GE Energy

Standard Field Testing Procedure for Emission Compliance Based on US EPA and ISO Methodology

I. TEST PHILOSOPHY

Testing to demonstrate emission guarantees (if required) will be performed using procedures that are mutually agreed to between GE and the Purchaser. GE engineers and/or technical advisors may be present at the tests for procedural direction. EPA test methods are preferred to demonstrate compliance with GE's emissions guarantees unless otherwise stated in the Tab 3 Performance Guarantees. ISO methods are also presented herein for comparability to the preferred EPA methods. Other test methods will be reviewed on a case-by-case basis, as necessary.

II. EMISSION TESTING

A. General

Emission testing identified herein shall be within [GE's] or [Customer's] scope of supply using procedures which are mutually agreed upon. GE and Customer must mutually agree on the use of the testing firm. Sampling for inlet concentrations may be required, at the sole discretion of GE, in order to demonstrate compliance with emission guarantees. GE guarantees apply to the net increase of these pollutant emissions above ambient background levels. Re-testing (at purchaser's expense) must be allowed, if required.

The purpose of this GEK is to provide overall guidance for emissions testing methodology; a site-specific test protocol should be developed for each project by [GE] or [Customer] according to contract requirements. Any other test methods than those described herein need to be reviewed and approved by GE for applicability of use.

A Turbine Emissions Performance Test Readiness Checklist has been attached at the end of this document to provide guidance on pre-test preparations, and should be completed prior to any testing.

B. Testing When Duct Burners Are Present

When testing a unit equipped with duct burners, testing should be conducted such that the contribution from the gas turbine can be differentiated from that from the duct burners. For gaseous pollutants, this can sometimes be accomplished by testing simultaneously upstream and downstream of the duct burners. If this type of testing is not possible, testing should be performed with the duct burners off and then repeated with the duct burners on. Further details will be contained in the site-specific test protocol.

C. Nitrogen Oxides Emissions

Before the official compliance testing is begun, the NOx reduction system (e.g. dry low NOx (DLN) or water injection) will be adjusted (tuned) to meet performance and emissions criterion. Where water and/or steam injection is used for NOx abatement, the gas turbine control system will contain a pre-programmed schedule for either water or steam injection. This schedule may be adjusted to achieve an appropriate emission level and minimize the supply requirements. Once the proper injection schedule has been established, it is maintained throughout the testing, and is programmed into the control system.

1. GE Preferred Method: The NO_x emission testing and related oxygen testing will be in accordance with U.S. EPA Method 20 presented in the Code of Federal Regulations Title 40, Part 60 (40 CFR part 60 Appendix A, 40 CFR part 60 Subparts GG – Standards of Performance for Stationary Gas Turbines, Da, Db, and KKKK – Standards of Performance for Stationary Combustion Turbines, with the following modifications, limitations and additions:

    a) The NO_x instrument will be limited to a chemiluminescent type which meets 40CFR60 Appendix A, Method 7E.

    b) The span of the NO_x analyzer will be set for appropriate range of the expected NO_x readings, rather than the specified 300 ppm.

    c) Oxygen will be sampled simultaneously with all NO_x readings since 40 CFR Part 60, Subpart GG (and GE's NO_x guarantee) requires corrections to 15% O_2. Method 3A from 40 CFR Part 60 Appendix A is used for the oxygen analysis, as modified by the Method 20 calibration procedure.

    d) Section 60.335(c)(1) of Subpart GG has been replaced by U.S. EPA Memorandum dated June 2, 1997 for GE gas turbines using either water or steam for NO_x reduction. The EPA memorandum approves the GE injection control algorithm in lieu of the Subpart GG ISO correction equation.

    e) Section 60.335(c)(1) of Subpart GG is also not applicable to gas turbines with dry low NO_x combustors.

2. ISO Method: ISO Method 11042, Part 1 is acceptable for testing of gas turbines for NO_x, but is not the preferred GE method. This method references ISO Method 10849, which is the automated analysis method for NO_x. The main differences of the ISO method with respect to EPA Method 7E are:

    a) ISO 11042 does not include a system bias check.

    b) The ISO drift check is performed over 2 hours while the length of the EPA drift check varies depending on the regulatory requirement.

    c) ISO 11042 span and zero drift allowances are tighter than EPA Method 7E, and are not achievable/realistic for the expected low NOx levels.

    d) ISO 11042 does not include a converter efficiency check.

GE recommends the use of EPA Method 20 for NO_x testing. If ISO Method 11042 is used, a chemiluminescent-type analyzer must be used, following the span and drift allowances of EPA Method 20 and a system bias check should also be performed according to EPA Method 20; in addition, an O_2 traverse and multi-point sampling must be performed in accordance with Method 20.

D. Carbon Monoxide Emissions (If Required)

Sampling for CO is typically the same as sampling for NO_x with the same line feeding the different instruments.

1. GE Preferred Method: EPA Method 10 per 40 CFR Part 60 Appendix A is used, but only the continuous sample method per Section 5.1 is acceptable to GE. A recorder is mandatory, not optional as per 5.3.9, with a span that gives an appropriate range of the expected readings. In addition, the more stringent EPA Method 6C calibration requirements should be followed instead of those listed in Method 10.

2. ISO Method: ISO Method 11042, Part 1 also applies to acceptance testing of gas turbines for CO. This method references ISO Method 12039, which is the automated analysis method for CO. The main differences of the ISO method with respect to EPA Method 10 are:

    a) ISO 11042 does not include a system bias check.

    b) ISO 11042 span and zero drift allowances are tighter than EPA Method 10.

GE recommends the use of EPA Method 10 for CO testing. If ISO Method 11042 is used the span and drift allowances of EPA Method 6C should be followed and a system bias check should also be performed according to EPA Method 6C.

E. Unburned Hydrocarbon Emissions (If Required)

1. GE Preferred Method: Sampling and analysis to measure unburned hydrocarbon (UHC) emissions must be done on a wet basis to avoid condensing out the higher hydrocarbons. Moisture determination by EPA Method 4 (or Method 5) is necessary to convert results to a dry basis. Method 25A per 40CFR60 Appendix A is used for unburned hydrocarbons. Results are presented as methane (CH_4). This method uses a flame ionization detector (FID) or analyzer. Calibration gases should be methane in air matrix to avoid synergism effects.

2. ISO Method: ISO Method 11042, Part 1 also includes guidelines for acceptance testing of gas turbines for UHC. This method uses a FID like the EPA method. The main differences of the ISO method with respect to EPA Method 25A are:

    a) ISO 11042 does not include a system bias check.

    b) ISO 11042 span and zero drift allowances are tighter than EPA Method 25A, and are not achievable/realistic for the expected low UHC levels.

    c) The minimum range allowed is 0 to 10 ppm and the measured concentration must be at least 50 percent of the instrument range.

Expected UHC emissions from most of GE's gas turbine units will be below the threshold for the ISO method, therefore it is not recommended for GE units, where expected UHC concentrations are less than 5 ppm.

F. Volatile Organic Compound Emissions (If Required)

1. GE Preferred Method: When volatile organic compound (VOC) emissions (non-methane, non-ethane hydrocarbons) are required, Method 18 per Section 8.2.2 (Direct Interface Sampling and Analysis) should be used. This method requires a gas chromatograph at the site. GE requires calibration of the measurement train at the sampling probe.

2. ISO Method: There are no performance specifications within ISO 11042 for VOC measurement, only suggested procedures, therefore GE recommends the use of EPA Method 18.

G. Sulfur Emissions (If Required)

1. GE Preferred Method: Sulfur emissions will be determined by use of fuel flow data and fuel analysis for sulfur content according to ASTM Method D3246.

2. ISO Method: ISO 11042 recommends the use of fuel analysis for determination of sulfur dioxide emissions, therefore it is in accordance with

GE's preferred method. The above ASTM Method, or demonstrated equivalent, should be used for sulfur analysis.

H. Particulate Matter Emissions - Front-Half Filterable Solids Only (If Required)

1. GE Preferred Method: Particulate matter (PM) emissions shall be determined by sampling, analysis and calculation in accordance with U.S. EPA Methods 5 or 5B with traversing per Methods 1 and 2, per 40 CFR 60 Appendix A. The following modifications and limitations on choices within the methods apply:

a) Sampling probe internal surfaces must be made of chemically inert and non-catalytic material such as quartz.

b) The filter material shall be quartz.

c) Nozzle, probe and filter must be heated to 248 to 273°F (120 to 134°C) per Method 5, or at least 10°F (5.6°C) higher than the dew point of sulfuric acid in the exhaust duct. Use of Method 5B requires nozzle, probe and filter to be heated to 320 to 345°F (160 to 174°C) and precludes any concern over determination of the sulfuric acid dewpoint. The Method 5B pre- and post-test filter bakes are also conducted at the elevated temperatures indicated previously.

d) Probe wash shall be high purity acetone per Method 5.

e) Sampling technique shall provide a fairly large exhaust gas sample, with an objective of 125 standard cubic feet (SCF) (3.5 standard cubic meters (SCM)); minimum sample time shall be 3 hours per run.

f) Sulfates are generally excluded from the GE guarantees for particulates.

g) Allowance for background ambient particulate levels must be provided, as appropriate. The means by which to measure ambient PM levels will be determined on a case-by-case basis, if necessary.

2. ISO Method: ISO Method 11042, Part 1 also applies to acceptance testing of gas turbines for PM with reference to ISO Method 9096, a manual-gravimetric, multi-point sampling procedure. The main differences of the ISO method as compared to EPA Method 5 are:

a) ISO 9096 covers both in-stack and out-of-stack filter methods.

b) ISO 11042 calls for 12 to 20 sampling points, whereas the EPA methods specify 8 to 24 sampling points.

c) ISO 9096 is recommended for concentrations from 20 mg/m^3 to 1000 mg/m^3.

d) ISO 12142 is similar to ISO 9096, but is recommended for lower PM concentrations in the range of 5 mg/m^3 to 20 mg/m^3.

If an ISO Method is used it should be ISO 12142 with an out-of-stack filter heated to temperatures in accordance with EPA Method 5B; the minimum sample time must be 3 hours per run; the sampling points should be determined according to EPA Method 1; and high-purity reagents must be used to avoid contamination.

3. The above modifications and limitations also apply to any PM testing, regardless of method. The following operational conditions should also be met whenever testing for PM:

a) The combustion turbine must run for a minimum of 200 total-fired hours prior to any PM testing, and must operate at base load for a minimum of 3 to 4 hours prior to any PM test run to achieve steady-state wheelspace temperatures.

b) The combustion turbine inlet and exhaust systems must be cleaned and free of any dirt, sand, mud, rust or other contaminants.

c) Exhaust must be wiped down to prevent metal weepage from stainless steel becoming airborne.

d) Check for spaces left in the HRSG and leaks in the inlet, as applicable.

e) The area around the turbine is to be treated (e.g. sprayed down with water) to minimize airborne dust.

f) A compressor wash prior to testing is highly recommended.

A pre-test checklist that outlines the above operational conditions is attached at the end of this document for use prior to GE emissions testing.

I. PM10 Emissions (Front-Half Filterable and Back-Half Condensable) (If Required)

PM10 is PM that has an aerodynamic diameter less than 10 microns.

1. GE Preferred Method: PM10 emissions shall be determined by sampling, analysis and calculation in accordance with U.S. EPA Methods 5, 5B or 201A for front-half filterable particulate matter and Method 202 for back half condensable particulate matter with traversing per Methods 1 and 2. All methods are per 40 CFR 60, Appendix A except for Methods 201A and 202, which are per 40 CFR 51, Appendix M. The following modifications and limitations within the methods apply:

   a) Sampling probe internal surfaces must be made of chemically inert and non-catalytic material such as quartz.

   b) The filter material shall be quartz.

   c) Nozzle, probe and filter must be heated to 248 to 273°F (120 to 134°C) per Method 5, or at least 10°F (5.6°C) higher than the dew point of sulfuric acid in the exhaust duct. Use of Method 5B requires nozzle, probe and filter to be heated to 320 to 345°F (160 to 174°C) and precludes any concern over determination of the sulfuric acid dewpoint. The Method 5B pre- and post-test filter bakes are also conducted at the elevated temperatures indicated previously.

   d) At the conclusion of each test run, the sample train must be purged with zero N_2 gas at a rate of 20 liters per minute (lpm) for a period of one hour.

   e) Probe wash shall be high purity acetone per Method 5.

   f) Sampling technique shall provide a fairly large exhaust gas sample, with an objective of 125 SCF (3.5 SCM).

   g) Minimum sample time shall be 3 hours per run for Methods 5 or 5B and 6 hours per run for Method 201A.

   h) Method 201A shall use cyclone only; cascade impactors should not be used.

   i) Impinger solution shall be extracted with ACS grade methylene chloride per Method 202.

   j) Method 202 equipment shall be free of stopcock grease.

   k) Allowance for background ambient particulate levels must be used.

2. ISO Method: There is no ISO method for PM10, therefore GE recommends the use of EPA Method 5B for front-half PM and Method 202 for back-half PM, if required..

3. The following operational conditions should also be met whenever testing for PM10:

a) The combustion turbine must run for a minimum of 200 total-fired hours prior to any PM10 testing, and must operate at base load (steady-state wheelspace temperatures) for a minimum of 3 to 4 hours prior to any PM test run.

b) The combustion turbine inlet and exhaust systems must be cleaned and free of any dirt, sand, mud, rust or other contaminants.

c) Exhaust must be wiped down to prevent metal weepage from stainless steel becoming airborne.

d) Check for spaces left in the HRSG and leaks in the inlet, as applicable.

e) The area around the turbine is to be treated (e.g. sprayed down with water) to minimize airborne dust.

f) A compressor wash prior to testing is highly recommended.

J. Opacity (If Required)

1. GE Preferred Method: Opacity shall be measured in accordance with EPA Method 9 from 40 CFR 60, Appendix A. If a continuous opacity monitor is installed in the exhaust stack and has been certified against a reference method (EPA Method 9 or equivalent), the data from this continuous monitor may be used in lieu of Method 9, subject to approval by GE.

2. ISO Method: ISO Method 11042, Part 1 utilizes the Bacharach source test procedure for smoke number determination. There is no direct correlation between percent opacity and measurements based on the Bacharach scale. Therefore, only EPA Method 9 (or a certified continuous opacity monitor) may be utilized to demonstrate compliance with GE's opacity guarantee, if required.

K. Ammonia Slip (If Required)

1. GE Preferred Method: EPA has not yet promulgated a method for measuring ammonia slip. In the interim, GE has established a preference for the use of on-site sampling and analysis plus calculations in accordance with the industry procedure of indophenol absorptiometrics to determine ammonia slip emissions. This procedure requires the use of reactant solutions and a photoelectric spectrophotometer at the plant site. Additional testing details will be incorporated into a site-specific test protocol, as required.

2. ISO Method: ISO method 11042 does not provide performance specifications for ammonia measurement. The standard proposes using chemiluminescent NO_x analyzers. A converter is used to oxidize the NH_3 to

NO, while a second converter reduces NO_2 to NO without affecting the NH_3; the difference between these two NO_x readings is the NH_3 concentration. A single analyzer with two converters or two separate analyzers may be used.

GE recommends the use of the indophenol method for its low detection limit and on-site results.

L. Formaldehyde (If Required)

1. GE Preferred Method: If a customer requires formaldehyde testing for their permit, GE recommends that it should be measured using California Air Resources Board (CARB) Method 430. This method is a wet-impingement method, and uses dinitrophenylhydrazine (DNPH) as the impinger solution. In order to enhance the method to achieve a detection level of less than 91 parts per billion by volume, dry (ppbvd) at 15% O_2 (the proposed EPA limit in 40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines), the following modifications to the method must be followed:

   a) Using typical field blank results, the target sample volume should be approximately 100 liters. At the maximum sampling rate allowed in the method of 0.5 lpm, a run time of 3 hours and 20 minutes is necessary to achieve the minimum aldehyde mass ratio. Sampling rate shall not exceed 0.5 lpm.

   b) Background levels of formaldehyde in the sampling equipment, reagents, and ambient environments are chronic challenges to measuring low parts per billion levels of formaldehyde in the stack. Ambient formaldehyde contamination of the collected sample in the field shall be minimized through appropriate containment and handling of all samples and sampling equipment in clean, formaldehyde-free areas. In some locations, purged glove boxes or similar apparatus may be required. In addition, the sample train must be assembled and recovered in a tented area purged with 99.999% nitrogen.

   c) A pre-test leak check, but no post-test leak check (to minimize sample contamination), shall be performed as specified in Section 8.1.4 of the method. A small, fresh activated charcoal tube (such as commercially available tubes used for personal exposure or indoor air sampling) should be temporarily attached to the end of the probe (e.g. with a short length of Teflon tubing) prior to performing leak checks to minimize contamination from ambient air.

   d) Other measures to avoid potential field contamination shall include: use a fresh, pre-cleaned polytetrafluoroethylene (PTFE), borosilicate glass, or quartz probe liner for each test run; do not perform a post-test rinse of the sampling probe unless visible condensate is present; do not recycle probe liners in the field.

e) Maintain the sampling probe temperature range between 248 and 273°F (120 to 134°C) to avoid condensation of water in the probe, which would necessitate a probe rinse.

f) The laboratory selected to perform the sample analyses shall demonstrate a limit of detection (LOD) capability of less than 0.5 µg of formaldehyde per sample. LOD shall be calculated as specified in CARB Method 430 Section 11.6.

g) Sampling equipment shall include screw-top DNPH impingers that can be fitted with either Teflon-lined screw caps (for storage and shipment) or an impinger stem (for sampling) that have been charged and sealed in the laboratory that will be used for sample analyses. The pre-charged impingers and samples shall be stored and shipped at 4 degrees Celsius, using dry ice, until immediately before and after sampling and laboratory analysis.

h) The cleaned sampling equipment is to be sealed in the laboratory and not opened until final train assembly at the sampling location.

i) All handling of wetted sampling equipment is to be performed using polyethylene laboratory gloves to eliminate the potential for aldehydes contamination from the skin. Latex, nitrile, or vinyl gloves shall not be used.

j) To minimize potential contamination, it is advised that the test team members not consume alcohol during the 24 hours prior to sampling and throughout the sampling campaign. Metabolites of alcohol include aldehydes. Alcohol digestion and respiration significantly increases formaldehyde levels in exhaled air, concentrations of 200 ppb and greater have been measured. Aldehydes are also transpired through the skin. Test team members should also refrain from smoking during test activities. If necessary, test team members shall wash their hands with soap and rinse thoroughly with clean water after a smoking break before returning to test activities. Exhaust from vehicles also contains formaldehyde. The sample recovery area should not be in the vicinity of a source of exhaust. Use of aftershave lotion, cologne or perfume should be avoided while testing.

k) Every test shall include at least one sampling train blank (field blank) for each test run, as specified in CARB Method 430 Section 10.1.1. The field blank shall be performed immediately prior to each run. The field blank shall include all of the same components and procedures as a test run, including a leak check as described above in item 3.

l) The blank-corrected sample value shall be calculated exactly as specified in CARB Method 430 Section 11.10, i.e. based on the concentration of formaldehyde in the liquid samples and blanks (e.g., ug/mL).

m) For maximum accuracy, it is recommended that a sampling train control console that incorporates both a calibrated precision rotameter and a low-flow dry gas meter be used for the tests (e.g., an EPA Method 0030 Volatile Organic Sampling Train control console). A standard Method 5 dry gas meter shall not be used for determining sample volume because the sample flow rate is below the calibrated range of such equipment. Alternatively, a precision rotameter alone may be used provided it is properly instrumented to measure inlet sample gas temperature and pressure and the indicated rate is corrected for actual conditions.

n) The CARB Method 430 reporting protocol of five times the field blank if results are below detection limits should not be used. Stack sample results should be corrected by the field blank average. Applicability of the CARB Method 430 reporting protocol will yield over-reporting values if the stack level is below five times the average field blank (FB) level.

2. ISO Method: There is no known ISO method for measurement of formaldehyde.

M. Certification of Calibration Gases

All gases used in certification of instruments or performance of emissions guarantee demonstrations shall be analyzed and certified in a manner and by a laboratory mutually agreeable to GE and Purchaser. Examples of acceptable certification are:

1. U.S. EPA Standard Methods
2. U.S. EPA Protocols
3. U.S. National Bureau of Standards Certification Procedures
4. ISO Standard Methods (e.g. ISO/TS 14167).

N. Exhaust Gas Flow Determination

1. GE Preferred Method: GE has established preferences for the determination of exhaust flow based on accuracy of the determination. GE recommends the following:

   a) The primary exhaust flow determination shall be by the F-factor method per 40CFR60, Appendix A, Method 19 (as specified in Method 20 for gas turbine emissions). The F-factor constants from Table 19-1 shall be applied in all cases where possible per Paragraph 3.1.

   b) Where available, the compressor inlet airflow signal shall also be used to compute exhaust flow. Exhaust flow on a dry basis is the turbine inlet airflow minus the water vapor plus the fuel flow minus the water formed from the combustion of hydrogen in the fuel. Gas turbine inlet air is measured using the compressor inlet air scroll as a flow element.

   c) Flow measurements by Velocity Traverse, per 40 CFR 60, Appendix A, Methods 1 and 2, can result in errors of 25 percent or more in this application, and is not acceptable.

2. ISO Method: ISO Method 10780 is similar to EPA Method 1 and 2, using an L and S type pitot tube to determine the velocity and volume flow rate of a gas stream, and is therefore not recommended for the reason cited in N.1.(c) above.

O. Fuel Bound Nitrogen Determination

1. GE Preferred Method: Prior to emission testing, analyses for fuel bound nitrogen must be determined in accordance with ASTM D4629, which is based on a combustion/chemiluminescence method.

P. Reporting Preliminary Test Results

The Vendor must use the attached spreadsheets as applicable for reporting preliminary test results prior to test site demobilization or make provisions to complete prior to site demobilization. A more comprehensive set of data will be required for final reporting, to be specified in the project-specific test protocol. Please contact GE for the most recent version of these spreadsheets prior to submittal.

Summary Table for Reporting Preliminary Test Results Prior to Demobilization

Revise as necessary based on what is applicable to the testing project.

Simple Cycle or Combined Cycle without duct firing.

Project Name ________________________

Site Location ________________________

Date				
Test Number	1	2	3	Average
Start and End Time of Test				
Test Condition				
TURBINE OPERATING CONDITIONS				
Compressor Discharge Pressure (psig) (CPD)				
Compressor Inlet Temperature (°F) (CTIM)				
Fuel Flow (lb/sec) (FQG, FQLM1)				
Steam or Water Injection Flow rate (lb/sec) (WQJ)				
Power Augmentation Steam (lb/sec) (WQJA)				
Steam or Water Flow/Fuel Flow Ratio (WXJ)				
Generator Output (MW) (DWATT)				
Heat Input (MMBtu/hr)				
Inlet Guide Vane Setting (CSGV)				
Mean Turbine Exhaust Temperature (°F) (TTXM)				
Specific Humidity (lb H_2O/lb Dry Air) (CMHUM)				
Barometric Pressure (in. Hg) (AFPAP)				
Stack Exhaust Temperature (°F)				
DLN Split Percent (FSRXSR)				
AMBIENT DATA				
Wet Bulb Temperature (°F)				
Dry Bulb Temperature (°F)				
Barometric Pressure (in. Hg) (AFPAP)				
Specific Humidity (lb H2O/lb Dry Air) (CMHUM)				
FUEL ANALYSIS				
Heating Value (Btu/lb)				
Fd factor (dscf/MMBtu)				
Fc factor (dscf/MMBtu)				

Summary Table for Reporting Preliminary Test Results Prior to Demobilization (Continued)

Revise as necessary based on what is applicable to the testing project.

Simple Cycle or Combined Cycle without duct firing.

Project Name ______________________

Site Location ______________________

Date				
Test Number	1	2	3	Average
Start and End Time of Test				
Test Condition				
EMISSON DATA				
NOx (ppmvd)				
NOx (ppmvd @15% O_2)				
O_2 (% by volume, dry basis)				
CO_2 (% by volume, dry basis)				
CO (ppmvd)				
Moisture (% by volume)				
UHC (ppmvw, ppmvd)				
VOC (ppmvw, ppmvd)				
SO_2 (ppmvd @15% O_2)				
NOx (lb/hr, lb/MMBtu)				
CO (lb/hr, lb/MMBtu)				
UHC (lb/hr, lb/MMBtu)				
VOC (lb/hr, lb/MMBtu)				
SO_2 (lb/hr)				
Fo				
Exhaust Flow (dscfm, by Fd factor)				
Exhaust Flow (dscfm, by Fc factor)				

Summary Table for Reporting Preliminary Test Results Prior to Demobilization Revise as necessary based on what is applicable to the testing project. Combined Cycle with duct firing. Project Name ______________________ Site Location ______________________				
Date				
Test Number	1	2	3	Average
Start and End Time of Test				
Test Condition				
TURBINE OPERATING CONDITIONS				
Compressor Discharge Pressure (psig) (CPD)				
Compressor Inlet Temperature (°F) (CTIM)				
Fuel Flow (lb/sec) (FQG, FQLM1)				
Steam or Water Injection Flow rate (lb/sec) (WQJ)				
Power Augmentation Steam (lb/sec) (WQJA)				
Steam or Water Flow/Fuel Flow Ratio (WXJ)				
Generator Output (MW) (DWATT)				
Turbine Heat Input (MMBtu/hr)				
Inlet Guide Vane Setting (CSGV)				
Mean Turbine Exhaust Temperature (°F) (TTXM)				
Specific Humidity (lb H_2O/lb Dry Air) (CMHUM)				
Barometric Pressure (in. Hg) (AFPAP)				
Stack Exhaust Temperature (°F)				
DLN Split Percent (FSRXSR)				
Duct Burner Fuel Flow (lb/sec)				
Duct Burner Heat Input (MMBtu/hr)				
AMBIENT DATA				
Wet Bulb Temperature (°F)				
Dry Bulb Temperature (°F)				
Barometric Pressure (in. Hg) (AFPAP)				
Specific Humidity (lb H2O/lb Dry Air) (CMHUM)				
TURBINE FUEL ANALYSIS				
Heating Value (Btu/lb)				
Fd factor (dscf/MMBtu)				
Fc factor (dscf/MMBtu)				
DUCT BURNER FUEL ANALYSIS				
Heating Value (Btu/lb)				
Fd factor (dscf/MMBtu)				
Fc factor (dscf/MMBtu)				

Summary Table for Reporting Preliminary Test Results Prior to Demobilization (Continued)

Revise as necessary based on what is applicable to the testing project.

Combined Cycle with duct firing.

Project Name ______________________

Site Location ______________________

Date				
Test Number	1	2	3	Average
Start and End Time of Test				
Test Condition				
JOINT FIRE CONCENTRATIONS				
NOx (ppmvd)				
NOx (ppmvd @15% O_2)				
O_2 (% by volume, dry basis)				
CO_2 (% by volume, dry basis)				
CO (ppmvd)				
SO_2 (ppmvd @15% O_2)				
Moisture (% by volume)				
Fo				
TURBINE ONLY CONCENTRATIONS				
NOx (ppmvd)				
NOx (ppmvd @15% O_2)				
O_2 (% by volume, dry basis)				
CO_2 (% by volume, dry basis)				
CO (ppmvd)				
Moisture (% by volume)				
JOINT FIRE EXHAUST FLOW & MASS EMISSION RATES				
HRSG Exhaust Flow (dscfm, by Fd factor)				
HRSG Exhaust Flow (dscfm, by Fc factor)				
NOx (lb/hr, lb/MMBtu)				
CO (lb/hr, lb/MMBtu)				
TURBINE ONLY EXHAUST FLOW & MASS EMISSION RATES				
Transition Duct Exhaust Flow (dscfm, by Fd factor)				
Transition Duct Exhaust Flow (dscfm, by Fc factor)				
NOx (lb/hr, lb/MMBtu)				
CO (lb/hr, lb/MMBtu)				
DUCT BURNER MASS EMISSION RATES				
NOx (lb/hr, lb/MMBtu)				
CO (lb/hr, lb/MMBtu)				

Turbine Emissions Performance Test Readiness Checklist

Customer:____________________ Checklist Completed By:________________ Title:_______
Site:__________________________ Date:_______
Unit:__________________________

Please answer all of the following questions and return this form **at least 72 hours prior to the test date.** Questions should be directed to the GE Power Generation Manager of Environmental and Acoustics Engineering.

	SYSTEM / OPERATION	Circle (Y, N, or N/A)			If no, why?	
GAS TURBINE FUEL SYSTEM						
1	Has Mark V or VI fuel flow reading accuracy been checked using ASME Method?	Y	N	N/A		
2	Has gas turbine reached full load on gas fuel firing?	Y	N	N/A		
3	Has running on gas at full load exceeded 10 hours?	Y	N	N/A		
4	Has distillate oil fuel flow divider accuracy been checked across the load range?	Y	N	N/A		
5	Has gas turbine reached full load on oil fuel firing?	Y	N	N/A		
6	Has running on oil at full load exceeded 10 hours?	Y	N	N/A		
7	Has fuel transfer from gas to oil been conducted?	Y	N	N/A		
8	Has more than one transfer been conducted?	Y	N	N/A		
9	Has fuel transfer from oil to gas been conducted?	Y	N	N/A		
10	Has more than one transfer been conducted?	Y	N	N/A		
11	Have purge and check valves been operating properly?	Y	N	N/A		
12	If fuel transfer in either direction has not been smooth, has the system been recalibrated and tested?	Y	N	N/A		
13	**Has a fuel oil sample been taken and tested for fuel bound nitrogen (FBN), sulfur content and ash content? Fuel sample analysis results: FBN:__________________ ppm by weight Sulfur:_________________ % by weight Ash:___________________ %	Y	N	N/A		X1

WATER / STEAM INJECTION SYSTEM						
14	**Is water injection system operating within specification across the load range?	Y	N	N/A		X2
15	Has the flow meter been calibrated?	Y	N	N/A		
16	Is the system set to operate in automatic mode across the load range?	Y	N	N/A		

	SYSTEM / OPERATION	Circle (Y, N, or N/A)			If no, why?	
INLET BLEED HEAT						
17	Has inlet bleed heat system been commissioned?	Y	N	N/A		
18	Is the system set to operate in automatic mode?	Y	N	N/A		
CONTROL SYSTEM / INSTRUMENTATION						
19	Have gas fuel flow signals been checked (zero and span)?	Y	N	N/A		
20	Have oil fuel flow signals been checked (zero and span)?	Y	N	N/A		
21	Has humidity sensor accuracy been checked using a psychrometer?	Y	N	N/A		
22	Have bell mouth D.P. sensors been calibrated?	Y	N	N/A		
23	Have the air flow calculations been verified?	Y	N	N/A		
CONTINUOUS EMISSION MONITORS						
24	Has the CEMS system been installed and checked out?	Y	N	N/A		
25	Is the system currently conducting daily calibrations (zero and span)?	Y	N	N/A		
26	Does the CEMS have nearly full bottles of calibration gases?	Y	N	N/A		
HRSG STACK						
27	**Have the proper EPA test port locations been verified?	Y	N	N/A		X3
28	Have the proper CEMS test port locations been verified?	Y	N	N/A		
29	Are the proper walkways, ladders and platforms installed?	Y	N	N/A		
30	Is the stack properly insulated in the areas that personnel will be working or passing?	Y	N	N/A		
31	Is reliable electric power available at test area?	Y	N	N/A		
BYPASS STACK						
32	Is emissions testing of bypass stack required by permit?	Y	N	N/A		
33	**Have the proper EPA test port locations been verified?	Y	N	N/A		X4
34	Have the proper CEMS test port locations been verified?	Y	N	N/A		
35	Are the proper walkways, ladders and platforms installed?	Y	N	N/A		
36	Is the stack properly insulated in the areas that personnel will be working or passing?	Y	N	N/A		
37	Is reliable electric power available at test area?	Y	N	N/A		

SYSTEM / OPERATION		Circle (Y, N, or N/A)			If no, why?	
DUCT BURNER						
38	Does the HRSG have a duct burner (DB)?	Y	N	N/A		
39	Is the DB designed for dual fuel firing?	Y	N	N/A		
40	Is it scheduled to burn natural gas fuel?	Y	N	N/A		
41	Is it scheduled to burn distillate oil fuel?	Y	N	N/A		
42	Has the gas fuel flow meter been calibrated?	Y	N	N/A		
43	Has the oil fuel flow meter been calibrated?	Y	N	N/A		
44	**Has the DB been fully fired on gas fuel?	Y	N	N/A		X5
45	**Has the DB been fully fired on oil fuel?	Y	N	N/A		X6
46	Are air emission monitoring ports located upstream of the DB in the transition duct?	Y	N	N/A		
47	Is black smoke noticeable when firing DB on oil?	Y	N	N/A		

SELECTED CATALYTIC REDUCTION (SCR)						
48	Does the HRSG incorporate an SCR system?	Y	N	N/A		
49	Has the SCR system been checked for proper installation?	Y	N	N/A		
50	**Has the ammonia system been checked out for proper function over the load range?	Y	N	N/A		X7
51	Has the SCR system been operated at full load?	Y	N	N/A		

CARBON MONOXIDE (CO) CATALYST						
52	Does the HRSG incorporate a CO catalyst?	Y	N	N/A		
53	**Has the catalyst system been checked for proper installation?	Y	N	N/A		X8

Env. Engr. to check off whether key questions were answered and enter score here.

Score
__ / 8
Env. Eng. use only

ADDITIONAL COMMENTS

GE Energy

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