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GE Energy

Process Specification Fuel Gases For Combustion In AeroDerivative Gas Turbines

These instructions do not purport to cover all details or variations in equipment or to provide for every possible contingency to be met in connection with installation, operation or maintenance. Should further information be desired or should particular problems arise which are not covered sufficiently for the purchaser's purposes the matter should be referred to the GE Company.

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TABLE OF CONTENTS

1	GENERAL	1
2	FUEL GAS CLASSIFICATION	3
2.1	Natural and Liquefied Petroleum Gas (LPG)	3
2.2	Gasification Fuels	3
2.3	Process Gases	4
2.4	Refinery Gases	5
3	FUEL PROPERTIES	5
3.1	Heating Values	5
3.2	Modified Wobbe Index Range	5
3.3	Superheat Requirement	6
3.4	Flammability Ratio	6
3.5	Gas Constituent Limits	6
3.6	Gas Fuel Supply Pressure	6
4	CONTAMINANTS	6
4.1	Particulate	7
4.2	Liquids	7
4.3	Sulfur	7
Appendix 1	DEFINITIONS	9

LIST OF TABLES

Table 1.	Fuel Gas Usability	1
Table 2.	Test Methods for Gaseous Fuels	2

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 USABILITY						
Fuel Type	LHV Btu/SCF (kJ/NM³)	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:

- 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.
- 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.

NM³ 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/NM³) (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/NM³) (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/NM³). The Hydrogen (H₂) content of these fuels is normally above 30% by volume and have H₂/CO mole ratio between 0.5 to 0.8. Oxygen blown gasification fuels are often mixed with steam for thermal NO_x 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/NM³) LHV. The Hydrogen (H₂) content of these fuels can range from 8% to 20% by volume and have a H₂/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 NO_x 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 and 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 consist 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 H₂ and H₄C 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 H₂ 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:

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

This is equivalent to:

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

Where:

- LHV = Lower Heating Value of the Gas Fuel (Btu/scf)
- SG_{gas} = Specific Gravity of the Gas Fuel relative to Air
- MW_{gas} = 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 $\pm 10\%$ 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:

$$\begin{array}{rcl}
 \text{ppm sodium inlet air} \times \text{Air/Fuel Ratio} & = & \\
 \text{ppm sodium in water or steam} \times & & \\
 \quad \frac{\text{Water or Steam}}{\text{Fuel}} \text{ ratio} & = & \\
 \text{ppm sodium in fuel} & = & \\
 \text{Total fuel equivalence for sodium from all} & \text{_____} & \\
 \text{sources not to exceed} & 0.2 \text{ ppm} &
 \end{array}$$

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 HRSG supplier for additional information.

4.3.3 Selective Catalytic Reduction (SCR) Deposition

Units utilizing ammonia injection downstream of the gas turbine for NO_x 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.