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GE Power Systems

Gas Turbine Liquid Fuel Specifications

These instructions do not purport to cover all details or variations in equipment nor 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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I. GENERAL

This specification is for the several types of liquid fuels suitable for use in the General Electric heavy duty gas turbines with firing temperatures of 1600°F (870°C) or higher. It is intended as a guide for users of these turbines for the procurement, use, and where necessary, treatment of fuels.

The fuel properties specified herein include both those which could affect turbine operation and those additional properties which the turbine user may need to specify for his installation. These latter properties are related to fuel storage and handling and local safety and environmental codes.

All of the fuels covered in this specification shall be hydrocarbon oils free from organic acids and free from excessive amounts of solid, fibrous or other foreign matter likely to make frequent cleaning of suitable filters necessary. The fuels shall be stable over storage and shall be compatible with other fuels with which they could normally be mixed.

Procurement of the fuel to specifications is only the first step to successful heavy duty gas turbine operation. Further steps required of the user are: (a) prevention of contamination before, during, and after delivery, (b) proper design of fuel storage, heating and transfer facilities, (c) proper management of the entire facilities with regard to maintenance procedures and schedules and (d) proper design and operation of any fuel treatment equipment.

In addition to outlining the overall fuel requirements, this specification also defines minimum acceptable air quality standards for turbine inlet air, and water requirements for installations which employ either steam or water injection in their cycles. These have been included since the total contaminants entering the turbine must be considered.

II. FUEL CLASSIFICATION AND OPERATIONAL CONSIDERATIONS

Liquid fuels applicable to heavy duty gas turbines range from petroleum naphthas to residual fuels. Within this range, fuels vary in hydrocarbon composition, physical properties, potential pollutants and trace metal contaminant levels. Since contaminants are a most important consideration in fuel application, the liquid fuels have been divided into two basic classes: true distillates (ash-free) and ash-bearing fuels.

Table 1 summarizes the general types of liquid fuels in these two classes and some operational requirements in gas turbine applications. Refer to Appendix A for common names and characteristics of specific fuels within each general type.

III. FUEL SPECIFICATIONS

The required physical and chemical properties of the four classes of liquid fuels are detailed in Table 2. These properties have been divided into two categories: those required for gas turbine performance (Section 3.1, Table 2) and those which may be limited to meet local environmental codes (Section 3.2, Table 2).

Maximum allowable limits are specified for five critical trace metal contaminants: sodium, potassium, vanadium, lead and calcium. General Electric heavy duty gas turbines will operate at levels higher than those specified in Table 2; however, increased maintenance of hot gas path parts may result. Therefore, it is required that the General Electric Gas Turbine Division be consulted for fuel treatment recommendations when the analysis of the fuel as delivered to the gas turbines exceeds the levels indicated. Fuels outside of the specified limits of certain physical properties may also be used, but General Electric should be consulted for consideration of any impact on the operation of the turbine or fuel treatment system, where required.

The Ash-Bearing Fuels in Table 2 are divided into two types: 1) Crudes and Blended Residual Fuels, and 2) Heavier Residual Fuels. The heavy-duty gas turbine will operate satisfactorily on both types, although fuel treating and heating requirements and stack particulate emission levels will generally be less for the first type (Crudes and Blended Residual Fuels).

Table 1 - Comparison of Liquid Fuels and Some Hardware Requirements				
	True Distillates		Ash-Bearing Fuels	
Fuel Type	Light	Heavy Blended Residual Fuels	Crudes and Blended Residual Fuels	Heavier Residual Fuels
General Properties Ash Content Viscosity Volatility	Trace Low High/Medium	Trace Medium Medium	Low/Medium Wide Range Wide Range	High High Low
Nearest ASTM Type* Gas Turb., D2880 Burner, D396 Diesel, D975	0-GT, 1-GT 2-GT 1, 2 1-D, 2-D	3-GT (4) (4-D)	3-GT 4, 5 4-D	4-GT 6 —
Explosion-Proofing	Refer to applicable codes	Refer to applicable codes	Refer to applicable codes	Refer to applicable codes
Start-Up Fuel Required	With very light fuels	Some fuels	Nearly always	Always
Fuel Pretreatment	Usually none	Usually none	Nearly always	Always
Fuel Preheating	Some in cold locations	Nearly always	Nearly always	Always
Fuel Filtration	Always	Always	Always	Always
Fuel Combustion Atomization	Low pressure air	Low pressure air	Low or high pressure air	High pressure air
Combustor	Standard fuel	Standard fuel	Heavy fuel	Heavy fuel
Turbine Cleaning Capability	Not Required	Not Required	Required	Required
* <i>Book of ASTM Standards, parts 23 and 24</i> Note: The considerations listed in this table are not all-inclusive.				

Table 2 - Liquid Fuel Specifications

Appli- cability	Property	Point of Applica- bility (a)	ASTM Test Method (c)	True Distillates (b)		Ash-Bearing Fuels (b)	
				Light	Heavy	Crudes and Blended Residual Fuels	Heavier Residu- al Fuels
3.1 Gas Turbine Require- ments	Kin. Viscosity, cSt, 100°F (37.8°C), min	Delivery	D445	.5(d)	1.8	1.8	1.8
	Kin. Viscosity, cSt, 100°F (37.8°C), max (e)	Delivery	D445	5.8	30	160	900
	Kin. Viscosity, cSt, 210°F (98.9°C), max (e)	Delivery	D445	—	4	13	30
	Specific Gravity, 60°F (15.6°C), max	Delivery	D1298	Report	Report	.96	.96(f)
	Flash Point, °F(°C), min (g)	Delivery	D93	Report	Report	Report	Report
	Distillation Temp. 90% Point, °F(°C), max	Delivery	D86	650(338)	Report	—	—
	Pour Point, °F(°C), max	Delivery	D97	0 (-18) or 20 (7) below min. ambient	Report	Report	Report
	Hydrogen, Wt %, min (k)	Delivery	(i)	Report	Report	Report	Report
	Carbon Residue, Wt. % (10% Bottoms) max Direct Pressure Atomization	Delivery	D524	.25	—	—	—
	Carbon Residue, Wt. % (100% Sample) max Air Atomization, Low Pressure	Delivery	D524	1.0	1.0	1.0	—
	Carbon Residue, Wt. % (100% Sample), Air Atomization, High Pressure	Delivery	D524	—	—	Report	Report
	Ash, ppm, max	Combustor	D482	50	50	Report	Report
	Trace Metal Contaminants, ppm, max (h)	Combustor	(i)				
	Sodium plus Potassium			1	1	1	1
	Lead			1	1	1	1
	Vanadium (untreated)			.5	.5	.5	.5
	Vanadium (treated 3/1 wt. ratio Mg/V)			—	—	100	500
	Calcium			2	2	10	10
	Other Trace Metals above 5 ppm			Report	Report	Report	Report
The specifications below apply only when specific environmental codes exist							
3.2 En- viron- mental Code Related Require- ments	Sulfur, Wt. %, max	Delivery	D129	Compliance to any applicable codes. Fuel-bound nitrogen may be limited to meet any applicable codes on total NO _x emission.			
	Nitrogen, Wt. %, max	Delivery	(i)				
	Hydrogen, Wt. %, min.	Delivery	(i)	Minimum hydrogen level may be necessary to meet any applicable stack plume opacity limits (k).			
	Ash plus Vanadium, ppm, max.	Delivery	(i)	Ash plus vanadium content of ash-bearing fuels may be limited to meet applicable stack particulate emission codes (l).			

NOTES TO TABLE 2

- a. The fuel properties specified refer to the fuel at different points in the overall system:
Delivery — Fuel as delivered to the turbine site.
Fuel Skid — Fuel at inlet of fuel skid at turbine.
Combustor — Fuel at turbine combustors.
- b. Typical fuels within each general type are discussed in Appendix A.
- c. ASTM Book of Standards, Parts 23 and 24.
- d. In the viscosity range of 0.5 cSt to 1.8 cSt, special fuel pumping equipment may be required.
- e. The maximum allowable viscosity at the fuel nozzle is 20 cSt for high pressure air atomization and 10 cSt for low pressure air and direct pressure atomization. The fuel may have to be pre-heated to reach this viscosity, but in no instance shall it be heated above 275°F (135°C). (This maximum fuel temperature of 275°F is allowed only with residual fuels.) The viscosity of the fuel at initial light-off must be at or below 10 cSt.
- f. A specific gravity of 0.96 is based on average fuel desalting capability with standard washing systems. Fuels with specific gravities greater than 0.96 may be desalted to the required minimum sodium plus potassium limits by using higher capability desalting equipment (with higher attendant cost) or by increasing the gravity difference between the fuel and wash water by blending the fuel with a compatible distillate.
- g. The fuel must comply to all applicable codes for flash point.
- h. A total ash less than 3 ppm is acceptable in place of trace metal analysis.
- i. No standard reference tests exist; methods used should be mutually acceptable to General Electric and the user.
- j. Water content of crude oils should be reduced to the lowest level practical consistent with capability of available fuel treatment equipment, to minimize the chance of corrosion of fuel system components. In no case shall the water content exceed 1.0 vol. %.
- k. A minimum hydrogen content is set both to control flame radiation in the combustor and to limit smoke emissions, where the latter is required by local codes. The limits are 12.0% minimum for true distillates and 11.0% for Ash-bearing fuels (11.3% where the carbon residue exceeds 3.5%). In each case it is assumed that the proper combustor and fuel atomization system are used.

Where the hydrogen content of the fuel is below these limits, General Electric should be consulted for appropriate action.

- l. Local codes on total stack particulate emissions may set an upper limit on the sum of the ash (non-filterable) in the original fuel plus the vanadium content. The vanadium together with the required magnesium inhibitor may be a major contributor to total stack particulate emissions. In estimating these emissions for comparison with the code, all of the following sources may have to be considered: vanadium, additives, fuel ash and total sulfur in the fuel; non-combustible particulates in the inlet air; solids from any injected steam or water; and particles from in-

complete fuel combustion. Where an estimate of stack particulate emissions is required, General Electric should be consulted.

IV. FUEL HANDLING AND TREATMENT

A. True Distillate Fuels

Light true distillate fuels normally have sufficiently low pour points that preheating is not required under most ambient conditions. Heavy true distillates, on the other hand, may have high pour points due to high wax content or high wax melting temperature which make preheating necessary to prevent filter plugging. Both types of distillates may also require preheating to meet the viscosity requirement at the fuel nozzle for proper atomization.

True distillate fuels as refined have low water, dirt and trace metal contaminant levels. Where subsequent transportation, handling and storage are carefully managed, these low levels should persist at the gas turbine. In locations where there is danger of contamination such as salt bearing water, auxiliary fuel clean-up equipment should be provided to restore the original quality.

In addition to potential hot corrosion from salt in water, water accumulated at the bottom of a storage tank can also cause problems. Micro-organisms tend to grow at the water-fuel interface generating both chemicals corrosive to metals in the fuel system and also slime which can plug fuel filters.

Adequate fuel storage and handling practices must be employed to minimize water and other contaminants in the fuel. These include settling the fuel before use, providing floating suction and periodic removal of water from the bottom of the tank. In applications where adequate settling periods can not be accommodated, more rapid purification methods may be required. Available purification equipment includes centrifuges and electrostatic dehydrators. The overall fuel system design should avoid slugs of water, and any clean-up system should have the capability to remove such slugs.

B. Ash-Bearing Fuels

Depending on the physical properties and the trace metal contaminant levels of these fuels, functions of the source and refinery treatment, they usually require pretreatment before burning in a gas turbine. Three basic steps in pretreatment are:

1. Preheating
2. Water washing for salt removal
3. Vanadium inhibitor addition

Preheating is used where it is necessary to: 1) raise the fuel temperature sufficiently above its pour point to allow free flow and to prevent filter plugging, and 2) to lower the fuel viscosity to reduce the flow resistance and to provide proper atomization at the fuel nozzles.

Desalting by water washing will be necessary with some crude oils and is nearly always necessary with residual oils to reduce the sodium plus potassium levels. Sodium and potassium can cause hot corrosion of the turbine blading by sulfidation attack at the operating temperatures of the turbine. Sodium and potassium can also contribute to turbine fouling. Desalting is accomplished by mixing the fuel with 3% to 10% potable water to extract the soluble salts, followed by separation of the salt-laden water by cen-

trifugation or electrostatic coalescence. Washing also removes some of the calcium depending on the specific chemical nature of the calcium compounds. Lead is not removed by water washing.

Vanadium can also cause hot corrosion of the turbine blading, but it is not removed by water washing because it is present in the fuel in a complex oil-soluble form. The corrosive action can be inhibited by adding an approved magnesium additive to the fuel to provide a minimum 3 to 1 weight ratio of magnesium to vanadium. It is also recommended that this ratio not exceed 3.5 to 1 in order to minimize deposition.

Periodic cleaning of deposits from turbine hot gas path section is generally necessary when high ash content fuels are used. Cyclic operation of the turbine may remove some the deposit by thermal shock. General Electric should be consulted for approved cleaning agents, water quality and cleaning procedures for those applications where turbine cleaning is required.

V. NON-FUEL CONTAMINANTS

A. Air-Borne Contaminants

Contaminants in air can cause erosion, corrosion and fouling of the compressor. These contaminants can also contain the same trace metals as found in fuels and which cause corrosion to the hot section.

Compressor erosion can be caused by sand or flyash; compressor corrosion by noxious fumes such as HCl or H₂SO₄; compressor fouling by liquid or solid particles which adhere to the compressor blading. Hot section corrosion can be caused by sodium from, e.g., sea salt, salt particles, carry-over of treatment chemicals used in evaporative coolers, chemical process effluents; potassium from flyash or fertilizers; lead from automobile exhausts; and vanadium from residual fuel fired steam plants.

Specifically, with respect to hot section corrosion, the total of Na, K, V and Pb should not exceed 0.005 ppm by weight in air. If it is anticipated that this level will be exceeded, General Electric should be consulted for recommendations on the selection and use of proper air filtration equipment.

B. Water-Borne Contaminants

Water or steam that is used for NO_x control or steam that is injected to augment output should not contain impurities which cause hot section deterioration or deposits. Specifically, the total of Na + K + V + Pb should not exceed 0.5 ppm by weight in the water or steam. If the total of these contaminants exceeds this level, General Electric should be consulted with respect to water or steam purification equipment and procedures.

In the case where contaminants are present in water or steam the total limits in the fuel should be controlled such that the total concentration equivalent in the fuel (from both sources) conforms to the limits in Table 2.

Refer to the next section 5.3 for the method for calculating the equivalent concentration in the fuel.

C. Non-Fuel Contaminant Relationships

The total contaminant level in the combustion products must be controlled. The following relationship can be used to convert the contaminants in air, steam/water and fuel to equivalent contaminants in the fuel alone, assuming all are equally effective:

$$\left(\frac{A}{F}\right) X_A + \left(\frac{S}{F}\right) X_S + X_F = [\text{Equivalent contaminants in fuel alone}]$$

where:

$\frac{A}{F}$ = air-to-fuel mass flow ratio

$\frac{S}{F}$ = steam/water-to-fuel mass flow ratio

X_F = contaminant concentration (weight) in fuel (ppm)

X_A = contaminant concentration (weight) in inlet air (ppm)

X_S = contaminant concentration (weight) in injected steam/water (ppm)

VI. FUEL AND ADDITIVE EVALUATION AND SAMPLING

A. Fuel Evaluation Procedure

A supplier's fuel analysis shall be submitted to the General Electric Gas Turbine Division covering all the fuel requirements outlined in Table 2 of this specification. If the required analytical services are not available to the user, he may make arrangements to purchase such services from General Electric. See Appendix C for fuel sampling and analysis requirements.

B. Requalification of Fuel: Fuel Changes

The fuel properties outlined in the specification and originally agreed upon by General Electric Company and the user will determine some of the equipment selection and certain operating conditions of the gas turbine system. If at a later date the user desires to use a fuel outside of the original agreed-upon limits, he should inform the General Electric Company in writing. He should supply a complete analysis for evaluation and requalification in a similar manner as outlined above.

C. Additive Qualification

Additives used in gas turbine fuels such as vanadium inhibitors, desalting demulsifiers, bacterial growth retardants or smoke suppressants must meet the approval of the General Electric Gas Turbine Division. One critical requirement of an additive is that it has a low trace metal content (sodium, potassium, vanadium, calcium and lead), so that the inhibitor does not add these contaminants to the fuel.

APPENDIX A - FUEL DESCRIPTIONS

A. True Distillates

1. Light True Distillates

Naphtha - A light volatile fuel with a boiling range between gasoline and Light Distillate. The lower flash point and higher volatility require special safety considerations. Its very low viscosity may result in poor lubricity.

Other Names:

JP-4, Jet B

O-GI Gas Turbine Fuel

Kerosene - A light, highly refined and slightly more volatile fuel than Light Distillate. Normally more expensive than No. 2 distillate.

Other Names:

1-GT Gas Turbine Fuel

No.1 Burner Fuel

1-D Diesel Fuel

JP-5, Jet A

Range Oil, Lamp Oil

Light Distillate - Widely available volatile distillate fuel with good combustion characteristics, being readily atomized and clean burning.

Other Names:

2-GT Gas Turbine Fuel

No. 2 Burner Fuel

Diesel Oil

Marine Gas Oil

Domestic Fuel

Diesel Fuel - Closely related to Light Distillate fuel except for additional requirements peculiar to diesel engine operation such as Cetane Number.

Other Names:

2-D Diesel Fuel

2. Heavy True Distillate

An essentially ash-free petroleum distillate with the highest boiling range. Heavy True Distillate has had limited and localized availability, frequently being a refinery by-product. This fuel may require heating for handling and forwarding due to high pour point. It may also be more difficult to atomize for optimum combustion.

Other Names:

Heavy Gas Oil

Navy Standard Distillate

B. Ash-Bearing Fuels

1. Crudes and Blended Residual Fuels

Crudes - Crude oils from different geographical areas vary widely in levels of trace metal contaminants, ash, sulfur and wax and in such physical properties as viscosity, gravity and distillation range. Most crudes will have flash points below 100°F (38°C) due to highly volatile components. Some very low ash crudes, typified by Indonesian and North African crudes, have 0 to 5 ppm of vanadium requiring minimal or no inhibition. Other crudes for gas turbine application range up to 100 ppm vanadium. Most crudes require desalting, especially if water transportation has been used.

Blended Heavy Distillate - Petroleum distillate contaminated with or blended with lesser amounts of residual petroleum products, but with vanadium contents of 5 ppm or less. They may have wax contents requiring heating for pumping and filtering. They may also require washing for desalting, especially if water transportation has been used.

Other Names:

3-GT Gas Turbine Fuel

4-D Diesel Fuel

Marine Diesel Fuel

Blended Residuals - Blended residuals lie between blended heavy distillates and heavy residuals. They are commonly blended to specific maximum sulfur levels to meet applicable codes. Vanadium contents are in the 5 ppm to 100 ppm range normally. These fuels require complete fuel treatment.

Other Names:

No. 4 Burner Fuel

No. 5 Burner Fuel

Light Residual Oil

Light Furnace Oil

Intermediate Bunker Fuel

2. Heavier Residual Fuels

Residual Fuels - These are low volatility petroleum products remaining at the end of all various refinery distillation processes. As such they contain nearly all of the ash-forming materials present in the original crude oil plus some additional that may be introduced in processing. They usually contain high molecular weight hydrocarbons such as asphaltenes, which can cause storage sludging problems. Residual fuels may have been blended with low cost distillates to lower the sulfur content and/or reduce the viscosity to insure pumpability.

All residual fuels require heating for pumping, filtering and proper air atomization at the fuel nozzle. Residual fuels all require washing to reduce the sodium level and vanadium inhibition by addition of a General Electric approved Magnesium base additive.

Other Names:

No. 6 Burner Fuel

Boiler Fuel

Bunker C. Fuel

Marine Fuel Oil

APPENDIX B - MEANING OF SPECIFICATION TESTS

Chemical tests are specified because slag-forming substances present in oil ash can cause turbine corrosion and deposits, and the presence of sulfur can result in corrosion of heat recovery equipment in the turbine exhaust. Certain physical tests are specified because they influence the operation of the gas turbine fuel handling, fuel treatment and combustion systems.

A. Ash and Trace Metal Contaminants

Ash-forming materials may be present in a fuel as oil-soluble organometallic compounds, as water soluble salts in water dispersed in the fuel or as solid foreign contaminants. The most common ash-forming elements which can be present in fuels are aluminum, calcium, iron, magnesium, nickel, potassium, sodium, silicon and vanadium. Ash-forming materials are present to varying degrees in crude oils depending on their geographical source. They are concentrated in the residual fractions during the refining process, leaving the light distillates contaminant-free; however, ash-forming materials may be introduced later by contamination with salt-bearing water or with other petroleum products during transportation and storage.

Gas turbine operating experience has shown that some of the ash-forming substances that may be present in the fuel can lead to corrosion and deposit problems. These problems are most acute with residual and crude oils which contain larger quantities of the troublesome substances.

Corrosion can result from (1) vanadium, (2) sodium, (3) potassium or (4) lead. These elements as well as calcium (and others such as magnesium, manganese, iron, silicon and aluminum) can cause ash deposits which are difficult to remove. Calcium can act as an effective inhibitor for vanadium corrosion, but its deposition tendencies have precluded its use.

In light distillate fuels, the total ash content is usually very small, and trace metal contamination is essentially a sodium (salt) problem. There are also usually traces of lead and calcium and smaller traces of potassium and vanadium. It is advantageous to purchase fuel within the specified contaminant limits and to maintain this quality during transportation, handling and storage. On-site desalting by contaminated water removal or by fuel washing of distillate fuels with relatively high sodium levels is required to keep corrosion of the hot gas path and the fuel system components such as flow dividers and fuel pumps at a very minimum level.

Crudes and contaminated distillates almost without exception have high enough salt levels, or the risk of significant salt levels, that they require desalting. The vanadium levels may also be significant and require the addition of a magnesium-base inhibitor to establish a ratio of 3 parts of magnesium to 1 part of vanadium by weight.

Residual fuels have the highest ash and trace metal contaminant levels usually necessitating complete fuel pretreatment: desalting and vanadium inhibition by a magnesium-based additive (3Mg/IV). Due to the less favorable physical properties of residual fuels, it is not possible to consistently reduce the sodium to the low levels obtainable in light crudes and distillates. The higher sodium levels in treated residual fuels result in controlled corrosion and deposit accumulation with some increase in maintenance. Calcium levels may be high in some residual fuels, but they may be appreciably lowered by the fuel treatment. Nickel, which is not removed by fuel treatment, may also be high in certain residual fuels and is somewhat beneficial in that it tends to neutralize vanadium corrosion in much the manner of magnesium. Residual fuels contain harmless aluminum, iron and silica as components of suspended solids (dirt). A significant portion of these suspended particles are removed either in the fuel washing or by fuel filtration.

B. Sulfur

Sulfur occurs in fuels as combustible organic compounds yielding sulfur oxides on combustion. These combine with any traces of sodium or potassium present to form alkali sulfates; a principal source of hot corrosion. The sulfur level in a fuel cannot be lowered enough by refining to avoid the formation of alkali sulfates, so that they must be controlled by limiting the sodium and potassium levels in the fuel.

Gas turbine installations utilizing exhaust heat recovery equipment could have metal temperatures below the dewpoint of sulfuric acid, and in these cases it is necessary to know the sulfur level in the fuel to avoid acid corrosion of heat transfer surfaces. The maximum allowable sulfur to avoid sulfuric acid condensation will depend on the specific heat recovery equipment used. For fuels exceeding this maximum level, the operating temperature of the heat recovery equipment could be changed accordingly to avoid condensation of acid products.

The sulfur level of liquid fuels is regulated in many localities as a means of controlling the emission of sulfur oxides in the exhaust gases.

Crude oils burned directly as fuels may also contain active sulfur in the form of hydrogen sulfide or mercaptans. These substances, especially in the presence of water, may cause corrosion to fuel system components. For this reason, the water content of such fuels should be kept as low as possible.

C. Nitrogen

Fuel-bound nitrogen in petroleum fuels comes largely from organo-nitrogen compounds present in the original crude oil. In some distillate fuels, fuel-bound nitrogen may also come from additives such as stabilizers.

This chemically-bound nitrogen in the fuel will contribute to the total nitrogen oxide pollutant in the exhaust gases, adding to the nitrogen oxides from the direct combination of atmospheric nitrogen and oxygen in the gas turbine combustion reaction. The particular combustion system and operating conditions will affect the total nitrogen oxide production from both atmospheric and fuel-bound nitrogen.

D. Hydrogen

The percent combined hydrogen in a hydrocarbon fuel is a critical factor in controlling stack smoke levels. In general, the higher the hydrogen content in a liquid fuel the lower the smoke level will be. As an example: paraffinic hydrocarbons with high hydrogen contents (14-15%) have much less tendency to smoke than do aromatic hydrocarbons which can have 10% or less hydrogen.

Hydrogen is usually determined by an accurate measurement of the amount of water produced in the controlled combustion of a weighed amount of fuel.

E. Carbon Residue

Carbon residue is measured as the residue remaining when a fuel sample is completely distilled in a standard apparatus. To obtain measurable residue with light distillates, the fuel is first distilled to remove 90% (ASTM Method D86) by volume, and then the carbon residue is determined on the "10% Bottoms."

One effect of a high carbon residue is carbon formation near the fuel nozzle. To control this, air atomization is used in the combustion of all but the lightest fuels, high pressure air being required for the heaviest fuels.

F. Water and Sediment

Water and sediment in a fuel oil tend to cause fouling of the fuel handling facilities and the gas turbine fuel system. Accordingly they should be kept at as low a value as practicable and always within the maximum values shown in this specification.

The sediment in fuel can be gums, resins, asphaltic materials, carbon, scale, sand or mud. It is mainly a problem in residual fuels. Very few distillate fuels leave the refinery with more than 0.05% water and sediment. However, poor handling practices can unnecessarily raise this level, and once an oil becomes contaminated it may not be feasible to restore its original cleanliness, such as the case of lead or vanadium contamination.

Gas turbines are normally equipped with high capacity 5 micron filters. Since there are practical limits to the efficiency of filtration systems, a fraction of the solids entering the filter remains in the oil and can be an important factor in fuel system component life.

Fuel storage tanks should be designed with floating suctions that are equipped with low level bottom limits to insure that the suction is always some distance from the bottom to avoid the water and sediment that collects there. The operator should drain the bottom of the tank periodically to reduce the accumulation and the risk of contamination. Automatic water drainage systems are preferred.

G. Filterable Dirt

Filterable dirt is essentially the suspended solid particulate matter in a distillate fuel which can cause fuel filter maintenance problems. It is measured as the weight of solids held on a low porosity filter during the filtration of a given volume of fuel.

H. Viscosity

The viscosity of fuel is a measure of its resistance to flow. It is important in the fuel auxiliary equipment since it determines pumping temperature, atomizing temperature and oil pump pressure.

In order to obtain proper operation of the gas turbine, the maximum viscosity at the fuel nozzles must not exceed 10 centistokes for pressure atomizing or low-pressure air-atomization fuel systems, and 20 centistokes for high-pressure air-atomizing systems. When these limits are exceeded, poor ignition characteristics, smoking, unsatisfactory combustor exit temperature distribution, lowered combustion efficiency or formation of carbon may occur. In most cases, fuel heating must be employed to insure that these viscosity limits at the fuel nozzle are met under all ambient conditions. In all cases the fuel at initial light-off must be at or below 10 cSt viscosity.

Minimum viscosity limits are imposed to safeguard the high pressure fuel pump, which depends on the lubricating qualities of the fuel for satisfactory operation. It should be noted that naphtha fuel can have a minimum viscosity as low as 0.5 cSt at 100°F (37.8 °C).

Special pumps may be required for viscosities below 1.8 cSt at 100 °F.

I. Pour Point

The pour point of a fuel is the temperature at which it will barely flow under standard conditions, and it is significant in connection with fuels that may require heating to make them pumpable and with fuels fed to a pump by gravity flow.

Petroleum oils when cooled may change to a plastic state as a result of partial separation of wax (wax pour) or by congealing of hydrocarbons (viscous pour) comprising the oil.

A waxy fuel must be maintained at a high enough temperature to ensure that all of the wax is in solution to prevent wax crystals from clogging filters and lines. For distillates, wax separation can usually be avoided by heating the fuel to at least 20-30°F (11-17°C) above the pour point. Waxy crude oils used as fuels may require even higher temperature differentials. Each type of waxy fuel must be evaluated individually for minimum wax solution temperature. (For methods, refer to page C2.)

J. Fuel Gravity

The specific gravity is not a critical property of gas turbine fuels. Within a given fuel type it can indicate the chemical composition of the hydrocarbons. As an example, a distillate with a low specific gravity will be largely paraffinic whereas a high specific gravity will be more aromatic. The latter would have a greater tendency to smoke with other factors being equal.

Gravity can have an economic significance where the fuel is purchased by volume since the total heat units will decrease with decreasing specific gravity.

Residual fuels requiring washing will be more difficult to wash if the specific gravity approaches that of water.

In the petroleum industry it is customary to use API gravity instead of specific gravity for convenience since the API system eliminates the small decimal difference between fuel samples encountered in the use of specific gravity. It is always referenced to 60°F (15.6°C).

$$API = \left[\frac{141.5}{Spec. Grav.} \right] - 131.5$$

Some typical examples are:

	Specific Gravity	API Gravity
Water	1.00	10.0
Kerosene	0.78-0.83	50-39
No. 2 Distillate	0.82-0.86	41-33
Crudes and Blends	0.80-0.92	45-22
Residual Oils	0.92-1.05	22-3

K. Distillation

The heavy duty gas turbine is not sensitive to the distillation characteristics of the fuel per se.

Extremely volatile fuels such as naphthas require the use of a start-up fuel (light distillate) due to the low temperature at which they vaporize, giving the possibility of combustible vapors in the fuel lines.

Very high end-point fuels, approximately 1000°F (538°C), can have excessive traces of vanadium which have distilled over. For this reason pure distillate usually would have a maximum end point specification. (This is also prevented by setting a maximum vanadium level.)

L. Flash Point

The flash point of a fuel is the temperature at which fuel vapors will flash when ignited by an external flame.

The flash point is regulated for safety in fuel handling and storage. By itself it is not critical to turbine operation although it can affect the requirements for auxiliary equipment such as motors, relays, heaters, etc.

Minimum permissible flash points are regulated by local, state or federal laws.

Explosion-proofing of equipment may be required by local, state or federal regulations or other applicable codes when the flash point is below a minimum permissible value.

M. Thermal Stability

The thermal stability of an oil is a measure of its ability to resist breaking down when heated to form deposits of resins and sludge. This can occur in the fuel nozzle area and in fuel heaters especially if the heater surface is far hotter than the surrounding oil. This polymerization to form deposits is a time-temperature phenomenon: being accelerated by high temperatures, long exposure times and contact with air.

Thermal stability is most critical for high viscosity residual fuels which require high temperatures to meet fuel atomization viscosity requirements. The maximum allowable temperature specified is 275°F (135°C).

N. Compatibility

Mixing certain residual type fuels with dissimilar residual fuels or diluting residual type fuels with certain distillates may result in the formation of tarry precipitates. The precipitation may occur immediately after mixing or may take some time to develop. Heating for prolonged periods of time will generally accelerate the separation.

This tarry residue can accumulate in the bottom of tanks and can settle out in fuel lines and on filters.

When the separation of residue occurs, it is usually in those residual fuels which have a heavy asphaltene fraction present as a colloidal metastable gel; such as those which have had an intensive heating history during refining. The nature of a solvent used for dilution (blending) is also important; paraffinic (low specific gravity) distillates are more apt to cause precipitation than aromatic (high specific gravity) distillates.

One method of testing for compatibility is to make a 50-50 mixture of two oils and then subjecting the mixture to a thermal stability test. A simple screening test is the ASTM D2781, "Compatibility of Fuel Oil Blends by Spot Test."

ASTM Specifications do not specify this property, again because it has not been the practice of the oil suppliers to make this test. These specifications do not call for the test on the light distillate oils because it is very rare that they encounter compatibility difficulties with one another. However, for the heavier oils, it is necessary to start up and shut down the gas turbine on a light distillate oil; therefore, it is advisable to test the compatibility of the heavy oil/distillate mixture.

O. Cetane Number

Cetane number is an index of the burning quality of fuel in a diesel engine. It is specified only when the turbine fuel is also used in a diesel starting engine.

Cetane number is most accurately measured in a special test engine, but a reasonably accurate value can be obtained from a correlation between the specific gravity and the 50% distillation point.

APPENDIX C - FUEL ANALYSIS DATA REQUIREMENTS

To evaluate a liquid fuel for gas turbine application certain physical and chemical data are required. Basic specification requirements are given in Table 2, Section 3. Certain other data are needed for engineering purposes. Table 3 is a list of required data. Following is pertinent information on some of the analytical tests.

A. Sampling

Since analyses of small traces of metals are involved, and since some tests use small amounts of sample, it is very important that the fuel sample is uniform and representative of the fuel as received by the user or shipped by the supplier. If the fuel is taken from a container, it should be thoroughly mixed mechanically before sampling. For sampling from storage tanks, refer to ASTM Standard Method for Sampling Petroleum Products, D-270-65.

The sample for analysis should be stored preferably in plastic or plastic-lined metal containers. Avoid metal cans with soldered seams and containers with seals (rubber) which can disintegrate and contaminate the fuel. The container should only be about two-thirds full so that it may be well shaken before taking analytical samples. Heavy residual fuels should be in wide-mouth containers.

B. Heating Value

The heating value measured is the High (Gross) Heating Value, where the water produced is condensed. The Low (Net) Heating Value is obtained by calculation from the Higher Heating Value by one of several methods including ASTM D 1405 and D240. The latter requires an accurate value for percent hydrogen while the former requires an aniline point (ASTM D1012) and specific gravity.

C. Viscosity

Viscosities at two temperatures are needed for a viscosity-temperature relationship for the fuel; the two temperatures normally being 100°F (37.9°C) and 210°F (98.9°C). If the pour point is between 70°F (21°C) and 90°F (32°C), the lower temperature should be 122°F (50.0°C). For pour points between 90°F (32°C) and 120°F (49°C), the lower temperature should be 150°F (65.6°C).

D. Carbon Residue

Ramsbottom carbon residue (ASTM D524) is preferred as more accurate. If the Conradson method (ASTM D189) is used, the results should be converted to Ramsbottom (see D524).

E. Trace Metal Analysis

Trace metal contaminant levels are usually measured by spectrometric methods such as atomic absorption, flame emission or a spark source spectrometry. The first two methods use a solvent diluted fuel sample while the latter operates directly on the original fuel. In any case, the reference standards must match the fuel properties as closely as possible. For very accurate analyses of vanadium and lead, it is better to ash the fuel and run the spectrometric analysis on an aqueous solution of the treated ash. In the ashing procedure, special care must be taken not to lose these elements.

F. Wax Content and Wax Melting Point

Crude oils and heavy true distillates should be tested to determine the minimum fuel temperature required to keep all of the wax in solution.

One approach is to remove the wax from the fuel and then to determine its melting point, which represents the maximum solution temperature. There is no standard method for wax separation, but there are several laboratory procedures which are satisfactory. They all involve dilution of the fuel with a poor wax solvent and then chilling to 0°F (−18°C) or lower to separate the wax crystals which are filtered out at low temperature.

An instrumental procedure which measures the wax solution temperature directly on the fuel is Differential Scanning Calorimetry (DSC). This method is still being developed and has not yet been successful with all crude oils.

For light distillate fuels, ASTM D 2500 Cloud Point or ASTM D3117 Wax Appearance Point may be used.

Table 3 – Fuel Analysis Data

Property	ASTM Method (1)	Measured Value
Gross Heating Value, Btu/lb	D240	_____
Kin. Viscosity, cSt, 100°F (37.8°C)	D445	_____
Kin. Viscosity, cSt, 122°F (50.0°C)	D445	_____
Kin. Viscosity, cSt, 210°F (98.9°C)	D445	_____
Specific Gravity, 60°F (15.6°C)	D1298	_____
Specific Gravity, 100°F (37.8°C)	D1298	_____
Pour Point, °F(°C)	D97	_____
Flash Point, °F(°C)	D98	_____
Distillation Range (Not on Residuals)	D86	_____
		IBP _____ °
		10% _____ °
		20% _____ °
		30% _____ °
		40% _____ °
		50% _____ °
		60% _____ °
		70% _____ °
		80% _____ °
		90% _____ °
		EP _____ °
Carbon Residue, Wt. %	D524	_____
Sulfur, Wt. % (Very Light Distillates)	D1266	_____
Sulfur, Wt. % (All Other Fuels)	D129	_____
Hydrogen, Wt. %		_____
Nitrogen, Wt. %		_____
Total Ash (2), ppm	D482	_____

Table 3 – Fuel Analysis Data (Cont'd)

Trace Metals, ppm (2)		
Sodium		
Potassium		
Vanadium		
Calcium		
Lead		
Other Metals Over 5 ppm		
Sediment & Water Vol. %	D1796	
Water, Vol. %	D95	
Filterable Dirt, mg/100ml	D2276	
Wax, Wt. %		
Wax, Melting Point, °F		
Cetane No. (Diesel Engine Start Only)	D975	

(1) Book of ASTM Standards, Part 17

(2) A total ash less than 3 ppm is acceptable in place of trace metal analysis

(3) Wax data only on crudes and heavy distillates



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