Attachment 1 - Equipment Scope of Supply

Basic Scope Description

Turbine

General Electric gas turbine model LM6000 is a two-shaft/two-spool engine consisting of a five-stage low pressure compressor, a fourteen-stage high pressure compressor, a two-stage high pressure turbine, and a five-stage low pressure turbine. The engine is equipped with a stainless steel mesh screen in the inlet air stream for "last chance" protection against foreign object damage. The engine is shock mounted and shipped in position, with the exception of the coupling spacer, which is removed and shipped in a separate container

Generator

Air cooled, 2-pole generator operating at 13.8 kV, 60 Hz. Generator is capable of handling customer power requirement throughout a wide ambient temperature range. The generator includes a brushless excitation system with permanent magnet generator. Neutral and line side cubicles are included.

Turbine/Generator Enclosure

The package is supplied with weatherproof, acoustic enclosures. The enclosures are designed to achieve noise abatement to an average of 85 dB(A) at 3 ft. (1.0 m) away and 5 ft. (1.5 m) above grade during full load operations. The enclosures are completely assembled and mounted over the equipment prior to testing and shipment. Both turbine and generator compartments are fully ventilated with redundant fans (one running, one stand-by). Explosion-proof lighting is provided in both compartments.

Turbine/Generator Baseplate

The package is supplied with the support structures for the gas turbine generator set consisting of a two-piece skid assembly, which is sectioned between the gas turbine and the generator. The full depth, bolted section is designed to provide the full structural properties of the wide flange I-beams. Full depth crossmembers are utilized to provide for a rigid design that is suitable for installation in earthquake areas (IBC2000) as well as providing a convenient structure for transportation.

Air Inlet System

The package is supplied with a modular, multi-stage filtration system consisting of inlet screens, a prefilter and a final barrier filter. All air for ventilation systems is filtered to the same level as turbine combustion air. An anti-ice, an evaporative cooling, a combustion air heating or a chilling system is available as an option. Filtered air is silenced before entering the turbine plenum. This design results in a compact arrangement and eliminates the need for customer supplied inlet ducting when the standard design is utilized. Internal lighting of the filter house is provided to facilitate inspection and service. Package is also supplied with platforms and ladders to service the inlet filter.

Turbine Exhaust

The package is supplied with a circular, axial exhaust outlet with connection flange to facilitate in-line mounting of an HRSG or simple cycle exhaust stack.

Fuel System

The package is supplied with a natural gas fuel system that utilizes an electronically controlled fuel-metering valve. For full-load operation, the gaseous fuel must be supplied to the baseplate at 675 psig±20 (4,654 ±138 kPag). Gas fuel must meet General Electric specification MID-TD-0000-1

Lube Oil Systems

The package is supplied with two separate lube oil systems: one synthetic for the gas turbine and one mineral for the generator. The oil reservoirs and piping are all stainless steel, and the lube oil system valves have stainless steel trim. The turbine coolers, oil reservoir, and filters are mounted on the auxiliary equipment module. The mineral lube coolers, reservoir and filters are located on the main skid baseplate. The auxiliary equipment module provides simplified piping connections and reduces customer's installation time and costs. Customer must supply cooling water to the shell and tube coolers. Turbine lube oil must meet MID-TD-0000-6

Electro-Hydraulic Start System

The package is supplied with an electric motor driven hydraulic pump assembly, filters, cooler and controls, mounted on the auxiliary equipment module. A hydraulic motor is also mounted on the gas turbine accessory gearbox. Hydraulic hoses are furnished to connect the auxiliary equipment module and the main baseplate.

Fire Protection System

The package is supplied with a factory installed fire protection system complete with optical flame detection, hydrocarbon sensing and thermal detectors, piping and nozzles in both the generator and the turbine compartments. The fire protection system includes cylinders containing CO_2 mounted on a separate skid. A 24 V DC battery and charger to power the fire protection system is also included. All alarms and shutdowns are annunciated at the turbine control panel (TCP). An alarm sounds at the turbine if the gas detectors detect high gas levels, or if the system is preparing to release the CO_2. When the system is activated, the package shuts down, and the primary CO_2 cylinders are discharged into the turbine and generator compartments via multiple nozzles, and the ventilation dampers automatically close. After a time delay and if required, the reserve supply of CO_2 is discharged.

Digital Control System

The package is supplied with a free-standing Turbine Control Panel (TCP) suitable for mounting in an indoor, non-hazardous area. The control system features an integrated turbine control system, vibration monitor, digital meter, digital generator protective relay module and an HMI (human machine interface) display of key discrete and analog data. Alarm and shutdown events are displayed on the HMI automatically. An Ethernet TCP/IP EGD or RS485 Modbus Port is provided to transmit unit conditions (status, pressures, temperature, etc.) to the customer's distributed control system. The HMI is a desktop PC located next to the TCP. Power for the control panel is provided by a dedicated 24V DC battery system with dual 100% capacity chargers, which are shipped separately for installation by others.

Battery System

The equipment package is supplied with 24 V DC battery systems for the fire protection and gas turbine generator control systems, as described in those sections. All battery systems are valve-regulated lead acid (VLRA) type. Battery systems ship loose for indoor customer installation. If the optional Power Control Module is selected, Seller will install the GE supplied DC battery systems in that module.

Generator Protective Relays

The package is supplied with a microprocessor-based generator protective relay module, mounted in the TCP. The protective relay system includes functions necessary for protection of the generator.

Soak Wash System

The package is supplied with a turbine cleaning system, which allows customers to clean the compressor section of the turbine during full power operation. The same system reservoir and piping are utilized for off-line soak washing. Auxiliary skid connections are provided for customer supplied purified water at a maximum of 50 psig (345 kPag) and air at 100 – 120 psig (689 – 827 kPag). Customer is required to provide water meeting MID-TD-0000-4, detergent meeting MID-TD-0000-5 and air filtered to ISA S7.3 standards.

Component Testing and Package Test

Every new gas turbine is performance tested under load in a GE Test Cell, using procedures developed for flight turbine reliability. The generator is tested to ANSI C50.14 or IEC 34.3 standards at its factory of manufacture.

All gas turbine generator sets receive a static test including:

- Switch State (N.O. or N.C., actuation, wiring, and setpoint)
- Temperature element output, and wiring
- Transmitter range, output, and wiring
- Solenoid operation
- Control valve torque motor, excitation, and return signal

- Fire system continuity, and device actuation
- System flushing verification
- Tubing integrity

A full load string test is available as an option.

Drawings, Data and Manuals

The package is supplied with a customer drawing package that includes general arrangement drawings, flow and instrument diagrams, electrical one-line drawings and interconnection plan drawings. Additional electrical schematic diagrams and logic drawings are provided for record. See Attachment 8 for a detailed typical list and typical drawing delivery.

Operation & Maintenance (O&M) and Installation & Commissioning (I&C) manuals are provided and are printed in English. Six hardcopies of the O&M Manuals, three hardcopies of the I&C manuals, and one CD with both are included in the base offering. The manuals cover operating concepts for power generating equipment, guides to troubleshooting, basic information on components, and equipment within the turbine generator set.

Seller provides all engineering drawings on a secure server www.project-net.com. Each customer can enter this database and view, print or annotate project drawings. ProjectNet provides the customer with immediate access to the latest drawing revisions. ProjectNet speeds job completion and saves weeks of time mailing drawings back and forth.

Training

The base scope of supply includes hands-on training for up to 10 operators and supervisors, where students are assumed to have at least a journeyman's knowledge of electrical generating plant operation and to be proficient in reading piping flow and instrument drawings, mechanical drawings, and have a working knowledge of electrical generators, and gas turbines. The course is designed around an eight-hour day, five consecutive day schedule. Instructors, using specially developed training materials, provide a firm groundwork of basic theory, plus advanced concepts with classroom and hands-on training. Training includes Gas Turbine Familiarization plus System Design & Operations and Maintenance.

The trainer conducts the course in a lecture/seminar format where each major topic is supported by literature with detailed descriptions and associated engineering drawings. A student-training manual is given to each student and the client's turbine-generator system is used for hands-on training to supplement the classroom instruction. At the completion of several related topics the students are given a progressive examination to measure the effectiveness of the presentation and as a tool to identify if any student has not grasped the material. At the completion of the course a final examination is given which covers the entire course material and students are given a certificate of completion.

Training is conducted at the Project site. Local training at the Customer's facility is available upon request. The Customer would be responsible for providing all necessary training equipment for classes not held at the manufacturing location.

Improvements and Changes

It is understood that the Seller has the right to make changes in product design and add improvements to products or services at any time without incurring any obligations to install the same on or in connection with the Equipment or Services provided hereunder.

Performance Testing

Seller will attend the Facility performance test in support of the gas turbine performance test to demonstrate Performance Guarantees of the Equipment at Site. Facility performance, emissions, and noise tests are the responsibility of the Buyer. Seller's performance test procedures in Attachment 5 will be incorporated into the Facility performance test procedure that will be provided by the Buyer.

Optional Equipment and Services Checklist and Descriptions

(I) Included (S) Quoted Separately

Factory Options

I	Option A	Variable Inlet Guide Vanes (VIGV)☐
I	Option B	LM6000PD - Dry Low Emissions System (DLE) ☐
I	Option C	SPRINT® Power Augmentation☐
I	Option D	Combustion Air Cooling – Chiller Coil☐
I	Option E	Lube Oil Cooler - Fin/Fan☐
I	Option F	Power System Stabilizer (PSS) ☐
I	Option G	Left-handed Piping Connections (one of three Units)
I	Option H	Left-handed Lineside Cubicle (two of three Units)

I	Option J	Remote Monitoring and Diagnostic Service (First Year Service Included)
I	Option K	DC Backup Lighting

Factory Options Descriptions

Option A Variable Inlet Guide Vanes (VIGV)

Seller furnishes the LM6000 engine with variable inlet guide vanes (VIGV).

This option is included with Option B

Option B LM6000PD - Dry Low Emissions System (DLE)

A dry low emissions system can be provided for use on gaseous fuel. This system reduces emissions over the entire power range without water or steam. NOx emissions can be guaranteed at 25 ppm (Ref. 15% O2).

This option includes Option A. A gas chromatograph is also included to monitor the heating value of the gas fuel and adjust combustor flame temperature.

Option C SPRINT® Power Augmentation

SPRINT® boosts engine performance up to 50.0 MW (ISO conditions) using a spray intercooling design that increases the mass flow by cooling the air during the compression process. The system is based on an atomized water spray injected through spray nozzles placed at two locations, one between the high pressure and low pressure compressors, and the second at inlet bellmouth. Water is atomized using high pressure air taken off of the eighth stage bleed. The water flow rate is metered, using the appropriate engine control schedules and at the inlet bellmouth. Bellmouth and inter-stage portions on SPRINT® alternate operation based on turbine inlet temperature. Customer supplies 22 gpm (83 lpm) of demineralized water to the connection on the unit. Water must meet GE specification MID-TD-0000-3.

Option D Combustion Air Cooling – Chiller Coil

Lowering the combustion air inlet temperature can increase the power output of the LM6000 generator set. When specified, Seller can furnish high performance inlet air chilling coils as an integral part of the air inlet system. Customer provides adequate quantities of chilled water and interconnecting piping to Seller furnished chilling coils at the filter house. The same coils can be used for anti-icing.

Option E Lube Oil Cooler - Fin/Fan

This replaces the standard simplex shell and tube coolers for the lube oil systems. A simplex core fin-fan cooler complete with changeover valve mounted on a separate base plate with dual fans is installed on a separate foundation.

Option F Power System Stabilizer (PSS)

The power system stabilizer (PSS) sends supplementary control signals to the generator's voltage regulator to control power fluctuations and improve the stability of the power system. A power system study is to be completed by a third party and has been excluded from Seller's scope of supply. With the study complete, Seller can assist the customer in programming the PSS with the set points established in the power system study.

Option G Left-handed Piping Connections

In the standard LM6000 configuration, the customer's piping connections are on the right side, as viewed from the exciter. As an option, the unit can be built with the customer's piping connections on the left side, as viewed from the exciter. The turbine removal door is placed on the side opposite the piping connections.

Option H Left-handed Lineside Cubicle

As viewed from the exciter end of a standard unit, the generator line-side cubicle is on the right-hand side and the neutral cubicle is on the left-hand side. When specified, the location of these cubicles can be reversed. However, the termination box for generator instrument and control wiring box, (MGTB) must remain on the right-hand side, and the turbine main terminal box (MTTB) must remain on the left.

Option I Lineside Cubicle Entry Configuration Options

Top Bus Duct Entry

The standard lineside cubicle is configured for bottom cable entry. With this option, the lineside cubicle is configured for top bus duct entry.

Top Cable Entry

The standard lineside cubicle is configured for bottom cable entry. With this option, the lineside cubicle is configured for top cable entry.

Option J Remote Monitoring and Diagnostic Service

Monitoring and Diagnostics Service helps plant operators improve availability, reliability, operating performance, and maintaining effectiveness. Monitoring of key parameters by factory experts may lead to early warning of equipment problems and avoidance of expensive secondary damage. Diagnostic programs seek out emerging trends; prompting proactive intervention to avoid forced outages and extended downtime. The ability for GE engineers to view real-time operation accelerates troubleshooting and sometimes removes the need for service personnel to visit the plant. Remote Monitoring and Diagnostic Service requires a customer supplied communications link (telephone or cell phone). One year of service is included with this option.

Option K DC Backup Lighting

Seller furnishes DC backup lighting in the turbine and generator enclosures as an option. DC lights turn on if AC power fails.

The following configurations will be provided.

Unit One Configuration

Right Hand Customer Piping

Left Hand Lineside Cubicle

Right Hand Neutral Cubicle

Unit Two Configuration

Left Hand Customer Piping

Right Hand Lineside Cubicle

Left Hand Neutral Cubicle

Unit Three Configuration

Right Hand Customer Piping

Left Hand Lineside Cubicle

Right Hand Neutral Cubicle

Limits of GEPPI Scope

Listed below are the limits/exclusions to the Seller standard Scope of Supply. All piping, wiring, cables, ducts, etc. connecting to these points is furnished by customer (others) unless modified by specification agreement.

Equipment System	Limits of GEPPI
• All piping, including Fuel Gas, Fuel Oil, Steam, Cooling Water, Heating Water, Demineralized Water, Lube Oil, Compressed Air, Instrument Air, Hydraulic Start Oil	• Flanged or threaded connection on Seller baseplate.
• Inlet Air-to-Filter	• Atmosphere (non-standard duct by others)
• Turbine Package Ventilation/Cooling Air	• Atmosphere (non-standard duct by others)
• Turbine Exhaust	• Exhaust flange on main baseplate
• Instruments on Seller's Baseplate	• Terminal box on baseplate
• Instrument wiring in Turbine Control Panel	• Terminal in Turbine Control Panel
• High Voltage Connections	• Bus bar in Seller Lineside cubicle
• Generator Ground Connections	• Seller Neutral cubicle
• Electric Motors	• Terminal box on individual motor
• Ladders and Platforms for Air Filter	• Ladders and Platforms for Inlet Air Filter maintenance only
• 24 V DC Batteries and Chargers for Control System and Fire and Gas Systems	• Battery terminals to baseplate (if supplied loose)

Exclusions:

- Civil engineering design of any kind
- Building and civil works
- Site facilities
- Support steelworks and hangers for the gas turbine ducting, silencing, and pipe work
- All inlet, exhaust, and ventilation ducting other than included in the scope of supply
- Drains and/or vent piping from the gas turbine package to a remote point
- Fuel storage, treatment and forwarding system
- Site grounding
- Lightning protection
- Power system studies
- Sensing and metering voltage transformers
- Machine power transformers, and associated protection
- Grid failure detection equipment
- Off loading, transportation and storage
- Off skid cabling, and design of off skid cable routing
- Balance of plant and energy optimization controls
- Anchor bolts, embedments, and grouting (quoted separately)
- Distributed plant control
- Customer's remote control
- Field supervision (quoted separately)
- High voltage transformer(s), cables, and associated equipment
- Interconnecting piping, conduit, and wiring between equipment modules
- Plant utilities, including compressed air supply and off skid piping

- Battery containment
- Lube oil measurement other than that defined in the scope of supply
- Additional lube oil breather ducting other than that defined in the scope of supply
- Fuel transfer pump
- Off skid fuel block and vent valves
- Fuel supply pipework beyond the scope of supply
- Generator controls other than that defined in the scope of supply
- Load sharing control
- Balance of plant controls
- Field Performance Testing
- Site Labor
- Ladders, Stairs, and Platforms for equipment beyond the gas turbine

Site Conditions

The following table outlines the criteria conditions at the proposed jobsite for the design of the equipment:

Location	Caleta Cruz, Peru'
Elevation	Approx. 120 Feet
Minimum Site Temperature	59F
Maximum Site Temperature	94F
Design Point Ambient Temperature / Relative Humidity	89.8 F (32.1 C) 60.4% RH
Primary Fuel Source	NG
Seismic Design Criteria (CTG Package	IBC 2000, Site Class D, Design Category F, Category II Facility with 1.25 Importance Factor
Maximum Wind Speed (Wind Load)	150 MPH
Roof Live / Snow Load	60 PSF
Near Field Noise at 3 ft horizontal and 5 ft vertical, NOTE 1	The below is based upon the placement of fin fan cooler to be reviewed by GE: 85 DBA ARITHMETIC AVERAGE SOUND PRESSURE LEVEL (DB REF 20 MICROPASALS, RMS) AT LOCATIONS AROUND THE PACKAGE (VERTICAL DISTANCE OF 5FT. (1.5M) ABOVE GRADE AT A HORIZONTAL DISTANCE OF 3FT (1M) FROM THE EXTERIOR PLANE OF EQUIPMENT AS TESTED IN A FREEFIELD CONDITION OVER A HARD REFLECTING GROUND PLANE. THIS GUARANTEE COINCIDES WITH THE OPERATING AT BASE-LOAD)
Far Field Noise, NOTE 1	65 dB(A) at 400 ft

NOTE 1: Far field noise is based on single-unit only operation. Multiple units operating at the same time will have an impact on both near and far field noise levels.

INSERT GE Fluid Specifications

MID-TD-0000-1
Revised, November 2001

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GE Energy

Process Specification
Fuel Gases For Combustion In AeroDerivative Gas Turbines

TABLE OF CONTENTS

LIST OF TABLES

1 GENERAL

GE AeroDerivative gas turbines have the ability to burn a wide range of gaseous fuels as shown in Table 1. These gases present a broad spectrum of properties due to both active and inert components. This specification is designed to define guidelines that must be followed in order to burn these fuels in an efficient, trouble-free manner, while protecting the gas turbine and supporting hardware.

Table 2 identifies the acceptable test methods to be used in determining gas fuel properties.

TABLE 1
FUEL GAS USABLILITY

Fuel Type	LHV Btu/SCF (kJ/NM^3)	Wobbe Number	Major Components	Operational Comments	Applicability SAC	DLE
Pipeline Natural Gas	850-1200 (33383-47128)	45-60	Methane	No Restrictions	Yes	Yes
Medium BTU Natural Gas	400 - 850 (15709-33838)	20-45	Methane, Hydrocarbons (HC), carbon dioxide, Nitrogen	Requires > 700 BTU/scf (27492 kJ/NM^3) for starting. May require modified fuel nozzles. Contact GE	Yes	No, See Note 8.
Liquefied Petroleum Gas (LPG)	2300-3200 (90330-125676)	70-75	Propane, Butane	May require specific fuel nozzles. Contact GE	Yes	No
Gasification Gases						
- Air Blown	150-200 (5891-7855)	6-8	Carbon monoxide, Hydrogen, HC, Nitrogen, Water Vapor	Contact GE	Yes	No
- Oxygen Blown	200- 400 (7855-15709)	8-20	Carbon monoxide, Hydrogen, HC, Water Vapor	Contact GE	Yes	No
Process Gases	300-1000 (11782-39274)	15-50	Methane, Hydrogen, Carbon monoxide, Carbon dioxide	Requires >700 BTU/scf (27492 kJ/NM^3) for starting. Restricted transient operation.	Yes	See Note 8
Refinery Gases	1000-1300 (39274-51056	45-60	Methane, Hydrogen, Carbon monoxide, Ethylene, Propylene, Butylene	No restrictions. Hydrogen content should be reviewed by GE.	Yes	See Note 8

Notes:

1. When considering the use of alternate fuels, provide details of the fuel constituents, fuel temperature, and expected engine usage conditions and operating characteristics to GE for evaluation and recommendations.

2. Values and limits apply at the inlet of the gas fuel control module.

3. Heating value ranges shown are provided as guidelines. Specific fuel analysis must be furnished to GE for evaluation. The standard configured single annular combustor (SAC) gas turbines require a fuel with a LHV no less than of 6500 BTU/pound. The Dry Low Emissions (DLE) combustion system requires a minimum LHV of 18000 BTU/pound. (Reference Section 3.1)

4. The quantity of sulfur in gas fuels is not limited by this specification. Experience has shown that oxidation/corrosion rates are not significantly affected by fuel sulfur levels up to 1.3% sulfur. Hot corrosion of hot gas path parts is affected by the presence of the specified trace metals. Sulfur levels shall be considered when addressing HRSG Corrosion, selective catalytic reduction (SCR) deposition, exhaust emissions, system material requirements, elemental sulfur deposition and iron sulfide. (Reference Section 4.3)

5. The fuel gas supply shall be 100% free of liquids. Admission of liquids can result in combustion and/or hot gas path component damage. (Reference Section 3.3)

6. Wobbe Number, or Modified Wobbe Number Index, is described in 3.2.

7. Gases with Wobbe Number Index greater than 40 may be applicable for DLE. Contact GE.

8. Process and refinery gases with <5% hydrogen content and low CO and CO2 content may be acceptable for DLE application. Contact GE.

NM^3 is at 0°C, 101.325kPa (sea level)

TABLE 2
TEST METHODS FOR GASEOUS FUELS

PROPERTY	ASTM METHOD
Gas Composition to C6+	D1945 - Standard method for constituents of gases by gas chromatography
Heating Value	D3588 - Procedure for calculating calorific value and specific gravity of gaseous fuels
Specific Gravity	D3588 - Procedure for calculating calorific value and specific gravity of gaseous fuels
Compressibility Factor	D3588 - Procedure for calculating calorific value and specific gravity of gaseous fuels
Dew Point (see note 1)	D1142 - Water vapor content of gaseous fuels by measurement of dew point temperature
Sulfur	D1072 - Test for total sulfur in fuel gases (see note 2) D3246 - Test for total sulfur in fuel gases
Chemical Composition	D2650 - Standard method for chemical composition of gases by mass spectrography

Notes:

1. Hydrocarbon and water dew points shall be determined by direct dew point measurement (Chilled Mirror Device). If dew point cannot be measured, an extended gas analysis, which identifies hydrocarbon components from C1 through C14, shall be performed. This analysis must provide an accuracy of greater

than 10 ppmv. A standard gas analysis to C6+ is normally not acceptable for dew point calculation unless it is known that heavier hydrocarbons are not present, as is most often the case with liquefied natural gases.

2. This test method will *not* detect the presence of condensable sulfur vapor. Specialized filtration equipment is required to measure sulfur at concentrations present in vapor form. Contact GE for more information.

2 FUEL GAS CLASSIFICATION

2.1 Natural and Liquefied Petroleum Gas (LPG)

Natural gases are predominantly methane with much smaller quantities of the slightly heavier hydrocarbons such as ethane, propane and butane. Liquefied petroleum gas is propane and/or butane with traces of heavier hydrocarbons.

2.1.1 Pipeline Natural Gas

Natural gases normally fall within the calorific heating value range of 850 to 1200 Btu/SCF (33383-47128 kJ/NM^3) (LHV). Actual calorific heating values are dependent on the percentages of hydrocarbons and inert gases contained in the gas.

2.1.2 Medium BTU Natural Gas

Natural gases are found in and extracted from underground reservoirs. These "raw gases" may contain varying degrees of nitrogen, carbon dioxide, hydrogen sulfide, and contain contaminants such as salt water, sand and dirt. Processing by the gas supplier normally reduces and/or removes these constituents and contaminants prior to use in the gas turbine. A gas analysis must be performed to ensure that the fuel supply to the gas turbine meets the requirements of this specification.

2.1.3 Liquefied Petroleum Gases

The heating values of Liquefied Petroleum Gases (LPGs) normally fall between 2300 and 3200 Btu/SCF (90330-125676 kJ/NM^3) (LHV). Based on their high commercial value, these fuels are normally utilized as a back–up fuel to the primary gas fuel for gas turbines. Since LPGs are normally stored in a liquid state, it is critical that the vaporization process and gas supply system maintains the fuel at a temperature above the minimum required superheat value. Fuel heating and heat tracing is required to ensure this.

2.2 Gasification Fuels

Other gases that may be utilized as gas turbine fuel are those formed by the gasification of coal, petroleum coke or heavy liquids. In general, the heating values of gasification fuel are substantially lower than other fuel gases. These lower heating value fuels require that the fuel nozzle gas flow passages be larger than those utilized for fuels of higher heating values.

Gasification fuels are produced by either an Oxygen Blown or Air Blown gasification process.

2.2.1 Oxygen Blown Gasification

The heating values of gases produced by oxygen blown gasification fall in the range of 200 to 400 Btu/SCF (7855-15709 kJ/NM^3). The Hydrogen (H_2) content of these fuels is normally above 30% by volume and have H_2/CO mole ratio between 0.5 to 0.8. Oxygen blown gasification fuels are often mixed with steam for thermal NOx control, cycle efficiency improvement and/or power augmentation. When utilized, the steam is injected into the combustor by an independent passage. The current guideline for Hydrogen plus CO constituent is limited to 75% by volume for LM6000 and to 85% for the other AeroDerivative gas turbines. Due to high hydrogen content of these fuels, oxygen blown gasification fuels are normally not suitable for Dry Low Emissions (DLE) applications, for which the Hydrogen content is limited to 5% by volume.. The high flame speeds resulting from high hydrogen fuels can result in flashback or primary zone re–ignition on DLE pre–mixed combustion systems. Utilization of these fuels shall be reviewed by GE.

2.2.2 Air Blown Gasification

Gases produced by air blown gasification normally have heating values between 150 and 200 BTU/ SCF (5891-7855 kJ/NM^3) LHV. The Hydrogen (H_2) content of these fuels can range from 8% to 20% by volume and have a H_2/CO mole ratio 0.3 to 3:1. The use and treatment of these fuels are similar to that identified for oxygen blown gasification.

For Gasification fuels a significant part of the total turbine flow comes from the fuel. In addition, for oxygen blown fuels there is a diluent addition for NOx control. Careful integration of the gas turbine with the gasification plant is required to assure an operable system. Due to the low volumetric heating value of both oxygen an air blown gases, special fuel system and fuel nozzles are required.

2.3 Process Gases

Many chemical processes generate surplus gases that may be utilized as fuel for gas turbines. (i.e. tail or refinery gases). These gases often consisting of methane, hydrogen, carbon monoxide, and carbon dioxide that are normally byproducts of petrochemical processes. Due to the hydrogen and carbon monoxide content, these fuels have large rich to lean flammability limits. These types of fuels often require inerting and purging of the gas turbine gas fuel system upon unit shutdown or a transfer to a more conventional fuel. When process gas fuels have extreme flammability limits such that the fuel will auto ignite at turbine exhaust conditions, a more "conventional" start–up fuel, such as methane, is required.

Additional process gases utilized as gas turbine fuels are those which are byproducts of steel production. These are:

2.3.1 Blast Furnace Gases (BFGs)

Blast Furnace Gases (BFGs), alone, have heating values below minimal allowable limits. These gases must be blended with other fuel to raise the heating value to above the required limit. Coke Oven and/or Natural Gases or hydrocarbons such as propane or butane can be utilized to accomplish this.

2.3.2 Coke Oven Gases

Coke oven gases are high in H_2 and H_4C and may be used as fuel for single annular combustion (SAC) systems, but are not suitable for Dry Low Emissions (DLE) combustion applications. These fuels often contain trace amounts of heavy hydrocarbons, which when burned could lead to carbon buildup on the fuel nozzles. The heavy hydrocarbons must be "scrubbed" or removed from the fuel prior to delivery to the gas turbine.

2.3.3 COREX Gases

COREX gases are similar to oxygen blown gasified fuels, and may be treated as such. They are usually lower in H_2 content and have lower heating values than oxygen blown gasified fuels. Further combustion related guidelines could be found in Bureau of Mines Circulars 503 and 622.

2.3.4 Hydrogen

The presence of gaseous hydrogen in the fuel can present special problems due to the high flame speed and high temperatures associated with combustion, and the very wide flammability limits of this gas. Treatment of fuels containing hydrogen are separated into three categories, less than 5% by volume, 6% to 30% by volume and over 30%. If the hydrogen fuel content is 5% or less, no special precautions are necessary and starting on this fuel mixture can be permissible, assuming there are no other restrictive substances in the mix.

For fuels containing more than 5%, but 30% or less hydrogen, an alternative starting fuel may be required by local safety codes and a special exhaust system purge cycle is incorporated into the gas turbine start sequence to eliminate accumulated fuels from an aborted start. In addition, special high point venting is required for both the fuel gas and turbine compartments since the fuel constituents are normally lighter than air. The vents hold the compartment at a slight vacuum relative to local ambient. Special precautions must also be taken to completely seal the fuel delivery system from leaks. Consult the local authorities for specific local safety codes.

If the fuel contains more than 30% hydrogen, electrical devices used in the fuel gas and turbine compartments should be certified for use in Group B (explosive) atmospheres. Consult the local authorities for specific local safety codes.

2.4 Refinery Gases

Many hydrocarbon fuels contain olefin hydrocarbon compounds which have been thought to prohibit their use in aeroderivative gas turbines.

Fuel temperature is also a consideration in order to use standard fuel nozzles and to avoid the possibilities of fuel polymerization. Maximum fuel temperature of 125°F (52°C) is recommended. It may be possible to go as high as 190°F (88°C), but this may require non-standard fuel nozzle sizing and should be considered on a case by case basis. Please contact GE for assistance.

Because refinery gas fuels usually have significant higher hydrocarbon and olefin content the combustor flame temperatures are typically higher, resulting in higher than normal (high methane gas) NOx emissions. Contact GE for effect on emissions.

3 FUEL PROPERTIES

3.1 Heating Value

A fuel's heat of combustion, or heating value, is the amount of energy, expressed in Btu (British thermal unit), generated by the complete combustion, or oxidation, of a unit weight of fuel. The amount of heat generated by complete combustion is a constant for a given combination of combustible elements and compounds.

For most gaseous fuels, the heating value is determined by using a constant pressure, continuous type calorimeter. This is the industry standard. In these units, combustible substances are burned with oxygen under essentially constant pressure conditions. In all fuels that contain hydrogen, water vapor is a product of combustion, which impacts the heating value. In a bomb calorimeter, the products of combustion are cooled to the initial temperature and all of the water vapor formed during combustion is condensed. The result is the HHV, or higher heating value, which includes the heat of vaporization of water. The LHV, or lower heating value, assumes all products of combustion including water remain in the gaseous state, and the water heat of vaporization is not available.

3.2 Modified Wobbe Index Range

While gas turbines can operate with gases having a very wide range of heating values, the amount of variation that a single specific fuel system can accommodate is much less. Variation in heating value as it affects gas turbine operation is expressed in a term identified as modified Wobbe Index (Natural Gas, E. N. Tiratsoo, Scientific Press Ltd., Beaconsfield, England, 1972). This term is a measurement of volumetric energy and is calculated using the Lower Heating Value (LHV) of the fuel, specific gravity of the fuel with respect to air at ISO conditions, and the fuel temperature, as delivered to the gas turbine. The mathematical definition is as follows:

Modified Wobbe Index $= LHV/(SG_{gas} \times T)^{1/2}$

This is equivalent to:

Modified Wobbe Index $= LHV/[(MW_{gas}/28.96) \times T]^{1/2}$

Where:

LHV	=	Lower Heating Value of the Gas Fuel (Btu/scf)
SGgas	=	Specific Gravity of the Gas Fuel relative to Air
MWgas	=	Molecular Weight of the Gas Fuel
T	=	Absolute Temperature of the Gas Fuel (Rankine)
28.96	=	Molecular Weight of Dry Air

The allowable modified Wobbe Index range is established to ensure that required fuel nozzle pressure ratios be maintained during all combustion/turbine modes of operation. When multiple gas fuels are supplied and/or if variable fuel temperatures result in a Modified Wobbe Index that exceed the ±10% limitation, independent fuel gas trains, which could include control valves, manifolds and fuel nozzles, may be required for standard combustion systems. For DLE applications the Wobbe Index range must be between 40 and 60. An accurate analysis of all gas fuels, along with fuel gas temperature profiles shall be submitted to GE for proper evaluation.

3.3 Superheat Requirement

The superheat requirement is established to ensure that the fuel gas supplied to the gas turbine is 100% free of liquids. Dependent on its constituents, gas entrained liquids could cause degradation of gas fuel nozzles, and for DLE applications, premixed flame flashbacks or re-ignitions. A minimum of 50°F (28°C) of superheat is required and is specified to provide enough margin to compensate for temperature reduction due to pressure drop across the gas fuel control valves.

3.4 Flammability Ratio

Fuel gases containing hydrogen and/or carbon monoxide will have a ratio of rich to lean flammability limits that is significantly larger than that of natural gas. Typically, gases with greater than 5% hydrogen by volume fall into this range and require a separate startup fuel. Consult the local authorities for specific local safety codes.

Fuel gases with large percentage of an inert gas such as nitrogen or carbon dioxide will have a ratio of rich–to–lean flammability limits less than that of pure natural gas. Flammability ratios of less than 2.2 to 1 as based on volume at ISO conditions (14.696 psia and 59°F (101.325 kPa and 15°C)), may experience problems maintaining stable combustion over the full operating range of the turbine.

3.5 Gas Constituent Limits

Gas constituents are not specifically limited except to the extent described in Fuel Gas Classification. These limitations are set forth to assure stable combustion through all gas turbine loads and modes of operation. Limitations are more stringent for DLE combustion systems where "premixed" combustion is utilized. A detailed gas analysis shall be furnished to GE for proper evaluation.

3.6 Gas Fuel Supply Pressure

Gas fuel supply pressure requirements are dependent on the gas turbine model and combustion design, the fuel gas analysis and unit specific site conditions. Minimum and maximum supply pressure requirements can be determined by GE for specific applications.

4 CONTAMINANTS

Dependent on the type of fuel gas, the geographical location and the forwarding means there is the potential for the "raw" gas supply to contain one or more of the following contaminants:

1. Tar, lamp black, coke
2. Water, salt water
3. Sand, clay
4. Rust
5. Iron sulfide
6. Scrubber oil or liquid
7. Compressor Lube oil
8. Naphthalene
9. Gas Hydrates

It is critical that the fuel gas is properly conditioned prior to being utilized as gas turbine fuel. This conditioning can be performed by a variety of methods. These include but are not limited to media filtration, inertial separation, coalescing and fuel heating. Trace metal, particulate and liquid contamination limits are given below. These limits are given in parts per million by weight (ppmw) corrected to the actual heating value of the fuel. It is critical that fuel gas conditioning equipment be designed and sized so that these limits are not exceeded.

4.1 Particulate

Contamination limits for particulates are established to prevent fouling and excessive erosion of hot gas path parts, erosion and plugging of combustion fuel nozzles and erosion of the gas fuel system control valves. The utilization of gas filtration or inertial separation is required. The filtration level should be a beta ratio of 200 minimum (efficiency of 99.5%) at 5μ or less. The total particulate should not exceed 30 ppm by weight. GE requires the use of stainless steel piping downstream of this last level of filtration.

4.2 Liquids

No liquids are allowed in the gas turbine fuel gas supply. Liquids contained in the fuel can result in nuisance and/or hardware damaging conditions. These include rapid excursions in firing temperature and gas turbine load, primary zone re-ignition and flashback of premixed flames, and when liquids carry over past the combustion system, melting of hot gas path components. When liquids are identified in the gas supply, separation and heating is employed to achieve the required superheat level.

4.3 Sulfur

There is no specific limit on natural gas fuel sulfur content if the engine is used in an application where both the fuel and environment are free of alkali metals. There are several concerns relative to the levels of sulfur contained in the fuel gas supply. Many of these are not directly related to the gas turbine but to associated equipment and emissions requirements. These concerns include but are not limited to:

4.3.1 Hot Gas Path Corrosion

Typically, use of sulfur bearing fuels will not be limited by concerns for corrosion in the turbine hot gas path unless alkali metals are present. Sodium, potassium and other alkali metals are not normally found in natural gas fuels, but are typically found to be introduced in the compressor inlet air in marine environments, as well as in certain adverse industrial environments. The total amount of sulfur and alkali metals from all sources shall be limited to form the equivalent of 0.6 ppm of alkali metal sulfates in the fuel. Unless sulfur levels are extremely low, alkali levels are usually limiting in determining hot corrosion of hot gas path materials. For low Btu gases, the fuel contribution of alkali metals at the turbine inlet is increased over that for natural gas and the alkali limit in the fuel is therefore decreased. The total amount of alkali metals [(a)] in gas fuels used with engines having marinized (corrosion-resistant) coatings on the high pressure turbine blading shall not exceed 0.2 ppm [(b)].

(a) Sodium, potassium, and lithium. Experience has shown that sodium is by far the preponderant alkali metal, if any, found in gaseous fuels.

(b) This limit assumes zero alkali metals in the inlet air or injected water or steam. When actual levels are above zero, the maximum allowable sodium content of the fuel must be reduced in accordance with the following relationship:

ppm sodium inlet air x Air/Fuel Ratio	=	
ppm sodium in water or steam x $\frac{\text{Water or Steam}}{\text{Fuel}}$ ratio	=	
ppm sodium in fuel	=	
Total fuel equivalence for sodium from all sources not to exceed		0.2 ppm

4.3.2 HRSG Corrosion

If heat recovery equipment is used, the concentration of sulfur in the fuel gas must be known so that the appropriate design for the equipment can be specified. Severe corrosion from condensed sulfuric acid results if a heat recovery steam generator (HRSG) has metal temperatures below the sulfuric acid dew point. Contact the HSRG supplier for additional information.

4.3.3 Selective Catalytic Reduction (SCR) Deposition

Units utilizing ammonia injection downstream of the gas turbine for NOx control can experience the formation of deposits containing ammonium sulfate and bisulfate on low temperature evaporator and economizer tubes. Such deposits are quite acidic and therefore corrosive. These deposits, and the corrosion that they cause, may also decrease HRSG performance and increase backpressure on the gas turbine. Deposition rates of ammonium sulfate and bisulfate are determined by the sulfur content of the fuel, ammonia content in the exhaust gas, tube temperature and boiler design. Fuels having sulfur levels above those used as odorants for natural gas should be reported to GE . In addition, the presence of minute quantities of chlorides in the inlet air may result in cracking of AISI 300 series stainless steels in the hot gas path. Contact the SCR supplier for additional information.

4.3.4 Exhaust Emissions

Sulfur burns mostly to sulfur dioxide, but 5% to 10% oxidizes to sulfur trioxide. The latter can result in sulfate formation, and may be counted as particulate matter in some jurisdictions. The remainder will be discharged as sulfur dioxide. To limit the discharge of acid gas, some localities may restrict the allowable concentration of sulfur in the fuel.

4.3.5 Elemental Sulfur Deposition

Solid elemental sulfur deposits can occur in gas fuel systems downstream of pressure reducing stations or gas control valves under certain conditions. These conditions may be present if the gas fuel contains elemental sulfur vapor, even when the concentration of the vapor is a few parts per billion by weight. Concentrations of this magnitude cannot be measured by commercially available instrumentation and deposition cannot therefore be anticipated based on a standard gas analysis. Should deposition take place, fuel heating will be required to maintain the sulfur in vapor phase and avoid deposition. A gas temperature of 130°F (54°C) or higher may be required at the inlet to the gas control valves to avoid deposition, depending on the sulfur vapor concentration. The sulfur vapor concentration can be measured by specialized filtering equipment. If required, GE can provide further information on this subject.

APPENDIX 1 – DEFINITIONS

Dew Point

This is the temperature at which the first liquid droplet will form as the gas temperature is reduced. Common liquids found in gas fuel are hydrocarbons, water and glycol. Each has a separate and measurable dew point. The dew point varies considerably with pressure and both temperature and pressure must be stated to properly define the gas property. Typically, the hydrocarbon dew point will peak in the 300 to 600 psia (2068 to 4137 kPa) range.

Dry Saturated Conditions

The gas temperature is at, but not below or above, the dew point temperature. No free liquids are present

Gas Hydrates

Gas hydrates are semi–solid materials that can cause deposits that plug instrumentation lines, control valves and filters. They are formed when free water combines with one or more of the C1 through C4 hydrocarbons. Typically the formation will take place downstream of a pressure reducing station where the temperature drop is sufficient to cause moisture condensation in a region of high turbulence. Because hydrates can cause major problems in the gas distribution network, the moisture content is usually controlled upstream at a dehydration process station.

Gas Hydrate Formation Line

This is similar to the dew point line except the temperature variation with pressure is much less. The hydrate line is always below or at the moisture dew point line as free water must exist in order for hydrates to form. Maintaining 50°F of superheat above the moisture dew point will eliminate hydrate formation problems.

Glycol

Glycol is not a natural constituent of natural gas but is introduced during the dehydration process. Various forms of glycol are used, diethylene and triethylene glycol being two most common. In some cases glycol is injected into the pipeline as a preservative. In most cases, glycol may only be a problem during commissioning of a new pipeline or if an upset has taken place at an upstream dehydration station.

Superheat

This is defined as the difference between the gas temperature minus the liquid dew point. The difference is always positive or zero. A negative value implies that the value is being measured at two differing states of pressure and temperature and is not valid. A measured gas temperature below the theoretical dew point means that the gas is in a wet saturated state with free liquids present.

Saturation Line

This is the same as the dew point line.

Wet Saturated Conditions

A point where a mixture consists of both vapor and liquids.

Requirements for Water and Steam Purity for Injection in Aero Derivative Gas Turbines

1.1 Scope

This document establishes the purity requirements for water for NOx suppression and SPRINT® injection into gas turbine engines and for Steam for injected into the gas turbine whether for NOx suppression or power augmentation.

1.2 Definitions

For the purpose of this specification, the following definitions shall apply:

NOx Suppression Water - Water introduced into the engine combustor for the purpose of suppressing the oxides of nitrogen (NOx) in the engine exhaust gases.

SPRINT® Water – Water introduced into the engine inlet or into the high pressure compressor inlet for purpose of power enhancement.

2. Applicable Documents

2.1 American Society of Testing and Materials Publications.

ASTM D512 Standard Test Method for Chloride Ion in Water

ASTM D516 Standard Test Method for Sulfate Ion in Water

ASTM D859 Standard Test Method for Silica in Water

ASTM D1066 Standard Practice for Sampling Steam

ASTM D1125 Standard Test Method for Electrical Conductivity and Resistivity of Water

ASTM D3370 Standard Practices for Sampling Water from closed Conduits

ASTM D4191 Standard Test Method for Sodium in Water by Atomic Absorbtion Spectography

ASTM D4192 Standard Test Method for Potassium in Water by Atomic Absorbtion Spectography

ASTM D5907 Standard Test Method for Filterable and Non-Filterable Matter in Water

ASTM D5464 Standard Test Method for pH of Water with Low Conductivity

2.2 Environmental Protection Agency (EPA) Test Methods

EPA 160.3 Residue, Non-Filterable and Total Suspended Solids

EPA 150.1 pH Electrometric

EPA 120.1 Conductance, Specific Conductance at 25°C

EPA 200.7 Metals & Trace Elements

EPA 325.3 Chloride, Titrimetric Mercuric Nitrate

EPA 375.4 Sulfate, Turbidimetric

3. Water Requirements

3.1 Water Sampling Requirements

The sampling shall be in accordance with ASTM D3370. A minimum of one (1) gallon or four (4) liters shall be supplied.

3.2 Water Purity Requirements

The water shall meet the following requirements when tested in accordance with the designated test method:

	Limit	Test Method
Total Suspended Solids and Total Dissolved Solids, mg/L, max	5	ASTM D5907 or EPA 160.3
pH	6.0 - 8.0	ASTM D5464 or EPA 150.1
Conductivity, µS/cm at 25°C	< 1.0	ASTM D1125 or EPA 120.1
Sodium + potassium, ppm, max	See 3.3	ASTM D4191 and D4192 or EPA 200.7
Silica (SiO_2), mg/L, max.	0.1	ASTM D859 or EPA 200.7
Chlorides, mg/L, max	0.5	ASTM D512 or EPA 325.3
Sulfates, mg/L, max	0.5	ASTM D516 or EPA 375.4

3.3 Sodium & Potassium Limits in Water or Steam

The maximum amount of NA + K allowed in the water or steam injected into the engine depends upon the total NA + K contamination from all sources; i.e., from the fuel, air, water and steam. The maximum Na + K allowed is determined from the equation:

(ppmFuel) + (ppmAir)*A/F + (ppmWater)*W/F + (ppmSteam)*S/F = 0.2 ppm

Where:

ppmFuel	=	Parts per million Na + K in fuel
ppmAir	=	Parts per million Na + K in Air
ppmWater	=	Parts per million Na + K in water
ppmSteam	=	Parts per million Na + K in steam
A/F	=	Air/Fuel Ratio (Wt. Basis)
W/F	=	Water/Fuel Ratio (Wt. Basis)
S/F	=	Steam/Fuel Ratio (Wt. Basis)

3.4 Water Filtration Requirements

The water shall contain no particles larger than 20 microns absolute.

4.0 Steam Requirements

4.1 Steam Purity

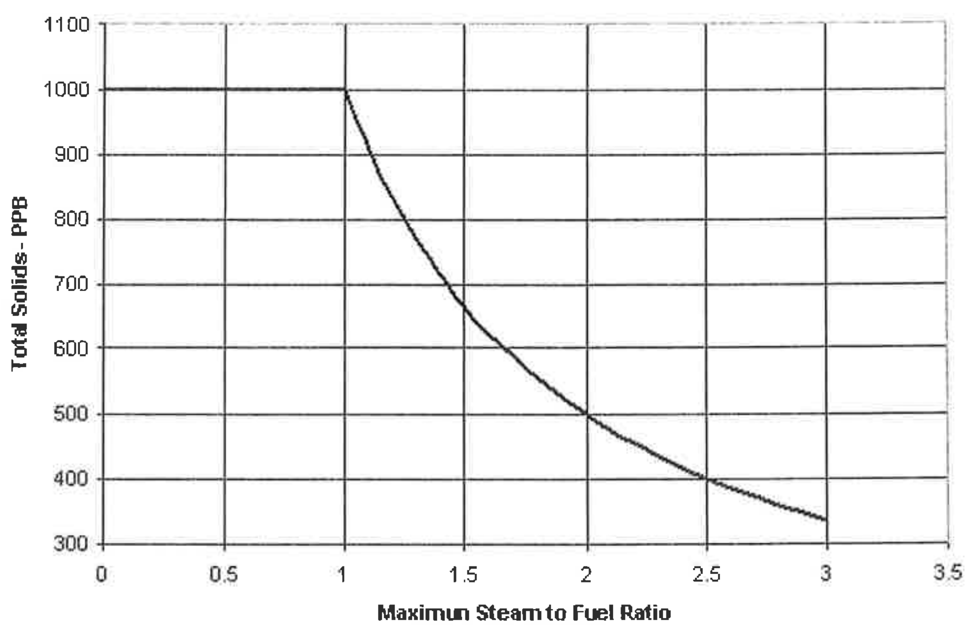
The Steam shall meet the following requirements when tested in accordance with the designated test method:

- Sodium + Potassium (Na +K) – See paragraph 3.3
- Total Conductivity (Cation + Anion)

  Normal: <1.5 μS/cm (95% of operation time)
  Abnormal: < 2.0 μS/cm (5% of operating time)

- Total Solids

The maximum total solids depends on the steam/fuel weight ratios at which the gas turbine is to operate in the specific application. The value is determined form the following figure. Contaminant size shall not exceed 250 microns. With the exception of silica, there is no differentiation between types of solids as long as other limitations of this section are met. Silica in the steam is limited to 20 ppb.



4.2 Steam Sampling

Steam samples should be taken in accordance with ASTM D1066.

Compressor Cleaning Water Purity Specification for GE Aircraft Derivative Gas Turbines in Industrial Applications

1.1 Scope

This specification establishes the requirements for purified water for use in cleaning the compressor of gas turbine engines where the intent is to restore performance by removing the build up of deposits on compressor components. The water quality defined in this specification applies to water used in both on–line compressor cleaning and crank–soak compressor cleaning.

1.2 Definitions

For the purpose of this specification, the following definitions shall apply:

On–line Compressor Cleaning - A method of removing the build up of deposits on compressor components while the engine is operating. On–line cleaning as accomplished by spraying cleaning solution into the inlet of the engine while the engine is operating.

Crank–Soak Compressor Cleaning - A method of removing the buildup of deposits on compressor components while the engine is motored by the starter. Crank–soak cleaning is accomplished by spraying cleaning solution into the inlet of the engine while the engine is operating unfired at crank speed.

Liquid Detergent - A concentrated solution of water soluble surface active agents and emulsifiable solvents.

Cleaning Solution - A solution of emulsion of liquid detergent and water or a water and antifreeze mixture for direct engine application. The recommended dilution of liquid detergent and water shall be specified by the liquid detergent manufacturer.

2. Applicable Documents

2.1 Issue of Documents

The following documents shall form a part of this specification to the extent specified herein. Unless a specific issue is specified, the latest revision shall apply.

2.1.1 American Society of Testing and Materials

Available from American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103.

ASTM D1192	Equipment for Sampling and Steam
ASTM D1293	Tests for pH of Water
ASTM D4191	Tests for Sodium in Water by atomic Absorbtion Spectography
ASTM D4192	Tests for Potassium in Water by Atomic Absorbtion Spectography
ASTM D5907	Tests for Filterable and Non-Filterable Matter in Water
ASTM D3370	Practices for Sampling Water

3. Requirements

3.1 Sampling Requirements

The sampling shall be in accordance with ASTM D1192 and ASTM D3370. A minimum sample of one (1) gallon or four (4) liters shall be supplied.

3.2 Chemical Requirements

The water shall meet the following requirements when tested in accordance with the designated test method.

	Limit	Test Method
Total matter, ppm, max	100	ASTM D5907
pH	6.5 - 8.5	ASTM D1293
Sodium + potassium, ppm,max	25	ASTM D4191 & ASTM D4192

3.3 Filtration Requirements

The water shall contain no particles larger than 100 microns absolute.

Liquid Detergent for Compressor Cleaning for GE Aircraft Derivative Gas Turbines

This specification establishes the requirements for liquid detergent products used to prepare cleaning solutions for cleaning the compressors of gas turbine engines, where the intent is to restore performance by removing the build–up of deposits on compressor components. Such deposits include salt, soils or oils that may be ingested from the atmosphere.

The cleaning process shall be carried out by spraying the cleaning solution into the bellmouth of the engine while the engine is running at power (on–line cleaning) or while the engine is being cranked (crank soak cleaning).

For the purposes of this specification, the following definitions shall apply:

Liquid Detergent - A concentrated solution of water soluble surface active agents and emulsifiable solvents.

Cleaning Solution - A solution or emulsion of liquid detergent in water or a water and antifreeze mixture for direct engine application. The recommended dilution of liquid detergent and water shall be determined by the liquid detergent manufacturer.

1. Applicable Documents

The following documents shall form a part of this specification to the extent specified herein. Unless a specific issue is specified, the latest revision shall apply.

ASTM D88	Standard Test Method For Saybolt Viscosity
ARP 1795	Stress–Corrosion of Titanium Alloys, Effect of Cleaning Agents on Aircraft Engine Materials
AMS 1424	Deicing/Anti-icing Fluid, Aircraft (Newtonian-SAE Type 1)

2. Detergent Properties

2.1 Composition

The chemical composition of the detergent is not limited, other than as specified herein.

2.2 Biodegradability

Use of the liquid detergent/cleaning solution shall conform to local regulations for water pollution. Use of biodegradable ingredients is recommended.

2.3 Toxicity

Use of the liquid detergent/cleaning solution shall conform to local regulations for industrial hygiene and air pollution. Use of nontoxic ingredients is recommended.

2.4 Health and Safety Information

The liquid detergent manufacturer shall make available health and safety information for the liquid detergent as required by applicable local, state and federal regulations.

2.5 Solids

The liquid detergent shall contain no particles larger than 20 micron.

2.6 Physical and Chemical Properties

The liquid detergent shall meet the test requirements.

3. Test Requirements

3.1 Liquid Detergent

3.1.1 Residue or Ash Content

Residue or ash content shall not exceed 0.01 percent when tested in accordance with paragraph 4.1.

3.1.2 Low Temperature Stability

The liquid detergent shall show no evidence of separation of component parts when maintained at 40°F ± 3 (5°C ± 2). It is highly desirable although not mandatory that the fluid shall remain liquid below 32°F (0°C).

3.1.3 Cold Weather Solution Compatibility

The liquid detergent shall show no separation, layering or precipitation when mixed to the liquid detergent manufacturer's recommended dilution in one or more of the following antifreeze solutions after 2 hours at 10°F ± 3 (-12°C ± 2):

- Isopropyl Alcohol
- Monopropylene glycol (PG)
- Acetone

See paragraph 6.1 for more information regarding liquid detergent and antifreeze mixtures.

3.1.4 Hard Water Compatibility

The liquid detergent shall show no separation or layering when mixed with synthetic hard water prepared in accordance with paragraph 4.2.

3.1.5 Acid and Alkali Acceptance

The liquid detergent shall show no separation, layering or precipitation when tested in acidic or alkali media in accordance with paragraph 4.3.

3.1.6 Salt Water Tolerance

The liquid detergent shall show no separation or gelling when mixed with 3.5 percent salt water in accordance with paragraph 4.4.

3.1.7 Viscosity

The liquid detergent shall have a viscosity of 50 to 200 SUS at 77°F (25°C) when tested in accordance with ASTM D88.

3.1.8 pH

The pH of the liquid detergent as received shall be from 6.5 to 8.5 when measured with a suitable pH meter employing a glass electrode.

3.2 Cleaning Solution

3.2.1 Corrosive Elements

Maximum levels of elements in the cleaning solution which may promote various types of corrosion, shall be no greater than as shown in Table 1, when analyzed by methods in paragraph 4.5.

Table 1. Maximum Corrosives Limit

Total alkali metals (sodium + potassium + lithium, etc.)	25 ppm max.
Magnesium + calcium	5 ppm max.
Vanadium	0.1 ppm max.
Lead	0.1 ppm max.
Tin + Copper	10 ppm max.
Sulfur	50 ppm max.
Chlorine	40 ppm max.

3.2.2 pH

The pH of the cleaning solution shall be from 6.5 to 8.5 when measured with a suitable pH meter employing a glass electrode.

4. Test Methods

4.1 Residue or Ash Content

Weigh 10 ± 0.1 gram sample of liquid detergent in a weighed 30 ml porcelain crucible. Heat gently to volatilize any water or solvents. (Crucible may be placed in air oven at 105°C ± 2 for 24 hours, followed by 240°C ± 2 for 24 hours to insure all volatile matter is evaporated.) Finally, ignite contents over Bunsen Burner, first at low temperature under good oxidizing conditions until all ignitable material is consumed, then place a crucible in a muffle furnace at 1040 to 1100°C for 2 hours. Cool in desiccator, and weigh.

Percent residue or ash = (100 x A)/W

Where: A = grams of residue
W = grams of sample

4.2 Hard Water Compatibility

4.2.1 Preparation of Synthetic Hard Water

A hard water solution is prepared by dissolving the following in one liter of just boiled and cooled distilled water:

a. 0.20±0.005 gram Calcium Acetate, reagent grade Ca(C2H3O2)2 • H20

b. 0.15±0.005 gram Magnesium Sulfate, reagent grade MgSO4 • 7 H20

4.2.2 Hard Water Test

5 ml of liquid detergent shall be added to a clean 50 ml cylinder. 45 ml of synthetic hard water shall be added and mixed well. The solution shall be examined for compatibility after 16 hours at 77°F ± 5 (25°C ± 3).

4.3 Acid and Alkali Acceptance

The liquid detergent shall be mixed with distilled water in accordance with the liquid detergent manufacturer's recommended dilution. To 50 ml of the solution, add 1 ml of 75 percent phosphoric acid. To another 50 ml of the solution, add 5 ml of 75 percent phosphoric acid. To another 50 ml of the solution, add 1 ml of 50 percent potassium hydroxide. Let all three mixtures stand for one hour at 77°F ± 5 (25°C ± 3), and then examine for acid or alkali acceptance.

4.4 Salt Water Tolerance

Prepare a 3.5 percent by weight solution of sodium chloride in distilled water. Add 15 ml of salt solution to 35 ml of liquid detergent and let stand for 1 hour at 77°F ± 5 (25°C ± 3). Examine for salt water tolerance.

4.5 Elemental Content

Elemental content shall be determined using the following methods:

Element	Method
Sulfur, Phosphorous	Inductivity Coupled Plasma Spectroscopy - Atomic Emission Spectroscopy (ICP-AES)
Chlorine	Microcoulometric filtration
Sodium, Potassium	Atomic Absorption (AA)
Other metals	ICP-AES or AA

5. Material Compatibility

5.1 Compatibility with Engine Materials

Use of the detergent gas turbine cleaner shall not have adverse effects on engine system materials such as titanium stress corrosion, hot corrosion of turbine components or damage to lubrication system components.

5.2 Titanium Stress Corrosion

A titanium stress corrosion test in accordance with ARP 1795 or equivalent may be run on the liquid detergent at the discretion of GE.

6.1 Cold Weather Usage

In cold weather, liquid detergent must be added to antifreeze mixture rather than to water alone. At present, the only acceptable antifreeze solutions are:

- Isopropyl Alcohol
- Monopropylene glycol (PG)
- Acetone

Monopropylene glycol (PG) must be per AMS 1424 and may be used down to 20°F (-7°C)

Antifreeze mixtures are shown in Table 2. The liquid detergent manufacturer must specify which, if any, of the antifreezes specified above is not compatible with the liquid detergent.

The use of non-isopropyl alcohol, ethylene glycol or additives containing chlorine, sodium or potassium are not permitted since they may attack the titanium and other metals in the gas turbine.

It is extremely important that the liquid detergent and antifreeze solution be a homogeneous mixture when sprayed into the bellmouth of the gas turbine. If after 2 hours the liquid detergent and antifreeze solution separates, (see paragraph 3.1.3) agitation of the mixture in the wash water tank is permissible. However, the liquid detergent manufacturer shall specify that agitation is required.

Table 2. Water Wash Antifreeze Mixtures.

Compressor Washing Antifreeze Mixtures						
Outside Air Temp, °F (°C)	Monopropylene glycol (PG) % Vol	H2O % Vol	Acetone % Vol	H2O % Vol	Isopropyl Alcohol % Vol	H2O % Vol
+20 to +50 (-7 to 10)	21	79	25	75	22	78
+10 to +20 (-12 to –7)	N/A	N/A	40	60	34	66
0 to +10 (-18 to –12)	N/A	N/A	53	47	47	53
-10 to 0 (-23 to –18)	N/A	N/A	63	37	72	28
-20 to –10 (-29 to –23)	N/A	N/A	69	31	88	12
-30 to –20 (-34 to –29)	N/A	N/A	75	25	97	3
Compressor Rinsing Antifreeze Mixtures						
Outside Air Temp, °F (°C)	**Monopropylene glycol (PG) % Vol**	**H2O % Vol**	**Acetone % Vol**	**H2O % Vol**	**Isopropyl Alcohol % Vol**	**H2O % Vol**
+20 to +50 (-7 to 10)	14	86	20	80	18	82
+10 to +20 (-12 to -7)	N/A	N/A	33	67	27	73
0 to +10 (-18 to -12)	N/A	N/A	43	57	39	61
-10 to 0 (-23 to -18)	N/A	N/A	50	50	58	42
-20 to -10 (-29 to -23)	N/A	N/A	55	45	70	30
-30 to -20 (-34 to -29)	N/A	N/A	60	40	77	23

Lubricating Oil Specification for GE Aircraft Derivative Gas Turbines

This document provides the requirements and application guidelines for selection of lubricating oils which can be satisfactorily utilized in GE Marine and Industrial Aeroderivative Applications. It is recommended that the lubricating oil selected be reviewed with GE prior to its use.

1.0 Oil Specifications

Oils conforming to the US Department of Defense (DoD) Specifications shown in paragraph 2.1 are acceptable for use in GE Aircraft Derivative gas turbines, provided they are listed on the Qualified Product List (QPL) for the specific Specification.

1.1 Commercial Specifications

Commercially available synthetic based lubricating oils, per the Supplier's Specification, are acceptable for use in GE Aircraft Derivative gas turbines, provided they are listed in Section 4 of this document. Such oils largely conform to the primary requirements of the oils in Section 1.0, but certain variations have been approved. Such oils have been qualified by the Supplier to meet the requirements of this document.

2.0 Applicable Documents

The following documents shall form a part of this document to the extent specified herein. Unless a particular issue is specified, the latest revision shall apply.

2.1 US DoD Specifications

MIL-PRF-23699 Lubricating Oil, Aircraft Turbine Engines, Synthetic Base, Class STD

MIL-L-7808 Lubricating Oil, Aircraft Turbine Engines, Synthetic Base, Type I

2.2 American Society of Testing and Materials.

The following documents are available from American Society for Testing and Materials, Customer Service, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959:

ASTM D2532 Low Temperature Viscosity

ASTM D97 Pour Point

ASTM D445 Kinetic Viscosity

3.0 Requirements

The lubricating oil shall conform to the requirements of MIL- PRF -23699, however, exceptions to the following requirements will be considered:

- Low temperature Viscosity when tested per ASTM D2532.
- Pour Point when tested per ASTM D97.
- Viscosity at 40°C and 100°C when tested per ASTM D445
- Base Stock Composition

The specific variations to MIL-PRF-23699 shall be provided by the oil supplier, along with performance difference impacts, for review by GE.

3.1 Material Compatibility

The lubricating oil shall be compatible with the same elastomer seal and metallic materials as the MIL-PRF-23699 compliant lubricating oils are.

The lubricating oil shall be mixable with MIL-PRF-23699 or MIL-L-7808 compliant oil in a ratio of up to 5% of either oil, without adversely affecting the property integrity of the majority, or operating, oil. Mixing of oils is not intended, but will result due to engine location changes.

4.0 Qualification

Lubricating oil shall be considered qualified and acceptable for use in GE Aircraft Derivative gas turbines demonstrating conformance to the requirements and after being listed in paragraph 4.4. The qualification program shall be carried out by the oil supplier in conjunction with a sponsoring gas turbine owner/operator. GE's participation will be limited to technical consultation, review and final approval only.

4.1 Performance Tests

The oil supplier shall conduct tests in accordance with the requirements of MIL-PRF-23699 and compare the results with the requirements stated therein. All results, and specifically the variations to MIL-PRF-23699 requirements, shall be reviewed with GE prior to initiation of Service Evaluation Testing. Specifically, the material presented for review shall include, as minimum, the following:

- Physical/Chemical Properties and variations to MIL-PRF-23699
- Expected impact to operating systems due to Property variations
- Material Compatibility Lists & Test results
- Oil Coking Test Results

4.2 Service Evaluation Tests

The oil shall undergo service evaluation testing in a LM Series gas turbine application(s). The sponsoring operator will accept total responsibility for all results related to operating with the candidate lubricating oil. The service evaluation engine shall have a known hardware condition baseline, based on depot inspection or new delivery, immediately prior to the service evaluation test.

Service evaluation testing shall be conducted on a minimum of three LM series gas turbines, each accumulating at least 8,000 operating hours, at a baseload operating site, prior to inspection. During operation, periodic oil samples shall be tested and trended for physical and chemical property changes. Inspection shall be performed at an authorized depot, and shall be in accordance with the applicable repair manual.

Inspection shall be focused on the oil wetted parts, including the bearings, gears, elastomer seals, sump oil seals, actuators, and lube/hydraulic pumps. GE will be permitted to witness any of the inspections, at the discretion of GE.

4.3 Qualification Report

The oil supplier, and/or operator, shall prepare and submit a Final Qualification Report to GE. The report shall include, as a minimum, the following:

- Oil Brand Description including the complete formulation
- Certified physical, chemical and performance test results
- Material Safety Data Sheets
- Service evaluation test history including all significant operational and maintenance events
- Service evaluation oil sample trending results
- Final depot engine inspection results

Upon final review and approval of the Final Qualification Report by GE, the candidate oil will be included on the approved oils list.

Formulation changes affecting any approved performance characteristics must be reviewed with GE for impact on qualification results.

4.4 Approved Lubricating Oils

In addition to the oils listed on QPL-23699 (Class STD) and QPL-7808, (Qualified Products List), the following lubricating oils are approved for use in GE Aero Derivative gas turbines and gas generators:

1. None at this time.

Attachment 2 - Schedule Options

Schedule of Options

This schedule of options is designed to describe only those options that have either been quoted separately to the Buyer or have not yet been elected by the Buyer as of the Effective Date of this Contract. The Buyer shall have the right to select the below options in accordance with the provisions set forth below. If elected, the Parties shall execute a Change Order and the price for these options shall be added to the Contract Price set forth in Article 3 of the Contract.

Proposal Reference	Description	Addition to Contract Price US Dollars	Deadline for Exercise Of Option
Lineside Cubicle Entry	Top Bus Duct Entry	$0	On or before either the Order Definition Meeting or October 15, 2008
Lineside Cubicle Entry	Top Cable Entry	$0	On or before either the Order Definition Meeting or October 15, 2008
Attachment 1	Optional Gas Turbine Generator Set	$18,082,000	On or before January 31, 2009
Section 14.1	6-month Passive Warranty Extension	$90,000 / Unit	On or before either the Order Definition Meeting or October 15, 2008

Optional Lineside Cubicle Entry Configuration

Top Bus Duct Entry

The standard lineside cubicle is configured for bottom cable entry. With this option, the lineside cubicle is configured for top bus duct entry.

Top Cable Entry

The standard lineside cubicle is configured for bottom cable entry. With this option, the lineside cubicle is configured for top cable entry.

Optional Gas Turbine Generator Set

The Buyer shall have a one-time option to purchase One (1) additional Unit at the pricing provided for in the above table. This option, if executed in accordance with these provisions, is subject to prior sale. The Buyer may elect to exercise this option at the Buyer's sole discretion, provided that the Buyer executes a Change Order on or before January 31, 2009. The purchase of an additional Unit pursuant to the exercise of such option will be subject to the terms and conditions of this Contract, except as otherwise provided herein, and shall be done in accordance with the Change Order provisions of this Contract. The Scheduled Delivery Date for the optional Unit will be within the timeframe of July 1, 2010 and September 30, 2010 and will be at Seller's discretion. Provided that the Scheduled Delivery Date for the optional Unit is set no later than September 30, 2010, then the Contract Price of such Unit will be as set forth above.

6-Month Passive Warranty Extension

Seller has an option to extend the 30-month duration in Section 14.1 (iii) to 36-months by executing a Change Order in accordance with the provisions of this Contract for the price in the above table.

Attachment 3 - Lien Waiver Form

Waiver of Lien

The undersigned, GE Packaged Power, Inc. (Seller), for and in consideration of payments for work performed and materials furnished to ________________ (Buyer), pursuant to the Contract between the Seller and the Buyer dated ______________, hereby waives and releases any and all liens and claims or right to liens on the assets of the Buyer, including, but not limited to the work performed and the materials furnished pursuant to the Contract, provided that Buyer remits payment for the following outstanding invoices:

All bills or accounts for labor, material and services furnished in performance with the Contract will be paid by Seller to its Suppliers in accordance with the contractual terms of the agreements between the relevant Suppliers and Seller and Seller shall indemnify Buyer against any such failure of Seller to pay its debts to Suppliers when due.

Dated this _________ day of ______________________________200_.

Seller

____

(GE Packaged Power, Inc.)

____

(Signature of Officer)

____

(Printed Name Of Officer)

Attachment 4 - Scheduled Delivery Date(s)

Unit Number	Equipment Description	Scheduled Delivery Date
Unit #1	LM6000 Gas Turbine Generator (GTG) Package	18 September 2009
Unit #2	LM6000 Gas Turbine Generator (GTG) Package	23 October 2009
Unit #3	LM6000 Gas Turbine Generator (GTG) Package	27 November 2009

Attachment 5 - Test Procedures and Protocol

SPECIFICATION FOR GAS TURBINE GENERATOR PERFORMANCE TEST MEASUREMENT (SGTGPTM) - LM6000PD SPRINT

I. INTRODUCTION

An Owner's acceptance of a gas turbine power generation facility is usually preceded by proof of compliance with specific performance requirements for the gas turbine generator set(s). GE Energy provided a performance guarantee of Gross Power Output and Gross Heat Rate that is passed through to the Owner.

If the Customer plans to use the results of the field test as a basis to determine the fulfillment of contractual requirements, a manufacturer's representative will provide the following field services:

- Supervise collection of data by owners, operators, engineers or other qualified parties for the gas turbine generator set.
- Validate calibration of pertinent instruments.
- Reduce the recorded data in accordance with the manufacturing site performance data correction procedure.
- Issue a field performance test report.

II. SCOPE AND PURPOSE

The primary purpose of this test shall be to demonstrate the guaranteed generator electrical output and heat rate for GE Aeroderivative Gas Turbine Generator (GTG). The guarantee power level will be achieved without exceeding specified engine control limits: High-pressure rotor speed, high-pressure compressor discharge pressure and temperature, and low-pressure turbine inlet temperature. In addition the guarantee power and heat rate will be achieved while ensuring that the GTG is not running with any vibration alarms present.

Other tests, such as emissions and noise, are typically identified by the permitting regulatory agency and, therefore, not covered in this document.

The scopes of responsibilities, for all parties involved in the performance test, are as follows:

- One GE ENERGY Test Engineer who is responsible for supervising all aspects of the test.
- GE ENERGY and Customer representatives will be responsible for recording the data that is being collected.
- The GE ENERGY test engineer performs the computations of the test results.
- Personnel are to be provided by Customer to assist in logging manual data or collecting fuel samples.
- One operator representing the Customer will be responsible for operating the unit. The operator maybe assisted by GE ENERGY Controls Technician.
- A compressor cleaning crew will be utilized for an offline compressor water wash. This

procedure is to be conducted no more than three days prior to the performance test.

- In addition to the above, CUSTOMER, independent engineers, and GE ENERGY may have observers on the site during the test.

III. TEST PROCEDURE

GE Energy testing procedures are in general compliance with ASME PTC 22-1997. Comments to ASME PTC 22-1997 are available for review.

A. Test Setup

The customer will make every effort to insure the test takes place before 200 fired hours have elapsed on each gas turbine engine. Furthermore, the GTG must operate at steady base load and in new and clean condition for 24 cumulative hours prior to commencing the test. GE Energy representatives shall determine, in their sole discretion, whether the GTG meets these criteria.

If more than 200 fired hours have elapsed before the test, GE Energy shall have the right to inspect the turbine to determine the condition of the unit. If, at GE Energy's sole discretion, the subject unit is not in new and clean condition, appropriate action shall be taken to put the unit in new and clean condition. After 200 fired hours, degradation factors, for gross power and gross heat rate, may be applied.

B. Preparation

An off-line water wash is to be conducted on the unit, no more than 3-days prior to the scheduled performance test of initial unit.

Test instruments used for determinations shall be calibrated in accordance to the National Institute of Standards and Technology. GE Energy will provide calibration certificates for instruments brought to site for the performance test. GE Energy on package instrumentation providing signals to the unit's Turbine Control Panel will be checked and properly adjusted prior to testing. **NOTE:** Additional details of the instrument requirements are provided in *Table 1 –Accuracy of Required Instruments* at the end of this document.

C. Conduct of the Test

1. Definition of Test Boundary

The test boundary establishes the equipment to be included in the test. All input and output energy streams must be determined with reference to the point at which they cross the test boundary.

The test boundary for this test includes the Gas Turbine Generator and Control Limits.

2. **Determination of GTG Steady State Condition**
   Test data will be recorded only when the GTG is operating at a steady state base load condition as defined by the following parameters:
   - Compressor Inlet Temperature, T2 ±4.0°F
   - Barometric Pressure ±0.5%
   - Power Output ±2.0%

3. **Test Duration and Number of Data Sets**
   One test point will be conducted over a (50) *fifty-minute period.* A test point is defined as six complete sets of instrument readings recorded at (10) *ten-minute intervals.*

4. **Data Collection Methodology**
   Data collection methodology will be as follows:
   - One GE ENERGY Test Engineer who is responsible for supervising all aspects of the test.
   - GE ENERGY and Customer representatives will be responsible for recording the data that is being collected.
   - Personnel are to be provided by Customer to assist in logging manual data or collecting fuel samples.
   - One operator, representing Customer, will be responsible for operating the unit. The operator maybe assisted by GE ENERGY Controls Technician
   - Manually collected data: Designated personnel provided by both GE ENERGY and Customer will collect all test data manually.
   - Automated data collection: Aside from printed HMI screens, there is no other automated data collection associated with this test.
   - Data sampling frequency: A complete data set will be collected once every ten (10) minutes.

   The Customer and GE Energy representative will sign all data sheets at the completion of the test. The Customer will be provided with copies of all data sheets. GE Energy will retain the originals for use in preparing the official test report.

5. **Gas Fuel Analysis and Sampling**
   The owner will arrange for sampling and analysis of fuel. Analysis of fuel shall give composition of the natural gas in mole %, HHV, LHV (per ASTM D-1945), and specific gravity (per ASTM D-3588). See Appendix IV for analysis methods.

   Three (3) fuel samples are to be collected during the performance test. First sample at the beginning of the test, second sample approximately 25 minutes into the test, and the third sample at the conclusion of the test. Sample bottles are to be marked with the time, data, unit/sample number, and fuel temperature at time of test.

Two (2) of the three (3) samples are to be sealed, labeled and sent off for analysis by GE Energy. The third sample is to be held at the site until such time as the results of the analyzed samples are reviewed and deemed acceptable by GE Energy and Customer.

IV. INSTRUMENTS REQUIRED

Table 1 gives a general list of the test equipment, recommended accuracies, and parties responsible for supplying such equipment to conduct the performance test. GE will also provide the following equipment to supplement any equipment not supplied by the customer: power meter, barometer, psychrometer, inlet plenum manometer, and exhaust duct manometer.

A. Generator Power Output

Generator output shall be measured by a precision 3-phase wattmeter.

GE Energy furnished current transformers are certified to ±0.3% accuracy. A total kW monitoring system uncertainty of ±0.5% is attainable with this calibrated system.

B. Fuel Heat Input - Gaseous Fuels

The GTG package does not include a fuel meter. Fuel flow is measured via flow metering valves. The accuracy of the flow metering valves will not meet the required specification for performance test fuel measurement. Therefore the owner will need to provide a fuel-measuring device, which will have an accuracy of ±0.8% or better.

Pressure at the fuel gas meter is to be measured with a pressure transducer having ±0.25% accuracy. Temperature at the fuel gas meter is to be measured an accuracy of ±1°F. Flow is to be converted from Actual line conditions to Standard conditions. Compressibility of the fuel will be determined using the performance test fuel analysis.

C. Engine Inlet Air Conditions

Ambient Dry, and Wet Bulb are to be measured with a psychrometer shielded from direct sunlight. Relative Humidity is to be determined using a psychometric chart.

Compressor Inlet Temperature (T2) will be measured using the two RTDs located at the inlet of the compressor. Expected uncertainty relative to true mean engine inlet temperature is ±1.0 F.

Barometric pressure at the test site shall be measured with a barometer accurate to ±0.01 inches of mercury.

The engine inlet air relative humidity will be equivalent to the ambient relative humidity. If the inlet air to the unit is evaporative cooled, the engine inlet humidity shall then be determined using the ambient dry and wet bulb temperatures, the compressor inlet temperature and a psychometric chart. A total accuracy of ±0.001-inlet water/air ratio is expected.

Engine inlet pressure loss shall be measured with a slack tube manometer with one line installed on the calibration valve of the P0 pressure transmitter and the other open to atmosphere. A total accuracy of ±0.25 inches of water is assumed. Alternately, inlet pressure loss may be calculated by taking the difference of barometric pressure and the P0 value.

D. Engine Exhaust Static Pressure

For exhaust loss measurement a slack tube manometer will be utilized if a connection port is made available. The customer is responsible for supplying a ¼" test port connection for exhaust loss measurement. GE does not provide test ports between the turbine exhaust and exhaust stack, SCR, or boiler.

Engine exhaust static pressure shall be measured at the discharge of the engine exhaust collector upstream of any heat recovery, catalytic converter or sound attenuation equipment. A total accuracy of ±0.25 inches of water is assumed

Typically the measurements taken between the exhaust duct and stack will fluctuate greatly due to the short length of duct and turbulent flow. Due to the fluctuating reading, an accurate exhaust loss reading may not be achievable. Should this be the case, the design value for exhaust loss will be used.

V. ENGINE LIMIT ASSESSMENT

The following Unit Control Limit Parameters are to be recorded during the performance test for engine limit assessment:

- High Pressure Rotor speed, XN25
- Compressor Discharge Pressure, PS3
- Compressor Discharge Temperature, T3
- Low Pressure Turbine Inlet Temperature, T48

VI. TEST EXECUTION

The GE ENERGY Performance Engineer has the overall responsibility for starting and stopping test, for directing plant operation and the test personnel, and for all other aspects of the test execution. However, the test director may not deviate from the test plan without prior mutual agreement by all parties to the test.

A. Unit Operating Conditions

1. **Permissible Mode of Unit Control:**
   All Unit components will be operating within the respective manufacturer's specified continuous operating limits at base load. Test data will be recorded only when GTG is at base load and at a control limit (T3, PS3, and/or T48), and all test instrumentation are functioning satisfactory and in steady state condition for at lease 30 minutes prior to testing. Please Note: If unit is in XNSD control, MW Limit Control, and/or Maximum or Minimum Fuel Control, then the performance test will not be conducted.

2. **Operating Status of GTG Package Auxiliary Loads:**
   The test should be conducted with normal auxiliary package service loads in operation. All GTG Package Auxiliary and BOP equipment loads are to be excluded from the test.

3. **Emissions:**
   Combustion Mapping must be completed prior to the performance test to insure the GTG meets the guarantee emission requirements. The performance test will not be conducted if emissions are in excess of the guaranteed limits.

B. Permissible Variable Deviations During Test Runs

1. **Typical Performance Test Restart Situation:**
   Any deviation outside of the following limits will require at restart of the performance test from that point forward until a complete 50-minute test has been completed and the permissible variable deviations are with in the limits listed.
   - Compressor Inlet Temperature ±4.0°F
   - Barometric Pressure ±0.5%
   - Power Output ±2.0%

2. **Typical Performance Test Abort Situation:**
   - SPRINT must be online for the performance test, if SPRINT flow goes offline during the performance test, then the test will be aborted.
   - The unit must be at base load with all systems operating (Inlet Heater if required, Inlet Chiller if applicable, gas compressors if required, etc...). If any of these systems go offline during the performance test, the test will be aborted.
   - If the unit trips offline for any reason, then the test will be aborted.
   - Unit goes into Maximum or Minimum Fuel Control.

The performance test will be restarted as soon as the problem leading up to the abort situation is rectified.

VII. EVALUATION OF TEST RESULTS

The Gas Turbine Generators are designed and guaranteed to produce a certain output with a certain heat rate for a given set of ambient and operating conditions. As the ambient conditions deviate from the design values, the actual performance of the GTG changes. The ambient conditions at the time of testing are likely to be different from the values stated in the basis of guarantee. To account for these deviations from design ambient conditions, site-specific correction will be applied to the raw data to derive equivalent design condition results.

A. Methodology for Data Reduction

Procedure to be used in the calculation of corrected results:

Where,
Gross Corrected Power = Measured Power at GT Generator Terminals Corrected for the Parameters Listed Appendix II, Section A

Gross Corrected Heat Rate = Calculated Heat Rate Corrected for the Parameters Listed Appendix II, Section A

B. Method and criteria for evaluation of test results with regard to guaranteed performance

GE ENERGY will evaluate test data once test fuel analyses are received. Test data correction is performed in accordance with this document along with site specific correction curves.

When compliance decisions are required based on the test, the parties involved must recognize the total tolerance due to measurement uncertainties associated with each particular test result.

Each measured test parameter's tolerance is defined as twice the estimated standard deviation (2 sigma). The uncertainty in the compliance parameter resulting from this tolerance is calculated for each measured test parameter. These uncertainties are then combined by root-sum-square analysis to obtain the total uncertainty for that compliance parameter. *Table 2* illustrates typical uncertainty calculations. The unit will be considered acceptable when the corrected test results are equal or better than the guaranteed value with allowance for test uncertainty.

A full test report will be issued to the customer two weeks after the fuel analysis has been received.

Table 1: Accuracy of Required Instruments

Instruments	Customer	GE ENERGY	Recommended
Dry Engine Operation			
Recording wattmeter	X		±0.5%
Potential transformers	X		±0.3%
Current transformers		X	±0.3%
GT thermocouple system		X	±3.0°F
Primary fuel gas meter	X		±0.8 %
Fuel gas sampling device	X		Lab
Fuel gas pressure sensor	X		±0.25%
Fuel gas temperature sensor	X		±1.0°F
Engine inlet temperature (2)		X	±1.°F
Ambient air thermocouples	X		±1.°F
Barometer	X		±0.015 in Hg.
Ambient air psychrometer	X		±1.°F
Inlet plenum manometer	X		±0.25in. H2O
Exhaust duct manometers	X		±0.25in. H2O

Table 2: Instrument Uncertainty

VARIABLE	UNITS	UNC	Ni	RSC	Fi^2	RSS
POWER AT TEST						
CONDITIONS						
WATT-HOUR METER	%	0.5	1	1	0.2500	
PTs	%	0.3	3	1	0.0300	
CTs	%	0.3	3	1	0.0300	
MEASURED POWER UNC					0.3100	0.5568
CORRECTED POWER						
MEASURED POWER					0.3100	
COMP INLET TEMP	°F	1	2	0.303	0.0459	
BAROMETER	PSIA	0.007	1	0.043	0.0000	
INLET LOSS	inH20	0.25	1	0.086	0.0005	
EXHAUST LOSS	inH20	0.25	1	0.025	0.0000	
SPEC. HUMIDITY	lb/lb	0.001	1	0.092	0.0000	
CONTROL TEMP	°F	2.00	8	0.237	0.0281	
CORRECTED POWER UNC					0.3845	**0.6201**
HEAT RATE (GAS FUEL)						
AT TEST CONDITIONS						
FLOW METER	%	0.50	1	1	0.2500	
FUEL TEMP	%	0.20	1	1	0.0400	
FUEL PRESSURE	%	0.25	1	1	0.0625	
FUEL ANALYSIS	%	0.50	1	1	0.2500	
MEASURED POWER	%				0.3100	
MEASURED HEAT RATE UNC					0.9125	0.9552
CORRECT HEAT RATE						
MEASURED HEAT RATE					0.9125	
COMP INLET TEMP	°F	1	2	0.055	0.0015	
BAROMETER	PSIA	0.007	1	0.006	0.0000	
INLET LOSS	inH20	0.25	1	0.027	0.0000	
EXHAUST LOSS	inH20	0.25	1	0.021	0.00	
SPEC. HUMIDITY	lb/lb	0.001	1	0.050	0.0000	
CORRECT HEAT RATE UNC					0.9141	**0.9561**

Legend - UNC = measurement uncertainty; Ni = number of instruments; RSCi = sensitivity coefficient; Fi = (RSCi * UNCi/sqrtNi)^2; RSS = Root sum square