CHAPTER 6

MODULAR POWER GENERATION— TURBINES, GASIFICATION, COMBINED CYCLE GENERATION

MODULAR POWER GENERATION

There will be new applications of cogeneration in the near future. During most of the 1980s, there was a reprieve from the energy problems of the middle and late 1970s. Now there is uncertainty over electric power supplies.

There will be a large need for innovative new energy systems. It is expected that cogeneration systems will play a large role on residential, commercial, and industrial levels. Innovation will be the key. New types of systems that are both technologically and economically feasible will be developed since the technology exists for both large and small cogeneration systems.

Cogeneration is the process of producing and utilizing two types of energy at the same time. This usually means that the generating system has one primary type of energy it is producing and which will be used and another type that is normally wasted. The cogeneration system captures the waste energy and converts it into a usable form. Electrical generating facilities produce two types of energy, electricity and heat. A cogeneration facility will use both types of energy. Typically, in the electrical generating system, the heat is released into the air or cooling water. Cogeneration is the process by which both types of energy are utilized. See Figure 6-1.

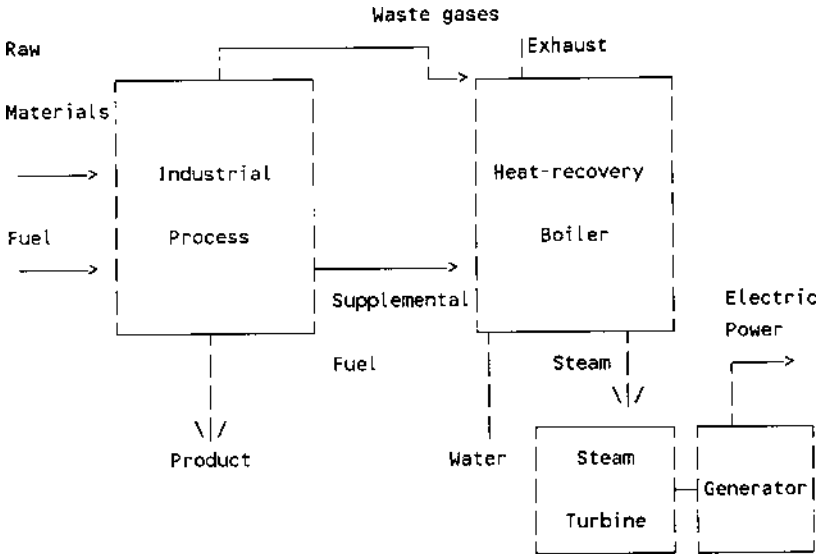

Figure 6-1. Steam cogeneration system

Cogeneration systems have been used mostly for large industrial systems. This has been due to the ratio of initial cost to payback. Cogeneration equipment is relatively expensive both to purchase and to install. If there is not enough energy to recover the cost, the recovered energy may be too high.

However, cogeneration systems can be used anywhere that energy is wasted. There are usable amounts of heat expended by a number of household appliances. These include air conditioning compressors, refrigerators, freezers and clothes dryers.

Recent residential cogeneration systems include a gasoline engine powered electrical generator with a heat exchanger. The heat exchanger transfers heat from the engine to a closed water circulation system to provide hot water. The unit is heavily insulated to trap both heat or noise. Another system uses a heat exchanger to capture the waste heat from central air conditioning units. This system also uses the recaptured heat to fill water heating needs.

Cogeneration systems have been used for decades and have gone through a number of cycles. In each cycle, different types of technologies have evolved to satisfy the market.

In the early years of electric power, cogeneration systems were used because of the unreliability of utility supplied electrical power. Businesses needed their own generating systems if they were to have power on demand and since they were already making an investment in generating systems, they could spend a little more and get a cogeneration system that had greater efficiency.

Once utilities began to become more reliable and less expensive, the popularity of generating and cogenerating with individually owned systems began to decline. These individual generating systems had only a specialized small market and were seldom used. The next cycle occurred during the energy shocks of the 1970s when cogeneration became a more common type of system.

We are now in another cycle where an increasing number of cogenerating systems are being designed and installed. It also appears that the popularity of cogeneration systems may not go through the wide popularity swings as it has in the past. This is because of the underlying changes in the modern economy. Instead of being in an industry-centered economy, which means concentration, there is the shift to a technology-based economy, which allows dispersion. This is coupled with a heightened concern for efficiency and the environment, provides basic strength for the cogeneration market.

The cost savings for cogeneration systems can be substantial, since they typically harness energy that is already being produced by some other process and is being wasted. The cogeneration process is using free energy that is doing nothing to generate electricity.

In order to keep the cogenerator operating efficiently, it must run for extended periods of time, so there may be times when the local demand for electricity will be less than the available power. In these circumstances, it is desirable to sell power to the utility company.

Prior to about 1980 very few utilities would purchase excess power from a customer. In 1978, Congress passed legislation which led to electric utilities being required to purchase cogenerated electricity. It specified that the rate at which the utility pays for electricity must be based upon the avoided cost. These costs are determined from the value of the fuel which the utility would otherwise have purchased to meet the system load, as well as savings associated with not having to expand their facilities or purchase power from other utilities in order to meet the demand.

TOPPING AND BOTTOMING SYSTEMS

Cogeneration systems can be classified as topping or bottoming systems. A topping system is used for generating electricity and a by-product of generating electricity, the heat, is used for some other use. A topping system is an electric generator with heat exchangers to provide hot water for the facility.

A bottoming system has some other energy process take place first, and the waste energy from that source is used to produce electricity (Figure 6-2). This is common in industrial applications where high temperature or high pressure steam is produced and normally wasted after the manufacturing processes are completed.

Another by-product of industrial processes are the gases that are emitted. Rather than emitting them directly into the atmosphere, they can be piped into a turbine which turns a generator to produce electricity.

Although the initial cost of this type of system can be high, the payback can occur from 2 to 7 years where the system will have paid for itself, and begin to provide energy savings. The rate of payback depends on the efficiency of the system and by the cost of buying utility supplied electricity.

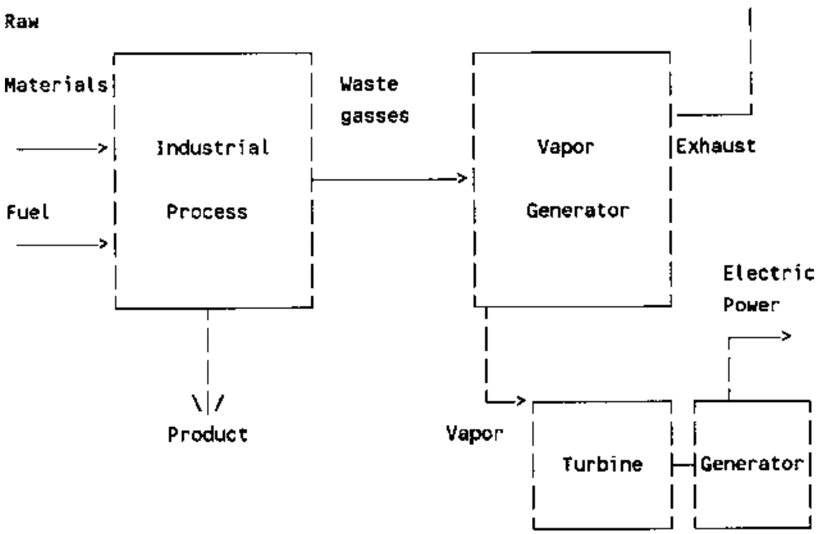

Figure 6-2. Cogeneration bottoming system

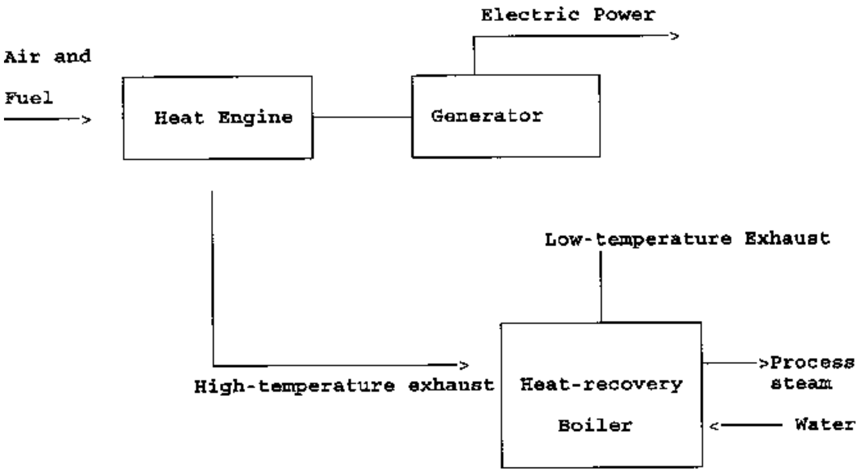

Figure 6-3. Topping system

In a topping system, a heat engine generator is used to provide electricity (Figure 6-3). Then the heat produced by the engine is also utilized. The exhaust gases are piped into a heat recovery boiler which produces steam for industrial processes.

Cogeneration equipment falls under Article 445 of the National Electrical Code (Generators). The provisions of Article 445, along with other applicable parts of the code must be complied with for residential, commercial, or industrial cogeneration systems. This covers only the electrical portion of the cogeneration system. Cogeneration systems also have thermal and mechanical systems which must meet other applicable codes.

PEAK REDUCTION

One use of generators and cogeneration is peak reduction or shaving. The reduction of peak loads can result in significant savings. Utility companies may charge industrial customers a separate demand charge, in addition to their regular electric rates. These charges can be substantial and if the customer can avoid these charges, notable amounts may be saved.

Since the utility company must provide power upon demand, in the amounts demanded, their transmission wires, poles, and transformers must be sized according to the highest possible demand that will be placed upon them. A facility with heavy equipment can have high momentary demands for power. Large electric motors often have a starting current of eight times their normal operating current. For industrial customers, utility companies have needed to install demand meters, and to charge high rates for maximum demands.

The demand charge is actually a reservation fee paid by the customer regardless of the use of the standby service. Ratchets are also used which require the customer to pay the reservation fee for an extended period. These requirements vary greatly from state to state.

Beyond larger power lines and transformers, the utility company has to build more or generating capacity because of these maximum demands. Because of this, some electric utilities offer large customers economic incentives if they enroll in load curtailment programs.

These are programs in which the utility and the customer cooperate on a contractual basis to reduce customer demand during periods of high power usage, such as in the summer months when air conditioner usage is high.

A typical load curtailment contract may specify that the utility may at its option and within a specified time period, usually between 30 minutes and 2 hours, request the customer to cut back or curtail the load. These programs are helpful to the utility, since they can substantially reduce total demand during periods of peak usage. Peak demand drops of 1000-kW could save a customer over $100,000 per year.

Originally, standby service was designed to provide power to customers which have their own generation during outages. Today, standby service means that customers can seek supplies on the open market, protecting themselves from interruptions.

Standby rates were designed in the early years of power generation to discourage interconnection by those that generated their own electricity. Utilities priced the service at a level that made it uneconomical for customers to implement on-site generation. The Public Utility Regulatory Policies Act (PURPA) of 1978 made this illegal and directed the states to implement reasonably priced standby service.

EXCESS POWER

The electricity sold to the utility company must be of the same frequency and voltage characteristics as the utility company's power. The frequency of the generated electricity and the frequency of the power supplied by the utility must also be synchronized.

This is commonly done for large installations by synchronizing controllers. These controls operate the synchronous generator (alternator), monitor the utility company's power and synchronize the two systems. Synchronous generators are like the synchronous motors used in clocks, they must run in step with the electric system frequency. They are more often referred to as alternators and are used in 1000-MW steam turbine generating plants. Small alternators are also used in wind energy systems of 1 to 10-kW. Most of these smaller units are permanent magnet types.

Alternators can generate electricity at unity power factor and because they are self exited they can operate independently of the central power station. Some alternators operate at their own speed and frequency. This variable frequency output is used for resistance heating, welding or rectified to charge batteries. It can also be fed to a static converter for conversion to 60-Hz for parallel operation with utility power.

DC generators are used in battery systems or for loads such as heating. They are also used with static inverters to power AC loads or send power to the power grid. DC generators include rotating motor-generators along with photovoltaic or electrochemical fuel cell sources.

There is also the option of using an induction generator which will supply power with the same characteristics as the utility company's power. Induction generators are self-regulating, adjusting to varying torques and load conditions.

An induction generator is basically an AC squirrel-cage motor. When connected to the utility company's power, it will run at its standard speed, which is usually about 4% below the speed of the rotating magnetic field within the motor, called synchronous speed.

While the motor is running on the utility company's power, if you drive the motor faster than the synchronous speed, the motor will generate power back into the utility company's lines. When operating in this mode, it acts as an induction generator since it is no longer working as a motor but as a generator.

When connected this way, the induction generator will generate electricity with the same exact characteristics as the utility power. No synchronizing controller is required and driving the machine faster will not change the frequency of the power it produces, it just increases the amount of power produced. Induction generators cease generating when the utility source is cut off, unless power factor capacitors are connected.

POWER FACTOR

One disadvantage of induction generators is the power factor that worsens when the kW output is reduced. The power factor is a ratio between the true or real power and apparent power. The highly magnetic loads of motors and transformers increase the apparent power which does not show up on standard power meters.

For industrial customers, utility companies install power factor meters, and charge special power factor charges, which can be costly. A large effort goes into the reduction of power factors. This is usually done by adding capacitors, since their capacitive reactance offsets the inductive reactance from magnetic loads.

If the generator goes off line, there must be a time delay of several seconds before it can be reconnected. If it were immediately reconnected, there would be large transients due to the phase differences between the decaying generator voltages and the utility voltage. A waiting period of several seconds is usually sufficient.

A controller is also required to disconnect the motor/generator from the power lines if utility power drops out. This is called a no voltage feature and often involves a special no voltage relay. Low voltage units, as opposed to no voltage units are also available.

CONVERTERS

Modern converters are solid state electronic units that convert AC to DC, DC to AC or AC to AC at another voltage and frequency. They are usually called inverters when used for DC to AC conversion. Line commutated converters depend on an AC source, usually grid power for their operation. They require lagging, reactive loads which may equal or be greater than the converter power rating. The chopped wave output of these converters can cause metering errors, electrical interference and excessive heating in motors.

Self commutated converters are more expensive, do not require central station power and can operate by themselves to supply standby power. They generally supply a better waveform. A synchronous converter may be a line commutated or self commutated device which is triggered by the utility and synchronizes its output with the utility.

QUALITY OF VOLTAGE

Problems with flicker and with alternately bright and dimming lights are usually associated with varying loads and motors starting currents on the same power circuit. They may also be caused by generators with varying output. Voltage problems are related directly to the size of the generator as well as the capacity of the circuit to which it is connected.

The likelihood of problems from a single cogenerator can be minimized if the rated output is limited to about 1/2 of the distribution transformer rating. This means about two to ten kW for a single phase unit or 25 to 100-kW for three phase units. The larger values are used for locations near the substation.

Other problems with voltage control can appear as additional cogenerators are connected. Especially if the capacity of on-site generators becomes significant compared with the total load. A wider range of regulation may be obtained with additional line regulators.

Electric system operating conditions may vary from minimum load with all generators operating to full load with all generators off. The connection might need to include the increased circuit capacity or a separate circuit for the power producers.

TURBINES

Small turbines are becoming important as auxiliary sources of power. The gas turbine and the steam turbine were conceived simultaneously. In 1791, John Barber's patent for the steam turbine described other fluids or gases as potential energy sources. Barber's gas turbine was a unit in which gas was produced from heated coal, mixed with air, compressed and then burnt. This produced a high speed jet upon the radial blades of the turbine wheel rim. Others before him that recorded similar schemes, include:

- Giovanni Branca - impulse steam turbine—1629,
- Leonardo da Vinci - smoke mill—1550,
- Hero of Alexandria - reaction steam turbine—130 BC.

These early gas turbines schemes would today be more accurately called turboexpanders, since the source of compressed air or gas is a by-product of a separate process. These ideas were not turned into working equipment until the late 19th Century when Charles de Laval and others produced working hardware. The use of steam turbines grew and the technology became available to gas turbines, gas generator compressors and power-extraction turbines.

The axial flow compressors of today's gas turbines resemble the reaction steam turbine with the flow direction reversed. The similarities between steam and gas turbine components are rooted in their common history.

In 1905, a gas turbine and compressor unit was installed at the Marcus Hook Refinery of the Sun Oil Company near Philadelphia, PA. It provided 5,300 kilowatts (4,400 kilowatts for hot pressurized gas and 900 kilowatts for electricity). The first electricity generating turbine for a power station was built at Neuchatel in Switzerland in 1939. This 4,000-kilowatt turbine used an axial flow compressor delivering excess air at 50 pounds per square inch to a single combustion chamber and driving a multi-stage reaction turbine. Excess air was used to cool the exterior of the combustor and to heat that air for use in the turbine.

An early utility gas turbine powerplant in the U.S. was the Huey Station unit of the Oklahoma Gas & Electric Company in Oklahoma City. This 3,500-kilowatt unit went on-line in 1949. It was a simple-cycle gas turbine with a fifteen stage axial compressor, six straight flow-through combustors placed circumferentially around the unit, and a two-stage turbine.

During World War I, the reciprocating gasoline engine was being refined for the small, light aircraft of the time. The gas turbine was big and bulky, with too large a weight-to-horsepower output ratio to be considered for an aircraft powerplant. However, the turbo-charger became an addition to the aircraft piston engine. The exhaust-driven turbo-charger was developed in 1921, which led to the use of turbo-charged piston engine aircraft in World War II.

In 1937 British Thomson-Houston Company built and tested Frank Whittle's jet engine. It consisted of a double entry centrifugal compressor and a single stage axial turbine. A turbojet engine consisting of a compound axial-centrifugal compressor similar to Whittle's design and a radial turbine was built by the German aircraft manufacturer Heinkel. In 1939 a turbojet aircraft powered by this engine made the first flight of a jet powered aircraft.

Throughout the war years various changes were made in the design of these engines. Radial and axial turbines were used along with straight through and reverse flow combustion chambers, and axial compressors. The compressor pressure ratio started at 2.5:1 in 1900, went to 5:1 in 1940, 15:1 in 1960, and is currently approaching 40:1.

Since World War II, improvements made in aircraft gas turbine-jet engines have been transferred to stationary gas turbines. Following the Korean War, Pratt & Whitney Aircraft provided the cross-over from the aircraft gas turbine to the stationary gas turbine. In 1959, Copper Bessemer installed the world's first aircraft industrial gas turbine, in a compressor drive. This unit generated 10,500 brake horsepower (BHP) driving a pipeline compressor.

In airborne applications the units are referred to as jets, turbojets, turbofans, and turboprops. In land and sea-based applications the units are referred to as mechanical drive gas turbines.

Jet engines are gas generators where the hot gases are expanded either through a turbine to generate shaft power or through a nozzle to create thrust. Some gas generators expand the hot gases only through a nozzle to produce thrust. These units are identified as jet engines or turbojets. Other gas turbines expand some of the hot gas through a nozzle to create thrust and the rest of the gas is expanded through a turbine to drive a fan. These units are called turbofans. When a unit expands most of its hot gases through the turbine driving the compressor, and the attached propeller and no thrust is created from the gas exiting the exhaust nozzle, it is called a turboprop. Turboprops have much in common with land and sea-based gas turbines. The engines used in aircraft applications may be either turbojets, turbofans, or turboprops, but they are commonly called jet engines.

The turbojet is the simplest form of gas turbine since the hot gases generated in the combustion process escape through an exhaust nozzle to produce thrust. Jet propulsion is the most common use of the turbojet, but it has been adapted to drying applications, supersonic wind tunnels, and as the energy source in a gas laser. The turbofan combines the thrust provided by expanding the hot gases through a nozzle (as in the turbojet) with the thrust provided by the fan. The fan acts as a ducted propeller. In recent turbofan designs the turbofan approaches the turboprop in that all the gas energy is converted to shaft power to drive the ducted fan. Turboprops use the gas turbine to generate the shaft power to drive the propeller, there is no thrust from the exhaust.

In the 1967 Indianapolis 500 Race a Pratt & Whitney turboprop powered car led the race for 171 laps, only to have a gearbox failure on the 197th lap. The car had an air inlet area of 21.9 square inches. Later, race officials modified the rules by restricting the air inlet area to 15.999 square inches or less. A year later race officials further restricted the air inlet area to 12.99 square inches. This effectively eliminated gas turbines from racing.

While some engines are derivatives of these aircraft engines, a majority of land based gas turbines were derived from the steam turbine. Like the steam turbines, these gas turbines have large, heavy, horizontally split cases and operate at lower speeds and higher mass flows than the aircraft derivatives at equivalent horsepower. A number of hybrid gas turbines in the small and intermediate size horsepower range have been developed to incorporate features of the aircraft derivatives and the heavy industrial gas turbines.

In the mid-1960s, the U.S. Navy implemented a program to use gas turbines as a ship's propulsion powerplant. The first combat ship constructed was the *USS Achville*, a Patrol Gunboat which was commissioned in 1964. The U.S. Navy has also outfitted larger ships. The Arleigh Burke Class Destroyer used four aircraft derived gas turbines as the main propulsion units with 100,000 shaft horsepower. By the end of 1990s, the U.S. Navy had over 140 gas turbine propelled and 27 navies of the world had over 330 ships with some 800 gas turbines.

Gas turbines have also been used to power automobiles, trains, and tanks. The Abrams tank is equipped with a gas turbine engine. This 63 ton unit can travel over 40 miles per hour on level ground.

Gas turbines can have many different forms, single or dual shaft, hot or cold end drive. A gas turbine can be viewed as a gas generator and a power-extraction-turbine, where the gas generator consists of a compressor, combustor, and compressor-turbine (Figure 6-4). The compressor-turbine is the part of the gas generator that develops the shaft horsepower to drive the compressor. The power-extraction-turbine is the part of the gas turbine that develops the horsepower to drive the external load. The energy that is developed in the combustor, by burning fuel under pressure, is the gas horsepower (GHP).

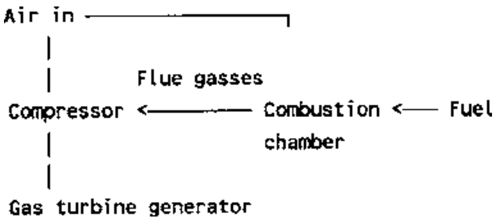

Figure 6-4. Conventional gas turbine

On turbojets, the gas horsepower that is not used by the compressor-turbine to drive the compressor is converted to thrust. On turboprops, mechanical drive, and generator drive gas turbines the gas horsepower is used by the power extraction-turbine to drive the external load.

The gas horsepower may be expanded through the remaining turbine stages, as done on a single shaft machine, or through a free power turbine, as done on a split shaft machine. The additional energy is converted into shaft horsepower and depends on the efficiency of the power extraction turbine.

A single spool-split output shaft gas turbine, also called a split-shaft mechanical drive gas turbine, is a single-spool gas turbine driving a free power turbine. The compressor/turbine component shaft is not physically connected to the power output (power turbine) shaft, but is coupled aerodynamically. This aerodynamic coupling, also called a liquid coupling, allows easier, cooler starts on the turbine components. It allows the gas turbine to reach self-sustaining operation before it drives the load. The gas turbine can operate at this low idle speed without the driven equipment rotating. This type of configuration is used in compressor and pump drives as well as electric generator drives.

This arrangement also allows the power turbine to operate at the same speed as the driven equipment. In generator drive applications the power turbines may operate at either 3,000 or 6,000 rpm to match 50-cycle or 60-cycle generators. Centrifugal compressor and pump application speeds are usually in the 4,000 to 6,000 rpm range. Matching the speeds of the drive and driven equipment eliminates the need for a gearbox.

One new power source is the 20 to 60 kilowatt, regenerated, gas turbine power package. This package, in combination with a battery pack, can deliver low emission power in automobiles.

TURBINE EVOLUTION

The growth of the gas turbine in recent years has been driven by metallurgical advances that allow high temperatures in the combustor and turbine components. Other factors include both aerodynamic and thermodynamic breakthroughs and the use of computer technology in the design and simulation of turbine airfoils and combustor and turbine blades. There have been improvements in compressor design, increases in pressure ratio, combustor and turbine design.

Gas turbines have always been tolerant of a wide range of fuels from liquids to gases, to high and low Btu heating values and are now functioning satisfactorily on gasified coal and wood.

Another factor has been the ability to simplify the control of a highly responsive unit using computer control technology. Computers start, stop, and govern the operation of the gas turbine. They also provide diagnostics and predict future failures.

The gas turbine is a highly responsive, high speed unit. In aircraft applications, a gas turbine can accelerate from idle to maximum take-off power in less than 60 seconds. In industrial gas turbines, the acceleration rate is limited by the mass of the driven equipment.

Without the proper control system, the compressor can go into surge in less than 50 milliseconds and the turbine can exceed safe temperatures in less than a quarter of a second. A power turbine can go into overspeed in less than two seconds.

Improvements in the properties of creep and rupture strength were steady from the late 1940s through the early 1970s. In 1950 390°F

(200°C) was achieved in operating temperature. This resulted from age-hardening and precipitation strengthening which utilized aluminum and titanium in the nickel matrix to increase strength. Since 1960, sophisticated cooling techniques have been used for turbine blades and nozzles. Since 1970, turbine inlet temperatures have increased to 500°F (260°C) and in some units as high as 2,640°F (1,450°C). The increase in turbine inlet temperature is possible with new air cooling techniques and the use of complex ceramic core bodies for hollow, cooled cast parts. The turbine blades and nozzles are formed by investment casting. A critical part is the solidification of the liquid metal after it is poured into the mold. Undesirable grain sizes, shapes, and transition areas can cause premature cracking of turbine parts. In the equiaxed process, uniformity of the grain structure occurs. Strength is improved if grain boundaries are aligned in the direction normal to the applied force.

This elongated or columnar grain formation in a preferred direction is called directional solidification. It was introduced by Pratt & Whitney Aircraft in 1965.

CONTROL

Control of the gas generator turbine and power-extraction turbine takes place by varying the gas generator speed, which is accomplished by varying the fuel flow. The following parameters may be monitored; fuel flow, compressor inlet and discharge pressures, shaft speed, compressor inlet temperatures, turbine inlet and exhaust temperatures (Figure 6-5). At a constant gas generator speed, as ambient temperature decreases, the turbine inlet temperature will decrease slightly and the gas horsepower will increase significantly. This increase in gas horsepower results from the increase in compressor pressure ratio and aerodynamic loading. This means the control must protect the gas turbine on cold days from overloading the compressor airfoils and overpressurizing the compressor cases. To get maximum power on hot days it is necessary to control the turbine inlet temperature to constant values, and allow the gas generator speed to vary.

The control senses ambient inlet temperature, compressor discharge pressure and gas generator speed. These are the three main variables that

```
  Fuel flow
      |
      |
Fuel valve signal---> Fuel flow-burner pressure
                                Fuel/Air ratio

                                      Acceleration
                                      Turbine inlet temperature
                                      Speed limiters
                     Setpoint (watts)  Ambient temperature bias
                     -----------------> Ambient pressure bias
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Figure 6-5. Gas turbine-generator control

affect the amount of power that the engine will produce. Sensing the ambient inlet temperature also helps to insure that the engine internal pressure are not exceeded, and sensing the turbine inlet temperature insures that maximum allowable turbine temperatures are not exceeded. Sensing the gas generator speed allows the control to accelerate through critical speed points. Gas turbines are typically flexible shaft machines and have a low critical speed.

The controls fall into several groups: hydromechanical (pneumatic or hydraulic), electrical (wired relay logic), and computer (programmable logic controller or microprocessor). Typical hydromechanical controls include cams, servos, speed (fly-ball) governors, sleeve and pilot valves, metering valves and temperature sensing bellows.

Electrical type controls include electrical amplifiers, relays, switches, solenoids, timers, tachometers, converters, and thermocouples. Computer controls may incorporate many electrical functions such as amplifiers, relays, switches, and timers. These functions are programmable.

This flexibility in modifying the program may be done by the user or operator in the field. Analog signals such as temperature, pressure, vibration, and speed are converted to digital signals before they are processed. The computer output signals to components such as the fuel valve, variable geometry actuator, bleed valve and anti-icing valve must be converted from digital to analog formats.

Until the late 1970s, control systems operated only in real time with no ability to store or retrieve data. Hydromechanical controls had to be calibrated frequently, weekly in some cases, and were subject to contamination and deterioration due to wear.

Multiple outputs such as fuel flow control and compressor bleed-air flow-control required independent, control loops. Coordinating the output of multiple loops, using cascade control, was a difficult task and often resulted in a compromise between accuracy and response time.

Many tasks had to be done manually. Station valves, prelude pumps and cooling water pumps were manually switched on before starting the gas generator. Protection devices were limited and the margin between temperature control setpoints and safe operating turbine temperatures had to be made large since hydromechanical controls cannot react quick enough to limit high turbine temperatures, or to shutdown the gas generator, before damage may occur.

In the early 1970s, electric controls consisted of a station control, a process control, and a turbine control. All control functions such as start, stop, load, unload, speed, and temperature were generated, biased, and computed electrically. Output amplifiers were used to drive servo valves, using high pressure hydraulics, to operate hydraulic actuators. These actuators may also contain position sensors to provide electronic feedback. The advent of programmable logic controllers and microprocessors in the late 1970s eliminated these independent control loops, and allowed multi-function control. Control system functions include sequencing, routine operations and protection.

Sequencing steps are used to start, load, unload, and stop the unit. The typical cycle used in a normal start are shown in Table 6-1.

When the start sequence is complete, the gas turbine will have reached self-sustaining speed and control is taken over by the routine operation controller. This controller maintains operation until it receives an input from the operator, or the process to load the unit. Before initiating this loading, control is turned over to the sequence controller to position the inlet and discharge valves and circuit breakers. In electric generator drives this is when the synchronizer is used to synchronize the unit to the electric grid. When these steps are completed, control is turned back over to the routine operation controller. At this time, the speed control governor, acceleration scheduler, temperature limit controller, and pressure limit controller become active. Table 6-2 lists gas turbine generators.

Table 6-1. Starting Cycle for Gas Turbine—10 to 30 Seconds

Starter on
Fuel on
Engine lights up - Exhaust gas temperature rise
Engine attains self-accelerating speed
Ignition off
Starter cuts out - Peak starting exhaust gas temperature rise
Engine attains idle RPM - Exhaust Gas Temperature drops to idle

Varying the fuel flow results in higher or lower combustion temperatures. As the fuel flow is increased, combustor heat and pressure increase and heat energy to the turbine is increased. Part of this increased energy is used by the compressor-turbine to increase speed which causes the compressor to increase airflow and pressure. The remaining heat energy is used by the power extraction turbine to produce more shaft horsepower. This cycle continues until the desired shaft horsepower or some parameter limit such as temperature or speed is reached.

To reduce shaft horsepower, the control reduces the fuel flow. The lower fuel flow reduces combustion heat and pressure. As the heat energy available to the compressor-turbine drops, the compressor-turbine slows down lowering the compressor speed as well as airflow and pressure. The downward movement continues until the desired shaft horsepower is reached.

If the fuel flow is increased too quickly, then excessive combustor heat is generated and the turbine inlet temperature may be exceeded or this increase in speed may drive the compressor into surge.

If the fuel flow is decreased too rapidly, then the compressor may not be able to reduce airflow and pressure fast enough. This can result in a flame-out or compressor surge, since speed decreases move the compressor operating point closer to the surge line. High turbine inlet temperature will shorten the life of the turbine blades and nozzles, and compressor surge can severely damage the compressor blades and stators

Table 6-2. Typical Gas Turbine Generators—Combined Cycle

Company/ Model	Frequency	ISO Rating Output (MW)	Efficiency	Gas Turbine Output (MW)	Steam Turbine Output (MW)
ABB Power					
KA26-1	50	366	58.5	232.6	133.4
KA35-2	50/60	45.8	43.3	33.2	12.6
Ansalado Energia					
164.3	50/60	90.4	51.6	60.6	32
294.3A	50	706	57	466	249
GHH Borsig Turbomaschnen GMBH					
FT8	50/60	32.8	48.6	25.7	7.5
FT8 Twin	50/60	68.9	59.4	51.6	18.5
Ebara Corp.					
FT8 Power	50/60	32.2	48.7	24.7	7.58
FT8 Twin	50/60	65.3	49.2	49.6	15.6
Fiatavio Per L'Energia					
CC130	50	127.2	48.85	50.0	38.6
CC30	60	32.8	52.56	10.2	22.5
Gec Alsthom					
VEGA 105	50/60	38.7	41.9	25.9	13.3
VEGA 209FA	50	705.4	55.5	448.8	265.7
GE Power Systems					
S106B	50/60	59.2	48.6	37.5	22.6
S260	60	105.0	52.4	77	30
Hitachi					
Limited	50/60	69.1	47.6	44.8	24.2
	50/60	471.7	47.6	227.8	118.7

(*Continued*)

Table 6-2. (*Continued*)

Japan Gas Turbine KK					
	50/60	163.8	52.1	105.5	58.3
	50/60	924.4	57.9	465.2	259.2
Kawasaki Heavy Industries Limited					
KA13E2-1	50	238.4	52.0	158.5	79.9
M7A-01	50/60	16.3	41.9	11.0	52.9
Mitsubishi Heavy Industries Limited					
MPCP1(701)	50	194.5	50.5	128.7	65.8
MPCP2(501G)	60	688.9	58.2	455.4	233.5
Mitsui Engineering & Shipbuilding Company					
SB30	50/60	770	38.1	506	264.0
SB120	50/60	32.8	42.4	22.34	10.4
Rolls Royce					
	50/60	36.6	42.2	26.4	11.0
	50/60	655.3	51.9	449.8	221.9
Siemens AG Power Generation Group					
GUD 1.64.3	50/60	90.0	51.5	61	31
GUD 2.94.3A	50/60	705	57	466	249
Solar Turbines					
IPS30	50/60	29	42	20.7	9.2
IPS60	50/60	70.3	42	51.7	22.7
Thomassen International BV					
STEG 106 B-DP	50/60	61.7	50.1	39.2	22.5
STEG-LM160	50/60	52.1	51.9	38.5	13.6
Turbo Power & Marine					
FTB Power Pac	50/60	32.8	49.3	25.0	839.5
FTB Twin Pac	50/60	67.0	50.2	50.4	17.7
Turbotechnical					
CC-201	50/60	28.3	44.5	19.0	10.0
CC-260	50	103.0	51.4	75.2	30.0
Westinghouse Electric Corp.					
RB211	50/60	37.3	50.59	26.2	11.7
701F	50	713.3	55.22	478.0	243.9

and possibly the rest of the gas turbine. Flame-out creates thermal stresses that become critical with each shutdown and re-start.

COMPRESSOR SURGE

The control must also guard against surge during rapid power changes, start-up, and periods of operation when the compressor inlet temperature is low or drops rapidly. The gas turbine is more susceptible to surge at low compressor inlet temperatures.

Normally, changes in ambient temperature are slow compared to the response time of the gas turbine control system. The temperature range from 28°F (-2.0°C) to 42°F (6.0°C) with high humidity is a major concern. Operation in this range can result in ice formation in the plenum upstream of the compressor. Anti-icing schemes increase the sensible heat by introducing hot air into the inlet. Anti-icing is another control function that must address the effect temperature changes can have on compressor surge.

An acceleration schedule loads the unit as quickly as possible. As the load goes from the idle-no-load position to the full-load position, the fuel valve is opened and as the load approaches the setpoint, the speed governor begins to override the acceleration schedule output until the fuel valve reaches its final running position. During this time the temperature limit controller and the pressure limit controller monitor temperatures and pressures so that the preset levels are not exceeded.

The temperature limit controller for turbine inlet temperature uses the average of several thermocouples taking temperature measurements in the same plane. When the temperature or pressure reaches its setpoint, the limit controller will override the governor controller and maintain operation at a constant temperature or pressure. The control allows the operating point to move along a set of points that define the operating line for the load conditions.

A protection controller continuously checks the speed, temperature, and vibration for levels that may be harmful to the operation of the unit. Usually two levels are set for each parameter, an alarm level and a shutdown level. When the alarm level is reached, the system provides a warning that there is a problem. If the transition from alarm to shutdown condition takes place too rapidly and operational response is not possible, the unit is automatically shutdown. Overspeed is one parameter that does not include an alarm signal.

Turbine inlet temperature is the most frequently activated limiting factor. One level is set for base load operation and a higher level is set for peaking operation.

AUXILIARY EQUIPMENT

Auxiliary turbine equipment includes the starting system, ignition system, lubrication system, air inlet cooling system, water or steam injection system for NO_x control or power augmentation and the ammonia injection system for NO_x control.

These systems may be direct driven and connected directly to the shaft of the gas turbine. In most cases, one of the lubrication pumps is direct connected. Indirect drives use electric, steam, or hydraulic motors for power. Indirect drives allow redundant systems, increasing the reliability. Electric systems are powered by a directly driven electric generator.

Starting systems may drive the gas generator directly or through a gearbox. Starters may be diesel or gas engine, steam or gas turbine, electric, hydraulic, or pneumatic air or gas. The starter must rotate the gas generator until it reaches its self-sustaining speed and drive the gas generator compressor to purge the gas generator and the exhaust duct of volatile gases before initiating the ignition cycle. The starting sequence engages the starter, purges the inlet and exhaust ducts, energizes the ignitors and switches the fuel on.

The starting system must accelerate the gas generator from rest to a speed just beyond the self-sustaining speed of the gas generator. The starter must develop enough torque to overcome the drag torque of the gas generator's compressor and turbine, the attached load including accessories and bearing resistance. The single shaft gas turbines with directly attached loads used in electric generators represent the highest starting torque.

Another function of the starting systems is to rotate the gas generator, after shutdown, to begin cool down. The purge and cooldown functions have resulted in the use of two-speed starters. The lower speed is used for purge and cooling and the higher speed is used to start the unit.

Gas generators are started by rotating the compressor. The starter may be directly connected to the compressor shaft or indirectly connected with an accessory gearbox or impingement air may be directed into the compressor-turbine. Starters for gas generators include alternating current and direct current motors, pneumatic motors, hydraulic motors, diesel motors and small gas turbines.

If alternating current (AC) power is available, three-phase induction type motors are preferred as drivers. The induction motors is directly connected to the compressor shaft or the starter pad of the accessory gearbox. Once the gas generator reaches self-sustaining speed, the motor is de-energized and usually disengaged through a clutch mechanism.

If AC power is not available (black start applications), direct current (DC) motors are used. The source of power is a battery bank. One approach is to convert the DC motor electrically into a electric generator to charge the battery system. This is useful where the battery packs are also used to provide power for other systems. Battery-powered DC motor starters are mostly used in small, self-contained gas turbines under 500 brake horsepower (BHP).

Electric motors require explosion proof housings and connectors and must be rated for the area classification in which they are installed. Typically this is Class 1, Division 2, Group D.

Pneumatic starter motors may be the impulse-turbine or vane pump type. These motors use air or gas as the driving force, and are coupled to the turbine accessory drive gear with an overriding clutch. The overriding clutch mechanism disengages when the drive torque reverses and the gas turbine self-accelerates faster than the starter. Then, the air supply is shut-off. Air or gas must be available at approximately 100 psig and in sufficient quantity to sustain starter operation until the gas generator exceed self-sustaining speeds.

If a continuous source of air or gas is not available, banks of high and low pressure receivers and a small positive displacement compressor can provide air for a limited number of start attempts. The starting system should be capable of three successive start attempts before the air supply system must be recharged. In gas pipeline applications, the pneumatic starter may use pipeline gas as the source of power.

Hydraulic pumps can provide the power to drive hydraulic motors or hydraulic impulse turbine, Pelton Wheel starters. Hydraulic systems are often used with aircraft derivative gas turbines.

Large heavy frame, 25,000 SHP and above, gas turbines require high torque starting systems. Most of these units are single shaft machines and the starting torque must be sufficient to overcome the mass of the gas turbine and the driven load. Diesel motors are preferred for these large gas turbines. Since diesel motors cannot operate at gas turbine speeds, a speed increaser gearbox is used to boost the diesel motor starter speed to gas turbine speeds. Diesel starters are usually connected to the compressor shaft. Besides the speed increaser gearbox, a clutch mechanism is needed to insure that the starter can be disengaged from the gas turbine. Diesel motors can run on the same fuel as the gas turbine, eliminating the need for separate fuel supplies.

Small gas turbines may be used to provide the power to drive either pneumatic or hydraulic starters. In aircraft, a combustion starter, which is essentially a small gas turbine, is used to start the gas turbine in remote locations. They are not used in industrial applications.

Impingement starting uses jets of compressed air piped to the compressor turbine to rotate the gas generator. The pneumatic power source for impingement starting is similar to air starters.

Ignition is only required during start-up. Once the unit has accelerated to self-sustaining speed the ignition system can be de-energized. The ignition system is not energized until the gas generator reaches cranking speed and remains at this speed long enough to purge volatile gases from the engine and exhaust duct.

When the igniters are energized, fuel can then be admitted into the combustor. These two functions are often done simultaneously and called pressurization.

Two igniters are usually used, one on each side of the engine. During the start cycle each igniter discharges about 2 times per second and provides an energy pulse of 4 to 30 joules. A joule is the unit of work or energy transferred in one second by an electric current of one ampere in a resistance of one ohm. One joule/second equals one watt.

Once the gas generator starts the igniter is no longer needed and any further exposure to the hot gases of combustion shortens its life. Some igniter are spring loaded and retract out of the gas path as the combustion pressure increases.

The potential at the spark plug is about 25,000 volts. The ignition harness to each igniter plug is shielded and the ignition exciter is hermetically sealed.

Ignition systems include inductive and capacitive AC and DC, with high and low tension systems. The capacitive systems generate the hottest spark. Since the energy stored in the capacitor is proportional to the square of the voltage, it is more economical to use a high voltage to charge the capacitor. A radio frequency interference filter is used to prevent ignition energy from affecting local radio signals.

An AC transformer, or transistorized chopper circuit transformer, boosts the voltage to about 2,000 volts in the low tension system (Figure 6-6). A rectifier allows the flow of current into the storage capacitor but prevents most of the return flow. This voltage is boosted up to charge a smaller high tension capacitor.

The low voltage charge in the storage capacitor is not enough to jump the gap across the spark plug electrodes. The initial path is provided by a higher voltage discharge from the high tension capacitor (Figure 6-7). It discharges first to bridge the gap across the electrodes of the spark plug and reduces the resistance for the low tension discharge. The low tension capacitor then discharges providing a long, hot spark.

The inductive ignition system uses the rapid variation in magnetic flux in an inductive coil to generate enough energy for the spark (Figure

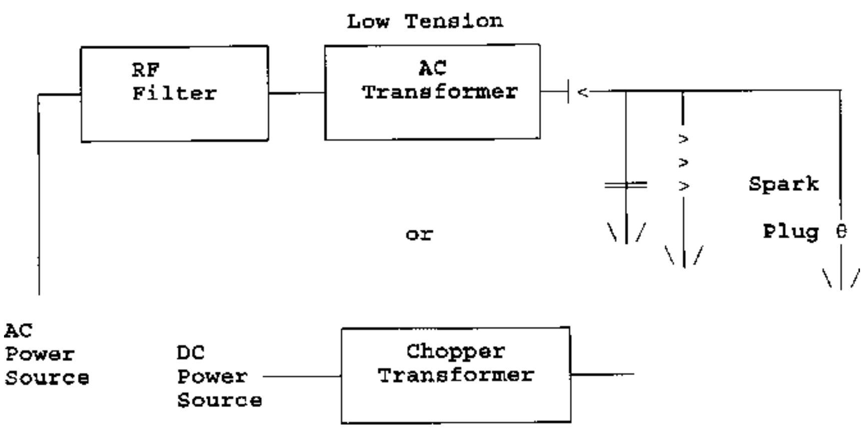

Figure 6-6. Low voltage ignition system

6-8). This system produces a high voltage spark, but the energy is relatively low and is only suitable for easily ignitable fuels.

Ignitor plugs use an annular-gap or constrained-gap. The annular-gap plug projects slightly into the combustor, while the constrained-gap plug is positioned in the plane of the combustor liner and operates in a cooler environment.

Lubrication systems provide lubrication between the rotating and stationary bearing surfaces and remove excessive heat from those surfaces. The bearings may be hydrodynamic or anti-friction types. The lubrication in a hydrodynamic bearing converts sliding friction into fluid friction. Anti-friction bearings work on rolling friction. The shaft load is

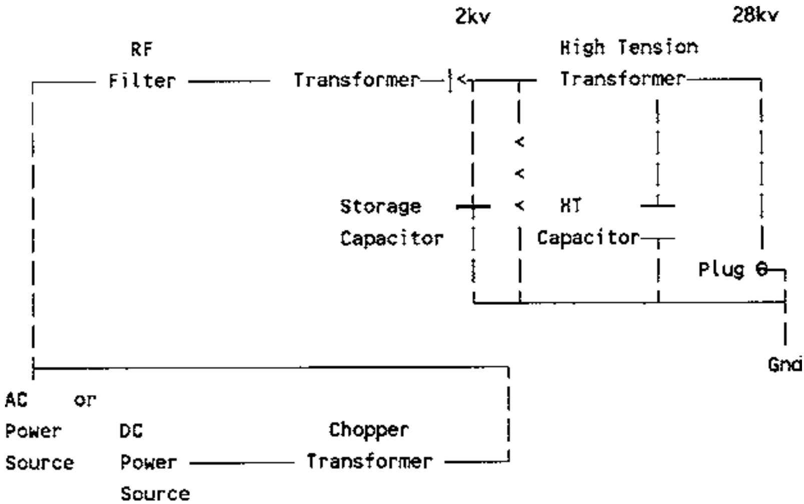

Figure 6-7. High energy capacitor ignition system

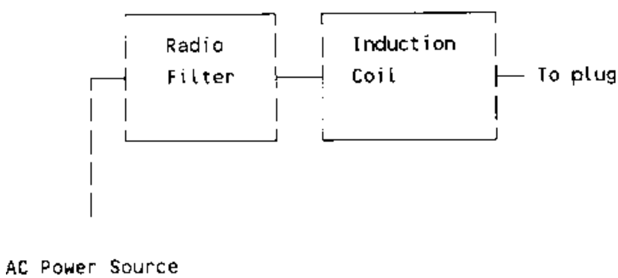

Figure 6-8. DC inductive-type ignition system

supported by the rolling elements and races in a metal-to-metal contact.

Most heavy frame gas turbines use hydrodynamic bearings with mineral oil while the aircraft derivative gas turbines use anti-friction bearings with a synthetic oil. Mineral oils are distilled from petroleum crude oils and are generally less expensive than synthetic lubricants. Synthetic lubricants do not occur naturally but are made by reacting organic chemicals, such as alcohol or ethylene with other elements. Synthetic lubricants are used in high temperature applications of less than 350°F (175°C) or where fire-resistant qualities are required.

The bearings in gas turbines are lubricated by a pressure circulating system. This consists of a reservoir, pump, regulator, filter, and cooler. Oil in the reservoir is pumped under pressure through a filter and oil cooler to the bearings and then returned to the reservoir for re-use. In cold climates a heater in the reservoir warms the oil prior to start-up.

The reservoir also serves as a deaerator. As the lubrication oil moves through the bearings, it can entrap air in the oil. This results in oil foaming. The foam must be removed before the oil is returned to the pump or the air bubbles can result in pump cavitation. To deaerate the oil the reservoir surface area must be large enough so screens and baffles may also be built into the reservoir.

Filters are used to remove bearing wear particles from the oil. While 5 or 10 micron filters can be used for running conditions, 1 to 3 micron filters are used for break-in periods or after overhauls. Redundant oil filters are used along with a three-way-transfer valve. If the primary filter clogs, the transfer valve is switched over to the clean filter.

Wear particles from the pump and gas turbine bearings will accumulate in the filter element along with temperature related oil degradation and oil additives. This can create a sludge that accumulates in the filter. As the filter clogs, the differential pressure across the filter increases. Instrumentation includes a pressure differential gauge for local readout, and a differential pressure transducer for remote readout and alarm. The differential pressure alarm setting is typically 5 psig.

Regulators are used to maintain a constant pressure level in the lube system. These regulators allow the operation of a secondary pump for preventive maintenance.

Lube oil coolers remove heat from the oil before it is re-introduced into the gas turbine. The amount of cooling required depends on the friction heat generated in the bearings, heat transfer from the gas turbine to the oil by convection and conduction and heat transfer from the hot gas path through seal leakage. The oil is cooled to 120°F-140°F (50°C-60°C). To maximize the heat transfer, fins are installed on the outside of tubes and turbulators are placed inside each cooling tube. The turbulators help to transfer heat from the hot oil to the inner wall of the cooling tubes and the fins help dissipate this heat. Cooling media may be either air or a water/glycol mix. Air/oil coolers are used in desert regions, while tube and shell coolers are found in the Arctic regions and most coastal regions.

Air/oil coolers use ambient air as the cooling media. Cooling fans are usually electric motor driven, often with two speed motors. This allows high and low cooling flows. To closely match the cooling flow to the required heat load, changeable pitch fan blades may be used. As the heat load changes, the blades can be adjusted to meet the new heat flow requirements. Air/oil coolers may also include top louvers to protect the cooling coils from hail. These louvers are not effective for temperature control.

ENERGY EFFICIENT COGENERATION SYSTEMS

Cogeneration can offer an effective way to conserve energy while reducing energy costs. However, a cogeneration plant is capital intensive and the matching process is critical. Development is both plant-specific and site-specific.

An industry may use fossil fuel to produce heat and will buy electricity from the local utility. The fuel will be burned to produce hot gases for direct applications, such as drying or indirect applications such as steam generators or boilers and combustion engines doing mechanical work, such as gas turbines.

In all of these conversion processes, only a part of the original heat content of the fuel is utilized. The remainder is rejected. Unless this reject heat is put to good use, it can contribute only to global entropy increase.

Combustion gases are carriers of energy and supply the conversion equipment with available heat. This is the heat content which can be converted to work by reducing the temperature of the carrier medium.

STEAM TURBINES

One of the most common methods of cogenerating electricity involves using excess steam from industrial processes (Figure 6-9). Steam turbines are popular drives for rotary equipment and are second only to electric motors. Some steam turbines can only be used for constant speed applications because of the characteristics of their steam supply valves. Their governors are not suitable for throttling.

Steam turbines are energy conversion machines. They extract energy from steam and convert it into shaft energy. Sizes range from a few kW to over 1000-MW. Rotational speeds vary from 1,800 to 12,000 rpm. Gas turbines run at speeds up to 18,000 rpm when driving a compressor or generator.

The amount of energy that can be extracted from the steam depends on the enthalpy drop across the machine. The enthalpy of the steam in turn depends on the temperature and pressure. In order to operate at maximum efficiency, the steam should hit the turbine blades at sonic velocities. The efficiency of steam turbines increases with size, the superheat temperature of the steam and the degree of vacuum at the turbine exhaust.

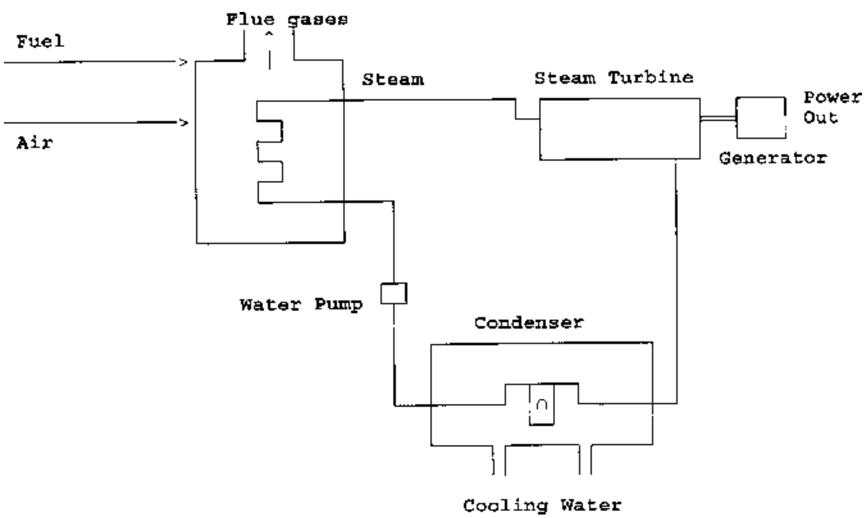

Figure 6-9. Conventional steam turbine

Steam turbines may be condensing or noncondensing. In condensing turbines the steam is condensed at the exhaust of the turbine. The exhaust pressure is subatmospheric. In systems with these turbines, the steam used for process must be extracted before the turbine's exhaust. Extraction valves are used to supply the process steam.

Noncondensing turbines produce power by operating as a pressure reducer. Noncondensing units are also called backpressure units where the exhaust pressure is greater than atmospheric. The turbine exhaust becomes low pressure process steam. Noncondensing turbines are less expensive to buy and operate, since the energy is extracted from the steam while it has a higher enthalpy and smaller volume per unit of energy. This reduces the size of the turbine.

Turbines may have a steam flow that is described as axial or radial and a small number even have tangential flow. A unit may be single-stage or multistage. The number of parallel exhaust stages can also be used to describe turbines such as single or double flow.

Generating electricity in these systems depends on steam flow which may not increase or decrease to meet the demanded load. In a condensing turbine system, the boiler pressure can be increased to provide enough electricity to meet the demand. Condensing turbines are not usually available smaller than 5,000 kW, since they are less efficient than noncondensing units. The heat of the steam is lost once it leaves the turbine. They are also more expensive.

The cost range for a 1-MW steam turbine is about $130-330/kW. For 25-MW turbines this drops to less than $100/kW. These costs are for noncondensing systems without peripheral items, such as piping and electrical switchgear. They do include turbines, generators, baseplates and lube systems. Maintenance for these systems usually runs about 0.3 to 0.4 cents per kilowatt hour.

Electricity generated by steam turbine cogeneration systems can be about 1/3 less expensive than electricity from a utility. Steam turbine cogeneration systems are generally not cost efficient below the 1-MW range. Systems above 20-MW have been popular for many years, because of their cost savings.

BIOFUELS

Biofuels come from biomass products which may be energy crops, forestry and crop residues and even refuse. One feature of biofuels is that 3/4 or more of their energy is in the volatile matter or vapors unlike coal, where the fraction is usually less than half. It is important that the furnace or boiler ensure that these vapors burn and are not lost.

For complete combustion, air must reach all the char, which is achieved by burning the fuel in small particles. This finely-divided fuel means finely-divided ash particulates which must be removed from the flue gases.

The air flow should be controlled. Too little oxygen means incomplete combustion and leads to the production of carbon monoxide. Too much air is wasteful since it carries away heat in the flue gases. Modern systems for burning biofuels include large boilers with megawatt outputs of heat.

Direct combustion is one way to extract the energy contained in household refuse, but its moisture content tends to be high at 20% or more and its energy density is low. A cubic meter contains less than 1/30 of the energy of the same volume of coal.

Refuse-derived fuel (RDF) refers to a range of products resulting from the separation of unwanted components, shredding, drying and treating of raw material to improve its combustion properties. Relatively simple processing can involve separation of large items, magnetic extraction of ferrous metals and rough shredding. The most fully processed product is known as densified refuse-derived fuel (d-RDF). It is the result of separating out the combustible part which is then pulverized, compressed and dried to produce solid fuel pellets with about 60% of the energy density of coal.

Anaerobic digestion, like pyrolysis, occurs in the absence of air. But, the decomposition is caused by bacterial action rather than high temperatures. This process takes place in almost any biological material, but it is favored by warm, wet and airless conditions. It occurs naturally in decaying vegetation in ponds, producing the marsh gas that can catch fire.

Anaerobic digestion also occurs in the biogas that is generated in sewage or manure as well as the landfill gas produced by refuse. The resulting gas is a mixture consisting mainly of methane and carbon dioxide.

Bacteria breaks down the organic material into sugars and then into acids which are decomposed to produce the gas, leaving an inert residue whose composition depends on the feedstock.

The manure or sewage feedstock for biogas is fed into a digester in the form of a slurry with up to 95% water. Digesters range in size from a small unit of about 200 gallons to ten times this for a typical farm plant and to as much as 2000 cubic meters for a large commercial installation. The input may be continuous or batch. Digestion may continue for about 10 days to a few weeks. The bacterial action generates heat but in cold climates additional heat is normally required to maintain a process temperature of about 35°C.

A digester can produce 400 cubic meters of biogas with a methane content of 50% to 75% for each dry ton of input. This is about 2/3 of the fuel energy of the original fuelstock. The effluent which remains when digestion is complete also has value as a fertilizer.

A large proportion of municipal solid wastes (MSW), is biological material. Its disposal in deep landfills furnishes suitable conditions for anaerobic digestion. The produced methane was first recognized as a potential hazard and this led to systems for burning it off. In the 1970s some use was made of this product.

The waste matter is miscellaneous in a landfill compared to a digester and the conditions not as warm or wet, so the process is much slower, taking place over years instead of weeks. The product, called landfill gas (LFG), is a mixture consisting mainly of CH_4 and CO_2.

A typical site may produce up to 300 cubic meters of gas per ton of wastes with about 55% by volume of methane. In a developed site, the area is covered with a layer of clay or similar material after it is filled, producing an environment to encourage anaerobic digestion. The gas is collected by pipes buried at depths up to 20 meters in the refuse.

In a large landfill there can be several miles of pipes with as much as 1000 cubic meters an hour of gas being pumped out. The gas from landfill sites can be used for power generation. Some plants use large internal combustion engines, standard marine engines, driving 500-kW generators but gas turbines could give better efficiencies.

Methanol can be produced from biomass by chemical processes. Fermentation is an anaerobic biological process where sugars are converted to alcohol by micro-organisms, usually yeast. The resulting alcohol is ethanol. It can be used in internal combustion engines, either directly in modified engines or as a gasoline extender in gasohol. This is gasoline containing up to 20% ethanol.

One source of ethanol is sugarcane or the molasses remaining after the juice has been extracted. Other plants such as potatoes, corn and other grains require processing to convert the starch to sugar. This is done by enzymes.

The fuel gas from biomass gasifiers could be used to operate gas turbines for local power generation. A gas-turbine power station is similar to a steam plant except that instead of using heat from the burning fuel to produce steam to drive the turbine, it is driven directly by the hot combustion gases. Increasing the temperature in this way improves the thermodynamic efficiency, but in order not to corrode or foul the turbine blades the gases must be very clean which is why many gas-turbine plants use natural gas.

In systems where the wastes from processing vegetable material provide the input, process heat (hot steam) as well as electric power may be the output. For these systems the steam-injected gas turbine (STIG) is well-suited.

This type of turbine is driven by both combustion gases and high-pressure steam and can operate with flexibility by responding to varying demands for heat. The total system is a biomass integrated gasifier/steam-injected gas turbine.

Advances in gas turbine technology have been driven by the aircraft industry, and the development of reliable gasification systems for clean coal combustion, have resulted in these flexible biomass electricity systems of 20-100-MW.

Steam-injected gas turbines appeared in the U.S. in the 1980s (Figure 6-10). Originally, they were fired by natural gas and then adapted for the gas from coal gasification. An advanced form of this technology is intercooled steam injection. Conventional sugar mills can generate 15-25-kWh of electricity per ton of cane crushed. Electricity generation with steam turbines can produce up to 100-kWh per ton of cane. Steam injection technology can boost this to 280-kWh a ton.

One 37-MW combined-cycle gas turbine system based on conventional combined-cycle gas turbine technology and an air-blown Ahistrom gasifier should achieve a 42% overall conversion efficiency.

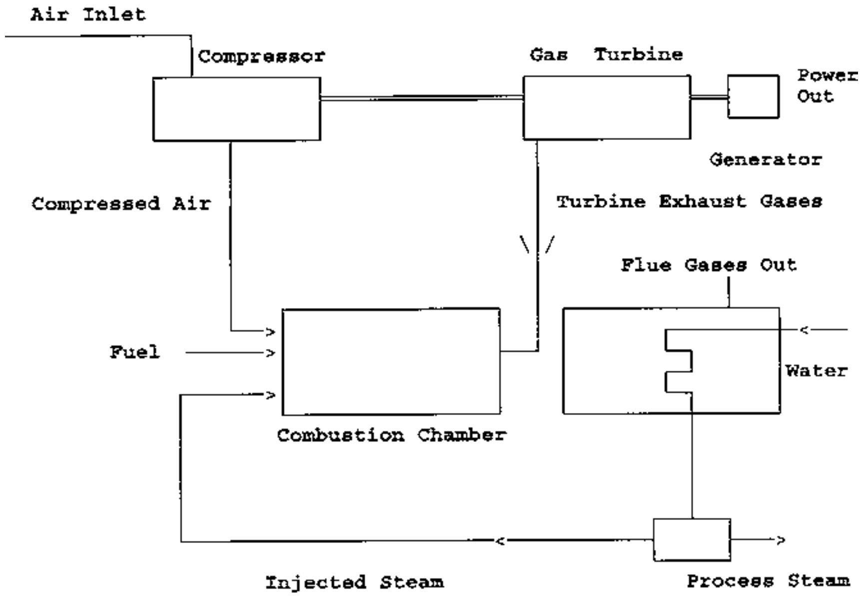

Figure 6-10. Steam-injected gas turbine

GASIFICATION

Gasification includes a range of processes where a solid fuel reacts with hot steam and air or oxygen to produce a gaseous fuel (Figure 6-11). There are several types of gasifiers, with operating temperatures ranging from a few hundred to over a 1000°C, and pressures from near atmospheric to as much as 30 atmospheres.

The resulting gas is a mixture of carbon monoxide, hydrogen, methane, carbon dioxide and nitrogen. The proportions depend on the processing conditions and if air or oxygen is used.

Gasification is not new. Town gas is the product of coal gasification and was widely used for many years before it was displaced by natural gas. Many vehicles towing wood gasifiers as their fuel supply were used in World War II.

The growth of interest in biomass gasification in recent years may result in a fuel which is much cleaner than the original biomass, since undesirable chemical pollutants can be removed during the processing, together with the inert matter which produces particulates (smoke) when

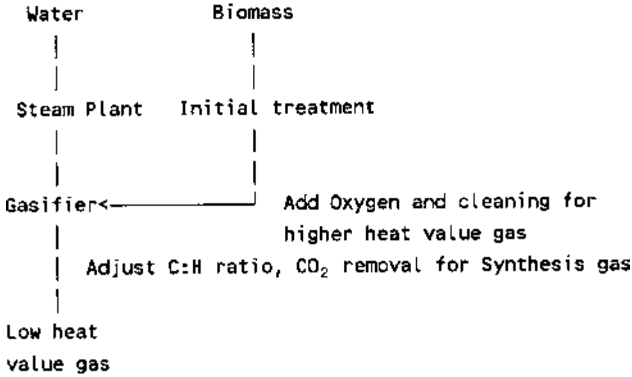

Figure 6-11. Gasification process

the fuel is burned. The resulting gas is a much more versatile fuel. Besides direct burning for heating, the gas can also be used in internal combustion engines or gas turbines. Gasification under the proper conditions can also produce synthesis gas, a mixture of carbon monoxide and hydrogen which can be used to synthesize almost any hydrocarbon.

The simplest process results in gas containing up to 50% by volume of nitrogen and CO_2. Since these have no fuel value, its energy is only a few megajoules per cubic meter or about a tenth of that of methane, but it is a clean fuel.

Pyrolysis is the simplest and probably the oldest method of processing one fuel in order to produce a better one. Conventional pyrolysis involves heating the original material in the near-absence of air, typically at 300-500°C, until the volatile matter has been driven off. The residue is commonly known as charcoal, a fuel which has about twice the energy density of the original and burns at a much higher temperature.

In much of the world today, charcoal is produced by pyrolysis of wood. Depending on the moisture content and the efficiency of the process, 4-10 tons of wood are required to produce one ton of charcoal, and if no attempt is made to collect the volatile matter, the charcoal is obtained at the cost of perhaps two-thirds of the original energy content.

In more sophisticated pyrolysis techniques, the volatiles are collected, and careful control of the temperature controls their composition. The liquid product can be used as fuel oil, but is contaminated with acid and must be treated before use. Fast pyrolysis of plant material, such as wood or nutshells, at temperatures of 800-900°C converts about 10% of the material to solid charcoal and about 60% into a gas of hydrogen and carbon monoxide. Lower temperatures allow fewer potential pollutants are emitted than in full combustion. Small-scale pyrolysis plants have been used for treating wastes from the plastics industry as well as disposing of used tires.

A gasifier which uses oxygen instead of air produces a gas that consists mainly of H_2CO and CO_2. Removing the CO_2 leaves a mixture called synthesis gas, from which almost any hydrocarbon compound may be synthesized including methane with an energy density of 23-GJ per ton.

Methanol can be used as a substitute for gasoline. The technology has been developed for use with coal as the feedstock by coal-rich countries at times when their oil supplies were threatened.

COMBINED CYCLE TECHNOLOGY

The conversion of coal to a gaseous fuel can be done using coal gasification. Then the application of combined cycle technology can be used for the production of power using the coal gas. This is called integrated gasification-combined-cycle (IGCC).

Most recent domestic powerplants are based on either simple or combined cycle natural gas fueled combustion turbines. Coal-fired powerplants are still a major source of power worldwide. The emissions produced by coal combustion have led to environmental concerns. This has led to the installation of flue gas scrubbers in conventional coal-fired powerplants.

IGCC is a power source concept which is not only more acceptable from an environmental standpoint, but also provides higher efficiency. Applying combined cycle technology to power production from coal requires conversion of coal to a gaseous fuel via a coal gasification process. Coal gasification processes involve partial combustion of the coal to provide energy for further conversion of the coal into a gaseous fuel. This fuel's primary components are carbon monoxide, hydrogen and nitrogen.

In a coal gasification system, partial combustion takes place in the gasifier and is completed in the gas turbine combustors. Particulates and sulfur are removed by cyclones and a HGCU unit between these stages. The final fuel arriving at the machine, although of low heating value, requires relatively few changes to the gas turbine.

An IGCC system is used at the Sierra Pacific Power Company's Pinon Pine Powerplant. It includes the integration of an advanced technology gas turbine in an air-blown gasifier. This 800-ton-per-day air-blown integrated gasification combined cycle plant is at the Sierra Pacific Power Company's Tracy Station near Reno, Nevada. A General Electric MS6001FA gas turbine/air-cooled generator and steam turbine/ TEWAC generator is used with a combined cycle output of about 100-MW.

This was the first air-blown IGCC powerplant to incorporate an F-technology gas turbine generator. This type of combustion turbine has a high combined cycle efficiency which enhances the economics of an IGCC application.

A simplified IGCC system incorporates air-blown gasification with hot gas cleanup. This eliminates the oxygen plant and minimizes the need for gas cooling and wastewater processing equipment. The existing Tracy Station is a 400-MW, gas/oil-fired power generation facility about 20 miles east of Reno at an elevation of 4280 feet above sea level.

A Kellogg-Rust-Westinghouse (KRW) ash-agglomerating fluidized-bed gasifier operates in the air-blown mode and is coupled with hot gas cleanup (HGCU) will provide a low heating value fuel gas to power the combustion turbine. High temperature exhaust from the combustion turbine supplies the energy required to generate steam in a heat recovery steam generator (HRSG) for use in a steam turbine. Both the combustion turbine and the steam turbine drive generators supply approximately 100-MW of power to the electric grid.

The pressurized (20 bars) KRW gasifier has in-bed desulfurization, external regenerable sulfur removal and fine particulate filters. Advanced KRW gasification technology produces a low-Btu gas with a heating value of approximately 130 Btu/SCF. This is used as fuel in the combined-cycle powerplant, and includes hot gas removal of particulates and sulfur compounds from the fuel gas. Desulfurization is accomplished by a combination of limestone fed to the gasifier and treatment of the gas in desulfurization vessels using a zinc-based sulfur sorbent such as Z-Sorb.

Particulates are removed by a pair of high-efficiency cyclones and a barrier filter. These operations are carried out at the elevated temperature of approximately 1000°F (538°C) to eliminate thermodynamic inefficiency and the costs of cooling and cleaning the gas at low temperature, which is done in most IGCC systems. Since the water vapor is not condensed in the hot gas cleanup process, water effluents are reduced and contain only feed water treatment effluent and boiler and cooling tower blow down.

Sub-bituminous coal is received at the plant from a unit train consisting of approximately 84 railcars of between 100- and 110-ton capacity, arriving approximately once a week. Coal is received at an enclosed unloading station and transferred to a coal storage dome. The unloading station has two receiving hoppers, each equipped with a vibrating-type unloading feeder that feeds the raw coal conveyor systems.

The steam turbine is a straight condensing unit with uncontrolled extraction and uncontrolled admission. The steam conditions are 950 psia (65.5 Bars), 248°F (510°C) inlet, with exhaust at 0.98 psia (66m Bars). The uncontrolled extraction pressure is 485 psia (33.4 Bars), and the uncontrolled admission is 54 psia (3.7 Bars). The turbine has 26 inch (0.66m) last stage buckets in an axial exhaust configuration. The turbine is baseplate mounted, with a combined lubrication and control system mounted on a separate console. The control is a GE Mark V Simplex system. The generator is a baseplate mounted GE TEWAC unit rated at 59000 kVA at 0.85 power factor.

The gas turbine is a General Electric MS600FA. It is aerodynamically scaled from the larger MS7001FA machine. Key characteristics of the FA cycle are the 235°F (1288°C) firing temperature allowing high combined cycle efficiencies and the ability of the combustion system to burn a wide spectrum of fuels.

The MS6001FA has a compressor or cold-end drive flange, turning an open-ventilated GE 7A6 generator (82000 kVA @ 0.85PF) through a reduction load gear. The exhaust is an axial design directing the gas flow into the HRSG.

The MS6001FA uses an axial flow compressor with 18 stages, the first two stages are designed to operate in transonic flow. The first stator stage is variable. Cooling, sealing and starting bleed requirements are handled by 9th and 13th stage compressor extraction ports.

The rotor is supported on two tiltpad bearings. It is made up of two subassemblies, the compressor rotor and turbine rotor, which are bolted together. The 16-bladed disks in a through-bolted design provide stiffness and torque carrying capability. The forward bearing is carried on a stub shaft at the front of the compressor.

The three-stage turbine rotor is a rigid structure with wheels separated by spacers with an aft bearing stub shaft. Cooling is provided to wheel spaces, all nozzle stages and bucket stages one and two.

The main auxiliaries are motor driven and arranged in two modules. An accessory module contains lubrication oil, hydraulic oil, atomizing air, natural gas/doped propane skids and bleed control valves. The second module would normally house liquid fuel delivery equipment but in this application, holds the syngas fuel controls. A fire resistant hydraulic system is used for the large, high temperature syngas valves.

The fuel system is designed for operation on syngas, natural gas or doped propane. Only natural gas or doped propane can be used for start up with either fuel delivered through the same fuel system. Once the start is initiated it is not possible to transfer between natural gas and doped propane until the unit is on-line.

A full range of operation from full-speed/no-load to full-speed/full-load is possible on all fuels. Transfers, to or from syngas, can take place down to 30% of base load. This maintains a minimum pressure ratio across the fuel nozzle preventing the transmission of combustor dynamics or cross-talk between combustors. Cofiring is also possible with the same 30% minimum limit apply to each fuel. A low transfer load also minimizes the amount of syngas flaring required.

The gasifier has a fixed maximum rate of syngas production. At low ambient temperatures, fuel spiking is needed to follow gas turbine output.

The MS6001FA gas turbine can accept a limited amount of natural gas mixed with the syngas, to boost the Btu content. In this application the maximum expected is about 8% and an orifice in the natural gas mixing line will limit supply to 15% in the event of a valve malfunction. This protects the gas turbine from surges in the combustor. On hot days power augmentation can be achieved with steam injection or evaporative coolers.

The natural gas/doped propane fuel system, uses a modulating stop ratio valve to provide a constant pressure to a critical flow control valve. The position of the valve is then modulated by the speed control to supply the desired fuel flow to the combustors. When not in use, the natural gas/ doped propane system is purged with compressor discharge air.

Syngas is supplied from the gasifier at a temperature and pressure of approximately 1000°F (538°C) and 240 psia (16.5 Bars). The values depend on the operating conditions.

The specific heating value of the syngas can vary, so the delivery system is sized to accommodate the resulting volumetric flow changes. The low Btu content and elevated temperature of the syngas mean that large volumes of gas are needed. Flow from the gasifier takes place in a 16-inch (41cm) diameter pipe with a 12-inch (30cm) diameter manifold supplying syngas to the six combustors via 6-inch (15cm) diameter flexible connections. In contrast, the corresponding figures for natural gas are 4 (10), 3 (7.6cm) and 1.25 inches (3.1cm).

Syngas at 1000°F (538°C) burns spontaneously when in contact with air. The fuel system is designed to eliminate syngas-to-air interfaces. Both steam and nitrogen purging and blocking systems may be used.

Nitrogen has been used as a purge medium in other IGCC applications. While operating on syngas, nitrogen would be supplied at a pressure higher than the syngas and would use a block and bleed strategy to prevent contact with the purge air supply. Operating on natural gas, the syngas would be blocked by an additional stop valve and a stop ratio valve. The nitrogen purge valves open to flush syngas from the entire system downstream of the stop valve, and then close. Compressor discharge air is then used to purge the line from the control valve to the combustor while nitrogen provides a block and bleed function between the control valves. Sequencing of the valves maintains separation between syngas and air.

The turbine uses a reverse flow can-annular combustion arrangement typical of GE heavy duty gas turbines. There are six combustors, equally spaced and angled forward from the compressor discharge case. Compressor discharge air flow over and through holes in the impingement sleeve provide cooling to the transition piece. The remainder of the flow passes through holes in the flow sleeve. The air then flows along the annulus formed by the case and the liner.

The combustor uses conventional film cooling. Fuels and dilutents are introduced through nozzles in the end cover. The combustor is the diffusion type.

A dual gas end cover is used with large syngas nozzles and natural gas/doped propane nozzles for the alternate fuel. Steam injection nozzles are used for power augmentation at high ambient temperatures and NO_x control.

The combustion cases have provisions for flame detectors and cross-fire tubes, along with extraction ports to supply compressor discharge air to the gasifier.

CONTROL SYSTEM

The plant is controlled by a Distributed Control System (DCS). The turbine control system interfaces with the DCS. The natural gas/doped propane fuel system provides a signal which indicates which fuel is in use. Logic in the control system makes the necessary specific gravity adjustments for fuel flow measurement.

The syngas control system provides an integrated control system for the syngas boost compressor and the gas turbine to minimize fuel supply delivery pressure losses. The boost compressor raises the compressor extraction pressure prior to the gasifier. After the gasifier, fuel is metered to the gas turbine through the stop ratio and gas control valves. Pressure drops through these valves are minimized by controlling them to the full open position during normal control operation. In this way the system operates at the minimum pressure drop and controls the gasifier flow via the boost compressor by controlling the gas turbine output. When the fuel flow is not meeting demand, a signal is sent to the gasification control panel, which translates this input to the necessary response from the boost compressor/gasifier. Syngas output is increased or decreased as demanded while the stop ratio and gas control valves remain wide open.

The control handles fuel transfers, co-firing, purge/extraction valve sequencing, steam injection, surge protection along with the standard gas turbine control functions.

WASTE HEAT GAS TURBINES

Gas turbines are used for cogeneration in refineries. The fuels used to generate steam, in most cases, are generated internally in the refinery.

These fuels vary seasonally and are subject to the particular seasonal mix demanded by the market. The primary use of steam is for pumping and compression.

Just outside of Athens, Greece, at the Motor Oil Refinery in Corinth and the Hellenic Refinery in Aspropyrgos are two plants that have been in operation since 1985 and 1990, with a total of 140,000 and 55,000 operating hours.

Today, more refineries are finding savings in overlooked areas within their processing plants. The effort is focused on how to use by-products. The preferred solution is in-plant cogeneration systems. The refinery cogeneration plants are saving energy and satisfying growing environmental concerns. Refinery requirements for electric power and heat are being met with cogeneration systems consisting of one or more gas turbine-generators and heat recovery steam generators (HRSGs) which utilize the gas turbine waste heat. The generated steam is used either for additional power generation and/or process heat for refinery applications. The refinery must tailor its products to market demand and the gas turbine units must be operated with varying types of fuel, liquid to gaseous, or both simultaneously. The quality, calorific value, viscosity may vary as well as changing electrical and process heat demands. The units can utilize multiple fuels of changing quality and calorific value, including the waste gases derived from the refining process.

Medium size gas turbines are suited for industrial cogeneration, because they are compact, heavy-duty industrial machines with proven reliability and efficiency. The GT10B is rated at 24.6-MW with a simple cycle Heat Rate of 9,970 Btu/kWh. The GT35 is rated at 16.9-MW with a simple cycle heat rate of 10,665 Btu/Wh. Both gas turbines have NO_x emissions of 25 ppm with natural gas fuel.

The refinery near Corinth is about a 1-hour drive north of Athens. The refinery was installed in 1972 and is a medium size refinery with sophisticated conversion; fluid catalytic cracking, alkylation, isomerization, lube oil processing and traditional distillation, reforming and hydrotreating units. The refinery processes 7,500,000 tons of crude oil per year, and produces 150,000 tons/year of lubrication oil.

The cogeneration plant in the early 1980s had several objectives. One was energy conservation using refinery flare gas (11,000 ton/year). Another was to increase productivity by avoiding shut-downs due to the interruption of electrical power. Others were to increase process steam availability using gas turbine exhaust energy and to reduce operating costs and pollution.

In 1985, the refinery cogeneration plant, consisting of two ABB STAL GT35 Gas Turbine-Generator units, was placed in operation. The two gas turbines exhaust into a single two pressure heat recovery steam generator (HRSG) with supplementary firing capability. The combined electrical output of the two units is 27-MW and a total 52 tons/hour of high pressure steam for power generation and 16 tons/hour of low pressure process steam for refinery purposes.

The primary combustion fuel is refinery flare gas originating from different refinery process streams as waste by-products. It consists mainly of propane and butane in varying proportions ranging from 60% to 100% propane and 40% to 0% butane by volume. The by-product flare gas also contains a varying concentration of H_2S, up to a maximum of 10,000 ppm. Even, 20-25 ppm of H_2S concentration is considered a highly corrosive environment for gas turbine applications, but, the GT35 operates at a low hot blade path temperature. The exhaust temperature is 710°F which is below the melting point of sulfur.

The flare gas varies in qualities, pressures and temperature. Its heating value approximates that of natural gas (1,145 Btu/scf). The cogeneration plant back-up fuel is gasified LPG (liquefied petroleum gas) with a heating value of 2,500 Btu/scf.

To use the flare gas for gas turbine combustion, it is deslugged by a liquid trap which separate the liquid phase from the gas stream. It is then processed through a low pressure compressor and the condensates from the compressed fuel gas are further removed by a gas-liquid separator. Then, the combustion fuel gas is raised to a pressure of 330 psia by a high pressure compressor. The fuel gas is fed to the two gas turbines at a temperature of 203-248°F and pressure of 300 psia.

The Corinth cogeneration plant utilizes its by-product (cost-free) flare gases as the primary combustion fuel for the gas turbines. The cogeneration system eliminates costly refinery downtime due to power outages from the local power grid. The cogeneration plant also eliminates the threat of electrical rate hikes.

The cogeneration plant has reduced NO_x emissions to an air quality well below the acceptable limits imposed by the authorities. The plant's noise emission is 52-dBA at 400 feet.

Utilization of the refinery flare gas has produced an accelerated pay back period for this plant of 2.6 years. The net savings from the plant for 1992 were U.S. $8,000,000.

The Hellenic Refinery in Aspropyrgos, Greece, was installed in 1958, with an initial throughput of 8,500,000 tons per year. This is a state-owned refinery that has been modernized over the years both in capacity output and plant efficiency.

A combined cycle/cogeneration plant was placed in operation in 1990. The cogeneration system consists of two GT10 gas turbine-generator units, two dual pressure heat recovery steam generators (HRSG) of the forced circulation type with by-pass stack, and one ABB condensing steam turbine-generator unit. Saturated steam is also produced for general refinery purposes.

The GT10 unit electrical output is 17-MW and the steam turbine-generator is rated at 15-MW. The combined electrical output of the cogeneration system is 49-MW. The generated high pressure steam of 612 psia/760°F from the HRSGs operates the condensing steam turbine-generator set. Each HRSG also produces 18,520 pounds/hour of low pressure steam at 68 psia/342°F for refinery purposes.

The Aspropyrgos cogeneration plant operates normally on refinery flare gas. This fuel has a heating value range of 18,360 Btu/pound to 23,580 Btu/pound, however, heating values of as high as 29,520 Btu/pound have been recorded. The gas turbines are also capable of firing propane, diesel oil and a mixture of the various refinery by-product gas streams. The two turbine units start up on diesel oil.

The refinery installed its own in-plant electrical power and steam plant because of the high price of electrical power and the unreliability of the local electrical power supply. There was also the desire to improve refinery efficiency and plant profitability. The refinery average electrical consumption is 33,300-kW and it exports its excess electrical generation.

Plant reliability has been close to 100% up to its first major inspection. The first major inspection of the two turbines was performed after 25,000 hours of operation (scheduled major inspection is 20,000 operating hours). Unit #2 was inspected and immediately returned by service. More corrosion was found on Unit #1 then expected. It was overhauled, the first two stages of turbine vanes and blades were replaced and cracks in the combustor were field repaired.

Traces of lead, zinc and natrium were found in the gas turbine compressors during the inspection. ABB field service personnel have observed, on occasions, that implosion doors of the air inlet plenums were found to be opened by operators during the plant operation. A metallurgical analysis of the damaged parts indicated that rapid and frequent changes of fuel quality also contributed to damage and cracks in the combustor.

Spare parts and maintenance costs of the two turbines up to the first Major Inspection was U.S. $140,000 for the first 3 years. For a total of 50,000 operating hours at a combined output of 34,000-kW, the service cost comes to less than 0.2 mils/kWhr. The estimated total cost of parts and service of the major inspection of Unit #2 was U.S. $1,120,000, which is equivalent to 2.6 mils/kWhr. The pay back of the plant is estimated at 3.5 years.

In the next several decades natural gas and syngas-fired combined cycle plants are expected to make up as much as 20% of the new electric generating plant additions. Powerplants will utilize techniques such as the atmospheric fluidized bed combustion systems, advanced pressurized fluidized bed combustion systems, integrated gasification-combined-cycle systems, and integrated gasification-fuel cell combined-cycle system.

Many of these will be implemented to facilitate the use of solid fuels such as coal, wood waste and sugar cane waste. The technologies include combined cycle with inlet air cooling, compressor inter-cooling, water or steam injection and the use of water or steam to internally cool turbine airfoils to enhance gas turbine performance and output.

Advances in aircraft engine technology such as airfoil loading, single crystal airfoils, and thermal barrier coatings are being transferred to industrial gas turbines. Improvements in power output and efficiency depends mainly on increases in turbine inlet temperature. The union of ceramics and super alloys provides the material strength and temperature resistance necessary for increased turbine firing temperatures. However, increasing firing temperature also increase emissions.

Catalytic combustors will reduce NO_x formation within the combustion chamber. They will also reduce combustion temperature and extend combustor and turbine parts life.

Increased power in excess of 200+ megawatts can be provided without increasing the size of the gas turbine unit, but the balance of plant equipment such as, pre- and inter-coolers, regenerators, combined cycles and gasifiers will increase the size of the facility needed.

The size of these various process components must be optimized to match each component's cycle with the gas turbine cycle, as a function of ambient conditions and load requirements. Computer systems will interface and control these various processes during steady-state and transient operations.

A major effort will be made to produce gas turbines capable of burning all types of fossil fuel, biomass and waste products. There will be intensified efforts to supply hydrogen, processed from non-fossil resources, for use in petroleum based equipment. The objective will be to produce recoverable, cost effective, and environmentally benign energy.

Ultimately the gas turbine will be needed to burn hydrogen, even with a plentiful supply of fossil fuel. The use of hydrogen eliminates the fuel bound nitrogen that is found in fossil fuels. Hybrid electric cars may use gas turbine generators as range extenders. It would provide a constant power source to continuously charge the on-board battery pack.

With combustion systems currently reducing the dry NO_x level to 25-ppmv and catalytic combustion systems demonstrating their ability to reduce emissions to single digits, the use of hydrogen fuel promises to reduce the emission levels to less than 1-ppmv. The gas turbine will need to achieve this low level in order to compete with the fuel cell.

Hospitals, office complexes, and shopping malls are prime markets for 1 to 5 megawatt powerplants. Operating these small plants, on site, can prove to be more economical than purchasing power through the electric grid from a remote powerplant. This is especially true with the current restructuring of the electric utility industry.

To reduce the expense of turbine units under 5 megawatts, the next breakthrough must be in the production of axial blade and disc assemblies as a single component. The greatest single obstacle to reducing gas turbines costs is in the manufacturing process, machining and assembly. A typical gas turbine has over 4000 parts. About one third of these parts are made from exotic materials with high development costs. Maintaining the turbine is also complicated and requires the same technical skills, as building a new unit.

Advanced design tools such as computational fluid dynamics (CFD) will be used to optimize compressor and turbine aerodynamic design. Producing the blade and disc assembly as a single part would reduce the quantity of parts and the requirements for dimensional tolerances between parts. In very small gas turbines, manufacturers are returning to the centrifugal wheel in both the compressor and the turbine. The advantage is that it can be produced as a single part. This type of small gas turbine generator is now available for the low power market with units from Capstone, Allied Signal, and Elliott. These units operate on gaseous or liquid fuel and generate from 20 to 50 kilowatts.

The gas turbine (turbofan, turbojet, and turboprop) will continue to be the major engine in aircraft applications. In the next decade, over 75,000 gas turbines, turbojet and turbofan, may be built. The gas turbine will also be used to a greater extent in marine applications, mainly in military applications and in fast-ferries. However, the greatest growth will be in land based, stationary, powerplant applications.

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