

# GAS TURBINE FUELS—SYSTEM DESIGN, COMBUSTION AND OPERABILITY

by

**Cyrus B. Meher-Homji**

**Bechtel Fellow and Senior Principal Engineer**

**Bechtel Corporation**

**Houston, Texas**

**Justin Zachary**

**Bechtel Fellow and Technology Manager**

**Bechtel Power Corporation**

**Frederick, Maryland**

**and**

**Andrew F. Bromley**

**Vice President, Operations**

**Turbotect (USA) Inc.**

**Houston, Texas**



*Cyrus B. Meher-Homji is an Engineering Fellow and Senior Principal Engineer at Bechtel Corporation, in Houston, Texas. He is assigned to the LNG Technology Group and LNG Product Development Center. Mr. Meher-Homji works on the development of new concepts relating to LNG turbomachinery and supports LNG projects. His 30 years of industry experience covers gas turbine and compressor application and design, engine development, and troubleshooting.*

*Mr. Meher-Homji has a B.S. degree (Mechanical Engineering) from Shivaji University, an M.E. degree from Texas A&M University, and an M.B.A. degree from the University of Houston. He is a registered Professional Engineer in the State of Texas, a Fellow of ASME, life member of AIAA, and is active on several committees of ASME's International Gas Turbine Institute. He has several publications in the area of turbomachinery engineering. Mr. Meher-Homji is a member of the Turbomachinery Symposium Advisory Committee.*



*Justin Zachary is an Engineering Fellow and Technology Manager at Bechtel Power Corporation, in Frederick, Maryland. He has extensive experience with gas and steam turbines, performance analysis, thermodynamic cycle analysis, and combustion. He participated on several ASME Performance Testing Codes committees including PTC 22, PTC 6, and PTC 47. Prior to joining Bechtel Power, he has*

*worked in R&D and engineering positions for Siemens, GE, and Rolls Royce.*

*Mr. Zachary received a Ph.D. degree from Western University, Canada, and is a registered Professional Engineer in the State of Quebec. He is an associate editor of Power Magazine and is active on ASME IGTI committees, has published more than 73 technical papers covering a wide spectrum of topics for technical conferences and journals, and is a Fellow of ASME and has several patents in combustion.*



*Andrew Bromley is Vice President of Operations for Turbotect (USA) Inc., in Houston, Texas, where he is responsible for Turbotect's U.S. activities in the areas of gas turbine fuel treatment and compressor cleaning technology. He has 30 years of experience with gas turbines and has specialized in the areas of high temperature corrosion, fuel chemistry, fuel treatment, hot gas path and compressor fouling, compressor washing, and other chemical applications associated with gas turbine performance.*

*Mr. Bromley holds a diploma in Chemistry and an M.S. degree (Corrosion Science & Engineering) from City of London Polytechnic. He is a chartered professional member of the Royal Society of Chemistry and the Institute of Metallurgy & Materials, and an active member of the ASME/IGTI Division.*

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## ABSTRACT

Fuel supply is one of the most critical factors governing the reliability and operability of a gas turbine. The supply of fuel that does not meet gas turbine combustion requirements can result in serious operability and maintenance problems and in extreme cases, rapid load shedding or trip of a gas turbine. It is important that gas turbine and process specialists work together in an integrated fashion appreciating both turbine combustion issues and practical aspects relating to fuel system treatment and design. To this end, interdisciplinary communications between process groups, machinery engineers, and fuel system designers as to all aspects of fuel production, delivery and conditioning is critical to successfully obtaining a fuel stream that meets original equipment manufacturer (OEM) specifications.

This paper comprehensively covers gas, liquid and new alternative fuels for gas turbines and explains the interrelationships of fuel system design, fuel properties, and gas turbine operability in terms of dry low NOx/dry low emission (DLN/DLE) combustion. The treatment covers mechanical drive gas turbines, and smaller engines commonly used in the oil and gas markets, and large advanced gas turbines used in power generation and combined cycle applications.

The area of gas fuel systems and liquid fuel systems will be covered in detail from a combustion perspective. Case studies related to failures due to fuel related problems are provided to indicate the importance of fuel treatment and quality control.

## INTRODUCTION

Over the past three decades, gas turbines have become a dominant source of power for large scale power generation, and for mechanical drive applications. Factors that have resulted in this increased utilization include their improved thermal efficiency, availability and the ability to operate on a wide spectrum of gaseous and liquid fuels.

While natural gas has been the fuel of choice, there is a large population of engines worldwide in which liquid fuels are used. Many developing countries have limited supply of natural gas or distillate fuel and alternative fuels are being considered and implemented worldwide. These range from distillates to residual fuels that have their own treatment challenges. Naphtha is a fuel of choice in some parts of the world. The fuels that will be focused on in this paper will include natural gas, and liquid fuels. Using alternative fuels such as liquefied natural gas (LNG), liquefied petroleum gas (LPG), naphtha, residual-grade oil and crude oil presents unique challenges in their transportation, onsite storage, fuel handling, fuel combustion, safety and design of balance of plant (BOP) systems. Narula (1998) provides an overview of the implementation issues of different fuels.

Combustion has always been a major challenge in the development of gas turbines. When Sir Frank Whittle worked on his turbojet prior to World War II, combustion intensities required were 20 times the prevailing boiler technology of the time. A rudimentary test rig used by Whittle for combustor development is shown in Figure 1 and combustor design challenges faced by early jet pioneers are detailed by Meher-Homji (2000). With combustor heat release intensity on large gas turbines being as high as 1000 MW/m<sup>3</sup> today, combustion testing is one of the most important and challenging areas of gas turbine development (Correa, 1998). The use of lean premixed combustors adds additional challenges and complexities to the fuel delivery system. An overview of the main issues relating to gas turbine combustion that need to be understood by designers of fuel delivery systems is provided in this paper.



Figure 1. Whittle's Rudimentary Gas Turbine Combustor Test Rig, BTH Factory, Rugby, Circa 1936. (Meher-Homji, 1998).

It is very important to have interdisciplinary communication and understanding between process groups, machinery engineers, and fuel system designers for all aspects of fuel production, delivery and conditioning to obtain a fuel stream that meets OEM specifications and ensures high operational reliability. It is helpful for process engineers to understand the underlying reasons for the constraints placed on fuel quality. An excellent overview of fuel suitability for gas turbines is provided by Kurz, et al. (2004), Elliott, et al. (2004), and Stuttford (2007).

## Gas Turbine Fuels

In broad terms, gas turbine fuels can be classified as gaseous or liquid. Common gaseous fuels include:

- Natural gas
- LNG
- LPG
- Refinery gas
- Coke oven gas
- Coal gas
- Hydrogen

Liquid fuels include:

- No. 2 diesel
- Kerosene
- Jet A
- Naphtha
- Condensates
- Ethanol and methanol
- Heavy residual-grade oils and crude oils

An overview of gas turbine fuels and associated comments are provided in Table 1 (Narula, 1998). Another form of fuel classification is shown in Table 2 and illustrates the tremendous range of candidate gas turbine fuels that are currently available. This wide range of fuel options also represents an equally wide range of fuel properties and fuel qualities that present both economic opportunities and technical challenges to modern, industrial gas turbines. Important issues that impact fuel selection and gas turbine performance are discussed in the following sections.

Table 1. Gas and Liquid Fuels for Gas Turbine Engines.

FUEL	Typical LHV MJ/Nm <sup>3</sup> (BTU/SCF)	DLE/ DLN Capability (in general)	Comments/see notes below
Natural gas	35.5 (900)	yes	1,2,4 ( may require heating depending on DP)
Coal seam gas			
CBM			
LNG	35.5 (900)	yes	2,3,6
LPG typical blend	104.8 (2,700)	no	2,5
Propane	91.2 (2,300)	no	2,5
Butane	118.5 (3,000)	No	2,5
Refinery Gas	Varies	No	7,
Blast furnace gas	3.6 (90)	No	7,8,17
Coke oven gas	11.8 (300)	No	7,11,14,16
Hydrogen	10.8 (270)	No	9, 10, 16
<b>LIQUID FUELS</b>	Typical LHV MJ/kg (BTU/lb)		
No 2. Distillate	42.7 (18,400)	Yes	1,2
Kerosene	43 (18,500)	yes	2
Jet A	43.2 (18,600)	Yes	2
Naphtha	44.2 (19,000)	yes	2,12,13,14
Condensate fuel	45.2 (19,400)		2,12,13,14
Methanol	19.9 (8,555)	No	2,12
Ethanol	26.8 (11,522)	No	2, 12
Crude Oil	41.2 ( 17,700)	No	7,13
Heavy Fuel Oil	39.6 (17,000)	No	7, 13

### Notes:

- 1 Standard fuel
- 2 Clean burning fuel
- 3 Needs Vaporization
- 4 Low transportation and storage cost
- 5 Medium transportation and storage cost
- 6 High transportation and storage cost
- 7 Needs scrubbing of contaminants
- 8 Needs enrichment with higher heating value fuel
- 9 High flame temperature
- 10 Needs separate startup fuel
- 11 Fuel needs heating to preclude condensate dropout
- 12 Poor lubricity
- 13 Low flash point
- 14 High vapor pressure and highly volatile- needs separate startup fuel
- 15 Needs preheating and treatment
- 16 High >40% H2 fuel

Table 2. Candidate Gas Turbine Fuels.

Category	Examples	Category	Examples
Natural gas -85% methane CH <sub>4</sub>	NG LNG	Light distillates	GT-0, Naphtha, Jet B GT-1, Kerosene, Jet A GT-2, diesel oil
Gas condensates Heavy liquid fractions of natural gas	Condensate NGL	Middle & heavy distillates	Industrial fuel oil (IFO) Light & heavy gas oil
Light gas products	Refinery fuel gas (FG) Propane (C3) Butane (C4) Liquid pet. gas (LPG)	Residual-grade heavy fuel oils	No.6 oil, Bunker C, LSWR, LSFO, etc.
Industrial waste gases	Coke oven gas Blast furnace gas	Crude oils	Many different grades and properties
Aromatic refinery bi-products	Benzene Toluene Xylene } BTX	Asphalt Coke	IGCC, via gasification processes to "Syngas"
FCC bi-products	Light cycle oil (LCO) Heavy cycle oil (HCO) Cycle oil slurry	Gas to liquids technology (GTL)	Synthetic liquid fuels from NG or syngas etc
		Bio-fuels	Diesel from grains / fats Ethanol-based fuels
		<b>BLENDS of all the above</b>	

Higher and Lower Heating Value

Fuels are often purchased on the basis of higher heating value (HHV) while gas turbine performance is calculated on the basis of the lower heating value of the fuel. The difference between the two heating values is the energy content that relates to the fuel bound hydrogen that forms water as a byproduct of combustion. The HHV is measured on the basis of the chemical energy of the fuel and accounts for the total heat released including the formation of water vapor. The lower heating value (LHV) on the other hand is a measure of the useable energy. Looking at it in a simplistic manner, approximately 6 percent by weight of liquid fuels ends up being wasted in the combustor versus 11 percent for natural gas. Consequently the LHV fuel consumption should be increased by 1.06 for liquid fuels and 1.11 for natural gas to determine the amount of fuel needed on a HHV basis (i.e., related to the fuel purchase agreement).

Common Fuel Properties—  
Weights and Energy Content

The bulk weight of common gas turbine liquid fuels is shown in Table 3. The table shows the gravity at 60°F (15°C), the density, and the weight per 42 gallon barrel. The Btu content (HHV) for typical fuels is shown in Table 4.

Table 3. Typical Gas Turbine Liquid Fuel Bulk Weights.

Fuel	Gravity at 60F	Gals/lb	Lbs/gal	Lbs/42gal BBL	BBL/metric tonne
Crude Oil (middle east)	25.6	0.1333	7.5	315	6.998
Crude Oil US domestic	36	0.14217	7.034	295	7.463
Distillate Oil	31.3	0.13817	7.237	304	7.253
Residual Oil	18	0.12687	7.882	331	6.66
LPG	---	0.22104	4.524	190	11.603

Table 4. Typical Gas Turbine Fuel Energy Content and Equivalence.

Fuel	42 Gal BBL Crude Oil	1000 cuft Natural gas	42 Gal BBL Distillate	42 Gal BBL Residual	42 Gal BBL LPG
Fuel BTU Content (MMBTU)	5.8	1.035	5.825	6.287	4.011
42 Gal BBL Crude Oil	1.00	5.604	0.996	0.923	1.446
1000 cuft Natural gas	0.178	1.00	0.1776	0.165	0.258
42 Gal BBL Distillate	1.004	5.628	1.00	0.927	1.452
42 Gal BBL Residual	1.084	6.074	1.079	1.00	1.567
42 Gal BBL LPG	0.692	3.875	0.689	0.638	1.00

Gas Turbine Fuel Pricing Considerations

Liquid fuel prices are closely linked to quality, and this becomes a critical factor in calculating the economic viability of a particular fuel. Distillates are significantly more expensive than

residual-grade oils by a factor of about 2:1 as shown in Table 5 (Bromley, 2009), and in certain regions this differential can be as high as 3:1 depending on local market conditions. Thus, even though fuel treatment programs will be needed and gas turbine performance will be impaired, the bottom-line economic incentives for burning residual oil can be extremely attractive. Trends in fuel prices are also shown in Table 5.

Table 5. Fuel Price Comparison; Approximate U.S. Dollars per MMBtu.

	2005	2006	2007	2008	2009
Natural gas	8.64	6.73	6.97	9.00	3.00
Crude oil	8.72	10.46	11.79	15.80	12.50
No.2 distillate oil	~ 13.50	~ 15.50	~ 17.00	~ 24.00	~ 23.00
Residual oil	~ 7.50	~ 8.50	~ 9.50	~ 14.00	~ 9.50
Ratio dist/resid	~ 1.8	~ 1.8	~ 1.8	~ 1.7	~ 2.4

The decision to use a type of fuel is not always decided by its cost, but in several parts of the world it often depends on governmental dictates. Other factors and considerations that go into choosing a fuel are project specific and include:

- Price and quality (which are closely linked).
- Local availability and supply reliability.
- Appropriateness of the fuel for the intended application.
- Acceptability of fuel quality for the particular gas turbine model. The use of heavy fuels is usually not allowed on advanced class gas turbines or aeroderivatives but is allowed for E-Class gas turbine technology.
- The possibility of converting from heavy-fuel to gas and combined cycle.
- Local environmental (emissions) considerations.
- Local government regulations.

Effect of Fuels on Gas Turbine Performance

The type of fuel impacts gas turbine performance. For simple cycle gas turbines, natural gas will produce 2 to 3 percent more power than operation on distillate oil due the higher specific heat of the combustion products, which results from the higher water vapor produced by a higher hydrogen to carbon (H/C) ratio. Ash bearing fuels such as residual oil normally require a reduction in gas turbine firing temperature.

Natural gas consists primarily of methane but can contain heavier hydrocarbons such as ethane, propane or pentanes that will tend to increase the heating value. Natural gas can also include inerts such as nitrogen and carbon dioxide, which will tend to lower the heating value. A comparison of key properties of methane and propane is shown in Table 6.

Table 6. Fuel Properties—Comparing Methane and Propane.

Hydrocarbon	Methane	Propane
Symbol	CH <sub>4</sub>	C <sub>3</sub> H <sub>8</sub>
Mol Weight	16	44
Weight %, Carbon	75	82
Weight %, Hydrogen	25	18
C/H Ratio	3	4.5
LHV (Lower Heating Value), KJ/kg	50,044	45,227

Methane has a higher heating value than propane on a weight basis due to its higher hydrogen content. When burned, methane will produce more water vapor than propane and also produce more carbon dioxide (CO<sub>2</sub>). This will result in a higher specific heat and consequently more work produced in the gas turbine section. Consequently, fuels with higher hydrogen content will tend

to produce more power. This factor often offsets the higher mass flow of propane fuel (due to its lower LHV) to heat the air to the same temperature.

Inert gases in the fuel tend to increase power as the mass flow rate of the fuel increases (to provide the necessary heat input), resulting in an increase in turbine section work, while the compressor section work remains essentially unchanged. Secondly, as more fuel is added, there is an increase in the compressor pressure ratio that results in a higher expansion ratio across the turbine.

A graph showing power correction factor versus fuel heating value is shown in Figure 2. Moving from A to D represents a decrease in heating value, with methane as the fuel and an increasing mass fraction of inert gas. The fuels represented on this graph are shown in Table 7. Pure methane is represented as point A in the graph with a heating value of 50 MJ/kg. Fuels with higher heavies (higher C/H ratios) are represented by lines such as BE and CF.

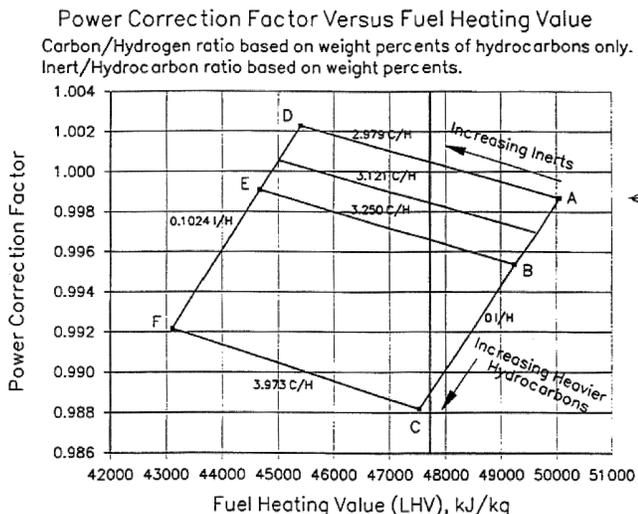


Figure 2. Power Correction Factors for Variations in Fuels. (Cloyd and Harris, 1995)

Table 7. Gas Compositions Used for Figure 2.

Gas	A	B	C	D	E	F
CH <sub>4</sub> , Vol %	100	80	0	95	75.341	0
C <sub>2</sub> H <sub>6</sub> , Vol %	0	20	100	0	18.835	90.73
N <sub>2</sub> , Vol %	0	0	0	4	4.659	8.04
CO <sub>2</sub> , Vol %	0	0	0	1	1.165	1.23
C/H Ratio	2.979	3.250	3.973	2.979	3.250	3.973
(Inerts) I/H Ratio	0	0	0	0.1024	0.1024	0.1024

The increase in power with lower carbon to hydrogen ratios is a result of more water vapor in the combustion products. Water vapor having a higher specific heat than dry air and other combustion products, it contains more available energy. This produces more work from the gas turbine and also produces more steam in the event that a combined cycle or cogeneration heat recovery steam generator (HRSG) is present.

High fuel volumes increase fuel piping and valve sizes and costs. This is often the case for integrated gasification combined cycle (IGCC) applications where low- or medium-Btu gases are frequently supplied at high temperatures, and which further increases their volume flow if the low-Btu gases are saturated with water prior to delivery to the combustor. This causes an increase in the combustion products' heat transfer coefficients and raises the metal temperatures in the turbine section. This situation is similar to water injection where a control curve "shift" may have to be made to compensate for this effect.

Some combustion systems require the use of diluent injection (steam or water) to meet NOx emission requirements, and this is usually the case for DLN combustion systems when firing distillate oil. The injection of water or steam not only increases the gas turbine output but also provides additional exhaust energy to enhance the output of the bottoming steam cycle.

Simulations at an ambient temperature of 15°C were modeled using commercially available thermal engineering software for a nominal 45 MW gas turbine by varying fuel flow LHV values. The gas turbine is an industrial engine with the following salient parameters:

- Nominal power 45 MWe
- Ambient temperature of 15°C, relative humidity of 60%, sea level
- Axial Compressor pressure ratio 20:1
- Air flow rate 128 kg/sec
- Turbine inlet temperature (TIT) 1288°C
- Exhaust gas temperature (EGT) 538°C
- Thermal efficiency 37% (LHV basis)
- Inlet and outlet losses 10 and 12.45 millibar
- Generator efficiency of 98.5%
- Fuel—gas with varying LHV values

The LHV was lowered in steps from a base value of 49,112 kJ/kg. The impact of LHV on power and thermal efficiency is shown in Figure 3. The power and thermal efficiency are represented as normalized values, with the datum being the value at the base LHV. Also shown in this figure (on the right ordinate) is the turbine expansion ratio. As the LHV drops, the turbine output increases and the expansion ratio increases because the increased volume of fuel flow causes the compressor to operate at a higher pressure ratio, resulting in a higher turbine expansion ratio. The changes in axial compressor and turbine section work (in kW) along with the gas turbine output are shown in Figure 4. While the compressor work increases slightly, the turbine work grows more significantly due to the combined effect of the increased fuel mass flow and expansion ratio.

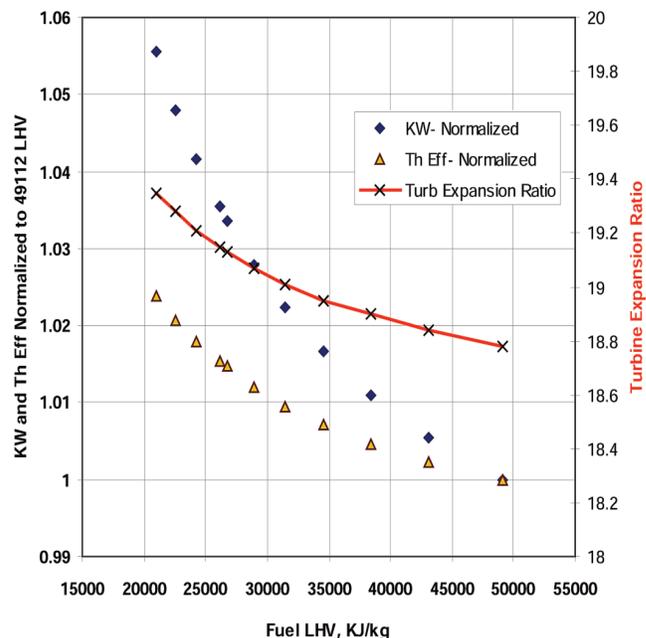


Figure 3. Impact of Change in LHV on Gas Turbine Power, Efficiency and Turbine Expansion Ratio.

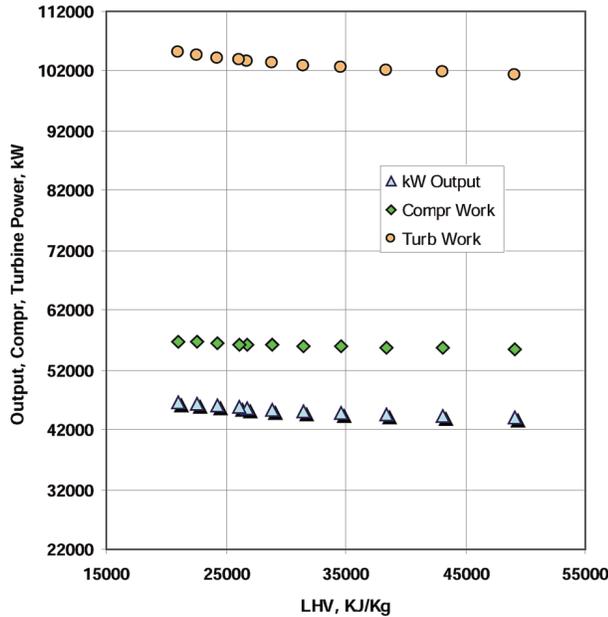


Figure 4. Impact of Change in LHV on Compressor and Turbine Work and Overall Output.

Fuel Impact on HRSGs

For gas turbines employing exhaust heat recovery and burning sulfur bearing fuels, the amount of sulfur plays a role in determining the power or steam available from the bottoming steam cycle. It is critical to know the acid dew point of the exhaust gas so the heat recovery equipment can be designed to prevent corrosion from condensed sulfuric acid.

The use of heavy fuels in combined cycles is very rare, but combined cycles commonly operate on lighter liquid fuels. Fuels that create ash require special HRSG design approaches. Soot blowers need to be installed to remove the ash from the heat transfer surfaces. HRSG tube fin spacing must be sufficient so that the soot blowers can effectively remove the ash. Fin spacing depends on the amount of particulate matter in the gas turbine exhaust gas. Typical fin density of 3 to 5 fins per inch may be needed for these fuels compared to the normal 5 to 7 fins per inch for natural gas design.

As combustion occurs, sulfur in the fuel combines with oxygen to form sulfur dioxide, and under excess air conditions there is further oxidation of SO<sub>2</sub> to SO<sub>3</sub>. The sulfur trioxide then combines with water and condenses as sulfuric acid at or below the prevailing dew point temperature. Thus, severe corrosion of HRSG surfaces can occur if the exhaust gas cools sufficiently for condensation to occur.

The dew point is a function of the amount of sulfur in the fuel as well as a function of the amount of water vapor in the exhaust gas. Since the combustion of distillate oil and natural gas produce different amounts of water vapor, they have different dew points and the higher the amount of water being present, the higher the dew point. Water and steam-injected systems will have higher dew points.

Gas turbine fuel quality therefore has a significant impact on the bottoming cycle design and cost. The range of fuel characteristics must be known to ensure the system is designed to deal with the variability.

Gas Turbine Cycle Performance with Different Fuels

To explain what happens in a gas turbine in terms of performance with different fuels, a Frame 7EA has been modeled using thermal engineering software. The modeling was based on:

- Site ambient conditions: 1.011 bar, 15°C, 60% RH
- Gas turbine (GT) @ 100% rating, inferred TIT control model, control curve limit
- Total inlet loss = 10 millibar, exhaust loss = 12.45 millibar

The fuels used for the modeling include methane, typical natural gas, digester gas (low Btu gas), distillate fuel and heavy fuel oil. Salient fuel properties are shown in Table 8. Key cycle parameters for gas turbine operation at an ambient temperature of 15°C for the selected fuels are shown in Table 9 that provides:

- Output power and heat rate.
- Fuel mass flow rate and LHV.
- Compressor discharge pressure (CDP).
- Turbine inlet temperature and exhaust gas temperature.
- Work of compressor section.
- Work of turbine section.
- Exhaust gas flow rate and composition.

Table 8. Fuel Properties Used for Gas Turbine Simulations.

Fuel	CH4	Natural Gas (no H2S)	Digester gas	Blast Furnace Gas	Distillate Oil	No.6 Residual (Heavy Fuel)
Mol Wt	16.04	17.74	26.35	29.34	-	-
Total LHV+ Sensible Heat at 25C, kJ/kg	50,047	46,281	18,891	2,474.2	42,330	41,072
Volumetric LHV@ 25C, kJ/scm	32,824	33,558	20,3502	2,968	-	-
Volumetric HHV@ 25C, kJ/scm	36,422	37,152	22,581	3,076	-	-
LHV, kJ/kg					42,330	41,072
HHV, kJ/kg					45467	43,364
Specific Gravity @ 15.56C					0.8654	0.9861
Deg API @ 15.56C					32	12
Specific Heat@25C/ 300C, kJ/kg-C					1.884/2.889	1.8/2.721
Kinematic Viscosity @37.78C, cSt					2.8	35
Thermal conductivity @37.78C, W/m-C					0.0809	0.0797
Pour Point, C					-17.78	18.33
Minimum Pumping Temp, C					-12.22	37.78
Minimum Atomizing Temperature, C					-6.667	93.93

Table 9. Salient Parameters Based on Simulations for Frame 7EA Gas Turbine Operating on a Range of Fuels.

FUEL	A CH4	B Natural Gas (no H2S)	C Digester gas	D Blast Furnace Gas	E Distillate Oil	F No.6 Residual (Heavy Fuel)
LHV kJ/kg	50074	46280	18891	2474	42331	41113
GT Output, kW	87076	85148	87538	78341	83264	72173
Heat Rate, kJ/kWhr	10937	10933	10881	10007	11043	11304
Compr Discharge Pressure, Bara	12.62	12.63	12.9	14.23	12.65	12.15
Compressor Work, kW	105812	105899	107730	115487	105465	102528
Turbine Total Work, kW	192898	190059	197310	195754	190715	176556
Fuel Flow Rate, kg/sec	5.165	5.588	14.01	88.02	6.034	5.512
Thermal Efficiency, % (LHV)	32.91	32.93	33.09	35.97	32.6	31.85
Exhaust Flow Rate, kg/sec	298.8	299.2	307.7	381.7	299.7	299.2
TIT, C	1113	1113	1104	833	1113	1034
EGT, C	538	538	434	362	539	492
Exhaust Gas Composition, %						
N2	74.92	74.99	73.55	74.72	75.69	76.21
O2	13.97	13.98	13.55	13.44	14.1	15.2
CO2	3.096	3.161	4.893	8.889	4.169	3.844
H2O	7.115	6.974	7.118	2.213	5.132	3.78
Ar	0.9023	0.9018	0.8846	0.7406	0.9115	0.9177
SO2	-	-	-	-	-	0.45

It is important to note that the base turbine inlet temperature considered in this comparison is 1113°C (2035°F). For residual fuel, and only as an estimated value, the TIT has been derated to 1034°C (1893°F). For the blast furnace gas with very low heating value, derating to 833°C (1531°F) was imposed to maintain the compressor margins.

*Greenhouse Gas Emissions*

Carbon dioxide and nitrous oxide (N<sub>2</sub>O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO<sub>2</sub> during the combustion process. The thermal efficiency of the gas turbine is a major factor that governs the CO<sub>2</sub> produced. A simulation of 26 gas turbines showing the correlation between thermal efficiency and CO<sub>2</sub> output in terms of kg/MW-hr is shown in Figure 5. Relative CO<sub>2</sub> emissions for selected engines are shown in Figure 6 considering a Frame 5C as the base. The dramatic drop (approximately 30 percent) in relative CO<sub>2</sub> emissions by the use of high efficiency aeroderivative engines can be seen in this figure.

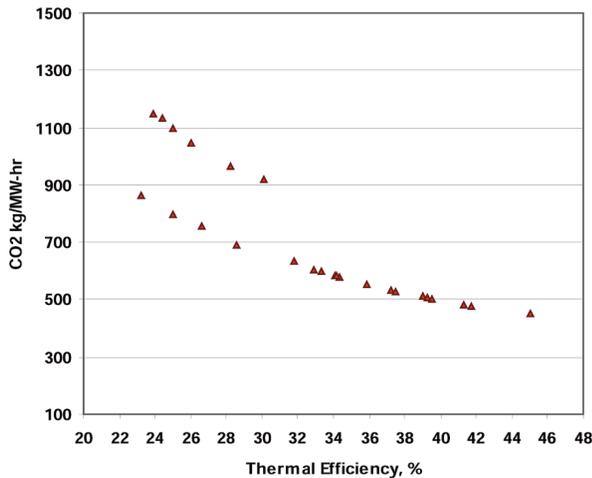


Figure 5. Thermal Efficiency and CO<sub>2</sub> Emissions in kg/MW-hr (Simulation of 26 Gas Turbines).

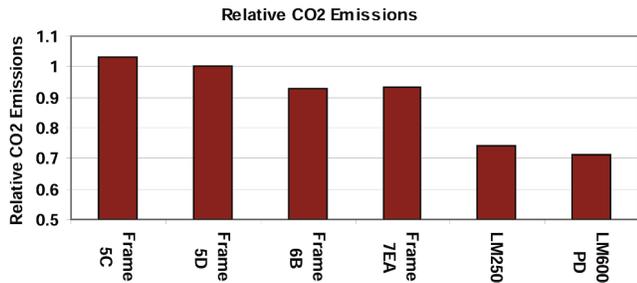


Figure 6. Relative CO<sub>2</sub> Emissions of Different Drivers.

**GAS TURBINE COMBUSTION FROM A FUELS PERSPECTIVE**

In order for fuel delivery system designers to design reliable fuel systems, it is important to have an understanding of gas turbine combustors and combustion principles and terminology. This is helpful in understanding the criticality of fuel cleanliness and stringent OEM guidelines regarding Na, K, and the limitations related to addition of inerts or heavies in gaseous fuels.

For an overview of some actual parameters surrounding an engine, the authors have simulated a Frame 9131FA gas turbine operating on natural gas. The simulation is based on:

- Fuel = natural gas, supplied @ 25°C
- Fuel molecular weight = 17.74
- LHV @ 25°C = 46280 kJ/kg

- GT @ 100% rating, inferred TIT control model, control curve limit
- Site ambient conditions: 1.013 bar, 15°C, 60% RH
- Total inlet loss = 10 millibar, exhaust loss = 12.45 millibar

The cycle flow schematic developed using thermal engineering software is shown in Figure 7. Under the conditions shown, this gas turbine produces an output of 256,924 kW at a thermal efficiency of 36.9 percent. The pressure ratio of this machine is 15.8:1 with a compressor discharge pressure of 15.88 bara. The fuel pressure required is 26.4 bara and the fuel flow rate is 15.03 kg/sec, which is approximately 2.3 percent of the air flow rate of 647.6 kg/sec. Combustor heat release is 695,678 kW. The combustor pressure loss is approximately 5 percent, and the turbine rotor inlet temperature (TRIT) is 1327°C (2421°F).

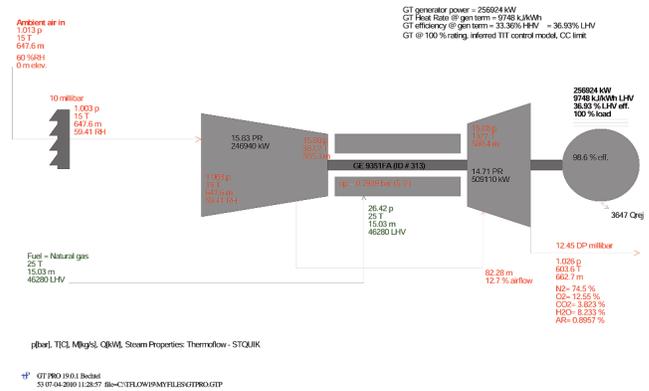


Figure 7. Cycle Flow Schematic for a 257 MW Gas Turbine.

A brief treatment is made of traditional combustors, and details are provided on premix DLN/DLE combustors that are extensively used in industry currently. An outstanding reference for gas turbine combustion is the text by Lefebvre (1983).

*Traditional Combustors*

The combustor is one of the most challenging technology components in a gas turbine. It has to mix and combine the air and fuel, ignite the fuel and ultimately control the temperature distribution to the turbine nozzle section. A traditional combustor will have three main zones of operation as shown in Figure 8.

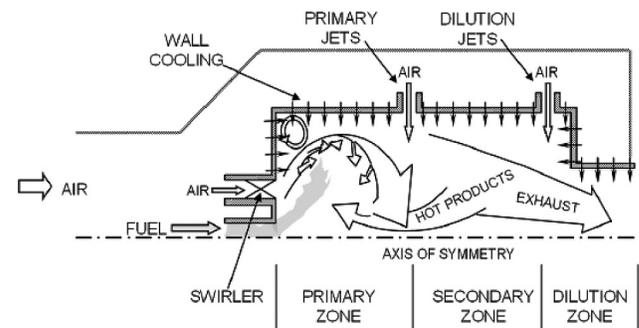


Figure 8. Traditional Combustor. (U.S. DOE/NETL, 2006)

The primary zone is the zone in which the main combustion occurs. Air enters via a swirler that creates a low pressure region at the centerline, thus creating a recirculation zone. The fuel combusts in this region and is ignited by the existing flame. Primary air jets enter the flow and “restrict” or bound the primary zone. The primary zone typically operates fuel rich with an equivalence ratio  $\phi > 1.0$ . In the secondary zone, the CO is oxidized to CO<sub>2</sub>. The equivalence ratio in this zone is approximately 0.8 (Samuelsen, 2006). Finally in the dilution zone, compressor discharge air is added to control and profile the temperature of the

combustion products into the turbine nozzle. The radial and circumferential variation of the temperature entering the turbine section is managed by this dilution flow.

The effect of fuel properties on combustion design parameters is presented in Table 10. Flammability limits for selected fuels are provided in Table 11.

Table 10. Effect of Fuel Properties on Combustion Design Parameters.

Fuel Property	Design Parameter	Notes
Heating Value	Ignition/ Blow out Emissions Efficiency Pressure Drop Pressure Pulsations	<ul style="list-style-type: none"> <li>Lower BTU gas means higher mass flow (a 200 BTU/SCF gas will have approximately 5 X the volume flow). In general this results in higher output, increased pressure ratio and a reduction in the stall margin.</li> <li>Mixing of air and fuel also becomes more challenging and traverse number is affected</li> </ul>
Flame Temperature	Blowout Emissions Efficiency Metal Temperature	<ul style="list-style-type: none"> <li>Adiabatic flame temperature drops as the BTU value drops though flame temperature is not solely dependant on LHV.</li> <li>Fuels like H2 and CO have LHV approximately 30% of natural gas but have much higher flame temperatures.</li> <li>High flame temperatures result in greater NOx</li> <li>Metal temperature surrounding the primary zone of the liner will be affected by flame temperature. Gaseous fuel flames are non luminous compared to liquid fuels. As flame temperature goes up liner cooling requirements will also increase.</li> </ul>
Flammability Limits	Ignition/ Blowout Emissions Cross firing (if can annular) Efficiency Pressure Pulsations	<ul style="list-style-type: none"> <li>To sustain combustion, a recirculation region is aerodynamically maintained in the combustor primary zone. Stability in this zone depends on the flammability limit.</li> <li>A gradient of FARs exist and depends on load condition. Typical FAR will vary 3:1 across the load range. The wider the flammability limit of a fuel the more suitable it will be for off design operation. This is important during startup conditions where mixing and combustion efficiencies are poor.</li> <li>As a rule of thumb a flammability ratio of 2.2 or greater is sufficient for operation from startup to full load.</li> </ul>
Reaction Rate	Blowout Emissions Efficiency	<ul style="list-style-type: none"> <li>A lowering of the reaction rate will result in CO in the exhaust.</li> </ul>
Water vapor content	Blowout Emissions	<ul style="list-style-type: none"> <li>Most GT Fuels only contain a trace of water vapor. IGCC gasses may contain significant amounts of water</li> </ul>

Table 11. Flammability Limits for Selected Fuels.

FUEL	Lower Flammability Limit, %Volume	Lower Flammability Limit, %Volume	Flammability Ratio = UFL/LFL
Natural Gas	4.9	15.1	3.08
Methane (CH4)	5.0	15.0	3.00
Propane (C3H8)	2.1	9.5	4.52
Hydrogen (H2)	4	75	18.75
Carbon Monoxide (CO)	12.5	74	5.92
Landfill gas (55% CH4+45% CO2)	10.1	20.6	2.04
Lurgi Coal Gas	12.6	51.8	4.11
Coke Oven Gas	4.9	30.2	6.16

Dry Low Emission Combustors

A well-known representation of NOx and CO formation as a function of flame temperature is shown in Figure 9. It can be seen that as the flame temperature increases, NOx increases exponentially. On the other hand, CO levels tend to drop with increased flame temperature. There is an optimum temperature (approximately 1850°K = 1577°C) at which both NOx and CO is at acceptable levels. The goal of DLN/DLE systems is to attain this temperature and ensure stability and good operability over a range of loads and ambient conditions.

Indicative trend, level depends also on residence time

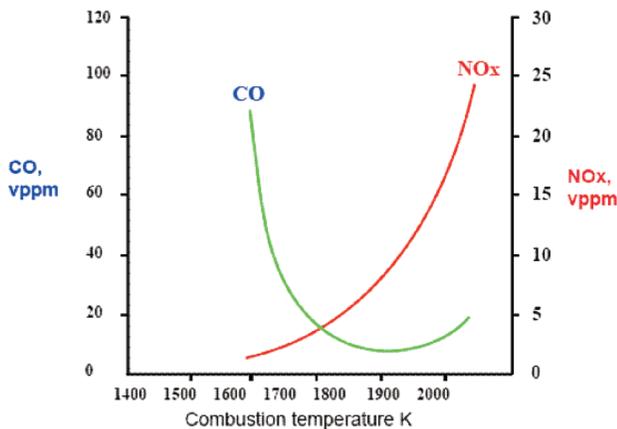


Figure 9. NOx- CO Relationships as a Function of Combustion Temperature.

Dry low NOx combustors (DLN or DLE) operate by essentially lowering the flame temperature by running fuel lean. This is done by premixing the fuel and air (similar to a Bunsen burner) so that the mixture is relatively uniform to avoid the presence of hot spots in the flame (i.e., localized areas of high fuel to air ratios [FARs]) that generate NOx. To summarize, DLN/DLE systems:

- Operate fuel lean at a low flame temperature compared to traditional combustors.
- Attempt to pre-mix the flame to get good mixing to minimize hot spots during combustion.

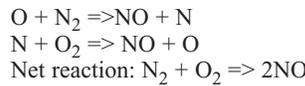
An overview of dry low emission combustors may be found in Correa (1998), and recent developments in Campbell, et al. (2008), Popovic, et al. (2010), and Wisniewski and Handelman (2010).

Zeldovich Reaction and NOx Formation

There are two mechanisms that create NOx in gas turbine combustors:

- Thermal NOx, which is the oxidation of atmospheric bound nitrogen in the combustion air.
- The conversion of fuel bound nitrogen into NOx.

Thermal NOx is formed by a series of chemical reactions that involve the dissociation and subsequent reaction of oxygen and nitrogen to form NOx, following the well-known Zeldovich mechanism (Zeldovich, et al., 1947). The Zeldovich reaction is represented by:



This reaction rate increases exponentially with flame temperature and the NOx generated is called “thermal” NOx. Maintaining the flame temperature around 1800°K to 1850°K (1526 to 1577°C) ensures minimization of NOx. Fuel-bound NOx is usually of less importance for normal fuels. Molecular nitrogen present in some kinds of natural gas does not contribute significantly to NOx, but may be important with some low Btu fuels.

To summarize:

- To minimize NOx, the combustor must have a low flame temperature and consequently must operate in fuel-lean conditions ( $\phi < 1$ ). Typical values of equivalence ratio are 0.5 to 0.55 but this is also a function of the quality of the gas.
- The fuel must be well mixed so that it is uniform (to minimize the presence of hot spots caused by high localized FARs).
- The equivalence ratio cannot be too lean or CO emissions will increase and there will be a risk of extinction by a lean blow out mechanism.
- Longer residence time in the flame zone gives more time for NOx formation and for CO to be consumed.
- The Zeldovich reaction increases with the square root of combustor pressure, and is therefore a greater challenge with high pressure ratio gas turbines.

With DLN/DLE technologies, the following fundamental combustor operability criteria must be satisfied regardless of the fuel that is being utilized. Meeting these criteria under a variety of conditions is a considerable design challenge.

- Ability to operate over a wide ambient temperature range
- Ability to operate over a wide range of loads
- Robustness to autoignition
- Robustness to flashback

- Emissions compliance (NO<sub>x</sub>, CO, UHC, smoke)
- Acceptable combustion dynamic pressures
- Robustness to lean blowout
- Adequate durability of combustor components

#### Types of Combustion Flames

Flames that can occur in a gas turbine combustor can be broken into two categories as shown in Figure 10. In a conventional combustor, approximately 70 percent of the airflow bypasses the combustion zone, while in a lean premixed design, a much smaller quantity of air is bypassed as the fuel and air are mixed to fuel lean conditions. The figure also shows that the flame temperatures are considerably different with the lean combustion. In the lean premixed approach the flame temperature is approximately 660°C (1118°F) cooler than that in a traditional combustor. The resulting temperature going into the turbine nozzle section would be the same.

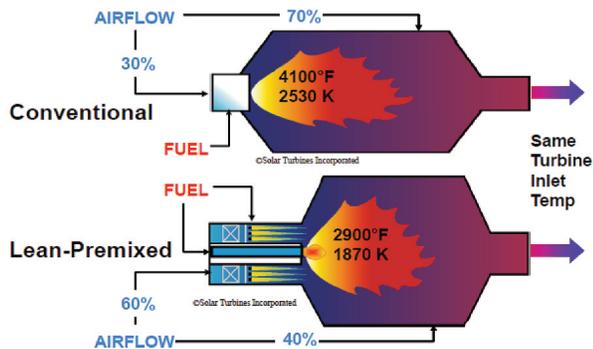


Figure 10. Premixed Flame Versus Conventional Combustion. (Courtesy R. Kurz, Solar Turbines)

Diffusion flames are those used in traditional combustors with both the fuel and the air (oxidizer) supplied in an unmixed state. Heat is released as the two species diffusively mix and react. The diffusion of the reactants balances the generation of products and heat, thus allowing reactions to occur with ideal stoichiometry. It is this diffusion process that gives this combustor its name. Excess air is mixed downstream of the reaction zone. In diffusion type combustors, a significant part of the airflow is diverted to the secondary and tertiary sections.

In premixed flames (commonly used in DLN/DLE systems), the fuel and the oxidizer are premixed before arriving at the flame region and the rate of combustion is defined by the flame speed. Premix burner designs for a large heavy duty gas turbine are shown in Figure 11. A well-known example of a premixed flame is the Bunsen burner. The types of flame are depicted in Figure 12 with a diffusion flame shown on the left and a fully premixed flame on the right. If the premixed fuel flow rate is faster than the flame speed, then the flame will be “blown off.” If, on the other hand, the flame speed is large compared to the local gas velocity, the flame will propagate into the premix region, resulting in flashback. The flame speed for various fuels is shown in Table 12. The flame speed as a function of the fuel type and equivalence ratio is shown in Figure 13.



Figure 11. Premix Burner Design (Heavy Duty Gas Turbine).

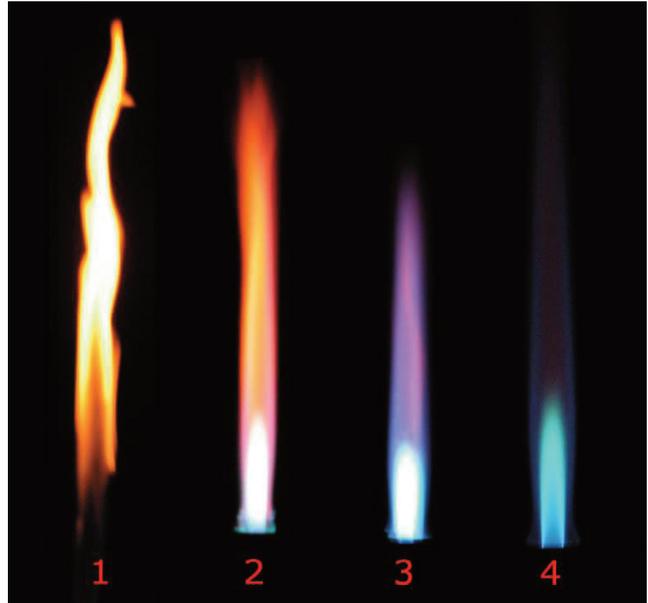


Figure 12. Bunsen Burner Diffusion Flame (Left) and Full Premix Flame (Right). (Photo by A.J. Fija kowski, Wikipedia Commons)

Table 12. Flame Speeds for Different Fuels and Ratio to Methane Flame Speed.

FUEL	Max flame speed, cm/sec	Ratio Flame Speed /Flame speed of CH <sub>4</sub>
Methane, CH <sub>4</sub>	37.3	1.00
Ethane C <sub>2</sub> H <sub>6</sub>	44.2	1.185
Propane C <sub>3</sub> H <sub>8</sub>	42.7	1.145
Hydrogen, H <sub>2</sub>	291	7.8
Carbon Monoxide, CO	43	1.15

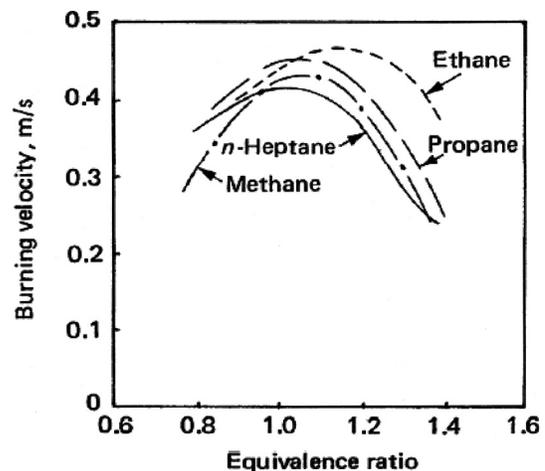


Figure 13. Laminar Flame Speed and Equivalence Ratio for Different Fuels. (Lefebvre, 1983)

#### Combustion Principles and Terminology

Basic principles relating to fuel combustion are presented here. An outstanding paper by Richards, et al. (2001), covered the main issues and the key elements relating to low emission combustion and is highly recommended as a reference. Salient features are presented below.

##### Fuel to Air Ratio

The most significant parameter used to characterize combustion is the fuel to air ratio (F/A or FAR), expressed either on a volume or mass basis. With precisely enough air to (theoretically) consume

all of the fuel, combustion is said to have a stoichiometric FAR ratio. Adding more air produces combustion that is fuel-lean, and adding less air produces fuel-rich combustion. Because differing fuels have different stoichiometric FAR ratios, it is often normalized by dividing the actual FAR by the stoichiometric FAR, resulting in the equivalence ratio.

$$\phi = \text{FAR}_{\text{actual}} / \text{FAR}_{\text{stoich}} \quad (1)$$

In other words,  $\phi = 1$ , represents stoichiometric combustion,  $\phi < 1$ , represents fuel-lean combustion (excess air), which is typical of lean premixed combustors, and  $\phi > 1$ , represents fuel-rich combustion (excess fuel).

#### Flame Temperature

Flame temperatures are determined by a balance of energy between reactants and products. In principle, the highest temperatures would be produced at  $\phi = 1$  as all of the fuel and oxygen are consumed. In reality, species dissociation and heat capacity shift the peak temperature to an equivalence ratio of  $\phi = 1.05$  (Richards, et al., 2001). The fuel type determines the flame temperature as shown in Table 13. The difference in flame temperature of approximately 150°C (270°F) between methane and both H<sub>2</sub> and CO is what makes the development of DLN combustors challenging for syngas (IGCC applications).

Table 13: Adiabatic Flame Temperatures for Different Fuels.

Fuel Type	(Air/ Fuel) stoich	FAR stoich	Flame Temp, °C
Methane, CH <sub>4</sub>	17.2	0.058	1963
Ethane C <sub>2</sub> H <sub>6</sub>	16.1	0.06	1971
Propane C <sub>3</sub> H <sub>8</sub>	15.6	0.064	1977
Hydrogen H <sub>2</sub>	34.2	0.029	2107
Carbon Monoxide CO	2.5	0.4	2111

#### Issues for Premix Flames and Fuel Variability

There are several factors relating to fuel variability that affect premix flames. These include:

- Flame anchoring and flashback.
- Autoignition.
- Static and dynamic flame stability.

#### Flame Anchoring and Flashback

One of the complications caused by lean premix operation is the flashback problem. As the air and fuel are mixed prior to entering the combustion chamber, the combustor aerodynamics must be designed to produce a recirculation zone where the products of combustion are shielded from the surrounding high velocity gases. The hot gas serves as an ignition source for the premixed gas, and anchors the flame in the combustor. The flame surface establishes itself at points in the flow where the local gas velocity balances the flame propagation speed, and the location of the flame is therefore determined by the turbulent flame speed and the local gas velocity. The velocity boundary layers near the fuel injector produce a slow speed region where it is possible for flame to propagate back into the combustor. If the flame travels into the fuel injector, combustion can be sustained in wake regions where the fuel has not yet mixed with the air and produce very high temperatures in the pre-mixer. Even with no flashback, modifications in the fuel properties can cause a repositioning of the flame so that the fuel injector gets overheated and thermally damaged.

The situation is often aggravated by dynamic pulsations. Changes in fuel can result in combustion oscillations that can be severe enough to momentarily reverse the fuel nozzle flow causing overheating in the pre-mixer. Examples of flashback damage are shown in Figure 14, and Figure 15.



Figure 14 Flashback Damage. (Angello and Castaldini, 2004)



Figure 15 Flashback Damage. (Latcovich, 2002)

Recent findings reported by U.S. DOE/NETL (2006) have indicated that a parameter of importance is the turbulent flame speed when it comes to practical premixers. The turbulent flame speeds respond differently for different fuels as opposed to the traditional assumption that it is proportional to the laminar flame speed.

#### Autoignition

Premixers must be designed to avoid autoignition that occurs when pre-mixer conditions are suitable to initiate combustion even if no flames are present. If the pre-mix air temperature is high enough, then simply injecting fuel into the air will initiate combustion. This can damage the pre-mixer and cause subsequent additional downstream damage.

This problem is particularly severe in high pressure ratio engines or engines where heavies exist in the gas fuel, or where there may be trace amounts of oil derived either from the pipeline or fuel gas compressor. The compressor discharge temperatures and pressures that are obtained for a large population of gas turbines (at an ambient temperature of 15°C) are shown in Figure 16. These data are based on software simulation for a range of gas turbines operating over a wide range of pressure ratios. Autoignition times for fuels at gas turbine conditions may be found in Cowell and Lefebvre (1986).

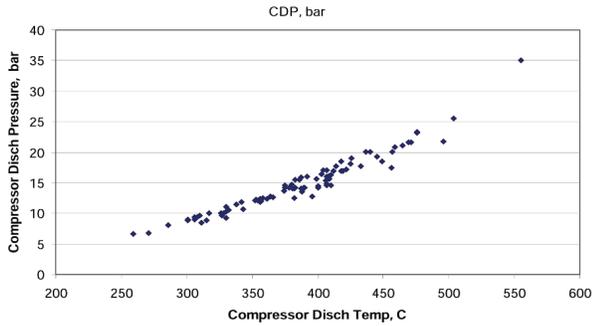


Figure 16. Scatter Plot for a Large Population of Gas Turbines Showing Compressor Discharge Temperature and Compressor Discharge Pressure—Data Derived from Software Simulations on a Large Number of Engines).

To avoid autoignition, premixing fuel injectors are designed around the characteristic autoignition time scale. The autoignition time for methane is longer than the residence time in the premix passages, so autoignition for methane can easily be avoided. However the presence of higher hydrocarbons will significantly lower the autoignition time. Research has shown (Brandt, et al., 2003) that the autoignition time scale can change by a factor of seven depending on the type of natural gas. Ethane content in natural gas plays a big part in this. Autoignition time scales are also reduced at higher pressures, making this a potential problem in very high pressure ratio aeroderivative engines. A representation of autoignition temperatures is shown in Figure 17. The impact of increasing levels of propane on ignition time is shown in Figure 18.

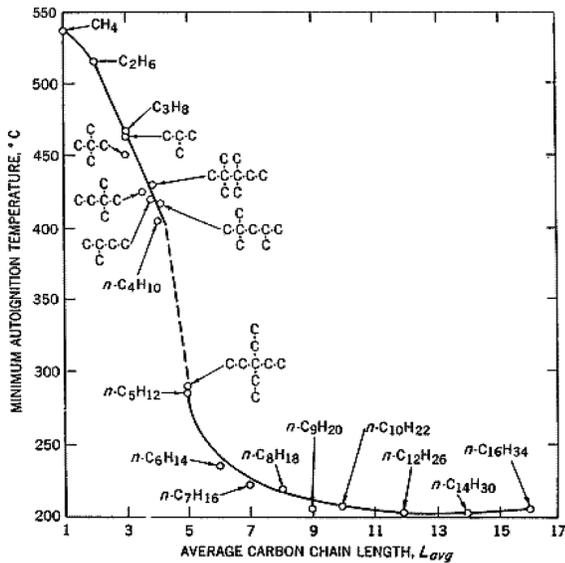


Figure 17. Autoignition Temperatures. (Coward and Jones, 1952).

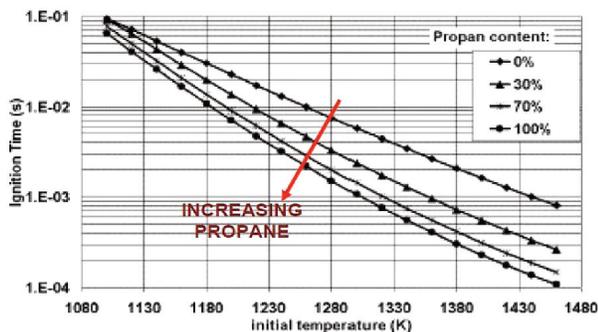


Figure 18. Impact of Propane Content on Ignition Time. (Brandt, et al., 2003)

There is another fundamental issue with premixer design. On the one hand it is good to have a longer residence time to ensure good mixing to avoid hot spots due to localized fuel rich spots. However, from an autoignition standpoint, the desire is to exit the premixer as fast as possible to avoid autoignition.

Liquid hydrocarbon dropout is also a very serious issue. Wilkes and Dean (1997) have suggested that dew point condensation should be monitored so that appropriate superheat can be provided to the gas stream to avoid liquid dropout.

Static and Dynamic Flame Stability

Combustion stability is of great significance with lean premix DLN or DLE combustors. Details may be found in a valuable book edited by Lieuwen and Yang (2005).

Combustor stability can be categorized into two classes (Lieuwen, 2006):

- Static stability—Relates to the anchoring of the flame in the combustor and how well it can be maintained during transient loading or unloading conditions when the lean blow out margin may be encroached. With low equivalence ratios being employed, modern premix combustors often operate close to the lean blow out or lean extinction margin. A common situation is during a rapid load drop where the fuel flow is suddenly reduced. As was explained earlier, operation near the lean extinction zone is to keep low flame temperatures in order to minimize NOx, but excessively cool regions should be avoided to minimize CO. These competing requirements are made more complex by dynamic pulsations and oscillations.

- Dynamic stability—This problem (pressure oscillations or humming) has been one of the major issues plaguing lean premix combustors. In premix systems, small disturbances in pressure create immediate changes in airflow producing a change in reaction stoichiometry. Near the lean blow out limit, small changes in reaction stoichiometry can lead to significant variations in heat release. If these variations are synchronized (or in resonance) with the pressure field, oscillating combustion can be sustained resulting in frequencies that can range from a few Hertz to high frequency screech. The dynamics and pulsation can be affected by ambient temperature, load, relative humidity and fuel quality. The dynamic pressure pulsations can occur at a variety of frequencies including low frequency dynamics in the 10 to 50 Hz range (known as rumble), intermediate frequencies between 200 to 400 Hz, and high frequency dynamics that occur at very high “screech” frequencies (above 1000 Hz). Some engines use acoustic damping approaches such as quarter wave tubes as shown in Figure 19.

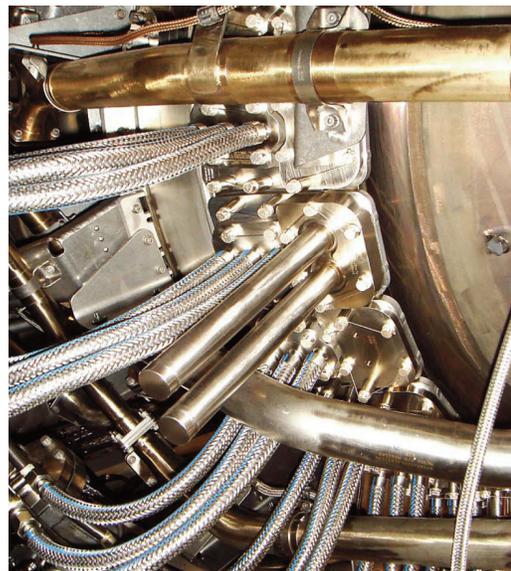


Figure 19. Resonance Tubes in an Aeroderivative Engine (Pulsation Control).

Pulsation damage to a transition piece is shown in Figure 20. Damage to a crossover piece caused by excessive pulsations is shown in Figure 21. Further details on fuel interchangeability may be found in Klassen (2005).



Figure 20. Transition Piece Damage Due to Dynamics.



Figure 21. Connecting Tube Damage Due to Pulsations. (Angello and Castaldini, 2004)

## GAS FUEL SYSTEM DESIGN CONSIDERATIONS

Gas turbine OEMs provide fuel specifications in their documentation, and it is typically the user's responsibility to ensure that gas quality at the skid edge flange meets the specification in terms of quality, temperature and pressure. With the introduction and widespread use of premix dry low NO<sub>x</sub> combustors, these requirements are much more stringent than with standard or water injected combustors. It is always advisable to provide the gas turbine OEM a clear definition of the fuels or range of fuels that are intended to be used in order to allow them to check the suitability. This is a prudent approach as opposed to just trying to follow a specification, as the specifications are to some extent guidelines, and certain engineering considerations can be considered by the OEM if the full picture is provided.

Meeting the specification involves an integrated design of the overall fuel system, including gas cleanup, filtration, gas heating and an evaluation of the fuel properties with respect to dew point.

### Pipeline Gas Composition

Natural gas is a widely used fuel and Akhtar (2001) provides details on gas conditioning in terms of dew point control. The water content in U.S. natural gas is limited to 112 mg/m<sup>3</sup> or 7 lbs/MMSCF of gas. To maintain typical water level content of 4 to 7 lb/MMSCF, ethylene glycol is used for scrubbing the gas. Process upsets in the treating facility can result in carryover of the scrubbing liquid. Most of the solids in a pipeline are generated from oxidation and corrosion of the pipeline and will appear in the form of fine iron oxide particles. Details of contaminants and issues relating to pipeline gas are provided in Baldwin (1977). Swanekamp (2005) states that in the current market, natural gas is being delivered with more variable heating values and with heavy components.

### Gas Characteristics

The original equipment manufacturer typically specifies the acceptable fuel properties to user. While different OEMs have different requirements regarding fuel gas properties, they can largely be described as pertaining to the following items (Nord and Anderson, 2003):

#### Lower Heating Value and Wobbe Index

The mixing of the fuel gas with the air supplied from the compressor depends partly on the gas velocity, and for a specific burner type there is a range of gas velocities that will produce sufficient mixing. This relationship is often represented in terms of the Wobbe Index or number.

$$\text{Modified Wobbe Index} = \frac{\text{LHV}}{\sqrt{\text{SG}_{\text{gas}} \times T_{\text{gas}}}} \quad (2)$$

where:

LHV = Lower heating value of gas fuel (Btu/scf)

SG<sub>gas</sub> = Specific gravity of gas with respect to air = MW<sub>gas</sub>/28.96

T<sub>gas</sub> = Fuel gas temperature, degrees Rankine

If two different gaseous fuels have the same Wobbe Index, they can be supplied to fixed metering orifices at the same fuel pressure and produce the same heat output at a given combustor pressure. It is very important to note that the Wobbe number or modified Wobbe number is an overview-type parameter and should not be considered as the only parameter to determine suitability of a fuel gas. While gas turbines with traditional combustors can operate with gases having a wide range of heating value, such as 7,440 to 111,600 kJ/SCM (200 to 3,000 Btu/SCF), the amount of variation that a *specific* fuel system can accommodate is narrower. For ignition and start up, the typical allowable variation in the Wobbe Index is often limited to ±5 percent but for operation the allowable variation may be greater, and is primarily governed by the minimum allowable fuel nozzle pressure ratio (FNPR) as set by the gas turbine vendor. With DLN/DLE combustors the range of heating values is severely limited.

#### Contaminants

Plugging and erosion drive the requirements regarding contamination issues. All OEMs require a filter upstream of their equipment to ensure that contamination requirements are met. Other than occurrences such as a burst filter or open filter bypass line, these filters will ensure that the gas is free of solid contaminants. Some common contaminants likely to be found include tar, lamp black, coke, water, salt water, sand, clay, rust, iron sulfide, scrubber/liquid oil, lube oil, naphthalene and gas hydrates. Before delivery to the gas turbine, the fuel gas conditioning system must remove these contaminants. Fuel gas delivered to the gas turbine must not contain any significant concentrations of liquid droplets or solid particles. Typically the fuel gas should be prefiltered to 3 to 5 microns.

Water content of the fuel gas should not exceed the saturation amount by more than 0.25 percent by weight. The total amount of other contaminants contained in the fuel should not exceed 0.1 to 1.0 ppm. These are just typical values, and in all cases the OEM must be consulted for specific limits. If HRSGs are used, the concentration of sulfur in fuel gases must also be specified. Severe corrosion from sulfuric acid condensation results if a waste heat recovery unit has metal temperatures below the sulfuric acid dew point. Approximate dew points for typical natural gas fuel are 77°C (170°F) for 30 ppm sulfur, and 121°C (250°F) for 0.3 percent sulfur. If fuel gases contain H<sub>2</sub>S (sour gas fuels), materials in the fuel conditioning system must comply with NACE Standard MR0175-93.

#### Pressure

Fuel pressure requirements are governed by the air pressure in the combustion chamber, as well as pressure drops across control valves and fuel nozzles. Failure to meet this requirement will prevent the gas

turbine from meeting the power demand. The required fuel pressure is therefore a function of ambient temperature (as compressor discharge pressure is also a function of ambient temperature), and the amount of inerts in the fuel gas. The gas fuel supply pressure must exceed both the maximum fuel nozzle pressure drop and the minimum gas control valve pressure drop necessary to maintain sonic velocity at the control valve throat. As a rough rule of thumb, at least 1.2 to 1.6 times the compressor discharge pressure is required.

#### Temperature

The need to avoid two-phase fuel (liquid carryover) with its associated fluctuating heat input drives the temperature requirement for superheat. Typically, the superheat requirement should be 28°C (50°F) above the dew point. This superheat level is just a guideline and must be checked using actual fuel composition. It is important to note that control valves, fuel nozzles, as well as other devices that cause a pressure drop will also cause a Joule Thompson temperature drop. A rule of thumb commonly used is a 7°F drop per 100 psig pressure drop (3.9°C per 6.9 bar pressure drop). As the dew point is very sensitive to the presence of higher hydrocarbons, dew point monitoring is highly recommended in cases where variations in fuel composition are expected. Both the moisture and hydrocarbon dew points must be considered. Problems caused by liquids and contaminants in gas turbine fuel are covered by Newbound and Norek (1997) and Norek and Newbound (2005).

#### Composition

Requirements regarding fuel gas composition in OEM specs are driven by a number of factors including autoignition, flame temperature, emissions and stability. It should be pointed out that these requirements are general and OEMs must be consulted as a matter of course for any fuel that has to be used.

#### Flammability Limits

Gases containing hydrogen or carbon monoxide will have a rich-to-lean flammability limit ratio that is significantly larger than the flammability limits of natural gas. If the lean flammability limit is such that a normal ignition mixture will be flammable when diluted to gas turbine exhaust conditions, the ignition mixture is regarded as a hazardous gas. In this case, a start-up fuel such as natural gas should be used to bring the turbine up to a steady-state running condition. Natural gases with a large percentage of inert gases (such as nitrogen or carbon dioxide) may at a certain point have combustion instability issues.

#### Fuel System Design Problems

There are several issues that must be considered in the design of the plant fuel system

#### Fuel System Design Capacity

The fuel system design must consider the lowest ambient temperature, and also take into account that future upgrades may involve inlet chilling that will cause an increase in fuel flow rate.

#### Sizing of Key Equipment

Supplier for filter separators should be carefully evaluated and experience with similar systems evaluated. The flow through these devices should also be carefully considered, including cold-day scenarios or peaking operation.

#### Selection of Back up Fuel Systems

For mechanical drive applications such as an LNG facility, several back-up fuel sources need to be present. The changeover rate between these alternate sources must be carefully considered in light of the rate of change of the modified Wobbe number. Depending on the situation, mixing drums or special online instrumentation may have to be employed.

#### Heating Value Control

The specified heating value for the gas turbine must be maintained when different sources of fuel are used. The use of temperature to control the modified Wobbe number is normally used.

#### Dew Point Measurement

28°C (50°F) is a typical superheat margin over the dew point required by gas turbine OEMs. It is very important that the analysis done to determine the dew point is an extended analysis that considers individual hydrocarbons up to C14, as opposed to lumping hydrocarbons together as "C6+." Depending on the gas components the correct C14 component analysis can yield a dew point dramatically different to the C6+ type analysis. Wilkes (1996) states extreme differences of 55.5°C (100°F) can result. Further details are provided in Wilkes and Dean (1997).

#### Fuel Gas Skids and Fuel Monitoring

Typical fuel gas condition systems consist of:

- A scrubber to contain bulk liquids and reduce liquid loading on the downstream filter/coalescer.
- A duplex coalescing filter typically arranged in a vertical pressure vessel. Filter elements need to be changed when a predetermined pressure drop is reached.
- A heat source (electric or steam typically).
- Online gas chromatograph or other dew point meters to calculate the dew point.

Details on fuel gas treatment systems and dew point monitoring, may be found in Wilkes (1996) and Wilkes and Dean (1997). Other items of importance include:

- Dew point heaters should be located upstream of the scrubber coalescers.
- Stainless steel fuel gas piping is recommended.
- Avoid low points where condensation can collect.
- Consider insulating fuel gas piping or heat tracing.
- Install a coalescing filter as close to the gas turbine as possible.
- Upon excessive EGT spreads, investigate fuel gas quality.
- Ensure thorough cleaning during commissioning.

A typical fuel filter skid is shown in Figure 22.

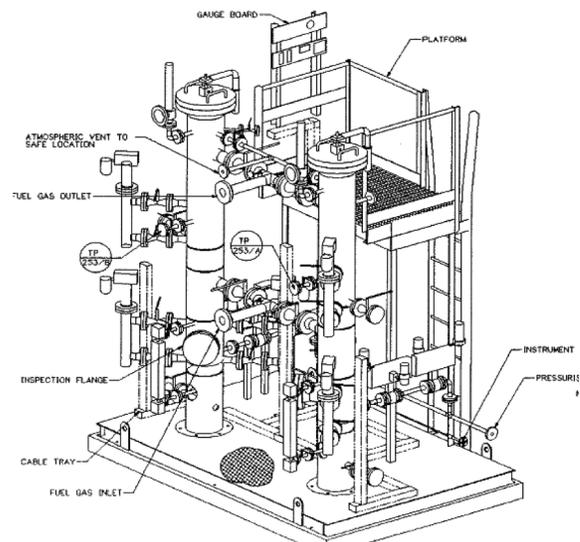


Figure 22. Duplex Fuel Filter Skid.

It is also possible to get absolute separators that have multistage elements and can deliver an excellent quality of gas to the turbine.

*Practical Installation Aspects—Flange Leak Testing*

Several gas turbines require disassembly of the fuel gas piping during major maintenance activity. A major time-consuming but very important activity is flange leak testing, which has traditionally been done by the use of masking tape that is wrapped around the flange and then a hole is poked in it as shown in Figure 23 (left hand side) after the fuel system is pressurized and a sniffer system used to check for leaks. A lot of down time is spent in the removal of this tape after the testing is done. An alternative and elegant method described by Woods (2007, 2009) employs a specially designed elastomeric polymer band that can withstand temperatures of up to 500°F as shown in Figure 23 (on the right hand flange). The installation of this band is shown in Figure 24. Woods reports that this approach can save considerable time during an outage and accelerate the process of flange leak testing.



Figure 23. Flange Leak Testing. (Courtesy Flange Band-It LLC)

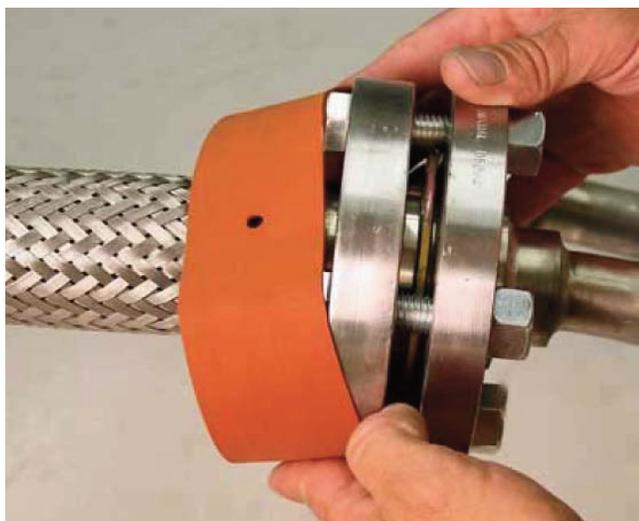


Figure 24. Installation of Band for Flange Leak Testing. (Courtesy Flange Band-It LLC)

*Syngas—IGCC Applications*

Gasification of solids such as coal, provides clean gaseous fuels for gas turbines through integrated gasification combined cycle plants. Gasification involves partial oxidation performed under pressure by an oxidant (either air or oxygen) and steam. Beyond the production of gas turbine fuels, gasification provides an opportunity to capture carbon dioxide prior to combustion. Both air-blown and oxygen-blown IGCC fuels have relatively low volumetric energy

contents when compared to natural gas. Traditionally, IGCC applications have employed diffusion flame combustors that have been designed for the higher levels of hydrogen contained in syngas. Syngas can be obtained from a wide variety of coal grades and also from biomass and petroleum coke. Typical syngas qualities obtained from IGCC applications are shown in Table 14 (Tennant, 2010).

Table 14. Typical IGCC Syngas Compositions.

Syngas	A	B	C	D	E	F	G
H2	24.8	37.2	35.4	34.4	8.6	61.9	22.7
CO	39.5	46.6	45.0	35.1	26.2	26.2	30.6
CH4	1.5	0.1	0.0	0.3	8.2	6.9	0.2
CO2	9.3	13.3	17.1	30.0	14	2.8	5.6
N2+AR	2.3	2.5	2.1	0.2	42.5	1.8	1.1
H2O	22.7	0.3	0.4	-	-	-	39.8
Pre diluent LHV, BTU/ft3	209	253	242	210	183	317	163
kJ/M3	8224	9962	9528	8274	7191	12492	6403
GT Temp, C	330	371	121	96	204	38	200
H2/CO Ratio	0.63	0.79	0.98	-	0.33	2.36	0.74
Diluent	Steam	N2	N2/Steam	Steam	-	Steam	Moisture
Equiv LHV Post Diluent BTU/Ft3	150	118	113	198	-	200	-
kJ/M3	5910	4649	4452	7801	-	7880	-

Several process applications using older gas turbines can operate with high hydrogen fuel, but newer high firing temperature machines pose a challenge. The key combustion characteristics of hydrogen are low ignition energy, low density, high flame speed, high flame temperature and wide flammability range. DLN type combustors are limited to a maximum 10 percent H<sub>2</sub> content due to potential flashback.

*LNG as a Gas Turbine Fuel*

With the number of LNG liquefaction trains growing rapidly and international shipments of LNG increasing, liquefied natural gas has become an important fuel for gas turbine operation and presents challenges as they may contain higher levels of ethane, propane or nitrogen compared to traditional pipeline gas.

In order to evaluate LHV differences among several LNG sources, published average values compared with a typical U.S. pipeline quality natural gas are shown in Figure 25. The largest difference is 6.25 percent for LNG originating from Abu Dhabi. From Trinidad, the major U.S. source of LNG import, the difference was only about 2 percent.

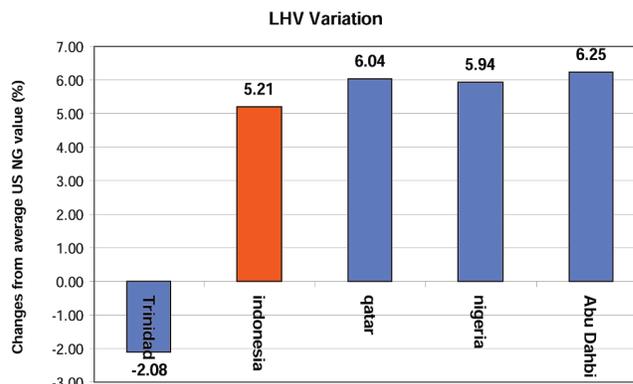


Figure 25. LNG LHV Values Compared to Average U.S. Natural Gas.

Similarly, a comparison of the relative percentage difference between the Wobbe Index of various LNG sources and a typical U.S. natural gas is shown in Figure 26. Indonesian and Nigerian LNG had the highest discrepancies around 7 percent. Again the LNG from Trinidad has less than 0.5 percent difference, well within the gas turbine industry acceptance limits for Wobbe Index variation.

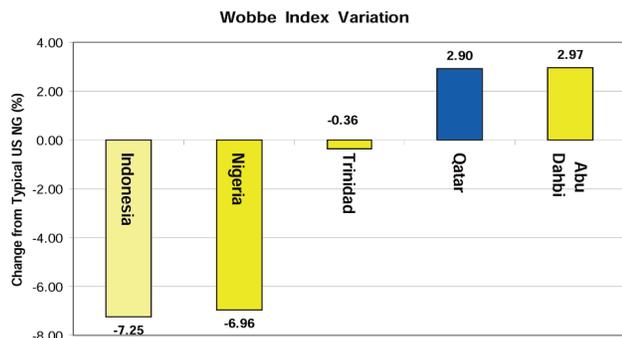


Figure 26. Relative Wobbe Index Variation of LNG Supply Compared to Average U.S. Natural Gas.

The variation in C1, C2 and C3 content in LNG from different countries is shown in Figure 27. Details may be found in Zachary (2007).

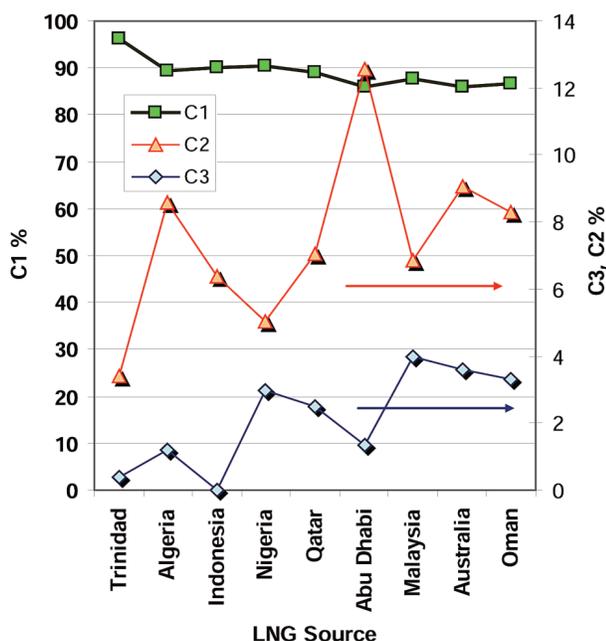


Figure 27. Variation of C1, C2 and C3 in LNG Supply.

#### Fuel System Instrumentation

##### for Performance Testing Considerations

ASME PTC 19.5 deals extensively with several types of flow meters and their expected accuracy. ASME PTC 22 (gas turbine performance) also discusses the merits and formulae used for several flow meter types. In most cases, temporary and freshly-calibrated flow meters are used for performance testing.

A brief description of flow meters used for natural gas fuel flow measurement is provided below:

- Orifice meters—An orifice gas meter consists of a straight length of pipe inside which a precisely known orifice is located. The gas static pressure, density, viscosity, and temperature must be measured or known in addition to the differential pressure that is measured. Orifice meters are less accurate over large ranges of flow rates but are extensively used and understood in industrial applications since they are easy to service and have no moving parts.
- Turbine flowmeters—These use a small turbine that is rotated by the flow. The rate of spin is measured to determine the flow. Turbine gas meters infer gas volume by determining the speed of the gas moving through the meter. These meters do not impede the flow of gas, but are limited at lower flow rates.

- Vortex flowmeters—An obstruction in a pipe creates vortices on the downstream side of the obstruction. Temperature or pressure sensors measure the vortices to gauge the strength of flow.
- Ultrasonic flowmeters—This is a device that will either measure the flow velocity, volume or mass flow of a liquid or a gas. An ultrasonic flow meter can be categorized as either a Doppler type (which uses the Doppler shift principle) or a transit time device that measures the differential temperature or time of flight path.
- Coriolis mass flowmeter—This meter uses the “Coriolis” effect to measure the amount of mass moving through the element. Mass flow is measured directly, which gives it a distinct advantage over volumetric flow devices. In calculating the gas turbine efficiency one needs to evaluate the plant heat input. The plant heat input measurement has two elements: the mass flow of the fuel and its heating value. If a volumetric flow meter is used to calculate the mass flow, the gas density is required. The calculation of the gas density is done based on the gas composition and therefore any test uncertainty associated with the gas composition affects the heat input accuracy on two counts. The use of a direct mass flow meter eliminates the need for calculation of the density.

A selection of the appropriate fuel measurement device must be made for each specific application and plant testing requirements. The provision of a straight slave spool in the fuel lines allows the use of temporary flowmeters, aimed at confirming the accuracy of online measuring devices.

#### Gas Composition Measurement

The measurement of natural gas composition is required to determine the heat input to the plant. The traditional approach is to extract gas samples from the supply to the turbine fuel line and send them to a laboratory for analysis. Online measurement of natural gas composition by gas chromatographs or other devices is now more common. These devices are capable of identifying the concentration of various hydrocarbons and other inert elements within the fuel gas stream.

#### Property Measurements

A gas chromatograph is a chemical analysis instrument for identifying components in a complex sample. Currently the price of gas chromatographs (particularly for C6+ type) has reduced, allowing its routine use for “online” gas composition measurement. Unfortunately, for rapid changes in natural gas composition as in the case of large slugs of gas originating from an LNG source, the changes in the fuel compositions cannot be accommodated by a GC due to the slow response of the detection system. However, it is possible to determine the composition of gaseous mixtures with a composition close to that of natural gas by infrared analysis. Using regression methods, in reference to data from chromatographic analysis and spectroscopic data, reasonable estimates of the gas mixture composition are achievable. The detection and response time of these IR methods is much faster than that of online gas chromatographs.

## LIQUID FUELS

Natural gas will undoubtedly continue to be the preferred fuel for land-based gas turbines, not only because of its convenient delivery and handling, but also due to its clean and efficient combustion properties. However, in certain regions of the world natural gas is either not available or in short supply, and in these situations the local power producers must turn to alternative liquid fuels with qualities ranging from light distillates to heavy residual-grade oils or unrefined crude oils. Liquid distillates such as diesel oil or kerosene are also widely used as secondary back-up fuels in dual-fuel applications, which is often a contractual obligation in case of disruptions to natural gas supplies. Dual-fuel capability may also enable the primary fuel (i.e., natural gas) to be purchased at a more favorable price.

Decisions as to which fuel to use are usually project specific, and must consider fuel price (which is closely linked to quality) as well as overall performance and plant availability. Fuels should be appropriate for the intended application and, especially in the case of low-grade fuels, must also be suitable for the particular gas turbine model. Residual-grade oils and crude oils will require additional balance of plant and onsite treatment programs, and these items also need to be carefully considered during the initial planning and design stages. The use of residual oil and crude oil in gas turbine applications and the underlying requirements for fuel treatment has been reviewed by Bromley (1986, 2006). BOP design considerations and the importance of realistic fuel specifications for heavy fuel projects are described by Moliere, et al. (2002).

When faced with the nonavailability of natural gas and the high price of distillates, the use of low-grade fuels in heavy-duty gas turbines has proved to be economically attractive in numerous plants around the world, and new projects involving residual oils and crude oils continue to be developed. A map showing regions of the world where various liquid fuel qualities are utilized for gas turbine applications is shown in Figure 28.

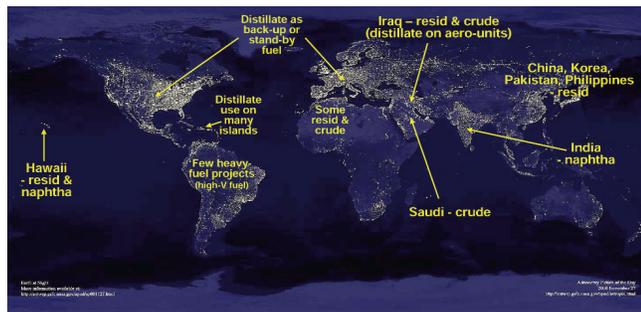


Figure 28. Regional Examples of Liquid Fuel Trends in Gas Turbine Applications.

It is also worth mentioning that many gas turbine projects (mostly in Asia) were specifically developed to burn low-grade residual oils for an *initial* operating period—often lasting 10 years or more—and were later converted to natural gas when it became available in the region. In many cases the conversion to gas was also linked to the addition of a combined cycle. These upgrades usually attract significant publicity, but the successful operating years on low-grade oil are often overlooked or forgotten. It should be remembered, however, that in most cases the local population would have been without electricity for many years if these projects (sometimes considered risky) had not been undertaken.

In some cases fuel choice is actually a nonissue, because power producers must burn whatever fuel is available. During the current difficult situation in Iraq, for example, both natural gas and light distillates are in extremely short supply, and their limited availability will continue until the needed refining and pipeline infrastructure can be restored. As a result, many new power plants have been installed over the last five to six years involving heavy-duty gas turbines burning either locally produced crude oil or residual grade oil from nearby refineries. Some of these fuel qualities are not ideal, but treatment programs at the power plants have enabled successful operation and, as a result, numerous new heavy-fuel projects and expansions are currently under construction. Iraq is an example where there is simply no alternative to the use of low-grade liquid fuels, other than to prolong the chronic power shortages facing this country at the moment.

#### Refinery Processes

Distillates and residual-grade fuels originate in the oil refinery, and are produced from the fractionation of crude oil as illustrated in Figure 29. The lower boiling point distillates are relatively free of sulfur and trace metals, but contaminant concentrations increase in the higher boiling point fractions toward the bottom of the

distillation column. In fact, these components become concentrated in the “residuum,” so that residual-grade oils contain higher contaminant levels than the crude oil from which they were produced. This is an important consideration for gas turbine applications, because trace metal impurities create ash deposits during combustion and, unless treated, are responsible for various high-temperature corrosion mechanisms. Other properties such as density and viscosity also increase on moving down the distillation column.

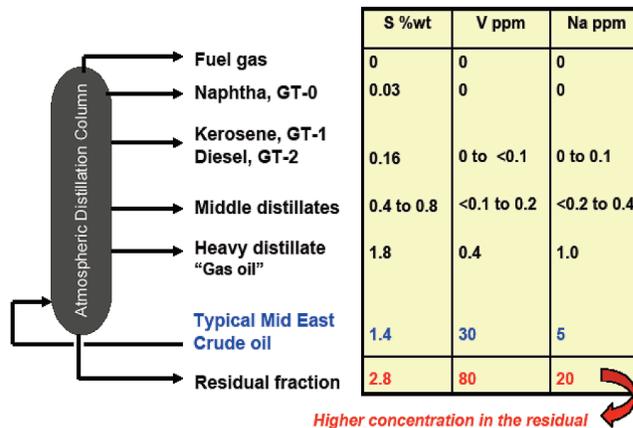


Figure 29. Simplified Schematic of Crude Oil Distillation Showing Typical Contaminant Levels.

#### Distillates

Distillates are classified as “clean” fuels because of the absence of ash-forming trace metal impurities. Combustion characteristics are similar to natural gas and, without considering price, they are the most logical fuel alternative.

Several different grades of distillate are available and those most commonly used as gas turbine fuels are *No. 2 distillate* (also known as No. 2 diesel oil, No. 2 fuel oil or heating oil) and *kerosene*—which in Britain is often called paraffin. *Naphtha* is also gaining popularity as a gas turbine fuel, and is actually the generic name for a group of volatile and low-boiling point distillates normally used as a feedstock for gasoline production. However, depending on the desired product mix at a particular refinery, portions of the naphtha fraction can be sold directly as fuel. Due to the high volatility of naphtha, explosion-proof fuel handling systems are needed and have been developed for this purpose, and many successful gas turbine applications now exist around the world including the U.S. Probably the largest use of naphtha is in India, where it is burned as the primary fuel in almost all gas turbines in that country.

Distillates normally do not require additional treatment at the gas turbine power plant, but certain fuel properties can influence reliable operation. For example, some diesel oils and kerosenes have relatively high wax content and (more importantly) high wax melting temperatures, so fuel heating systems must be designed to prevent wax crystallization and filter plugging. Also, naphtha and certain kerosenes are known to have poor lubricating properties, and lubricity improvement fuel additives are often needed to protect critical components such as fuel pumps and flow dividers.

#### Distillate Contamination

It should always be remembered that “clean fuels” can also become accidentally contaminated during delivery, such as by seawater contact from marine transportation. Unfortunately this is an all too common occurrence, and numerous gas turbine blade failures (caused by sulfidation corrosion) have been reported that relate directly to sodium-contamination of distillates. Actually, the potential for hot corrosion with distillate fuels is greater than with residual grade oils or crude oils. This is because ash-forming trace metals are anticipated in heavy fuels, so treatment programs are

always applied at the power plant. However, distillates are assumed to be contaminant-free, so fuel quality monitoring may not be as diligent and fuel treatment systems may not be installed. Furthermore, gas turbine firing temperature is normally higher for distillate fuels and protective blade coatings may not be applied, so the risk and consequence of hot corrosion are higher.

The possibility of sodium contamination during the marine transportation of fuels results mainly from the fact that seawater is used as “ballast,” i.e., to adjust the buoyancy of an empty tanker after discharging its cargo. Most of the new, large, oceangoing super tankers are now equipped with segregated (dedicated) ballast tanks, but many older vessels and coastal barges still use their product tanks for seawater ballast. Note that OEM specifications for sodium plus potassium (actually for total alkali metals) in gas turbine fuels range from as little as 0.1 ppm up to 1.0 ppm maximum, depending on the gas turbine model, and it does not take much seawater to exceed these limits. In fact, *8 gallons of seawater in 1 million gallons of distillate will contribute 0.11 ppm Na + K.*

In coastal or marine locations, the ingestion of airborne sea salt can also initiate hot corrosion regardless of fuel type, and this risk applies equally to natural gas or liquid fuel applications.

Fuel contamination with traces of lead (Pb) and zinc (Zn) has also been reported, and which also causes high temperature corrosion of gas turbine blades. These metals are not natural components of petroleum and contamination can usually be explained by contact with leaded-gasoline or (respectively) with galvanized materials. Leaded-gasoline is still used in the Middle East, Africa, parts of Asia and Latin America, and lead additives are also used in aviation gasoline. Typical OEM limits for Pb in GT fuels are in the range 0.5 to 1.0 ppm maximum. *33 gallons of leaded-gasoline in 10,000 gallons of distillate will contribute about 1.03 ppm Pb.*

#### *Residual-Grade Oils and Crude Oils*

These fuels are classified as “contaminated” because they contain relatively high concentrations of various trace metals (sodium and vanadium, etc.) and other impurities such as solids and sediments. Trace metals create ash deposits during combustion, which impacts gas turbine performance and availability but can also lead to serious high temperature corrosion issues unless fuel treatment programs are applied at the power plant. Such treatment programs use centrifugal separation processes to remove those contaminants that are removable, such as water-soluble sodium salts and water-extractable solids. Then, special chemical additives are injected to inhibit the corrosive effect of oil-soluble trace metals (primarily vanadium) remaining in the fuel.

Residual oils are usually blends of several different refinery residues, i.e., from atmospheric distillation, vacuum distillation, and various cracking processes, etc. Their properties vary tremendously depending on the crude oil feedstock and the degree of fractionation and processing within a particular refinery. Generally, residual oil quality around the world is deteriorating, and this is simply because refineries try to maximize their yield of light distillates and high-value products such as gasoline. The net effect is that residual fractions become heavier, more viscous, and more contaminated with trace metals.

As a result, so-called “straight-run” residuals (typically termed “No. 6” grade) are normally not sold without some degree of additional blending with a light- or middle-distillate, in order to meet minimum sales specifications for the major markets—such as maximum sulfur or maximum viscosity, etc. However, these basic sales specifications may not adequately address all important items needed for gas turbine applications—such as trace metal content, which is usually limited to a maximum of 100 ppm by the OEMs. In many cases, therefore, it may be necessary to establish a project-specific fuel specification with the supply refinery, which may involve additional distillate blending to further reduce trace metal content, but of course this will also increase the price of the residual fuel oil.

More competitive fuel prices can usually be achieved if residual oils are purchased on the spot market, rather than from a single-source refinery. However, this greatly increases the chance of quality variations from one fuel delivery to another, because these residual oils can originate from a multitude of different crude oil feedstocks and blend scenarios. Power plants purchasing spot-market fuels should be extra diligent in analyzing each and every fuel delivery to ensure continued conformance to the original contractual specification.

Residual oils coming from different (or unknown) source refineries should also be carefully monitored for stability and compatibility before mixing different batches. This issue relates to asphaltenes (a heavy bitumen-type component of petroleum), and the fact that asphaltenes can be *destabilized* if oils with incompatible chemistries are inadvertently blended. If destabilization occurs, asphaltenes will agglomerate (floculate) and eventually precipitate out of the oil as sludge. This can result in very serious fuel system problems such as the plugging of fuel filters, flow-dividers and burner nozzles, etc.

Asphaltene destabilization is well known within the petroleum industry, and a classic example of a severely plugged oilfield flow line is shown in Figure 30. Great measures are taken to prevent the occurrence of these type problems, but incidents can still arise within the fuel distribution and fuel-user markets. For example, the mixing of residual oils from different refineries and different crude oil feedstocks can create asphaltene instability, or if a stable residual oil is blended with an incompatible distillate. This subject is quite complex, but as a general statement aromatic and paraffinic petroleum should not be mixed. For example, an aromatic residual oil (which normally will also have a high asphaltene content) should not be blended with a paraffinic (i.e., “waxy”) residual oil, and especially not with a paraffinic distillate such as kerosene. Asphaltene instability can also occur if incompatible crude oils are blended. Test procedures are available to determine asphaltene stability and to monitor fuel compatibility (ASTM 1993, 2006).



Figure 30. Asphaltene Deposition in an Oilfield Crude Oil Pipeline.

Various names and abbreviations are used around the world to describe residual-grade fuels including “bunker fuel,” “furnace oil,” “mazut,” “LSHS” (low sulfur heavy stock), “LSWR” (low sulfur waxy residual), etc. The most common term within the gas turbine industry is “HFO” (heavy fuel oil).

Worldwide there are numerous gas turbine power plants operating successfully on various qualities of residual oil, with vanadium content typically ranging from about 30 to 90 ppm. Most applications are in Asia, Middle East and North Africa. New projects are also being developed in Latin America. Details of one particular heavy fuel operation at a 600 MW combined cycle plant in the Philippines are provided by Basler and Marx (2001). An interesting feature of this facility is that a fuel blending system is installed so that the received residual oil (which may contain up to 3.5 percent sulfur) can be blended as and if required with a

calculated amount of No. 2 diesel oil to ensure a maximum of 2.75 percent sulfur, as specified in the operating permit. Fuel compatibility issues as discussed above are carefully monitored.

Unrefined *crude oils* are also used as primary gas turbine fuels in certain regions of the world; particularly in Saudi Arabia and currently in Iraq. Crude-firing applications also exist in Equatorial Africa and throughout the oil and gas industry. In most cases crude oil is used simply because of its convenient and abundant local availability compared to other fuel options. The Kingdom of Saudi Arabia, for example, has successfully burned locally produced crude oil in the majority of its gas turbine power plants since the 1970s, and several new (and very large) projects are currently underway. Note also that Saudi Arabian light crude is relatively low in trace metal content (typically about 15 ppm vanadium), and actually this makes it a more attractive fuel than the locally available residual-grade oils. Arabian “super light” crude oil with less than 1 ppm vanadium is now starting to be produced in the region and will likely also be considered as a candidate gas turbine fuel.

Crude oil properties vary throughout the oil-producing countries of the world, but generally they remain relatively constant and specific to a particular oil field or group of oil fields within a region. Crude oils can be “heavy” or “light” (referring to their density), “sweet” or “sour” (relating to their sulfur content), and can also have different chemical natures that influence their chemical properties and the type of products derived during refinery processing. A very general classification of the main crude oil chemistries is shown in Figure 31. Heavy metal contents (vanadium and nickel) also vary according to the geological age and geographic location of the formation, and correlate closely to the chemical nature of the petroleum. For example, highly asphaltic crude oils (e.g., South America) tend to have high vanadium content, whereas waxy paraffinic crudes (typical of South East Asia) generally demonstrate low vanadium content. These geographic trends are illustrated in Table 15. As discussed above, chemical and physical properties of residual-grade fuels are significantly influenced by the properties of the crude oil feedstock from which they are derived.

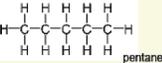
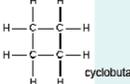
Type	Typical characteristics
Paraffinic	Straight-chain “aliphatic” molecules High wax content Good feedstock for lube oils 
Naphthenic	Saturated cyclic-ring structures Good feedstock for petrochemicals 
Aromatic or Asphaltic	Unsaturated “aromatic” ring structures High asphaltene & vanadium content Feedstock for distillates, heavy fuel oils (HFO), pitch, tars and petroleum coke 

Figure 31. Typical Classification of Crude Oil Chemistries.

Table 15. Typical Vanadium and Nickel Contents in Selected Crude Oils.

Region	V (ppm)	Ni (ppm)
South America	50 to 500	10 to 50
California	30 to 200	10 to 100
Alaska	15 to 30	5 to 10
Middle East	5 to 50	1 to 10
North Africa	0 to 50	0 to 15
S. E. Asia	0 to 3	5 to 30

Environmental Considerations

The trend toward low sulfur fuels and reduced SOx emissions can be expected to continue, and in certain cases this may limit the locally-available fuel options. Refineries processing sweet crudes generally have low-sulfur products available, and in some cases additional (but expensive) desulfurization processes are involved. Market price tends to be higher, as is the differential between distillate and residual grades.

An application in Hawaii is worth mentioning because it is currently the only residual oil-fired gas turbine facility in the United States. Fuel decisions at this cogeneration facility were based not only on a significant price difference between residual oil and distillate, but also because a low-sulfur grade residual oil (<0.5 percent S) was locally available. Hawaii is an example where natural gas supplies are limited, and generally not available for industrial use. Other gas turbine plants on the islands are operating on various grades of No. 2 diesel oil, and at least one facility is burning naphtha in aeroderivative units.

Ultra-low sulfur distillates (5 to 30 ppm S) are fast becoming mandated within the transportation and power generation markets. Aside from higher price, these type fuels can also have poor lubricating properties and lubricity improvement additives may be required to protect gas turbine components such as flow dividers and fuel pumps. Lubricity trends for traditional No. 2 diesel oil and the impact of ultra-low sulfur grades are summarized in Figure 32.

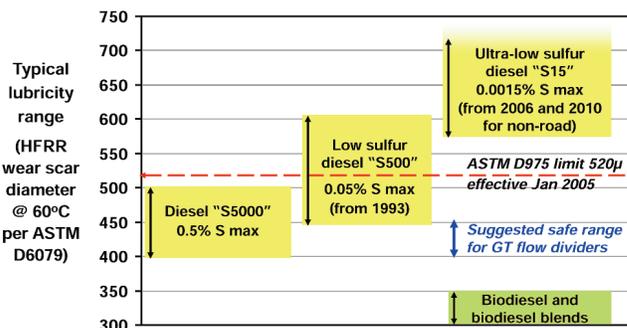


Figure 32. Lubricity Trends for Traditional and Ultra-Low Sulfur Diesel Oils without Lubricity Improvement Additives.

Gas Turbine Considerations with Liquid Fuels

The type and model of gas turbine must be suitable for the particular grade of oil, and the application must be supported by the OEM. Heavy-duty engines with lower firing temperatures are used for burning residual oil and crude oil, and also for distillates if fuel contamination is expected. Several “work horses” from various manufacturers have proved to be very suitable for these type applications, and essentially involve up to and including “E-Class” technology. Specific models with successful track-records firing heavy fuels include F5, F6B, F7E/9E, W-251, W-501D, V84.2, V94.2, GT11N and GT13D.

Derating is also recommended for ash-forming fuels, and turbine inlet temperature at base load may be limited to a maximum of about 1050°C (1922°F) or lower. This is only a guideline, however, and actual OEM recommendations will vary according to the contractual fuel specification, blade cooling, metallurgy, hot gas path coatings, and the particular gas turbine model. There are also slight differences within the industry as to the specific definition of “turbine inlet temperature” and/or “firing temperature,” and the actual position in the hot gas path where this temperature is defined. For example, variances of about 30 to 40°C can be accounted for if this temperature is defined as being just upstream of the first stage turbine inlet nozzle, immediately after the first-stage inlet nozzle, or at a point between the first-stage nozzle and first-stage rotating blade. In all cases the specific OEM recommendations should be followed. The main reason for derating and limiting TIT is to minimize the formation of hard ash deposits on turbine blades,

which is a function of ash chemistry and the prevailing temperature at which the ash is exposed. Higher firing temperatures create harder and more compact deposits that are difficult to remove.

Advance technology “F-Class” models and aeroderivative turbines are normally restricted to firing only natural gas or high-quality clean distillates. This said, the possibility of distillate contamination and/or the ingestion of airborne sea salt become important considerations for these higher firing temperature engines.

#### Plant Availability

Lower fuel quality increases maintenance frequency according to the so-called “interval reduction factor,” and additional periodic outages (perhaps weekly) will also be required for hot gas path (HGP) washing when firing ash-forming fuels. Therefore, plant availability on residual-grade oils or crude oils cannot be expected to match that of natural gas, and this reality should be clearly understood (and designed for) at the development stage of any new project.

Given the attractive price of residual oils, a different but proactive design philosophy would be to include additional installed capacity (such as one extra gas turbine unit) to compensate for maintenance outages. Surprisingly this approach is rarely adopted, most likely because of competitive pressures when bidding on the basis of dollars per MW-installed.

#### High Temperature Corrosion and Liquid Fuel Treatment

Residual-grade fuel oils and crude oils are classified as “contaminated” or “ash-forming” fuels because they contain relatively high concentrations of various trace metals that create ash deposits during combustion. Ash fouling impacts gas turbine performance and availability, but can also lead to serious high temperature corrosion problems of hot gas path components unless appropriate fuel treatment programs are applied at the power plant. Such treatment programs use physical separation processes to remove those contaminants that are removable, and special chemical additives to inhibit the corrosive effect of oil-soluble trace metals that remain in the fuel.

#### Classification and Origin of Fuel Contaminants

The most common fuel contaminants are summarized in Table 16 and are classified as being either “water-soluble,” “water-extractable” or “oil-soluble.” This classification is useful because it gives an indication as to whether contaminants can be removed from the fuel by purification processes such as fuel washing, or whether they are chemically bound to the oil and will enter the hot gas path.

Table 16. Contaminants in Liquid Fuels and Typical Ranges.

Class	Contaminant	Unit	Residual grade	Crude oils	Distillates
Water soluble	Sodium (Na)	ppm	10 – 150	2 – 50	0 – 10
	Potassium (K)	ppm	1 – 15	1 – 10	0 – 2
	Calcium (Ca)	ppm	0 – 10	1 – 10	0 – 2
Water extractable	Solids & sediment	ppm	100 – 5000	100 – 1000	10 – 100
	Free water	% vol	0.1 – 1.0	0.1 – 1.0	0.01 – 0.1
Fuel soluble	Vanadium (V)	ppm	1 – 300	1 – 100	0 – 1
	Nickel (Ni)	ppm	1 – 100	1 – 30	0 – 1
	Lead (Pb)	ppm	0 – 5	nil	0 – 5
	Zinc (Zn)	ppm	0 – 5	nil	0 – 5
	Sulfur (S)	% wt	up to 5	up to 3	up to 1
	Asphaltenes	% wt	up to 6	up to 5	<1
	Wax	% wt	up to 30	up to 50	3 – 5

Sodium (Na), potassium (K) and calcium (Ca) are *water-soluble* contaminants, and result primarily from the entry of underground formation water or seawater during crude oil production. Much of this water is separated in the oilfield via dehydration processes, and salt content is further reduced at the refinery prior to crude oil distillation. However, some quantity of Na and K always remains in the residual fraction and additional contamination often results from the disposal (into residual oils) of refinery waste streams—which though not good practice, still commonly happens. Contact with seawater during

marine transportation to the power plant will also introduce additional sodium, and can occur with any grade of fuel including distillates. Water-soluble trace metals can be removed (or at least significantly reduced) by a physical separation process known as fuel washing.

Heavy oils also contain various solids and sediments that can lead to filter plugging and erosion problems. These contaminants are classified as “water-extractable” because they are normally associated with the water phase and can be removed during the fuel washing process. Typical materials include sand, silt, rust, scale, or even asphaltic sludges that may have separated from the petroleum. Refinery processing can also introduce catalyst fines (cat fines), which are small and very abrasive particles containing alumina (Al<sub>2</sub>O<sub>3</sub>) and silica (SiO<sub>2</sub>). This material is used as an inert catalyst support in refinery cracking units, but if it contaminates residual oils it can be very abrasive to gas turbine fuel system components such as pumps and flow-dividers.

Vanadium (V) and nickel (Ni) are natural oil-soluble components of most crude oils. They are present as organo-metallic complexes known as porphyrins, and are chemically bound to the heavy asphaltic fractions of the petroleum. Concentrations can range from a few parts per million (ppm) to several hundred ppm according to the type, age and geographic location of the crude oil formation as shown in Table 15. Refinery distillation has the effect of concentrating these trace metals in the high-boiling point residue, so that levels found in residual-grade oils are considerably higher than in the crude oil feedstock (refer to Figure 29).

#### Origin of Vanadium and Nickel in Crude Oils

The origin of V and Ni in crude oil is quite interesting, and most probably originates from certain marine organisms such as the *sea squirt* and *sea cucumber* (Figure 33) that are known to contain extremely high concentrations of these heavy metals within their bodies. Together with huge quantities of decaying plankton and algae, it is believed that these creatures settled to the ocean floors as part of the complex biomass that eventually formed crude petroleum about 180 million years ago.



Figure 33. The Sea Cucumber Contains about 6,500 ppm Vanadium in its Body. These Types of Organisms are Believed to be a Biological Source of Heavy Metals in Crude Petroleum.

The biological origin theory is also supported by the fact that several other organo-metallic complexes occur throughout nature and have remarkably similar molecular structures to the vanadium and nickel porphyrins found in petroleum. Hemoglobin, for example, the oxygen-carrying component of blood is a porphyrin containing iron (Fe), and chlorophyll, an essential component of all green plants is a porphyrin containing magnesium (Mg).

Sulfur is also a natural component of petroleum products and is included as a contaminant because it participates in certain high temperature corrosion mechanisms and also impacts emissions. In cogeneration and combined cycle applications, high sulfur fuels can also lead to acid dew point corrosion of HRSGs.

#### Effect of Trace Metal Contaminants

All trace metals in fuels are undesirable because they create ash compounds during combustion, and these mixtures of oxides

and sulfates will deposit within the hot gas path. Ash fouling reduces turbine output, and in severe cases it can also cause plugging of critical air-cooling channels on blades and vanes. Various high-temperature corrosion mechanisms can also be initiated if ash deposits melt (and remain in the liquid phase) on component surfaces. However, if ash melting point is sufficiently high that deposits remain in the solid state, these type corrosion processes cannot proceed. Thus, ash melting point and blade surface temperature are important parameters that jointly determine whether corrosion will occur, and also influence how it can be controlled.

Several different types of high temperature corrosion are possible, and more detailed descriptions can be found in Stringer (1977), and in Stalder and Huber (2000). The main mechanisms are illustrated as a function of temperature later in Figure 38. For gas turbines firing residual-grade oil, crude oil or contaminated distillates the two most important corrosion processes are known as *sulfidation corrosion* and *vanadic oxidation*.

#### *Sulfidation Corrosion*

Also known as Type II hot corrosion, this type of attack involves the combined effect of fuel sulfur (S) and sodium (Na), which may originate as a water-soluble fuel contaminant or as airborne sea salt entering via the compressor inlet. Sodium sulfate ( $\text{Na}_2\text{SO}_4$ ) is formed during the combustion process, which then condenses and melts on component surfaces within the hot gas path. The following reaction steps then occur:

- Molten  $\text{Na}_2\text{SO}_4$  reacts with the alloy surface and destroys protective (chromium-rich) oxide films.
- Sulfur then penetrates the alloy and precipitates chromium sulfides.
- Depletion of available chromium retards the reformation of protective oxide layers, thus allowing rapid and localized oxidation of the alloy substrate.

Note that traces of other alkali metals such as potassium (K) will also initiate sulfidation corrosion and behave essentially the same as sodium. Sulfidation attack is a very dangerous form of pitting corrosion that can result in rapid and catastrophic blade failures—especially when combined with mechanical stress or fatigue. The sulfidation example in Figure 34 occurred on a 1970s vintage unit in less than 1000 hours of operation on distillate fuel that was found to contain about 2 ppm Na from seawater contamination. It shows the rapid progress and severity of this type corrosion even on low firing temperature units.



Figure 34. Sulfidation Corrosion on a 1970s Vintage Low-Firing Temperature Gas Turbine. Failure (Shown at Right) Occurred after about 1000 Hours Operation on Distillate Fuel Containing 2 ppm Sodium from Seawater Contamination.

Sulfidation corrosion is controlled by imposing very strict limits on total alkali metals (Na+K) entering the hot gas path from all sources, i.e., via fuel and air, and also via water or steam that may be injected for power augmentation or NO<sub>x</sub> control. Typical OEM specifications for Na+K range from as little as 0.1 up to 1.0 ppm maximum depending on GT model and fuel type. Note that even low-sulfur fuels contain sufficient sulfur to enable the hot corrosion mechanism if alkali metals are also present. It is therefore not realistic to control sulfidation corrosion by reducing sulfur content, and the most practical approach is to limit the entry of sodium and potassium. Studies on sulfidation corrosion and its inhibition are reported by DeCrescente (1980).

#### *Vanadic Oxidation*

This type of corrosion can occur whenever fuels containing vanadium (V) are burned, such as residual-grade oils and crude oils. It is caused by molten ash deposits of vanadium pentoxide ( $\text{V}_2\text{O}_5$ ), melting point 675°C (1247°F), which condense on blade surfaces and rapidly destroy protective oxide films. This leads to further oxidation of the alloy surface and further destruction, etc., so that normal oxidation rates are *accelerated* and the service life of components and coatings is significantly reduced. An example of vanadium-induced surface oxidation is shown in Figure 35. The accumulation of ash deposits and hard corrosion products can also result in serious vibration and balancing issues. Similar surface oxidation mechanisms are also initiated by traces of lead (Pb) and zinc (Zn) in gas turbine fuels.



Figure 35. Example of Accelerated Surface Oxidation Caused by Vanadium in Heavy Fuel Oil.

It is important to note that fuels containing both vanadium and sodium can generate a variety of mixed oxides known as sodium vanadates, and these ash mixtures can have extremely low melting points around 532°C (990°F). This significantly increases the risk of molten-ash corrosion (even with derated firing temperatures), and is the main reason why water-soluble sodium salts are reduced to extremely low levels during the fuel treatment process. The main effects of trace metal contaminants and other fuel impurities are summarized in Table 17.

Table 17. Effect of Fuel Contaminants.

Class	Contaminant	Main effect
Water soluble	Sodium (Na)	Ash fouling and sulfidation corrosion
	Potassium (K)	
	Calcium (Ca)	
Water extractable	Solids & sediment	Ash fouling, sludge, filter plugging, erosion
	Free water	Microbiological corrosion in fuel tanks
Fuel soluble	Vanadium (V)	Ash fouling and accelerated oxidation
	Nickel (Ni)	Ash fouling; interferes with V-inhibition
	Lead (Pb)	Ash fouling and accelerated oxidation
	Zinc (Zn)	Ash fouling and accelerated oxidation
	Sulfur (S)	Sulfidation corrosion; environmental
	Asphaltenes	Fuel stability, sludge, filter plugging
	Wax	Filter plugging (impacts process temps)

#### Fuel Treatment to Control High Temperature Corrosion

Treatment programs for crude oils and residual-grade oils involve physical separation processes to reduce water-soluble sodium and potassium salts to acceptable low levels. Chemical additives containing magnesium are then applied to inhibit the corrosive effect of vanadium, which remains in the fuel. Overall design of the treatment program must be based on the contractual specification of the raw (untreated) fuel that will be received, as well as the treated fuel specification for the particular gas turbine model.

The effect of fuel contaminants and their impact on high temperature corrosion is described by Moliere, et al. (1995), and Johnson (1996). Valuable early studies in this field that are still valid today are reported by Felix (1977, 1979). A useful overview of gas turbine fuel treatment and the use of magnesium-based additives can be found in Zubler and Stalder (1998).

#### Removal of Sodium and Potassium

A process known as “fuel washing” is used and involves the injection of a quantity of fresh wash water into the raw fuel to dilute and extract water-soluble salts and water-wettable solids. After mixing, the emulsified oil and water phases are then re-separated to produce outlet streams of treated (i.e., washed) fuel and effluent water, which now contains the extracted salts and solids. The most widely used separation technology for gas turbine fuel treatment systems involves centrifuges, which increase oil-water separation rate by increasing gravitational force. The principle of separating oil-water emulsions by centrifugal force is based on Stokes Law and can be summarized as follows:

$$\text{Rate of separation} = \frac{K \cdot (D_w - D_o) \cdot G \cdot d^2}{V_o} \quad (3)$$

where:

- Dw and Do = Density of water and oil, at process temperature
- G = Gravitational force
- d = Water droplet diameter
- Vo = Viscosity of the continuous oil phase, at process temperature
- K = System constant

It can be seen that the separation rate of emulsified water droplets increases by increasing gravitation (centrifugal) force, by increasing their diameter through coalescence, and also by reducing oil viscosity with system heating. There must also be a certain density difference between the oil and water phases, and this parameter becomes a treatment limitation if (for example) residual oil density is too high. A realistic maximum density is about 0.985 g/cc, and oils above 0.991 probably cannot be reliably treated.

The quantity (and quality) of wash water and the number of washing and separation stages depends on actual sodium and potassium content in the raw fuel and the maximum limits that are specified for the treated fuel. As indicated by Stokes Law, system design is also influenced by other fuel properties such as density and viscosity. Two-stage treatment systems are normally required for residual-grade

oils and most crude oils, and wash water quantity is typically 7 to 10 percent of the fuel flow. Light-gravity fuels such as contaminated distillates can normally be treated in a single-stage system using about 2 percent wash water. Note that in multistage fuel-washing systems the oil and water flows are countercurrent. Fresh wash water is injected ahead of the final mixing and separation stage, and separated water is recycled for use in the previous stage. This improves washing efficiency and minimizes wash water consumption.

A small quantity of a chemical “demulsifier” is normally used in the fuel washing process to improve oil-water separation. Particularly with heavy fuels, demulsifiers also help to extract solids and sediments into the water phase, and reduce oil carryover in the effluent water stream.

Figure 36 shows a typical process schematic for a two-stage centrifugal treatment system for residual oil or crude oil, (Moliere, et al., 1995, 2010). Injection points for chemical demulsifier and vanadium inhibitor additive (as discussed in the following section) are also shown. A two-stage centrifugal treatment plant designed for residual-grade fuel is shown in Figure 37. These type systems include all ancillary equipment needed to support the treatment process—including fuel and wash water heating, pumping, demulsifier and fuel additive dosing, and effluent water treatment, etc. Details of various fuel oil treatment plant designs and operational experience are provided by Henke and Dreyman (1981).

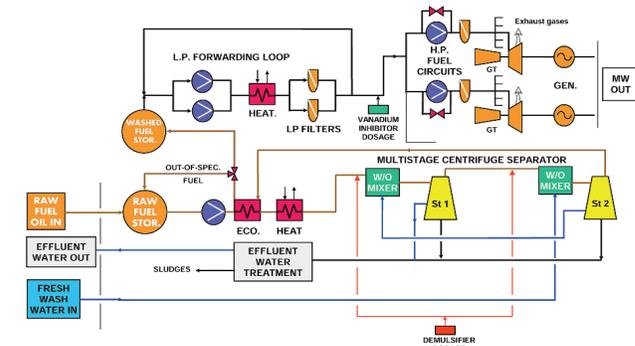


Figure 36. Schematic of a Typical Two-Stage Centrifugal Fuel Treatment System for Residual Oils or Crude Oils.



Figure 37. Two-Stage Centrifugal Fuel Treatment Plant for Heavy Fuel Oil. (Courtesy Westfalia Separator)

Maximum allowed limits for sodium and potassium (Na+K) depend on the type of gas turbine involved, and there is some variance between the different OEMs. However, typical guidelines are as follows:

- Lower-firing temperature heavy-duty models: 0.5 to 1.0 ppm maximum
- Higher-firing temperature heavy-duty models: 0.2 to 0.5 ppm maximum
- Most aeroderivative models: 0.1 to 0.5 ppm maximum

By definition these limits apply to “total Na+K” entering the hot gas path from all sources, i.e., from fuel, air and any water or steam that may be injected for NO<sub>x</sub> control or power augmentation. As can be seen these limits are very strict.

#### *Additive Treatment to Control Vanadic Oxidation*

Vanadium is not removed in the fuel washing process, so chemical additives based on magnesium are used to inhibit the vanadic oxidation process. They function by modifying ash composition to increase ash melting point, thus ensuring that deposits on turbine blades do not melt and remain safely in the solid state. The main ash component without Mg is vanadium pentoxide (V<sub>2</sub>O<sub>5</sub>), with a low melting point of 675°C (1247°F), and this ash would be molten at typical blade temperatures. However, with the addition of sufficient magnesium a different ash component is created, called magnesium orthovanadate (Mg<sub>3</sub>V<sub>2</sub>O<sub>8</sub>). This mixed-oxide has a significantly higher melting point of about 1243°C (2270°F) and remains solid at typical blade temperatures.

Assuming Na+K has been reduced to OEM specification limits as outlined above, a minimum treatment ratio of  $Mg/V = 3$  is normally recommended, i.e., the addition of 3 ppm magnesium for each 1 ppm vanadium in the fuel on a wt/wt basis. This treatment formula may need to be adjusted if other oil-soluble trace metals such as nickel, lead or zinc are present, and specific guidelines set by the particular OEM should be followed. Nickel, for example, is not regarded as a corrosion-promoting contaminant because it forms relatively-high melting point ash deposits. However, nickel interferes with the vanadium inhibition mechanism by combining with some of the magnesium, so that higher additive dosage may be required.

Competing reactions with fuel sulfur also occur and create magnesium sulfate (MgSO<sub>4</sub>) as an additional ash component, and this is another reason why sufficient Mg must be injected. Actually, formation of MgSO<sub>4</sub> is very important, because it is the only water-soluble component of the ash mixture and enables deposits to be removed by periodic water-washing of the hot gas path. However, if blade temperature is too high, MgSO<sub>4</sub> decomposes to magnesium oxide (MgO), and ash deposits become harder and much more difficult to remove. Note that this is the main reason why turbine firing temperature is limited (as discussed above) when burning ash-forming fuels. Important thermodynamic studies on ash composition and the impact of blade temperature are reported by Lay (1974).

#### *Fuel Additive Types and Additive Dosing*

Oil-soluble fuel additives containing magnesium are used to inhibit the effect of vanadium in residual-grade oils and crude oils. They are delivered in a ready-to-use liquid form and metered into the washed fuel just ahead of the gas turbine—normally at an injection point between the low-pressure (LP) and high-pressure (HP) fuel pumps as shown by the schematic in Figure 36. The additive dosing control system should be designed to interface with the gas turbine, so that dosage is automatically adjusted according to fuel flow and load. Underdosing must be avoided to ensure that vanadium corrosion is controlled, but overdosing should also be avoided to minimize the creation of unnecessary quantities of ash. Regular fuel analyses should be performed to confirm correct additive dosage and to enable adjustments if required.

Oil-soluble type magnesium additives are recommended because of their convenience, ease of handling, and reliability. However, several different products are available on the market and field experience has shown that quality and performance differences can occur—depending largely on the chemistry of the additive and its particular manufacturing process. For example, certain oil-soluble Mg additives are known to have higher tolerance to traces of water (which is always present in heavy fuels), whereas other products may react with water and create gels and sludge that can plug fuel filters and flow dividers, etc. Additives must also conform to strict contaminant limits so that

treated fuel specifications are not compromised. Extremely small additive particle size is also important to prevent erosion of fuel system components and to ensure high chemical reactivity (with vanadium) in the combustion zone.

Other oil-soluble additive formulations containing chromium (Cr) and/or silicon (Si) are also available for specific applications. For example, Cr-additives are used to inhibit sulfidation corrosion, and can be considered as an alternative to fuel washing in cases where low and/or occasional sodium contamination occurs—such as by seawater contamination of distillate fuels or by airborne salt ingestion in coastal locations. The theory and use of chromium-containing additives for hot corrosion control have been reported by Zetlmeisl, et al. (1984), and more recently by Stalder and Huber (2000).

#### *Power Degradation and Ash Removal*

Gas turbines operating on contaminated fuels will inevitably suffer a reduction in power output due to ash fouling, which results from a combination of the trace metals in the fuel and the additive. Power losses can be partially recovered by injecting mild abrasives (such as nutshells), but this only dislodges ash from inlet nozzles and first stage blades. Far more effective cleaning is achieved by periodic water washing of the hot gas path, while the unit is offline and cooled to an acceptable temperature. Actual wash procedures can be optimized at site, but basically they involve water injection during run-up to a certain crank speed, run-down to a lower speed for a “soaking period” (very important), run-up to crank speed for a rinsing cycle, followed by drying and air-purge. The use of an approved water-based detergent (as used for compressor washing) has also been found to be beneficial during turbine washing. Surface tension barriers caused by unburned hydrocarbon films are overcome and water penetration into the ash is improved. Wash frequency depends on the quantity of ash that has accumulated, and in the case of residual-grade fuels it may be necessary to wash as often as weekly.

Ash retention is also influenced by operating mode, and units that are peaking or cycling generally incur less power degradation than units running at continuous base load. This is simply due to thermal cycling, which has the beneficial effect of loosening ash deposits by expansion and contraction. As mentioned previously, it is also very important to limit turbine firing temperature (higher TIT means harder deposits), and OEM derating recommendations should be followed.

#### *Key Elements in the Successful Use of Liquid Fuels*

In the absence of natural gas, low-grade and lower-cost residual oils or crude oils can be burned successfully in heavy-duty gas turbines, and numerous examples exist around the world. In many cases the local population would have been without electricity if these projects had not been undertaken. Although these type projects are often considered to be risky, it is a fact that more high-temperature corrosion failures have occurred with contaminated distillate fuels than with heavy fuels—simply because distillates are “assumed” to be clean and often they are not. Heavy fuels are known to be contaminated and are treated accordingly. Key success factors for heavy fuel applications include:

- The selected fuel must be appropriate for the particular gas turbine model, and vice-versa.
- The consequences of derated performance and lower availability must be clearly understood at the planning stage, and installed capacity should be designed accordingly.
- Realistic and detailed raw fuel specifications must be established early in the project, so that suitable fuel treatment systems can be designed and included in balance of plant engineering.
- High-quality and field-proven fuel additives should be selected and dosed at the recommended treatment ratio.

- A well-equipped site laboratory and experienced laboratory staff are essential for heavy fuel operations.
- Untreated and treated fuel quality should be monitored regularly and routinely to ensure continued compliance with fuel purchase contracts and OEM specifications.

### ALTERNATIVE GAS TURBINE FUELS

The previous sections focused primarily on natural gas and the more common liquid fuel options such as diesel oil, residual-grade oil and crude oil. However, as was shown in Table 2, numerous other gaseous and liquid fuels are available and are being considered for specific GT applications. These different type fuels cover a huge range of chemical and physical properties, which further demonstrates the extreme versatility of the combustion turbine.

Many of the fuel alternatives are hydrocarbon biproducts and waste streams from various refinery “cracking” and conversion processes, and additional options will undoubtedly arise as new refining technologies are introduced. In many cases the incentive to burn these “exotic” materials is not just to provide an additional fuel source, but rather as an efficient disposal method for unwanted and possibly hazardous wastes—such as aromatic biproducts containing benzene. This method of incineration is feasible because of the high combustion temperature of gas turbines, and it also enables cogeneration of steam and power for the refinery. Similar cogeneration schemes are applied for waste refinery gases and low-Btu blast furnace gas, etc. One can also assume that gasified fuels derived from coal, coke or asphaltic residues will become more prevalent *if and when* IGCC technology becomes an economic reality.

Processes known as “gas-to-liquid” (GTL) technology are also increasing in popularity, and involve the conversion of synthetic or natural gas into very high-purity diesel oil, with virtually no sulfur content and high cetane number. In addition to environmental advantages, GTL processes can also enable the local availability of liquid fuel in areas where only gas is available. High-value synthetic lubricants and waxes can also be produced. Most GTL technologies are based on the “Fischer-Tropsch” process, as described by Schubert, et al. (2001). Of interest, gas turbines are also utilized as prime-movers for the supply of air and oxygen needed by these type processes.

Policies designed to curb greenhouse gases, the rising cost of traditional fuels, and market trends toward renewable technologies have also spurred interest in *biofuels*—both gaseous and liquid.

Gaseous biofuels (“biogas”) are produced by the biological breakdown of organic matter in the absence of oxygen, and several different processes are available. One process is based on the anaerobic digestion or fermentation of biodegradable materials such as manure, sewage, municipal waste, green waste, plant material or energy crops. This type of biogas comprises primarily methane and carbon dioxide. Other processes involve the gasification of wood or other biomass material, and this type of biogas comprises primarily nitrogen, hydrogen, and carbon monoxide, with only trace amounts of methane and a resulting low Btu content. Biogas is produced only in modest volumes. It requires compression prior to gas turbine use, and must be burned close to its source.

*Liquid biofuels* are produced from several different processes, and probably represent the current major focus for synthetic liquid gas turbine fuels. So-called “biodiesel” can be derived from various energy crops such as soy beans, rape seed, palm oil or other vegetable oils, and “bioalcohols” can be produced via fermentation processes from natural sugars.

Fuels from vegetable oils can be obtained by simply crushing oil-rich seeds, which involves a minimum of chemical processing. These products tend to have higher density, higher flash point and higher hydrogen content than petroleum diesel, but lower LHV by mass. Also, due to their high viscosity they require special considerations for storage and pumping to the gas turbine. Some demonstration units have operated on these type oils but it is not yet a popular fuel.

Of greater interest are processes that involve the esterification of vegetable oils such as soy, rape or palm. Animal fats are also potential feedstocks. This is a chemical process whereby organic fatty acids in the vegetable oil or animal fat are converted to esters by reaction with an alcohol or OH group. Basically this is an acid-base neutralization reaction. Fuels produced by this type process are known as “biodiesel,” and are essentially free of aromatics and sulfur. They have density and viscosity properties very similar to petroleum diesel, but their heating value is typically about 10 percent lower. Another important feature is that these type biodiesels have significantly improved lubricating properties compared to conventional diesel, and especially compared to low-sulfur diesel. Excellent lubricity can be achieved by blending small quantities of biodiesel into petroleum diesel. Blends of 2 percent or 20 percent biodiesel in petroleum diesel are referred to as “B2” and “B20,” respectively. Pure biodiesel is known as “B100.”

Biodiesel is a fuel that is currently in focus for gas turbine applications, and as reported by Campbell, et al., (2008), several heavy-duty and aeroderivative engines have been successfully tested on biodiesel.

One potential problem is that these type fuels may contain up to 5 ppm sodium plus potassium, which significantly exceeds OEM limits for gas turbine applications. This contamination level is stated as a possible maximum in the recently-released ASTM D6751 (2007) specification for “B100” biodiesel. Furthermore, and perhaps of even greater significance, the sodium content of biodiesel may be organically-bound (or very tightly emulsified), which makes it difficult to remove by physical purification processes such as centrifugal separation. More research is needed in this area, but the issue may be related to the esterification process and the formation of sodium carboxylate compounds known as “soaps.”

The third type of liquid biofuel is alcohol, including ethanol and methanol. Bioethanol results from the fermentation of natural sugars such as sugar beet or sugar cane, etc., followed by distillation. Methanol can be produced from a biomass-to-liquids process, and is a feedstock for the production of biodiesel. Recent tests conducted and reported by Moliere, et al. (2009), indicate successful application of ethanol (derived from sugar cane) on a Frame 6B gas turbine. This important field test also addressed the issue of fuel lubricity, which is very low in the case of alcohol fuels and could result in flow-divider problems. However, a lubricity improvement additive (ER-517N) was added to the ethanol at specific dosage rates, and normal flow-divider performance was maintained throughout the test. A thorough review of fuel lubricity, its impact on flow-divider operation, and the use of lubricity improvement additives can be found in Stalder and Roberts (2003). Additional details on biofuels are provided by Moliere (2005) and Moliere, et al. (2007). Properties of liquid biofuels are also addressed by Campbell, et al. (2008).

An up-to-date review of the complete subject of alternative liquid fuels can be found in Moliere, et al. (2010). This recent paper provides a comprehensive overview of the most viable fuel options and their properties, and describes the various refinery processes from which many of them originate. The different biofuel categories are also explained and important information on biodiesel and bioalcohol properties is provided. This paper (Moliere, et al., 2010) also addresses the planning and operational aspects of changing and/or transitioning from one fuel type to another.

It is interesting to note that the use of alternative fuels in heavy-duty gas turbines actually dates back to the early 1950s, and an extremely informative paper by Bankoul (1980) is highly recommended. This article describes the early and very successful application of “unconventional” fuels such as heavy oils and low-Btu furnace gases in single-combustor gas turbines. This was an important technology step that contributed to an emerging

market in the 1970s for crude oil firing, particularly in Saudi Arabia and other parts of the Middle East. Much of today's knowledge on high temperature corrosion, ash chemistry, fuel treatment and the use of magnesium additives stems directly from these early studies and is still valid.

### FUEL RELATED GAS TURBINE FAILURES

There are numerous failure mechanisms that are caused as a result of fuel related problems. These include:

- Environmental attack (oxidation, sulfidation, hot corrosion, standby corrosion) of hot section blades and stators, transition pieces and combustors.
- Erosion and wear.
- Combustor damage due to autoignition, flashback, etc.
- Thermal aging.
- Combined failure mechanisms—creep/fatigue, corrosion/fatigue, oxidation/erosion, etc.

The environment must be considered when evaluating any failure within a gas turbine. Hot section components are subject to attack from oxidation and various other high temperature corrosion mechanisms. While some of the failure mechanisms were already discussed in the context of liquid fuels, they are covered below for completeness. A detailed treatment of gas turbine blade failures is provided in Meher-Homji and Gabriles (1998), and a series of valuable papers are to be found in Dundas (1990, 1993a, 1993b).

#### Oxidation and High Temperature Corrosion

Several different types of high temperature corrosion can influence the behavior of hot section components and coatings (Stringer, 1977). As described by Stalder and Huber (2000), the main mechanisms impacting modern industrial gas turbines can be illustrated as a function of temperature, as shown in Figure 38, and can be summarized as follows:

- *Low temperature "Type II" hot corrosion, also known as sulfidation corrosion*—This is the most common type of hot corrosion in industrial gas turbines and occurs in the temperature range 650 to 800°C (1200 to 1470°F). Essentially it involves a combination reaction between fuel sulfur and alkali metals such as sodium and potassium that can originate from fuel contamination or by the ingestion of air containing salts. Alkali sulfates (primarily sodium sulfate  $\text{Na}_2\text{SO}_4$ ) are formed, which condense and melt on component surfaces. Protective oxide films are destroyed, allowing sulfur to penetrate into the alloy and precipitate chromium sulfides. Chromium depletion retards the reformation of protective oxide films and renders the alloy susceptible to rapid and localized oxidation. Pitting occurs, and with the combined effect of mechanical stress, catastrophic failures can result. This mechanism is primarily driven by alkali metal (Na+K) concentration. Metallurgical control requires high chromium content in the alloy or coating. Important studies on sulfidation corrosion are reported by DeCrescente (1980).
- *High temperature "Type I" hot corrosion*—This type corrosion occurs in the temperature range 700 to 1000°C (1292 to 1832°F) and also involves the effect of fuel sulfur and the formation of sulfides within the alloy substrate. A denuded zone of base metal is often found along with intergranular attack and sulfide spikes. This high temperature corrosion process is also accelerated by alkali metals and chlorine, but the mechanism is primarily driven by the prevailing temperature.
- *Pure oxidation*—This mechanism dominates above 950 to 1000°C (1742 to 1832°F) since condensation of molten and corrosive deposits no longer takes place. Oxide films are formed, and can be

considered a natural self-protection mechanism. For a given alloy or coating composition and design operating temperature range, the rate of oxidation is normally predictable and acceptable for the intended service life. Oxidation processes are important for nickel-base alloys, but when subjected to vibration and start-stop thermal cycles during operation, nickel oxide layers tend to crack and spall. This phenomenon may also occur on the inner surfaces of blade cooling passages and result in blade failure. Coatings are available to mitigate this effect and can be applied to the blade surface and also to internal cooling holes. Oxidation rates increase with increasing temperature, so gas turbines operating at high firing temperatures require increased oxidation protection, and blade cooling becomes very important. At temperatures above 1100°C (2012°F), blade coatings can also undergo oxidation degradation due to the loss of protective elements in the coating by diffusion into the base material.

- *Accelerated oxidation*—This can be considered as a "disturbance" or acceleration of the normal oxidation rate of the alloy, and is caused by the condensation of molten and corrosive ash deposits on the surface of blades and vanes. This is the primary mechanism of so-called "vanadic oxidation," which can occur when operating on residual-grade oils and crude oils containing vanadium. Ash deposits comprising vanadium pentoxide ( $\text{V}_2\text{O}_5$ ) are created, with a low melting point of about 675°C (1247°F). At typical blade surface temperatures this ash remains molten (liquid phase) and destroys protective oxide films by an aggressive fluxing action. This promotes further oxidation and further oxide destruction, etc., resulting in an acceleration of the normal oxidation rate and the progressive removal of base alloy material from blade surfaces. This type of corrosion attack is mitigated by the use of magnesium-containing fuel additives, which raise the ash melting point and prevent the formation of molten deposits. These type additives are known as vanadium inhibitors.

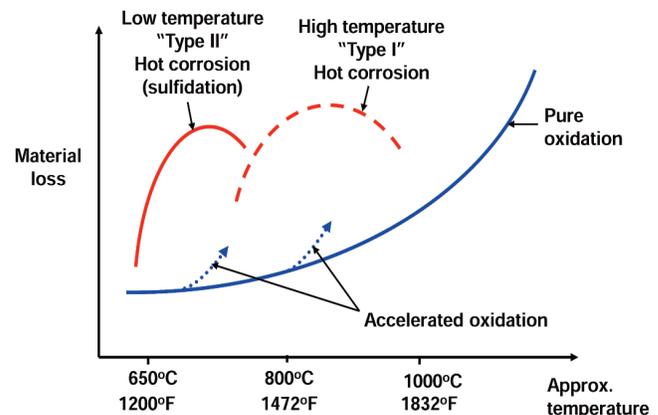


Figure 38. High Temperature Corrosion Mechanisms Illustrated as a Function of Temperature. (Stalder and Huber, 2000)

Note that if sodium is also present in the fuel at concentrations that exceed OEM limits, mixed oxides (sodium vanadates) will be created with extremely low ash melting points of around 532°C (990°F). This impedes the effect of magnesium in controlling Vanadic oxidation and significantly increases the risk of molten-ash corrosion. In these cases, corrosion failures may also involve both accelerated oxidation and sulfidation mechanisms. Similar accelerated oxidation mechanisms are also caused by traces of lead (Pb) and zinc (Zn) in fuels, such as may occur in contaminated distillates.

Blades from an aeroderivative gas turbine which experienced hot corrosion while operating on No. 2 diesel oil are shown in Figure 39. A photograph of the associated fuel combustor nozzle is shown in Figure 40.

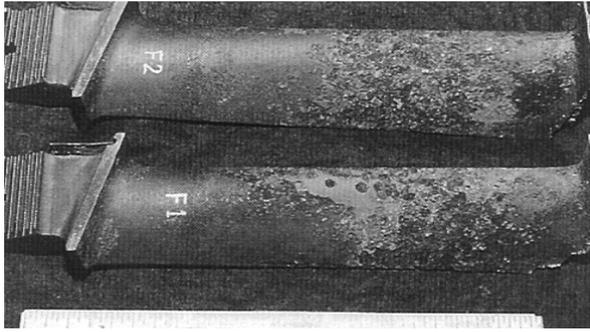


Figure 39. Aeroderivative Blade Operating with Contaminated Fuel.



Figure 40. Coked Combustor Nozzle.

#### Combination Mechanisms

Several failures are caused by multiple failure mechanisms. Corrosion, promoted by fuel impurities for example, can reduce blade section size and drop the fatigue strength. Fretting wear in the blade attachment regions can reduce damping causing increased vibration amplitudes and alternating stresses. Foreign object damage can cause nicks and cracks that can then be propagated by low or high cycle fatigue. Consequently, failure analysis must investigate all engineering causes including design issues, environmental factors, cleanliness of the fuel, air quality, material, coatings, and gas turbine operating and maintenance history.

#### Damage Caused by

##### Hydrocarbon Liquids in Fuel Gas

Gas turbine hot section damage can occur due to the presence of liquids in the fuel gas, plugging of fuel nozzles, or due to internal gas turbine fires and explosions. The presence of hydrocarbon liquid can cause over firing either in all or a few combustion chambers. The presence of liquid hydrocarbons in natural gas depends on the temperature and pressure of the gas. Despite precautions, it is not uncommon for natural gas to entrain liquids. Liquid carryover from pipeline gas scrubbers can occur due to:

- Foaming.
- Gas flow and pressure that exceeds scrubber capacity.
- Improper operation of a centrifugal separator.
- Surges in liquid due to rapid fluctuations in gas pressure.

Liquids have different volumetric heating values and have different flow characteristics in piping and fuel nozzles. Thus, when liquids are present in natural gas, gas turbine performance is affected depending on the concentration of the liquid compared to the gas. At low concentration levels, the liquid is typically in aerosol form and the turbine control system will react by reducing fuel flow due to the apparent higher heating value of the fuel. The flame will change color from transparent blue to a luminous flame

with a color ranging from yellow to red. This can also occur if iron sulfide or sodium compounds are present. With liquids in the fuel, the combustion may be rough, resulting in gas supply pipe vibration causing wear of transition pieces or manifolds. At moderate liquid concentration levels, the liquid gets segregated due to inertia effects and is unevenly distributed to the fuel distribution system. The control system may then behave in an unstable manner because of exhaust gas temperature variations.

Combustion imbalance from one combustion chamber to another can cause high exhaust gas spreads in excess of 45°C (80°F), which have a damaging effect on the blades. If a significant level of liquid is present in the gas, (causing the heating value to be greater than 110 percent of the nominal value) then rapid destruction of hot gas components can occur. Exhaust gas temperature spreads can become exceedingly high and in extreme cases, rotating blades can melt. If the melting is uniform, the vibration levels may not increase. Complete hot gas path destruction can, at times, occur in a period of 5 to 10 minutes.

Damage due to liquids in the natural gas fuel can include:

- Damage to the premixer hardware and combustor due to autoignition, flashback or pulsations.
- Transition piece failures: This can be due to several factors. Greater cyclic stresses due to liquids being introduced intermittently cause damaging pressure pulsations. At times, seals rupture allowing compressor discharge air to enter at the first stage nozzle which causes severe temperature distortion and is damaging to the blades. Unburned liquid droplets can ignite creating a flame near the stator nozzle.
- Thermal distress of blading, caused by a distorted temperature profile.
- Compressor surge, due to rapid increase in back pressure.

It is therefore extremely important for natural gas fuel to be properly treated and have a superheat temperature of at least 28°C (508°F) above the hydrocarbon or moisture dew point. As was mentioned in an earlier section, gas analysis for determination of dew point should consider all components in the gas. It is also important to note that in a case where several gas turbines are being fed by a fuel line, depending on the location of the gas turbine, a situation may exist where some experience problems and others do not.

#### Low Fuel Nozzle Pressure Ratio and Excessive Pressure Fluctuations

The combustor fuel nozzle tip acts as a metering orifice. The fuel nozzle pressure ratio (FNPR) is defined as:

$$\text{FNPR} = (\text{Fuel gas pressure})/(\text{Combustor liner pressure}) \quad (4)$$

Excessive pressure fluctuations in the combustor liner would propagate upstream into the fuel nozzle. These pressure pulsations coupled with low fuel nozzle pressure ratios cause a high variation in the fuel flow and heat release. Pulsations can damage hot gas components. Liquids in the fuel can contribute to a lower fuel nozzle pressure ratio. The liquids cause an increase in the heating value per unit volume. Consequently, a smaller volumetric flow is required. The reduction in flow results in lower nozzle pressure ratios that further compound the pulsation problems.

Problems in the fuel system that can cause blockage of the fuel nozzles such as coking will also cause severe vibratory stresses on the blades. Excessive coking on the fuel nozzles will cause:

- Higher pressure to occur on the other fuel nozzles causing the flame to move downstream in the combustor.
- Flow and temperature distortion that can damage the turbine.

Balancing of nozzle flow should be done as precisely as possible. A target of 1 percent or less is recommended and will have a long-term benefit to the operation of the turbine. It is important to note that the blockage of the fuel nozzles may also be due to external factors such

as debris derived from the fuel filters. It is most important to have a means for detecting such problems by an EGT monitoring system that examines qualitative pattern changes and not just absolute limits.

#### Internal Fires and Explosions

Explosions occur when fuel is injected into hot engines and uncontrolled ignition occurs, causing extensive blade damage. Dundas (1990) lists four potential situations:

- Fuel is injected into a hot engine and does not ignite as intended but ignites when it comes into contact with hot internal surfaces. Autoignition can occur in the combustor, the turbine section or the exhaust duct. The autoignition temperature of No. 2 fuel oil is around 390°C (500°F).
- Flameout that occurs when an engine is in normal operation. If fuel continues to flow, it may reignite when it touches hot internal surfaces.
- During switch-over from liquid to gaseous fuels. Improper purging of the original fuel or improper scheduling of the valving can cause an explosion in the combustion section.
- Fire at the bottom of a combustor where liquid fuel collected after shutdown and, for some reason, was not drained. The pool of liquid is ignited by hot gases during a subsequent start. Dundas (1990) points out the importance of shutting off fuel very rapidly and indicates that an *upper* limit of 500 milliseconds is required with the ideal value being less than 150 milliseconds.

#### Case Study—Fuel System

##### Related Turbine Blade Failure

This case involved a heavy duty gas turbine in 50 Hz power generation service burning heavy fuel. The failure occurred in the third stage of the turbine. The blades were equipped with an integral shroud at the outer tip diameter. Each shroud was interlocked with the adjacent blades to resist the natural tendency of the blade to untwist with centrifugal force and the effects of airflow. The machine normally ran on a blend of residual fuel and high speed diesel. When a trip occurred, the fuel left in the piping tended to solidify unless removed while still warm. After a normal shutdown, the procedure was to allow the turbine to coast down to a normal stop and then accelerate it on the starter to crank speed while the fuel line was purged with high speed diesel. The fuel was expected to drain from the machine during the purge cycle.

On the day of the failure, the machine tripped and a purge cycle was initiated. An exhaust gas temperature scan indicated a maximum temperature of 730°C (1346°F), which was much higher than the expected 500°C (932°F). An EGT spread of 277°C (500°F) was also noted. The exhaust gas temperature profile that occurred is shown in Figure 41. Blade metallurgical analysis confirmed that catastrophically high temperatures had been reached. A gamma prime phase modification was found in the microstructure of the blade material.

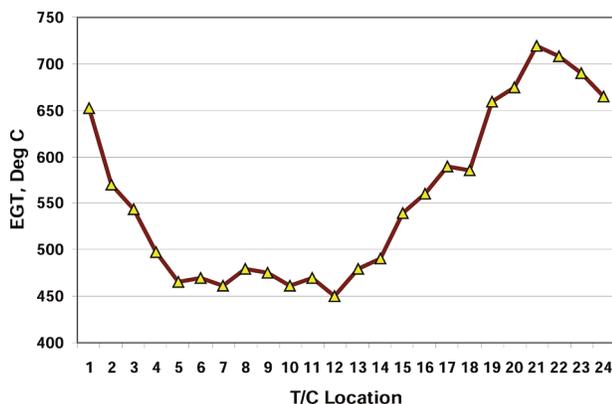


Figure 41. Exhaust Gas Temperature Profile Distortion During Fire. Temperatures as High as 730°C Were Reached.

This high temperature occurred as the engine took fire (autoignition) in an uncontrolled manner, with combustion occurring in the third stage blade area of the machine. The tip shrouds of the blades deformed due to the rapid temperature change. The strength of the blading was severely reduced due to the elevated temperature. Because the tip shrouds were displaced, the natural frequency of the blades was modified to a much lower value. This change in natural frequencies caused a blade fatigue failure. The solution to this problem addressed modification of fuel purging procedures to ensure that no fuel accumulation could occur.

#### Fuel or Air Contaminants

As discussed above and in earlier sections, hot corrosion damage can occur as a result of contaminants entering the combustion zone via the fuel or the air, and higher firing temperatures have aggravated the propensity for these type problems. The entry of airborne salt can be severe in marine and coastal environments, but studies have shown that it can also be a significant issue in inland installations. Airborne salt ingestion even in the ppb range can cause hot corrosion. The subject of salt percolation through gas turbine inlet filters has been studied and reported by Stalder and Sire (2001).

Fuel contamination with salt water is extremely common when fuels are transported by barges, and can render clean distillates to be out of specification upon delivery to the gas turbine power plant. Most turbine manufacturers set an upper limit for Na + K of 0.1 to 1.0 ppm by weight, depending on the gas turbine model, and these limits can be easily exceeded by traces of seawater.

Figure 42 shows a turbine nozzle segment with large amounts of salt, and it is not surprising that this turbine exhibited hot corrosion as can be seen in Figure 43. Another example of serious damage to a hot section nozzle caused by hot corrosion is shown in Figure 44. Note that in this case the leading edge cooling hole has been totally compromised.

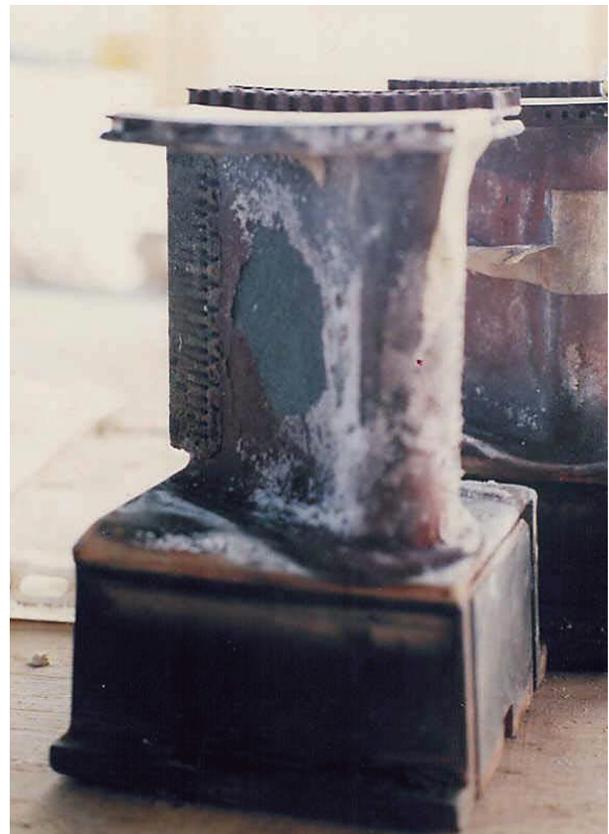


Figure 42. Fuelborne Salt on Nozzle.



Figure 43. Hot Corrosion Blade Distress.



Figure 44. Nozzle Distress Due to Hot Corrosion.

All grades of liquid fuel can be expected to always contain some quantity of water, typically less than 0.1 percent in the case of distillates and up to 1.0 percent in heavy fuel oils. During tank storage this water will slowly settle over time, and the settling process is continuous as fuel is drawn off and new fuel is received. Settled water should be regularly drained from the bottom of fuel tanks, and although settling rate is slow, the quantity of water drawn from tank bottoms will be surprisingly high. If not removed, water accumulated at tank bottoms can allow the growth of bacteria, which are often very corrosive to tank internals. Bacterial slime may also plug fuel filters if it is redistributed into the bulk of the tank and becomes discharged with the fuel. Bacterial problems are very common in dual fuel operations, where back-up distillate fuel may be stored for several years.

Settled water may also contain salts, so gravity separation (although slow) is beneficial. For this reason, and because contamination concentration will be higher in the lower regions, fuel tanks with floating suction are recommended. Floating suction ensures that fuel is always drawn from the top of the tank, so that settled contaminants are not disturbed. This type design also prevents “slugs” of high salt-content water (or

bacterial slime) being sent to the gas turbine. A fuel oil tank that had not been designed with floating suction as per recommended practice, but with discharge pipes at the bottom, is shown in Figure 45.



Figure 45. Poor Design of Piping from No. 2 Diesel Fuel Tank.

#### Case Study—Hot Corrosion Damage of an Industrial Gas Turbine

A heavy duty 65 MW industrial gas turbine that had accumulated 5,000 hours and 110 starts was operating at base load when it tripped on high vibration. Repeated restarts resulted in vibration trips. Upon disassembly, it was found that 40 percent of the second stage bucket tip shrouds had suffered material loss due to hot corrosion and weakening of the cross section as shown in Figure 46. First stage blades also showed signs of hot corrosion.

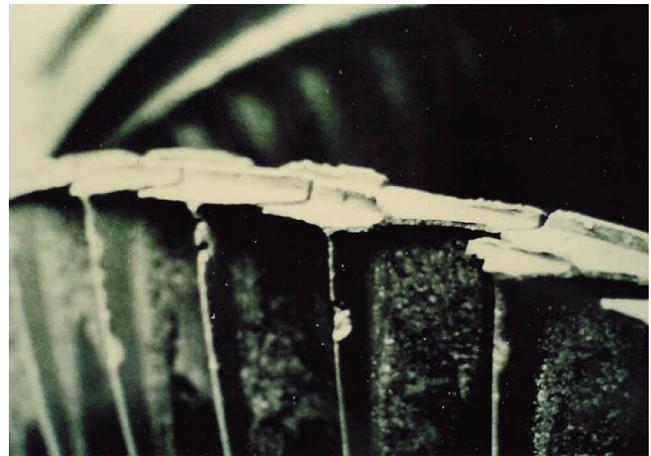


Figure 46. Second Stage Turbine Blade Hot Corrosion Distress.

A study of the hot gas path deposits indicated that salt was present and molten at operating temperature. This is typical of Type II (low temperature hot corrosion). By examining the chemistry of air- and fuel-side deposits, it was determined that salt ingestion was occurring both from the fuel and the air.

#### Damage Caused by Liquid Hydrocarbons in Fuel Gas

In another case, on a single shaft gas turbine in power generation service, the presence of hydrocarbon liquids in the fuel resulted in damage shown in Figure 47. There was a breached hole in the inner sidewall of the first stage nozzle which allowed liquids to be trapped within the wheel space and then ignite, resulting in a fire that caused the notch pattern damage on the first stage blade.



Figure 47. First Stage Blade Damage Due to Liquid Hydrocarbon Related Fire.

*Combustor Fretting Damage Caused by Gas Fuel Variability*

Varying fuel quality caused excessive vibration and fretting to the combustors and transition pieces on a heavy duty gas turbine. The damage caused to one of the transition piece brackets is shown in Figure 48. The damage and wear on the liner hula seals are shown in Figure 49.



Figure 48. Bracket Damage Due to Vibration and Fretting.



Figure 49. Damage on Liner Seals.

*Large Heavy Duty Gas Turbine Failure*

A large 123 MWe heavy duty gas turbine operating on natural gas experienced failures that included:

- Rotor blade rubs on the casing.
- Compressor discharge case strut cracks.
- Fuel nozzle swirler tip wear.
- Combustor liner spring seal failures.
- Transition piece cracks, discoloration and wear.

The problems and site observations are represented in the diagram shown in Figure 50.

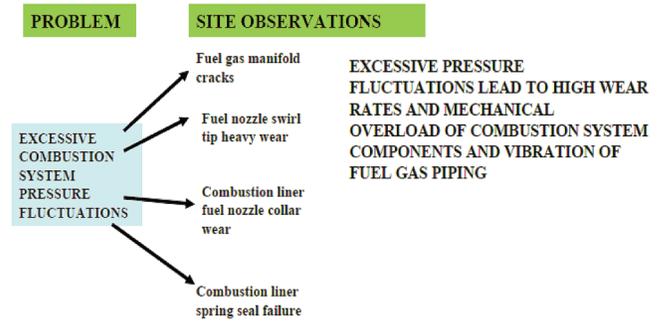


Figure 50. Problem and Site Observations.

Low fuel nozzle pressure ratios can lead to excessive combustion system pressure fluctuations. The reason this occurs is that the fuel nozzle gas tips act as metering orifices and when the pressure ratio (fuel gas pressure/pressure inside combustor liner) across the holes is low, pressure fluctuations in the combustion liner propagate upstream into the fuel nozzle. These large pressure fluctuations from the combustion process, superimposed on low pressure ratio at the nozzle tip, lead to large variations in fuel flow. In turn, the fuel flow variation feeds the combustion liner pressure fluctuations, leading to even greater pressure fluctuations that result in heavy wear of combustion components and the vibration of fuel gas piping. This is shown schematically in Figure 51.

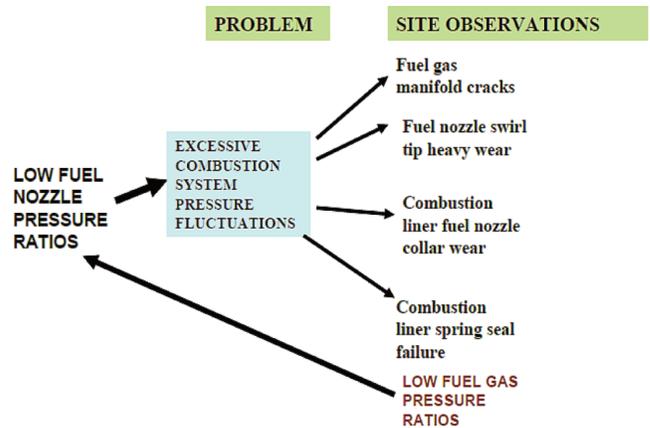


Figure 51. Excessive Combustion Pressure Fluctuations—Causes and Effects.

The reason why liquids in the fuel gas result in lower FNPRs is that holes in fuel nozzle swirl tips act as orifices to meter gas volumetric flow. The fuel gas volumetric flow is determined by caloric input required by the gas turbine, and as the heating value of fuel gas with liquids is much higher, a lower volumetric flow is required, which results in a lower FNPR. This is shown schematically in Figure 52.

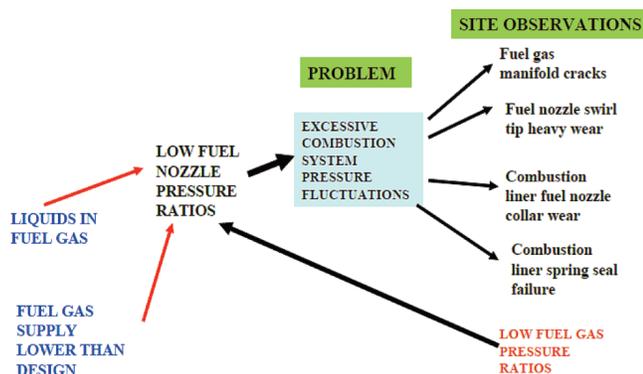


Figure 52. Low Fuel Nozzle Pressure Ratios—Causes and Effects.

Lower fuel temperatures can also contribute to lowering the FNPR. The hole size and volumetric flow determines pressure ratios and, at lower fuel temperatures, the gas has a higher density and more energy per unit volume. This leads to a lower requirement in terms of fuel gas volumetric flow, which also lowers the FNPR.

An explanation of why entrained liquids can distort the temperature profile is provided below and is shown in Figure 53. Liquids flowing through the gas side of a fuel nozzle do not follow gas streamlines and tend to concentrate at the axial centerline of liner. The combustion of small amounts of hydrocarbon liquid results in significantly higher gas temperatures than with dry fuel gas. Very often, the liquid droplets in the gas tend to pass through and burn further downstream. As the combustion gas profile has to “bend” as it flows through the transition piece, the hot center ends up near the outer radial edge. This leads to an overtemperature in this region of the transition piece, and also the first stage nozzle and downstream nozzles, shrouds, and blades.

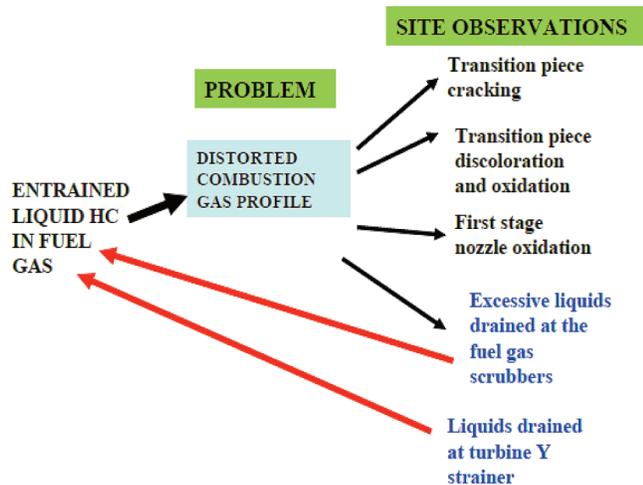


Figure 53. Distorted Gas Combustion Profile—Causes and Effects.

Liquids in the fuel can also cause surge events in the compressor. A slug of liquid hydrocarbon has a volumetric heat value of approximately  $1500 \times$  the comparable volume of fuel gas. This results in a very high and rapid heat release and, as the first stage nozzle typically runs choked, this sudden increase in temperature causes a rapid increase in back pressure which can push the operating point over the surge line.

## SUMMARY

This paper has provided an overview of the key issues related to understanding fuel systems for gas turbines in the context of combustion. It is very important that all parties involved in the fuel forwarding system design have an appreciation of the basics of combustion, and what the constraints are.

With gas fuels and lean premixed combustors, care is needed in dealing with issues of fuel variability, fuel transitioning, and ensuring that the degree of superheat and cleanliness is as per the OEM requirements. In several projects, there is uncertainty relating to the fuel and these contingencies must be carefully resolved during the early design phase. Adequate time for combustion tuning must be worked into the schedule. It is also important to have a close dialog with the gas turbine manufacturer with regard to expected fuel issues. The modified Wobbe number is a good overall parameter but may not always provide the full picture.

For lean premixed systems, care must be taken to avoid excessive margins resulting in part load operation that may be a problem under certain conditions. Dynamic situations of load loss or the sudden need to add load must be carefully considered and analyzed.

For liquid fuels, fuel quality is extremely important. With very stringent limits on Na and K being imposed by the OEMs, all aspects of fuel transportation, storage and treatment must be carefully considered. It should be remembered that so-called “clean” fuels such as No. 2 diesel oil can become contaminated during delivery to the power plant, and diligent monitoring of fuel quality is important. Heavy liquid fuels such as residual-grade oils and crude oils can be expected to always contain ash-forming contaminants, but actual quality varies tremendously throughout the world. However, successful operation can be achieved if appropriate fuel treatment systems are installed and effective fuel additives are applied. Accurate and realistic fuel specifications need to be established at an early stage of the project. Only heavy-duty lower-firing temperature GT models should be considered for heavy fuel applications.

Numerous other gaseous and liquid fuel alternatives are available for gas turbine applications, ranging from refinery wastes and petroleum biproducts to biofuels produced from vegetable oils and natural sugars. Properties cover an extremely wide range and demonstrate the versatility of the combustion turbine in handling such different fuel qualities.

## NOMENCLATURE

$\phi$	= Equivalence ratio
$\eta$	= Thermal efficiency
AI	= Autoignition
CDP	= Compressor discharge pressure
$C_p$	= Specific heat
DLE	= Dry low emission
DLN:	= Dry low NO <sub>x</sub>
DP	= Dew point
FAR	= Fuel to air ratio
HGP	= Hot gas path
FHV:	= Flame holding velocity
FNPR	= Fuel nozzle pressure ratio
HFO	= Heavy fuel oil
HHV	= Higher heating value
HRSRG	= Heat recovery steam generator
IGCC	= Integrated gasification combined cycle
JT	= Joule-Thompson
LBO	= Lean blow out
LEL	= Lower explosive limit
LHV	= Lower heating value
LNG	= Liquefied natural gas
LPG	= Liquefied petroleum gas
LPM	= Lean premix
MM	= Million
MWI	= Modified Wobbe Index
OEM	= Original equipment manufacturer
ppmvd	= Parts per million, volume dry
RH	= Relative humidity
SG	= Specific gravity
TIT	= Turbine inlet temperature (= TRIT)
UEL	= Upper explosive limit
WI	= Wobbe Index

*Common Conversions*

Thermal eff	= 3412/Btu/kWhr
Btu × 1.055	= kJ
Gal × 3.785	= liters
Kg × 2.205	= lb
Btu/lb × 2.326	= kJ/kg
J × 0.239	= Cal

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