MITSUBISHI POWER

Gas Fuel Specification for DLN Combustor Application

STANDARD DOCUMENT

IBSTD-10007B R10.0

Not to be used for construction.
Some modification will be considered on detail engineering stage.

GAS FUEL SPECIFICATION for DLN COMBUSTOR APPLICATION

1. INTRODUCTION

This specification applies to natural gas fired gas turbines equipped with DLN (Dry Low NOx) combustors.

Historically, natural gas has been the primary gaseous fuel burned in gas turbines. Its clean burning characteristics and availability make it an ideal fuel for such applications.

The DLN combustor is designed to suit natural gas firing with low NOx emissions without water or steam injection. Many kinds of natural gas with widely varying chemical contents have been successfully used in our gas turbines.

The following specification discusses limitations and restrictions associated with DLN combustors so that the best application can be realized for the user. If any limits and/or restrictions described in this fuel specification are not satisfied, please consult us.

2. COMPONENT

In order to maintain stable combustion, natural gas fuel constituents should meet the requirements as outlined below.

2.1 Methane

Methane content in the natural gas after subtraction of inert gases is in the range of 80 to 98%mol.

Once a gas is defined for a specific application and the combustor is tuned, the variation of methane content in the natural gas after subtraction of inert gases should not exceed ±9%. It is necessary to adjust the combustion tuning if the methane content is outside the variation range of ±9% from the tuned point.

2.2 Inert gases

Inert gas content, typically nitrogen and carbon dioxide in the natural gas should not exceed more than 4%mol because inert gas content can affect the location of the combustion flame and the characteristics of combustion may be changed.

2.3 Hydrogen

Since the physical properties of hydrogen greatly differ from that of natural gas, special technical considerations are required when hydrogen is present in the fuel.

Dry low NOx capability to mix up to 30vol% of hydrogen in natural gas has been demonstrated in support of decades-long experience with high hydrogen content by-product gases. DLN combustors for up to 100% hydrogen operation are being modified.

If hydrogen is present in the fuel gas, please consult us for analysis and confirmation of the GT's ability to accept the fuel.

3. HEAT CONTENT

In order to determine the system handling capability, the heating value and specific gravity are characteristics which must be considered.

They are combined in a convenient term called "Gas Index" (equivalent to Wobbe Index).

Gas Index (GI) is defined as the ratio of the lower heating value (LHV) of the fuel to the square root of specific gravity.

$$GI = \frac{LHVvol}{\sqrt{S.G.}}$$

where

LHVvol is actual lower heating value in kJ/m^{3}N [Btu/Scf]

$$S.G. = \frac{Density\ of\ gas\ (Standard\ conditions)}{Density\ of\ air\ (Standard\ conditions)}$$

As an example for typical natural gas;

LHVvol = 35,500 kJ/m^{3}N [900 Btu/Scf]

S.G. = 0.6 [dimensionless]

GI = 45,830 kJ/m^{3}N [1,162 Btu/Scf]

From a control point of view, once a gas is defined for a specific application, the variation in calculated GI should not exceed ±5% of the design value.

If above limits are not satisfied, please consult us.

GI change rate shall not exceed 5% per minute.

4. PRESSURE

Depending upon unit frame size, minimum ambient temperature, elevation and applied fuels, the minimum required pressure level is 2.8 to 5MPag [400 to 730 psig] at the inlet of GT package. For specific pressure requirements, please consult us.

Once the pressure at the terminal point is determined, the following operating conditions shall be met for the gas turbine operation modes as specified in Figure 1.

(1) Pressure fluctuation range shall be restricted within ±0.14 MPa [21 psi].

(2) Speed of pressure variation shall not exceed 0.08 MPa [11 psi] per second.

(3) Peak to peak amplitude of pressure vibration with more than 10Hz frequency shall not exceed 0.001 MPa [0.14 psi] continuously for 2 seconds. If a reciprocating gas compressor is used, proper dampening equipment must be installed to reduce pressure vibrations to acceptable levels.

When a gas compressor will be installed, a centrifugal type compressor is recommended.

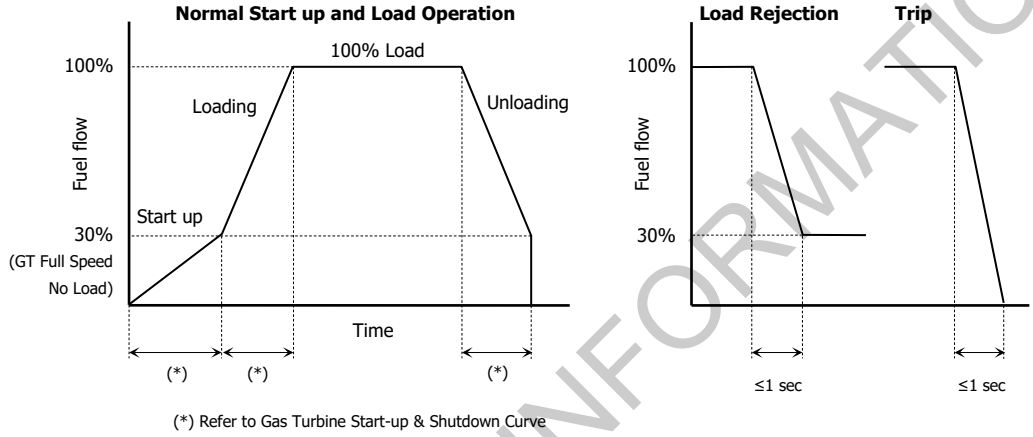

Figure 1 Gas Turbine Operation Modes

5. CONDENSABLE LIQUIDS

The fuel gas fed to the nozzles of the combustion system must contain no constituents in the liquid state. The constituent having the highest saturation temperature must have at least 11°C [20°F] superheat. Minor traces of heavier liquid hydrocarbons that might be carried over from the source of fuel supply should be removed from the fuel system. This carryover of liquid can usually be prevented by traps and heaters in the fuel supply line.

Minimum fuel gas supply temperature is recommended to be higher than 5°C [41°F] to prevent icing of fuel gas piping and associated equipment.

It is the customer's responsibility to insure that no liquid hydrocarbons are present in the gas as it is delivered to the gas turbine. Liquid carry-over can be detrimental to the life of various engine parts. Liquids can be removed by knockout scrubbers followed by separators and heaters. In order to prevent the accumulation of liquid in long pipes between the gas conditioning equipment and the physical arrangement, a "last chance" separator near the gas turbine is also recommended. Proper liquid level alarms and shutdown protection are also recommended.

6. SOLID PARTICLES

Solid particles should be limited to prevent erosion, deposition, and plugging of the fuel gas nozzles and gas turbine hot gas-path. Solid particles in the fuel gas as fed to the nozzles of the combustion system shall be limited to a maximum concentration of 30 ppmwt with up to 5 μm size. And the size of all solid particles shall not exceed 5 μm.

For this requirement 99.5%wt of all particles and 100% of all particles larger than 5 μm shall be removed by the filters supplied by the EPC contractor before delivery to the gas turbine.

It is important that the total solid particle content of the fuel gas is summed and the limits specified. Solid particles are typically composed of sand, rust, tar, iron and silica (SiO_2), etc.

Table 1 Solid Particle (Summary)

Total particle, maximum	30 ppmwt (on fuel weight basis)
Maximum particle size	5 μm

7. NITROGEN (FBN) CONTENT

Fuel bound nitrogen (FBN) causes to increase NOx formation in addition to the standard (thermal) NOx formed by the reaction between oxygen and nitrogen in the flame zone. Therefore in the event that there is FBN in the fuel gas, the guaranteed NOx level will be increased accordingly. To maintain low NOx emission, 0% FBN content in fuel gas is preferred.

8. OIL MIST AND VAPOR CONTENT

To prevent fuel nozzle clogging and unstable firing, the fuel gas utilized shall be oil free. If reciprocating gas compressor or screw type compressor is used, please consult us.

9. SULFUR CONTENT

The total sulfur in the fuel (from hydrogen sulfide (H2S) plus other sulfur compounds) is limited to 0.5 %wt (0.2%mol as H2S) maximum to avoid corrosion of the turbine hot section parts.

Note that guidelines above are limited to the gas turbine hot section parts.

The sulfur limitation will change based on the equipment configuration. Refer to relevant documentation for sulfur constraints imposed by other equipment (e.g. ,fuel gas system, HRSG, etc.).

Sulfur levels in excess of the recommended limitation can be tolerated as sour gas with special fuel system components. If the sulfur is contained in fuel gas, please consult us.

10. COMPOUNDS REQUIRING ADDITIONAL CONSIDERATION

There are some components in fuel gas which can generate a gum type matter that can cause nozzle clogging issues. These components have been identified below, but it is difficult to define the specific/individual limitations. The below guide line of the limitation of these components which will cause a clogging problem is based on our experience.

Table 2 Compounds requiring additional consideration

Butadiene, C_4H_6	< 1 ppmv
Styrene, C_8H_8	< 1 ppmv
NOx	< 0.5 ppmv
Inden, C_9H_8	< 1 ppmv
Cyclopentane, C_5H_{10}	< 1 ppmv
Benzene, C_6H_6	< 1 ppmv
Naphthalene, $C_{10}H_8$	< 50 mg/m^{3}N
Tar	< 1 mg/m^{3}N
BTX (Benzene, toluene and xylene)	< 1 mg/m^{3}N (Note)

Generally, the above components are not present in natural gas and/or LNG.

Note: If fuel includes BTX more than the criteria, please consult us.

11. TRACE METALS

Total trace elements in the fuel, water and inlet air flow shall not exceed our fuel specification requirements.

Trace metals can cause high temperature corrosion to the gas turbine hot parts. As a result more frequent combustor/turbine inspections and cleaning will be required.

Specifically, the combined total quantity of elements in the fuel, water and air must not exceed the following on a fuel weight basis:

Table 3 Trace Metals

Trace Metals	Per Million Parts of Fuel by Weight	Notes
Sodium, Na & potassium, K	0.5 ppmwt (0.3 ppmwt)	If 0.5ppmwt or greater, please consult us. (0.3ppmwt for latest F, G and J class)
Vanadium, V	0.5 ppmwt	
Lead, Pb	2.0 ppmwt	
Calcium, Ca	10 ppmwt	
Other trace metals	2.0 ppmwt	Zinc (Zn), barium (Ba), manganese (Mn), phosphorus (P), aluminum (Al), etc.

12. INLET AIR CONTAMINANTS

The compressor inlet air can have a large effect on the level of impurities entering the hot gas-path. To determine the extent of contamination, the air to fuel mass flow ratio is multiplied by the air contaminant level in ppmwt to obtain the contaminant concentration on an assumed fuel equivalent basis.

For example 10 ppbwt of sodium in the inlet air is equivalent to approximately 0.5 ppmwt sodium in the fuel on a weight basis.

13. WATER-BORNE CONTAMINANTS

Water employed for emissions control (i.e. water injection) and/or compressor cleaning can also increase the level of impurities entering the hot gas-path. Calculation of waterborne contaminants on an assumed fuel equivalent basis is accomplished in the same manner as illustrated for air borne contaminants.

In general, water injection quality standards for the gas turbines are stated as follows.

If levels of impurities exceed these limits, please consult us with regard to water purification systems.

(1) Reactive Dissolved Solids

Table 4 Reactive Dissolved Solids

Silicon, Si	18 ppmwt
Chlorides, Cl	6 ppmwt
Iron, Fe & Copper, Cu	0.1 ppmwt
Oxygen, O_2 (as determined by O2 saturated water)	2 to 9 ppmwt
pH	7.5 to 8.0

Note: Demineralized water is required.

(2) Total Dissolved Solids

Other solids not detected and present on the analysis above are assumed to turn to oxides in the combustion process and results in additional emissions at the exhaust stack. The quantity of dissolved solids is considered to be doubled due to oxidation in the combustion process and is exhausted as particulate. The quantity of solids in water and fuel is thus limited by local regulations.

Table 5 Total Dissolved Solids

Approximate total dissolved solids	90 ppmwt

14. Fuel, Air and Water Evaluation

Prior to burning gaseous fuels in the gas turbines, it is recommended that the customers submit gas fuel analysis for our review and recommendation. The fuel, air and water analysis should cover all requirements as specified in this specification.

Where analytical services are not available to the customer, services can be purchased from us.

The following will be reported;

(1) Water analysis ····· See Appendix I

(2) Fuel analysis ····· See Appendix II

(3) Air analysis ····· See Appendix III

APPENDIX I

Water Analysis

(1) Contaminants

		ppmwt
Sodium, Na	:	
Potassium, K	:	
Vanadium, V	:	
Calcium, Ca	:	
Lead, Pb	:	
Other metals (over 2 ppmwt)		

(2) Reactive Dissolved Solids

Silicon, Si	:	
Chlorides, Cl	:	
Iron, Fe and copper, Cu	:	
Oxygen, O_2 (as determined by O_2 saturated water)	:	

(3) Total Dissolved Solids

Dissolved solids	:	

APPENDIX II

Gas Fuel Analysis

(1) Chemical Analysis, as per ASTM D1945

		Mole percent
Hydrogen, H_2	:	
Helium, He	:	
Nitrogen, N_2	:	
Carbon dioxide, CO_2	:	
Methane, CH_4	:	
Ethane, C_2H_6	:	
Propane, C_3H_8	:	
Butane, C_4H_{10}	:	
Pentane, C_5H_{12}	:	
Carbon monoxide, CO	:	
Water vapor, H_2O (per ASTM D1142)	:	
Total sulfur, S	:	
Other	:	
Molecular weight	:	

(2) Heating Value

		kJ/m^{3}N	kJ/kg
Gross (Higher) heating value	:		
Net (Lower) heating value	:		

(3) Contaminants

		Mole percent
Hydrogen sulfide, H_2S	:	
Ammonia, NH_3	:	
Carbonyl sulfide, COS	:	
Condensable liquids	:	
Solids		
Amount	:	
Particle size range (μm)	:	
Other	:	

(4) Terminal Conditions

		Maximum	Minimum
Pressure range, MPag	:		
Temperature range, °C	:		

(5) Physical Properties

Specific gravity@15°C	:	
Critical pressure, MPag	:	
Critical temperature, °C	:	
Dew point, °C	:	

(6) Compounds Requiring Additional Consideration

		ppmv
Butadiene, C_4H_6	:	
Styrene, C_8H_8	:	
NOx	:	
Inden, C_9H_8	:	
Cyclopentane, C_5H_{10}	:	
Benzene, C_6H_6	:	
		mg/m^{3}N
Naphthalene, $C_{10}H_8$	:	
Tar	:	
BTX (Benzene, toluene and xylene)	:	

(7) Trace Metals

		ppmwt
Sodium, Na	:	
Potassium, K	:	
Vanadium, V	:	
Calcium, Ca	:	
Lead, Pb	:	
Other metals (over 2 ppmwt)	:	

APPENDIX III

Compressor Inlet Air Analysis

Contaminants

		ppmwt
Sodium, Na	:	
Potassium, K	:	
Vanadium, V	:	
Calcium, Ca	:	
Lead, Pb	:	
Other metals (over 2 ppmwt)	:	