The increasing demand for energy and the continuing increases in prices for standard fuels demand greater flexibility in the use of fuels in gas turbines.

Besides the standard fuels natural gas (typical heating values between 39 and 46 MJ/kg) and Diesel No. 2 fuel oil (42 MJ/kg), there is an increasing interest in low-BTU gases, synthetic gases (syngas here), and even liquid fuels (eg, heavy fuel oil, Naphtha, and condensates).

Low-BTU gases refer to fuels with heating values between 10 and 35 MJ/kg. Syngas denotes synthetically produced gases that generally have even lower heating values (LHVs), between 4 and 12 MJ/kg. This chapter specifies the essential requirements for process design of fuel systems used in oil- and gas-processing industries and outlines the major design parameters and guidelines for process design of fuel systems. It covers both gaseous and liquid fuel systems.

### 1.1 FUEL-SUPPL YING SYSTEMS

As the need for higher efficiency power plants increases, a growing number of combined-cycle power plants are incorporating performance gas fuel heating as a means of improving overall plant efficiency. This heating, typically increasing fuel temperatures in the range of 365°F/185°C, improves gas turbine efficiency by reducing the amount of fuel needed to achieve desired firing temperatures. For fuel heating to be a viable method of performance enhancement, feedwater has to be extracted from the heat recovery steam generator at an optimum location. Boiler feedwater leaving the intermediate pressure economizer is commonly used. Using gas-fired, oil-fired, or electric heaters for performance gas fuel heating will not result in a power plant thermal efficiency improvement.

Proper design and operation of the gas fuel heating system is critical to insure reliable operation of the gas turbine. Improper selection of components, controls configuration, and/or overall system layout could result in hardware damage, impact plant availability, and create hazardous conditions for plant personnel.

This chapter addresses the critical design criteria that should be considered during the design and construction of these systems. Fuel should be used to provide heat for power generation, steam production and process requirements.

Fuel systems are necessary to provide the proper fuel for a variety of users in the plant.

A fuel system should include facilities for collection, preparation, and distribution of fuel to users.

Alternative fuels (as required) should be made available at all consuming points. The commonly used ones are liquid fuel and gas fuel. One liquid fuel supplies at least one pump and its standby should be steam driven or available via other reliable power sources. Standby pumping units should be arranged for instantaneous start-up on failure of the operating unit.
Low-pressure users are items such as boilers, fired heaters, and reciprocating engines. High-pressure users are gas turbines. All fuel systems need to be kept free of solid contaminants that can plug instrumentation and fuel nozzles. In addition, fuel streams need to be maintained above the hydrocarbon dew point to prevent any liquid slugs in the fuel users.

The following section identifies general system requirements that apply to all gas fuel heating systems. These requirements, in addition to those described in the combustion specific system requirements section shall be followed during the design and development of the system. Gas fuel supplied to the gas turbine shall meet the particulate requirements. If the components in the gas fuel heating system are constructed of materials susceptible to corrosion, a method of final filtration upstream of the gas turbine interface is required. Particulate carryover greater than that identified in the standards can plug fuel nozzle passages, erode combustion hardware and gas valve internals, and cause damage to first stage turbine nozzles. The new gas piping system must be properly cleaned prior to initial gas turbine operation. Additional design considerations are those related to gas fuel cleanliness. The fuel delivered to the gas turbine must be liquid free and contain a specified level of superheat above the higher of the hydrocarbon or moisture dew points.

Saturated fuels, or fuels containing superheat levels lower than specified, can result in the formation of liquids as the gas expands and cools across the gas turbine control valves. The amount of superheat provides a margin to compensate for temperature decrease due to pressure reduction, and is directly related to incoming gas supply pressure. (Note: within this document, gas fuel heating strictly for dew point considerations is still considered to be in a “cold” state. Heating for performance purposes is considered “heated” fuel.) The design of the gas fuel heating system shall prevent carryover of moisture or water to the gas turbine in the event of a heat exchanger tube failure. Water entrained in the gas can combine with hydrocarbons causing the formation of solid hydrocarbons or hydrates. These hydrates, when injected into the combustion system, can lead to operability problems, including increased exhaust emissions and mechanical hardware damage. Proper means of turbine protection, including heat exchanger leak detection, shall be provided.

Gas being supplied to the gas turbine interface point shall meet the minimum gas fuel supply pressure requirements as defined in the proposal documentation. These minimum pressure requirements are established to insure proper gas fuel flow controllability and to maintain required pressure ratios across the combustion fuel nozzles. The gas fuel heating system shall be designed to insure that these requirements are met during all modes of operation over the entire ambient temperature range. The design of the gas fuel heating system shall insure that the design pressure of the gas turbine gas fuel system is not exceeded.

Overpressure protection, as required by applicable codes and standards, shall be furnished. In addition to minimum and maximum pressures, the gas turbine is also sensitive to gas fuel pressure variations. Sudden drops in supply pressure may destabilize gas pressure and flow control. Sudden increases in supply pressure may potentially trip the turbine due to a high temperature condition. Limitations on pressure fluctuations are defined in the gas turbine proposal documentation.

The gas fuel heating system shall be designed to produce the desired gas fuel temperature at the interface with the gas turbine equipment. Guaranteed performance is based on the design fuel temperature at the inlet to the gas turbine gas fuel module. The gas fuel heating and supply systems shall compensate for heat losses through the system. Compensation shall include but not be limited to elevated heater outlet temperatures, use of piping and equipment insulation, and minimization of piping length from heater outlet to turbine inlet. The gas fuel heating system shall be designed to support specified gas fuel temperature set points required by the gas turbine. These set points include high and
low temperature alarms, gas turbine controls permissives, and gas turbine controls functions. These set points are derived by GE Gas Turbine Engineering and are based on operability requirements and/or design limitations of components within the gas turbine gas fuel system. During specified cold and hot gas fuel turbine operating modes, the gas fuel heating system shall attain and maintain the fuel at a temperature that corresponds to a Modified Wobbe Index (MWI) within ±5% of the target value.

The MWI is a calculated measurement of volumetric energy content of fuel and is directly related to the fuel temperature and LHV. The MWI is derived as follows:

\[
MWI = \frac{LHV}{T_g \times SG}
\]

Where

- MWI, Modified Wobbe Index (temperature corrected);
- LHV, lower heating value of fuel (BTU/SCF);
- \(T_g\), absolute temperature (°R);
- SG, specific gravity of fuel relative to air at ISO conditions.

The ±5% MWI range insures that the fuel nozzle pressure ratios are maintained within their required limits. If gas fuel constituents and heating value are consistent, the 5% tolerance can be based strictly on temperature variation. If the heating value of the fuel varies, as is the case when multiple gas suppliers are used, heating value and specific gravity must be considered when evaluating the allowable temperature variation to support the 5% MWI limit.

For the use of gas fuels having a significant variation in composition or heating value, a permanent gas chromatograph shall be furnished in the plant’s main gas supply line. LHV and specific gravity readings from the gas chromatograph are used to regulate the amount of fuel heating so that the ±5% MWI requirement is satisfied. This control function shall be performed automatically by the plant control system.

1.1.1 FUEL SELECTION

Materials produced in the plant which cannot be sold for the least monetary value should possibly be used as fuel. Diverted to plant fuel oil system include visbreaker tar, lube extracts, waxes, and atmospheric residue. The selection of fuels used in the system should be based on the cost, availability and dependability of supply, convenience of use and storage, and environmental regulations.

All the previously mentioned materials should be used as liquid fuel, in a manner so as to maintain the threshold limits of the “Air Pollution Control” Standard. \(H_2S\) content of the fuel gas main header should comply with local regulations. Provision(s) should be made for using the liquefied petroleum gas (LPG) and/or natural gas to supplement the gaseous fuel.

Gaseous materials diverted to refinery fuel are those which cannot be processed to saleable products economically, and frequently include, \(H_2\), \(CH_4\), \(H_2S\), and \(C_2H_6\) and should consist essentially of \(CH_4\) and/or \(C_2H_6\).

1.1.2 GASEOUS FUEL

The main source of fuel gas should be the gas produced by process units and treated by the treating unit (if necessary). All fuel gas streams should be routed to a mixing drum where entrained liquid is
separated from the gas and where good mixing is ensured before distribution. In order to enable the balancing of gas production and gas consumption, necessary provisions for installation of LPG vaporizer and natural gas supplying systems to the fuel gas-mixing drum should be considered.

The liquid from the knockout drum and mixing drum should be drained to a closed recovery system or flare header. The fuel gas supply system should be equipped with enough controls and alarms, such as a low system pressure and high knockout drum liquid level alarms, to assure a safe fuel gas supply.

The fuel gas supply system should be designed to provide the consumers with liquid-free gas at constant pressure [about 350 kPa (g) or 3.5 bar (g)] and reasonably constant heating value.

Table 1.1 shows an example of a fuel gas specification for a commercial gas turbine. Specifications for a particular turbine can be obtained from the manufacturer.

The pressure controlling system should be provided to the fuel gas-mixing drum, which actuates from the fuel gas main header and responses to the steam control valve of the LPG vaporizer and/or natural gas control valve to supply the required pressure.

Alarms should be fitted to the pilot gas system to warn of low pressure/low flow. Gas turbines require more rigorous fuel specifications than do lower pressure systems. Table 1.1 shows an example of a fuel gas specification for a commercial gas turbine. Specifications for a particular turbine can be obtained from the manufacturer.

If main fuel gas header pressure drops to its preset value, LPG and/or natural gas should be used to supplement the make-up gas. The mains and all fuel gas lines should be steam traced and insulated to hold a temperature of at least 49°C to prevent condensation and hydrate formation.

A liquid knockout drum near the gas-consuming furnace (or group of furnaces) should be provided to prevent liquid from entering the burners.
To counteract the tendency of butane to recondense in the mixing drum, a steam coil in its base should be provided. Provision for installation of a relief valve to the flare header should also be considered.

The superheating of the gas can be accomplished in several ways. One way is simply to heat the feed stream directly. If the fuel is compressed before entering the fuel header, the temperature of the gas from the discharge cooler can be controlled to ensure proper superheat.

If the fuel is supplied from a higher-pressure system by pressure let down, the stream often needs some processing to prevent condensation. This can be provided by chilling the stream, scrubbing, and then reheating. Fuel gas conditioning systems based on Low Temperature Separation schemes are commercially available to accomplish this fuel conditioning.

1.1.3 LPG VAPORIZER

Liquefied petroleum gases (LPG) should be used as a fuel in gaseous form. A vaporizer system should be provided for this purpose.

The system should consist of the following:

1. one LPG surge drum
2. two LPG fuel pumps, one in operation (motor driven) and one stand-by (turbine driven)
3. one LPG vaporizer
4. all necessary controllers.

Various streams of LPG and butane should be received in the LPG surge drum and will be pumped into the fuel gas vaporizer.

Pressure in the LPG surge drum should be uncontrolled and will fluctuate with composition and temperature.

Levels in LPG surge drum should be controlled and recorded and provisions for high and low liquid level alarms should be installed.

Provision should be made to cut incoming LPG streams to the surge drum and pump LPG.

1.1.4 LIQUID FUEL

The ultimate aim in liquid fuel supply system design should be to ensure that the supply of suitable fuel to each fired heater/furnace will not fluctuate with load changes. All liquid fuels lighter than fuel oil should be filtered through mesh of about 0.3 mm aperture.

1.1.5 FUEL OIL SYSTEM

A typical system includes tankage from which the circulation pumps take suction, pumping the fuel oil through the heaters and strainers to the main circulation system. This serves all units that are potential users of fuel oil and returns to the tank, through a back-pressure controller.

The system should be designed to supply fuel oil to the furnaces at constant pressure and at the required viscosity. The required pressure depends on the type of burners used in the furnaces. The viscosity requirement should be met by means of temperature control.
The system should be designed so that from the fuel oil tanks, one supply and return header serves the processing units while a separate supply and return header serves the boiler plant.

In the system design, particular attention should be paid to the following:

1. **Piping System.** In the case of heavy fuel oil, measures should be taken to prevent plugging of lines. These may include heat tracing, insulation, and a separate flushing oil system (low pour point fuel). The flushing oil system will facilitate furnace starting up and shutting down operations and flushing out of lines, filters, and fuel oil heaters.

2. **Circulation Pumps.** To provide a reliable supply of fuel oil at least three pumps should be used. Typically, at least one pump should be turbine driven (upon availability of steam) and the others motor driven.

   Automatic cut-in of the stand-by pump should be provided when pressure in the fuel system becomes low. Loss of one pump may nevertheless result in a considerable pressure transient in the fuel oil supply system, which may cause furnaces to trip. By having three pumps each of about 70% capacity this effect is reduced considerably.

3. **Instrumentation.** The system should be equipped with a low-pressure alarm for supply header, located in each control house. Heaters on each fuel oil tank should be able to keep the content at about 65°C. This temperature should be limited to a maximum of 115°C to minimize the possibility of boil-over due to vaporization of water in the tanks. The fuel oil supply header temperature should be maintained at a temperature consistent with burner supply viscosity requirements.

   To obtain the required fuel oil supply temperature adequate heat exchangers (fuel oil heaters) heated by 2000 kPa (g) [20 bar (g)] medium pressure steam should be provided. These heaters should be installed in parallel arrangement, and all will be required to be in service when maximum fuel oil consumption is experienced.

   The fuel oil supply temperature should be regulated by controlling steam flow to the heaters.

   By using fuel oil at each unit, provision should be made for a fuel oil return line with block valve.

   A fuel oil return meter should be provided on each unit that consumes fuel oil. The recirculating fuel oil should be returned at a substantially temperature difference with respect to the exchanger effluent, and it may be directed back to the tank through the small vapor disengaging drum. Smoother operation will result, if it is always directed into the pump suction while the tanks are only heated to about 65°C. The fuel oil lines should be steam traced.

   The fuel oil system should be designed such that at least two parts are supplied to the heater, one part burned, and one part returned. Unless otherwise specified the size of the return header should be the same as the size of the supply header.

   Separate nozzles should be provided on storage tanks for the make up of fuel oil, recirculation, and the withdrawal of oil. The arrangement of nozzles should minimize any short-circuiting of oil that has recirculated.

   The fuel oil supply header should be controlled at a minimum pressure of 1000 kPa (g) [10 bar(g)], unless otherwise specified for process requirements.

   Relief valves should be located on the discharge of the pumps and on the fuel oil heaters. Relief valve discharges should be piped back to the fuel oil storage tank.

4. **Strainers.** To prevent plugging of the burners, parallel strainers should be installed in the discharge and suction of fuel oil distribution pumps, with the mesh sizes of 0.75 and 1.5 mm respectively (unless otherwise specified by the pump manufacturer).
1.1.6 REFINERY GASOLINE FUEL

Refinery gasoline fuel (visbreaker gasoline) may be considered as an alternative liquid fuel in steam boilers. A gasoline fuel system should have its own facilities for storage, pumping, and filters.

To accommodate variations in gasoline fuel demand, pressure control spillbacks should be considered to allow excess fuel to be returned to the storage tanks as required.

The following instruments should be provided in a boiler house control room:

1. Visbreaker gasoline storage tank low-level alarm.
2. Visbreaker gasoline supply header, pressure indication, and low-pressure alarm.
   
   Surge drum. Provision should be made to pump LPG directly into the flare header (if necessary).*

   LPG surge drum. Provision should be made to cut incoming LPG streams to the surge drum and pump LPG directly into the flare header (if necessary).
   
   By-pass line for LPG fuel pumps should be provided to transfer LPG from the LPG surge drum to the fuel gas vaporizer, in the event of high pressure in the LPG surge drum.
   
   LPG fuel pumps should have a minimum flow by-pass line to protect them at times of low consumption of LPG.
   
   Instrumentation should be provided to start the spare LPG fuel pump automatically in case of failure of the main pump.
   
   Size of the vaporizer, that is, whether a heat exchanger is required depends upon the following factors:
   
   1. maximum gas demand
   2. size and location of LPG surge drum
   3. minimum amount of gas carried in LPG surge drum
   4. climatic conditions
   5. gas pressure to be supplied by plant.

   Location of the safety valve on the fuel gas vaporizer should be in the vapor portion of the vaporizer to avoid the problem of having LPG going into the flare header.
   
   A vaporizer should be equipped with an automatic means of preventing liquid passing from vaporizer to gas discharge piping. Normally this should be done by a liquid level controller and positive shut-off liquid inlet line or by a temperature control unit for shutting off the liquid line at low temperature conditions within the vaporizer.

1.2 FIRED HEATERS FUEL SYSTEM

The fuel system should be in accordance with the following requirements.

The pilot gas, where practicable, should be taken from a sweet gas supply, independent of the main burner gas, or from a separate off-take on the fuel gas main, with its own block valve and spade-off

*This situation may occur temporarily due to low gas consumption.
position. Unless otherwise approved by the Company, the pilot gas pressure should be controlled at 35 kPa (0.35 bar) and the pressure-regulating valve should be the self-operating type.

Fuel manifolds around heaters should be sized such that the maximum pressure difference between individual burner off-takes should not exceed 2% of the manifold pressure at any time. In addition, account should be taken of the effect pipework sizes and arrangements of individual burners have on the distribution of fuel flow to each burner.

Individual burner isolation valves for the main fuels and steam should be located under the heater. The burner isolation valves, excluding pilots, should be located within an arm’s length of the peep holes giving a view of the flames from those burners. Where possible, a standard disposition of valves for each burner should be used; namely: from left to right, gas, oil, and steam.

All burners and pilot isolation valves should be of the ball valve type meeting BS 5351 or equivalent, subject to the operating temperature and pressure, including any purge steam, being within the rating of the valve seat. All burner isolation valves should have some readily recognizable indication of the valve position.

Each burner isolation valve for pilot gas should be positioned safely away from the burner and so that an electrical portable ignitor, when inserted in the lighting port, can be remotely operated from the burner valve position. In the case of floor-fired heaters, the pilot burner valves should not be located under the heater and should be operable from grade.

1.3 MINIMUM DATA REQUIRED FOR BASIC DESIGN

The following data should be provided as a minimum requirement for basic design calculation of liquid fuel to be used for normal operation or alternative operations, including startup.

- Net heating value, in (kJ/kg)
- Gross heating value, in (kJ/kg)
- Sulfur, in mass, in (mg/kg)
- Vanadium, in mass, in (mg/kg)
- Sodium, in mass, in (mg/kg)
- Nickel, in mass, in (mg/kg)
- Iron, in mass, in (mg/kg)
- Conradson Carbon, in (mass %) Ash, in (mass %)
- Other impurities in (mass %) or mass, (mg/kg)
- API
- Viscosity: dynamic in (Pa.s) at 100°C or at specified temperature (°C)
- Vapor pressure, in (Pa) at specified temperature (°C)
- Flash Point, in (°C)
- Pour Point, in (°C)
- Supply header operating pressure, in [kPa (g)] or [bar (g)] (max., normal, min.)
- Return header operating pressure, in [kPa (g)] or [bar (g)] (max., normal, min.)
- Supply header operating temperature, in (°C) (max., normal, min.)
- System mechanical design pressure and temperature, in [kPa (bar)] and (°C).
The following data should be provided as a minimum requirement for basic design calculation of fuel gas to be used for normal operation and for alternate operations, including startup, if pilot gas is not supplied from the fuel gas header, its properties should be provided.

- Relative density (specific gravity) at 15°C
- Net heating value, in (MJ/Nm³) or (kJ/kg)
- Gross heating value, in (MJ/Nm³) or (kJ/kg)
- Flowing temperature, in (°C) (max., normal, min.)
- Header operating pressure, in [kPa (g)] or [bar (g)] (max., normal, min.)
- System mechanical design pressure and temperature, in [kPa (g)] or [bar (g)] and (°C)
- Total sulfur, in mass, (mg/kg)
- Chloride, in mass, (mg/kg)
- Other impurities, in (volume %) or mass, (mg/kg)
- Flow rate available, in (Nm³/h).

The valves for controlling the flow of foul or waste gases to the individual nozzles should not be located underneath floor-fired heaters but should be positioned near the pilot gas valves.

A flame trap of an approved type should be fitted in the main foul or waste gas lines leading to a furnace, with a high temperature alarm actuator installed immediately downstream of the trap. Cleaning of the traps should be provided.

Irrespective of any purging arrangements within the burners, steam purging of the oil lines between the burner valves and the burners should be fitted.

The gas lines between the burner isolation valves and the burners should be fitted with a purge connection.

The steam and purge valves should be located adjacent to the burner isolation valves.

Each fuel supply header to a heater and individual pilot gas supplies to each burner, excluding waste or foul gases, should be fitted with two filters in parallel or with dual filters. Where the latter incorporate two filter elements in one housing, individual elements should be removable whilst in service without interruption of fuel flow. There should be no leakage from the operating compartment to the open compartment when one element is removed.

The filter mesh sizes should be as specified by the burner supplier and approved by the Company. The mesh material on main gas and pilot gas should be Monel. For the pilot gas filter the mesh size should be approximately 0.5 mm. In the case of the pilot gas supply, the pipework between the filters and the pilots should be in 18/8 stainless steel.

Piping should be in accordance with relevant standards, except that where fuel atomizers or gas nozzles require positional adjustment within the burner for optimum combustion, flexible piping for all fuels and steam connections to individual burners should be provided. This flexible piping should be of the fireproof continuously formed stainless steel bellows type, protected by metal braiding and approved by the Company.

The fuel oil, atomizing steam, and gas piping to the burners should be arranged so that the oil, main gas, or pilot nozzles can be removed without isolating the other fuel supply to that burner.

Individual gas and oil burner off-takes should be from the top of the headers. The ends of oil and fuel gas headers should be flanged to allow access for cleaning.
Pilot gas pressure reducing valves should be of the self-operated type and in accordance with API PR 550. They should be provided with isolation and hand-operated bypass valves.

All fuel control valves and meters should be conveniently located at grade and a safe distance from the furnace.

### 1.4 ATOMIZING STEAM AND TRACING

The atomizing steam supply should be run from the main and separately from the steam tracing supply and should not be used as steam tracing. Additionally, where light distillate fuel firing is specified, the atomizing steam lines should be lagged separately from the fuel lines to prevent vapor locking.

Atomizing steam off-takes to the burners should be from the top of the header and adequate trapping arrangements should be provided to prevent the admission of condensate to the burners, including steam traps at the end of manifolds.

Unless otherwise specified by the burner Vendor, the atomizing steam pressure should be controlled by a steam/oil differential pressure controller capable of operating over the specified firing range, or by a steam pressure controller.

Tracing of the fuel lines should be separated from other tracing systems. The heavy fuel oil system, including instrument legs, is to be traced right through to the burner, but that section of the fuel line common to both low flash and heavy fuel oils should be traced separately from the rest of the heavy fuel oil system. Tracing may be by steam or electricity.

Arrangements should be made to ensure that traced lines and associated instrumentation are not over pressured due to overheating if the fuel oil becomes stationary in the lines for extended periods.

Unless otherwise approved, fuel gas lines upstream of the burner isolating valves should be traced.

### 1.5 SHUT-OFF SYSTEMS

To ensure the effective isolation of furnaces from remote control positions, a solenoid initiated shut-off valve should be installed in each main furnace fuel line in addition to the control valve, and in each waste or foul gas line. They should be installed next to the control valves. These valves will normally be shut by remote manual or automatic initiation, for example, by “Heat-Off Switch,” but opened only by local manual operation. Additionally, these valves should be shut automatically when the main fuel pressure upstream of the control valves falls below the stable burning limit of the main burners, or the atomizing steam falls below a predetermined pressure.

Consideration should also be given to having the shut-off valve close automatically in the case of high liquid level in the fuel gas knockout drum. The shut-off valve should be operable from the control room. In addition a solenoid initiated shut-off valve should be installed in the pilot gas line to be operated only by the “Emergency Shutdown Switch.”

All systems should have a fail safe, that is, in normal operating conditions sensor contacts should be closed, relays and solenoid valves should be energized, and in the trip conditions, air-operated valves should vent.
1.6 GAS TURBINE FUEL ALTERNATIVES

For a gas turbines fuel system, reference should be made to API standard 616.

1.6.1 GASEOUS FUELS

For LPG a liquid phase formation in the combustor should be avoided.

For natural gas/LNG boil off, the inlet gas temperature should be above the dew point of liquid hydrocarbons.

For sour gas the following consideration should be applied:

1. corrosion-resistant gas supply hardware
2. any heat recovery equipment should have cold end protection.

Process gas, due to the wide variation in composition should be considered on a case-by-case basis.

Practically, all types of gaseous fuels should be burned in heavy-duty gas turbines, but do not necessarily have to be interchangeable in the same machine.

The standard gas turbine should be designed for a natural gas specification. A fuel falling outside these requirements should be accommodated by suitable modifications to the turbine control system, gas-fuel components, rating, and fuel handling equipment. Fig. 1.1 represents the fuel system of standard turbine.

The liquid hydrocarbon content of natural gas should be reduced to a maximum of 12 L/Nm³ “dry gas” before using it in a gas turbine.

Natural gas may have appreciable levels of hydrogen sulfide as a significant contaminant, which is known as sour gas. This hydrogen sulfide should be removed by fuel treatment. In some cases, it may

![FIGURE 1.1 Fuel System in Gas Turbine](image)
be burned directly in the gas turbine if the proper selection is made of materials and components in the gas turbine end fuel system.

1.6.2 LIQUID FUELS

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

1. True distillate fuels, which can normally be used without any change, but just as they are.
2. Ash-forming fuels, which generally require heating, fuel treating, and periodic cleaning.

Ash-forming fuels should require on-site fuel treatment to modify or remove harmful constituents. In addition, there should be provisions for periodically cleaning ash deposits from the turbine.

Liquid fuels, ranging from naphtha to residual fuels, should be successfully used in heavy-duty gas turbines.

True distillate fuels do not usually require heating for proper atomization, except for the heavy distillates and some light distillate used in cold regions. Heavy fuels should always require heating for proper fuel atomization; the temperature required being related to the type of fuel atomization.

For heavy residual fuels it may be necessary to heat the fuel to reduce the viscosity to the operating range of the fuel transfer and filter system. It may also be necessary to heat some crude and heavy distillates to keep wax dissolved.

A secondary and start-up/shut-down fuel should be considered for naphtha for safety reasons. A secondary fuel may need to be ready for heavy fuels, both for fuel system flushing and to provide fuel lightoff.

Explosion proofing of the gas turbine system may be required when used with low flash point fuels such as naphthas and some crude oils.

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

1.6.3 CLASSIFICATION OF PETROLEUM FUELS

- **Gaseous fuels.** Gaseous fuels of petroleum origin that consist essentially of methane and/or ethane.
- **Liquefied gaseous fuels.** Gaseous fuels of petroleum origin which consist predominantly of propane–propane and/or butanes–butenes.
- **Distillate fuels.** Fuels of petroleum origin, but excluding LPG. These include gasoline, kerosenes, gas-oils, and diesel fuels. Heavy distillates may contain small quantities of residues. The products belonging to distillate fuels can be obtained not only by distillation, but also for example, by cracking, alkylaion, etc.
- **Residue fuels.** Petroleum fuels containing residues of distillation processes.
- **Petroleum cokes.** Solid fuels of petroleum origin consisting essentially of carbon, mostly obtained by cracking processes.
Figs. 1.2 and 1.3 show typical refinery fuel–oil and fuel–gas systems.

### 1.7 OPERATION OF HEAT-OFF AND EMERGENCY SHUTDOWN SWITCHES

#### 1.7.1 HEAT-OFF SWITCH

Heat-off switch operation should include one or more of the following:

1. shut-off all fuel supplies, with the exception of pilot gas supplies, to all fired process heaters
2. shut-off heat to reboilers and feed pre-heater
3. in certain cases stop the unit charge pumps. In such cases these should be agreed with the Company.
1.7.2 **EMERGENCY SHUTDOWN SWITCH**

Emergency shutdown switch operation should include one or more of the following:

1. perform all the operations listed in heat-off (D.1)
2. initiate appropriate automatic devices
3. shut-off all nominated feeds to the Unit
4. fail safe critical control valves, a list of which is to be submitted to the Company
5. shut-off pilots for gas supplied to heaters.