center or the EPA. Readers should be aware that use of this GVP is voluntary, and that the GHG Center is not responsible for liabilities that result from its use.

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

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1.0 INTRODUCTION

Distributed generation (DG) utilizes small-scale electric generation technologies located near the electricity point-of-use. Many DG systems can be utilized in combined heat and power (CHP) applications, in which waste heat from the generator unit is used to supply local heating, cooling, or other services. This provides improved energy efficiency, reduced energy costs, and reduced use of natural resources. Current and developing DG technologies include microturbines (MTGs), internal combustion (IC) generators, small turbines, and Stirling engines.

1.1. SCOPE

This generic verification protocol (GVP) was developed for the evaluation of MTG and IC engine DG units with up to 2500 kilowatt (kW) electrical generation capacity and in CHP service. The GVP specifies procedures for evaluation of both gaseous- and liquid-fueled units. For ETV verifications, this GVP should be accompanied by an approved verification specific Test and Quality Assurance Plan (TQAP). The TQAP must include details and information specific to a technology verification that is not included in this GVP including:

- technology description
- technology specific verification parameters
- organizational chart
- deviations from the GVP
- site specific measurement instrumentation and specifications
- identification and oversight of subcontractors
- verification specific data quality objectives
- verification specific audits and data reviews
- health and safety requirements

Electrical and thermal performance, including electrical efficiency evaluation is described at three power command settings. Thermal and total efficiency procedures are included for CHP heating service. For heat driven cooling systems, overall net performance is determined without resorting to characterization of Coefficient of Performance (CoP), as this is beyond the scope of this GVP. No attempt is made to evaluate the effectiveness of utilization of recovered heat or cooling at the host site.

Some CHP systems incorporate auxiliary heat sources (such as duct burners) to maintain CHP performance when the DG prime mover's heat output is insufficient. Such systems can have many configurations, all with different potential impacts on CHP and overall performance. A single testing protocol which would consider all situations would be extremely lengthy. These systems are therefore beyond the scope of this GVP.

CHP systems produce more than one energy stream, each with a different value. Electricity is the highest value product of such a system. Chilling and heating streams have a value that is a function of the temperature at which the energy is delivered. High temperature hot water and very low temperature chilling loops provide higher value than more moderate temperatures. It is important, therefore, that in addition to simple efficiency figures, each energy stream is individually characterized.

All performance data must be evaluated in the context of the site conditions because system performance may vary with facility demands, ambient conditions and other site-specific conditions. This GVP is not intended to evaluate performance of the System Under Test (SUT) over a wide range of conditions or seasons outside of those found during testing.

This document, including appendices, details the following performance testing elements, with prescriptive specifications for:

- system boundaries
- definitions of important terms
- measurement methods, instruments, and accuracy
- test procedures
- data analysis procedures
- data quality and validation procedures
- reporting requirements
- other considerations (completeness, etc.)

This GVP addresses the performance parameters outlined in Figure 1-1.

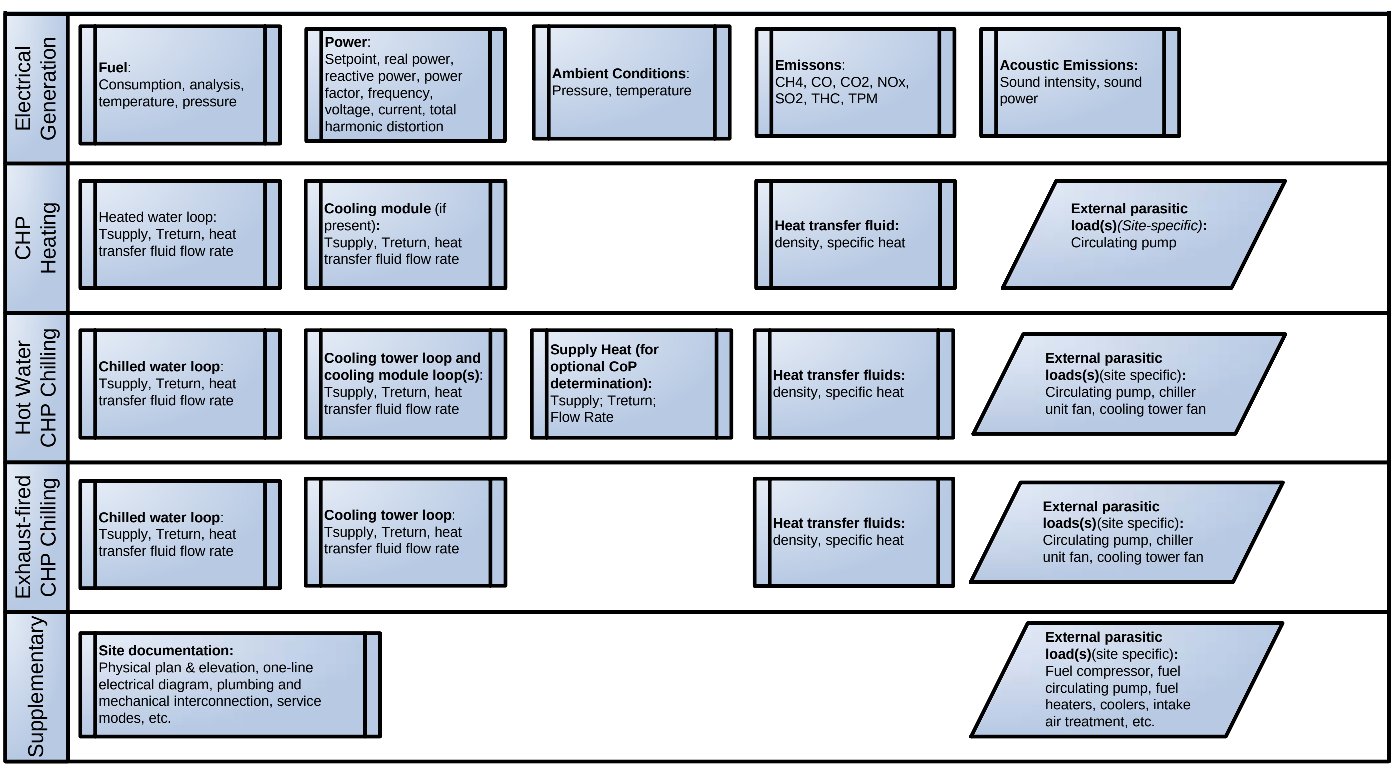


Figure 1-1. Performance Parameters and Data Collected for DG and CHP Testing

1.2. SYSTEM BOUNDARIES

The verification TQAP and its report should clearly identify the equipment included as part of the system being tested. Figure 1-2 shows a generalized boundary diagram which includes internal and external components, fuel, heat transfer fluid, exhaust gas, and ambient air flows. The figure indicates two distinct boundaries:

- device under test (DUT) or product boundary
- system under test (SUT) or system boundary

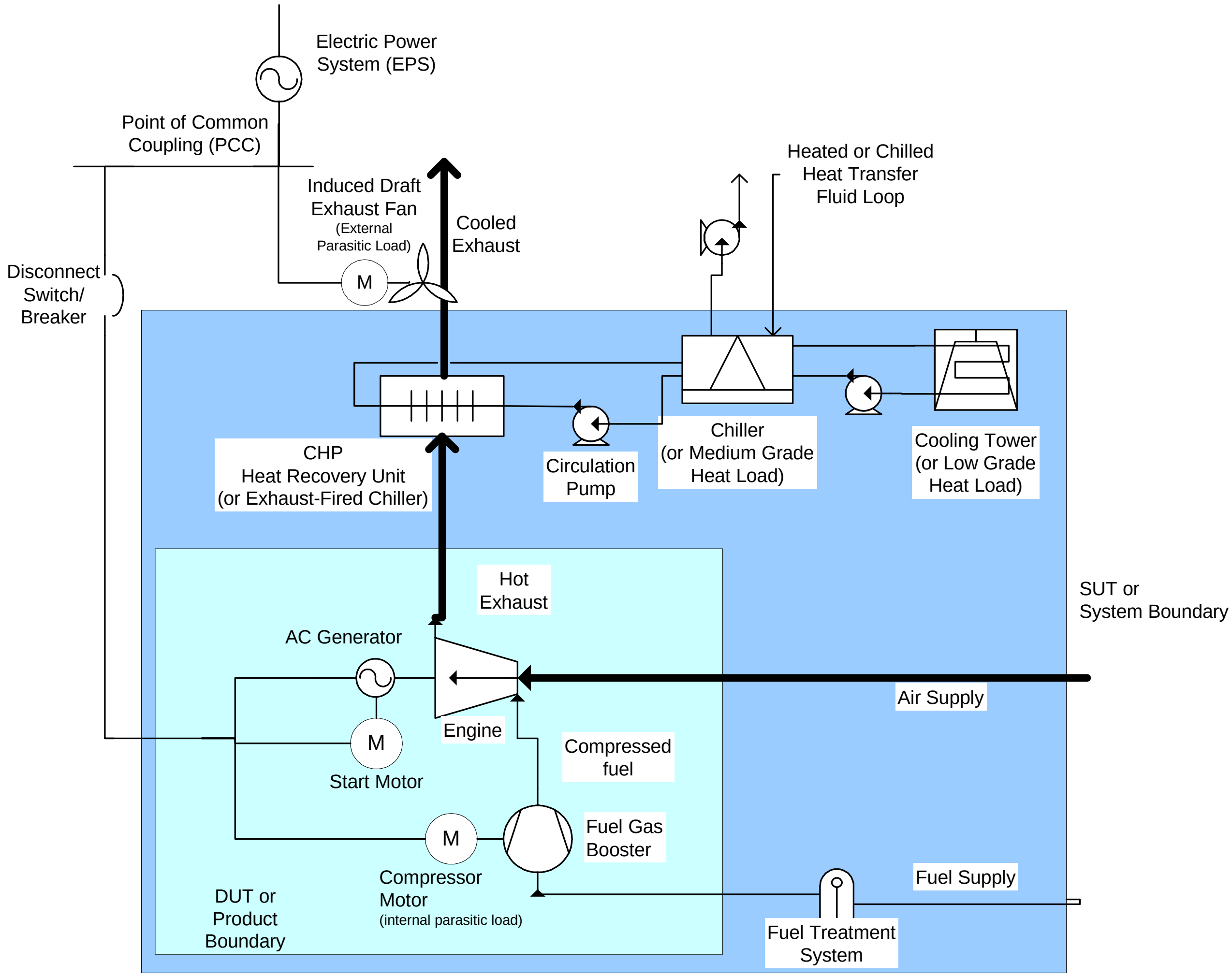


Figure 1-2. Generic System Boundary Diagram

In general, laboratory tests will use the product boundary to evaluate DG performance. Field tests conducted according to this GVP will incorporate the system boundary into performance evaluations.

The DUT boundary should incorporate components that are part of standardized offerings by manufacturers or distributors. If the seller's product consists of multiple skids which require field assembly, all such skids should fall within the DUT boundary.

The SUT boundary includes the DUT and those essential external parasitic loads or auxiliary equipment, such as fuel gas compressor, induced-draft (ID) fan, heat transfer fluid pump, etc., required to make the product fully functional. For example, if a product includes a heat recovery heat unit but not a circulating pump for the circulating heat transfer fluid, the circulating pump would fall within the SUT boundary but not the DUT boundary.

Auxiliary equipment that serves multiple units in addition to the test DG (such as large gas compressors) should be documented, but should not be included within the SUT boundary.
Figure 1-2 is not comprehensive because DG and CHP installations vary greatly from site to site and across applications. For example, individual parasitic loads may be included in some packages while others may require separate specification and installation. Appendix C provides additional boundary diagram examples.

1.3. FIELD TEST SUMMARY

Sections 2.0 and 3.0 describe the tests required for DG electrical performance and efficiency. This GVP requires these two sections and Section 4.0 for CHP thermal performance tests. Section 5.0 describes the required and optional atmospheric emissions tests.

Field tests include the following phases:

- burn-in
- setup or pretest activities
- load tests
  - electrical performance
  - electrical efficiency
  - CHP performance
  - atmospheric emissions

This GVP specifies three complete test runs at each of three power command settings (50, 75, and 100 percent) for the load test phases. Note that if the DUT cannot operate at these three power commands, three test runs at 100 percent power is an acceptable option. Each microturbine test run should last ½ hour; each IC generator test run is one hour.

Section 6.0 provides step-by-step test procedures. Test personnel should take the individual measurements in the order specified in Section 6.0 during each test run, depending on the performance parameters to be evaluated.

Section 7.0 provides all quality assurance/quality control (QA/QC) checks for instruments and procedures for data validation. If each measurement meets the minimum accuracy specification, analysts can report the overall estimated accuracy as cited in this GVP. The actual achieved parameter uncertainty may be calculated directly according to the detailed accuracy estimation methods presented in Appendix G.

Section 8.0 describes reporting requirements.

Figure 1-3 illustrates the test runs, test conditions, and parameter classes evaluated during each phase.

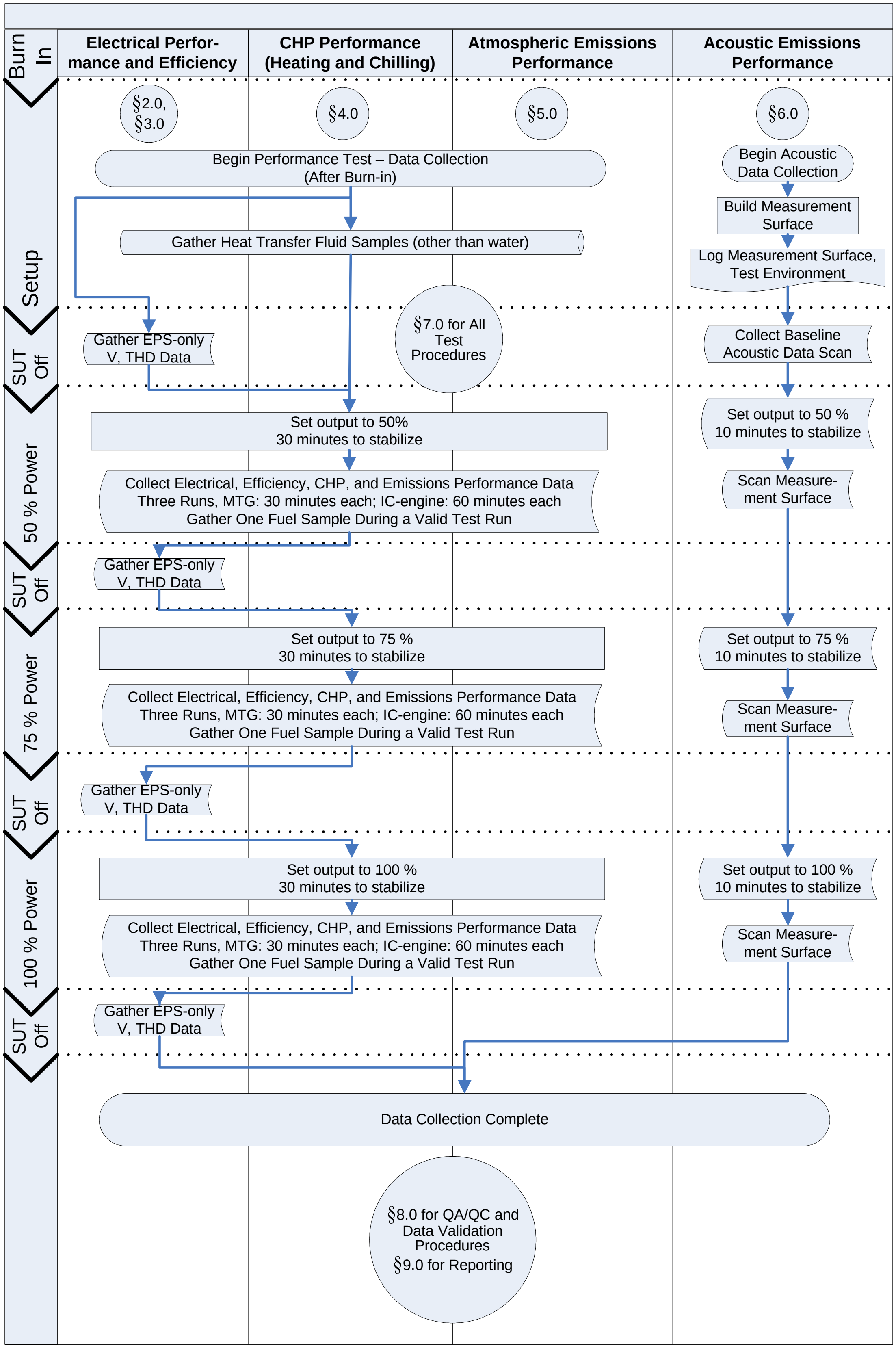


Figure 1-3. Test Phase Summary

2.0 ELECTRICAL PERFORMANCE

2.1. SCOPE

This section specifies the test procedures for electrical generation performance evaluation, including generating capacity and power quality. Appendix D provides definitions, equations, and useful relationships.

This GVP is designed for grid-parallel DG field operations of 480 volts or less. All instruments should be capable of measuring such voltages without a potential transformer (PT). The protocol can be applied to higher system voltages if the instruments have the capability or are used in conjunction with suitable PTs. Data analysts must account for the effects that PT accuracy has on overall measurement error (see Appendix G).

Grid-independent DG systems may also be evaluated with minor changes. For example, the test procedures which involve total harmonic distortion performance comparisons with the electric power system (EPS) may be omitted for grid-independent systems. The ability to use all generated power should be available for testing of grid independent systems.

2.1.1. Parameters and Measurements

A suitable measurement instrument and sensors, installed at the specified place in the electrical wiring, will measure the following parameters at each of the three power command settings:

- real power, kilowatts (kW)
- apparent power, kilovolt-amperes (kVA)
- reactive power, kilovolt-amperes reactive (kVAR)
- power factor, percent (PF)
- voltage total harmonic distortion (THD), percent
- current THD, percent
- frequency, Hertz (Hz)
- voltage, volts (V)
- current, amperes (A)

The following measurements (in addition to real power) will allow analysts to verify DG operating stability as compared to permissible variations, evaluate ambient conditions, and quantify external parasitic loads:

- fuel consumption, actual cubic feet per hour (acfh) for gas-fueled or pounds per hour (lb/h) for liquid-fueled equipment
- ambient air temperature, degrees Fahrenheit (^{o}F)
- ambient barometric pressure, pounds per square inch absolute (psia)
- external parasitic load power consumption, kVA (apparent power) or kW (real power)

Note that "ambient conditions" may require careful consideration depending on site characteristics. For example, interior installations require consideration of the combustion air intake location, whether it is under negative or positive pressure, exhaust induced draft (ID) fan effects (if present), and system cooling conditions. The ambient air sensors should be placed at a location which is representative of the air actually used by the SUT for the prime mover.

2.1.2. System Boundary

Figure 2-1 is a generalized instrument location schematic diagram for electrical performance measurements. The figure shows power meter locations with respect to the DUT and the point of common coupling (PCC). The PCC is the point at which the electric power system (EPS), other users, and the SUT have a common connection.

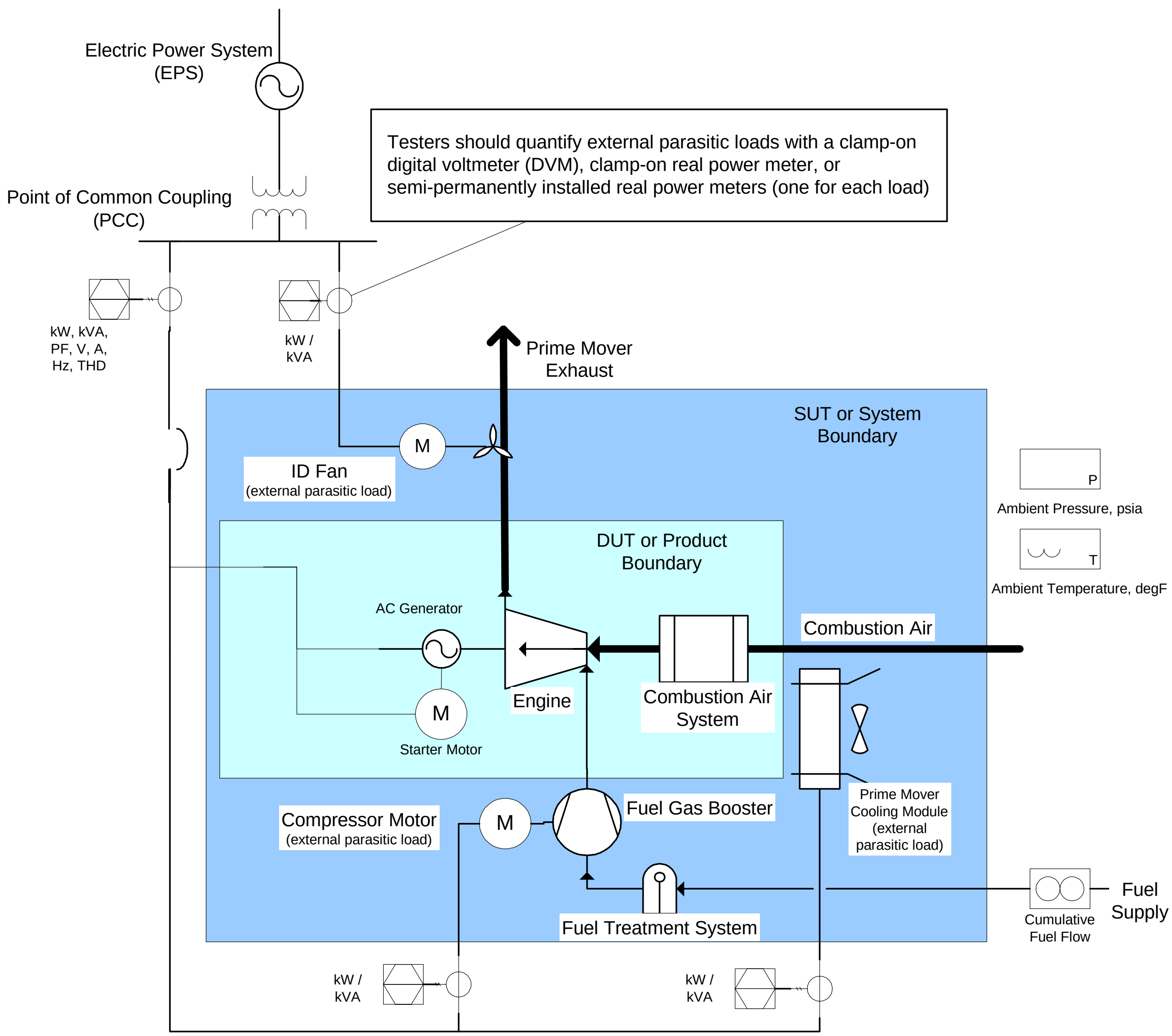


Figure 2-1. Electrical Performance Instrument Locations

Figure 2-1 shows a fuel gas compressor, an ID fan, and a prime mover cooling module which are not connected internally to their electric power source. These components are outside the product boundary (or DUT) but inside the system boundary (or SUT). Testers must inventory such external parasitic loads and plan to measure their power consumption as apparent power (kVA) with a clamp-on digital volt meter (DVM) or as kW with real power meters (one for each load). Accounting for external parasitic loads in terms of kVA is based on the assumption that real and apparent powers are approximately equal (power factor ≈ 1.0). Appendix G discusses the impact of this approximation on the electrical generation efficiency accuracy.

2.2. INSTRUMENTS

The power meter that measures the electrical parameters listed in Section 2.1.1 must meet the general specifications for electronic power meters in ANSI C12.20-2002 [1]. The meter must incorporate an internal datalogger or be able to communicate with an external datalogger *via* digital interface (RS-485, RS-232, LAN, telephone, etc.). The current transformer (CT) must conform to IEC 61000-4-30 Metering Class specifications [2]. Table 2-1 summarizes electrical performance and supplemental instrument specifications. Appendix F contains more detailed specifications and installation procedures.

Table 2-1. Electrical Performance Instrument Accuracy Specifications[a]

Parameter	Accuracy
Voltage	± 0.5 %
Current	± 0.4 %
Real Power	± 0.6 %
Reactive power	± 1.5 %
Frequency	± 0.01 Hz
Power Factor	± 2.0 %
Voltage THD	± 5.0 %
Current THD	± 4.9 % to 360 Hz
CT	± 0.3 % at 60 Hz
CT	± 1.0 % at 360 Hz
Temperature	± 1 °F
Barometric pressure	± 0.1 in. Hg (± 0.05 psia)
DVM voltage	± 1.0 %
DVM current	± 2.0 %
Fuel consumption	± 1.0 %
Real power meter kW[b]	± 1.0 %

[a]All accuracy specifications are percent of reading, provided by manufacturers, and subject to the calibrations and QC checks described in Section 7.0.
[b]If used for external parasitic load determinations.

The power meter and supplemental instruments must be accompanied by a current (within 6 years) National Institutes of Standards and Technology (NIST)-traceable calibration certificate prior to installation. The calibrations must include the internal data logger if used, or the external data logger should carry a NIST-traceable calibration of the analog to digital signal converter. The CTs must be accompanied by a manufacturer's accuracy certification.

The datalogger (internal or external) must have the capability to poll the power meter for each electrical parameter at least once every five seconds, then compute and record the one-minute averages. Additional channels will be required to perform CHP testing (see Section 4.0).

2.2.1. Permissible Variations

SUT operations should be reasonably stable during testing. PTC-22 [3] and PTC-17 [4] specify the maximum permissible variations. Key parameter variations should be less than those summarized in Table 2-2 during each test run. Test personnel will use only those time periods that meet these requirements to compute performance parameters.

Table 2-2. Permissible Variations

Measured Parameter	MTG Allowed Range	IC Generator Allowed Range
Ambient air temperature	± 4 °F	± 5 °F
Ambient pressure (barometric station pressure)	± 0.5 %	± 1.0 %
Fuel flow	± 2.0 %[a]	n/a
Power factor	± 2.0 %	n/a
Power output (kW)	± 2.0 %	± 5.0 %
Gas pressure[b]	n/a	± 2.0 %
Gas temperature[b]	n/a	± 5 °F

[a]Not applicable for liquid-fueled applications < 30 kW.
[b]Gas-fired units only

3.0 ELECTRICAL EFFICIENCY

3.1. SCOPE

Electrical generation efficiency (η_e) can also be termed the "fuel-to-electricity conversion efficiency." It is the net amount of energy a SUT produces as electricity compared to the amount of energy input to the system in the fuel, with both the outputs and inputs stated in common units. Heat rate expresses electrical generation efficiency in terms of British thermal units per kW-hour (Btu/kWh). Definitions and equations appear in Appendix C.

Efficiency can be related to the fuel's higher heating value (HHV) or its lower heating value (LHV). The HHV is typically (approximately) 10% higher than the LHV and represents maximum theoretical chemical energy from combustion. Appendix D, Equation D10 shows the relationship between the two efficiency statements. With few exceptions (such as condensing boilers) the full HHV of the fuel is not available for recovery. Therefore this GVP specifies determinations for $\eta_{e,LHV}$, or the electrical conversion efficiency referenced to fuel LHV.

3.1.1. Parameters and Measurements

Testers will quantify electrical generation efficiency and heat rate at each of the three power commands. Required measurements include the following:

- real power production, kW
- external parasitic load power consumption, kVA (apparent power) or kW (real power)
- ambient temperature, ^{o}F
- ambient barometric pressure, psia
- fuel LHV, Btu per standard cubic foot (Btu/scf) for gaseous fuels or Btu per pound (Btu/lb) for liquid fuels
- fuel consumption, standard cubic feet per hour (scfh) for gaseous fuels or pounds per hour (lb/h) for liquid fuels

Note that the definition of "ambient" conditions, while simple for outdoor installations, may require careful consideration for indoor applications. Air conditioning or ventilation equipment can substantially alter combustion air properties at the SUT air intake and therefore its performance. For example, the SUT may draw its combustion air from an interior room which is under negative pressure. The ambient pressure and temperature sensors should therefore be located in that room.

Fuel heating value determinations require gaseous or liquid fuel sample collection and laboratory heating value analysis. Fuel analyses provided by the fuel supplier are an acceptable alternative to fuel sampling so long as the analyses are current (within approximately one month of testing) and traceable (proper analytical procedures are documented). Fuel consumption determinations require the following measurements:

Gaseous Fuels

- fuel flow rate, acfh
- fuel absolute temperature, degrees Rankine (R)

- fuel absolute pressure, psia (which can be stated as the sum of ambient barometric pressure plus fuel gauge pressure)
- fuel compressibility (dimensionless) obtained from fuel sample laboratory analysis

Liquid Fuels

- fuel mass consumption, lb/h

During electrical efficiency test runs, the SUT and ambient conditions must conform to the permissible variations outlined in Table 2-2.

3.1.2. System Boundary and Measurement Locations

Figure 3-1 is a generalized instrument location schematic diagram. The figure shows measurement instrument locations with respect to the SUT and the PCC.

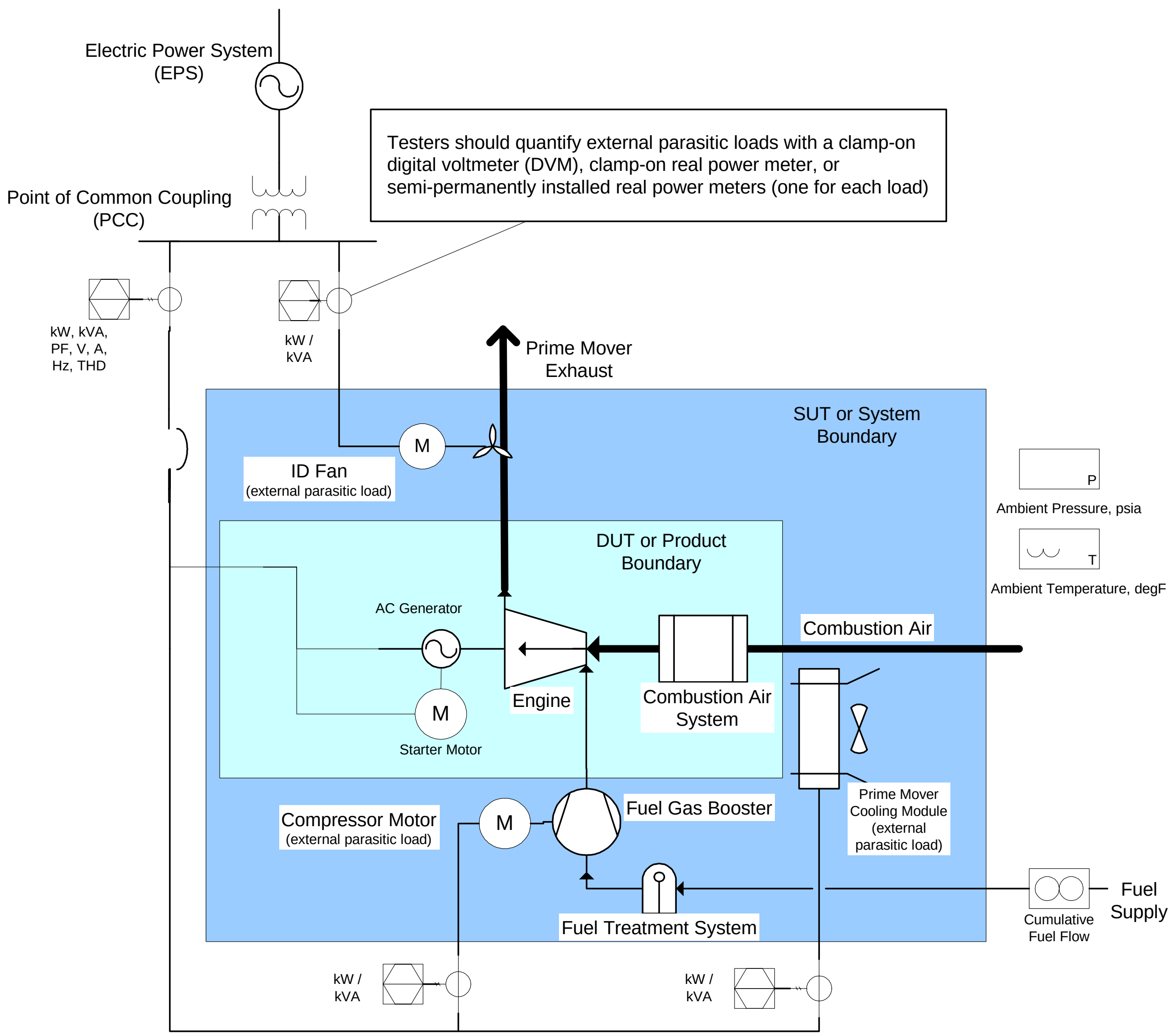


Figure 3-1. Electrical Efficiency Instrument Locations

3.2. INSTRUMENTS AND FUEL ANALYSES

Table 3-1 summarizes the required instruments, laboratory analyses, and accuracy specifications. Appendix F provides more detailed specifications, installation, and analysis procedures.

Table 3-1. Electrical Efficiency Instrument Accuracy Specifications

Fuel	Measurement	Maximum Allowable Error[a]
Gaseous fuel	Gas flow	± 1.0 % [5,6,7]
	Gas temperature	± 4.5 °F
	Gas pressure	± 0.2 psia
	LHV analysis by ASTM D1945 [8] and D3588 [9]	± 1.0 %
Liquid fuel	Platform scale (< 500 kW)	± 0.01 % of reading, ± 0.05 lb scale resolution
	Temperature-compensated flow meter (> 500 kW)	Single flow meter (MTG): ± 1.0 % Differential flow meter (diesel IC generator): ± 1.0 % of differential reading (achieved by approx. ± 0.2 % for each flow sensor)
	Density analysis by ASTM D1298 [10] (> 500 kW)	± 0.05 %
	LHV analysis by ASTM D4809 [11]	± 0.5 %

[a]All accuracy specifications are percent of reading unless otherwise noted, provided by manufacturers, and subject to the calibrations and QC checks described in Section 7.0.

Gaseous or liquid fuel consumption instruments and their readouts or indexes should be specified to ensure that their resolution is < ± 0.2 percent of the total fuel consumed during any test run. For example, if a MTG uses 100 ft^3 during a test run at 50 percent power command, the gas meter's index resolution must be less than 0.2 ft^3.

Table 3-2 presents supplemental equipment for SUT less than about 500 kW capacity.

Table 3-2. Supplemental Equipment for SUT < 500 kW

Description	Capacity
Day tank	100 gallon
Secondary containment	100 gallon, minimum
Return fuel cooler (diesel IC generator only)	Approximately 14000 - 22000 Btu/h for 500 kW engine

Equipment may include diesel fuel line heater or day tank heater in colder climates. These represent additional internal or external parasitic loads which test personnel should consider.

4.0 CHP THERMAL PERFORMANCE

4.1. SCOPE

This section presents test methods for determining thermal performance of CHP systems in heating or chilling service. Applicable CHP devices use a circulating liquid heat transfer fluid for heating or chilling. The CHP equipment itself is considered to be within the SUT boundary. The balance of plant (BoP) equipment, which employs the heating or chilling effect, is outside the system boundary. This GVP does not consider how efficiently the BoP uses the heating or chilling effect.

4.1.1. Parameters and Measurements

The field tests described in this GVP are intended to quantify the following CHP performance parameters:

- actual thermal performance in heating service, Btu/h
- actual SUT efficiency in heating service as the sum of electrical efficiency and thermal efficiency, percent
- maximum thermal performance, or maximum energy available for recovery, Btu/h
- maximum thermal efficiency in heating service, percent
- maximum SUT efficiency in heating service, percent
- actual thermal performance in chilling service, Btu/h or refrigeration tons (RT)
- maximum secondary heat in chilling service, Btu/h
- heat transfer fluid supply and return temperatures, ^{o}F, and flow rates, gallons per minute (gpm)

Actual thermal performance is the heat transferred out of the SUT boundary to the BoP for both CHP heaters and chillers. Actual thermal efficiency in heating service is the ratio of the thermal performance to total heat input in the fuel.

Refer to Figures 4-1 and 4-2 regarding maximum thermal performance, maximum thermal efficiency, and maximum SUT efficiency. Figure 4-1 shows simplified schematics for hot fluid- and exhaust-fired CHP systems. A CHP system in heating service may incorporate cooling modules for removal of excess heat from the CHP device, the prime mover (shown in Figure 4-2), and other sources during periods of low heat demand. The sum of the actual thermal performance, cooling tower rejected heat, and prime mover cooling module rejected heat represents the maximum available thermal energy. The ratio of the maximum available thermal energy to the fuel heat input is the maximum thermal efficiency in heating service. Similarly, maximum SUT efficiency is the ratio of the sum of the rejected heat, actual heat transferred, and the electric power produced divided by the system's fuel heat input.

Maximum secondary heat in chilling service is that available from secondary systems such as low-grade heat from cooling towers (Figure 4-1) or medium-grade heat from prime mover cooling modules (Figure 4-2). Actual or maximum thermal efficiency in chilling service is not meaningful because chiller system coefficient of performance (CoP) is not included in the scope of this document.

Note that throughout this document the "cooling tower" or "prime mover cooling module" could be replaced by any means of waste heat rejection, such as fan-coil unit or other heat exchanger.

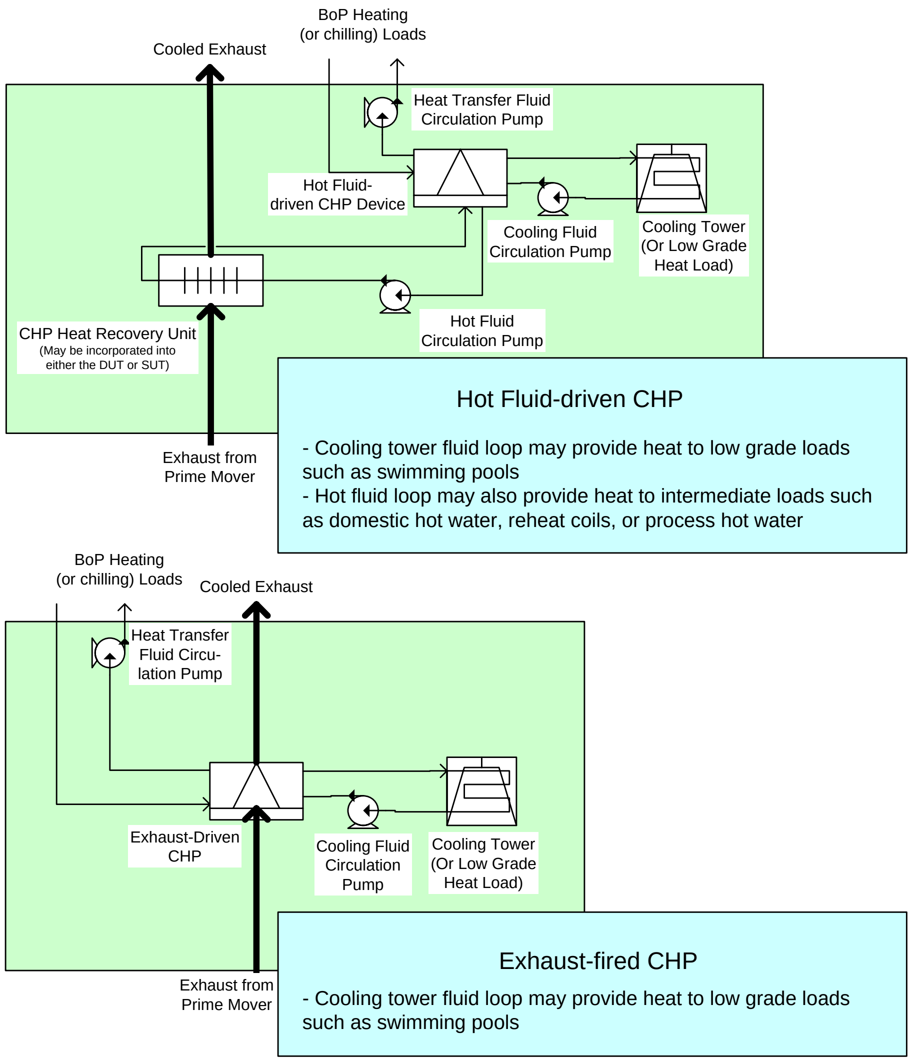


Figure 4-1. CHP Configurations: Hot Fluid- or Exhaust-fired

In either heating or chilling applications, thermal performance determination requires the following measurements and determinations at each of the three power commands:

- heat transfer fluid flow rate at the SUT boundary
- heat transfer fluid supply and return temperatures at the SUT boundary
- heat transfer fluid specific heat and density
- heat transfer fluid flow rate at each cooling tower
- heat transfer fluid supply and return temperatures at each cooling tower
- SUT heat input, as determined from the fuel consumption rate and heating value (Section 3.0)
- electrical efficiency (Section 3.0)

4.1.2. System Boundary

Figure 4-2 provides a sample system schematic which depicts a CHP system, instrument locations, internal and external parasitic load examples, and heat transfer fluid flow paths. The figure also shows the cooling tower's fan and circulation pump as a combined external parasitic load. The figure provides instrument locations for testing CHP systems in both heating and chilling service because the heat transfer schemes are similar.

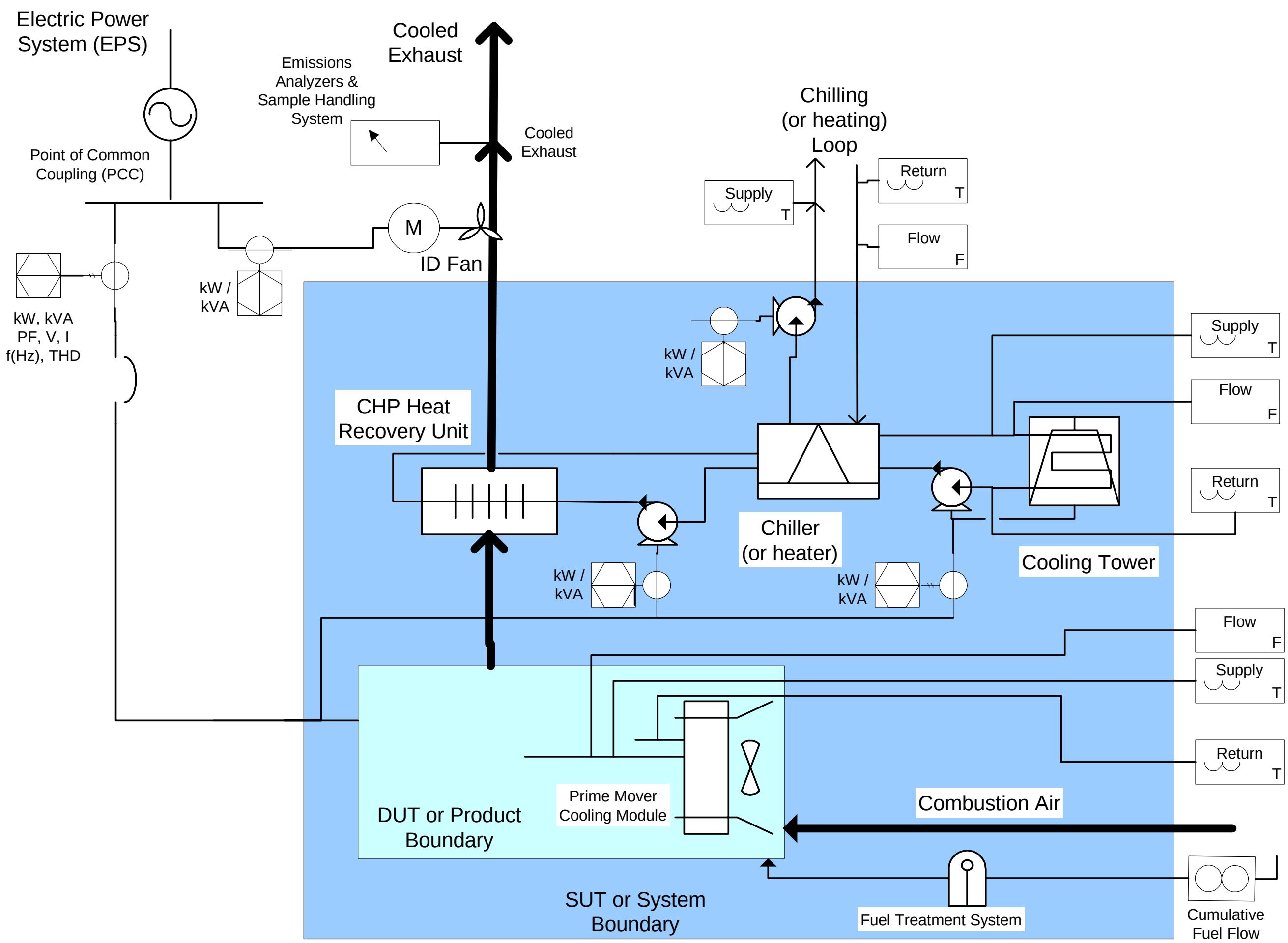


Figure 4-2. Example Hot Fluid-driven CHP System Schematic and Instrument Locations

The heat transfer fluid loop marked "Chilling (or heating) Loop" in Figure 4-2 represents the primary useful energy product in either heating or chilling service. Various combinations of heat transfer fluid loops can provide secondary energy to the BoP, such as:

- In a hot fluid-driven chiller, part or all of the hot fluid energy may be supplied to BoP thermal loads. In this case, thermal performance should be assessed while operating in the heating mode in addition to the chilling mode.
- In either hot fluid- or exhaust-fired chillers, the cooling tower loop fluid may be warm enough for low grade heat applications such as swimming pool heating. In this case, heat delivered to the useful loads should be measured.

Testers should therefore specify instrument placement on a site-specific basis, and create a SUT schematic which includes the instruments as part of the report.

4.2. INSTRUMENTS AND FLUID PROPERTY ANALYSES

CHP measurement equipment includes that listed in Sections 2.0, 3.0 and:

- heat transfer fluid flow meter(s) and transmitter(s)
- matched T_{supply} and T_{return} sensors, thermowells, and transmitters
- suitable multi-channel datalogger

Determination of thermal performance requires one complete flow meter and temperature sensor set for each heat transfer loop.

CHP performance determinations also require heat transfer fluid density (ρ) and specific heat (c_p). These values may be obtained from standard tables for water [12]. Laboratory analysis for density is required for propylene glycol (PG) solutions. Analysts will then use the density result to interpolate specific heat from ASHRAE standard tables for PG [13] or equivalent tables for other fluids.

Table 4-1 provides instrument and analysis accuracy specifications. Appendix F suggests specific instruments and installation procedures.

Table 4-1. CHP Thermal Performance Instrument Accuracy and Analysis Errors[a]

Parameter	Accuracy
Heat transfer fluid flow (including transmitter)	± 1.0 %
T_{supply}, T_{return} temperature sensors (including transmitters)	± 0.6 ^oF at expected operating temperature
Heat transfer fluid density by ASTM D1298 [14]	± 0.2 %[b]
Heat transfer fluid specific heat from ASHRAE tables [13]	± 0.2 %[b]

[a]All accuracy specifications are percent of reading unless otherwise noted, provided by manufacturers, and subject to the calibrations and QC checks described in Section 7.0.
[b]PG or other non-water heat transfer fluids only

5.0 ATMOSPHERIC EMISSIONS PERFORMANCE

5.1. SCOPE

This GVP considers emissions performance tests to be optional. If performed, the following subsection cites the appropriate Title 40 CFR 60, Appendix A [15] reference methods. This GVP highlights reference method features, accuracies, QA/QC procedures, and other issues of concern. The individual test methods contain detailed test procedures, so they are not repeated here.

5.1.1. Emission Parameters & Measurements

The gaseous emissions and pollutants of interest for all DG systems are:

- nitrogen oxides (NO_x)
- carbon monoxide (CO)
- oxygen (O_2)
- methane (CH_4)
- sulfur dioxide (SO_2)
- carbon dioxide (CO_2)
- total hydrocarbons (THC)
- TPM (diesel or other distillate fuel)

The reference methods to be used for each parameter are specified in Table 5-2. Note that systems firing gaseous fuels need not evaluate TPM emissions except in special cases such as those supplied by certain biogas sources. These may include landfill gas- or human waste digester gas-fired units that do not incorporate effective siloxane gas removal equipment. Most systems firing commercial natural gas need not evaluate SO_2 unless the fuel sulfur content is elevated.

In CHP systems with low temperature heat recovery loops (such as where condensation may occur) the emissions profile when recovering heat may differ from when exhaust gas bypasses the heat recovery unit. In this case emissions testing should take place in the worst case configuration. This is typically with the diverter in the bypass position.

Measurements required for emissions tests, if performed, include:

- electrical power output, kW (Section 2.0)
- fuel heat input, Btu/h (Section 3.0)
- pollutant, greenhouse gas (GHG), and O_2 concentration, parts per million (ppm), grains per dry standard cubic foot (gr/dscf), or percent
- stack gas molecular weight, pounds per pound-mole (lb/lb.mol)
- stack gas moisture concentration, percent
- stack gas flow rate, dry standard cubic feet per hour (dscfh)

Each of these measurements require sensors, contributing determinations, calibrations, sample collection, or laboratory analysis as specified in the individual reference methods.

5.1.2. Additional Emission Tests

Air toxic emissions can be evaluated depending primarily on fuel type, SUT design, and the needs of the site operator or test program manager. Table 5-1 lists the recommended test methods.

Table 5-1. Recommended Air Toxics Evaluations

	Pollutant			
	Formaldehyde	**Metals**	**Ammonia (NH_3)**	**Sulfur Compounds (TRS)**
Test Method	Method 323 (Proposed)	Method 29	Conditional Test Method CTM-027	Method 16A
Fuel Type or System Design				
Natural Gas	✓			
LPG	✓			
Biogas (digester)	✓		✓	✓
Landfill gas	✓		✓	✓
Petroleum (diesel)	✓	✓		
System with NO_x Emission Controls			✓	

Ammonia testing should also be considered for DG systems with NO_x catalytic or non-catalytic emission controls. Ammonia slip is a potential concern in such systems.

5.1.3. System Boundary

Figure 1-2 shows a generalized system boundary for emissions testing. Although most DG systems have a single exhaust stack, some CHP designs may utilize separated high temperature and low temperature exhaust streams with an exhaust diverter. The test manager should review SUT design to ensure that emissions tests incorporate all potential emission points.

5.2. INSTRUMENTS

The reference methods provide detailed instrument, sampling system components, and test procedure specifications. Table 5-2 summarizes the fundamental analytical principle for each method.

Table 5-2. Summary of Emission Test Methods and Analytical Equipment

Parameter or Measurement	U.S. EPA Reference Method	Principle of Detection
CH_4	18	Gas chromatograph with flame ionization detector (GC/FID)
CO	10	Non-dispersive infrared (NDIR)-gas filter correlation
CO_2	3A	NDIR
NO_X	20,7E	Chemiluminescence
O_2	3A	Paramagnetic or electrochemical cell
SO_2	6C	Pulse fluorescence, ultraviolet or NDIR
THC	25A	Flame ionization detector (FID)
TPM	5, 202	Gravimetric
Moisture	4	Gravimetric
Exhaust gas volumetric flow rate	2, 19	Pitot traverse or F-factor calculation

5.2.1. Analyzer Span Selection

The test manager should evaluate the system's emissions prior to the test campaign because experience has shown that DG emissions can vary widely at the specified power command settings (50, 75, and 100 percent). In general, expected stack gas concentrations should be between 30 and 100 percent of the analyzer span. Concentrations outside this range can cause a test run to be deemed invalid. Testers should plan to modify the analyzer spans as needed to prevent this.

It may be impossible, however, for a NO_X analyzer to meet this specification at low NO_X emission rates. It is acceptable in this case to adjust the analyzer span such that the expected NO_X concentrations fall between 10 and 100 percent of span.

Ambient (high sensitivity) analyzers will be required to perform these measurements at the specified accuracy due to extremely low emission rates of some DG sources. Care should be taken to match the instrumentation to manufacturer-specified or well-documented emission rates.

6.0 FIELD TEST PROCEDURES

6.1. ELECTRICAL PERFORMANCE TEST (LOAD TEST) PROCEDURES

The objectives of the load test phase are to:

- obtain site information and system specifications
- measure the DUT electrical generation performance at three power command settings: 50, 75, and 100 percent
- provide a stable test environment for acquisition of reliable electrical efficiency (Section 3.0), CHP performance (Section 4.0), or atmospheric emissions (Section 5.0).

6.1.1. Pre-test Procedures

The DUT should have completed a burn-in phase of at least 48 hours at 100 percent of power command for rebuilt equipment or new installations. At a minimum new DG units must have completed the manufacturer's recommended break-in schedule.

Log the site's DG installation data on the form provided in Appendix B2 and ensure that test instruments described in Section 2.2 have been properly selected, calibrated, and installed. Identify external parasitic loads to be evaluated during the test. Equipment for this evaluation should be documented on the Distributed Generator Installation Data form (Appendix B2). External parasitic loads that serve multiple users in addition to the DUT (such as large gas compressors serving several units) need not be measured. Note such common loads on the Appendix B2 log form and describe them in the test report.

6.1.2. Detailed Test Procedure

A 30 minute monitoring period with the SUT off or disconnected will precede and follow each test period to establish EPS baseline voltage and THD performance. Record the electrical parameters listed in Section 2.1.1.

Each test period will consist of:

- a period for SUT equilibration at the given power command, followed by three test runs
- Test runs will be ½-hour each for microturbine generators and 1-hour each for IC generators

If emission tests are being performed, each test run should be preceded and followed by the appropriate emission measurement equipment calibration and drift checks. Figure 1-3 shows a test run schematic timeline.

The step-by-step load test procedure is as follows:

1. Ensure all instruments are properly installed and calibrated in accordance with the Section 7.1 requirements and that field QC checks have been conducted and met acceptance criteria.
2. Initialize the datalogger to begin recording one-minute power meter data.
3. Synchronize all clocks with the datalogger time display. Disconnect the DG unit and shut it down for the one-hour baseline monitoring period. Record the time on a load test run log form (Appendix B3).
4. Enter the power command setting (beginning with 50% of full power), manufacturer, model number, location, test personnel, and other information onto the load test run log form (Appendix B3). Specify a unique test run ID number for each test run and record on the load test run log form.
5. If necessary, coordinate with other testing personnel to establish a test run start time. Record the test run start time and initial fuel reading on the log form in Appendix B4. Transfer the test run start time to the load test run log form (Appendix B3).
6. Record one set of ambient temperature and pressure readings on the load test run log form (Appendix B3) at the beginning; at least two at even intervals during; and one at the end of each test run.
7. Operate the unit at 50 percent of capacity for sufficient time to acquire all data and samples as summarized in Figure 1-3. Record the required data on the load test run log and fuel flow log forms (Appendix B3, B4) during each test run. If additional parameters are being evaluated during the load test phase (electrical efficiency, thermal efficiency, emissions), ensure that the data required in the applicable sections is documented.
8. Acquire and record external parasitic load data on the external parasitic load data log form in Appendix B5. Use a new log form for each test run.
9. If fuel analyses are needed for electrical efficiency determinations (Section 3.0), acquire at least one fuel sample during a valid test run at each of the three power command settings[1]. Use the procedure and log form in Appendix B6.
10. For CHP performance determinations (Section 4.0), acquire at least one[1] heat transfer fluid sample from each heat transfer fluid loop (fluids other than water only; do not sample pure water heat transfer fluids). Use the procedure and log form in Appendix B6.
11. At the end of each test run, review the electrical performance data recorded on the datalogger for completeness. Also review all other datalogger records as appropriate for completeness and reasonableness. Enter the maximum and minimum kW, ambient temperature, ambient pressure, etc. on the load test run log form and compare them with the maximum permissible variations listed in Table 2-2. If the criteria are not met repeat the test run until they are satisfied.
12. Repeat steps 4 through 11 at 75 percent of capacity. Use new fuel flow and load test run log forms.
13. Repeat steps 4 through 11 at 100 percent of capacity. Use new fuel flow and load test run log forms.
14. Disconnect the unit for at least one hour for EPS baseline monitoring.
15. Complete all field QA/QC activities as follows:
    - Ensure that all field data form blanks have the appropriate entry
    - Enter dashes or "n/a" in all fields for which no data exists
    - Be sure that all forms are dated and signed
16. Archive the datalogger files in at least two separate locations (floppy disk and computer hard drive, for example). Enter the file names and locations on the load test run log forms (Appendix B3).

[1] If the testing organization has had good experience with the analytical laboratory historically then one sample at each power command setting (for fuel) or one sample during the test campaign (for each heat transfer fluid) will suffice. Otherwise redundant samples should be taken to confirm analysis repeatability.

17. Forward the fuel & fluid samples to the laboratory under a signed chain of custody form (Appendix B7).

6.2. ELECTRICAL EFFICIENCY TEST PROCEDURES

Electrical efficiency test runs should occur simultaneously with the electrical performance test runs. Electrical efficiency determinations include all the tasks listed in Section 6.1 and:

- fuel consumption determination (Section 6.1.2, Step 7)
- fuel sampling and analysis (Section 6.1.2, Step 9)
- submit fuel samples for laboratory analysis at the conclusion of testing as needed.

6.3. CHP TEST PROCEDURES

6.3.1. Pretest Activities

All fluid loops should have been circulating for a period of at least 48 hours with no addition of chemical or makeup water to ensure well-mixed fluid throughout the loop.

Test personnel should log the heat recovery unit information in the Appendix B8 log form. The test manager should document CHP heat transfer fluid loop(s) and thermal performance instrument location(s) on a summary schematic diagram.

Immediately before the first test run, site operators should stop the heat recovery fluid flow or isolate the fluid flow meter from the SUT. Test operators will record the zero flow value on the Appendix B8 log form and make corrections if the zero flow value is greater than ± 1.0 percent, full scale.

6.3.2. Detailed Test Procedure

CHP performance test runs should occur simultaneously with the electrical performance and electrical efficiency test runs. The CHP system should be activated during testing at operating levels which are appropriate for the power command setting. CHP performance determinations include the tasks listed in Section 6.1 and the following data and sample collection activities:

- Ensure all instruments are properly installed and calibrated in accordance with the Section 7.1 requirements and that field QC checks have been conducted and met acceptance criteria.
- record one-minute average V_l (heat transfer fluid flow rate), T_{supply}, and T_{return} data during each of the three test runs at each power command (50, 75, and 100 percent) using the datalogger
- log fuel consumption and collect fuel samples (Section 6.1.2, Step 7)
- for heat transfer fluids other than water, collect at least one fluid sample during the load tests (Section 6.1.2, Step 9). Appendix B6 provides the sampling procedure and log form.
- at the conclusion of the load tests, forward any required fuel and fluid samples to the laboratory under a signed chain of custody form (Appendix B7)

6.4. ATMOSPHERIC EMISSIONS TEST PROCEDURES

Testers should plan to conduct three test runs at each of three power command settings (50, 75, and 100 percent) simultaneously with the electrical performance, electrical efficiency, or CHP performance test runs. Use of experienced emissions testing personnel is recommended because of the complexity of the methods.

Emissions performance determinations include the tasks listed in Section 6.1 and the following measurement and data collection activities:

- three instrumental analyzer test runs, 30 minutes each for MTG and 60 minutes each for IC generators, at each power command setting for each emission parameter. Each test run incorporates pre- and post-test calibration, drift, and other QA/QC checks
- instrumental analyzer determination of CO_2, CO, O_2, NO_X, SO_2 (if required), and THC emission concentrations as specified in the reference methods during each test run
- one Method 2 or Method 19 exhaust gas flow rate determination for each instrumental analyzer test run
- one Method 4 determination of exhaust gas moisture content at each power command setting during a valid test run
- exhaust gas sample collection during each test run at each power command and analysis for CH_4 in accordance with EPA Method 18
- TPM sample collection during one 120-minute test run for liquid-fueled MTGs or one 60-minute test run for liquid-fueled IC generators at each load condition in accordance with EPA Methods 5 and 202
- all QA/QC checks required by the EPA Reference Methods

Throughout the testing, operators will maintain SUT operations within the maximum permissible limits presented in Table 2-2. The field test personnel or emissions contractor will provide copies of the following records to the test manager:

- analyzer makes, models, and analytical ranges
- analyzer calibration records
- QA/QC checks
- field test data
- copies of chain-of-custody records for gas samples (for THC and TPM)
- analytical data and laboratory QA/QC documentation
- field data logs that document sample collection, and appropriate QA/QC documentation for the sample collection equipment (gas meters, thermocouples, etc.)
- calibration gas certificates

The following subsections present procedural concerns for the emissions tests. Appendix E summarizes operational concerns which are often overlooked during emissions testing.

6.4.1. Gaseous Pollutant Sampling

This GVP specifies analyzers for the majority of the emission tests. A heated probe and sample line conveys the exhaust gas sample to the appropriate pumps, filters, conditioning systems, manifolds, and then to the analyzers. Analysts report the CO_2, CO, O_2, NO_x, and SO_2 concentrations in parts per million volume (ppmv) or percent on a dry basis.

The THC analyzer reports concentrations in ppmv on a wet basis. Analysts should use the results of the Method 4 test to correct the concentrations to a dry basis.

Method 18 CH_4 analysis requires the collection of time-integrated exhaust samples with a suitable probe and evacuated stainless steel cylinders or a probe, sample pump, and Tedlar bags. An orifice or valve regulates the sampling rate to correspond to the test run's duration. Test personnel should document the samples in the field and transfer them to an analytical laboratory under signed chain-of-custody forms. The laboratory will analyze the samples for CH_4 with an FID-equipped gas chromatograph.

6.4.2. Total Particulate Matter Sampling

TPM sampling should be completed for diesel- or other oil-fired DGs. The Method 5 sampling system collects stack gas through a nozzle and probe inserted in the stack. The test operator adjusts the velocity of the stack gas which enters the nozzle to be the same as the stack gas velocity ("isokinetic sampling"). This minimizes TPM inertial effects and allows representative sampling.

The sample passes through a heated particulate filter whose weight gain, correlated with the sample volume, yields the particulate concentration. Following the filter, a series of water-filled impingers collects condensable particulate which, when dried and weighed according to Method 202, yields the condensable particulate concentration. For this GVP, each test run should be followed by an N_2 purge to remove dissolved gases. Analysts should stabilize potential H_2SO_4 in the sample using the NH_4OH titration. The sum of the probe wash, nozzle wash, and the two particulate catches yields the TPM concentration.

Sampling should occur at a series of traverse points across the area of the duct, with points selected according to EPA Reference Method 1 [15]. On small diameter exhausts, the method allows sampling at a single-point which represents the average gas velocity.

Testers should collect a large enough sample to allow a quantitative filter weight gain. For reciprocating IC generators, 32 scf collected over one hour is adequate. The longer recommended test run (120 minutes) and larger sample volume (64 scf) for MTGs increases the method's sensitivity. This is because MTG emissions are generally lower than IC generators. The TPM test run should occur during the instrumental analyzer test runs.

6.4.3. Exhaust Gas Flow Rate

Testers may employ either Method 2 or Method 19 for exhaust gas flow rate determinations. Method 2 measurements require a traverse of the exhaust duct with a pitot and manometer and correlation with the Method 3 (stack gas composition) and Method 4 (stack gas moisture content) determinations.

Method 19 employs "F-Factors" to estimate the combustion gas volume based on the fuel composition. This GVP recommends use of the F-factors in Table 19-2 of the method for natural gas, propane, or diesel fuel.

Analysts should calculate a site-specific F-factor for other fuels. This requires the fuel's ultimate carbon, hydrogen, oxygen, nitrogen, and sulfur elemental composition. Testers should collect one fuel sample at each power command (three samples total) during a valid emission test run and forward the samples to the laboratory for analysis. The laboratory should use accepted analytical procedures (not specified here) which yield ± 1.0 percent accuracy for each constituent. Analysts should use the mean analysis of the three samples in the Method 19 F-factor calculation. Appendices B6 and B7 provide the sampling procedure, log form, and chain of custody form.

The estimated exhaust gas flow rate uncertainty from use of Method 19 is approximately ± 3.2 percent, based on the ± 1.0 percent analytical accuracy. This GVP assumes that use of standard F-factors results in the same uncertainty level.

6.4.4. Emission Rate Determination

Emission testing provides exhaust gas concentrations as percent CO_2 and O_2, ppmvd CO, CH_4, NO_X, SO_2, and THCs, and gr/dscf TPM. Analysts first convert the measured pollutant concentrations to pounds per dry standard cubic foot (lb/dscf) and correlate them with the run-specific exhaust gas flow rate to yield lb/h. The report will include the mean of the three test results at each power command as the average emission rate for that setting. The report will also cite the normalized emission rates in pounds per kilowatt-hour (lb/kWh).

7.0 QA/QC AND DATA VALIDATION

7.1. ELECTRICAL PERFORMANCE DATA VALIDATION

After each test run, analysts should review the data and classify it as valid or invalid. All data will be considered valid once demonstration of all equipment QA/QC checks is completed. Data will only be invalidated if there is a specific reason for its rejection (such as process upsets or equipment malfunction), and the report will cite those reasons.

Each test run, to be considered valid, must include:

- at least 90 percent of the one-minute average power meter data
- data and log forms that show the DG operation conformed to the permissible variations throughout the run
- ambient temperature and pressure readings at the beginning and end of the run
- gas meter or liquid fuel day tank scale readings at the beginning and end and at least 5 readings during the run
- at least 3 complete kW or kVA readings from each external parasitic load
- completed field data log forms with accompanying signatures
- data that demonstrates all equipment met the allowable QA/QC criteria summarized in Table 7-1

Table 7-1. Electrical Generation Performance QA/QC Checks

Measurement	QA/QC Check	When Performed	Allowable Result
kW, kVAR, PF, I, V, f(Hz), THD	Power meter NIST-traceable calibration	6-year intervals	See Table 2-1
	CT documentation	At purchase	ANSI Metering Class 0.3 %; ± 1.0 % to 360 Hz (6^{th} harmonic)
V, I	Field QC sensor function checks (Appendix B1)	Beginning of load tests	V: ± 2.0 % I: ± 3.0 %
	Cross check against meter of similar accuracy	Before or during field testing	V: ± 2.0 % I: ± 2.0 %
All power parameters	Data logger function check	Beginning of load tests	Data records within ± 2 % of meter display
Ambient temperature	NIST-traceable calibration	18-month period	± 1 ^{o}F
Ambient barometric pressure	NIST-traceable calibration	18-month period	± 0.1 psia

7.1.1. Uncertainty Evaluation

CT and power meter errors compound together to yield the measurement uncertainty for most of the electrical parameters. Table 7-2 shows the maximum allowable error for each electrical parameter based on this GVP's power meter and CT accuracy specifications. The table also includes references to applicable codes and standards from which these errors were derived.

Table 7-2. Power Parameter Maximum Allowable Errors[a]

Parameter	Accuracy	Reference
Voltage	± 0.5 % (class B)	IEC 61000-4-30 [2]
Current	± 0.5 % (class B)[b]	IEC 61000-4-30 [2]
Real power	± 0.7 % overall[b]	IEC 61000-4-30 [2]
Reactive power	± 1.5 % overall[b]	n/a
Frequency	± 0.01 Hz (class A)	IEC 61000-4-30 [2]
Power factor	± 2.0 %[b]	IEEE 929 [5]
Voltage THD	± 5.0 %	IEC 61000-4-7 [6]
Current THD	± 5.0 % (to 360 Hz)[b]	IEC 61000-4-7 [6]

[a]All accuracy specifications are percent of reading except for frequency.
[b]Power meter and CT compounded uncertainty.

If the CTs and power meter calibration accuracies meet the Table 7-1 accuracy specifications, analysts may report the Table 7-2 values as the achieved accuracy. If the power meter and CT accuracy is less than specified in Table 7-1, analysts should estimate and report achieved accuracy according to the Appendix G procedures for estimating compounded error.

If measurement accuracy is better than the Table 7-1 specifications, analysts may either report the Table 7-2 values or calculate and report the achieved accuracies using the Appendix G procedures. Note that analysts may also use the Appendix G procedures to calculate and report achieved accuracy for THD for harmonic frequencies higher than 360 Hz if CT (and power meter) accuracy data are available for those frequencies.

7.2. ELECTRICAL EFFICIENCY DATA VALIDATION

After each test run and upon receipt of the laboratory results, analysts will review the data and classify it as valid or invalid. All invalid data should be associated with a specific reason for its rejection, and the report should cite those reasons.

Each test run, to be considered valid, must include:

- at least 90 percent of the one-minute average power meter data
- log forms that show the DG operation conformed to the permissible variations throughout the test run (Table 2-2)
- ambient temperature and pressure readings at the beginning and end of the run
- gas meter or day tank scale readings at the beginning, end, and at least one reading during the run
- completed field data log forms with accompanying signatures
- at least one fuel sample collected at each of the three power command settings, with log forms that show sample collection occurred during a valid test run.
- data that demonstrates all equipment met the allowable QA/QC criteria summarized in Table 7-1 (power meter, CTs, ambient temperature, and ambient pressure sensors) and Table 7-3.

Table 7-3. Electrical Efficiency QA/QC Checks

Measurement / Instrument	QA/QC Check	When Performed	Allowable Result
Gas meter	NIST-traceable calibration	Upon purchase or after repairs	± 1.0 % of reading
	Field QC check - Differential rate test for gaseous fuel meters	Beginning of test	± 10 % of expected differential pressure from calibration curve
Gas pressure	NIST-traceable calibration	2-year period	± 0.5 % FS
Gas temperature	NIST-traceable calibration	2-year period	± 4.5 °F
Weighing scale (DG < 500 kW)	NIST-traceable calibration	2-year period	± 0.1 % of reading
	Field QC check – challenge scale with reference standard weights	Beginning and end of test	± 2 % of reference standard
Flow meter(s) (DG > 500 kW)	NIST-traceable calibration	Upon purchase or after repairs	Single flow meter: ± 1.0 %, compensated to 60 ^{o}F Differential flow meter (diesel IC generators only): differential value ± 1.0 %, compensated to 60 ^{o}F
Gas LHV, HHV: ASTM D1945, D3588	NIST-traceable standard gas calibration	Weekly	± 1.0 % of reading
	ASTM D1945 duplicate sample analysis and repeatability	Once per lot of samples	Within D1945 repeatability limits for each gas component
Liquid fuel LHV, HHV: ASTM D4809	Benzoic acid standard calibration	Weekly	± 0.1 % relative standard deviation

7.2.1. Uncertainty Evaluation

Table 7-4 shows the estimated η_e uncertainty for electrical efficiency for gaseous and liquid fuels if each of the contributing measurements and determinations meet this GVP's accuracy specifications.

Table 7-4. Electrical Efficiency Uncertainty

	Parameter	Relative Accuracy, % External Parasitic Loads Measured as kVA	 External Parasitic Loads Measured as kW
Gaseous Fuels	Real Power, kW	± 2.2	± 0.7
	Fuel Heating Value (LHV or HHV), Btu/scf	± 1.0	± 1.0
	Fuel Rate, scfh	± 1.8	± 1.8
	Efficiency, η_e	**± 3.0**	**2.2**
Liquid Fuels	Real Power, kW	± 2.2	± 0.7
	Fuel Heating Value (LHV or HHV), Btu/scf	± 0.5	± 0.5
	Fuel Rate, lb/h	± 2.8	± 2.8
	Efficiency, η_e	**± 3.6**	**± 2.9**

The uncertainty evaluation is conducted using the procedures in Appendix G. If the contributing measurement errors and the resulting real power, fuel heating value, and fuel consumption rate determinations meet this GVP's accuracy specifications, analysts may report the appropriate table entries as the η_e uncertainty. Otherwise use procedures outlined in Appendix G to determine the actual uncertainty.

7.3. CHP PERFORMANCE DATA VALIDATION

After each test run and upon receipt of the laboratory results, analysts should review the data and classify it as valid or invalid. All invalid data will be associated with a specific reason for its rejection, and the report will cite those reasons.

Each CHP performance test run, to be considered valid, must include:

- at least 90 percent of the one-minute average V_l, T_{supply}, and T_{return} data
- completed field data log forms with accompanying signatures
- appropriate NIST-traceable calibrations and successful sensor function checks for the measurement instruments
- laboratory results for at least one heat transfer fluid sample (if other than water) collected during the load test phase
- data and field log forms that demonstrate all equipment and laboratory analyses meet the QA/QC criteria summarized in Table 7-5.

Table 7-5. CHP Thermal Performance and Total Efficiency QA/QC Checks

Description	QA/QC Check	When Performed	Allowable Result
Heat transfer fluid flow meter	NIST-traceable calibration	2-year period	± 1.0 % of reading
	Field QC check - sensor function checks	at installation	See Appendix B8
	Field QC check - Zero flow response check	at installation; immediately prior to the first test run	Less than ± 1.0 % of FS
T_{supply} and T_{return} sensor and transmitter	NIST-traceable calibration	18-month period	± 1 ^{o}F between 100 and 210 ^{o}F
	Field QC check - Sensor function check	at installation	See Appendix B8
Heat transfer fluid density *via* ASTM D1298 (for fluids other than water)	Laboratory analysis temperature set to T_{avg}	each sample	± 1 ^{o}F
	Hydrometer NIST-traceable verification	2-year period	Maximum error ± 0.5 kg/m^3
	Thermometer NIST-traceable verification	2-year period	Maximum error ± 0.2 ^{o}C (± 0.5 ^{o}F)

For actual and maximum total system efficiency determinations (in heating service), each thermal efficiency one-minute average must have a contemporaneous electrical efficiency one-minute average. This will allow analysts to determine the one-minute total efficiencies and subsequently the run-specific average efficiencies. The permissible variations within each test run should conform to the Table 2-2 specifications.

7.3.1. Uncertainty Evaluation

Assuming that all instruments and measurements conform to this GVP's accuracy specifications (including the stipulation that actual ΔT equals or exceeds 20 ^oF), Table 7-6 shows the contributing errors and estimated uncertainty for:

- thermal performance (Q_{out}) in heating and chilling service
- η_{th} and η_{tot} in heating service.

Table 7-6. Individual Measurement ΔT, Q_{out}, η_{th}, and η_{tot} Accuracy

Description		Relative Error	CHP Service
Heat transfer fluid flow, V_l, gph		± 1.0 %	Heating and chilling service
ΔT, ^oF		± 4.3 % when $\Delta T \geq 20\ ^oF$	
c_p, Btu/lb.^oF		± 0.1 %	
ρ, lb/gal		± 0.2 %	
Q_{out}, Btu/h		**± 4.4 %**	
Gaseous Fuels	Heating Value, Btu/scf	± 1.0 %	Heating service
	Fuel rate, scfh	± 1.8 %	
	Q_{in}, Btu/h	± 2.1 %	
	η_{th} (Q_{out}/Q_{in}*100), %	**± 4.9 %** (± 2.6 % absolute error)	
	η_e, %	± 3.0 % (± 0.8 % absolute error)	
	η_{tot}, %	**± 3.5 %** (± 2.8 % absolute error)[a]	
Liquid Fuels	Heating Value, Btu/scf	± 0.5 %	
	Fuel rate[d], scfh	± 2.8 %	
	Q_{in}, Btu/h	± 2.8 %	
	η_{th} (Q_{out}/Q_{in}*100), %	**± 5.2 %** (± 2.8 % absolute error)	
	η_e, %	± 3.6 % (± 0.9 % absolute error)	
	η_{tot}, %	**± 3.7 %** (± 2.9 % absolute error)[a]	

[a]Assumed η_{th} is 53 %, η_e is 26 %, η_{tot} is 79 %; See Appendix T for absolute versus relative error estimation procedures.

Overall uncertainty can deteriorate significantly if the given measurement accuracy specifications are not met. For example, if ΔT is 5 ^oF, its relative accuracy (given the specified ± 1 ^oF temperature sensor accuracy) will be ± 17.0 percent. This is much less accurate than the ± 4.3 percent when ΔT is 20 ^oF or more. The resulting overall η_{tot} relative uncertainty for a gas-fired MTG-CHP would be ± 11.5 percent instead of the ± 3.5 percent shown in Table 7-6

If measurement accuracies and determination uncertainties exceed the Table 7-6 specifications, analysts should estimate and report achieved uncertainty according to the Appendix G procedures.

If measurement accuracies and determination uncertainties are better than the Table 7-6 specifications, analysts may either report the Table 7-6 estimated parameter uncertainties or calculate and report the achieved uncertainties using the Appendix G procedures.

7.4. EMISSIONS DATA VALIDATION

The reference methods specify detailed sampling methods, apparatus, calibrations, and data quality checks. The procedures ensure the quantification of run-specific instrument and sampling errors and that runs are repeated if the specific performance goals are not met. Table 7-8 summarizes relevant QA/QC procedures. Satisfaction and documentation of each of the calibrations and QC checks will verify the accuracy and integrity of the measurements.

The field test personnel or emissions testing contractor will be responsible for all emissions data, QA log forms, and electronic files until they are accepted by the test manager. The test manager should validate that:

- each of the QA/QC checks noted in Table 7-8 are completed satisfactorily
- all instrumental analyzer results are in the form of chart recorder records or directly-recorded electronic data files. Each directly-recorded data file should consist of a series of one-minute averages, and each one-minute average should include at least ten data points taken at equal intervals during that minute
- all field data are at least 90 percent complete
- all paper field forms, chart records, calibrations, etc. are complete, dated, and signed
- emission testers have reported their results in ppmv for NO_x, SO_2, THC, CH_4 and CO, percent for O_2 and CO_2, or gr/dscf for TPM, all concentrations corrected to 15 percent O_2, and run-specific emission rates (lb/hr)

7.4.1. Uncertainty Evaluation

Table 7-7 specifies the compounded maximum parameter uncertainties for the test results if the calibrations and QA/QC checks specified in this GVP and the EPA Reference Methods 5 and 202 are achieved. In such cases, the compounded maximum measurement error can be cited as the parameter uncertainty.

Table 7-7. Compounded Maximum Emission Parameter Errors

Parameter	Maximum Error, %
CO, NO_X, CO_2, O_2, and SO_2 concentration (ppmv or %)	**2.0**
CH_4, THC, and TPM concentration (ppmv)	**5.0**
CO, NO_X, CO_2 and SO_2 emission rates (lb/kWh)	**4.4**
CH_4, THC, and TPM emission rates (lb/kWh)	**6.3**

If the QC checks or calibration specifications are not met, or if measurement errors are greater than those specified in Table 7-7, testers must repeat test runs.

Each of the instrumental methods includes performance-based specifications for the gas analyzer. These performance criteria cover analyzer span, calibration error, sampling system bias, zero drift, response time, interference response, and calibration drift requirements. EPA Methods 4 and 5 include detailed performance requirements for moisture and TPM determinations. Instruments and equipment should meet the quality control checks specified in Table 7-8 as well as the more detailed Reference Method specifications.

Table 7-8. Summary of Emission Testing Calibrations and QA/QC Checks

Parameter[a]	Calibration/QC Check[b]	When Performed/Frequency	Allowable Result	Response to Check Failure or Out of Control Condition
CO, CO_2, O_2, SO_2	Analyzer calibration error test	Daily before testing	± 2 % of analyzer span	Repair or replace analyzer
	System bias checks	Before each test run	± 5 % of analyzer span	Correct or repair sampling system
	System calibration drift test	After each test run	± 3 % of analyzer span	Repeat test
NO_X	Analyzer interference check	Once before testing begins	± 2 % of analyzer span	Repair or replace analyzer
	NO_2 converter efficiency		98 % minimum	
	Sampling system calibration error and drift checks	Before and after each test run	± 2 % 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 run	± 3 % of analyzer span	Repeat test
CH_4	Duplicate analysis	For each sample	± 5 % difference	Repeat analysis of same sample
	Calibration of GC with gas standards by certified laboratory	Immediately prior to sample analyses and/or at least once per day	± 5 %	Repeat calibration
TPM	Minimum sample volume	After each test run	Corrected Vol. ≥ 64 dscf (MTG) or 32 dscf (IC generator)	Repeat test run
	Percent isokinetic rate	After each test run	90 % ≤ I ≤ 110 %	Repeat test run
	Analytical balance calibration	Daily before analyses	± 0.0002 g	Repair/replace balance
	Filter and reagent blanks	Once during testing after first test run	< 10 % of particulate catch for first test run	Recalculate emissions based on high blank values, all runs; determine actual error achieved
	Sampling system leak test	After each test	<0.02 cfm	Repeat test
	Dry gas meter calibration	Once before and once after testing	± 5 %	Recalculate emissions based on high blank values, all runs; determine actual error achieved
	Sampling nozzle calibration	Once for each nozzle before testing	± 0.01 in.	Select different nozzle

Table 7-8. Summary of Emission Testing Calibrations and QA/QC Checks

Parameter[a]	Calibration/QC Check[b]	When Performed/Frequency	Allowable Result	Response to Check Failure or Out of Control Condition

[a] EPA reference methods are used to determine each parameter as listed in Table 5-2.
[a] Definitions and procedures for each of the calibration and QC checks specified here are included in the applicable reference method and not repeated here.

7.5. TQAP QA/QC REQUIREMENTS

The following sections describe additional QA/QC requirements that are specified in the ETV quality management plan (QMP). These QA components should be presented in a TQAP on a verification specific basis. These requirements are specified in the GHG Center's Quality Management Plan [16].

7.5.1. Duties and Responsibilities

The TQAP must include an organizational chart identifying a project manager, field team leader, GHG Center QA manager, the EPA QA manager, and key representatives for vendors, verification host facilities, and subcontractors. The TQAP will also identify the responsibilities and duties of each person identified in the organization chart including the following:

- Overall project management and coordination
- Management of field testing staff and subcontractors
- Data review and validation
- QA/QC review at both the GHG Center and EPA levels

7.5.2. Data Quality Objectives

For each of the verification parameters specified in a TQAP, the document should also specify data quality objectives (DQOs). It is expected that the DQOs will generally be to meet and demonstrate the methods, procedures, and QA/QC checks of this GVP. For some verifications however, there may be need to deviate from the GVP requirements based on technology or facility specific variables. For each of the DQOs, the TQAP should also specify data quality indicators (DQIs) that will be used to demonstrate achievement of the DQOs. For qualitative DQOs that reference the procedures and QA/QC checks in this GVP, the QA/QC checks of this section will represent the DQIs.

7.5.3. Reviews, Assessments, and Corrective Action

Following QMP guidelines, the TQAP should specify what types of reviews and assessments are planned for the verification and who will conduct these activities. These can include the following:

- Vendor, peer, and QA document reviews
- Audits of data quality
- Field readiness reviews
- Technical systems audits
- Performance evaluation audits

The TQAP will also include a plan for corrective action. Corrective action must occur when the result of an audit or quality control measurement is shown to be unsatisfactory, as defined by the DQOs or by the measurement objectives for each task. The corrective action process involves the field team leader, project manager, and QA manager.

8.0 REPORTS

Each report should group the results for the valid test runs at each power command setting together. The report for each tested parameter should cite:

- run-specific mean, maximum, minimum, and standard deviation
- run-specific assessment of the permissible variations within the run
- overall mean, maximum, minimum, and standard deviation for all valid test runs

Each test report should also contain the following:

- SUT block diagram which shows:
  - major components
  - internal and external parasitic loads
  - electrical interconnections (one line diagram)
  - fuel and CHP heat transfer fluid flows
  - measurement equipment locations
- maximum short-circuit current ratio
- ambient conditions (temperature, barometric pressure) observed during each test run and a comparison between the observed conditions and the standard conditions at which the manufacturer rated the DG (usually ISO standard of 60 ^{o}F, 14.696 psia)
- description of measurement instruments and a comparison of their accuracies with those specified in the GVP (distinguish between accuracy estimated from specifications and accuracy determined by measurement).
- summary of data quality procedures, results of QA/QC checks, the achieved accuracy for each parameter, and the method for citing or calculating achieved accuracy
- copies of laboratory QA documentation, including calibration data sheets, duplicate analysis results, etc.
- results of data validation procedures including a summary of invalid data and the reasons for its invalidation
- information regarding any variations from the procedures specified in this GVP
- narrative description of the DG installation, site operations, and field test activities including observations of site details that may impact performance. These include thermal insulation presence, quality, mounting methods that may cause parasitic thermal loads etc.
- copies of all completed field data forms and calibration certificates

Reports may optionally contain trend analyses and commentary. Extrapolation to different operating conditions (such as ISO conditions, SUT performance during other seasons, or part-load performance for CHP systems) may be included if they are supported by well-documented laboratory-based performance curves. Such extrapolations should be flagged as approximations only.

Testers should archive all original field data forms and maintain records for at least two years. They or the database managers will store all one-minute data, valid and invalid, as ASCII comma-separated-value (CSV) text files in at least two locations (CD-ROM and secure web server hard disk, for example). Text headers for all CSV data files should include, at minimum:

- test site name
- test site location

- test site business / mailing address, telephone number, and contact person
- DG system make, model, serial number, commissioning date, and hours of runtime at the beginning of the test campaign
- test manager name, title, company, address, and telephone number

The printed report should note the data file names and locations and should specify how readers may obtain copies.

The following subsections itemize the reported parameters.

8.1. ELECTRICAL PERFORMANCE REPORTS

Electrical performance test reports, as conducted according to Section 6.1, for each power command and test run should include:

- total real power (all three phases) without external parasitic loads, kW
- total reactive power (all three phases), kVAR
- total power factor (all three phases), percent
- voltage (for each phase and average of all three phases), V
- current (for each phase and average of all three phases), A
- frequency, Hz
- Voltage THD (for each phase and average of all three phases), percent
- Current THD (for each phase and average of all three phases), percent
- apparent power consumption for each external parasitic load, kVA
- total real power including debits from all external parasitic loads, kW. Also, include information regarding external parasitic loads that serve multiple sources and that were not included in the net power evaluation
- electrical one-line diagram for the SUT

8.2. ELECTRICAL EFFICIENCY REPORTS

Electrical efficiency test reports, as conducted according to Section 6.2, for each power command and test run, should include:

- electrical generation efficiency ($\eta_{e,LHV}$) without external parasitic loads
- electrical generation efficiency ($\eta_{e,LHV}$) including external parasitic loads
- heat rate (HR_{LHV}) without external parasitic loads
- heat rate (HR_{LHV}) including external parasitic loads
- total kW
- heat input ($Q_{in,LHV}$), Btu/h
- fuel input ($V_{g,std}$ for gas, $\dot{m}$ for liquid), scfh or lb/h
- electrical one-line for the SUT

The report should quote all laboratory analyses for:

- fuel heating value (LHV) for each power command setting, Btu/scf or Btu/lb

Note that electrical generation efficiency uncertainty should be reported in absolute terms. For example, if $\eta_{e,LHV}$ for gaseous fuel is 26.0 percent and all measurements meet the accuracy specifications in this GVP, the relative error is ± 3.0 percent (see Table 7-4). The absolute error is 26.0 times 0.030, or ± 0.78 percent. The report, then, should state $\eta_{e,LHV}$ as "26.0 ± 0.8 percent". This will prevent confusion because, for efficiency, both relative and absolute errors can be reported as percentages.

8.3. CHP THERMAL PERFORMANCE REPORTS

Thermal performance test reports for CHP systems in heating service, as conducted according to Section 6.3, for each power command setting and test run, should include:

- actual thermal performance (Q_{out}), Btu/h
- actual thermal efficiency ($\eta_{th,LHV}$)
- actual total system efficiency ($\eta_{tot,LHV}$)
- maximum thermal energy available for recovery (sum of actual thermal energy transferred and thermal energy available from cooling towers), Btu/h
- maximum thermal efficiency ($\eta_{th,LHV}$)
- maximum SUT efficiency ($\eta_{tot,LHV}$)
- heat transfer fluid supply and return temperatures, ^{o}F, and flow rates, gpm for each heat transfer fluid loop measured

This GVP recommends reporting η_{th} and η_{tot} and their achieved accuracies in absolute terms because efficiency and relative accuracies are both percentages. Refer to the previous subsection for a discussion on avoiding potential confusion due to terminology.

Test reports for CHP systems in chilling service should include:

- actual thermal performance, Btu/h and refrigeration tons (RT)
- heat transfer fluid supply and return temperatures, ^{o}F, and flow rates, gpm for each heat transfer fluid loop measured
- thermal energy available for recovery from cooling tower(s), Btu/h

Reports for all CHP systems should include:

- heat transfer fluid type(s)
- laboratory heat transfer fluid density results for each sample analyzed
- average c_p for each heat transfer fluid analyzed
- average ρ for each heat transfer fluid analyzed
- summary piping and heat flow schematic diagram for the SUT

8.4. ATMOSPHERIC EMISSIONS REPORTS

The testing contractor should provide a final emissions testing report for tests conducted according to Section 6.4. Reported parameters for each test run at each power command should include the following:

- emission concentrations for CO, CH_4, NO_X, SO_2, THCs, and other pollutants evaluated in ppmv, % for O_2, CO_2, and gr/dscf for TPM as measured and corrected to 15% O_2

- emission rates for CO_2, CO, CH_4, NO_X, SO_2, THCs, TPM, and other pollutants evaluated as lb/hr and lb/kWh electrical generation
- exhaust gas dry standard flow rate, actual flow rate, and temperature
- exhaust gas composition, moisture content, and molecular weight
- isokinetic sampling rate (TPM tests only)

9.0 REFERENCES

[1] *ANSI C12.20-2002: Code for Electricity Meter—0.2 and 0.5 Accuracy Classes*. National Electrical Manufacturers' Association, American National Standards Institute, Rosslyn, VA. 2001, www.ansi.org.

[2] *IEC 61000-4-30: Electromagnetic Compatibility (EMC)—Part 4-30: Testing and Measurement Techniques–Power Quality Measurement Methods*. International Electrotechnical Commission, Geneva, Switzerland. 2003, www.iec.ch.

[3] *ASME PTC 22-1997—Performance Test Code on Gas Turbines.* American Society of Mechanical Engineers, New York, NY. 1997, www.asme.org.

[4] *ASME PTC 17-1997—Reciprocating Internal-Combustion Engines*. American Society of Mechanical Engineers, New York, NY. 1997, www.asme.org.

[5] *IEEE Std. 929-2000—IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*. Institute of Electrical and Electronics Engineers, New York, NY. 2000, www.ieee.org.

[6] *IEC 61000-4-7: Electromagnetic Compatibility (EMC) – Part 4-7: Testing and Measurement Techniques – General Guide on Harmonics and Interharmonics Measurements and Instrumentation for Power Supply Systems and Equipment Connected Thereto*. International Electrotechnical Commission, Geneva, Switzerland. 2002, www.iec.ch.

[7] *MTG Test Protocol, Ver. 1.0*. Advanced Power and Energy Program (APEP), University of California, Irvine. Irvine, CA. 2003, www.apep.uci.edu/.

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

[9] *ASTM D3588-98—Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*. American Society for Testing and Materials, West Conshohocken, PA. 2001.

[10] *ASTM D1298-99—Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method*. American Society for Testing and Materials, West Conshohocken, PA. 1999, www.astm.org.

[11] *ASTM D4809-00—Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)*. American Society for Testing and Materials, West Conshohocken, PA. 2001, www.astm.org.

[12] *CRC Handbook of Chemistry and Physics*. Robert C. Weast, Ph.D., editor, CRC Press, Inc., Boca Raton, FL. 1980.

[13] *ASHRAE Fundamentals Handbook—Chapter 21: Physical Properties of Secondary Coolants (Brines)*. American Society of Heating, Refrigeration, and Air-Conditioning Engineers, Inc., Atlanta, GA. 2001, www.ashra.org.

[14] *ASTM D1298-99 Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method*. American Society for Testing and Materials, West Conshohocken, PA. 1999, www.astm.org.

[15] Code of Federal Regulations (Title 40 Part 60, Appendix A) *Test Methods (Various)*, U.S. Environmental Protection Agency, Washington, DC, www.gpoaccess.gov/cfr/.

[16] Southern Research Institute. *Environmental Technology Verification Greenhouse Gas Technology Verification Quality Management Plan, Version 1.2*, Research Triangle Park, NC, January 2001, www.sri-rtp.com.

Appendix A

Acronyms and Abbreviations

A	ampere
acfh	actual cubic feet per hour
ASERTTI	Association of State Energy Research and Technology Transfer Institutions
ASTM	American Society for Testing and Materials
Btu	British thermal unit
Btu/h	Btu per hour
Btu/kWh	Btu per kiloWatt-hour
Btu/lb	Btu per pound
Btu/scf	Btu per standard cubic foot
BoP	balance of plant
c_p	specific heat (constant pressure)
CARB	California Air Resources Board
CH_4	methane
CHP	combined heat and power
cm	centimeter
CO	carbon monoxide
CO_2	carbon dioxide
CoP	coefficient of performance
CSV	comma-separated value
CT	current transformer
DG	distributed generation
DOE	US Department of Energy
DUT	device under test
DVM	digital volt meter
dscfh	dry standard cubic feet per hour
EPA	US Environmental Protection Agency
EPS	electric power system
ETV	Environmental Technology Verification
FID	flame ionization detector
FS	full scale
GC/FID	gas chromatography with flame ionization detector
GHG	greenhouse gas
gph	gallons per hour
gpm	gallons per minute
gr/dscf	grains per dry standard cubic foot
GVP	Generic Verification Protocol
h	hour
HHV	higher heating value
Hz	Hertz
IC	reciprocating internal-combustion engine
ID	induced draft
ISO	International Organization for Standardization
kAIC	kiloampere interrupt current
kVA	kilovolt-ampere (apparent power)
kVAR	kilovolt-ampere reactive (reactive power)
kW	kilowatt (real power)
kWh	kilowatt-hour
LHV	lower heating value
lb	pound
lb/gal	lb per gallon
lb/h	lb per hour
lb/kWh	lb per kWh
lb/lb.mol	lb per lb-mole
mA	milliamp
ml	milliliter
mph	miles per hour
m/s	meters per second
MTG	microturbine generator
MTG-CHP	MTG with CHP
NDIR	non-dispersive infra-red
NIST	National Institute of Standards and Technology
NO_x	nitrogen oxides
O_2	oxygen
PC	personal computer
PCC	point of common coupling
PF	power factor
PG	propylene glycol
ppm	parts per million
ppmvd	ppm, volume basis, dry
psia	pounds per square inch, absolute
psig	pounds per square inch, gage
PT	potential transformer
QA/QC	quality assurance / quality control
rms	root-mean-square
RT	refrigeration ton

scf	standard cubic feet
scfh	scf per hour
SO_2	sulfur dioxide
SUT	system under test
THC	total hydrocarbons
THD	total harmonic distortion
THCD	total harmonic current distortion
THVD	total harmonic voltage distortion
TPM	total particulate matter
UIC	University of Illinois at Chicago
V	volt
VA	volt-ampere (apparent power)
VAR	volt-ampere reactive (reactive power)
w	Watt
^oC	degree Centigrade
^oF	degree Fahrenheit
^oR	degree Rankine, absolute
ΔT	absolute temperature difference, ^oR or ^oF
η	efficiency, percent
ρ	density, lb/gal

Notation for References, Tables etc.

All Figures and Tables in the GVP document are numbered using the Section number followed by a sequential digit. Appendices replace the Section number with the Appendix letter. Example references within the test are:

Figure 3-2	The second figure in Section 3
Table 6-1	The first table in Section 6
Eqn. D18	The 18^{th} equation occurring in Appendix D

References within the main text appear as a sequential number within square brackets, or [4] (fourth reference in the document) and may be found at the back of the document. References within the appendices appear as[D4] (fourth reference in Appendix D) and may be found at the back of the indicated appendix.

Appendix B

B1. Power Meter Commissioning Procedure

1. Obtain and read the power meter installation and setup manual. It is the source of the items outlined below and is the reference for detailed information.
2. Verify that the power meter calibration certificate, CT manufacturer's accuracy certification, supplementary instrument calibration certificates, and supporting data are on hand.
3. Mount the power meter in a well-ventilated location free of moisture, oil, dust, corrosive vapors, and excessive temperatures.
4. Mount the ambient temperature sensor near to but outside the direct air flow to the DG combustion air inlet plenum but in a location that is representative of the inlet air. Shield it from solar and ambient radiation.
5. Mount the ambient pressure sensor near the DG but outside any forced air flows.
6. Ensure that the fuel consumption metering scheme is in place and functioning properly.
7. Verify that the power meter supply source is appropriate for the meter (usually 110 VAC) with the DVM and is protected by a switch or circuit breaker.
8. Connect the ground terminal (usually the "Vref" terminal) directly to the switchgear earth ground with a dedicated AWG 12 gauge wire or larger. Refer to the manual for specific instructions.
9. Choose the proper CTs for the application. Install them on the phase conductors and connect them to the power meter through a shorting switch to the proper meter terminals. Be sure to properly tighten the phase conductor or busbar fittings after installing solid-core CTs.
10. Install the voltage sensing leads to each phase in turn. Connect them to the power meter terminals through individual fuses.
11. Trace or color code each CT and voltage circuit to ensure that they go to the proper meter terminals. Each CT must match its corresponding voltage lead. For example, connect the CT for phase A to meter terminals I_{A1} and I_{A2} and connect the voltage lead for phase A to meter terminal V_A.
12. Energize the power meter and the DG power circuits in turn. Observe the power meter display (if present), datalogger output, and personal computer (PC) display while energizing the DG power circuits.
13. Perform the power meter sensor function checks. Use the DVM to measure each phase voltage and current. Acquire at least five separate voltage and current readings for each phase. Enter the data on the Power Meter Sensor Function Checks form and compare with the power meter output as displayed on the datalogger output (or PC display), power meter display (if present), and logged data files. All power meter voltage readings must be within 2% of the corresponding digital volt meter (DVM) reading. All power meter current readings must be within 3% of the corresponding DVM reading.
14. Verify that the power meter is properly logging and storing data by downloading data to the PC and reviewing it.

B1. Power Meter Sensor Function Checks

Project Name:________________________________ Location (city, state):________________________________

Date:_________________________ Signature:____

DUT Description: ____

Nameplate kW:________________ Expected max. kW:__________________

Type (delta, wye):______________ Voltage, Line/Line:__________________ Line/Neutral:________________

Power Meter Mfr:________________________ Model:__________________ Serial No.: ________________

Last NIST Cal. Date: ____________________

Current (at expected max. kW):__________________Conductor type & size:_________________________

Current Transformer (CT) Mfg:________________________________Model: ______________________

CT Accuracy: (0.3 %, other): ___________ Ratio (100:5, 200:5, other):____________________

Sensor Function Checks

Note: Acquire at least five separate readings for each phase. All power meter voltage readings must be within 2% of the corresponding digital volt meter (DVM) reading. $\%Diff = ([PowerMeter/DVM] - 1) * 100$

Voltage

Date	Time (24 hr)	Phase A			Phase B			Phase C		
		Power Meter	DVM	%Diff	Power Meter	DVM	%Diff	Power Meter	DVM	%Diff

Note: Acquire at least five separate readings for each phase. All power meter current readings must be within 3% of the corresponding DVM reading.

Current

Date	Time (24 hr)	Phase A			Phase B			Phase C		
		Power Meter	DVM	%Diff	Power Meter	DVM	%Diff	Power Meter	DVM	%Diff

B2: Distributed Generator Installation Data

Project Name: ________________________________ Date: ___________________

Compiled by: (Company) ________________________ Signature: ____________________________

Site Information

Address 1: ____________________________ Owner Company: _____________________________

Address 2: ____________________________ Contact Person: ______________________________

City, State, Zip: ________________________ Address (if different): _________________________

Op'r or Technician: ______________________ Company Phone: ______________ Fax: _________

Site Phone: ____________________________ Utility Name: _______________________________

Modem Phone (if used): _________________ Contact Person: ______________________________

Altitude _____________ (feet; meters) Utility Phone: _______________________________

Installation (check one): Indoor__ Outdoor__ Utility Enclosure__ Other (describe)_____________________

Sketch of HVAC systems attached (if Indoor) ______ Controls: Continuous ____Thermostatic____Other__

Primary Configuration, Service Mode, and CHP Application
(check all that apply; indicate secondary power and CHP application information with an asterisk, *)

Delta		Wye		Grounded Wye	
Single Phase		Three Phase			
Inverter		Induction		Synchronous	
Grid Parallel		Grid Independent		Peak Shaving	
Demand Management		Prime Power		Load Following	
		Backup Power		VAR Support	
Hot water		Steam		Direct-fired chiller	
Indirect chiller		Other DG or CHP (describe)			

Site Description
(Check one)

Hospital	
University	
Resident'l	
Industrial	
Utility	
Hotel	
Other (desc.)	

Fuel
(Check one)

Nat'l Gas	
Biogas	
Landfill G	
Diesel #2	
Other (desc.)	

Generator Nameplate Data

Date: ____________Local Time (24-hour): ___________ Hour meter: __________

Commissioning Date: __________

Manufacturer: ___________________ Model: _________________ Serial #: _________________

Prime mover (check one): IC generator_____ MTG _____

Range: ____ to ____ (kW; kVA) Adjustable? (y/n) ____Power Factor Range: ___ to ___ Adjustable? (y/n) ____

Nameplate Voltage (phase/phase): ______ Amperes: _____Frequency: _______ Hz

Controller (check one): factory integrated _____ 3rd-party installed _____ custom (describe)________________

Maximum Short Circuit Current Ratio (Appendix B13): ________

B2: Distributed Generator Installation Data (cont.)

CHP Nameplate Data

BoP Heat Transfer Fluid Loop

Describe: ____

Nominal Capacity: ________ (Btu/h) Supply Temp. ______ (^oF) Return Temp. ______ (^oF)

Low Grade Heat loop

Describe: ____

Nominal Capacity: ________ (Btu/h) Supply Temp. ______ (^oF) Return Temp. ______ (^oF)

Chilling loop

Describe: ____

Nominal Capacity: ________ (Btu/h) Supply Temp. ______ (^oF) Return Temp. ______ (^oF)

Other loop(s): Describe: ____

Nominal Capacity: ________ (Btu/h) Supply Temp. ______ (^oF) Return Temp. ______ (^oF)

Parasitic Loads

Enter nameplate horsepower and estimated power consumption. Check whether internal or external. Internal parasitic loads are on the DG-side of the power meter. External parasitic loads are connected outside the system such that the power meter does not measure their effects on net DG power generation.

Description	Name-plate Hp	Est. kVA or kW	Internal (✓)	External (✓)	Function[a]
Fuel Gas Compressor					
CHP Heat Transfer Fluid Pump – Hot Fluid					
CHP Heat Transfer Fluid Pump - Low Grade					
CHP Heat Transfer Fluid Pump - Chilling					
Fans (describe)					
Other: Transformers, etc. (describe)					

[a]Describe the equipment function. Also note whether the equipment serves multiple units or is dedicated to the test DG.

B3: Load Test Run Log

Project Name:________________________________ Location (city, state):__________________________

Date:____ Signature:____________________________________

SUT Description:______________________ Run ID:________ Load Setting: %_____ kW_____
Clock synchronization performed (Initials):________ Run Start Time:_____ End Time:________
Data file names/locations (incl. path): File:____
IMPORTANT: For ambient temperature and pressure, record one set of readings at the beginning and one at the end of each test run. Also record at least two sets of readings at evenly spaced times throughout the test run.

B3-1. Ambient Temperature and Pressure

Time (24-hr)	Amb. Temperature, °F	Ambient Pressure	
		" Hg	PSIA = " Hg * 0.491
Average			

Permissible Variations

1. Each observation of the variables below should differ from the average of all observations by less than the maximum permissible variation.
2. Acquire kW and Power Factor data from the power meter data file at the end of the test run. Transfer fuel flow data from the Fuel Flow Log form. Obtain ambient temperature and pressure from Table A3-2 below. Obtain gas temperature and pressure from Appendix B4.
3. Choose the maximum or minimum with the largest difference compared to the average for each value.
4. Use the maximum or minimum to calculate the %Diff for kW, Power Factor, Fuel Flow, and Ambient Pressure:

$$\%Diff = \left(\frac{(MaxorMin) - Average}{Average} \right) * 100 \qquad \text{Eqn. B3-1}$$

5. For Ambient Temperature, *Difference = (Max or Min)-Average*

Variable	Average	Maximum	Minimum	%Diff or Difference	Acceptable? (see below)
Ambient air temperature					
Ambient pressure					
Fuel flow					
Power factor					
Power output (kW)					
Gas pressure					
Gas temperature					

Permissible Variations

Measured Parameter	MTG Allowed Range	IC Generator Allowed Range
Ambient air temperature	± 4 °F	± 5 °F
Ambient pressure (barometric station pressure)	± 0.5 %	± 1.0 %
Fuel flow	± 2.0 %[a]	n/a
Power factor	± 2.0 %	n/a
Power output (kW)	± 2.0 %	± 5.0 %
Gas pressure	n/a	± 2.0 %[b]
Gas temperature	n/a	± 5 °F[b]

[a]Not applicable for liquid-fueled applications < 30 kW.
[b]Gas-fired units only

B4: Fuel Consumption Determination Procedure

1. Start the test run by starting a stopwatch or timer at an integer gas meter or weighing scale reading. Log the initial meter reading, M_o, when the timer is started on the Fuel Flow Log Form below.
2. Collect each meter reading by holding the stopwatch or timer next to the meter index. Log the meter reading on the log form every 5 minutes at the instant that the stopwatch or timer shows the required elapsed time. If a meter reading is missed, collect a reading at the next integer minute. Cross out the missed "Stopwatch Elapsed Time" entry and note the corrected elapsed time in the table's first column.
3. Compute the elapsed time for each interval and enter it in the "t_i" column on the Fuel Flow Log Form below.
4. Record at least one 5-minute interval within 10 minutes of the start, one within 10 minutes of the end, and one near the middle of each test run. Other recording intervals are optional.
5. End the test run after at least 30 minutes for MTGs or 60 minutes for IC generators at the next integer gas meter or weighing scale reading. Log the final meter reading, M_f, and the exact elapsed time on the Fuel Flow Log Form.
6. Perform all applicable calculations and transfer the minimum, maximum, and average to the Load Test Log Form.

IMPORTANT: Ensure that the meter index or scale readout resolution is < 0.2 % during any complete test run. For example, if a MTG uses 100 ft^3 of gas during a test run, the meter index resolution must be less than 0.2 ft^3. While testing liquid-fueled units < 500 kW, the day tank may be replenished only with a common batch of fuel.

Fuel Flow Log Form

Project Name:______________________ Location (city, state):______________________

Date:______________________ Signature:______________________

SUT Description:______________________ Run ID:________ Load Setting: %_____ kW_____

Flow Meter Mfr.:______________ Model:______________ Serial #:______________________

Signature:______________________ Run Start Time (24-hr): ____________

Stopwatch Elapsed Time (min)	t_i = (Stopwatch Elapsed Time) minus (Previous Interval Elapsed Time)	Meter or Scale Reading		Diff; M_i-M_{i-1}	Hourly Flow Rate: Diff*60/t_i	Fuel °F	Gas PSIG (not needed for liquid fuel)
		Initial Meter. Reading, M_0					
5		M_1					
10		M_2					
15		M_3					
20		M_4					
25		M_5					
30		M_6					
End		M_f					
				Average Hourly Rate			
				Minimum			
				Maximum			

Ambient Pressure (from Load Test Run Log):__________ Gas = Average + Amb. Pressure:_________

B5: External Parasitic Load Measurement Procedure

This procedure is intended to measure apparent or real power consumption for external parasitic loads. Apparent power in volt-amperes (VA) is root-mean-square (rms) voltage times rms current, or V * A. Apparent power equals real power in watts if the power factor is 1.00.

External parasitic loads are those located outside the SUT boundary and connected such that the power meter cannot measure their net effect on power generation. Internal parasitic loads (control systems, internal pumps and compressors, etc. within the SUT) draw their power from the system before the power meter and need not be measured separately.

1. Obtain at least one set of voltage and current (or real power) measurements for each external parasitic load at each power setting (50, 75, and 100 percent) during load tests. Each measurement consists of a set of three readings.
2. Enter the name and description of each external parasitic load on the External Parasitic Load Data log form (Appendix B5). They should be the same as those that appear on Installation Data log sheet (Appendix B2).
3. Open the connection panel nearest to each parasitic load to give access to power conductors for measurement. Conduct all measurements while SUT is operating at the prescribed load setting.
4. For three-phase loads, three phase combinations are possible: A-B, B-C, and C-A. Note that only one phase combination (A-B) is possible for single-phase loads. With a true-rms clamp-on DVM, probe the A-B phase combination for three seconds to read the voltage. Record the highest reading on Appendix B5. Probe and record the next two phase combinations in turn. This constitutes one complete voltage reading.
5. Place the meter clamp around the phase A conductor for three seconds to read the current. Record the highest reading on Appendix B5 and proceed to the B and C phase conductors in turn. The three readings constitute one complete current reading.
6. Repeat steps 4 and 5 until three complete voltage and current readings are recorded for each external parasitic load.

Note that testers may also use hard-wired real power meter(s), one for each external parasitic load, or a single clamp-on real power meter for this purpose. The real power meters may be wired to suitable dataloggers, thus eliminating the need for manual measurements and may result in slightly more accurate readings than achieved with the DVM method.

B5: External Parasitic Load Data

Project Name:________________________________ Location (city, state):__________________________

Date:____ Signature:____________________________________

SUT Description:______________________ Run ID:________ Load Setting: %_____ kW_____

Load Description:									
Reading	**Volts A-B**	**Volts B-C**	**Volts C-A**	**Amps A**	**Amps B**	**Amps C**	**kW A-B**	**kW B-C**	**kW C-A**
1									
2									
3									
Average									
Apparent Power, per phase:				**V_{AB} $Amps_A$**	**V_{BC} $Amps_B$**	**V_{CA} $Amps_C$**			

Total Apparent Power: $S_{tot} = \frac{V_{ab}}{\sqrt{3}} Amps_a + \frac{V_{bc}}{\sqrt{3}} Amps_b + \frac{V_{ca}}{\sqrt{3}} Amps_c$ S_{tot}: ___________kVA

Total Real Power: $kW_{tot} = \frac{kW_{ab}}{\sqrt{3}} + \frac{kW_{bc}}{\sqrt{3}} + \frac{kW_{ca}}{\sqrt{3}}$ kW_{tot}: __________ kW

Load Description:									
Reading	**Volts A-B**	**Volts B-C**	**Volts C-A**	**Amps A**	**Amps B**	**Amps C**	**kW A**	**kW B**	**kW C**
1									
2									
3									
Average									
Apparent Power, per phase:				**V_{AB} $Amps_A$**	**V_{BC} $Amps_B$**	**V_{CA} $Amps_C$**			

S_{tot}: _____________ kVA kW_{tot}: ___________ kW

Load Description:									
Reading	**Volts A-B**	**Volts B-C**	**Volts C-A**	**Amps A**	**Amps B**	**Amps C**	**kW A**	**kW B**	**kW C**
1									
2									
3									
Average									
Apparent Power, per phase:				**V_{AB} $Amps_A$**	**V_{BC} $Amps_B$**	**V_{CA} $Amps_C$**			

S_{tot}: _____________ kVA kW_{tot}: ___________ kW

B6: Fuel and Heat Transfer Fluid Sampling Procedure

Gaseous Fuel Samples

1. Collect at least one fuel gas sample at each power command setting during a valid test run into an evacuated sample cylinder
2. Attach a leak free vacuum gauge to the sample canister inlet. Open the canister inlet valve and verify that the canister vacuum is at least 15 "Hg. Record the gage pressure on the Fuel Sampling Log form (Appendix A6).
3. Close the canister inlet valve, remove the vacuum gauge, and attach the canister to the fuel line sample port.
4. Open the fuel line sample port valve and check all connections for leaks with bubble solution or a hand-held analyzer. Repair any leaks, then open the canister inlet valve. Wait 5 seconds to allow the canister to fill with fuel.
5. Open the canister outlet valve and purge the canister with fuel gas for at least 15, but not more than 30 seconds. Close the canister outlet valve, canister inlet valve, and fuel line sampling port valve in that order.
6. Obtain the fuel gas pressure and temperature from the gas meter's pressure and temperature instrumentation. Remove the canister from the sampling port. Enter all required information (date, time, canister ID number, etc.) on the Fuel Sampling Log.
7. Fill out the Chain of Custody form (Appendix B7) and sample labels. Forward the samples to the analytical laboratory accompanied by the form. Retain a copy for inclusion with the other field data forms.

Liquid Fuels and Heat Transfer Fluid (for all fluids other than water)

IMPORTANT: Ensure that SUT operators do not add, withdraw, or otherwise modify heat transfer fluid composition(s) within 48 hours of testing. The heat transfer fluid circulation pump(s) should operate during the 48 hours prior to testing to ensure fluid homogeneity.

1. Collect at least one liquid fuel sample at each power command setting during a valid test run. Collect at least one heat transfer fluid sample from each heat transfer fluid loop tested at any time during the load test phase. All sample volumes should be between 200 and 300 milliliters (ml). Do not sample pure water heat transfer fluids.
2. Attach a suitable tube to the sampling valve or petcock if required.
3. Open the sampling petcock to purge about 50 ml of fuel or fluid from the sampling valve and tube into a suitable waste container.
4. Fill the sampling bottle with fuel or fluid. Cap it securely and enter all required information (date, time, T_{avg}, sample bottle ID number, etc.) on the Fuel Sampling Log (Appendix A6).
5. Fill out the Chain of Custody form (Appendix B7) and sample labels. Forward the samples to the analytical laboratory accompanied by the form. Retain a copy for inclusion with the other field data forms.

B6: Fuel and Heat Transfer Fluid Sampling Log

IMPORTANT: Use separate sampling log and Chain of Custody forms for each sample type (gas fuel, liquid fuel, heat transfer fluid). Record heat transfer fluid T_{Avg} on Chain of Custody form for laboratory reference.

Project Name:________________________________ Location (city, state):__________________________

Date:______________________________________ Signature:__________________________________

SUT Description:______________________ Run ID:________ Load Setting: %_____ kW_____

Fuel Source (pipeline, digester):________________________

Sample Type (gas fuel, liquid fuel, heat transfer fluid): ____________________________________

Fuel Type (natural gas, biogas, diesel, etc.):____

Note: Obtain fuel gas sample pressure and temperature from gas meter pressure and temperature sensors. Obtain heat transfer fluid temperatures from datalogger display.

Gas Fuel Samples Only

Date	24-hr Time	Run ID	Canister ID	Initial Vacuum, " Hg	Sample Pressure (from gas meter pressure sensor)	Sample Temperature (from gas meter temperature sensor)

Liquid Samples Only

Date	24-hr Time	Run ID	Sample ID	Heat Transfer Fluid Temperatures (for CHP applications; from datalogger display)		
				T_{supply}	T_{return}	$T_{Avg} = \frac{(T_{supply} + T_{return})}{2}$

Notes: ____

____

B7: Sample Chain-of-Custody Record

Important: Use separate Chain-of-Custody Record for each laboratory and/or sample type.

Project Name:________________________ Location (city, state):______________________________

Test Manager/Contractor________________________ Phone:______________ Fax:______________

Address: ______________________________ City,State / Zip: ______________________________

Originator's signature:______________________________Unit description:________________________

Sample description & type (gas, liquid, other.):____

Laboratory:________________________ Phone:______________ Fax:______________

Address:________________________ City:______________ State:________ Zip:_____

Sample ID	Bottle/Canister ID	Sample Pressure	Sample Temp. or T_{Avg}, (°F)	Analyses Req'd

Relinquished by:____________________ Date:______________ Time:______________
Received by:____________________ Date:______________ Time:______________

Relinquished by:____________________ Date:______________ Time:______________
Received by:____________________ Date:______________ Time:______________

Relinquished by:____________________ Date:______________ Time:______________
Received by:____________________ Date:______________ Time:______________

Notes: (shipper tracking #, other)____

B8: CHP Unit Information

Flow Meter Commissioning

Test personnel should perform the following flow meter commissioning and sensor function checks:

1. Record the flow meter specifications and calibration information on the Temperature and Flow Meter Commissioning Data log form.
2. Install flow meter, transmitter, and wiring.
3. Open the flow meter isolation valves or start the fluid circulation pump to ensure the meter is charged, leak free, and producing 4 - 20 milliamp (mA) output to the datalogger.
4. Stop the fluid circulation pump or close the flow meter isolation valves to stop all flow through the meter.
5. Record the datalogger zero flow result on the log form. The display should show 0.0 ± 1.0 percent of full scale, or 4 mA ± 0.2 mA.
6. Start the fluid circulation pump or open the isolation valves. Record reading on the log form and compare to the pump manufacturer's or installer's specifications for reasonableness.
7. Perform steps 2 through 5 at least once again immediately prior to the first test run.

Temperature Sensor Commissioning

Test personnel should complete the following temperature meter commissioning procedures and sensor function checks:

1. Upon receipt, apply a permanent ID number to the temperature sensor and its transmitter.
2. After initial NIST calibration, review the certificate. It must be current (within 18 months), and readings must be accurate to within ± 0.3 ^oF at 32 ^oF and ± 0.6 ^oF at 212 ^oF. The calibration certificate must specifically reference each sensor and transmitter pair as a unit. Calibration temperatures shown on the certificate should bracket the expected T_{supply} and T_{return} temperatures. Maintain a copy of the calibration certificate.
3. Record the temperature meter specifications and calibration information on the Temperature and Flow Meter Commissioning Data log form.
4. Connect each sensor to its transmitter. Install the signal wiring to the loop power supply and datalogger, but leave enough slack signal wire to allow the two sensors to be immersed in the same water bath. Immerse the two sensors in an agitated ice water bath. Record the readings from the power meter or datalogger monitor on the log form. Both readings should be within 1 ^oF of 32 ^oF and within ± 0.6 ^oF of each other.
5. Immerse the two sensors in an agitated hot water bath. Hot tap water is satisfactory. Record the readings from the power meter or datalogger monitor on the Temperature and Flow Meter Commissioning Data log. Readings should be within ± 1.2 ^oF of each other.

Integrated heat Flow Meters

Where a single transmitter incorporates inputs from two temperature sensors and a flow meter for the purpose of measuring heat flow is used, it is recommended that internal calculations not be used. The individual temperature and flow readings should be recorded as for separate meters.

B8: CHP Unit Information; Flow Meter and Temperature Meter Commissioning Data

Project Name:________________________________ Location (city, state):__________________________

Date:____ Signature:___________________________________

SUT Description:______________________

CHP Unit

Manufacturer: _______________________Model #:__________________ Serial #:______________

Nominal Btu/h:_______________________ at expected T_{supply}:_____________, T_{return}:______________

Thermal Application or BoP Equipment

Manufacturer: _______________________Model #:__________________ Serial #:______________

Description:____

____

____

Note: Enter the following information for each heat transfer fluid loop tested.

Temperature Sensor Manufacturer: _______________________Model #:__________________

T_{supply}: Sensor ID #: ____________Transmitter ID #: _____________ NIST Cal. Date: ____________

T_{return}: Sensor ID #: ____________Transmitter ID #: _____________ NIST Cal. Date: ____________

Low span, 4 mA = ________ ^oF High span, 20 mA = _________ ^oF

Bath Description	**T_{supply}, ^oF**	**T_{return}, ^oF**	**Allowable Value**	**OK?**	**Difference, ^oF**	**Allowable Value**	**OK?**
Ice water			32 ± 1 ^oF			± 0.6 ^oF	
Hot water			n/a			± 1.2 ^oF	

Flow Meter Manufacaturer:____________________Model: ___________________ID or Serial #:_____________

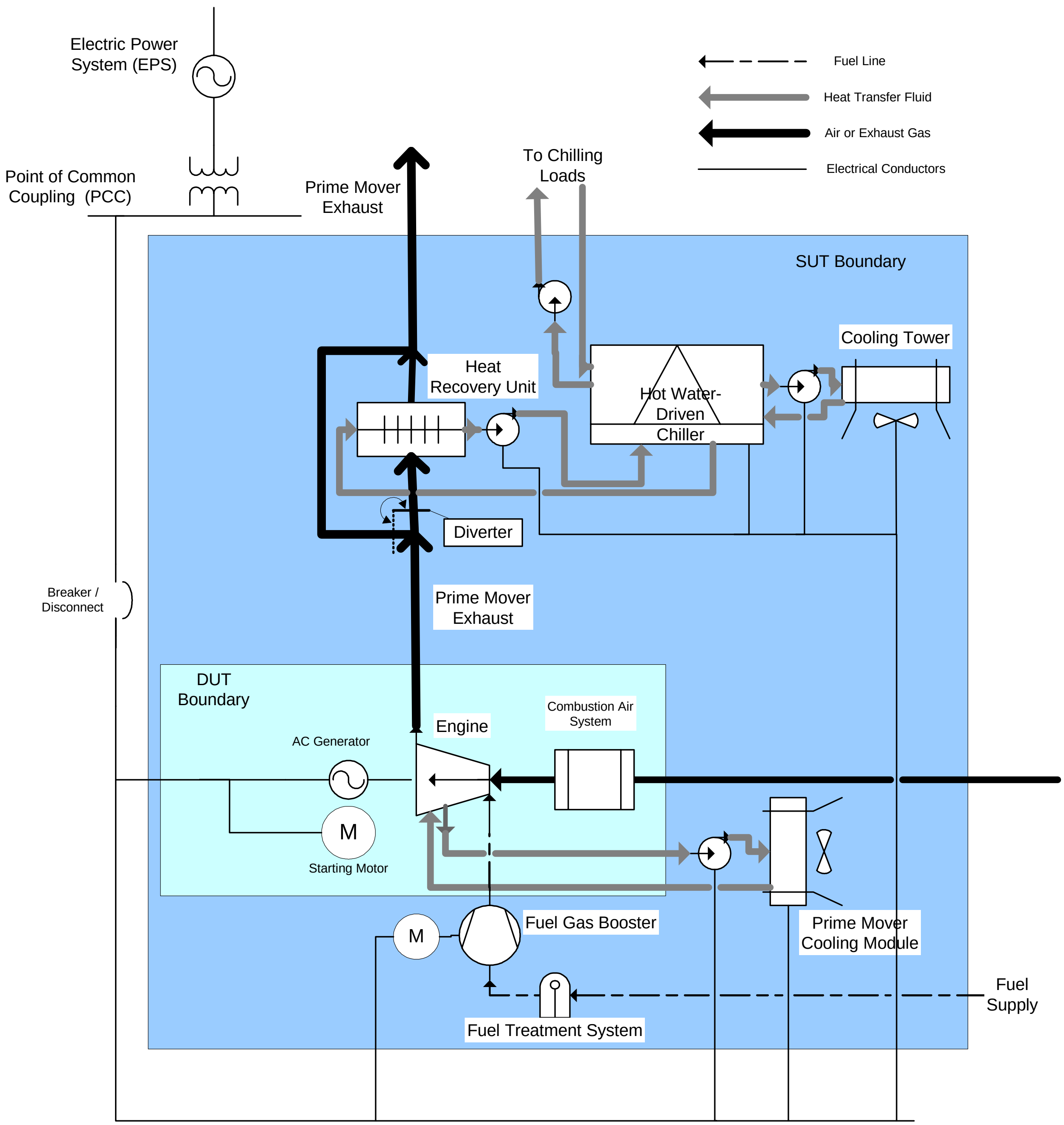
NIST Cal. Date: _____________Low span, 4 mA = ________ gpm; High span, 20 mA = ________ gpm

Installation Data			
Date:	**Signature:**		
Flow State	**Flow Reading, gpm or mA**	**Expected Value, gpm or mA**	**OK?**
zero flow			
Normal flow			
Pretest Data			
Date:	**Signature:**		
Flow Rate, gpm	**Flow Reading, gpm or mA**	**Expected Value, gpm or mA**	**OK?**
zero flow			
Normal flow			
Note: zero flow indication must be less than ± 1.0 % FS			

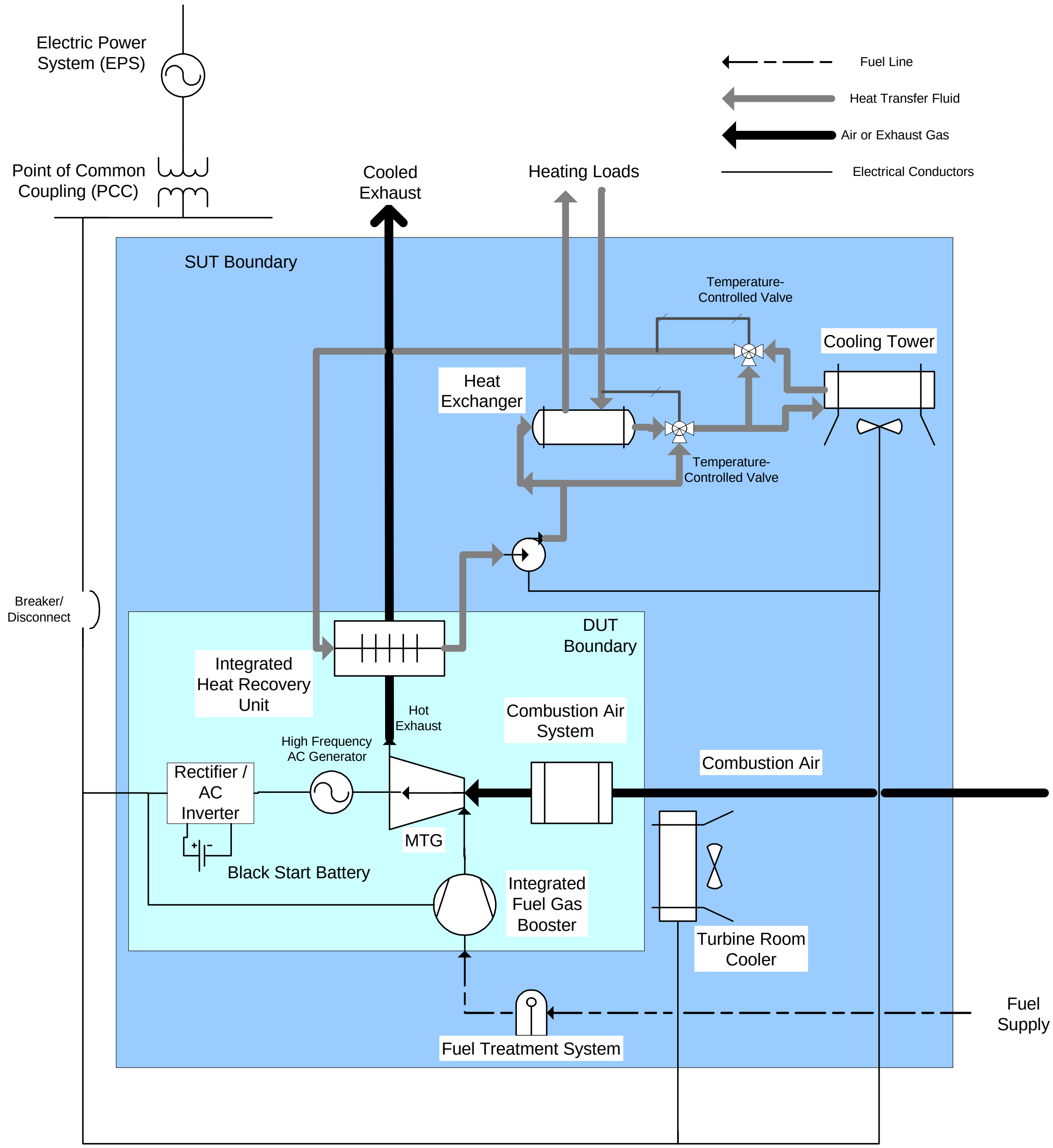
Installation Location (BoP loop, cooling tower loop, etc.) ____

Appendix C

C1: Generic IC-Engine Hot Fluid-driven CHP Chiller System with Exhaust Diverter



C2: Generic MTG Hot Fluid-Driven CHP System in Heating Service



Appendix D: Definitions and Equations

D1: Electrical Performance

Voltage

Voltage is a measure of the electromotive force or potential developed between separated positive and negative electric charges. In AC circuits, the root-mean-square (rms) voltage is the square root of the sum of the instantaneous voltage values, squared, or [D1]:

$$V = \left[\frac{1}{T} \int_{a}^{a+T} v^2 dt \right]^{1/2} \qquad \text{Eqn. D1}$$

Where:

V = rms voltage, V
T = time period
a = initial time
v = instantaneous voltage, V

For a pure sine wave, the rms voltage value is 0.7071 times the peak voltage value. Rms voltages for distorted wave forms can differ from this proportion.

Current

Current is a measure of the quantity of charge flowing past a fixed point during a one-second interval. A potential difference of one volt across a one ohm resistor generates a one ampere (A) current. Rms current in AC circuits is stated the same way as rms voltage.

Real Power

Real power is the combination of the voltage and the value of the corresponding current that is in phase with the voltage. Real power produces resistive heating or mechanical work, and can be expressed as [D1]:

$$P = \frac{1}{T} \int_{t_0 - T/2}^{t_o + T/2} vidt \qquad \text{Eqn. D2}$$

Where:

P = average real power at any time t_0, watts (W)
v = instantaneous voltage, volts
i = instantaneous current, amperes
T = time period

If both the voltage and current are sinusoidal and of the same period,

$$P = VI \cos\theta \qquad \text{Eqn. D3}$$

Where:

V = voltage rms value, V
I = current rms value, A
θ = phase angle between V and I, degrees

In three-phase wye-connected systems for purely resistive loads (where θ = 0), total power is:

$$P_{tot} = \frac{V_{ab}}{\sqrt{3}} I_a + \frac{V_{bc}}{\sqrt{3}} I_b + \frac{V_{ca}}{\sqrt{3}} I_c \qquad \text{Eqn. D4}$$

Where:

P_{tot} = total power, W
V_{ab} = rms voltage between phases a and b, V
I_a = phase a current, A
V_{bc} = rms voltage between phases b and c, V
I_b = phase b current, A
V_{ca} = rms voltage between phases c and a. V
I_c = phase c current, A

This relationship is useful for setting up instruments and troubleshooting.

Energy

Total energy in watt-hours is the real power integrated over the time period of interest. 1000 watts (W) produced for one hour (H) results in one kilowatt-hour (kWh) of energy transfer.

Reactive Power and Apparent Power

Reactive power develops when inductive, capacitive, or nonlinear sources and loads exist on the system. It does not represent useful energy that can be extracted from the system, but it can cause increased losses, over-current conditions, and excessive voltage peaks. Reactive power is calculated as[D1]:

$$Q = \sqrt{S^2 - P^2} \qquad \text{Eqn. D5}$$

Where:

Q = reactive power, volt-amperes reactive (VAR)
S = apparent power, calculated as V * A, VA
P = real power, W

Power Factor

Power factor is the ratio between real power and apparent power [D1]:

$$PF = \frac{P}{S} \qquad \text{Eqn. D6}$$

Power factor indicates how much of the apparent power flowing into a load or a feeder is real power, P.

Frequency

Frequency is the number of complete cycles of sinusoidal variation per unit time. Throughout most of North America, the EPS frequency is nominally 60 Hertz (Hz)

Total Harmonic Distortion

AC waveform distortion occurs at integer multiples, or harmonics, of the lowest sine wave frequency, or fundamental. Total harmonic distortion defines the relationship of all distorting integer harmonic waveforms with the fundamental. THD is the ratio of the root-mean-square (rms) summed harmonic current or voltage to the rms value of the fundamental, expressed as a percent of the fundamental [D2]. In equation form:

$$\%THD_I = 100\frac{\sqrt{\sum_{2}^{h}\left(I_h^2\right)}}{I_f} \qquad \%THD_V = 100\frac{\sqrt{\sum_{2}^{h}\left(V_h^2\right)}}{V_f} \qquad \text{Eqns. D7, D8}$$

Where:

%THD = total harmonic distortion, percent
f = fundamental harmonic order (60 Hz in North America)
h = harmonic order as an integer multiple of the fundamental (h = 2 for 120 Hz)
I = true rms current, A
V = true rms Voltage, V

External Parasitic Loads

Parasitic loads are those which are essential for proper SUT function. The power connections for some parasitic loads, such as fuel gas compressors, heat rejection unit fans, heat transfer fluid pumps, etc., may be on the PCC-side, or “upstream”, of the power meter (see Figure 2-1). Such loads are considered to be external parasitic loads.

D2: Electrical Efficiency Equations

Electrical Efficiency

Efficiency is the proportion of the fuel's heating value that appears as electricity at the DUT output terminals [D3, D4]:

$$\eta_e = \left(\frac{3412.14 * P}{Q_{in}}\right) * 100 \qquad \text{Eqn. D9}$$

Where:

η_e = electrical generation efficiency, percent
3412.14 = British thermal units per hour (Btu/h) per kW
P = average power output (considered as P_{tot} or P_{net}, see below), kW
Q_{in} = average heat input, Btu/h

The average power output, or P, is the mean of all the one-minute power readings logged during each test run (refer to Sections 2.3.1, 2.3.2). Power output may or may not incorporate losses from external parasitic loads, so two efficiency values are appropriate:

- efficiency calculated on a total power output basis, without considering external parasitic loads as a debit against performance
- efficiency including the external parasitic loads

Section 3.5.1.1 discusses how assumptions about external parasitic loads affect net power output and the electrical efficiency accuracy.

Electrical efficiency determinations in this GVP are based on the fuel's LHV and should appear as $\eta_{e,LHV}$. For reference, the relationship between $\eta_{e,HHV}$ and $\eta_{e,LHV}$ is straightforward. In general ,

$$\frac{\eta_{e,HHV}}{\eta_{e,LHV}} = \frac{LHV}{HHV}\text{, or approximately 0.90 (90 percent)} \qquad \text{Eqn. D10}$$

Heat Rate

Heat rate is the normalized heat input per unit of real power output [D3, D4]:

$$HR = \frac{Q_{in}}{P} \qquad \text{Eqn. D11}$$

Where:

HR = heat rate, Btu/kWh
Q_{in} = average heat input during each 30-minute test run, Btu/h
P = average power output, kW

Similar to efficiency, two heat rate reports are appropriate:

- heat rate calculated on a total power output basis, without considering external parasitic loads as a debit against performance,
- heat rate including the external parasitic loads.

Heat rate determinations based on the LHV of the fuel should appear as HR_{LHV}.

Heat Input, Gaseous Fuels

Gaseous fuel heat input determination requires measurement of the actual flow rate of the fuel averaged over each test run and corrected to standard conditions. Laboratory sample analysis for LHV is also required:

$$Q_g = q_g * V_{g,std} \qquad \text{Eqn. D12}$$

Where:

Q_g = heat input from fuel gas, Btu/h
q_g = fuel gas LHV from laboratory sample analysis, Btu/scf
$V_{g,std}$ = fuel volumetric flow rate at standard conditions (14.7 psia, 60 ^oF), scfh

The determination of volumetric flow rate for positive displacement flow meters, corrected to standard conditions, requires measurement of flow rate in acfh, gas pressure, gas temperature, and gas compressibility as follows:

$$V_{g,std} = V_m \left(\frac{p_{bar} + p_{fuel}}{14.7} \right) \left(\frac{520}{T_g} \right) \frac{Z_{std}}{Z_g} \qquad \text{Eqn. D13}$$

Where:

V_m = average gas meter flow rate during each 30-minute test run, acfh
p_{bar} = ambient barometric pressure, psia
p_{fuel} = gas fuel pressure at the gas meter, psig
14.7 = standard ambient pressure, psia
520 = standard absolute temperature, R
T_g = absolute gas temperature, R
Z_{std} = average gas compressibility at 14.7 psia, 60 ^oF from laboratory analysis
Z_g = average gas compressibility at test conditions from laboratory analysis

Heat Input, Liquid Fuels

Heat input from liquid fuel is:

$$Q_l = q_l * \dot{m} \qquad \text{Eqn. D14}$$

Where:

Q_l = heat input from liquid fuel, Btu/h
q_l = liquid fuel LHV from laboratory sample analysis, Btu/lb
$\dot{m}$ = liquid fuel mass consumption rate, lb/h

Liquid fuel mass consumption rate is:

$$\dot{m} = (Wt_1 - Wt_2) \left(\frac{60}{T_{elapsed}} \right) \qquad \text{Eqn. D15}$$

Where:

Wt_1 = initial day tank weight at the beginning of the time period, lb
Wt_2 = final day tank weight at end of the time period, lb
60 = minutes per hour
$T_{elapsed}$ = length of the test run, minutes (min)

D3: CHP Thermal Performance

Thermal Performance and Average Operating Temperature

The thermal performance is the energy transferred out of the CHP system boundary by the heat transfer fluid to the BoP and cooling tower(s), if present [D5]:

$$Q_{out} = V_l(\Delta T)c_p \rho \qquad \text{Eqn. D16}$$

Where:

Q_{out} = thermal performance, Btu/h
V_l = heat transfer fluid volumetric flow rate, gallons per hour (gph)
ΔT = absolute value of the difference between supply and return temperatures, $\left|T_{\sup ply} - T_{return}\right|$, °F
c_p = heat transfer fluid specific heat at the average operating temperature, Btu/lb.°F
ρ = heat transfer fluid density at the average operating temperature, lb/gal

In heating service, T_{supply} and T_{return} are the higher and lower temperature fluids, respectively. In chiller service, T_{supply} and T_{return} are the lower and higher temperature fluids, respectively.

In chiller applications, thermal performance can be expressed as refrigeration tons:

$$RT_{out} = \frac{Q_{out}}{12000} \qquad \text{Eqn. D17}$$

Where:

RT_{out} = transferred heat, RT
12000 = Btu/RT

Maximum thermal performance, or Q_{max}, in heating applications is the sum of the thermal energy transferred to the BoP ($Q_{out,BoP}$) and that rejected from the cooling tower(s), if present ($Q_{out,cooltower}$)

Maximum thermal performance in chilling applications is not meaningful because the energy transferred to the BOP is used for chilling while heat rejected from cooling module(s), if present, could be used only for heating. They should be reported separately.

The average operating temperature is:

$$T_{avg} = \frac{T_{\text{supply}} + T_{\text{return}}}{2} \qquad \text{Eqn. D18}$$

Thermal Efficiency

For CHP units in heating service only, thermal efficiency (η_{th}) is the proportion of the fuel's heating value that appears as useful heat recovered from the CHP system:

$$\eta_{th} = \left(\frac{Q_{out}}{Q_{in}}\right) * 100 \qquad \text{Eqn. D19}$$

Where:

η_{th} = thermal efficiency, percent
Q_{out} = thermal energy transferred, Btu/h
Q_{in} = heat input, Btu/h

The thermal energy transferred (Q_{out}) is that which is moved out of the system boundary to the BOP. Where cooling module(s) are present, the maximum thermal efficiency is:

$$\eta_{th,\max} = \left(\frac{Q_{\max}}{Q_{in}}\right)*100 \qquad \text{Eqn. D20}$$

Where:

$\eta_{th,max}$ = maximum thermal efficiency, percent
Q_{max} = maximum thermal performance: the sum of $Q_{out,BOP}$ and $Q_{out,cool\ module}$, Btu/h
Q_{in} = heat input, Btu/h

Thermal efficiency determinations based on the fuel's HHV will appear as $\eta_{th,HHV}$. Those based on LHV will appear as $\eta_{th,LHV}$.

Total Efficiency

For CHP units in heating service only, total efficiency is:

$$\eta_{tot} = \eta_e + \eta_{th} \qquad \text{Eqn. D21}$$

Where:

η_{tot} = total efficiency, percent
η_e = electrical generation efficiency (Section 5.2.1)
η_{th} = thermal efficiency

In chilling applications heat that is normally discarded through a cooling tower or fan-coil unit may be recovered for low-grade service, such as to provide swimming pool heat. This lower grade product may be presented as a thermal efficiency. However the heating or chilling energy value depends on how high (for heating) or low (for chilling) the temperature is for each loop. Therefore each "efficiency" may be reported separately.

D4: Emission Rates

Normalized Emission Rates

Emission rate normalized against system power output to provide emission rates (lb/kWh) is:

$$ER_{N,kW} = \frac{E_j}{kWh_j} \qquad \text{Eqn. D22}$$

Where:

$ER_{N,kW}$ = normalized emission rate, lb/kWh
E_j = mean emission rate at load condition j, lb/h
kWh_j = mean power production at load condition j, kW

D5: References

[D1] *IEEE Std 120-1989— Master Test Guide for Electrical Measurements in Power Circuits*. Institute of Electrical and Electronics Engineers, Inc., New York, NY. 1989

[D2] *IEEE Std 519-1992—Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*. Institute of Electrical and Electronics Engineers, Inc., New York, NY. 1992

[D3] *ASME PTC 22-1997—Performance Test Code on Gas Turbines.* American Society of Mechanical Engineers, New York, NY. 1997

[D4] *ASME PTC 17-1997—Reciprocating Internal-Combustion Engines*. American Society of Mechanical Engineers, New York, NY. 1997

[D5] *ANSI/ASHRAE 125-1992: ASHRAE Standard Method of Testing Thermal Energy Meters for Liquid Streams in HVAC Systems*. American Society of Heating, Refrigeration, and Air-Conditioning Engineers, Inc., Atlanta, GA. 1992

Appendix E: Often-overlooked Emission Testing Requirements

Requirement	Parameters affected	Impact if not conducted
Clean sample lines and probe	NO_x, SO_2, TPM	Positive bias from residuals
Properly heated sample line (record the temp)	NO_x, THC, CH_4	Negative bias from condensation
Proper analyzer ranges and cal gases (readings should be over 30 percent of range)	NOx, CO, THC, SO_2	Bias results
Proper moisture removal system (minimize contact between gas and condensed water)	NO_x	Negative bias
Clean glassware	TPM, metals, NH_3, HCOH	Positive bias in results
Do the reagent and field blanks specified in the methods	TPM, metals, NH_3, HCOH	Positive bias in results
Straight run, cyclonic flow checks	TPM, metals	Bias results
Method 4 last impinger temp.	Stack gas moisture content	Negative bias
Witness Method 5 sampling train leak check (operator to not touch sampling controls once the leak check starts, etc.)	TPM	Negative bias
Witness Method 5 pitot tube leak check (operator to not touch sampling controls once the leak check starts, etc.)	TPM	Bias results
Calibration gases certified and within expiration dates	NO_x, CO, CO_2, O_2, THC, CH_4	Bias results

Appendix F: Sample Implementation

F1: Scope

This sample implementation provides detailed measurement instrument specifications and suggests instruments which would fulfill the GVP's accuracy specifications for DG units less than approximately 500 kW. Numerous instruments of equivalent capabilities are available. Mention of brand names or model numbers does not imply exclusivity or endorsement.

This Appendix also provides generic installation procedures and schematics for reference.

F2: Electrical Measurements and Datalogging

Power Meter

The power meter must meet ANSI C12.20-2002 [F1] and the GVP's specifications as shown in the following table:

Table F-1: Electrical Instrument Specifications

Parameter	Maximum Allowable Error	Citation
Voltage	± 0.50 % (class B)	IEC 61000-4-30 [F2]
Current	± 0.40 % (class B)	" "
Real Power	± 0.6 % overall	" "
Reactive Power	1.5	n/a
Power Factor	± 2.00 %	IEEE 929 [F3]
Frequency	± 0.01 Hz (class A)	IEC 61000-4-30 [F2]
Voltage THD	± 5.00 %	IEEE 519 [F4]
Current THD	± 4.90 %	IEEE 519 [F4]

[a]All accuracy specifications are percent of reading, except where noted.
[b]Full scale (FS) is 600 V, phase-to-phase
[c]Full scale depends on the selected current transformer (CT) range

Current Transformers

Current measurements require one CT for each phase. A CT with the proper current ratio will produce a 5 A output (or output appropriate for the power meter) when the DUT is operating near its rated capacity.

The following table lists common CT current ratios and associates each with common DUT capacity ratings.

Table F-2: Common CT Ratios and DUT Ratings

Current Ratio	kW per Phase[a]	3-Phase Total, kW	Recommended Nominal DUT Capacity
100:5	27.7	83.1	≤ 75 kW
200:5	55.4	166.3	150 kW
400:5	110.8	332.6	300 kW
800:5	221.7	665.1	600 kW
1200:5	332.6	997.7	900 kW
1600:5	443.4	1330.2	1.2 MW
2000:5	554.3	1662.8	1.5 MW
3000:5	831.4	2494.2	2.2 MW

[a]Assumes 480 V rated system voltage.

The GVP (and IEC 61000-4-30) specifies that CT accuracy class be ± 0.5 percent or better.

Other Instruments

Table F-3 suggests appropriate supplemental instruments and summarizes the GVP's specifications.

Table F-3: Supplemental Instrument Specifications

Parameter		Max. Allowable Error	Range	Instrument Error
Ambient Temperature		± 1.0 ^{o}F	- 20 to 120 ^{o}F	± 1.0 % FS[a]
Ambient Barometric Pressure		± 0.1 "Hg (± 0.05 psia)	0 to 15 psia	± 0.25 % FS (± 0.04 psia)
External Parasitic Loads:	Voltage	± 1.0 % of reading	0 - 600 V	± 1.0 % of reading
	Current	± 2.0 % of reading	0 - 600 A[b]	± 2.0 % of reading

[a]± 1.0 % of full scale represents ± 1.2 ^{o}F. Ambient temperature is used only to verify stable SUT operations, and the maximum permissible variation is ± 4 ^{o}F.
[b]This current capacity is sufficient for 480 V loads up to approximately 500 kW, or 166 kW per phase.

Loop Power Supply

Installers should review the sensor specifications to evaluate the need for series current-limiting resistors (usually 250 ohm).

Datalogger

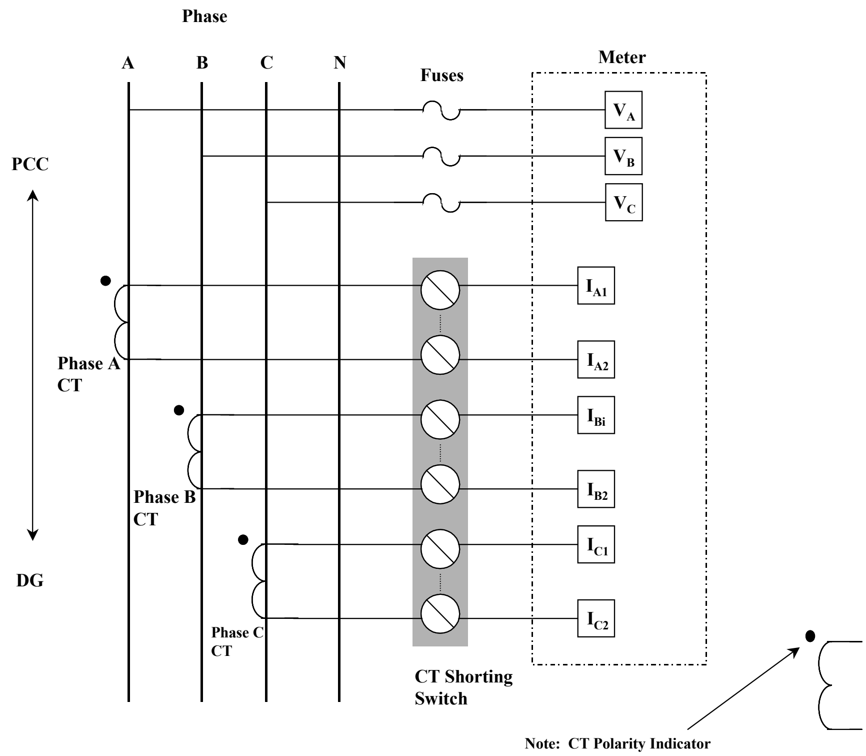
The test manager (or a designated database manager) must download the data to a laptop computer or over a phone line before the datalogger capacity limit is reached. Confirm datalogger capacity to prevent data loss. The power parameters may be logged within the power meter (if this function is available) or externally.

Note that three analog channels and datalogger inputs (heat transfer fluid flow, T_{supply}, T_{return}) are required for each thermal performance measurement location.

Electrical Instrument Installation

Figure F-1 shows a generalized installation schematic for a 4-wire WYE system. It is important that the voltage sensing lead for each phase be associated with the proper CT for that phase. Note that most instruments can accommodate delta-wired systems if necessary. Refer to the power meter manufacturer's instruction manual for specific installation procedures.

Figure F-1. Four-wire Wye Instrument Connections



Instrument installation consists of:

- installing and commissioning the power meter and supplementary instruments, and
- performing sensor function checks.

The installer must de-energize and physically remove each phase conductor from its terminal to allow for solid-core CT installation. Split-core CTs do not require this. Refer to manufacturers' specifications to ensure that CT polarity is correct.

The maximum (one-way) CT lead length should not exceed the manufacturer's specifications and depends on the wire size (usually at least 12 gauge).

CT secondary wire leads should be physically connected to a functioning power meter, to a closed shorting switch, or twisted together as a dead short circuit before energizing the power circuit. This is an important safety measure because CTs can generate high voltages while a phase is energized if the CT secondary circuit is open. Shorting switches are advantageous because they allow easy instrument service without disturbing SUT wiring or operations.

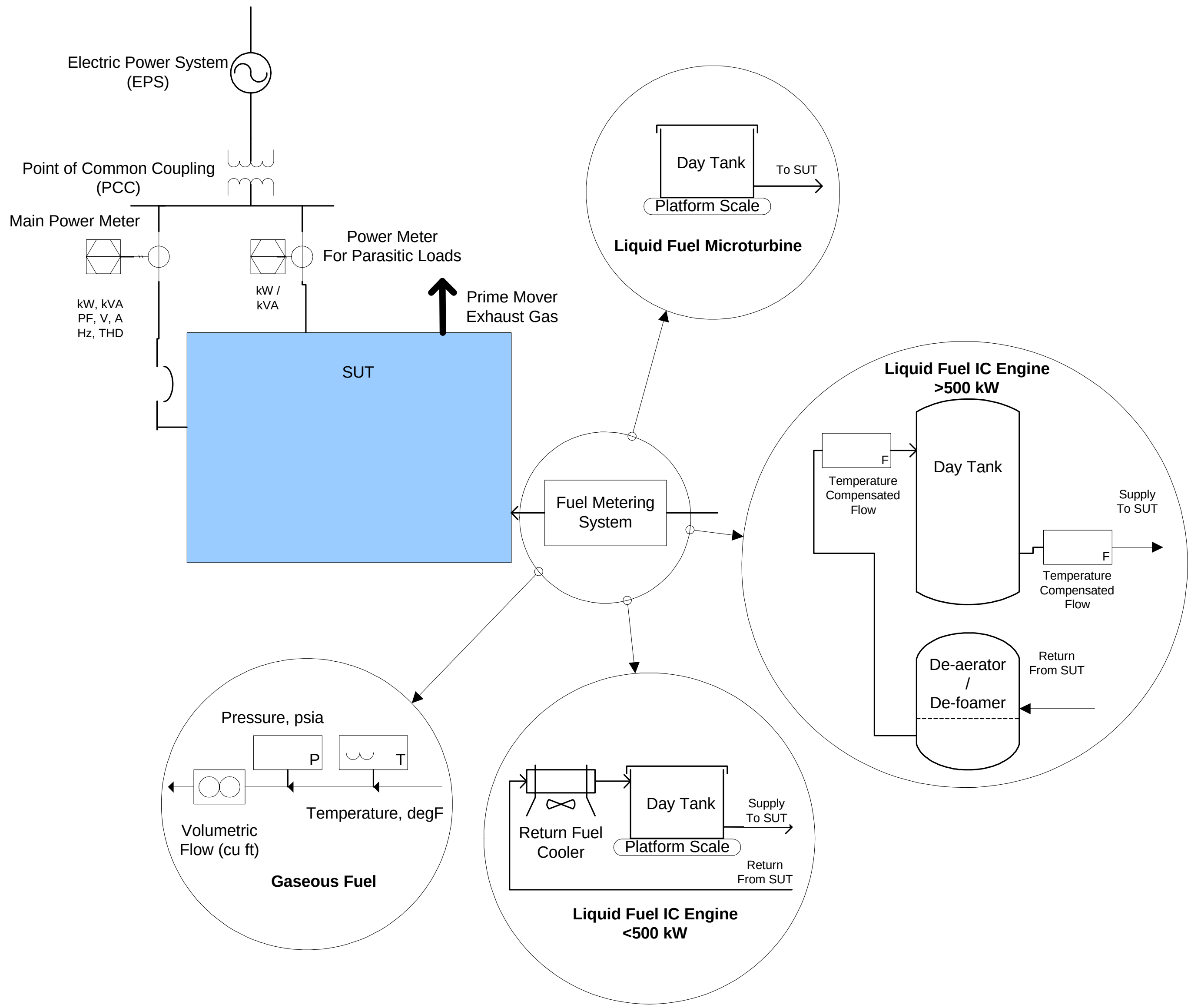
Most power meter manufacturers specify a fuse in series with each voltage sensing wire. The fuse rating should be as specified by the power meter manufacturer (usually 0.5 to 2.0 A). The fuse and its holder should be capable of at least 200 kiloamperes interrupt current (KAIC).

F3: Electrical Efficiency Measurements

This subsection specifies instrument requirements, laboratory analyses, allowable measurement error, and installation procedures for measuring SUT fuel input, Q_{in}. Section F2.0 provided power meter and CT specifications and installation procedures for measuring power output, P, and external parasitic loads.

Figure F-2 outlines the different fuel measurement configurations considered here.

Figure F-2. Fuel Measurement Systems



Gas Fuel Consumption Meter

This implementation suggests use of displacement-type gas meters. These meters are readily available, reliable, and meet the GVP's ± 1.0 percent accuracy specification. Installers should specify the meter size so that the actual fuel consumption of the SUT is between approximately 10 and 100 percent of the meter's capacity at all three power commands.

Table F-4 suggests common meter capacities to be used with hypothetical DUT capacities. For reference, LHV and $\eta_{e,LHV}$ are assumed to be 911 Btu/scf and 26 percent, respectively.

Table F-4: Gas Meter Sizing

DUT Capacity, kW	Heat Input, Btu/h	Gas Consumption, scfh	Meter Capacity, scfh
30	393700	432	800
70	918600	1009	3000
100	1312400	1441	3000
250	3281000	3602	5000
500	6562000	7204	11000
1500	19685000	21613	23000
2000	26247000	28818	38000
3000	39371000	43226	56000

Collection and analysis of fuel samples from biogas or landfill gas sources is strongly recommended prior to specifying the gas meter because such gases can be extremely corrosive. At a minimum, the samples should be analyzed by ASTM D5504 [F5] for sulfur compounds including H_2S and mercaptans. The meter manufacturer can then recommend a suitable meter for corrosive service if required.

Pressure and Temperature Sensors

This GVP suggests a direct-insertion bimetal thermometer and bourdon-type pressure gauge. Table F-5 presents the example instrument specifications.

Table F-5: Pressure and Temperature Instrument Specifications

Parameter	Maximum Allowable Error	Range	Accuracy
Pressure	± 2.0 %	0 - 15 psig	± 0.5 % FS (FS = 15 psig)
Temperature	± 1.0 %[a]	-20 - 120 ^oF	± 1.0 % FS (FS = 120 ^oF)

Gas Meter Installation

Site or test personnel should plan the gas flow meter installation with respect to the meter's specific requirements. Some common gas meters, for example, must be mounted such that the lubrication reservoirs and index are in the proper orientation. Other gas meter styles, such as orifice meters, require straight pipe runs or flow straighteners upstream and downstream of the metering element [F6]. Whatever the meter configuration, the site may wish to install isolation valves and a bypass loop to allow meter service without disturbing SUT operations.

The meter run should incorporate pressure and temperature sensor ports adjacent to the gas meter for those meters which are not pressure- or temperature-compensated. The temperature sensor port should provide for a thermowell. This will allow the sensor to be removed without disturbing the gas flow and the sensor need not be hermetically sealed.

A fuel sampling port with the appropriate valve should be available.

Liquid Fuel Mass Consumption for DG Units < 500 kW

Day Tank and Secondary Containment

Actual equipment and configuration can vary widely. A 100-gallon polyethylene or metal tank placed on a 1000 lb capacity platform scale will provide enough fuel to operate a 70 kW MTG for about 14 hours. The same installation would fuel a 500 kW diesel IC generator for approximately 1½ hours (at 50 gph or 350 lb/h). This is permissible if testers refuel the day tank from a common supply before each test run.

Always check with the vendor prior to purchase to ensure that the day tank materials are compatible with the fuel. Some facilities may require a secondary containment pan under the platform scale and day tank to control potential fuel spills.

Platform Scale

The scale's capacity should not exceed 1000 lb. The scale's accuracy specification should be ± 0.01 percent of reading and ± 0.05 lb display resolution. This resolution is usually specified as "non-commercial" or "not legal for trade." Such scales are readily available for rental or purchase.

Return Fuel Cooler (Diesel IC Generators Only)

The required return fuel cooler capacity depends on the return fuel flow rate and return temperature. The return temperature should be below about 140 ^{o}F. The fuel in the day tank (as supplied to the engine) should not exceed about 110 ^{o}F.

In general, diesel engine return fuel flow rate ranges between about 4½ times (for Caterpillar brand) and 2 ½ times (for other brands) of the engine's actual fuel consumption. Return fuel flow from a 500 kW IC generator should be between 180 to 260 gph, or 930 to 1500 lb/h. At a diesel fuel specific heat of 0.5 Btu/lb.^{o}F, the cooler capacity should therefore be between 14,000 and 22,000 Btu/h (assuming 110 and 140 ^{o}F supply and return temperatures, respectively). Numerous fan- or liquid-cooled heat exchangers are available for this purpose. In one instance, a 15-foot coil of copper tubing placed in a cooler full of ice was adequate for a 200 kW diesel engine.

Liquid Fuel Mass Consumption Flow Meters for DUT > 500 kW

Prime movers without return fuel flow require one temperature-compensated fuel flow meter connected to a suitable datalogger. The flow meter accuracy specification, corrected to 60 ^{o}F, is ± 1.0 percent of reading. Turbine flow meters are available which meet these specifications.

Differential measurements of supply and return fuel flow are necessary for diesel IC generators larger than 500 kW or other prime movers with return fuel flow. This requires two separate flow meters (see Figure F-2). The return fuel flowmeter installation should incorporate an upstream integral or external de-aerator / de-foamer. The accuracy specification of the differential value, corrected to 60 ^{o}F, is ± 1.0 percent of reading. In general, this means that each flow meter's temperature-compensated accuracy should be better than ± 0.2 percent.

Note that test personnel should review the expected prime mover fuel supply (and return) flow rates at all three power commands (50, 75, and 100 percent) prior to specifying the flow meter(s) to ensure that the flow rates fall within the manufacturer's calibrated instrument response.

Liquid Fuel Meter Installation

Installation for either liquid fuel metering scheme consists of obtaining and plumbing the appropriate leak-free fuel-rated hoses or pipelines. Hoses should be suspended at day tank installations to ensure that they do not contact the tank or affect scale readings. Installers may wish to incorporate bypass pipelines, valves, and tee fittings to allow insertion and removal of the meters without affecting SUT operations.

F4:Thermal Performance and Efficiency Measurements

Heat Transfer Fluid Flow Meter

The proper heat transfer fluid flow meter size depends on the expected fluid flow rate at the design temperature. Testers should consult with the CHP designer prior to meter selection and sizing. Turbine meters are suitable for the flow rates expected at typical CHP installations. Flow meter and transmitter accuracy specification is ± 1.0 percent of reading.

Heat Transfer Fluid Temperature Meters

The GVP's temperature sensor specification is ± 0.55 ^{o}F accuracy from 100 to 180 ^{o}F and about ± 0.60 ^{o}F from 180 to 212 ^{o}F.

CHP Flow and Temperature Meter Installation

Installation consists of:

- designing, fabricating, and installing the flow meter, isolation valves, and fluid sampling port (if needed)
- installing thermowells, sensors, and transmitters
- wiring the transmitters to the loop power supply and the datalogger.

Most flow meters require a straight run of pipe to ensure undisturbed flow. This straight run usually incorporates at least 15 pipe diameters to the nearest upstream disturbance (elbow, restriction, etc.) and five diameters to the nearest downstream disturbance. The actual number of diameters depends on the flow meter and disturbance type. The meter run can incorporate flow straighteners where space is constrained. The flow meter manufacturer can provide the necessary details. CHP installations which do not use pure water as a heat transfer fluid should have a fluid sampling port and valve available. This GVP recommends installation of isolation valves to allow flow meter removal and service without disabling SUT operations. Figure F-3 provides a reference schematic.

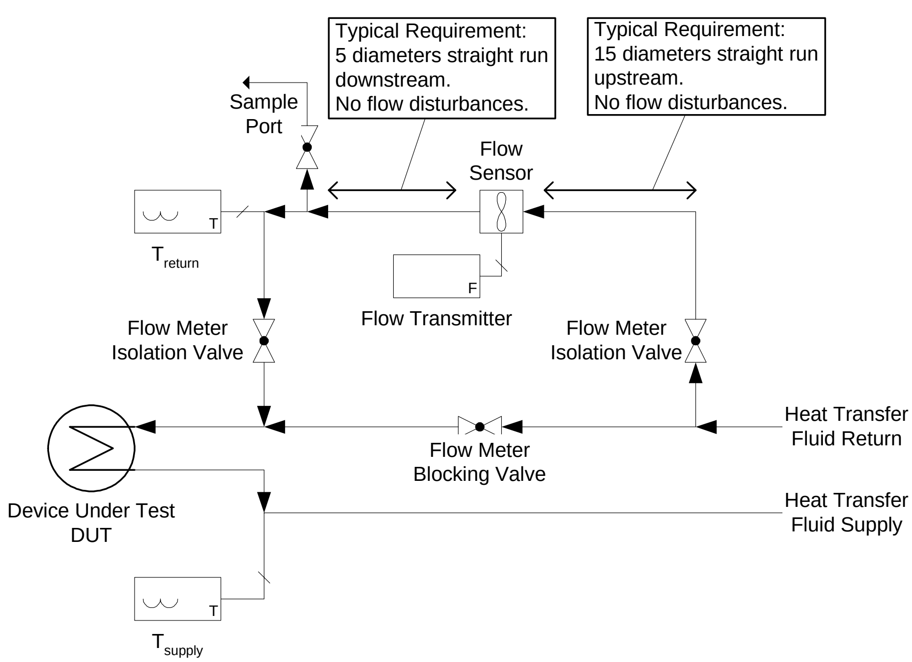


Figure F-3. Heat Transfer Fluid Flow Meter and Temperature Sensor Schematic

F5: Example Equipment

Note that the manufacturers referenced here have been successfully used in the past and are provided for convenience only. This does not represent an endorsement. Any product that meets or exceeds the requirements outlined above is acceptable for the purpose of this GVP.

Table F-6: Example Test Equipment

Device	Measurement(s)	Model	Manufacturer
Power Meter	Voltage, Current, Real Power, Reactive Power, Power Factor, Frequency, Voltage THD, Current THD (w. internal 24 hour datalogger function)	ION 7330	Power Measurements Ltd.
Current Transformer (CT)	Current	19RL, 191, 194, 195	Flex-Core
Temperature	Temperature	30EI60L040-20/120/F/C	Ashcroft[a]
Barometric Pressure	Ambient Barometric Pressure	PX205-015AI	Omega Instruments
External Parasitic Loads	Voltage, Current	335 Clamp-on	Fluke Instruments
Shorting Switch	CT Shorting Switch	U3889	Flex-Core
Voltage Leads	Voltage Sensor Leads w. Fuses (3-pack)	H6911-3	Veris Industries
Power Supply	For 4-20 mA instrument loops	U24Y101	Omega Instruments
Pressure	0-15 psig	1981	Ametek
Day Tank	100 gallon polyethylene	38555K33	McMaster-Carr
Spill Containment	Containment pan	12635T14	McMaster-Carr
Platform Scale	1000 lb capacity	"Aegis"	Fairbanks Morse
Liquid Fuel Meter	Turbine flow meter		Omega Instruments
Fuel Meter (gas)	Displacement gas meter	Roots series	Dresser Industries
Liquid Fuel Meter (differential)	Liquid fuel supply and return; temperature-compensated flow	FuelCom series	Flow Technology, Inc.
Flow Meter	Heat transfer fluid flow (turbine type)	FTB	Omega Instruments
Flow Transmitter	Transmitter for turbine flow meter	FLSC-62	Omega Instruments
Temperature Sensor	Heat transfer fluid temperatures ("class A" Platinum resistance temperature detector)	PR-18-2-100-1/4-6-E-CLA	Omega Instruments
Temperature Transmitter	For above RTD 0-200 F range	TX92A-2	Omega Instruments

[a]ASME PTC-22 and other protocols specify ± 1.0 ^{o}F. The 1.0 % FS accuracy of the Ashcroft thermometer suggested here represents ±1.2 ^{o}F, which is a reasonable compromise for inexpensive field instrumentation.

F6: References

[F1] *ANSI C12.20-2002: Code for Electricity Meter--0.2 and 0.5 Accuracy Classes*. National Electrical Manufacturers' Association, American National Standards Institute, Rosslyn, VA. 2001.

[F2] *IEC 61000-4-30: Electromagnetic Compatibility (EMC)—Part 4-30: Testing and Measurement Techniques-Power Quality Measurement Methods*. International Electrotechnical Commission, Geneva, Switzerland. 2003.

[F3] *IEEE Std. 929-2000—IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*. Institute of Electrical and Electronics Engineers, Inc., New York, NY. 1992.

[F4] *IEEE Std 519-1992—Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*. Institute of Electrical and Electronics Engineers, Inc., New York, NY. 1992.

[F5] *ASTM D5504-01—Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence*. American Society for Testing and Materials, west Conshohocken, PA. 2001.

[F6] *AGA Report No. 3, Orifice Metering of Natural Gas Part 2: Specification and Installation Requirements (2000)*. American Gas Association, Washington, DC. 2002.

Appendix G. Uncertainty Estimation

G1: Scope

This Appendix presents compounded error estimation procedures for quantities which are developed from two or more instruments (or analyses) with individual measurement errors. It includes examples which use the ASERTTI Microturbine and Microturbine-CHP Field Testing Protocol, Sections 2.0 through 7.0, as a basis.

In addition to following the specified procedures to ensure data quality, evaluation and reporting of the achieved uncertainty is an important aspect of this GVP. Where applicable, two methods of uncertainty evaluation are acceptable.

First, if each measurement meets its minimum accuracy specification, analysis can report the overall estimated uncertainty as that cited in the GVP. If all specifications are not met, analysts should instead calculate the actual parameter uncertainty in accordance with the methods specified below.

Second, the achieved parameter uncertainty may be calculated based on actual measurement instrument calibration data, actual laboratory error, field conditions, and other uncertainties determined as described in the GVP. Analysts may compound the measurement errors to determine the achieved uncertainty (or relative error) for the parameter of interest using the methods specified below.

G2: Measurement Error

This Appendix defines measurement error, uncertainty, or accuracy as the combination of all contributing instrument errors and instrument precision. It makes no effort to separate the two or to quantify sampling error. An instrument manufacturer's accuracy specification (or laboratory analysis accuracy statement, etc.) is sufficient if it is accompanied, at a minimum, by current applicable National Institutes of Standards and Technology (NIST)-traceable calibration(s), appropriate QA/QC checks, or other supporting documents which support the accuracy statements.

Absolute and Relative Errors

Absolute measurement error is an absolute value compared to a given value or operating range. An example is: "± 0.6 ^{o}F between 100 and 212 ^{o}F" for a temperature meter.

Relative measurement error, generally stated as a percentage, is:

$$err_{rel} = \frac{err_{abs}}{reading} 100 \qquad \text{Eqn. G-1}$$

Where:

err_{rel} = relative error, percent
err_{abs} = absolute error, stated in the measurement's units
reading = measurement result, stated in the measurement's units

The reference basis for relative accuracy statements can be either the instrument's full scale or span or the measurement reading. The following examples show the relationships between relative and absolute measurement errors.

Relative Error Accuracy Statement	FS (or span)	Absolute Error
"Temperature accuracy is ± 1.0 %, FS"	120 ^{o}F	± 1.2 ^{o}F at 60 ^{o}F
"Temperature accuracy is ± 1.0 % of reading"	n/a	± 0.6 ^{o}F at 60 ^{o}F

Compounded Error for Added and Subtracted Quantities

For added or subtracted quantities, the absolute errors compound as follows [G1, G2]:

$$err_{c,abs} = \sqrt{err_{abs1}^{2} + err_{abs2}^{2}} \qquad \text{Eqn. G-2}$$

Where:

$err_{c,abs}$ = compounded error, absolute
err_{1} = error in first added or subtracted quantity, absolute value
err_{abs2} = error in second subtracted quantity, absolute value

As an example, the GVP defines the heat transfer fluid ΔT as the difference between T_{supply} and T_{return}. The uncertainties in each temperature measurement compound together to yield the overall ΔT uncertainty. The absolute error for each temperature meter specified in the GVP is ± 0.6 ^{o}F, from 100 to 212 ^{o}F. The resulting ΔT absolute error is constant at $\sqrt{0.6^2 + 0.6^2}$, or ± 0.85 ^{o}F. Relative error will vary with the actual ΔT found during testing.

Compounded Error for Multiplied or Divided Quantities

For two multiplied or divided quantities, the relative errors compound to yield the overall error estimate [G2, G3, G4]:

$$err_{c,rel} = \sqrt{err_{1,rel}^{\,2} + err_{2,rel}^{\,2}} \qquad \text{Eqn. G-3}$$

Where: $err_{c,rel}$ = compounded relative error, percent
$err_{1,\,rel}$ = relative error for first multiplied quantity, percent
$err_{2,\,rel}$ = relative error for second multiplied quantity, percent

For example, the power meter described in the GVP measures the CT output and applies the appropriate scaling factor by multiplication. The GVP specifies current THD accuracy as ± 4.9 percent at 360 Hz. Compounded with the specified ± 1.0 percent CT accuracy at that frequency, the overall current THD accuracy is $\sqrt{4.9^2 + 1.0^2}$ or ± 5.0 percent.

G3: Examples

This section provides example uncertainty calculations for each of the GVP's parameters. Each parameter is a combination of multiplied/divided or added/subtracted values. The relative or absolute errors compound accordingly. Accuracy actually achieved in field testing may be estimated by entering the actual instrument or measurement accuracies in the appropriate calculations.

Electrical Generation Performance Uncertainty

The electrical generation performance accuracy depends on the power meter accuracy alone for the parameters shown in Table G-1. This table essentially repeats the GVP's specifications for those parameters. For other parameters, CT uncertainty compounds multiplicatively according to Eqn. G3 with the power meter accuracy. Table G-2 shows the effects.

Table G-1: Directly Measured Electrical Parameter Uncertainty

Parameter	Accuracy
Voltage	± 0.5 % of reading
Voltage THD	± 5.0 % of reading
Frequency	± 0.01 Hz
Ambient temperature	± 1 ^{o}F
Ambient barometric pressure	± 0.1 "Hg or ± 0.05 psia

Table G-2: Compounded Electrical Parameter Uncertainty

Parameter	Power Meter Accuracy	CT Accuracy	Compounded Uncertainty
Current	± 0.4 %	± 0.3 %	± 0.5 %
Real power	± 0.6 %		± 0.7 %
Reactive power	± 1.5 %		± 1.5 %
Power factor	± 2.0 %		± 2.0 %
Current THD	± 4.9 % (to 360 Hz)	± 1.0 % (to 360 Hz)	± 5.0 % (to 360 Hz)
[a]All accuracies are percent of reading			

Electrical Efficiency Uncertainty

The electrical efficiency determination accuracy depends on the real power, fuel heating value, and fuel consumption uncertainties. Each of these quantities incorporate individual measurements and corresponding errors.

Real Power Uncertainty

The GVP specifies that electrical efficiency must be reported as two values:

- efficiency calculated on a total power output basis, without considering external parasitic loads as a debit against performance
- efficiency including the external parasitic loads.

External parasitic loads are considered as a debit against SUT performance. Their inherent measurement errors will contribute to the real power determination and overall η_e uncertainties.

This GVP suggests the quantification of the external parasitic loads' apparent power consumption as either kVA with a clamp-on DVM or kW with individual real power meters (and datalogger channels) installed at each load.

Use of the clamp-on DVM increases the η_e error more than use of a real power meter because the clamp-on DVM will report external parasitic loads as apparent power, or kVA. Subtraction of kVA from kW is strictly accurate only when the parasitic load power factor is unity (or 1.00). For lower power factors, the subtraction will negatively bias the η_e result. As an example, a 100 kW MTG could have the following inductive parasitic loads and power factors:

Table G-3: Example External Parasitic Loads

Example Load Type	Load (apparent power)	Power Factor	Load (real power)
Compressor motor	5 kVA	0.80	4.0 kW
Circulation pump motor	3 kVA	0.70	2.1 kW
Total:	8 kVA	0.76	6.1 kW

If the parasitic loads are measured as kVA, real power would be reported as 92 kW (100 kW minus 8 kVA) instead of 93.9 kW (100 kW minus 6.1 kW). This 1.9 kW negative bias compounds additively with the ± 0.7 percent real power uncertainty (Table G-2) according to Eqn. G-2. This increases real power uncertainty to the ± 2.2 percent shown in Table G-4.

Table G-4: Real Power Uncertainty

Parameter Description	Value	Absolute Error	Relative Error
DUT real power output	100 kW	0.7 kW	0.7 %
External parasitic load as kVA, 0.76 power factor	8 kW	1.9 kW	23.8 %
SUT real power, net	92 kW	2.0 kW	2.2 %

If the loads are measured with ± 1.0 percent-accurate real power meters, the overall real power uncertainty increases slightly to ± 0.74, rounded to ± 0.7 percent. The disadvantage in measuring external parasitic loads with real power meters is the need for installation of a meter (and datalogger channel) at each load. Clamp-on real power meters are available whose impact on achieved accuracy falls between these two limits.

Gaseous Fuel Heating Value, Pressure, Temperature, and Consumption Uncertainty

<u>Heating Value</u>
The GVP specifies ± 1.0 percent relative accuracy for the gaseous fuel heating value, as supported by laboratory NIST-traceable calibrations, duplicate analyses, and other QA/QC checks.

<u>Absolute Gas Pressure</u>
The gaseous fuel consumption determination requires the gas absolute pressure at the meter, or the sum of ambient barometric pressure (p_{bar}, psia) and gas pipeline gage pressure (p_{fuel}, psig). The specified instrument accuracies are:

- p_{bar}: ± 0.05 psia
- p_{fuel}: ± 0.5 % FS, or ± 0.075 psig if FS is 15 psig

Standard gas delivery pressure at the metering location for many installations is between 0.25 and 1.0 psig (4 to 16 ounces, or 6 to 25 inches, water column). The GVP therefore assumes that p_{bar} and p_{fuel} are 14.2 psia and 0.50 psig, respectively; total absolute pressure is 14.7 psia. The absolute errors compound per Eqn. G-2 as: $\sqrt{.05^2 + .075^2}$, or ± 0.09 psia. In this case, the relative error is $[0.09/14.7]*100$ or ± 0.6 percent.

<u>Absolute Gas Temperature</u>

Fuel consumption also requires the absolute gas temperature, which is 460 °R plus the gas temperature reading in ^oF. The specified temperature sensor accuracy is ± 1.0 percent, FS, or ± 1.2 ^oF if FS is 120 ^oF. For 60 ^oF gas temperatures, the relative error is $[1.2/(60+460)]*100$, or ± 0.2 percent

Fuel Gas Consumption
The gas pressure and temperature relative uncertainties contribute to the overall fuel consumption uncertainty as shown in Table G-5. The table also summarizes the remaining gas consumption measurements, their associated relative accuracy, and the resulting compounded relative accuracy. All quantities are multiplied or divided, so their relative errors compound per Eqn. G-3.

Table G-5: Gaseous Fuel Consumption Uncertainty

Parameter	Relative Accuracy
V_m, acfm	± 1.0 %
$p_{bar} + p_{fuel}$, 14.7 psia assumed	± 0.6 %
T_g, or t_{fuel} + 460, ^oR	± 0.2 %
Z_{std}, compressibility at standard conditions (from lab analysis)	± 1.0 %
Z_g, compressibility at field conditions	± 1.0 %
Fuel consumption, scfh	**± 1.8 %**

Liquid Fuel Heating Value and Consumption

Heating Value
The GVP specifies ± 0.5 percent relative accuracy for the liquid fuel heating value.

Liquid Fuel Consumption
The GVP defines liquid fuel consumption as the fuel day tank weight at the end of a test run subtracted from the starting weight. Three errors contribute to liquid fuel consumption uncertainty. They are:

- platform scale error: ± 0.01 percent of reading
- display resolution error: ± 0.05 lb
- subtraction error

The worst case errors occur for low fuel consumption rates and high day tank weights. A 30 kW MTG operating at 50 percent power command will consume approximately 5.40 lb of fuel during a ½-hour test run. Table G-6 shows the resulting measurement errors for a starting weight of 950 lb. All quantities are added or subtracted, so their absolute errors compound per Eqn. G-2.

Table G-6: Liquid Fuel Consumption Uncertainty

Measurement	Example	Error Description	err_{rel}	err_{abs}
Wt_1	950.00	scale	± 0.01 %	± 0.095 lb
		display		± 0.05 lb
		scale + display		± 0.107 lb
Wt_2	944.60	scale	± 0.01 %	± 0.094 lb
		display		± 0.05 lb
		scale + display		± 0.107 lb
Wt_1 - Wt_2	5.40	subtraction	**± 2.8 %**	± 0.151 lb

Electrical Efficiency

The real power, fuel heating value, and fuel consumption relative errors compound multiplicatively (Eqn. G-3), as summarized in Table G-7.

Table G-7: Electrical Efficiency Accuracy

	Parameter	Relative Accuracy, %
Gaseous Fuels	Real Power, kW	± 2.2
	Fuel Heating Value (LHV or HHV), Btu/scf	± 1.0
	Fuel Rate, scfh	± 1.8
	Efficiency, η_e	**± 3.0**
Liquid Fuels	Real Power, kW	± 2.2
	Fuel Heating Value (LHV or HHV), Btu/scf	± 0.5
	Fuel Rate, lb/h	± 2.8
	Efficiency, η_e	**± 3.6**

Note that, for efficiency, both relative and absolute errors are stated as percentages. It is less confusing to report the achieved absolute accuracy rather than relative accuracy. For a gas-fueled MTG which attains 26 percent electrical efficiency, the absolute uncertainty would be 26 * 0.030, or ± 0.78 percent. The report would state "η_e was 26 ± 0.78 percent."

CHP Efficiency Uncertainty

CHP heating service efficiency determinations require system heat input (Q_{in}) and thermal performance (Q_{out}). The fuel heating value and consumption, multiplied together, yield Q_{in}. Q_{out} at each thermal performance measurement location is the product of the difference between T_{supply} and T_{return} (ΔT), the fluid density or specific gravity (ρ), the fluid specific heat (c_p), and the heat transfer fluid flow rate (V_l).

Heat Input (Q_{in})

Table G-8 shows the compounded Q_{in} uncertainty for gaseous and liquid fuels.

Table G-8: Q_{in} Accuracy

	Parameter	Relative Accuracy, %
Gaseous Fuels	Fuel Heating Value (LHV or HHV), Btu/scf	± 1.0
	Fuel consumption, scfh	± 1.8
	Q_{in}, Btu/h	**± 2.1**
Liquid Fuels	Fuel Heating Value (LHV or HHV), Btu/scf	± 0.5
	Fuel consumption, lb/h	± 2.8
	Q_{in}, Btu/h	**± 2.8**

Q_{out} and Thermal Performance

ΔT

ΔT is T_{return} subtracted from T_{supply}. The T_{supply} and T_{return} absolute errors compound per Eqn. G-2. The GVP specifies ± 0.6 ^oF temperature meter accuracy between 100 and 212 ^oF. The compounded uncertainty for any ΔT will therefore be $\sqrt{0.60^2 + 0.60^2}$ or ± 0.85 ^oF. The relative error for 20 ^oF ΔT (Eqn. G-1) is $[0.85/20]*100$, or 4.3 percent.

Note that the achieved accuracy deteriorates quickly for smaller ΔT even though the sensor errors do not change. For example, at 5.0 ^oF ΔT, accuracy will be ± 17.0 percent (or $[0.85/5.0]*100$) with the specified ± 0.60 ^oF temperature meter error. Analysts should calculate and report the achieved accuracy if ΔT is less than 20 ^oF.

Heat Transfer Fluid Specific Gravity and Specific Heat

Most heat transfer fluids are propylene glycol in water (PG). The GVP specifies the PG laboratory analysis relative error for ρ (density) as ± 0.11 percent.

The reported ρ is the entry point in a table of PG densities for various concentrations. Interpolation of the reported value against the table entries yields the actual PG concentration. The PG concentration, in turn, is the entry point in a table of PG specific heats, c_p, for various concentrations. Analysts then interpolate the PG concentration against the table entries to obtain the c_p. This procedure implies that the laboratory analysis error affects c_p at two stages:

1) determination of actual PG concentration
2) determination of c_p from actual PG concentration

The errors compound multiplicatively per Eqn. G-3. The compounded c_p uncertainty is therefore ± 0.16 percent (or $\sqrt{0.11^2 + 0.11^2}$).

Compounded Q_{out} Uncertainty

The GVP specifies the heat transfer fluid flow meter accuracy as ± 1.0 percent of reading. Q_{out} is a product of the contributing measurements, so the relative errors compound per Eqn. G-3. The compounded accuracy, assuming that ΔT is at least 20 ^oF is $\sqrt{4.3^2 + 0.11^2 + 0.16^2 + 1.0^2}$ ($\sqrt{\Delta T_{err}{}^2 + \rho_{err}{}^2 + c_{p,err}{}^2 + V_{l,err}{}^2}$), or ± 4.4 percent.

CHP Efficiency

η_{th} in heating service is Q_{out} divided by Q_{in}, so the relative errors compound per Eqn. G-3. Table G-9 shows the compounded accuracy for gaseous and liquid fuels, assuming that ΔT is at least 20 ^oF.

Table G-9: η_{th} Accuracy

	Parameter	Relative Accuracy, %
Gaseous Fuels	Q_{in}, Btu/h	± 2.1
	Q_{out}, Btu/h	± 4.4[a]
	η_{th}, %	**± 4.9**
Liquid Fuels	Q_{in}, Btu/h	± 2.8
	Q_{out}, Btu/h	± 4.4[a]
	η_{th}, Btu/h	**± 5.2**

[a] ΔT is at least 20 ^oF

G4: Total Efficiency Uncertainty

η_{tot} in heating service is the sum of η_{th} and η_e, so the absolute errors compound per Eqn. G-2. Actual η_{th} and η_e results are needed to the calculate absolute errors and the resulting η_{tot} compounded error. As an example, assume that the SUT has η_{th} and η_e of 53 and 26 percent, respectively. Table G-10 shows the compounded accuracy for gaseous and liquid fuels, assuming that ΔT is at least 20 ^oF.

Table G-10: η_{tot} Uncertainty

	Parameter	Relative Error	Absolute Error
Gaseous Fuels	η_{th}, 53 % assumed	± 4.9 %	± 2.6 %
	η_e, 26 % assumed	± 3.0 %	± 0.8 %
	η_{tot}, 79 % assumed	**± 3.5 %**	**± 2.8 %**
Liquid Fuels	η_{th}, 53 % assumed	± 5.2 %	± 2.8 %
	η_e, 26 % assumed	± 3.6 %	± 0.9 %
	η_{tot}, 79 % assumed	**± 3.7 %**	**± 2.9 %**

[a] ΔT is at least 20 ^oF.

Note that, for efficiency, both relative and absolute errors are stated as percentages. It is less confusing to report the achieved absolute accuracy rather than relative accuracy. The example here, for gaseous fuels, would be reported as "η_{tot} was 71 ± 2.8 percent."

G5: References

[G1] *Methane Emissions from the U.S. Petroleum Industry*. EPA-600/R-99-010, U.S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC. 1999.

[G2] *Fundamentals of Analytical Chemistry, 4th Edition*. Douglas A. Skoog, Donald M. West, CBS College Publishing, Philadelphia, PA. 1982.

[G3] *Significance of Errors in Stack Sampling Measurements*. R. T. Shigehara, W. F. Todd, W. S. Smith, presented at the annual meeting of the Air Pollution Control Association, St. Louis, MO. 1970.

[G4] *Measurement Uncertainty of Selected EPA Test Methods*. R. T. Shigehara, presented at the Stationary Source Sampling and Analysis for Air Pollutants XXV Conference, Destin, FL. 2001.