

FUELS FLEXIBILITY IN HEAVY-DUTY GAS TURBINES

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INTRODUCTION

World events have highlighted the critical role that fuels play in power production. The cost and availability of fuel are preeminent planning considerations. Consequently, the ability of any prime mover to burn a wide range of fuels-or fuels flexibility-continues to be of primary importance.

In the past, most land-based gas turbines used natural gas or distillate fuels. A smaller but significant number used the lower-cost, poorer-grade fuels. During the past decade, however, there has been a decided change in this pattern. More and more, machines are being called upon to handle the lower-grade fuels, particularly in the international scene. Included in this category are blends, crudes, residual oils, and the lower heat-content gases. To this list will be added coal-derived fuels of the future.

The purpose of this paper is to discuss the properties of the various fuels and how these properties influence GE heavy-duty turbine design and operation.

EXPERIENCE

As of January 1983, 3570 GE-designed heavy-duty gas turbines have been shipped. As can be seen in Table 1, these gas turbines are designed to burn a variety of fuels and combinations thereof.

Heavy Fuels

Of particular interest is the experience on heavy or ash-forming fuels and the experience with gaseous fuels other than natural gas. In the period 1950 to 1960, 78 gas turbines operating on heavy fuels were installed in various industries, including 11 in electric utilities, 9 in oil pipeline service, 1 in ship propulsion, and 57 in railroad locomotives. They provided experience in excess of 2.7 million hours of economical service burning heavy fuel. The units ranged from 5000 kW and had firing temperatures of approximately 1450 F (788 C). Currently, over 300 units have been shipped or are on order; all are capable of burning ash-forming fuels. Tables 2, 3 and 4 list the 88 units which have been installed since 1961 that have operated on ash-forming fuel (crude oil, residual oil, blends, or heavy distillate).

Table 1
GE HEAVY-DUTY
GAS TURBINES SHIPPED FOR
SPECIFIC FUEL APPLICATIONS
(as of January 1983)

Fuel	
Natural Gas	1408
Process Gas	13
Dual Gas	60
Distillate	783
Naphtha	14
Kerosene	30
Distillate or Gas	964
Distillate and Gas	82
Crude	59
Crude and Distillate	32
Residual	120
Residual or Gas	4
Residual/Distillate/Gas	1
Total	3570

The following case histories are of interest to show the variety of heavy fuels that have been used:

- *Caltex-Sumatra*. Nine MS5001 units generate power for pumping crude oil from wells to the port of Dumai. These units accumulated 200,000 fired hours on a waxy crude — very low in vanadium (0.5 ppm) — which was water-washed to reduce sodium concentrations from 10 ppm to less than 1 ppm. The units have a total of over 580,000 fired hours, currently being fired on natural gas from the wells.
- *O.N.E. Morocco*. Six MS5001 units have accumulated a total of 75,000 fired hours, with over 63,000 hours on treated residual fuel. The residual fuel contains 50 to 70 ppm vanadium and up to 100 ppm sodium (before washing). It is desalted by two electrostatic precipitators and inhibited by an organic oil-soluble magnesium additive.
- *Ferrara*. Two MS5001 units in this refinery installation in Italy each accumulated 27,000

**Table 2
GEDESIGNED HEAVY-DUTY GAS TURBINES BURNING CRUDE OIL.
OPERATING EXPERIENCE**

Customer	Turbine Model	Appl. Code	No. of Units	Date Installed	Total Fired Hours	Fired Hours on Ash-Forming Fuels	Firing Temp. for Heavy Fuels (°F)	Metal Contamination Raw Fuels		Fuel Treatment Used
								Sodium (ppm)	Vanadium (ppm)	
MS3000										
SOPED	3002(B)	M	2	1961	220,000	120,000 ⁽¹⁾	1500			
Phillips	3002(J)	M	6	1976	45,000		1730	5.8	0.6	1-Stg. Centrifuge
MS5000										
Abu Dhabi	5001	EU	7	1969-75	288,000	1,000 ⁽¹⁾	1650/1550	25	0.15	1-Stg. Centrifuge
Caltex	5001	EI	9	1970-78	580,000	200,000 ⁽¹⁾	1650	10	0.6	1-Stg. Centrifuge
EEG Guatamala	5001 (P)	EU	2	1977-78	50,000	22,000	1650/1750	max. 50	max. 8	2 Stg. ESD- Storage— Centrifuge V inhibitor
SCECO-Qaisumah	5001 (P)	EU	4	1977-83	43,000	41,000	1650/1730	max. 20	max. 15	Centrifuge
MS7000										
Florida Power Corp. -Bartow	7001 (B)	EU	4	1972	37,400	12,000 ⁽²⁾	1840	10	3	2-Stg. ESD
Arizona Public Service	7001 (B)	EU	1	1975	2,700	200 (3)	1800	14	0.1	2-Stg. ESD
Arizona Public Service	7001 (C)	EU	3	1976	20,700	3,340	1840	14	0.1	2-Stg. ESD
SCECO-Riyadh	7001 (E)	EU	16	1980-81	158,000	150,000	1930	10	7-9	ESD in Refinery Tanks

Installation period: 1961-Present

Application Code:

EI -Industrial Power Generation
EU -Utility Power Generation
M -Industrial Mechanical Drive

(1) 1979 data-total fired hours are current data.
(2) No longer burns crude.
(3) Crude system tested only.

fired hours on a residual oil with 20-18 ppm vanadium and 9-90 ppm sodium (before washing). When plant gas became available in the late 1960s, the units were converted to burn gas. Total fired hours for these units now exceeds 170,000 hours.

- *GE — Lynn Utility Operation.* One of the more comprehensive test programs to demonstrate GE's capabilities for burning heavy oils at high firing temperatures was conducted at GE's plant in Lynn, MA. Here, beginning in 1973, one MS5001N machine (equipped with a heat recovery boiler to supply a substantial part of the plant's steam requirements) burns various grades of residual oils, including No. 6 residual, at a firing temperature of 1750 F (954 C). One test program increased the firing temperature to 1850 F (1010 C) for 700 hours to demonstrate the ability to burn heavy fuels at this temperature.

Additionally, two fuel treatment systems were utilized to demonstrate the respective capabilities of each. These were an Alfa Laval centrifuge wash system and a Petreco electrostatic desalting system.

Currently, this unit has over 32,000 fired hours of operation with 31,000 hours on heavy fuels.

- *Electro Empresa de Guatemala (EEG).* Two MS5001 units have accumulated a total of over 22,000 hours on Guatemalan crude oil with 5-50 ppm sodium and 4-R ppm vanadium (before washing). As initially installed, the fuel treatment system utilized a two-stage, counter-current desalting system (electrostatic precipitation principle) and vanadium inhibition via oil-soluble magnesium additives. In 1980, a pilot plant centrifuge purification system was installed between the day tank (holding washed crude) and the units.

Table 3
GE-DESIGNED HEAVY-DUTY GAS TURBINES BURNING RESIDUAL OIL
OPERATING EXPERIENCE

Customer	Turbine Model	Appl. Code	No. of Units	Date Installed	Total Fired Hours	Fired Hours on Ash-Forming Fuels	Firing Temp. for Heavy Fuels (F)	Metal Contamination Raw Fuels		Fuel Treatment Used
								Sodium (ppm)	Vanadium (ppm)	
MS5000										
Central Vermont	5001	EU	1	1961	10,550	700	1450			
Ferrara	5001	EI	2	1963	170,000	54,000	1400	9-90	20-118	2-Stg. Centrifuge V Inhibitor
GE Lynn	5001	EI	1	1970	32,000	31,000	1650	100 max.	100 max.	2-Stg. Centrifuge or 2-Stg. ESD V Inhibitor
Green Mtn. Power	5001	EI	1	1965	8,500	600	1500			V Inhibitor
O.N.E. Morocco	5001	EU	6	1974-78	75,000	63,000	1650	100 max.	70 max.	2-Stg. ESD V Inhibitor
Broken Hills Prop.	5002	SP	2	1973-74	32,000	30,600	1650	40	2	1-Stg. Centrifuge
Reksten	5002	SP	1	1974	10,000	9,100		100 max.	50-280	2-Stg. Centrifuge V Inhibitor
EMSA	5001	EU	2	1983	8,000	1,500	1650	50	20	2-Stg. Centrifuge V Inhibitor
MS7000										
Alcoa Surinam	7001 (B)	EU	1	1976	26,000	24,000	1750	60-150	80	2-Stg. Centrifuge V Inhibitor
Florida Power Corp.-De Bary	7001R(B)	EU	6	1976	42,500	33,500	1840	22-23	28-45	3-Stg. ESD V Inhibitor
Taiwan Power Vo.	7001 (E)	EU	1	1980	1,500	200	1955	1.2	24	1-Stg. Centrifuge (for test only) V Inhibitor

Installation period: 1961-Present

Application Code:

EI -Industrial Power Generation
 EU -Utility Power Generation

M -Industrial Mechanical Drive
 S -Ship Propulsion

Table 4
GEDESIGNED HEAVY-DUTY GAS TURBINES BURNING BLENDS
OPERATING EXPERIENCE

Customer	Turbine Model	Appl. Code	No. of Units	Date Installed	Total Fired Hours	Fired Hours on Ash-Forming Fuels	Firing Temp. for Heavy Fuels (F)	Metal Contamination Raw Fuels		Fuel Treatment Used
								Sodium (ppm)	Vanadium (ppm)	
MS5000										
Shell Curacao	5001	EI	1	1971	53,000	17,000	1700	0.6	0.5	1-Stg. Centrifuge
Indonesia-PLN	5001	EU	2	1974	42,000	40,000	1730	2.0	1.0	None Installed
MS7000										
Golden Valley	7001 (R)	EU	2	1976	47,500	47,500	1860	—	—	None Installed
Riyadh Elec. Co.	7001 (B)	EU	5	1977	173,000	168,000	1840	2-3	7	V Inhibitor Dist. Blend
MS9000										
EDF	9001	EU	1	1975	7,200	100	1840	1.0	0.5	None Installed

Installation period: 1961-Present

Application Code:

EI -Industrial Power Generation
 EU -Utility Power Generation
 M -Industrial Mechanical Drive

- *Saudi Consolidated Electric Company.* Four MS5001 units at the Qaisumah Power Station in Saudi Arabia have accumulated 41,000 hours on light Saudi crude oil with analysis of the raw fuel indicating normal sodium levels of 4-10 ppm. The fuel purification system consists of electric heaters followed by four MAPX-20 centrifuges operating in parallel. This plant is demonstrating the "purification" process which, to date, at this plant, has not required additional water to be added to the fuel, and only 20 gph are needed to eject solids from the centrifuges in order to effectively treat the fuel.

- *Florida Power Corporation — Bartow Station.* A block of four MS7001 heavy-duty gas turbines was installed by Florida Power Corporation at the Bartow site in 1972. These units operated successfully on Essider Libyan crude oil a total of 12,000 hours before the crude became unavailable in 1976. These machines operated at 1840 F (1004 C) firing temperature and are used for peaking service.

The crude oil was treated by washing to lower the sodium concentration to less than 1 ppm, using a two-stage electrostatic desalter, and by inhibiting the 3 ppm of vanadium with an oil-soluble magnesium additive. Due to the wax of Essider crude, the fuel was heated to 100-110 F (38-43 C) to avoid fuel filter plugging. The turbines were washed every three months to remove combustion ash deposits.

- *Florida Power Corporation — De Bary Station.* Six MS7001L regenerative gas turbines operating at 1850 F (1010 C) are installed at the Florida Power Corporation De Bary site. A total of 42,500 fired hours has been accumulated with 33,500 hours on residual oil.

The raw residual has up to 33 ppm of sodium and 40 ppm vanadium. The residual is washed to less than 1.0 ppm sodium by a three-stage electrostatic desalter. The vanadium is inhibited by an oil-soluble magnesium additive.

The formation of the turbine ash deposits is so light that turbine water washing is performed only after ~51,000 hours of operation. Washing is performed as part of the maintenance cycle after the summer and winter peaking operations. This characteristic of low ash deposits is due to the low contaminant level and the shutdown and restarting associated with peaking duty.

- *Alcoa-Surinam.* One MS7001 gas turbine has been operating at Paramaribo, Surinam since 1976. The site is an aluminum bauxite plant owned by the Alcoa Company. The gas turbine has a heat recovery boiler and supplies both electric power and process steam.

This turbine has operated at 1750 F (954 C) firing temperature for 26,000 hours. Over 24,000 of these hours have been on a poor-grade residual oil.

This raw residual has up to 80-125 ppm sodium and 70 ppm vanadium. The sodium is reduced to approximately 1 ppm by a two-stage DeLaval centrifuge. The vanadium has been inhibited by either oil-soluble or water-soluble magnesium additives. The turbine is equipped with both turbine washing and on-line cleaning equipment. This baseloaded, industrial power generation unit has demonstrated the practicality of the MS7001 unit as a heavy-fuel-burning, highly-reliable gas turbine. Borescope and visual inspection show no signs of hot-gas-path corrosion.

- *Saudi Consolidated Electric Company — Riyadh 7.* Sixteen MS7001's, operating in the desert environment of Saudi Arabia at SCECO's Riyadh 7 plant, are providing extensive experience burning ash-forming fuel, and have accumulated a total of 158,000 hours of oper-

Table 5
ALTERNATE GASEOUS FUELS EXPERIENCE

Type of Gas	Approximate LHV MJ/M ³ (Btu/ft ³)	Model	Number of Units
Low & Medium Btu			
CH ₄ + CO ₂	24.2 (650)	MS3002	1
H ₂ + CH ₄	13.0 (350)	MS5001	3
H ₂ + CH ₄	11.2 (300)	MS3002	2
H ₂ + CH ₄	11.2 (300)	MS3002	2
CH ₄ + N ₂	16.8 (450)	MS5001	4
Coke Oven	17.7 (475)	MS5001	2
Coke Oven	11.2 (300)	MS5001	1
CH ₄ + N ₂	11.7 (315)	MS3002	1
High Btu*			
C ₄ H ₁₀	116 (3100)	MS5001	1
LPG	111 (2980)	MS3002	1
C ₃ H ₈ + C ₄ H ₁₀	86-112 (2500-3000)	MS5001	7
C ₄ H ₁₀	112 (3000)	MS5001	1
De-Ethanized Still Product	86 (2300)	MS5001	2
C ₃ H ₈	86 (2320)		

*All fuels in vaporized form.

ation, with a predominate proportion (150,000) on crude oil at a rated firing temperature of 1930 F (1054 C).

The crude oil used in these machines is treated at the refinery source in an electrostatic desalting system.

- *Taiwan Power Company.* One MS7001 unit at the Tunghsiao Power Plant has been converted to burn residual fuel oil at a firing temperature of 1955 F (1068 C).

The unit has accumulated over 600 fired hours on a residual oil with 1.2 ppm sodium and 4 ppm vanadium levels before treatment in a centrifuge-based system.

Alternate Gaseous Fuels

GE heavy-duty gas turbines have operated successfully burning alternate gaseous fuels with heating values ranging from 11.2 to 116 MJ/m³ (300 to 3100 Btu/ft³ lower heating value (LHV)). A listing of gas turbines with alternate gaseous fuel capability by type of fuel, model series, and year of shipment is presented in Table 5.

On the basis of single combustor tests in the laboratory, the capability for successful operation with fuel heating values as low as 4 MJ/m³ (110 Btu/ft³) LHV has been demonstrated.

More recently GE initiated a program of extensive analytical calculations to investigate the combustion characteristics of a number of lower-heating-value fuels, typical of those produced by a fuel-conditioning process. The analytical calculations were coupled with atmospheric burner tests using a small scale diffusion flame burner. Based upon the results of this study, full-scale single-burner and sector tests were conducted in the Gas Turbine Development Laboratory to confirm expected MS5000 and LM2500 engine performance.

An example of the benefits derived from this extensive program is the finding that both the MS5000 and LM2500 gas turbines will operate satisfactorily while burning a 15.8 MJ/m³ (425 Btu/ft³) gas that comprised nearly 80 percent CO₂ by volume. In general, the only change required to the standard combustion system is modification of the gas fuel nozzle to handle the increased volume of fuel. A variation in heating value of more than ±20 percent could be tolerated while still maintaining adequate combustor performance.

Turbine/Fuel Design Criteria

For any gas turbine-manufacturer, the fuels that will be used will have a profound effect upon

both the machine design and the materials of construction. Some gas turbine applications will always use highly refined and clean fuels; aircraft jet engines are the prime example. In this case, materials and designs will primarily be limited by strength and oxidation characteristics. In most land-based gas turbines, however, use of cheaper, lower-grade fuels dictates that additional emphasis be placed upon corrosion resistance, deposits, and the more challenging combustion characteristics.

Maximum fuels flexibility has been a basic philosophy in the development of GE heavy-duty gas turbines throughout the more than 30 years of GE gas turbine manufacture. The cornerstone of the philosophy was actually laid in the early 1950s, as a result of experience with the ash-forming fuels burned at Central Vermont, Bangor Hydroelectric, Union Pacific Railroad, and Trans-Arabian Pipe Line (TAPLINE). As amended by continued improvements, this same philosophy exists today and will continue in the future.

It is significant to note that present fuels flexibility is being maintained at firing temperatures and machine sizes that were not feasible 10 to 15 years ago. In fact, firing temperatures are some 400 to 500 F (222 to 278 C) higher than those existing in 1950, with a correspondingly large increase in machine output and thermal efficiency.

Many of the old machines operate on natural gas, which by virtue of its general cleanliness and favorable combustion characteristics can still be regarded as the standard against which other fuels are compared. Many improvements that have maintained flexibility for lower grade fuels have been made in the modern, higher temperature machines such as the MS6001, MS7001, and MS9001 units.

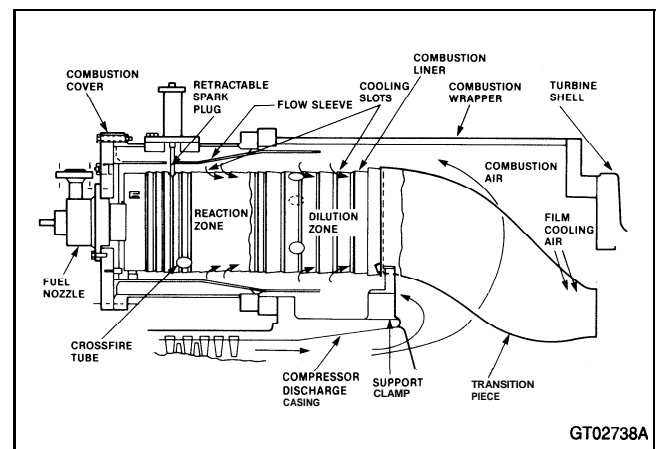


Figure 1. Reverse-flow combustion system

Combustion Design

All modern GE heavy-duty gas turbines use multiple reverse-flow combustors similar to that illustrated in Fig. 1. Each combustor is composed of a liner, transition piece, and fuel nozzle, chosen for its fuel flexibility, maintainability, and ease of testing at full-pressure, temperature, and flow conditions in the laboratory. The design parameters for a combustor are listed in Table 6.

Figure 1 shows that compressor discharge air flows around the transition pieces while cooling them. It enters the combustion liner through various air passages in the liner. Fuel injected into the combustion reaction zone burns with a portion of the available air entering the head end of the combustor. Recirculating flow patterns of air

Table 6
COMBUSTION DESIGN OBJECTIVES

Design Parameter	Fuel Property
Metal Temperatures	Residual Carbon Carbon/Hydrogen Ratio Aromatic Content
Smoke	Residual Carbon Hydrogen Content Aromatic Content
Ignition Reliability	Viscosity Heating Value Volatility Flammability Limits
Crossfiring Reliability	Flammability Limits Heating Value
Atomizing Air Requirements	Viscosity Surface Tension Density
Combustion Efficiency	Carbon/Hydrogen Ratio Aromatic Content Flammability Limit
Emissions	Carbon/Hydrogen Ratio Fuel-Bound Nitrogen Heating Value Water Vapor
Carbon Build-up	Carbon/Hydrogen Ratio Aromatic Content Viscosity

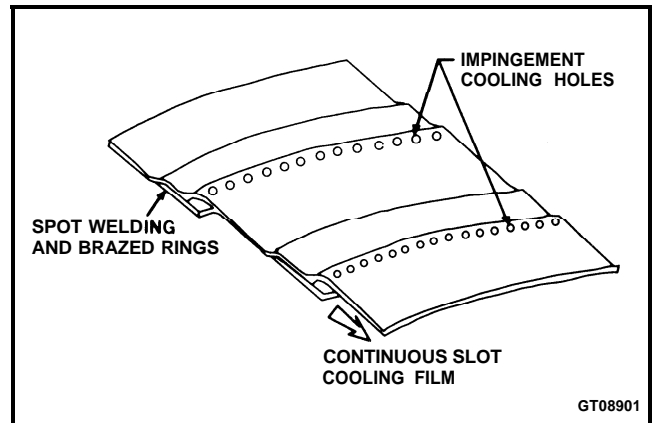


Figure 2. Slot-cooled liner, cutaway view

and burning gases provide flame stability. The hot combustion gases are then mixed with secondary air entering through downstream holes to dilute the gas and lower its temperature before it enters the turbine. The temperature profile of hot gases entering the turbine section is controlled to maximize the life of the turbine parts.

Heat transfers from the flame and hot gases to the liner walls and is removed by air sweeping over the inside and outside of the liner. The flow sleeve enhances liner cooling by increasing the cooling air velocity near the liner.

These combustors can burn a wide variety of fuels ranging from natural gas to the various process gases, and from naphtha to heavy residual oils. Dual fuel nozzles are often used to allow transfer between fuels without shutdown.

Neither mathematical nor geometric modeling has been adequate for combustion development because a scale model does not reproduce the chemical reactions, heat release rates, and aerodynamic mixing of the full-size design. Aerodynamic mixing, which is achieved by air jet penetration from the walls of the combustor, becomes more difficult as the liner diameter increases. Consequently, full-size combustor testing at full flow and pressure is necessary to ensure the adequacy of new designs. Almost all the development work can be accomplished on a single-burner test stand at full operating conditions.

The combustor ignition system includes spark plugs, crossfire tubes, and flame detectors. For reliability, two spark plugs and two flame detectors are used. Ignition in one of the chambers produces a pressure rise which forces hot gases through the crossfire tubes, thereby propagating rapid ignition to all other chambers. Flame detectors, located diametrically opposite the spark plugs, signal the control system when the ignition

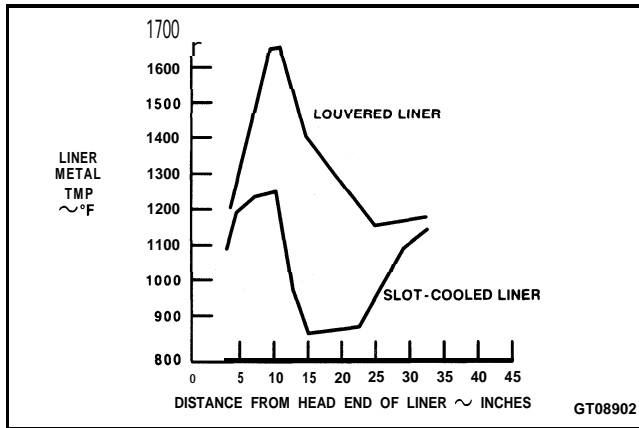


Figure 3. Maximum liner metal temperatures

process has been completed. Because of the simplicity and reliability of this technique, it is used in all GE-designed heavy-duty gas turbines.

The combustion system has evolved from the original application of heavy-duty machines burning residual oil. Engineering development work on this system has continued and has resulted, for example, in the use of the slot-cooled combustion liner (Fig. 2) on the MS6001, MS7001, and MS9001 gas turbines.

The slot-cooled liner, originally developed by GE for aircraft gas turbines, has been modified for application to the heavy-duty gas turbine. It provides more uniform, more effective cooling than is possible with a louvered liner. The slot-cooled liner operates with 250 F (139 C) lower metal temperatures than an equivalent louver system (Fig. 3). It also operates with lower temperature gradients, increasing the comparative life of the parts. The slot-cooled liner is superior to the louver type for the more radiant flames from heavy fuels, and it eliminates the corner stress concentration points of louvers.

Another important innovation in liner design has been decrease in length. This "short" liner provides increased stiffness as well as a reduction in the amount of cooling air required since the surface area to be cooled is reduced. There are currently over 120 MS6001, MS7001, and MS9001 machines operating with the slot-cooled liner.

The major impact of the heavy fuel properties on combustor design is on the liner metal temperature and carbon formation. The degree to which the fuel has been atomized is an important factor in establishing liner metal temperatures and reducing carbon formation. By using a finely atomized spray such as that produced by the atomizing air nozzle, flame radiation can be reduced by as much as 75 percent in the intermediate zone of the combustor. All liquid fuels for

the current design MS6001, MS7001, and MS9001 units are, therefore, air atomized at the fuel nozzle. Typical atomizing air pressure ratios (fuel nozzle air pressure/compressor discharge pressure) are in the range of 1.2 to 1.4 for light distillate fuels with higher ratios being required for heavy fuels. Fuels with kinematic viscosities of up to $20 \times 10^{-6} \text{m}^2/\text{s}$ can be successfully burned using atomizing air. The required pressure ratio is determined largely by experiment and consideration of several design factors including emissions, combustor metal temperatures, temperature profiles, and carbon build-up.

Nozzles and Buckets

Heavy-walled buckets and nozzles with large annular spacings are used to minimize the effects of corrosion and deposits. In addition, air cooling is used on the first- and second-stage nozzles as well as the first and second bucket stages of the MS6000, MS7000, and MS9000 gas turbines.

The cooling circuitry for the nozzles and buckets has been designed to avoid plugging by fuel ash deposits. The first- and second-stage buckets use internal convective cooling to maintain low metal temperature. This cooling system is designed to provide an exit for cooling air at the bucket tips (Fig. 4) where these exits are protected from ash impingement. Figure 4 also shows that the air exit holes in the bucket tip remain open and unplugged after long-term operation.

In the current design MS6001 and MS9001, and in late 1984 for the MS7001E, the first-stage nozzle cooling circuits and cooling air exit passages have been modified to further minimize the occurrence of plugging by ash deposits (Fig. 5). Should the suction-side film holes experience plugging by ash deposits, the forward cavity chamber cooling flow would then pass through

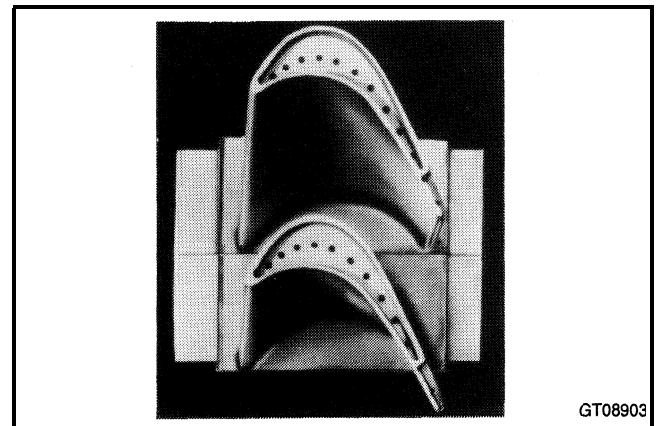


Figure 4. MS7001 First-stage turbine buckets (radial view)

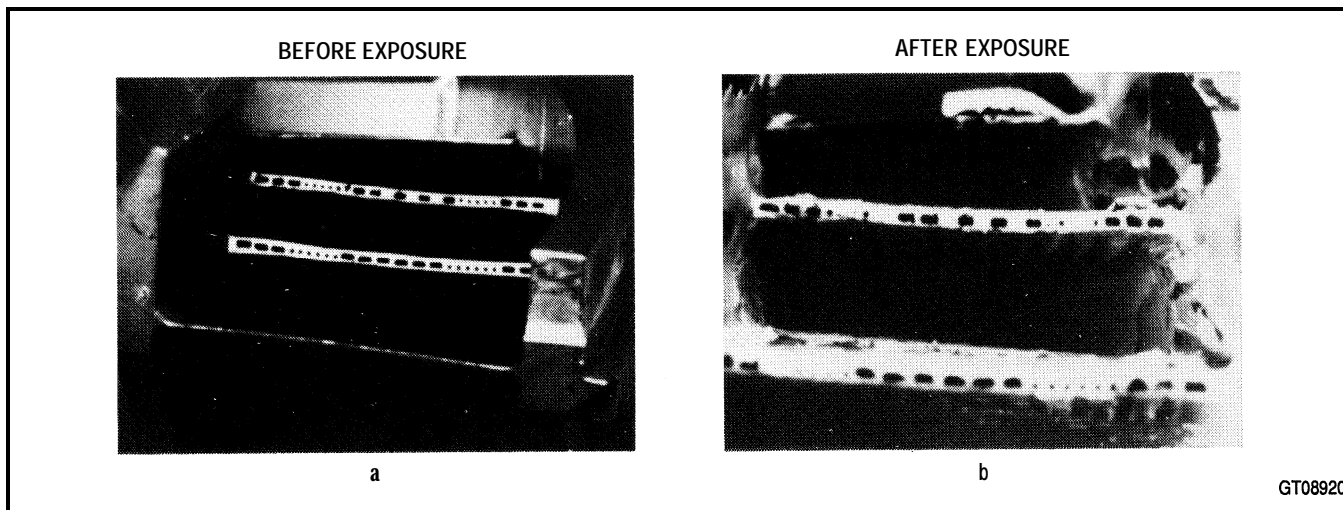


Figure 5. First-stage nozzle trailing edge cooling holes

the rib bypass holes into the aft cavity chamber. The cooling air entering the aft cavity chamber exits from the trailing-edge region of the nozzle vane through trailing-edge rectangular slots and through large pressure-side film holes, which are not subject to plugging by ash deposits. Figure 5 shows the trailing edge cooling hole plugging behavior of 40-mil diameter holes versus 50 x 120-mil slots before and after 150 hours burning doped No. 2 distillate with 200 V, 600 Mg, 1 Na in turbine simulator test.

Materials

Improved nozzle and bucket materials and long-life coatings on the first-stage buckets are used. A summary of these improvements is given in the "Materials" section of this paper; more detail is presented in Ref. 1.

Specifications

A tighter fuel specification is now utilized than that which existed 12 years ago. The economic-technical balance of this specification was set so that it is technically achievable while not increasing fuel costs significantly. It is also in line with current industry standards.

Auxiliary Components

Special provisions are made for handling the ash-forming liquid fuels. These modifications are largely outside of the turbine core (which is largely standardized in construction) and are frequently external modular items. Examples are provisions for air atomizing, handling and treat-

ing the fuel, and cleaning the turbine to remove ash deposits.

Turbine Ratings

Some ash-forming liquid fuels require a derating in firing temperatures, particularly in the larger machine models. This is accommodated by modifications to the control circuitry, as opposed to changes in the gas turbine proper.

MATERIALS

A key item in maintaining fuels flexibility at higher firing temperatures has been the corresponding improvements in hot-gas-path materials. The intent is to standardize all materials and designs in the core of the machine and to have these materials be suitable for all types of fuel, including the lower grades of fuel.

Many recent materials improvements have been required because of increased firing temperatures and machine sizes, independent of fuel. Included in this category are improvements in compressor, casing, wheel, inlet, and exhaust materials. However, it is in the most critical area of the hot-gas-path parts that fuels flexibility has always been a basic criterion. This most specifically applies to the first-stage nozzle partitions and buckets. Some of these developments will, therefore, be described in this section of the paper.

Basically, machines that will operate only with clean fuels and inlet air can use very high strength materials having relatively little corrosion resistance. The use of lower grade fuels will

require, however, some trade-off between strength and corrosion resistance and, more recently, the use of long-life coatings. It is in this area that much of the GE materials development activities have been concentrated over the years. A present, a particularly corrosion-resistant cobalt alloy is used for first-stage nozzle partitions, while a corrosion resistant nickel-base alloy (because of the higher stresses involved) plus a long life coating is used for first-stage buckets.

Present First-Stage Nozzle Partitions

The current alloy used for all heavy-duty gas turbine first-stage nozzles, and some later-stage nozzles, is a GE-patented cobalt-base alloy, FSX414. This alloy is a derivative of X40 and X45, both of which were also developed by GE. FSX414 contains less carbon than **X40**, for better repair weldability during initial manufacture and servicing.

A major improvement of FSX414 over X40 and X45 is its improved oxidation and corrosion resistance, which results from its higher chromium content. Long-life tests in a simulated gas turbine combustion chamber have demonstrated a two- to three-fold increase in oxidation resistance. Expressed another way, this improvement permits an increase in the firing temperature of approximately 100 F (55 C) for equivalent partition oxidation life (Fig. 6).

FSX414 is actually quite similar to its predecessor, X45, in virtually all other critical respects such as composition, thermal shock resistance, mechanical and rupture strength properties, and weldability.

The history of FSX414 offers a good example of the material development work required for the introduction of new alloys. Over 70 oxidation/corrosion tests ranging from 600 to 6,000 hours were run, and over 120 creep/rupture tests ranging from 50 to 9,000 hours were completed.

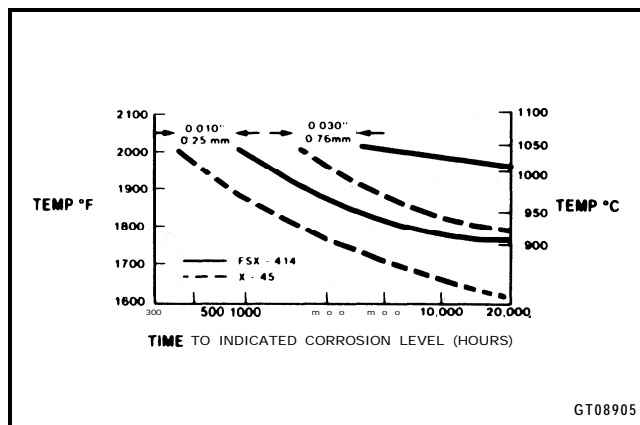


Figure 6. Small burner tests (comparison of X-45 and FSX-414 alloys oxidation in natural gas combustion atmospheres)

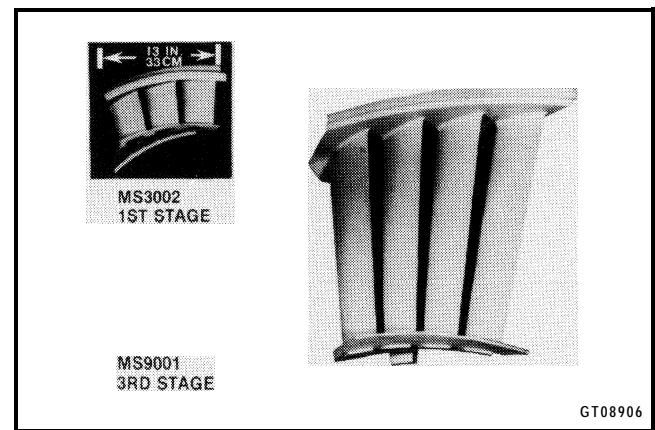


Figure 7. Investment-cast nozzles

In addition, sizeable investigations were conducted on castability, machinability, weldability, thermal-shock resistance, and metallurgical phase stability. The entire development covered a period of three to four years.

This improvement was being conducted at the same time as the need for larger parts became evident. A graphic demonstration of this is shown in Fig. 7, which compares the size of earlier nozzle segments with those of today's larger machines. A five-fold increase in segment weight is involved.

Present First-Stage Buckets

Of all gas turbine components, the first-stage bucket must withstand the most severe combination of temperature, stress, and environment. It is also the most critical component as far as determining the firing temperature, output, and efficiency of the overall machine.

Advances made in turbine bucket alloys since 1950 have resulted in increased allowable metal temperatures of approximately 250 F (139 C). While this increase may not appear very large at first glance, each increase of 100 F (55 C) in turbine firing temperature corresponds to an increase in machine output of between 10 and 13 percent and in thermal efficiency of from 2 to 4 percent. Thus the development of new alloys, while a time-consuming and expensive effort, yields significant rewards in the reduced dollar-per-kilowatt cost of turbines and in the reduced cost of turbine operation.

Figure 8 shows the trend of firing temperatures and alloy strength as a function of year. It can be seen from Fig. 8 that the increase in alloy strength accounted for the majority of firing temperature increases until about 1970, but has been slower since then. This has been due to two factors. First, emphasis has more recently been placed on the use of air cooling to increase firing

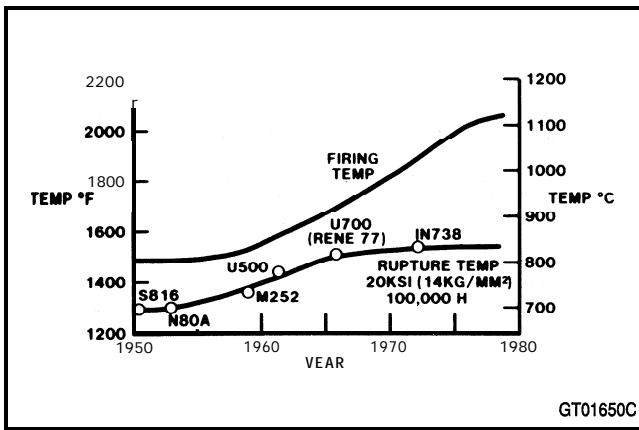


Figure 8. Past trend firing temperature & bucket material capability

temperatures. Second, hot corrosion of buckets became a more life-limiting factor as the metal temperatures approached the 1600 F (871 C) range. Together with the increased use of contaminated fuels, this temperature increase required that recent materials development be directed more to improving the hot corrosion resistance of the buckets. This has primarily been done by developing long-life coatings.

All first-stage buckets of GE heavy-duty gas turbines are now made with IN738, an alloy invented by the International Nickel Company. Extensive evaluations conducted by GE on this alloy resulted in small but critical changes in composition. Included in these evaluations were long-time creep/rupture, oxidation, corrosion, and fatigue testing, as well as heat treatment studies and metallurgical phase analysis. The results of these studies indicated that this alloy exhibits an excellent

combination of strength, metallurgical stability, and oxidation/corrosion resistance. In fact, this combination is considered superior to any alloy previously used.

A graphic comparison of the corrosion resistance of IN738 and its predecessor U700 (René 77) is shown in Fig. 9; all the given data is for uncoated material. The graph shows data taken from small burner corrosion tests conducted at 1600 F (871 C), which is in the general range of metal temperatures of today's buckets. There are about 30 test points in each crosshatched area. A substantial improvement in corrosion resistance of IN738 over U700 is seen. Interestingly enough, virtually all the accelerated laboratory data was produced before 1971 and was, in fact, the main basis upon which the production change to IN738 was made at that time. The value of these laboratory tests was subsequently demonstrated in the field, as is also shown in Fig. 9. The two buckets shown are back-to-back, same-machine comparisons of U700 and IN738 in a sour gas/contaminated air environment. The IN738 bucket is in considerably better shape, despite the four-fold longer service time it saw.

The combination of laboratory and field experience to date supports the fact that IN738 has four to six times better corrosion life than U700 (René 77) in corrosive environments

As in the case of nozzle partitions, this work was being done while simultaneously developing procedures for making larger buckets. A comparison of the sizes of buckets produced in the mid-1960s versus those of the 1970s is shown in Fig. 10—an approximately five-fold increase in weight of the parts took place.

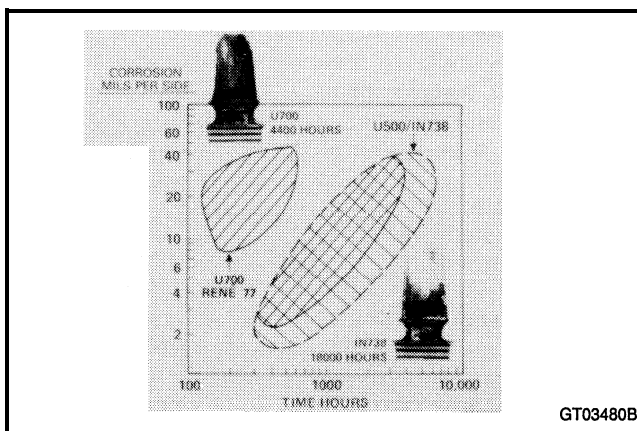


Figure 9. Comparison of U700 (René 77) and IN738 corrosion resistance (40 Microns = 1 Mil)

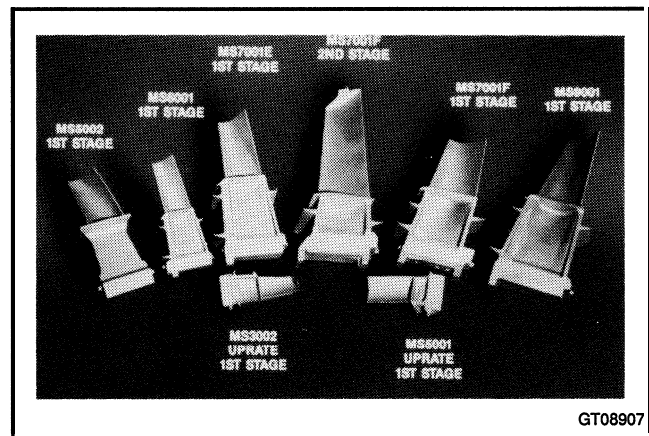


Figure 10. Investment-cast buckets

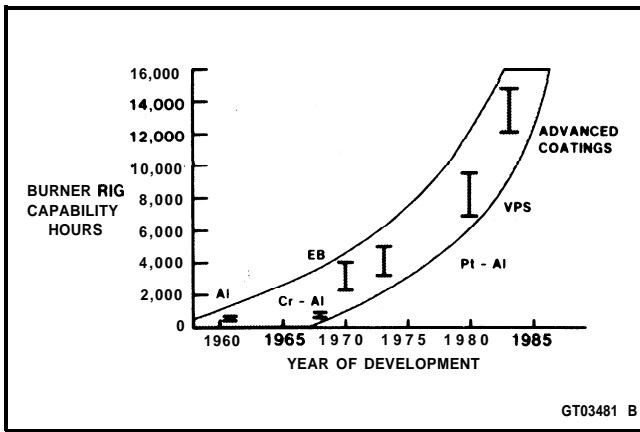


Figure 11. Coating chronology

Present Bucket Coatings

Bucket coatings originally considered for use in heavy-duty gas turbines were developed by the aircraft engine industry. It is evident, however, that the operating environments of heavy-duty gas turbines and aircraft engines are quite different. Although metal temperatures in heavy-duty gas turbines may be somewhat lower than those in aircraft engines, the fuel and the environment in which they operate are generally substantially more contaminated. In addition, longer-life coatings are needed for land-based gas turbines, because their overhaul intervals will be substantially longer than is the case for aircraftjet engines.

Coatings developed over the past few years have lives 10 to 20 times longer than coatings available 10 years ago, as shown in Fig. 11.

The coating currently used by GE is a platinum-aluminum diffusion coating. It is applied by electroplating a thin layer of platinum uniformly onto the bucket airfoil surface, followed by pack diffusion steps to deposit aluminum. This results in a nickel aluminide coating with platinum in solid solution. The function of all coatings is to provide a surface reservoir of elements which form very protective oxide scales that then prevent the contaminant elements from reaching the bucket alloy. The platinum increases the activity of the aluminum in the coating, enabling a very protective and adherent Al_2O_3 layer to form on the surface which prevents accelerated attack. This ability to form and maintain the Al_2O_3 layer is what makes this coating 10 times more corrosion resistant than the simple aluminide coatings developed for jet engines 15 years ago.

To date, over 600 sets of GE heavy-duty first-stage buckets have been coated with the Pt-Al coating and are in service on all machine models.

They are currently the standard on all first-stage buckets of new machines. Longest service time is over 30,000 hours.

An example of comparative corrosion on coated and uncoated IN738 buckets, run side-by-side in the same machine, is shown in Fig. 12. The two buckets were removed for interim evaluation from a customer's MS5002 gas turbine after 25,000 service hours. This unit burned sour natural gas containing about 3.5 percent sulfur, and is located in a region where the soil surrounding the site contained up to three percent sodium.

The uncoated bucket has a relatively uniform attack on the pressure face, with surface roughness and blunting of the leading edge indicating the beginning of corrosion. Examination of the coated bucket revealed only slight roughening of the surface near the trailing edge of the pressure-face and a slight amount of corrosion at the leading edge.

Comparative microstructures of the two buckets are shown in Fig. 13 at a point 2 inches (5.1 cm) from the tip near the leading edge. The uncoated IN738 bucket has penetration extending 10 to 15 mils (0.25 to 0.37 mm) into the base metal while the coated bucket shows no evidence of significant hot-corrosion attack. The coating on 90 percent of the coated bucket was essentially unattacked. Near the trailing edge, 2 to 3 mils of the 4mil (0.05 to 0.07 mm of the 0.1 mm) coating has been attacked, but the base metal was unpenetrated. Only at some locations on the leading-edge of the coated bucket was the coating penetrated, and to only a depth of 1 to 2 mils (0.025 to 0.05 mm).

Experience with uncoated IN738 buckets in this particular environment indicates that about 40,060 hours of bucket life can be attained. The

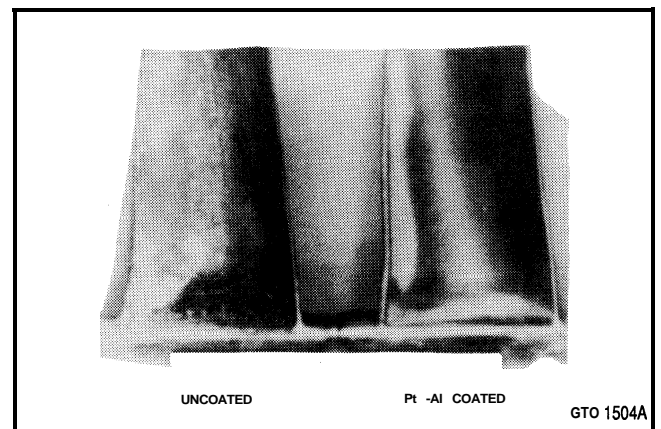


Figure 12. First-stage turbine buckets (coated and uncoated IN738-25,000 service hours)

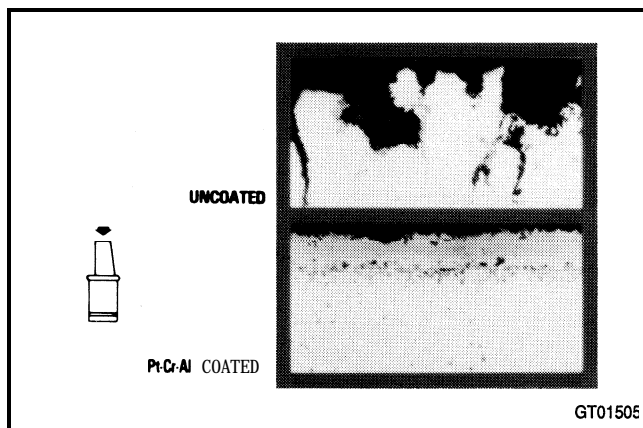


Figure 13. Metallographic examination (comparative experience)

coated bucket, based on this interim evaluation, should add an additional 30,000 hours of life.

Experience has shown that the lives of both uncoated and coated buckets depend to a large degree on the amount of fuel and air contamination. Coatings operating in less rigorous environments than described above will last longer.

As a result of successful laboratory and field evaluations, the Pt-Al coating is now standard for all first-stage buckets.

Field experience with these coatings has shown that bucket corrosion lives have increased 75 to 100 percent over uncoated IN738 buckets under similar corrosive operating conditions. With increasing turbine inlet temperatures, coatings are an even more important factor for providing desired bucket life.

Future Materials and Coatings

As may be appreciated, materials developments have been ongoing throughout the years. A major

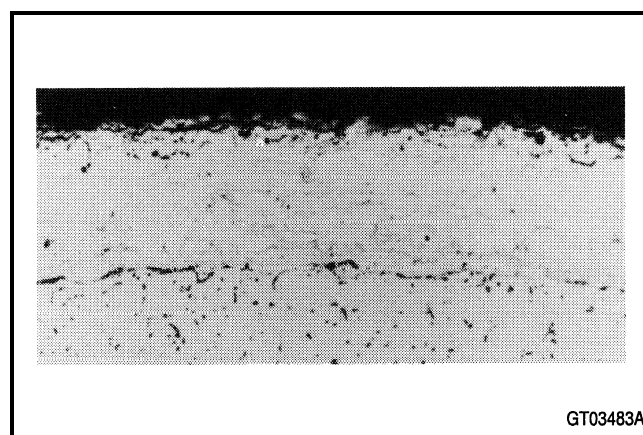


Figure 14. VPS Coating after 13,000 hour turbine exposure (at leading edge)

thrust of the last 10 years' effort has been increasing the corrosion resistance of the hot-gas-path parts—all aimed at increasing fuels flexibility. The prime result of this work, namely introducing IN738 and Pt-Al long-life coatings, has permitted an approximate ten-fold increase in bucket corrosion life over the bare U700 (René 77) buckets of the late 1960s.

A number of other developments are underway in hot-gas-path materials that could influence fuels flexibility in the future. These are described in Ref. 1, and two of the developments are summarized as follows:

- New bucket alloys continue to be explored, with the inevitable trade-off between strength and corrosion resistance. In these programs, corrosion resistance continues to be a strong determinant. Particularly for corrosive atmospheres, the inherent corrosion resistance of the bucket material will continue to be optimized, with added protection from coatings.

The most recent example of this continued development effort by GE is that of GTD-111. This alloy has been developed for first-stage bucket applications, and exhibits a strength/temperature capability over IN738 of 35 F (19 C). Most importantly, it has oxidation and corrosion characteristics comparable to IN738. Casting qualifications for selected bucket applications for selected bucket applications have been completed with the anticipation that there will be a selective introduction into service in the near future.

- New coatings possessing even more corrosion resistance have been under investigation for some time. In addition to laboratory testing

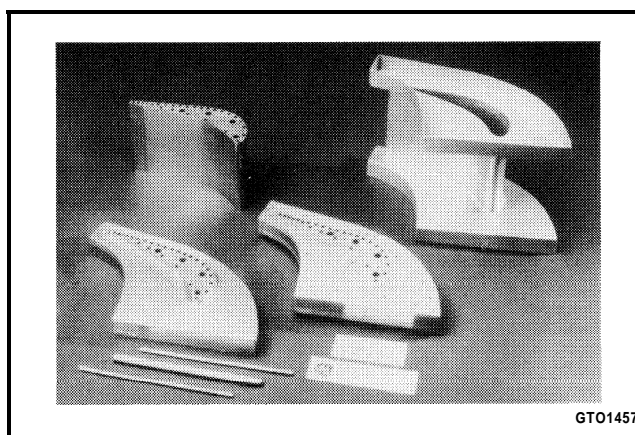


Figure 15. First-stage nozzle components

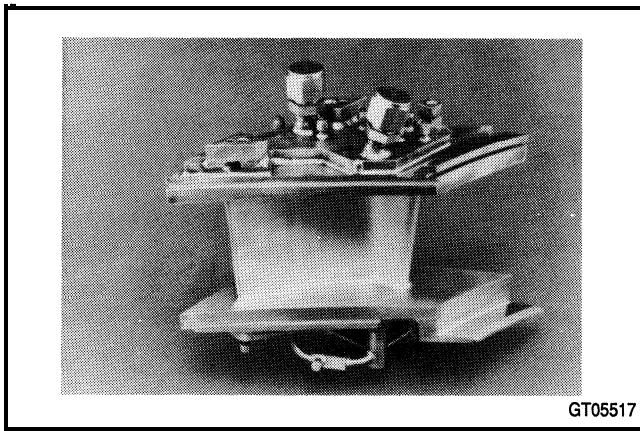


Figure 16. Composite water-cooled nozzle

of the coatings, many of them have been tested in field machines as part of "rainbow rotor" programs. Rainbow rotors contain a number of coatings in the same machine, so that all can be comparatively evaluated.

A coating that appears to have the most promise is high-velocity vacuum plasma spray. Test results to date indicate that the corrosion resistance of the high-velocity vacuum plasma spray coating, using a proprietary coating composition developed by GE, is considerably better than the present production coating. This is shown in Fig. 11. To date, some 35,000 hours of satisfactory turbine operation have been accumulated on rainbow buckets with this particular coating, an example is shown in Fig. 14. Much of our very recent effort has been involved in processing studies to ensure reproducibility and uniformity of these newer coatings. Beyond the rainbow rotor stage, some 25 sets of production buckets have now been coated in this manner and are now in service, with the anticipation that the rate of introduction will increase in the near future.

- Much development work has been conducted on a machine cycle that will have strong influence on future fuels flexibility in gas turbines. This is the water-cooled turbine, which features extremely high gas temperatures (2300 to 3000 F (1259 to 1649 C) for output, and efficiency improvements, with extremely low parts temperatures (less than 1000 F (539 C) for improved fuels flexibility.

This program was initiated by GE some 12 years ago, with sponsorship by the U.S. Department of Energy and the Electric Power Research Institute. The component parts for

the internally cooled first-stage test rig nozzle are shown in Fig. 15, and the assembled nozzle is shown in Fig. 16. This particular test nozzle has now been successfully rig tested at temperatures up to 2650 F (1454 C).

TRACE METAL CONTAMINANTS

The heavy-duty gas turbine is called upon to handle an ever-increasing variety of fuels. Major characteristics that separate these fuels from the standpoint of the gas turbine are as follows:

- *Physical and Cleanliness Characteristics.* Primarily of concern with the liquid fuels, and strongly influencing the fuel storage/handling/treatment/forwarding systems into the gas turbine proper. These systems are generally described in later sections of this paper, and in more detail in Ref. 2.
- *Thermal and Emissions Properties.* Resulting primarily from the hydrocarbon, nitrogen, and sulfur contents of the fuel, and having primary influence on design and operation of the combustion components.
- *Trace Metal Contaminants.* Determine corrosion and deposition tendencies in the hot-section components. Trace metal contaminants can conceivably be found in almost any fuel type, but in the practical case they are mostly of concern with the liquid fuels and some low grade gases. They can also originate with nonfuel sources such as the inlet air. Because they can apply to all fuels, their effects are described below.

Sources

Gas turbine performance and maintenance — particularly the life of the hot-gas-path parts — is very strongly influenced by the level of trace metal contaminants in the combustion products. These contaminants can come from fuel, inlet air sources, or injected steam or water. The gas turbine user should be alert to this, since proper control of these contaminants can make the difference between satisfactory and unsatisfactory machine operation. For this reason, a considerable amount of space in this paper is devoted to the effect and control of these trace metal contaminants.

A major key to fuels flexibility is the tolerance of the machine to trace metal contaminants. The five trace metals of most concern are vanadium,

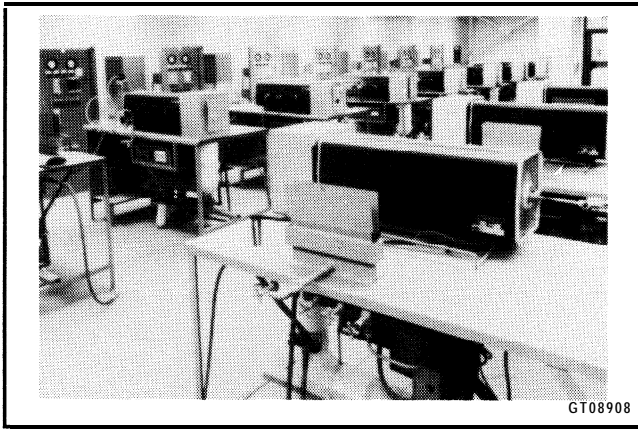


Figure 17. Small burner corrosion test area

sodium, potassium, lead, and calcium. If they are present in the combustion products in significant amounts, the first four can cause turbine blading corrosion, while all five can cause deposits. The level at which the amount becomes "significant" will reflect the tolerance of the machine to these trace metals. Generally, this level is measured in terms of parts per million (ppm) in the fuel. Although the concentration is small, it becomes much more significant with the realization that 1 ppm of fuel contaminant is equivalent to 1 pound (0.45 kilograms) of contaminant entering the turbine section about every 50 hours.

Although all five elements are critical, sodium and vanadium generally are the two most frequently found in petroleum fuels. Both of these can be tolerated only in small amounts before there is the danger of corrosion and deposits at elevated temperatures. The compounds that result during combustion (sodium sulfate, sodium vanadates, and vanadium pentoxide) are semimolten and corrosive at metal temperatures normally associated with gas turbine operation. To operate a gas turbine at firing temperatures lower than the corrosion threshold temperature of about 1100-1200 F (593-648 C) obviously implies a sizeable handicap in machine output and efficiency. It is for this reason that limits have to be placed on the levels of trace metals acceptable in modern gas turbines.

Trace metal contaminants are frequently thought to be associated only with the lower grades of fuel oils. However, they can also be found in fuel gases, improperly handled light fuel oils, and in nonfuel sources such as compressor inlet air, evaporative cooler carryover, and any water or steam injected into the cycle. Consequently, their effect should be of interest

and concern to all gas turbine users, irrespective of the fuel being used.

Bucket Corrosion Life

Heavy-duty gas turbine operating temperatures are largely set by the trade-off between strength and corrosion resistance of the first-stage bucket. It is, therefore, helpful to quantify the effects of contaminants so that a more realistic trade-off can be made. It has been known qualitatively for years that trace metal contaminants have a strong effect upon bucket life. The question has always been, "How much, and at what levels?"

GE has conducted a significant amount of research into bucket corrosion life, particularly during the past 10 years. The result of this research has been the formulation of a proprietary system capable of predicting the effect of trace metal contaminants on the life of hot-gas-path parts.

The heart of this corrosion life system is a correlation between corrosion measurements on installed gas turbines and those from long-time laboratory corrosion tests. The corrosion measurements on installed gas turbines and those from long-time laboratory corrosion tests. The correlation involves measurements on over 100 commercial machines, some of which had service times of about 100,000 hours. The corresponding laboratory tests were conducted in the small burner facility (shown in Fig. 17) where a total of over 30 million specimen test hours have now been accumulated with individual specimen test exposures up to 30,000 hours.

Although the correlation itself is proprietary, an example of its use is shown in Fig. 18. The upper part of Fig. 18 shows the effect of one contaminant (sodium) on the first-stage bucket cor-

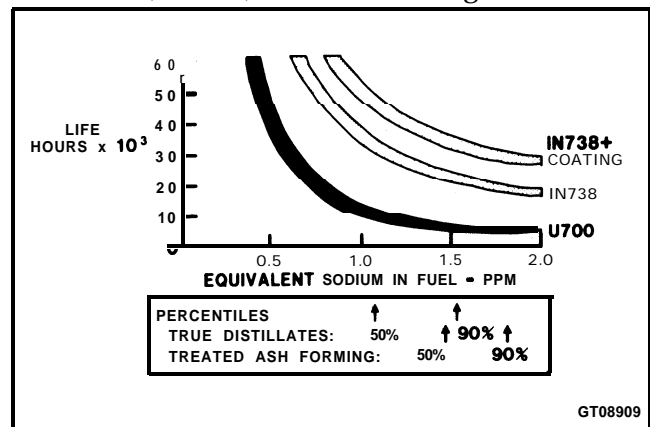


Figure 18. Effect of sodium on bucket corrosion life (fuel/air per GEI-41047, MS5001P)

rosion life for a particular machine model; other models will be different. The contaminant is expressed in terms of equivalent sodium in the fuel, even though it actually could come either from the fuel, inlet air, or water/steam injections.

There are other corrosive contaminants besides sodium, namely potassium, vanadium, and lead (although sodium is generally the most common one). The percentile distribution of the combination of these is shown in the lower part of Fig. 18 for typical populations of distillate and treated residual fuels. This distribution also includes an additional 0.2 ppm equivalent contaminant level to take care of contaminants coming from nonfuel sources, as will be discussed in the next section. In general, the fuel contaminants are less with gaseous fuels than with liquid fuels.

The major points to be observed from Fig. 18 are as follows:

- The significant effect that materials and coatings can have upon bucket corrosion life
- The equally strong effect that the levels of trace metal contaminants will have upon bucket corrosion life, providing the operator with an incentive to keep the fuel and air as clean as possible.

Nonfuel Contaminants

As has been mentioned, trace metal contaminants can come from either the fuel or from nonfuel sources. The source of the contaminants (be it fuel, air, water, or steam) is of less significance than their total level present in the combustion products entering the turbine section. For

instance, compressor inlet air could conceivably contain trace metal contaminants in the form of:

- Sea salt mist, fly ash, fertilizer dust
- Evaporative cooler carryover
- Industrial process effluents
- Dusts containing Na + K (including certain desert sands)

In a similar manner, injected water or steam for NO_x control or added turbine output could conceivably contain alkali or other trace metal constituents unless properly handled.

A convenient relationship can be used to convert these nonfuel contaminants to equivalent contaminants in the fuel alone, assuming all are equally effective:

$$(A/F)X_A + (S/F)X_S + X_F = \text{Total contaminant level as equivalents in fuel, ppm}$$

where

- A/F = air-to-fuel mass flow ratio
- S/F = steam (water)-to-fuel mass flow ratio
- X_F = contaminant concentration (weight fuel (ppm))
- X_A = contaminant concentration (weight in inlet air (ppm))
- X_S = contaminant concentration (weight in injected steam/water (ppm))

**Table 7
GASEOUS FUEL CLASSIFICATIONS**

Classification by Calorific Value	Calorific Value kcal/nm ³ (Btu/scf)	Typical Specific Fuels	Primary Gas Components
I Very High	10,700–44,500 (1,200–5,000)	Liquefied Petroleum Natural Gas Liquids	Propane Butane
II High	7,100–10,700 (800–1,200)	Natural Gas Synthetic Natural Gas Sour Gas	Methane
III Medium	2,700–7,100 (300–800)	Coal Gas (Oxygen Blown) Coke Oven Gas Refinery Gas	Hydrogen Carbon Monoxide Methane (minor)
IV Low	900–2,700 (100–300)	Coal Gas (Air Blown)	Carbon Monoxide Hydrogen Nitrogen
V Very Low	Under 900 (Under 100)	Blast Furnace Gas	Carbon Monoxide Nitrogen

**Table 8
TYPICAL PROPERTIES OF COMMON GASEOUS FUELS**

Property	Natural Gas	Coal Gas (Low Btu)	Coal Gas (High Btu)	Coke Oven Gas	Blast Furnace Gas
Heating Value (Btu/scf)	950/1 150	110/165	500/700	525/850	90/100
Heating Value (kcal/nm ³)	8500/10,250	1000/1450	4400/6200	4700/7600	800/900
Specific Gravity	0.58/0.72	0.80/0.92	0.41/0.48	0.40/0.45	0.95/ 1.05
Composition (Volume %)					
Methane, CH ₄	75/97	0.5/4.5	20/35	28/32	—
CH-Other Hydrocarbons	2/20	—	2/4	2/4	—
Hydrogen, H ₂	—	12/16	40/55	50/55	1/4
Carbon Monoxide, CO	—	2/32	5/15	5/7	25/30
Nitrogen, N ₂	1/16	30/55	4/11	1/6	55/60
Carbon Dioxide CO ₂	0.1	0.5/10	2/4	2/3	8/16

The liquid Fuel Specification GEI-41047 contains referral limits of contaminant levels in an inlet air, or water/steam ingestions, as will be described under “Liquid Fuels.” These limits would cause insignificant contribution to the total level of contaminants, and have minor effect upon parts’ lives. Should the customer anticipate that these limits will be exceeded, he can consider one of the following:

- Additional equipment such as inlet air filtration or water purification
- A corresponding and equivalent reduction in the permissible contaminants in the fuel oil.

GASEOUS FUELS

Historically, natural gas has been the primary fuel for gas turbines because it is clean burning, available, and relatively inexpensive. Today, it has limited availability as a gas turbine fuel for power generation in some areas of the world. In the future, it is expected that manufactured gases, especially from coal, will be widely used in gas turbines. Generally, these gaseous fuels will be most suited for continuous baseload combined-cycle operation.

Gaseous Fuel Classification

It is most meaningful from the standpoint of turbine application to classify gaseous fuels by their calorific values, which cover a very wide range: from a low of about 100 Btu/ft³ (900 kcal/nm³) to a high of 5,000 Btu/ft³ (44,500 kcal/nm³). Table 7 shows such a classification of gaseous fuels, while the typical properties of common gaseous fuels appear in Table 8.

Practically all types of gaseous fuels can be burned in GE heavy-duty gas turbines; some machines also have dual gas capability. The standard gas turbine is designed for natural gas based on the GE fuel gas specification. A fuel falling outside these requirements can be accommodated by suitable modifications to the turbine control system, gas-fuel components, rating, and fuel-handling equipment.

High-Calorific-Value Gases

These gaseous fuels are volatile hydrocarbons with a minor fraction of inert gases. They are very clean burning and perform well in today’s gas turbines.

- *Natural Gas.* This is largely methane with small amounts of other volatile hydrocarbons and inert gases. Most natural gas is sold as a “dry gas” where the liquid hydrocarbon content has been reduced to a maximum of 0.1 gal/ 1000 ft³ (13 liters/1 000 nm³).
- *Sour Gas.* In certain areas of the world, natural gas may have appreciable levels of hydrogen sulfide as a significant contaminant, this being known as sour gas. Hydrogen sulfide may be removed by fuel treatment by the producer. If not, the sour gas usually may be burned directly in the gas turbine if the proper materials are selected for components in the fuel system.
- *Liquefied Petroleum Gas (LPG).* This is a low-boiling-point liquid hydrocarbon fuel which can be vaporized and burned as a gas. It may be liquid propane, liquid butane, or a mix-

ture of the two. Liquid propane is preferred in colder regions because it is more readily vaporized. These gaseous fuels must be completely free of any liquid phase carryover. Generally, gas turbines capable of operating on a very high calorific value fuel such as LPG can also operate on natural gas.

Medium Calorific Value Gases

These fuels are “manufactured” gases in which carbon monoxide, hydrogen, and methane are the combustible components. Those produced from coal may have significant particulate levels and tar carryover as produced; therefore, gas clean-up is necessary. Also, pressurization for combustion in the gas turbine is necessary if the gaseous fuel is produced at atmospheric pressure, for example, coke oven gas. Medium calorific value gases may be transported by pipeline over moderate distances.

- *Gasified Coal.* There is considerable worldwide development activity in the production of clean fuel gases from coal. Gasification carried out with oxygen yields a fuel gas composed primarily of carbon monoxide and hydrogen with a calorific value of about 300 Btu/ft³ (2700 kcal/nm³). This gas would be cleaned to lower the sulfur levels so that exhaust gases meet environmental requirements. As a result of this clean-up, the levels of contaminants which cause corrosion and ash deposition in the hot section would be reduced to very low levels.
- *Process Gas.* Process gas is a broad classification of process byproduct gases, with a wide range of compositions. A common type is reformed refinery gas containing hydrogen, carbon monoxide, and methane, with a calorific value of about 530 Btu/ft³ (4700 kcal/nm³).

Low Calorific Value Gases

Low calorific value gases (often called “low-Btu gas” contain carbon monoxide and hydrogen as combustible components diluted with a relatively large fraction of inert components, largely nitrogen and carbon dioxide. It is made by air-blown gasification of coal and is usually processed to remove sulfur. it is not practical to transport low calorific value gases by pipeline; rather, they would be burned at the gasification site.

Contaminants in Gaseous Fuels

The fuel gas delivered to the gas turbine must not contain any significant concentrations of liquid droplets or solid particles. These may be removed by the fuel producer or supplier before delivery to the gas turbine. Liquefied fuel droplets or slugs in the combustor can cause rapid excursions in firing temperature and gas turbine load as well as over-temperature in the hot-gas-path. In the case of low-calorific-value gases, the presence of liquid water has been found to cause a blowout, probably due to a rapid lowering of flame temperature. Formation of liquids is prevented by providing at least 50 F (28 C) superheat to the fuel gas.

Particulate matter contamination in the fuel can cause erosion and plugging of gas orifices which in turn can cause changes in temperature profile (traverse number) and liner metal temperatures. For these reasons, it is specified that solid-particle content be limited to 30 ppm maximum-with sizes of 10 μm or less for natural gas-type fuels.

Some gaseous fuels, especially those derived from coals, can also contain trace metal contaminants which can cause hot corrosion in the gas turbine hot gas path. (These trace metal contaminants are discussed in the “Trace Metals” section of this paper). In order to avoid excessive hot corrosion, GE specifies maximum trace metal contaminant levels in the combustion products. These limits are a total of 0.024 ppm of Na plus K, 0.01 ppm of V, and 0.02 ppm of Pb. Because of the higher fuel/air requirements of coal-derived low-calorific-value gases compared to natural gas, the allowable trace metal limits in the fuel will be correspondingly lower. To maintain levels below the stated limits, the following equation is used:

Table 9
ALLOWABLE SODIUM CONCENTRATION
IN FUEL GAS

Type of Gas	Lower Heating Value-Btu/ft ³ (kcal/nm ³)	Fuel-to Air Mass Ratio F/A	Allowable Sodium Concentration in Fuel Gas- X _F (ppm)	
			X _A = 0	X _A = 0.01 ppm
Natural Gas	1025 (9925)	0.019	1.29	0.76
Recovery Gas	319 (2870)	0.058	0.44	0.27
Low-Btw Gas	107 (960)	0.263	0.12	0.08

For limit of 0.024 ppm in combustion products in a typical MS5001 gas turbine

$$\frac{X_A + (F/A)X_F}{1 + (F/A)} \leq X_E$$

where

- F/A = Fuel-to-air ratio (depends in part on heating value)
 X_F = Contaminant concentration (weight) in fuel (ppm)
 X_A = Contaminant concentration (weight) in inlet air (ppm)
 X_E = Contaminant concentration limit (weight) in combustion products (ppm)

These limits are shown in Table 9 for three gas fuels of widely differing heating values. The associated fuel-to-air ratios are given for operation in an MS5001 gas turbine at baseload. The imposed limit of total contaminant concentration in the combustion products is set at 0.024 ppm.

Sulfur, frequently in the form of hydrogen sulfide, is a common contaminant of gaseous fuels. In the United States, pipeline-quality natural gas usually has less than 20 ppmw of total sulfur and needs no special considerations. Other fuels may have higher sulfur contaminant levels.

Sulfur alone, in the complete absence of trace metal contaminants, is not harmful to hot-gas-path components (nozzles and buckets) if a judicious choice of materials is made. This finding has been borne out by extensive laboratory tests conducted by GE and verified by field data. However if, the total sulfur concentration is above 0.5 percent, GE should be consulted.

On any gas turbine utilizing steam or water exhaust heat recovery equipment, the sulfur content of the fuel is limited to 30 ppm, to prevent corrosion on the cold end of the heater or boiler.

Table 10
FUEL GAS SPECIFICATION

Contaminants	
Solids	• 30 ppm maximum, 10 m maximum
Water	• 0.25% above saturation maximum
“Dry” Gas	• 0.1 gallon vapor per 1000 ft ³ maximum (13.4 liters per 1000 m ³ maximum)
Hydrocarbons	• No condensation upon 20 F (6.7 C) drop
Heating Value	
Range	• 300-5000 Btu/scf (2670-44,500 kcal/nm ³)
Change	• ± 10 percent nominal
Flammability	• Upper to lower flammability ratio
Limits	-2.21 minimum
Composition	
Sulfur	• Exhaust heat recovery units only
Alkali Metal and Sulfur	• 5 ppm equivalent alkali metal
	• sulfates maximum

Standard machine*

Should it be necessary to use fuels with greater than 30 ppm sulfur, the temperatures in the heat recovery equipment can be raised so that the dew point of sulfuric acid in the gas is higher than the lowest metal temperature. Note that this concern only exists on units with water- or steam-heat recovery. Exhaust system metal temperatures on simple- and regenerative-cycle gas turbines are much higher than the dew point of sulfuric acid.

Under some circumstances there are contaminants which, by themselves, do not cause corrosion of the hot section, but have other effects on gas turbine operation and reliability. These include liquids in natural gases. These liquids condense on the sides of pipes and enter the combustors as slugs which cause a momentary overheating. Their presence is detected by rough turbine operation, very cold pipes (the liquids evaporate causing cooling) and, in extreme cases, cause local burning of nozzles and seals because the liquids are not completely burned in the turbine. Proper preparation of the gas at the well head and knock out drums will remove these liquids.

In natural gases, hydrates sometimes form that coat and clog control valves, making smooth control of gas flow difficult. Similarly, some compounds in coke oven gas such as butadienes cause fouling of control valves. To some degree, they can be eliminated by gas filtration.

Operational Consideration

The composition and properties of the various types of gaseous fuels affect the design, operation, and performance of the combustion and turbine sections of the gas turbine. The GE fuel gas specification for heavy-duty gas turbines, GEI-41040, is summarized in Table 10. Low calorific-value fuels are not included in this specification, but they are considered on a case-by-case basis.

Heating Value

The heating value (lower) is one of the important properties of a gaseous fuel. Most medium- and high-calorific-value gases can be burned with existing natural gas fuel nozzle and combustor designs with little change (except NO_x emissions) in combustion performance. As heating value decreases, more combustion system design and development is necessary, and the possibility of requiring both a conventional fuel for start-up/shut-down and restrictions in loaded operation increases. This is not necessarily a disadvantage if natural gas, medium-, or high-calorific-value gas is available in sufficient quantities for start-up and low-load operation.

The allowable variation in the calorific value for a given gaseous fuel is also important. The variation limit for the standard machine is ± 10 percent but there have been many cases where up to ± 20 percent was acceptable. For variations greater than ± 10 percent, each case is considered individually considering the fuel and operating environment.

It should be reemphasized that the heating value limits that appear in the GE Fuel Gas Specification GEI-41040, namely: 300 to 5000 Btu/ft³ (2700 to 44,500 kcal/nm³) with a ± 10 percent variation, are for the standard machine. Many gases outside these limits can be used by modifying the machine.

Gas Supply Pressure

For variation in gas delivery pressure as related to ambient temperature and compressor discharge pressure, it has been empirically determined that the combustor requires a minimum pressure drop across the fuel nozzle so that stable combustion at lower output levels can be maintained. This pressure drop defines the maximum gas nozzle orifice area. Coupled with the maximum fuel flow at full load and control pressure drops, the supply pressure requirements are determined. For example, in a cold ambient application it is possible to select a nozzle orifice size that would allow operation at a maximum horsepower with a possible limit on minimum horsepower.

Flammability Limits

In order for combustion to be sustained in a gas turbine combustor, a recirculating region is aerodynamically maintained in the head end of the combustor (primary zone). The stability of the combustion process in this zone depends upon many factors, such as recirculation strength, flame temperature, and flammability limits. Inside the recirculation zone, a gradient of fuel/air ratios exist. As gas turbine load and, hence, fuel flow change, the range of fuel/air ratio also varies. For the combustor as a whole, fuel/air ratio varies about 3:1 across the load range. The wider the flammability limits of a given fuel, the more suitable it will be for use at off-design points. This is particularly true at start-up conditions where mixing and combustion efficiencies are relatively poor.

Over the years it has been empirically determined that a flammability ratio of 2.2 or greater is sufficient for operation of the gas turbine from start-up to full load. For fuels which do not satisfy the flammability requirement, it is often possible to "richen" the mix-

Table 11
RELATIVE NO_x EMISSIONS*

Gas	T °C (°F)	Relative NO _x (2)
Natural Gas	2207 (4006)	1.00
Methane	2195 (3982)	0.95
Coke Oven Gas	2365 (4107)	1.25
Tail Gas	1872 (3401)	0.26
Carbon Monoxide	2500 (4536)	3.25
Hydrogen	2375 (4311)	1.97
Coal-Derived Gas	1560 (2837)	-0.07

(1) Assuming the absence of nitrogen bearing compounds

(2) NO_x / NO_x(natural gas)-ppmv/ppmv

ture by blending with small amounts of broad-range flammability gases. The heavier hydrocarbons and hydrogen are good examples of gases which could be used for this purpose.

Flammability limits for mixture of gases are calculated from the flammability limits of the individual components.

For the combustion designer, flammability limits are reflected during start-up in ignition/blow-out performance and crossfiring capability. For loaded operation, the blowout margin, CO emissions, efficiency, and possibly dynamic pressure pulsation are of concern. This means that decreasing flammability limits can require detailed design changes to the combustor recirculation zone and method of fuel addition.

The adiabatic stoichiometric undissociated flame temperature of a gas is not attained in the combustor reaction zone where dissociation and heat loss occur. The flame temperature is not solely dependent on heating value. Fuels such as carbon monoxide and hydrogen, with heating values roughly 30 percent that of natural gas, have higher flame temperatures.

Emissions

The assumption is often made that low-Btu gases will have low levels of exhaust emissions, particularly NO_x. Emissions of NO_x, CO, and hydrocarbons are influenced by temperature in the combustor reaction and postflame zones. As flame temperature decreases, NO_x will decrease while CO and hydrocarbons will tend to increase. Since the latter two emissions are indicative of combustion efficiency and stability, decreasing flame temperature can lead to both decreased efficiency and blowout margin.

An estimate of the effect of flame temperature on NO_x emissions is contained in Table 11. This table demonstrates the strong temperature effect on NO_x emissions. Note that hydrogen, with a rel-

atively low heating value, is estimated to have NO, emissions. Note that hydrogen, with a relatively low heating value, is estimated to have NO_x emissions twice that of natural gas. It cannot be assumed that low-Btu gases will automatically have low NO, levels. Because of the large amount of inerts, coal-derived low-Btu gases have low heating values and flame temperatures making them attractive from an emissions standpoint.

Another design parameter affected by flame temperature is metal temperatures surrounding the primary zone of the combustion liner. For a gaseous fuel, the flame will be nonluminous when compared to a liquid fuel which is luminous due to the presence of carbonaceous particles in the flame. Radiation from a nonluminous flame is due primarily to carbon dioxide and water vapor, i.e., the products of complete combustion. The amount of heat radiated to the walls of the combustor is the product of flame emissivity and temperature raised to the fourth power. As flame temperature increases, the cooling requirements for the liner also increase. This is not a problem for gaseous fuels since emissivities are usually considerably lower than those encountered with No. 2 distillate, and regardless of gaseous flame temperature, the radiant loading to the combustor wall will not be as great as is the case with distillate. Nevertheless, it may be desirable to alter the liner cooling to maintain acceptable metal temperature gradients on the liner.

Reaction Rate

In the combustion of any hydrocarbon fuel, a number of intermediate reaction species such as O, CO, OH, H, etc., are formed. The oxidation of CO is one of the slowest reactions to be completed. Since the combustion process inside a gas turbine combustor must take place rapidly, any decrease in reaction rate will lead to decreased combustion efficiency, i.e., CO in the exhaust. For low-Btu coal-derived gases, where low heating values and flame temperatures require large volumes of fuel for combustion, the potential for high CO emissions exists. Since most of the combustible constituents of this type fuel are in the form of CO and H₂, the ratio H₂/CO is important. As this ratio increases, flammability limits and reaction rates are enhanced and the propensity for CO emissions decreases.

Water Vapor Content

Normally, most gas turbine fuels contain only trace amounts of water vapor. Coal-derived gases, however, may contain significant amounts of water. Large amounts of water vapor, through its depressant influence on flame temperature, can lead to increased CO emissions but lowered NO, emissions.

Multiple-Fuel Gas Systems

The standard fuel gas system for GE heavy-duty gas turbines is illustrated in Fig. 19. The system utilizes a hydraulically-operated valve containing two elements—a speed ratio/stop valve and a control valve—in one body.

Control is provided by electrical signals from the turbine control panel. Systems of this type can readily accommodate lower heating value variations of ± 10 percent in the fuel gas supply. In some applications, larger variations can be served, but they must be reviewed on a case-by-case basis. Generally speaking, single-fuel gas systems of this type can be used for gases in the medium and high-calorific-value categories, i.e., those with lower heating values (LHV) from 800

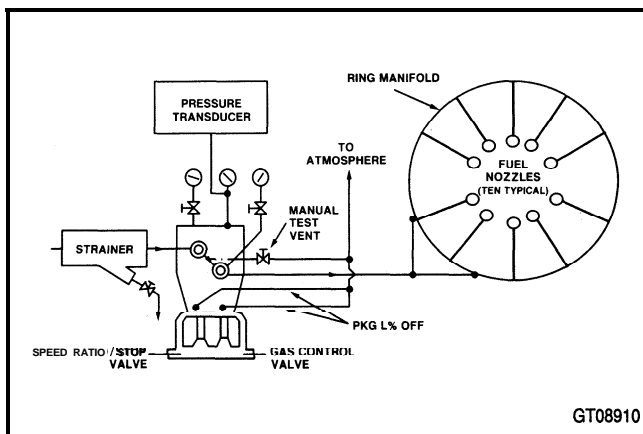


Figure 19. Gas fuel system

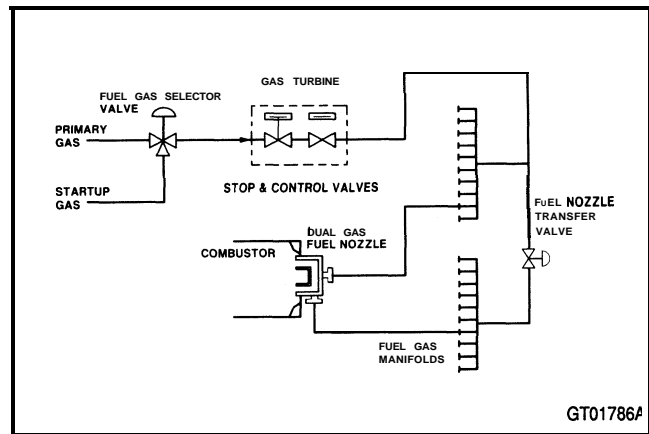


Figure 20. Dual-manifold gas fuel system

to 5000 Btu/ft³ (7100 to 44,500 kcal/nm³). However, variations in component sizes, principally the fuel nozzle orifices and the valve plugs and seats, are required to fit the design to the heating value, supply temperature, and other characteristics of the specific fuel to be burned.

When an unconventional or alternate gaseous fuel is involved, a dual-gas fuel system may be required for any one of a number of possible reasons. For example, a conventional fuel such as natural gas may be required for start-up and shut-down or for when the unconventional fuel may be temporarily unavailable. The extent of the modifications required to provide a dual-gas system is a function of the difference between the two gases in heating value, supply temperature and specific gravity. As a minimum it would be necessary to add a fuel selector valve to the standard fuel gas system shown in Fig. 19. The selector valve, installed upstream of the stop and control valve, would select or blend the gases as desired.

For larger heating value variations, such as might be encountered when a medium-calorific-value unconventional fuel (300 to 800 Btu/ft³, LHV) (2700 to 7100 kcal/nm³) is involved, it may be necessary to use two gas manifolds and sets of metering orifices in order to meet the pressure ratio limits set for the fuel nozzle. Such a system could incorporate standard stop and control valves in conjunction with a fuel nozzle transfer valve and a second gas manifold, as shown in Fig. 20.

To understand how this system functions, consider that the unit is started on natural gas (conventional fuel) and will transfer to the medium-calorific-value primary fuel when the turbine reaches normal operating speed. For this example, the medium-calorific-value gas port of the fuel selector valve and the fuel nozzle transfer valve are both initially closed. The unit may be started using the stop and control valves in the usual fashion. When the transfer is to be accomplished, the primary gas port is opened and the start-up gas port closed in the selector valve. Coincident with this change, the nozzle transfer valve is opened in order to maintain a nearly constant pressure ratio on the gas nozzles, which otherwise would have increased due to the large volumetric flow associated with operation on medium-calorific-value gas fuel.

When still larger differences between the properties of the unconventional fuel and the start-up and shutdown fuels occur, as may be the case

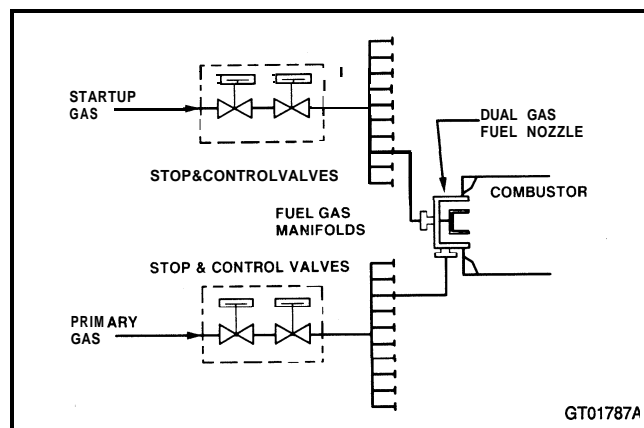


Figure 21. Parallel dual gas fuel systems

where the unconventional fuel is in the low-calorific-value category (100 to 300 Btu/ft³, LHV) (900 to 7200 kcal/nm³, LHV) parallel but completely separate fuel gas systems may be required. A single fuel nozzle assembly is still used, but two separate sets of gas passages are incorporated. This situation results from the large disparity in volume flows to be handled by the two systems, resulting in the necessity for two separate gas control valves. Such a system is shown schematically in Fig. 21. In many cases the low calorific value gas control valve and associated components would be mounted on an off-base skid because of their size. This situation stems from the fact that the volume flow of a low-calorific value fuel may be very large, particularly if it contains significant quantities of water, so that it must be supplied at high temperature to ensure that no liquid enters the gas turbine. In the extreme, the piping manifold for low-calorific-value fuel may be as large as 20-inch (50-cm) diameter for an MS7001 unit and 16-inch (40-cm) diameter for an MS5001 unit for fuel in the 100 Btu/ft³, LHV (900 kcal/nm³) class containing about 30 percent water by volume.

Considering the three possibilities described above, selection of the type of fuel system to be used in a specific application is a function of other factors in addition to heating value. Hence, to the extent that this discussion has identified appropriate fuel systems on the basis of lower heating value, the selections indicated should be considered in the sense of general guidance only; review of specific cases may yield different results. Since heating value is not the only criterion, a quantity known as the Wobbe number is used in comparing gas fuels and in preliminary assess-

ment of the design requirements for the fuel system. The Wobbe number is defined

$$W_n = \frac{LHV}{(SG)(T)}$$

where

- W_n = Wobbe number
 LHV = Lower heating value, Btu/ft³
 (kcal/nm³)
 SG = Specific gravity relative to air
 T = Fuel supply temperature, °R(K)

As an approximate guideline, the standard single-gas fuel system will accept Wobbe number deviations of at least ± 5 percent from the nominal value for which the system was designed.

For the dual-gas systems described earlier (Figs. 20 and 21) control methods and programs are available to accomplish transfer from one gas to the other under load. Also available are control systems capable of continuous burning of mixtures of the two gases with several options as to the method by which the relative quantity of each gas is determined.

LIQUID FUELS

Industry Classifications

Gas turbine liquid fuels have a wide range of properties, but for gas turbine applications they may be divided into two broad classes:

- True distillate fuels, which normally can be used as is or with minor cleanup to remove contaminants introduced during shipping and storage;
- Ash-forming fuels which generally require heating, fuel treating, and periodic turbine cleaning.

True distillate fuels include ASTM 0-GT, 1-GT, 2-GT gas turbine fuels, ASTM No. 1 and No. 2 burner fuel oils, and ATM 1-D and 2-D diesel fuel oils. More common designations are naphtha, kerosene, and diesel fuels which differ fundamentally only in their distillation ranges as a result of the refining process. As refined, true distillate fuels are free of ash-forming components and behave in a manner similar to natural gas, provided that proper attention is paid to fuel handling for the exclusion of contaminants.

Table 12
TYPICAL PROPERTIES, LIQUID FUELS

Fuel Type	True Distillates		Ash-Forming Fuels	
	Kerosene	No. 2 Distillate	Blended Residuals and Crudes	Heavy Residuals
Specific Gravity, 100 F (38C)	0.78/0.83	0.82/0.88	0.80/0.92	0.92/ 1.05
Viscosity, cSt, 100 F (38C)	1.4/2.2	2.0/4.0	2/100	100/1800
Flash Point, F	130/160	150/200	50/200	175/265
Flash Point, C	55/70	55/95	10/95	80/130
Pour Point, F	-50	-10/30	15/110	15/95
Pour Point, C	-45	-20/0	-10/45	-10/35
Gross Heating Value, kcal/kg	10,700/10,950	10,500/10,950	10,500/10,900	10,150/10,500
Gross Heating Value, Btu/lb	19,300/19,700	19,000/19,600	19,000/19,400	18,300/18,900
Filterable Dirt, % max	0.002	0.005	0.05	0.2
Carbon Residue (100% Sample), %	—	—	0.3/3	2/10
Sulfur, %	0.01/0.1	0.1/0.8	0.2/3	0.5/4
Nitrogen, %	0.002/0.01	0.005/0.06	0.06/0.2	0.05/0.9
Hydrogen, %	12.8/14.5	12.2/13.2	12.0/13.2	10.1/2.5
Ash (Fuel as Delivered), ppm	1/5	2/50	25/200	100/1000
Ash (Inhibited), ppm	—	—	25/250	100/7000
Trace Metal Contaminants (untreated)				
Sodium plus Potassium, ppm	0/0.5	0/1	1/100	1/350
Vanadium, ppm	0/0.1	0/0.1	0.1/80	5/400
Lead, ppm	0/0.5	0/1	0/1	0/25
Calcium, ppm	0/1	0/2	0/10	0/50

Ash-forming fuels include ASTM 3-GT and 4GT gas turbine fuels, ASTM No.4, No. 5 and No. 6 burner fuel oils, and ASMT 4D diesel fuel oil. These cover petroleum crude oils, petroleum residual fuels, and residual fuel-distillate blends. These fuels contain ash-forming contaminants in varying amounts depending on the crude oil(s) involved, refinery processing, and the transportation and handling history of the fuel. In addition, they contain other fuel components not present in true distillate fuels. They generally require onsite fuel treatment to modify or remove the harmful constituents and also require provisions for cleaning ash deposits from the turbine periodically.

Property Effects and Specification

A summary of typical properties, both for true distillates and ash-forming fuels, is shown in Table 12. Each property will have some influence on turbine operation, but the trace metal contaminants tend to be the most limiting. An explanation of the influence of most of these properties is as follows:

- Specific gravity is of concern only with respect to fuel storage and treatment (desalting) of the fuel. A higher specific gravity makes separation of contaminants more difficult.
- Viscosity and the viscosity-temperature relationship determine fuel pumping, heating, and atomization requirements. A minimum viscosity limit is usually stipulated to ensure adequate lubrication- **and life of the fuel** pump and flow divider system. High viscosities determine the heating requirement, as do the pour and wax separation points. Fuel distillation range, although not shown in Table 12, is important in the determination of fuel atomization requirements in that it will be reflected in the viscosity levels.
- Flash point dictates the need for explosion-proofing the gas turbine installation.
- Filterable dirt is of concern for fuel pump, flow divider, and fuel nozzle life. Reasonably fine filtration (generally 5 μm) ahead of the turbine is generally recommended to filter out the foreign material.
- Heating value, carbon residue, sulfur, nitrogen, and hydrogen influence the design and

operation of the combustion systems as well as the levels of emissions.

- Ash level, and particularly certain trace metal levels within that ash, is extremely critical in the prevention of unacceptable corrosion and ash deposition in the turbine section, as has been previously shown in Fig. 18.

The GE heavy-duty gas turbine specification for liquid fuels is documented in GEL41047. One of the most critical parts of the document is the permissible level of trace metal contaminants entering the turbine. The level of trace material contaminants at which this specification is set involves a technical and economic trade-off. On one hand, the contaminants should be as low as possible to promote long corrosion lives. On the other hand, the specification should not be so restrictive that it increases the cost of fuel significantly to a user, since fuel cost is general the most expensive part of generating power.

It is felt that the present specification level for trace metals is the best balance for the majority of GE gas turbine users, and it is in general agreement with the revised ASTM Specification D2880-80, Standard Specification for Gas Turbine Fuel Oils. However, if a particular user feels that his own economic evaluation requires extremely long corrosion life, he may wish to tighten the specification accordingly. On the other hand, specification limits can be relaxed somewhat if a user is willing to accept shorter corrosion lives. This might occur, for instance, if the machine is only going to be run for 100 hours every year.

The specification values for all trace metal contaminants are summarized, **both for fuel and nonfuel sources, in Fig. 22. A recommended level is placed upon** the contaminants coming from

	TRACE METALS				
	NA+K	Pb	Ca	V	
				UNTREATED	TREATED
• LIMITS IN FUEL - PPM					
• TRUE DISTILLATES	1	1	2	0.5	-
• ASH-FORMING FUELS					
• CRUOES AND BLENDS	1	1	10	0.5	100
• RESIDUALS	1	1	10	0.5	500
• LIMITS IN NONFUEL SOURCES					
• PPM IN INLET AIR	TOTAL LESS THAN 0.005				
• PPM IN WATER/ STEAM	TOTAL LESS THAN 0.5				

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Figure 22. Trace metal contaminant limits (specification GEL-41047)

nonfuel sources, such as inlet air and injected steam/water, as has previously been discussed on page 15. The inlet air contaminant level of 0.005 ppm, incidently, converts to an equivalent value of 0.2 ppm in the fuel when a typical fuel/air ratio is taken into account.

In the fuel entering the gas turbine, sodium plus potassium is limited to 1 ppm maximum, as is the lead. Calcium can be tolerated to 2 ppm in the distillate oils, and to 10 ppm in the ash-forming fuel machines that have provision for periodic removal of these deposits. Finally, vanadium content above 0.5 ppm will generally require the use of a magnesium additive, so that there is 3.0 to 3.5 times the weight of magnesium in the fuel as there is vanadium.

Turbine Modifications

Liquid fuels ranging from naphtha to residual fuels have been successfully used in GE heavy-duty gas turbines. Figure 23 shows the general considerations and/or provisions for using the different classes of fuels in these turbines.

True distillate fuels do not usually require heating of proper atomization, except for the heavy distillates and some light distillates used in cold regions. Ash-forming fuels nearly always require heating to between 120 and 260 F (50 and 125 C) for proper fuel atomization, the temperature required being related to the type of fuel atomization and the fuel viscosity. With high-pressure air atomization (necessary for heavy fuels), the fuel must be heated to reduce the viscosity to a maximum of 20 centistrokes. With low-pressure atomization (used for distillates and some **crudes**), the fuel is limited to a maximum viscosity of 10 centistrokes at the fuel nozzle.

Fuels may also require heating for pumping and forwarding. For heavy, lower-grade fuels, it may be necessary to heat the fuel to lower the viscosity to the operating range of the fuel transfer and filter system. It may also be necessary to heat some crudes and heavy distillates to keep wax dissolved. Petroleum waxes occur to varying extents in crude oils depending on the geographical source, with the wax tending to become concentrated in the heavy distillate fractions. Wax is a desirable fuel component from the standpoint of high heat content and high hydrogen content, but it can cause operational problems in the fuel system unless suitable provisions are made. Specific areas of concern are fuel washing (where required), fuel filtering, and fuel transfer where separated solid wax can overload centrifuges and plug fuel filters, fuel lines, and fuel nozzles. Heating a waxy fuel above the wax solution temperature and maintaining this minimum temperature throughout the fuel system will prevent wax separation and the resultant fuel-system problems.

A secondary and start-up/shutdown fuel is often required for naphtha for safety reasons. A secondary fuel is also normally necessary for heavy fuels both for fuel system flushing and to provide fuel lightoff.

Explosion-proofing of the gas turbine system is required with low-flash-point fuels such as naphtha and some crude oils.

Gas turbines for heavy-fuel application require a combustion liner designed for a more radiant flame.

Two of the major provisions that must be made for burning ash-forming fuel relate to trace metal contaminants. These provisions involve fuel treatment and gas turbine cleaning (deposit removal). These systems are discussed separately in later sections of this paper.

Where trace metal contaminants are concerned, true distillate oils are generally quite pure initially, with the ash content of most oils averaging less than 5 ppm at the refinery. Sodium, vanadium, and other trace metals in these fuels are commonly less than 1 ppm. The fuels, however, may pick up ash-forming contaminants in transportation, storage, and distribution. The most likely occurring critical contaminants are sodium from salt water, lead from gasoline in pipeline distribution, and vanadium from residual oil contaminants. It is important for good gas turbine performance to maintain distillate fuels as clean as possible from the refinery right to the gas turbine. An excellent ASTM symposium on fuel cleanliness is contained in ASTM publication STP 531, entitled "Manual

	TRUE DISTILLATES		ASH-FORMING FUELS	
	NAPH / KERO NO. 2 OIL	HEAVY	CRUDES BLENDS	HEAVY RESIDUALS BUNKER C
STARTUP FUEL	NAPH ONLY	SOME	SOME	YES
FUEL HEATING	NO	SOME	YES	YES
ATOMIZATION	LP / MECH	LP / MECH	LP / HP	HP
COMBUSTOR	STANDARD		HEAVY FUEL	
FUEL TREATMENT	NO	NO	YES	YES
TURBINE CLEANING	NO	NO	YES	YES

GT08912

Figure 23. Liquid fuels (common application requirements)

on Requirements, Handling, and Quality Control of Gas Turbine Fuels.”

In contrast--to the true distillate fuels, the lower grade fuels generally” contain appreciable levels of ash-forming contaminants, even as they are processed. They may pick up even more contaminants (such as salt water) in transportation and storage. These fuels will generally require the following:

- Desalting to remove water-soluble contaminants such as sodium and potassium to a specified level;
- Filtration to remove particle matter;
- Inhibition of vanadium contaminants by the use of a magnesium-base additive;
- Provisions for removing deposits from the turbine (turbine cleaning).

Fuel Delivery and Storage

Irrespective of fuel type, there are certain precautions that can be taken at the plant site to minimize the chance of contaminants entering the turbine. There are two approaches to ensure this condition:

- Minimizing the chance that the fuel will become contaminated by using careful transportation and storage methods;
- Removal of insoluble contaminants by setting filtration, centrifuging, electrostatic precipitation, or a combination thereof.

Each plant site will have to develop its own practices, which will largely be influenced by the fuel type and its transportation system. The following recommendations, however, are offered:

- Initially, a user is advised to discuss with the supplier any practical steps that can be taken to minimize fuel contamination during shipment to the site. Care in barging or trucking, cleaning the tank wagon or car before loading, and dedicated tanks or trucks are examples of good practices.
- Provide three storage tanks for each fuel, with each tank sized to provide a 24-hour uninterrupted supply of fuel. The use of three tanks will permit one tank to be in use

while the second tank is being filled and is settling after filling the third tank. After filling a tank, or adding additional fuel to it, a minimum of 24 hours settling should occur before taking fuel from the tank.

- Tank design should specify a fixed roof, in order to minimize salt or other contaminant pickup from the atmosphere. Storage tank bottoms should slope to an area from which water and other settled material can be removed periodically, to avoid a build-up of microorganisms at the fuel/water interface. The drain should be such that essentially all material can be removed.
- Fuel should not be pumped directly from the bottom of the tank. The tank should have floating suction in the fuel line that leads to the turbine. The suction travel should be limited so that the inlet is never below 18 inches (46 cm) from the tank bottom.
- Water and any other sediments should be drained from the storage tanks on a daily basis. After experience has been established with a given fuel and fuel source, the frequency of draining may be modified. The water must be disposed of in a manner that meets local environmental regulations. It should be emphasized that water can contain sodium and potassium and also microorganisms which grow at the water-oil interface and which give rise to sludges and other chemicals that might render filtering ineffective. It is for these reasons that as much water should be removed from the fuel as possible.
- Fuel being delivered to a storage tank should initially pass through a screen or coarse filter to remove any large particles. Inlet piping and any recirculating lines to the storage tank should be 18 inches (46 cm) minimum above the bottom of the tank. Baffling at the point of fuel entry is desirable. The incoming stream of fuel should not be directed toward the bottom of the tank or in such a way as to stir up any material settled on the tank bottom. A velocity diffuser can be used to minimize the net effect of incoming fuel.
- When tanks are intended to store high-viscosity fuels such as residuals, a means of heating must be provided to keep viscosity low

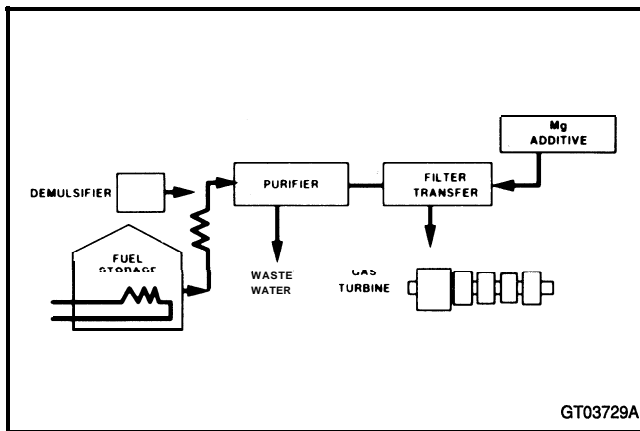


Figure 24. Fuel purification

enough so that the fuel may be pumped. Tank insulation is also desirable.

- Cadmium, zinc, and copper catalyze the decomposition of hydrocarbons. These elements and their alloys, therefore, should not be used in the construction of storage tanks and related items. The inside of the tank and associated piping should be cleaned after tank installation is complete to remove any corrosive weld slag or other contaminants.

Our experience indicates that a high percentage of the fuel pump, flow divider, check valve and short filter life problems are related to inadequate or poor fuel handling practices. Such steps as draining water and sediment from the tank each day, letting a tank settle for 24 hours before use, and making sure the drain is at the lowest point in the tank on existing tank systems can reduce equipment problems and increase availability.

Fuel Purification (Distillate and Light Crudes)

True light distillate fuels may be contaminated during shipment, and light crude oils may have small amounts of contamination due to oil well flooding with water which may contain salt. They normally require a purification system to remove the water soluble salts of sodium plus potassium.

Fuel purification does not involve adding water to the fuel, and in some cases it also does not involve fuel heating. In fuel purification it is assumed that the small sodium and potassium contamination level (up to 15–20 ppm of sodium) is concentrated in the water that is in the fuel, and if the water is removed, the sodium plus

potassium will also be removed. Sometimes a small amount (0.01 percent of an emulsion breaking fluid is required to aid in purification.)

Purification of crude oils should not be considered a universal substitute for traditional fuel washing (i.e., water addition and mixing prior to separation). Before purification is adopted in place of washing, it is necessary for GE to have the opportunity to evaluate the specific fuel, its physical properties (e.g., specific gravity, viscosity, etc.) and the degree to which water phase is removable.

The purification process is a one-stage extraction procedure—only centrifuges are used for purification. Figure 24 outlines a typical purification system.

It should be noted that the purification system is substantially less expensive than the fuel washing system used for heavier liquid fuels. This is due to the elimination of such items as a mixer, second-stage treatment, water treatment, treated fuel storage tanks, forwarding skids, and, sometimes, heaters.

Fuel Washing (Ash-Forming Fuels)

Since ash-forming fuel oils almost universally contain sodium, they normally require water washing to remove water soluble salts of sodium and potassium. Water soluble calcium salts will also be removed in the process. Fuel washing involves mixing heated fuel with a small amount (0.02 percent) of an emulsion-breaking fluid to aid in later separation. The washing process is a two- or three-stage extraction procedure with the extraction water flowing counter-current to the fuel. Each stage has a mixer to effect contact of the wash water with the fuel, followed by a device to separate the salt-laden water from the fuel. Either centrifuges or electrostatic desalters are used for this separation step.

The number of extraction stages required depends on the salt level in the fuel to be processed and on certain properties of the fuel, mainly specific gravity and viscosity. A typical washing system has two stages, as shown in Fig. 25. A more difficult fuel would require three stages for consistent production of a washed fuel, with a maximum total sodium plus potassium level of 1 ppm.

The successful operation of the fuel-washing system depends on a working difference between the specific gravity of the fuel and that of the water. Fuels with specific gravities close to 1.0 (above 0.97) might not be washable unless they

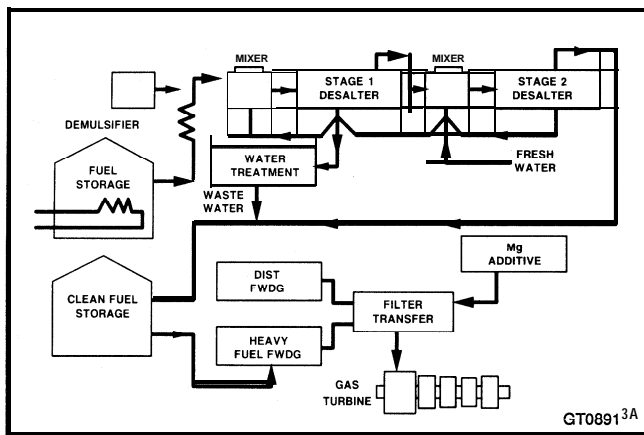


Figure 25. Ash-forming fuels treatment (two-stage centrifugal or electrostatic system)

are first blended with a lower specific gravity compatible liquid, or the specific gravity of the wash water itself is increased with magnesium sulfate.

Fuel Filtration

Proper filtration of fuel to remove solids, dirt, oxides, silicates, and related compounds is also required to minimize damage and/or clogging of fuel pumps, fuel dividers, and fuel nozzles. Of the three most commonly used fuels in gas turbine operation, only distillate fuel is received as a filtered fuel. Normally, crude and residual oils are received at the fuel treatment system unfiltered. Therefore, in addition to removing sodium, the fuel treatment system provides the initial filtration of the fuel as a by-product of that process.

The centrifuges used in fuel treatment systems described earlier remove particulate matter from the fuel as they are removing the water and sodium. Therefore, the centrifuges serve both a desalting and filtering function. The electrostatic system, while being an efficient desalter, is not as effective or efficient in removing the particulate matter from the fuel. Therefore, the filters downstream of the electrostatic system are required to remove more particulate matter, which generally results in a higher frequency of filter change-out.

Filtration ($5\mu\text{m}$) is almost always required immediately ahead of the turbine for any liquid fuel, even if it has been desalted. However, any upstream treatment system will have a decided effect upon the type and maintenance of such filtration equipment.

Fuel Inhibition (Ash-Forming Fuels)

Vanadium compounds present in the fuel at levels greater than 0.5 ppm can cause hot corro-

sion of the turbine section. Vanadium occurs in petroleum fuels as an oil-soluble form which cannot be removed from the fuel by water washing or by mechanical separation. However, the corrosive effect of vanadium can be counteracted by the addition of a suitable magnesium compound, the purpose of which is to raise the melting point of the ash above operating temperatures. There may also be a beneficial coating effect of thin ash deposits that form on the turbine blading.

To prevent vanadium hot corrosion in the turbine hot gas path, a minimum ratio of magnesium to vanadium is required. Higher rates than necessary should be avoided, to prevent excessive additive cost, to minimize stack particulate emissions, and to avoid higher rates of combustion ash build-up in the hot gas path.

For normal applications, a minimum of a 3:1 weight ratio of magnesium to vanadium is recommended with a maximum value of 3:5:1. For residual fuels and blended residual fuels where the vanadium levels are moderate to high, and the sodium plus potassium level is reduced to 1 ppm or less by washing, this 3:1 ratio is adequate. However, there are special cases where the sodium-to-vanadium ratio in the treated fuel is high enough for these elements to interact and cause hot corrosion. In these cases, the magnesium-to-vanadium ratio must be increased. High sodium-to-vanadium ratios can exist with some crude oils where vanadium levels are very low (0.5 to 10 ppm) and are especially critical when sodium removal to less than 1 ppm is not practical. Increasing the magnesium-to-vanadium ratio above 3:1 is recommended in such cases. For instance, the magnesium-to-vanadium ratio may have to be increased to about 5:1 for sodium-to-vanadium ratios of 1/15 and to about 10:1 for sodium-to-vanadium ratios of 1/5. Although the magnesium-to-vanadium ratios are high in these cases, the total level of magnesium required is not significant, since this only occurs with very low vanadium-level fuels.

The general types of magnesium additives that can be considered are oil-soluble (magnesium **sulfonate**), suspendible (magnesium oxide), and water soluble (magnesium sulfate). It has been demonstrated that these are equally effective as corrosion inhibitors on the basis of equal magnesium content. The oil-soluble-type additive is the most expensive of the three, and its use is most attractive for fuels having a lower vanadium content. Its use is simplest in terms of equipment.

The suspendible additive (MgO) consists of an oil dispersion of finely divided particles which is injected into the fuel and kept uniformly dis-

tributed in the fuel by the fine particle size and by a slow recirculation of the treated fuel. With this additive, the fuel can also be pre-treated and pre-analyzed. The presence of solid magnesium oxide particles presents the risk of abrasive wear of fuel pumps and flow dividers unless the particles are kept extremely small.

The water-soluble additive $MgSO_4$ is lowest in cost. It is injected on a continuous basis as a water solution into the fuel line directly ahead of the turbine, so that there is no chance of settling. The additive solution is generally injected at a rate between 0.5 and 2.5 percent of the total fuel flow.

In the selection of **any** of **these** magnesium additives, the concentrations of the critical trace metal contaminants (sodium, potassium, calcium, and lead) in the additive itself must be low enough so that the washed, inhibited fuel passes the turbine fuel specification for these contaminants.

Adding the inhibitor just off-base or on-base directly into the turbine fuel line eliminates problems associated with long term storage of treated fuel (inhibitor may separate out in some fuels), rewashing of fuel due to high sodium level (treated fuel cannot be rewashed) and differences in system design between oil-soluble and water-base inhibitors.

Silicon additives have been used to modify gas turbine combustion ash to make it drier, less dense, and more friable. Usually silicon has been used in combination with a magnesium additive. The operating advantage sought by modifying the ash is a low ash deposition rate in the hot gas path and/or an ash that is more readily removed by available turbine cleaning techniques.

The effect of silicon additives on the combustion ash deposition rate appears to depend on the complex interrelationship of fuel chemistry, deposit chemistry, and turbine firing temperature. Most of the reported successful use in the past has been at firing temperatures below 1550 F (843 C). At the state-of-the-art higher firing temperatures, the effect of silicon is complex and is still being studied closely for better understanding.

GE's laboratory experience in the turbine simulator indicates that there is only a limited range of fuel chemistries within which silicon reduces the ash deposit rates in the first-stage nozzle at firing temperatures of 1750 F and 1950 F (954 and 1066 C). Specifically, when the Na/V ratio in the fuel is between 0.01 and 0.05, deposit rates are reduced by a factor of between 5 and 10 and are washable by standard water wash-refire procedures.

At lower Na/V ratios, field experience has shown no benefit in deposit rates. In applications

involving waste heat boilers, excessive fouling of fin tubes has been observed.

At higher Na/V ratios (>0.05) and firing temperatures between 1750 F and 1950 F (954 and 1066 C), deposit rates are sometimes higher using silicon and are sometimes not removable by washing. One interesting characteristic, however, is that the silicon does render deposits formed at 1950 F (1066 C) partially removable by nutshell injection during operation. Deposits formed when using magnesium alone at this firing temperature have not been found to be removable by nutshell shells.

Silicon additives form ash deposits in waste heat boilers at a much higher rate than additives of magnesium alone. Silicon is usually added together with magnesium so that the weight ratio of silicon-to-magnesium-to-vanadium is typically 7:3:1, oil-soluble magnesium. The silicon-magnesium costs about four times that of the oil-soluble magnesium. For typical heavy-fuel applications, GE has not recommended the silicon-magnesium additives as a result of their higher cost and uncertainties in ash deposit rates and removal; however, it is recognized that in special situations there may be operational and/or economic benefits for use of the silicon-magnesium additives.

Fuel Analysis

An important part of the ash-forming fuel treatment is fuel-analysis, which is needed to ensure that the treatment system has produced a fuel that is within specification. The fuel shipments must also be analyzed to make sure that the contaminant levels are within the capabilities of the fuel-treatment system.

A flame photometer can be used for sodium level determinations in fuels having less than 0.5 ppm vanadium. The more contaminated lower-

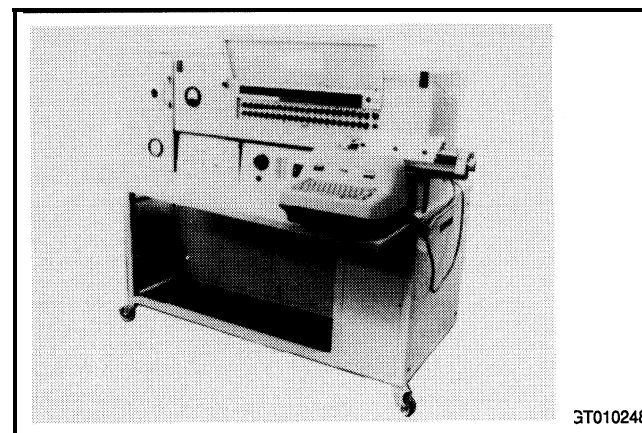


Figure 26. Emission spectrophotometer

grade fuels require equipment with greater capabilities. This equipment is referred to as a direct-reading emission spectrometer (Fig. 26). While this is a complex instrument, its operation is simple. The operator collects samples, inserts them one at a time in the excitation chamber, and presses a button. One minute later, the instrument prints out the levels of the critical contaminant elements automatically. About once every two weeks, the instrument calibration is checked, a process which takes approximately 45 minutes. The standards used for calibration have a matrix representative of the fuel to be analyzed. The contain precisely-measured amounts of trace metals, allowing accurate setting of the instrumentation. It should be mentioned that standards should be prepared with the additive type to be used in the turbine, in that the additive type may cause differences in readings with this type of instrument.

When the type of magnesium additive allows the use of a premixed fuel, fuel analysis is required only once per treated batch of fuel. With the magnesium additive injected continuously on-line, frequent periodic analyses are necessary for reliable gas turbine operation.

Turbine Deposits and Cleaning (Ash-Forming Fuels)

The combustion products from burning treated ash-forming fuels will still contain solid ash, the bulk of which comes from the magnesium additive used to inhibit vanadium. Although this ash is dry and noncorrosive (as opposed to molten product which would have resulted from nontreated fuel), a small fraction of it will adhere to turbine blading and will gradually reduce the output of the machine. The use of ash-forming fuels will, therefore, require some provision for

periodically cleaning deposits and restoring machine output. Cleaning is normally accomplished when the load capability has dropped between 5 and 10 percent, and at least before the possibility of compressor surge. For several GE models, compressor surge margin is such that substantially higher loss can be tolerated. The rate at which deposits accumulate, and their ability to be removed, will depend upon a number of factors such as fuel composition, treatment effectiveness, turbine design and temperatures, and the mode of gas turbine operation.

The test bed used for quantifying both deposit rates and cleaning techniques is the GE high-pressure turbine simulator rig shown in the schematic diagram in Fig. 27 and the photograph in Fig. 28. It is essentially a single-combustor system taken from one of the smaller GE gas turbines, with its combustion products being discharged into a segment of a production MS3000 first-stage nozzle. The rig runs at the same pressure, temperature, and airflow as a commercial machine. Since the airflow, gas temperature, and chamber pressure are known, a continuous record of the decreasing effective nozzle throat area can be monitored as the nozzle fouls. In terms of airflow, this turbine simulator is the largest known installation of its type in the world, and it has been run over the span of firing temperatures from 1600 to 2000 F (870 to 1090 C). These tests correlated well with the older field experience, and formed the basis for operation with the newer generation of machines. It has also been possible to quantify the effect of appropriate deposit cleaning techniques.

An example of deposits on the first-stage nozzle is shown in Fig. 29. The deposits on this particular part have the most influence upon machine output and performance. Shown is the condition of

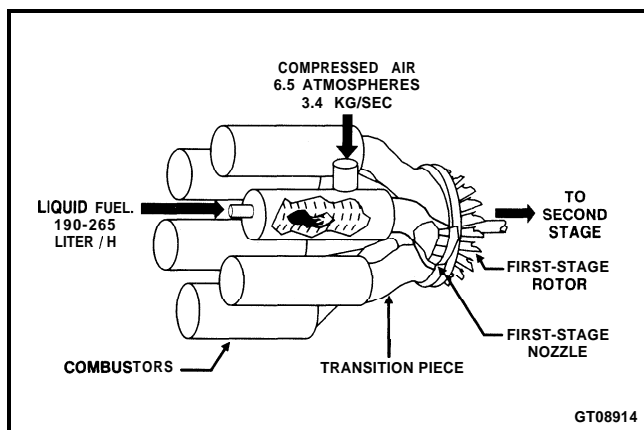


Figure 27. Gas turbine simulation by high-pressure rig

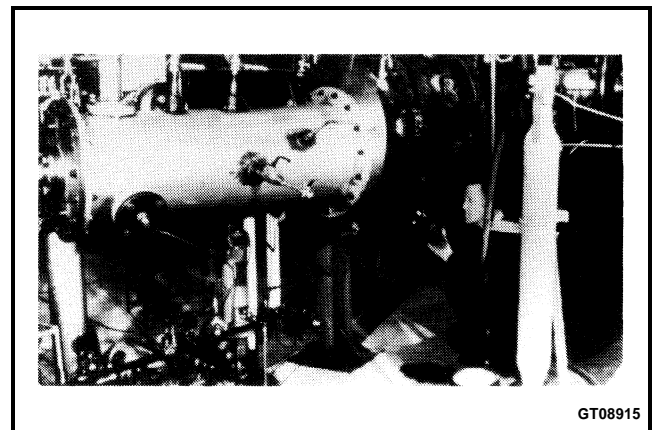
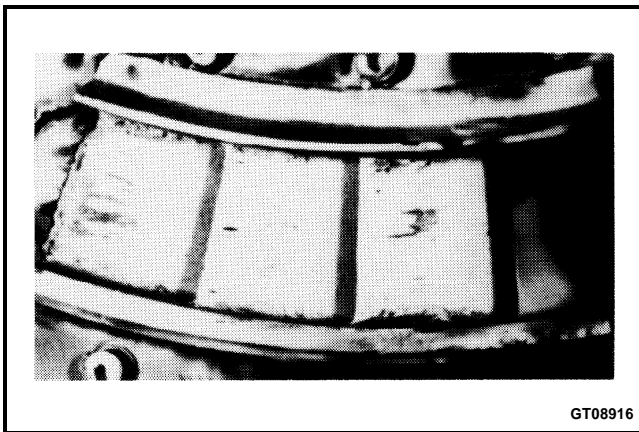


Figure 28. Turbine Simulator (high-pressure test facility)



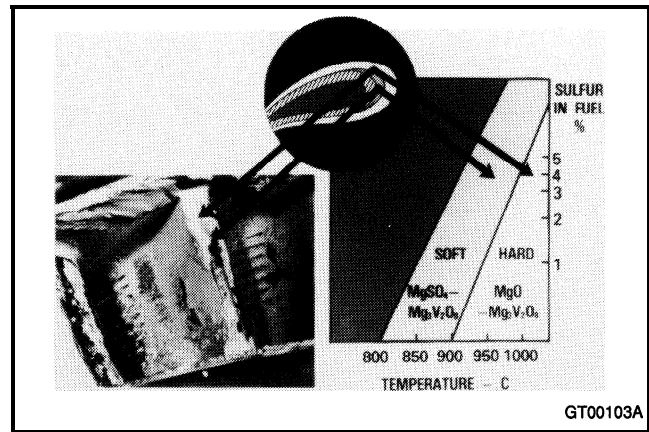
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Figure 29. Treated residual deposits [nozzle section after test (immediately after shutdown)]

the nozzle, with no cleaning, immediately after shutdown of a turbine simulator test at 1500 F (815 C). The deposits are light yellow, and are composed mostly of the combustion products of the magnesium additive itself.

The firing temperature at which these deposits are formed determines the chemical form of the ash. At lower temperatures, the ash is primarily magnesium sulfate ($MgSO_4$); at higher firing temperatures, it becomes magnesium oxide (MgO). For instance, Fig. 30 shows an example of a duplex deposit formed at 4750 F (953 C) on a cooled nozzle partition. The deposits on top of this layer are white MgO . These deposits, because they are insulated from the nozzle surface, are hotter than those next to the metal. The equilibrium between MgO and $MgSO_4$ which is influenced by temperature, sulfur, and pressure, is also given in Fig. 30 for a total pressure of 10 atmospheres.

The form of the magnesium compound in the deposit is most important with respect to turbine



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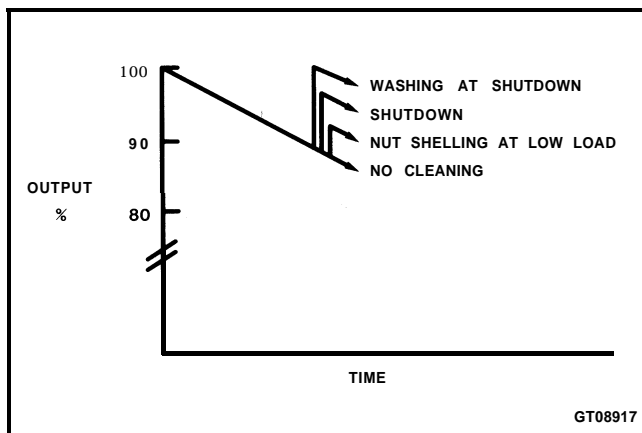
Figure 30. Layered ash deposit (first-stage nozzle)

cleaning. $MgSO_4$ is water soluble and hygroscopic; MgO is neither.

From time to time it will be necessary to remove deposits resulting from the use of treated ash-forming fuels. Fig. 31 shows three potential methods for removing deposits from turbine blading; any or all may be employed on the same machine. The three methods are turbine shutdown, nutshell injection, and shutdown plus washing.

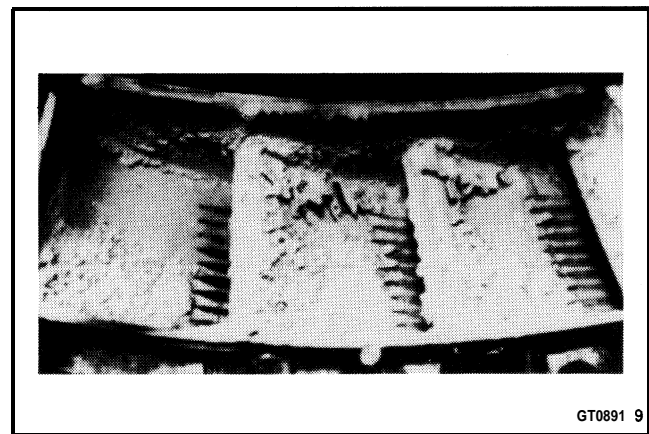
Turbine Shutdown

The ash deposits formed at temperatures below 1650 F (898 C) will tend to flake and spall after a machine shutdown of a few hours or overnight, and some will be blown through the exhaust when the machine is next started. The flaking and spalling are due in part to the fact that the deposits are largely $MgSO_4$; they tend to hydrate and increase in volume, as can be seen in Fig. 32. This method is obviously simple to



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Figure 31. Turbine ash deposit removal



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Figure 32. Treated residual deposits on nozzle section after test (after standing several hours to hydrate)

accomplish, but it does require machine shutdown, and becomes decreasingly effective above 1650 F (899 C).

Nutshell Injection

This is done at full speed, low load, and involves the injection of ground nutshells directly into the combustor liner. At firing temperatures up to 1750 F (953 C), this process will restore about one-half of the lost power. Its main advantage is that it can be accomplished while the turbine is running. As firing temperatures increase, nutshell injection becomes decreasingly effective in removing deposits.

Turbine Shutdown Plus Washing

This is the most effective way of cleaning, and involves injecting water into the combustion system after the machine has been shut down and cooled. The procedure is performed at cranking speed, and it removes virtually all of the deposits from the hot-gas-path parts. This, supplemented by nutshell injection, is now the standard method of cleaning, and is effective for removing deposits formed at any firing temperature. Longer washing periods are required for deposits that are formed at higher temperatures. This is because they consist largely of insoluble MgO, and it is necessary to allow time for water to penetrate to the inner MgSO₄ layer (Fig. 30). Only on refiring the turbine will these deposits be removed.

The length of continuous operation without a shutdown and/or washing/cleaning cycle will depend on the gas turbine, its operating conditions, and the quality of the treated fuel. In addition, as the ash deposits build up, the restriction of flow through the first-stage nozzle causes the compressor discharge pressure to build up to a point where compressor surge could occur. Generally, the operating period attained to date in commercial service (before a shutdown and/or washing/cleaning cycle was required) has been between 150 and 1500 hours in baseload operation. At part load the cleaning cycle is extended appreciably. This covers the spectrum of firing temperatures and fuels from the highest-ash residual to the lower-ash crudes.

Preferred Properties of Lower-Grade Fuels

GE heavy-duty gas turbines permit the use of virtually all lower grade fuels, and this is reflected by the applicable fuel specification, GEI-4104'7. The fuel suppliers normally specify only three proper-

ties of heavy fuels: maximum sulfur content, maximum viscosity, and minimum flash point.

It may be of advantage to the user to impose additional limits on certain key properties. In this way, the entire system could be designed for, and operate with, a "preferred" fuel rather than a "worst-case" fuel. The use of a "preferred" fuel could result in lower concentrations of trace contaminants in the heated fuel, and also lower fuel cost when both initial fuel and fuel treatment equipment costs are combined. Both corrosion and deposits resulting from the use of lower grade oils will depend upon the level of trace metal contaminants present in the combustion products and, therefore, in the treated fuel. Generally, the lower the contaminant levels, the better. Weighed against these advantages is the added fuel cost due to the somewhat more restrictive specifications. Frequently, fuel properties that are more favorable from the standpoint of fuel treatment can be obtained with only a minor effect on fuel price.

The key fuel properties concerned are shown in Fig. 33 along with three levels of properties. The first column is the maxima contained in Specification GEI-41047. The second column represents the design point for a typical fuel treatment system and covers most of the lower grade oils available in the United States and in many other parts of the world. The third column (and most favorable with respect to properties) is designated as a preferred limit.

Specific gravity, viscosity, and the sodium plus potassium content of the raw fuel all will have an influence on the final sodium plus potassium content of the treated fuel and/or the amount of treatment equipment. Calcium and lead limits, where shown, are equal to the specification values for the treated fuel. It is advantageous to mini-

	PROPERTY MAXIMA		
	SPEC 41047	STANDARD EQUIPMENT	PREFERRED LIMIT
PHYSICAL PROPERTIES			
. SPECIFIC GRAVITY AT 16 °C API	NO LIMIT	0.972 14	0.960 14
. VISCOSITY CST AT 38 °C	900	900	160
CHEMICAL PROPERTIES (PPM IN UNTREATED FUEL)			
• Na+K	NO LIMIT	150	60
• Ca	NO LIMIT	10	10
• Pb	NOT TREATABLE	1	1
• V	500	500	100

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Figure 33. Key properties of heavy fuels

mize vanadium, because it will reduce additive consumption and stack particulate emissions.

Economics of Fuel Selection

The selection of the type of liquid gas turbine fuel is important because the fuel is generally the largest single annual cost item. In some installations more than one type of liquid may be available which satisfies the users requirements, including combustion exhaust emissions. An important input in fuel selection is a detailed economic comparison study of the total annual gas turbine system cost for each candidate fuel. The main parts of such a comparison study would be:

- Fuel Cost
- Fuel Handling Costs
 - Investment costs: equipment for fuel storage, washing, inhibition, transfer, and turbine cleaning
 - Operating costs: labor, power, water, and chemicals
- Special Turbine Requirements:
 - Fuel atomization
 - Combustion system
- Turbine System Maintenance

- Frequency of replacement of hot-gas-path parts
- Frequency of turbine cleaning
- Gas Turbine Availability/Outages

Effective trade-offs can be made among the elements making up the overall study. An example would be a trade-off between the following:

- An adequate fuel washing system and a reasonable hot-gas-path parts replacement frequency, versus
- A very high efficiency fuel washing system with less frequent parts replacement

For a very high annual gas turbine usage rate, the latter might prove to have a lower overall cost; the former might cost less when intermediate service is involved. Another trade-off, where applicable, is the overall cost of using a lower grade fuel with "preferred properties" as opposed to "worst case" properties.

Where the user has a source of lower grade fuel at a lower price than a distillate fuel, the choice of the former may result in a significant overall annual cost saving if he intends to operate his machines on a continuous or semi-continuous basis.

GASEOUS AND LIQUID FUELS FROM COAL

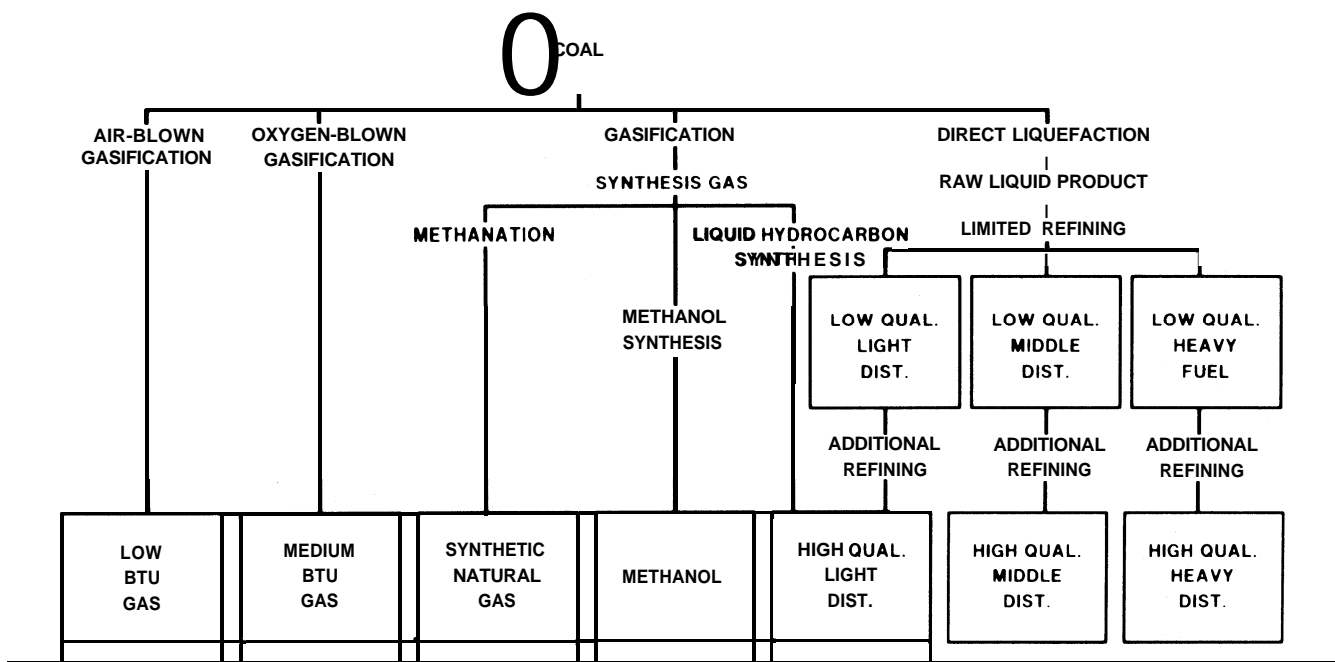


Chart 1

FUTURE FUELS

Additional fuels for future gas turbine power generation and industrial applications may be alternate fuels derived from coal, very heavy crudes, shale, and tar sands. As world petroleum supplies decrease, these alternate fuels will be produced in commercially significant quantities. GE is participating in these-fuel technologies, with the aim of establishing the fact that heavy-duty gas turbines will be able to burn new fuels as they become available.

The diversity of gaseous and liquid fuels that can be produced from bituminous and subbituminous coal by demonstrated technologies is shown in Chart 1. Coal gasification can produce gaseous fuels ranging from low-heat-content synthetic to substitute natural gas. The latter could be burned in today's gas turbines provided the fuel is clean. Heavy-duty gas turbines can also burn low-heat-content gases by making modifications, mainly in the combustion and fuel systems. GE has developed gas turbine combustors which have operated successfully even with very low-heat-content gases of the 110 Btu/ft³ (990 kcal/nm³), and GE is currently participating in the Cool Water Project, which will evaluate the use of a medium-heat-content gaseous fuel in an integrated coal gasifier/combined-cycle gas turbine power generation system. In the application of all of these coal-derived gases, cleanliness of the gas is necessary to ensure low maintenance and reliable operation of the gas turbine.

The high-quality, highly-refined liquid fuels derived from coal could be burned in today's gas turbines without modification. The lower quality, less refined liquid fuels from direct liquefaction of coal (shown in Chart 1 could offer a potential economic advantage if they could be used instead of the highly refined grades. However, the lower quality grades have low hydrogen/carbon ratios (high aromaticity) and higher fuel-bound nitrogen contents. To attain reliable combustor performance and to meet environmental restrictions for allowable NO_x exhaust gas emission levels, modification or major redesign of the gas turbine combustion system may be necessary to accommodate these lower quality liquid fuels. To this end, there are active combustor development efforts considering new designs and improved materials. The properties of coal-derived liquid fuels, which will eventually be available in commerce, will probably represent a balance between the highest possible quality on one hand, and practical economics and- maximum natural resource utilization on the other.

The other major fossil fuel sources-shale, tar sands, and very heavy crudes-can be converted

to liquids which can be substituted for conventional petroleum crude oils as feedstock for existing petroleum refineries. The resulting refined products would be quite similar to today's petroleum fuels, and should be equally applicable in gas turbines. Conversion of tar sands to petroleum-equivalent fuels is already being done on a limited commercial scale in Canada, and similar conversion plants for heavy crudes are being constructed in Venezuela. Shale conversion technology has been developed, but significant commercial production is not expected until the end of the 1980s.

SUMMARY

Fuel cost is generally the largest single expense involved in producing power. This factor, together with fuel availability considerations, has accentuated the need for fuel flexibility in gas turbines.

This paper has demonstrated that fuel flexibility has been a prime philosophy in GE heavy-duty gas turbines, not only for the past few years, but during the 30 years of building turbines. As such, the paper has described those fuel properties and characteristics that affect gas turbine use and operation.

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2. S.S. Dreyman, R.T. Henke, "Processing and Treating Ash-Forming Fuels for Reliable Operation of Heavy-Duty Gas Turbines," GE Gas Turbine Reference Library, Publication GER-3438, October 1981.

Appendix CONVERSION FROM STANDARD INTERNATIONAL (SI) UNITS TO OTHER UNITS

	To Convert	To	Multiply By
Density	kg/m ³	lb/ft ³	6.24x10 ⁻²
Pressure	kPa	g(f)cm ²	10.2
	kPa	lb(f)ft ²	1.45x10 ⁻¹
	kPa	atmos.	9.872x10 ⁻³
Heating value (Wt. Basis)	MJ/kg	kcal/kg	238.8
	MJ/kg	Btu/lb	429.9
Heating value (Vol. Basis)	MJ/m ³	kcal/m ³	238.8
	MJ/m ³	Btu/ft ³	26.84
Contamination (Gases)	mg/m ³	grains/ccf*	4.37x10 ⁻²
	mg/m ³	ppm(w)	0.818/Spec. Grav.†

* ccf = One hundred cubic feet

†Spec. Grav. = Specific gravity of gas referenced to dry air as 1.00