8.33 Power Plant Controls: Cogeneration and Combined Cycle

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INTRODUCTION

The controls of the unit operations used in the power plants (boilers, heat recovery steam generators, compressor, turbines, combustion controls, cooling towers, and condensers) are discussed in detail in other sections of this chapter. Also, these mechanical packages, as purchased, are often already provided with their integral control systems. For these reasons, this section will give more emphasis to the description of the mechanical equipment, its features, possible combinations, operation, and start-up and shutdown procedures.

This section will describe processes that can substantially increase the efficiency of power generation. These processes include cogeneration, combined cycle generation, and the use of both techniques in combination. Cogeneration is a mode of operation when the plant produces both heat (steam or hot water) and electricity. In a combined cycle power plant, electricity is produced by two turbines, a gas and a steam turbine. The gas turbine is operated by the combustion products of the fuel (Brayton cycle), while the steam turbine (Rankine cycle) is operated by the steam generated by the heat content of the exhaust gases leaving the gas turbine.

The efficiency of a traditional power station, consisting of a fired boiler, full condensing steam turbine, and electric generator, can hardly reach 40%. The major losses occur in the steam condenser, which wastes more than 45% of the total thermal energy that is supplied to the plant. Therefore, when the total electric power generated is constant, the overall power plant efficiency can be improved by lowering the inlet steam quantity to the condenser.

COGENERATION

Cogeneration means that there are two marketable products: electricity and heat. The heat is usually in the form of steam, but sometimes as hot water. The heat is sold to process industries (paper mills, tire production plants, petrochemical plants, textile mills, desalination plants, sugar mills, and so on) or for civil applications (district heating), and thereby the latent heat of the steam is not wasted, but utilized.

In order to obtain a significant improvement in the overall plant efficiency, it is necessary that 1) The portion of the steam that can be sold is a high percentage of the steam being generated. 2) The demand for steam is continuous and steady. This means that seasonal users like sugar mills or district heating applications are not as good applications as are paper mills or tire production plants. 3) The steam user should be near the power plant (1000–5000 ft, or 300–1500 m), in order to reduce steam transportation and heat losses.

As a consequence, the large generation units normally are not suitable for cogeneration, because the exported steam would be only a small portion of the total that is generated, making the application unattractive. Also, the distance of the power station from the users would make the installation economically impractical.

In some cases, steam generation can be more critical than electricity production. This might require the installation of an auxiliary boiler to guarantee the continuous availability at least of the minimum steam supply that is required to protect against damage to the user's plant or production, or to avoid incurring expensive penalties.

The steam can be obtained from back-pressure steam turbines or from controlled/noncontrolled extraction in the IP or LP stage of the turbine, in an amount determined by the user. Some percentage (0–100% according to the application) of the steam is returned as condensate to the power plant.

The quantity of the returned condensate can impact the size of the demineralization unit and can require continuous checking of the quality of the returned condensate. If the condensate quality is unacceptable as boiler feedwater, it might be dumped to wastewater treatment or to the demineralization plant, if the pH, and/or conductivity, and/or TOC, and/or silica are beyond the acceptable limits. Before entering the thermal cycle of the boiler in the hot well of the steam turbine condenser, the returned condensate is mixed with the demineralized make-up water.

Cogeneration with Combined Cycles

Smaller combined cycle power plants (up to 60–100 MW) are particularly suitable for cogeneration, because they can be located very close to the thermal user or even within the fence of the industrial plant. Figure 8.33a is a simplified process flow diagram showing a combined cycle with cogeneration, in which some steam is sent to the associated industrial plant.

In many cases, the steam is generated at two pressure levels and the heat recovery steam generator (HRSG) is designed to serve the steam users. In some installations, if the HP or LP steam characteristics are suitable for the steam turbine, flexible operation is obtained by sending the excess steam to the turbine or by drawing steam from the turbine supply to meet the needs of the users in the plant.

Figure 8.33b shows a steam distribution control system where the steam generated by the HRSG is distributed to the steam users in the plant while sending the remaining low-pressure (LP) steam to the steam turbine. In the case when no steam is required by the steam users, PV-1 is fully open and PV-2 and PV-3 are closed.

The system status and operation is summed up in Table 8.33c. When, compared to the HRSG production, the users require only a small amount of steam, PIC-1 output is in the 50–100% range and throttles PV-1, and the PIC-2 output is in the 0–50% range and modulates PV-3 while PV-2 is closed. When the users' demand for steam rises further and, therefore, PIC-2 output rises above 50% (exceeding the steam availability from the HRSG), it throttles PV-2, while the low-signal selector PY-2 selects the under-50% output of PIC-1 to throttle PV-1 and PV-1 is closed. In this mode, the LP steam generated by the HRSG is supplemented by steam from the turbine.

The purpose of the low-signal selector PY-2 is to prevent the depressurization of the LP drum in case of high steam demand from the users. PV-2 and PV-3 operate on a split range, so that PV-2 starts opening only when the PIC-2 output has risen above 50%.

Cogeneration with Internal Combustion Engines

In case of smaller loads (e.g., hospitals or small district heating), when the required amount of heat is small and is at a low temperature, the required electric power can be generated with internal combustion engines. These engines can generate up to 1–2 MW. The heating medium is pressurized hot water that is close to its boiling point.

In this configuration, the heat is obtained by recovering it from the cooling circuit, lubricating oil, and flue gas of the engine, by means of heat exchangers.

COMBINED CYCLES

In a combined cycle power plant, electricity is produced by two turbines, a gas and a steam turbine. The gas turbine is operated by the combustion products of the fuel (Brayton cycle), while the steam turbine (Rankine cycle) is operated by the steam generated by the heat content of the exhaust gases leaving the gas turbine. The name *combined cycles* comes from the fact that the gas turbine operates according to the Brayton cycle and the steam system operates according to the Rankine cycle.

As shown in Figure 8.33d, the dual-shaft combined cycle plant consists of a gas turbine (GT) with its associated electric generator, a heat recovery steam generator (HRSG), a steam turbine (ST) with its associated condenser and electric generator, plus auxiliaries like a demineralization/polishing process, a fuel gas or fuel oil system, and a closed circuit cooling water system. The gas turbine (GT) exhausts into the heat recovery steam generator (HRSG) where the heat content of the flue gas produces steam, which is fed to the steam turbine (ST).

The combined cycles configuration is preferred for base load applications, i.e., to operate continuously at full power or very close to it, even though sometimes they can also be used to meet peak loads. When operating at base load (100% load) with no steam used for cogeneration, 3/4 of the generated electric power will be generated by the gas turbine (GT) and 1/4 by the steam turbine (ST), if aeroderivative turbines are used. When using heavy-duty turbines 2/3 of the electric power will be from the GT and 1/3 from the ST.

At partial loads on a heavy-duty GT, the ratio between the generated power from the two sources changes and can be 60% from the GT and 40% from the ST. Given a specific GT with its associated HRSG, at each load (generated MW) by the GT, there corresponds a certain (proportional) generated power by the ST, such that in steady state, the total generated power can be controlled by controlling the generated power of the GT.

During transients (either an increase or decrease of the total power), the ratio of the generated power between the GT and the ST can be different, because the GT has a much quicker dynamic response (seconds) than the HRSG and ST assembly (minutes). This fact has normally little impact on the operation of the power station, because a combined cycle is always operating in almost steady-state conditions.

If the load increase is large, it is possible that after a first step of a limited value (e.g., 5%), the rate of change in the GT needs to be limited to 2–5%/min. This is because the ST is unable to accept a sudden change in steam characteristics and quantity. The net heat rate for combined cycle units >150 MW is in the range of 5700–6800 BTU/kWh (6015–7175 kJ/kWh), while for 60 MW it is in the range of 6500–7000 BTU/kWh (6860–7385 kJ/kWh).

Single-Shaft Arrangements

In Europe it is quite popular to have a single-shaft arrangement for the rotating machinery, and this design is now also increasingly accepted in North America. This arrangement decreases the overall cost even though it decreases the flexibility of the plant. In this design, there is only one electric generator, driven by both the gas turbine and the steam turbine. This means that the electric power plant is simpler,

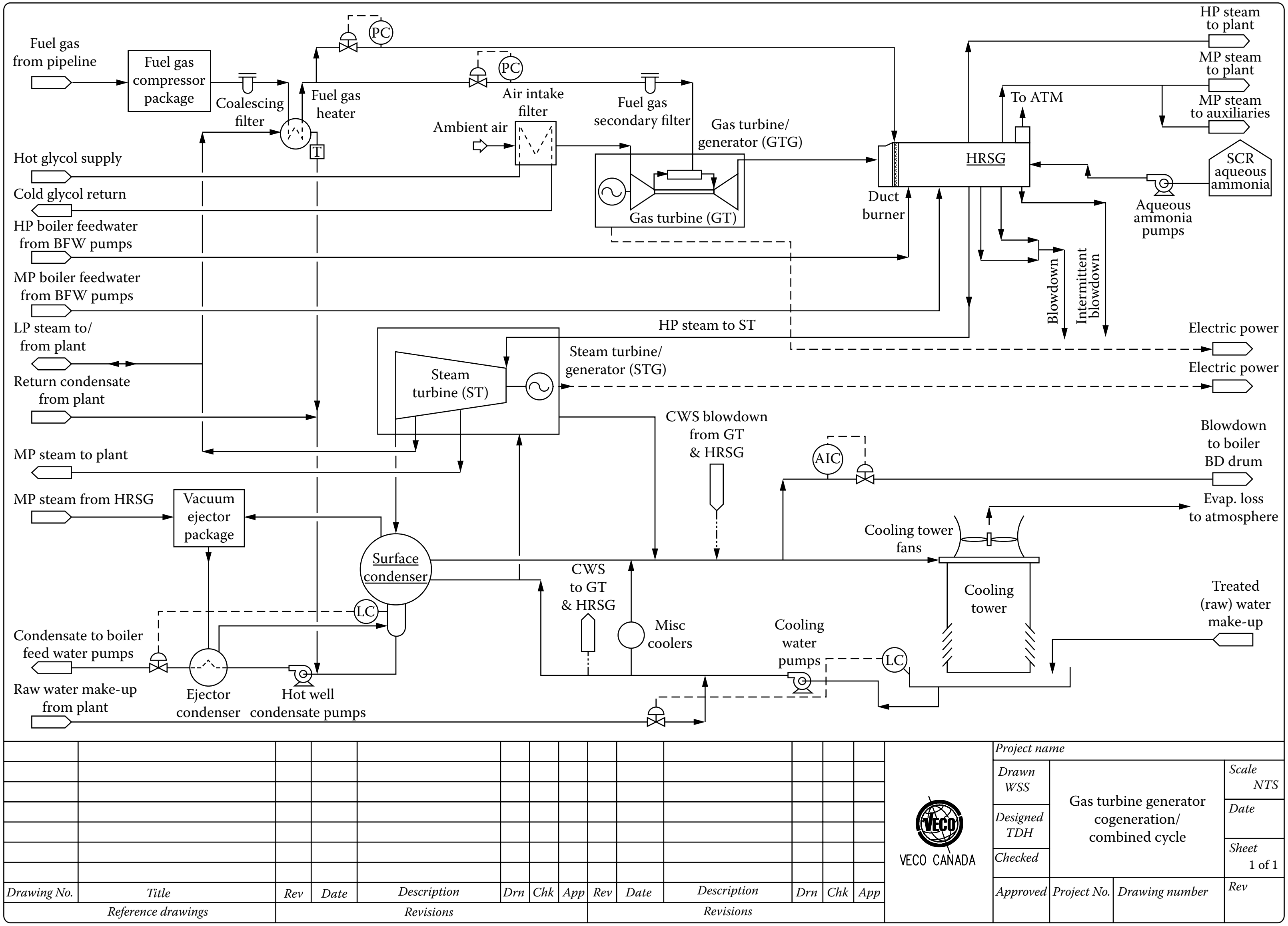

FIG. 8.33a

Piping and instrument flowsheet of a dual shaft cogeneration power plant with combined cycle. (Courtesy of VECO Canada Ltd.)

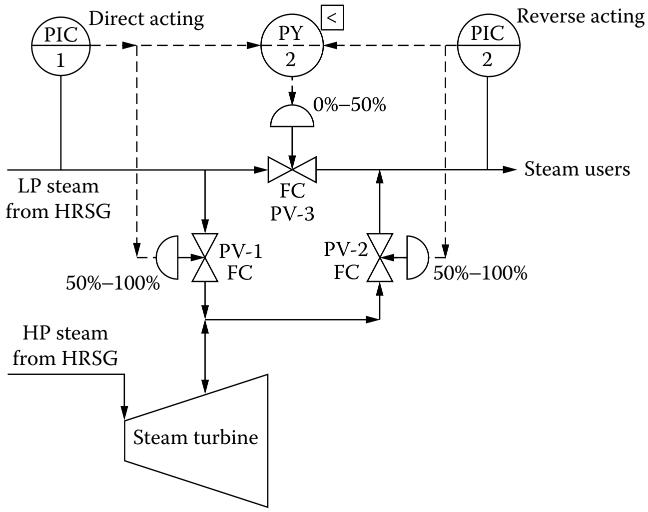

FIG. 8.33b
Control system used to distribute the steam generated by a heat recovery steam generator (HRSG) in such a way that the variable demand for steam can be met by either sending the excess to the steam turbine or by supplementing it from the steam turbine.

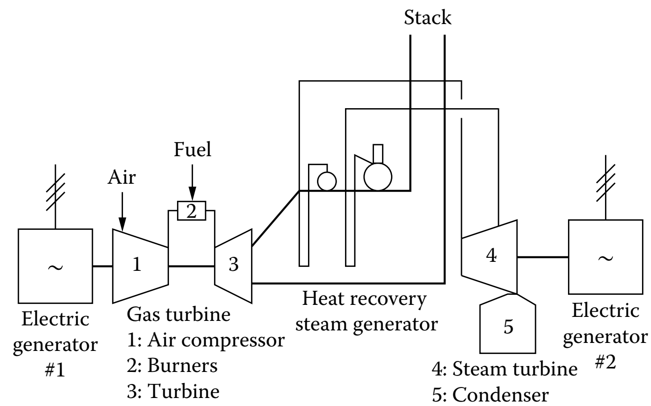

FIG. 8.33d
The main components of a dual-shaft combined cycle power plant.

because there is only one step-up transformer and one bay to connect to the grid.

There are two possible single-shaft configurations, shown in the top and bottom of Figure 8.33e: One is to locate the gas turbine and the electric generator at the two ends of the shaft (top) and the other is to locate the steam and gas turbines at the two ends of the shaft (bottom).

The configuration at the bottom requires a clutch or a special joint (e.g., SSS™) located between the generator and the ST. This is needed in order for the generator to be able to rotate during start, driven by the GT, with the ST stopped until the steam conditions are suitable for starting the ST with its own start-up procedure. If this joint is not used, an auxiliary boiler is needed or steam is derived from other HRSGs to supply steam to the seal glands and to the vacuum ejectors of the condenser, and at least a small amount to the ST.

The configuration on the top of Figure 8.33e always requires auxiliary steam for the vacuum system and for seal glands or from an auxiliary boiler or from other boilers available in the plant.

Alternative Configurations Sometimes, when an even number of GTs is used, it is possible to have two GTs/HRSGs

TABLE 8.33c
Status and Operation of Figure 8.33b Loop Components

Component Characteristics and Status	*User's Steam Demand is Zero*	*User's Steam Demand is < HRSG's LP Availability*	*User's Steam Demand is > HRSG LP Availability*
Direct-acting PIC-1 output	50–100%	50–100%	0–50%
Reverse-acting PIC-2 output	0%	0–50%	50–100%
PV-1 (fail closed, 50–100% range valve) status	Throttling	Throttling	Closed
PV-2 (fail closed, 50–100% range valve) status	Closed	Closed	Throttling
PV-3 (fail closed, 0–50% range valve) status	Closed	Throttled by PIC-2	Throttled by PIC-1
PY-2 (low-signal selector) selects the output of	PIC-2	PIC-2	PIC-1

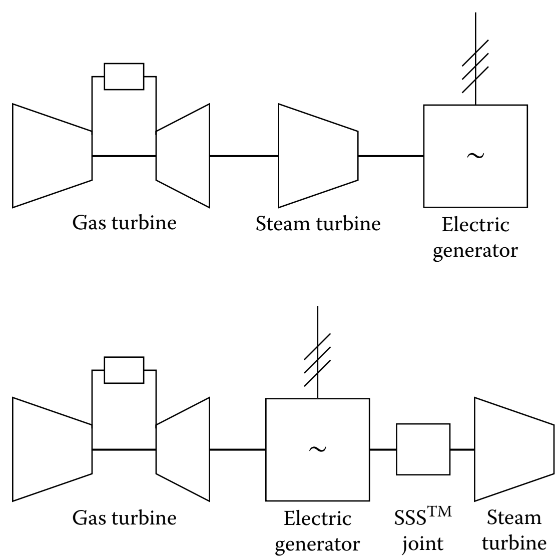

FIG. 8.33e
Single-shaft power plant configurations can locate the gas turbine and the electric generator at the two ends of the shaft (top) or can locate the steam and gas turbines at the two ends (bottom).

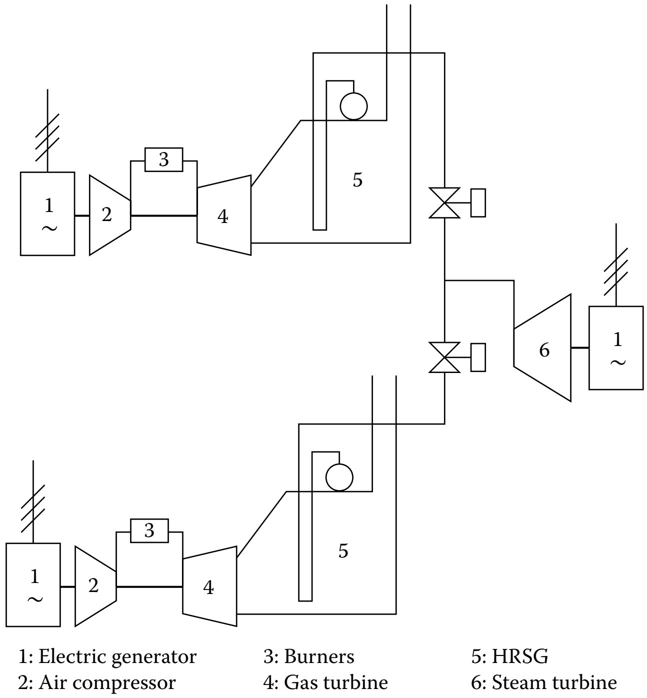

FIG. 8.33f
Power plant equipment configured in a 2 + 1 arrangement where two gas turbines and their two associated HRSGs are sending steam to the same steam turbine.

feeding only one ST. This configuration is known as 2 + 1. As a consequence, the electric generator/step-up transformer driven by the ST is roughly of the same power as the ones driven by the GT (Figure 8.33f). This simplification reduces the investment costs and reduces the electrical installation with the additional benefit of having similar electrical components. However, it is not rare that generators from different manufacturers are used because the GT supplier and the ST supplier could be different.

When aeroderivative GTs are used, sometimes a 3 +1 (i.e., three GT and one ST) configuration is used, with four identical generators. When only a GT is running, for instance during start up, the active HRSG is operating in a sliding pressure mode and the steam is delivered to the ST at about 65% of the normal pressure, with a minimum value of 50%. Sometimes, during the updating and modernization of existing power plants, the existing steam turbines can be reused. This involves a customized reconfiguration of the equipment in the plant as it is converted to operate in a combined cycle.

Main Equipment Blocks

Gas Turbine System The GT system consists of three main parts: the air compressor (axial type), the burners, and the turbine itself. The mechanical power generated by the turbine is partly (about 50%) used to drive the air compressor, so that the net generated power is the difference between the full-generated power and the power required by the air compressor.

The turbine types can either be "heavy duty" or "aeroderivative."

The heavy-duty design is of sturdy construction with the compressor running at the same speed as the turbine. The "aeroderivative" design is based on the design of aeronautical engines that have been modified for ground operation at continuous full load with no axial thrust. The turbine can be split into two parts, one rotating at the rated speed, and the other running at higher speed and driving the air compressor.

In general, these turbines are more delicate and more sensitive to changes in the fuel gas composition and to dirt deposited on the air compressor's blades, with subsequent decreases in the efficiency and in the generated power. The upper power for aeroderivative turbines is in the range of 40 MW at the shaft, but is expected to rise in the near future.

Gas Turbine Characteristics The characteristics of gas turbines are given at ISO conditions, which assumes no losses (i.e., no pressure drop in the inlet and outlet ducts), 59°F (15°C), 14.696 psia (101.325 kPa), 60% relative humidity. It is to be noted that the power generated by the turbine is highly dependent on air temperature. Starting from ISO conditions, roughly an increase of 35°F (20°C) of the inlet air temperature decreases the generated power by 10–13% and the efficiency by 3–5%, while a decrease of the air temperature of 20°F (11°C) increases the generated power by 6%.

In some instances, mainly for aeroderivative turbines, when the ambient temperature is high, the inlet air can be chilled before entering the air compressor to increase the throughput and efficiency. For heavy-duty GTs, the same effect can be obtained with so-called fog systems or wet compression.

The current generation of GTs has an efficiency of 33–38%, referred to as the low heating value of the fuel, when running in open cycle (i.e., exhausting to the atmosphere), thus approaching the overall efficiency of a traditional power station. The heat rate for heavy-duty turbines in sizes > 100 MW is in the range of 9,000–10,000 BTU/kWh (9,500–10,550 kJ/kWh), while for sizes of about 25 MW the heat rate is about 10,000–12,000 BTU/kWh (10,550–12,650 kJ/kWh). For aeroderivative turbines in sizes of about 40 MW, it is in the range of 8,200 BTUtu/kWh (8,650 kJ/kWh).

The GT is supplied as a package in which practically no custom tailoring is possible in the mechanical part because of the high development costs for the optimization of the blades and rotating speed(s) of the air compressor. The custom tailoring is limited to the extent of the supply for the auxiliaries, to the starting method, to the back-up fuel (if requested and feasible), to the voltages for the generator and auxiliary motors, to the cooling of the generator, to the available options for the governor, and so on. The turbine is optimized for operation at a power close to the base load (100% load) and has a turndown of approximately 100:55.

Temperature and Fuel Considerations The temperature in the combustion zone can be quite high [2280°F (1250°C) and even up to 2460°F (1350°C)] and is expected to increase even more with new developments in this technology (mainly due to the cooling of blades). This high temperature results in the nitrogen in the air combining with oxygen, with consequent production of NO_x concentrations that are well beyond the limits stated by almost all local regulations.

Additional nitrogen could be present in the fuel if it is obtained from coal gasification or from tail gas in some process industries. Hence, the need for NO_x abatement, which can be obtained in a wet process (by injecting steam or water into the combustion chamber) or by a dry method, with different flame configurations as a function of load. Nowadays, the latter solution is the preferred one even though it may involve flame instability at certain loads.

A dry method of NO_x reduction anticipates combustion with different flame shapes according to the load. Therefore, the flame shapes from the operating gas nozzles in a certain burner are different depending on the load. Changing from one shape to another involves flame instability, and therefore the loads corresponding to the change of flame shape should be avoided to prevent possible flame outage.

To limit the temperature in the combustion zone, a high excess air ratio is used, so that the oxygen content in the exhaust gas can reach 15%.

The preferred fuel is natural gas, but several types of turbines can accept either gas or liquid. For the dual-fuel-type designs, diesel oil is normally used as the back-up fuel. Some turbines can accept heavy oil as fuel, but the resulting emissions could exceed the limits stated in many states/countries. When liquid and gaseous fuels are used, the gas turbine should be equipped with a dual-fuel system, which is also needed when only gases are burnt, but these gases are characterized by much different "Wobbe Indexes."[1]

Operation The air compressors are very sensitive to pollution, particularly the aeroderivative machines. Thus, large intake filters are necessary. These filters should minimize the pressure loss and should be complete with cleaning systems and antifreeze protection. Depending on the type of turbine and air pollution, the air compressors need to be washed on-line every 8–48 hours, and washed off-line roughly every 1–3 months, when the power plant is out of service (Figure 8.33g). It is a desirable practice to perform the off-line compressor wash every time a long stop is required in order to improve the efficiency. The count down to the next washing is restarted after each wash-down.

The GT is unable to start by itself and requires a launching motor, which can be electric or diesel, or use the electric generator as a motor, fed from the grid via a variable-frequency inverter, also called a static frequency converter (SFC). The starting system is selected according to the availability of the grid. If black starting (i.e., power is not available from the grid) is required, then a diesel engine or a diesel generator feeding an electric motor should be used.

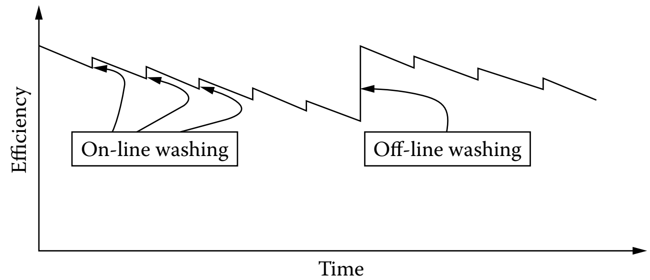

FIG. 8.33g
The gas turbine efficiency is slightly improved after each on-line wash, but periodic on-line wash is needed to return to full efficiency.

When the GT runs at rated speed and without meeting any load, it is said to be at Full Speed No Load (FSNL). For many GTs this is a stable operating condition, at which the generated power is nil but the exhaust flow and temperature are still relatively high as compared with base-load conditions. For large turbines, the FSNL exhaust mass flow is in the range of 70% of the maximum flow at ISO conditions, and the temperature is roughly 50%, even though the available temperature drop in the HRSG is about 25% due to the increase of the temperature at the stack.

Some new turbines feature at FSNL an exhaust flow of approximately 60% of the nominal and a temperature about 65% of the nominal. The enthalpy per mass unit of flue gas at FSNL is greater than 45% of the one at base load, so that the total enthalpy transferred from the GT to the HRSG at FSNL exceeds 30% of base load and impacts on the start-up procedure of the HRSG. The FSNL-generated HP steam flow is in the range of 20% at a pressure in the range of 20–30%, a temperature (°F) of about 50%, with the superheating temperature in the range of 30%. With the new GTs the SH steam flow is roughly 30% at a temperature of 70% approximately. The fuel gas consumption at FSNL is about 25% of the consumption at base load.

Pollution and Safety At FSNL, the NO_x and CO contents can be beyond the limits accepted by the regulations, so that the FSNL condition can be accepted only as a transient to warm-up of the HRSG and the ST. When a turbine cannot run at FSNL, but needs to feed some load (about 20%), this situation is called minimum technical load. Similarly, at these conditions the emission limits could not be met.

A minimum environmental technical load (about 50–60%, depending on the GT and the local regulations) can be defined as well, where the GT emissions are in line with the regulations

[1] Wobbe index W is the ratio between the heating value H_s in standard volumetric units and the square root of the specific gravity G.

$$W = H_S/\sqrt{G} \qquad \textbf{8.33(1)}$$

or can be brought in line by means of selective catalytic reduction (SCR) in the HRSG, if present.

The GT is supplied with its own governor that takes care of all safety and control functions including antisurge control of the compressor, inlet guide vanes (IGVs) control, burner control, start-up and shutdown sequences, and excessive vibrations. For an I&C engineer, the GT is almost a black box interfaced with the overall plant DCS via a serial link (simple or redundant) and relatively few directly hardwired commands.

In several instances the old turbine governors had a standard set of information transmitted over the serial link, and only few could be custom-tailored. Out of the standard set of information, a certain amount was not needed for the specific plant and, therefore, was discarded in the GT governor or in the DCS.

All safety functions of the GT are performed by the turbine governor that normally has a 2oo3 (two out of three) or a 1oo2D (one out of two diagnostics) configuration, which are usually independent from the control functions. The control functions are performed in simple, redundant, or 2oo3 configurations that ensure the degree of safety and availability requirement, which should be consistent with the size and criticality of the plant. The safety functions are also performed in the control processors and are used as back-up for the safety functions performed by the dedicated processors.

The governors are provided with their own operator interface and with processors that store information on the behavior of the turbine, including the sequence of events leading to a shutdown. The governor includes comprehensive self-diagnostics that allow easy maintenance while the GT is running, while still keeping all of the protections active.

The GT runs in temperature control mode when it is at base load. When it is ramping up, it is in speed control, with the temperature of the first row of blades constraint limiting on the generated power.

The GT is normally enclosed in an acoustic cabinet, complete with ventilation, fire- and gas- detecting, and fire-fighting systems.

Steam Injection Gas Turbine (STIG™) When the power generated by the gas turbine (GT) is low (< 15 MW), the combined cycle configuration discussed earlier would be uneconomical. For such applications, small GTs have been developed that can accept the partial or total injection of the steam that is generated in the associated HRSG upstream from the turbine blades of the GT. This results in increasing the mass of the flue gas in the turbine and the generated power, without the need of a small steam turbine.

Part of the steam is injected in the burner chamber for NO_x abatement in a wet mode on a preferential basis. This type of turbine is suitable for small cogeneration plants requiring a variable quantity of steam, while the surplus is sent to the GT. The sizing of the demineralization plant should consider the large amount of demiwater wasted to the atmosphere.

Heat Recovery Steam Generator The HRSG receives the exhaust gases from the GT discharge. The exhaust gas, flowing in counterflow with respect to the steam/water coils, cools down by transferring heat to steam/water. The flue gas temperature at the stack is about 230°F (110°C), even though lower temperatures [200°F (93°C)] can be used if the fuel gas is very clean and sulfur-free. The HRSG is, therefore, similar to a heat exchanger in which the shell side carries the flue gas and the various sections of the tube side carry steam or water.

It has also the characteristics of a boiler because there are one or more steam drums, where the generated steam is separated from boiling water before entering the superheaters. The HRSG can be horizontal or vertical, according to the direction of flue gas path.

The horizontal ones have a horizontal path for the flue gas flow, and the steam/water tubes are vertical, normally with natural circulation in the evaporator(s). The vertical ones have a vertical path for the flue gas flow, and the steam/water tubes are horizontal, thus requiring assisted circulation in the evaporators, at least during the start-up period. The horizontal HRSGs are the most common, with the vertical ones mainly being limited to the revamping of existing boilers or to installations where space is very tight.

Pressure and Temperature Levels The HRSG can have one, two, or three pressure levels according to the size of the plant. For plant sizes of 200–400 MW per line, the pressure levels used are HP, IP, and LP (high pressure, intermediate or medium pressure, and low pressure). Plants down to 30–60 MW usually have two pressure levels (HP and LP), and smaller units only have one pressure level. Sometimes, with three pressure levels, the LP section produces the steam needed for deaeration only.

The following tube banks are used for each pressure level (starting from the GT discharge): 1) steam superheaters, 2) evaporator, and 3) economizer. When more pressure levels are used, the banks of the various levels can be intermingled as to maximize the heat exchange efficiency, taking into consideration the differential temperature between the flue gas at that point and the steam/water in the tubes. In large boilers, the two HP superheaters that are in series can be split in two to four parallel banks. In the large HRSGs the reheating coil for the IP steam can be derived from the steam turbine and mixed with the IP steam, which is generated in the HRSG.

The differential temperature between the exhaust from the GT and the HP superheated steam is called the “approach” temperature, and it is in the range of 50°F (30°C). The differential temperature between the flue gas at the outlet of the evaporator section (inlet for water) and the saturated steam temperature is called the “pinch point” and is approximately 15°F (8°C).

Starting from the turbine discharge, the HRSG casing is mechanically made of a diverging cone to reduce the velocity of the exhaust gases, plus a rectangular section (internally

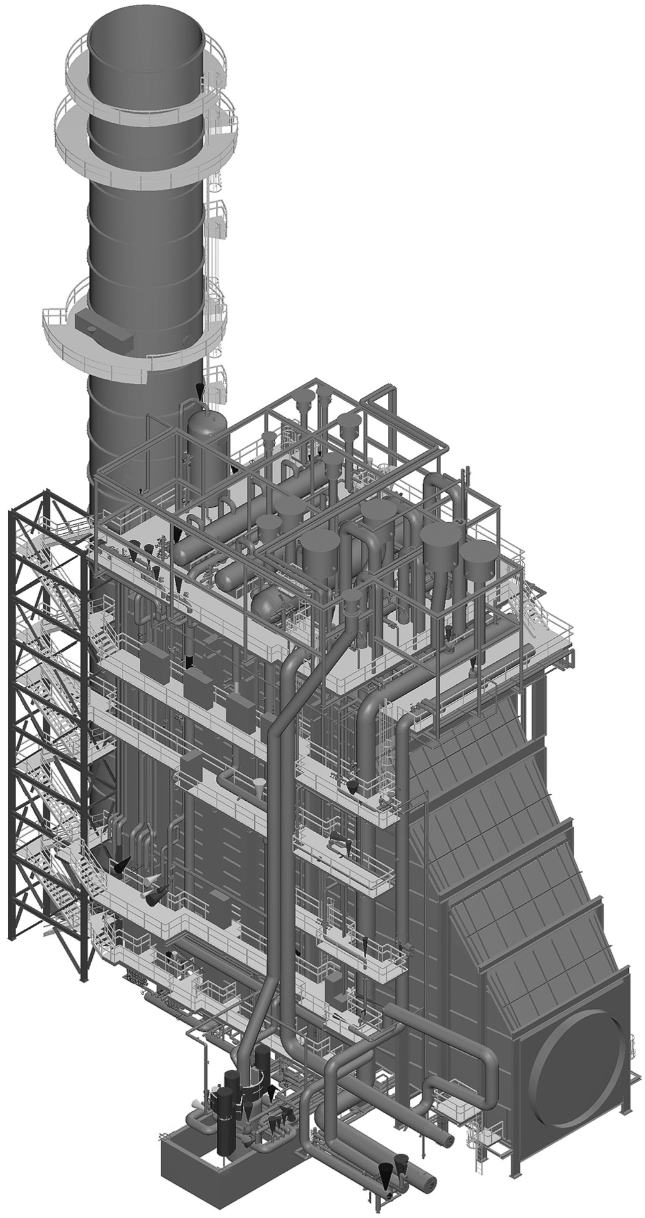

FIG. 8.33h
Heat recovery steam generator (HRSG) generates three pressure levels of steam. (Courtesy of Nooter Eriksen CCT.)

insulated and lined) housing the steam/water coils and the stack. Figure 8.33h shows a horizontal HRSG, with three pressure levels and integral deaerator.

Design Features In more recent times it has become a requirement to insert an empty module in the flue gas ducts of large HRSGs, which serves the possible future installation of a selective catalytic reduction unit for further NO_x abatement.

This empty module is installed in the expectation that in the future more stringent regulations will come into force. This empty module is positioned where the flue gas temperature is about 660–715°F (350–380°C).

Sometimes, a spool piece for future addition of an oxidation catalyst for CO abatement is included for the same purpose as the SCR and located in the same position. Nowadays in North America, almost all HRSGs are fitted with SCRs and occasionally with CO catalyst, while in Europe only provisions for SCRs are required.

In addition, many installations include a silencer in the stack or at least a dummy piece for the future installation of one. If the plant is to be operated in an intermittent mode (e.g., shut down overnight), a damper in the stack is required to protect against excessive cooling of the unit. The damper should be designed to fail open on high flue gas pressure, which failure position is normally obtained by counterweights, or with offset blades so the damper will open without the use of the actuator. Sometimes, actuators are included in order to have the maximum flexibility.

The pressure drop across the HRSG on the flue gas path is in the range of 8–15 in. (200–375 mm) water column. This pressure drop is the back-pressure of the GT and influences its generated power and efficiency by 1 and 2%, respectively.

The water/steam coils are helically finned on the outside to improve their heat exchange efficiency. In some cases, the HP superheater tubes can be nonfinned. Their construction material is carbon or alloy steel, as a function of the pressure/temperature rating required. The coldest coil (LP economizer or feedheater) can be stainless steel to protect it against corrosion on the inside, which might occur if the feedwater is not deaerated. If stainless steel is used, it will also protect against corrosion, which can be caused by acid condensation from the flue gas on the outside.

In some instances, for small plants where the GT exhaust temperature is relatively low, the HRSG can be designed to run dry (i.e., without damage if the water supply fails) in order to comply with some national regulations for unattended boilers.

The HRSGs are provided with a set of motor-operated valves that are installed in the steam and water lines. Each superheated steam line leaving the HRSG is provided with a shut-off valve and, in some cases, also an on/off bypass valve (mainly on HP) to intercept the steam to the user (turbine or industrial load).

The feedwater inlet lines to the economizers are also provided with on/off shut-off valves. Having these shut-off valves allows the "bottling in" of the HRSG by closing all inlet and outlet lines, thereby to keep the boiler pressurized when the shut-down period is expected to be short. Additional motor-operated valves are used to remotely and automatically operate the drains in the superheaters.

The HRSG also includes a pressurized blow-down tank and an atmospheric blow-off tank, and is also equipped with chemical injection pumps to keep the water and steam characteristics within the correct parameters required to maximize the life of the ST and the boiler itself. The HRSG is also equipped with nitrogen connections for purging (dry lay-up) to prevent corrosion in case of long shut-down periods.

Alternative Steam Generator Designs Other steam generator possibilities include an HRSG with the HP section only and a high rate of post-firing. In this case, the water/steam cycle is very similar to that of the standard fired boilers and utilizes water heaters to improve the overall efficiency. In such boilers, at some loads the efficiency can be higher than using a conventional HRSG.

Another possibility is the once-through steam generator OTSG), which is used mainly in combination with GTs in the capacity range of 40–50MW, although larger units are under development. These boilers, built with Incoloy 800 and 825 tube materials, operate without steam drums or blowdown systems and thus require a simplified control strategy.

Their flue gas flow is vertical upwards and the tubes are horizontal, thus allowing for a reduced footprint. These boilers feature the possibility of running dry (if required) and have very short start-up periods due to the thin wall of the tubes and to the missing steam drums. They are delivered in a few prefabricated pieces so that the field erection and installation takes place in a short period of time.

Steam Turbine Steam turbine controls are discussed in Section 8.38. The largest steam turbines today that can be fed by a single gas turbine/HRSG are in the range of 150 MW. Therefore, these steam turbines are still are relatively small for power generation. Only when one ST is fed by two HRSGs (in a 2 + 1 configuration[2]) can the steam turbine's rated power reach 250–300 MW.

The steam turbine is fed with HP superheated steam and is designed to also accept IP and LP steam from the HRSG and also to extract full steam flow at IP level in case of reheating. In addition, if the plant is cogenerative, suitable (controlled or noncontrolled) extractions shall be planned for. For example, if there is a requirement to feed thermal users with steam, it is possible to get this steam through one or more extractions (at the required pressures) from the steam turbine.

In many instances, the LP steam as generated in the LP steam drum has the correct pressure, but not in the required quantity. Therefore, there is a need to send steam from the LP section of the HRSG to the ST, or directly to the users, or to extract steam from the ST to comply with the demands of the users.

The vacuum condenser can be water- or air-cooled. The present trend is in favor of air-cooled condensers, particularly if the water availability is limited. The use of air-cooled vacuum condensers reduces the size of the cooling water towers required for the plant (still needed for cooling the rotating machinery) if closed circuit cooling is selected. This approach also eliminates the need for large flows of cooling water and the thermal pollution of rivers, lakes, or the sea, if open circuit cooling is used. The air-cooled condensers

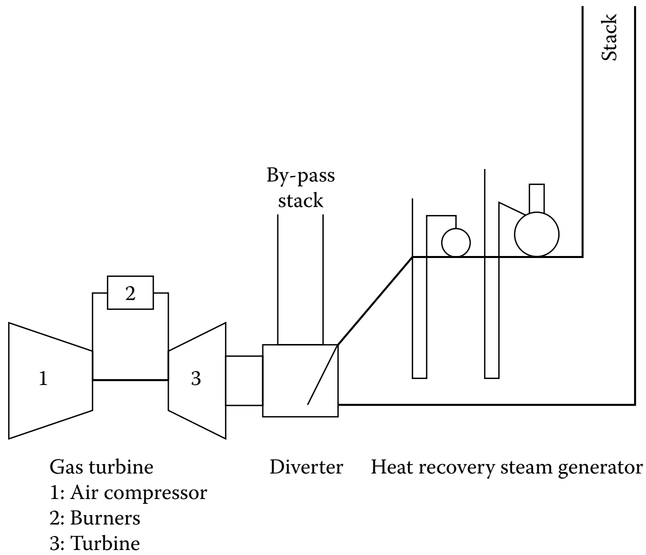

FIG. 8.33i
Diverter provides the flexibility to send the gas turbine exhaust gases to the HRSG or to the atmosphere.

slightly decrease the efficiency of the steam turbine, mainly in hot climates.

When the plant is located in built-up areas, there might also be an atmospheric condenser that receives the steam that is vented during the start-up to decrease the noise level at the plant. The auxiliary circuits of the steam turbine are the lube oil, control fluid, and vacuum system for the condenser. The vacuum system can be equipped with steam ejectors or with liquid ring pumps (vacuum pumps), or a combination.

Bypass Stack and Diverter In some instances, when the electric power generation is a must, it should be possible to run the gas turbine in open cycle and exhaust the flue gas to the atmosphere instead of sending it to the HRSG, regardless of the overall efficiency (Figure 8.33i). This requires a bypass stack and a diverter that closes the path to the HRSG and opens it to the atmosphere through the bypass stack. The diverter is connected to the GT exhaust duct before the diverting cone of the HRSG, and this implies that the GT has to meet the plant emissions limits, as any SCR in the HRSG is also bypassed.

Throttling by the diverter could also be used to control steam generation in the HRSG. This configuration is rare and limited to STIG applications or to applications in which the steam is generated only for process use and the demand for it is low compared to the amount that could be generated, based on the prevailing demand for electricity (e.g., some desalination plants in the Gulf area).

The most important characteristic of a well-designed diverter is its ability to completely switch the flue gas from the bypass stack to HRSG, under all operating conditions. This requires a good seal, so that the GT exhausts fully to the HRSG without loss of efficiency due to leaking hot flue

[2] 2 +1 configuration means two GTs/HRSGs feed only one ST. For more details, see later under the heading "Alternative Configurations."

gas. For this purpose, seal fans are provided that blow air into the gap between the diverter blade and the wall.

Post-Firing (Supplementary Firing) In some cases, it is wise to boost the steam production by supplementary firing in the flue gas duct, at least on a temporary basis. This is possible because of the high oxygen content in the exhaust gas from the GT. The burners are normally in-duct burners located at the end of the diverging cone, upstream of the final HP superheater or between the final HP superheater and the IP reheater. They are fed preferably with natural gas in order to keep the emissions within the regulatory limits and to prevent fouling of the finned tubes.

They require pilot burners and ignitors and a burner management system (BMS). The thermal power delivered by the burners is normally capable of increasing the generated steam in the range of 10–30% so that the overall electric power generated by the GT/ST increases roughly by 5–10%. Post-firing decreases the overall efficiency of the plant but allows it to cover peak demand. It can also be advantageous when electricity can be sold at different prices as a function of the time of the day.

Supplementary firing is inhibited when the GT load is lower than a preset value, ranging between 50 and 80%. The latter value is typical for aeroderivative GTs. These limitations are due to several factors like exhaust flow distribution (not always available at reduced load), flame shape that is longer at reduced flows, and low exhaust temperature inducing increased firing to compensate for reduced energy in the GT exhaust. Allowing the post-firing to be active at lower GT loads could cause excessive temperatures that could damage the HRSG.

Fresh Air Firing (Complementary Firing) When a combined cycle is used for cogeneration, the availability of the steam supply can be very critical for the process and it can be requested that the steam be not used for any other purpose. This requirement can be met by using an auxiliary boiler as a back-up or by fresh air firing in the HRSG.

Fresh air firing requires a diverter to close the outlet duct from the GT, a fresh air fan, and in-duct burners in the diverging cone upstream of the final superheater. All of these system components should be sized to meet at least the minimum contractually guaranteed steam quantity and deliver it for industrial use, while still keeping a good distribution of gases in the flue gas path (Figure 8.33j). The flue gas quantity cannot be decreased too much with respect to the normal flow without impairing the heat transfer. The airflow is normally at least 70% of the flue gas flow at base load.

In this configuration, the HRSG behaves as a fired boiler even though the efficiency is much lower due to high excess air heat losses and a poor thermal cycle. The superheat temperature of the generated steam is usually not suitable for steam turbine supply and, therefore, has to be wasted to avoid damages.

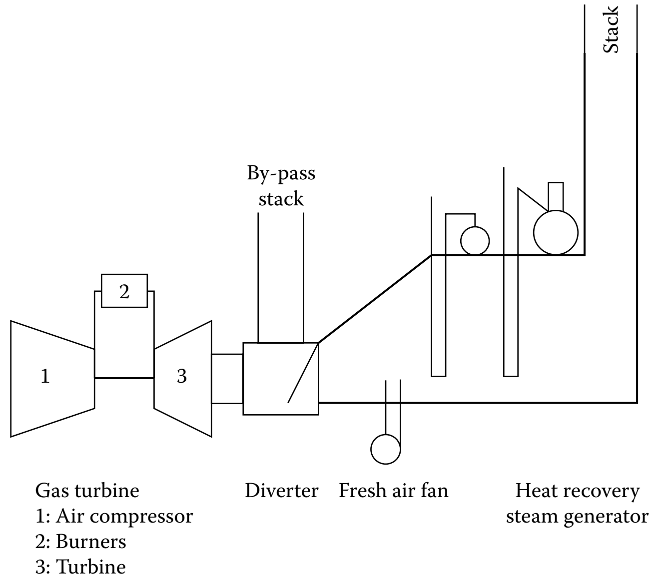

FIG. 8.33j
Equipment configuration when a fresh air fan is added to the combined cycle for complementary firing.

To reduce the pollutant emissions to the allowed limits, it is required to use flue gas recirculation (FGR).

Electric Generator The electric generator is a three-phase unit and can be air- or hydrogen-cooled. The excitation system is static and the voltage/cosφ control is obtained via the automatic voltage regulator (AVR) that is hardwired to the DCS or can be serially linked to the DCS, which is a less frequently used arrangement.

In large groups, at start-up the generator is fed with variable frequency and acts as the launching motor.

The lubricating system is normally common with the driver's system.

Auxiliary Systems

Steam and Water Cycle The steam and water cycle is dependent on the number of pressure levels of the HRSG. If the deaerator is integral with the LP steam drum, the LP drum has also the function of being the suction drum for the boiler feedwater (BFW) pumps that are working on a duty/standby basis. If there are HP and IP sections, the BFW pumps can be multiple-stage centrifugal pumps with an intermediate discharge for the IP section. Otherwise, the pumps have only a discharge nozzle for the HP section.

If required by the pump characteristics (and normally it is), an automatic minimum flow bypass should be installed on the HP discharge nozzle of the pump. It is preferable to use a four-way valve with the manual port used during pre-commissioning and commissioning to extend the life of the automatic port. Alternately, a flow control loop could be

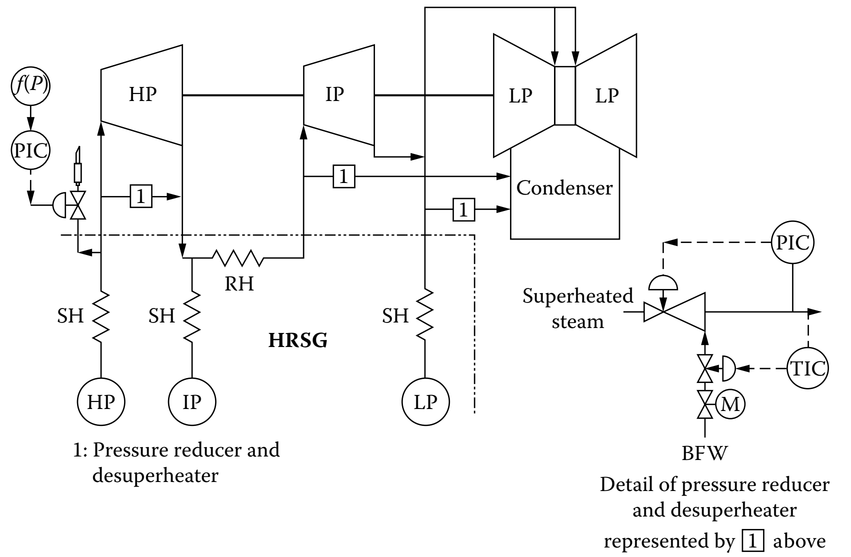

FIG. 8.33k

When high, intermediate, and low pressure (HP, IP, LP) steam turbines and plant users are combined with reheat and superheat (RH, SH) coils, bypasses containing pressure reducers and desuperheaters (1) need to be provided for start-up.

provided to maintain the water flow rate through the pump at a value that is above a preset minimum value and returning the unwanted flow to the suction drum (could also be the LP drum, in the case of an integral deaerator).

The superheated steam is conveyed to the steam turbine that should be bypassed during the start-up phase or in case of turbine shutdown or load rejection. A typical bypass arrangement is shown in Figure 8.33k.

The bypass arrangement includes 1) An HP bypass from HP header to IP header (cold reheat side if reheating is implemented) or LP header or condenser if only two pressure levels are required. 2) IP bypass from IP header (hot reheat side if reheating is implemented) to the condenser or to LP header (less frequently used arrangement). 3) LP by-pass from LP header to the condenser.

Each bypass requires a pressure reduction and desuperheating stage with boiler feedwater or condensate supplies at appropriate pressures so that the physical conditions of the reduced steam are fully compatible with the conditions of the downstream header.

In case of a 2 + 1 configuration, each HRSG has its own turbine bypass system installed upstream of the steam stop valves, so that the starting of the boilers can take place independently. Once the boilers are both on-line and paralleled on the steam header, these bypass valves are operated simultaneously, controlled by the steam header pressure and triggered by the steam turbine trip or load rejection.

An important decision to be made at an early stage of the design that affects the start-up procedure of the plant is how the steam lines are to be heated. It makes a difference if the HRSG starts with the steam stop valves closed or with the steam stop valves fully open and the steam intercepted by the ST admission valves. The latter configuration is preferred when long steam lines are used (e.g., in revamping old conventional power stations).

To keep the required steam purity, a small percentage (1–3%) of the water in the steam drums should be discharged to continuous blow-down and to discontinuous blow-off (as covered in more detail in Section 8.6 on boiler control). For large boilers there is a pressure blow-down tank into which the HP and IP steam drums drain. In addition an atmospheric blow-off tank is also provided to receive the water from the blow-down tank plus the drains from the LP drum and the blow-off from the HP and IP drums.

Small boilers only use one atmospheric tank. The water is cooled to an admissible temperature before dumping it to water treatment or collecting and sending it to the demineralization unit to minimize the quantity of the effluents.

AUXILIARY EQUIPMENT

Demineralization Plant

The water needed for filling the HRSG and as make-up water during normal operation is generated in a demineralization plant. The demineralization plant is usually controlled by its own PLC, which is serially interfaced with a redundant link to the DCS, but sometimes is controlled directly by the plant DCS system.

The demineralized water is stored in a tank that should be sized sufficiently large to provide water in case of disruption in the production. It should also store enough water to supply the quantity needed for pipe blowing in the precommissioning stage, without the need for waiting for the production of new water. This consideration can be the basis for sizing the demineralized water storage tank.

Fuel Gas System

The GT is best utilized when fuel gas, normally natural gas, is burned, because this is the cleanest available commercial fossil fuel and the one releasing the least amount of CO_2. Sometimes, natural gas is distributed at a pressure below that required by the GT, which normally requires 300–650 psig [20–45 bar(g)], as a function of its model.

If the available supply pressure is low, the addition of a compression station is required, which is normally composed of two reciprocating compressors or one centrifugal compressor. If two reciprocating compressors are used, one spares the other. They are followed by a multipurpose knock-out drum, serving the purposes of 1) pulsation damping, 2) residual liquid separation, and 3) surge tank duty to allow for switching the compressors without disrupting the gas supply to the GT.

In the case where the pressure of the natural gas is higher than required, it is necessary to provide a reducing station, which can require preheating with hot water or steam to prevent freezing caused by adiabatic expansion and to keep the gas above the dew point temperature. In this case electric heating or auxiliary hot water generators (boilers) could be required at least for the start-up phase, while during normal operation the heat from the HRSG is used.

The temperature decrease caused by the pressure reduction can be derived from pressure-enthalpy diagrams (see Reference 1 for pure methane). For this reason, the characteristic of the natural gas that is distributed in the grid is very similar to that of methane. As an example, a pressure reduction from 1000 psia (69 bara) at 60°F (16°C) to 435 psia (30 bara) would decrease the temperature to 30°F (–1°C). To obtain a gas at 435 psia (30 bara) and 95°F (35°C), the gas should be preheated to 122°F (50°C), with a heat delivery of 41 BTU/lb (95 kJ/kg) of gas.

The GT requires a very clean fuel gas, thus the gas at proper pressure needs to be further filtered in a location close to the GT. The line could be stainless steel downstream of the filters, to prevent any entrained rust from entering the GT. For safety reasons, servo-actuated double block and bleed valves should be installed upstream of the filters, and they should be independent from the valving supplied with the GT. In addition, the block valves should be fire-resistant.

A point to be checked with the GT manufacturer is the temperature at which the gas is delivered to the turbine. Some gas turbine manufacturers constrain the admissible temperature during the various stages of operations, with special regard to the start-up and shutdown conditions. Fuel gas heaters are usually fitted to the GTs in order to improve the efficiency of the GT cycle. Typically, the gas can be heated up to 365°F (185°C). The heating medium is hot water that is usually received from the IP economizer section of the HRSG, but sometimes from the condensate preheater.

In any case, it is essential that the water pressure be higher than the fuel gas pressure so any leakage that occurs will be water into gas and not vice versa. Some turbines are also very demanding in terms of the steadiness of the controlled gas pressure and its admissible rate of change (pulsation). These constraints impact on the gas system design and relevant instrumentation.

Liquid Fuel System

Some GTs can burn liquid fuel, even though this practice is decreasing because of emission constraints. However, in some countries this is still done. The use of liquid fuel requires careful discussion and agreement with the GT manufacturer on the features and characteristics of the fuel used. Some common requirements include 1) water shall be drained and shall not be fed to the turbine, 2) sediments shall not be pumped to the turbine, 3) the fuel shall be filtered to remove all particles that could clog the fuel injectors, and 4) the storage tank and lines shall be heated if the fuel is too viscous.

Also in the case of liquid fuels, the target is to obtain the cleanest possible fuel to extend the life of the turbine and to obtain a smooth operation. In particular, sodium, lithium, and vanadium should be eliminated, because they are highly corrosive to the GT blades at the combustion temperatures.

Closed Circuit Cooling Water

Water-cooled condensers, users like lube oil, control fluid, and bearings, all require cooling water. The cooling water can be supplied in two closed circuits, both being fed by the cooling tower. One circuit is for the water-cooled condensers and the other for all process coolers and other users (rotating machinery).

The cooling towers can be of modular design, equipped with double-speed air fans (see Sections 8.16 and 8.17). The water-cooled condenser can be cooled by river (seldom sea) water, which requires proper intake works and adequate design to prevent local overheating of the river (or sea). With a cooling water temperature rise of 18°F (10°C) in the condenser, the flow of cooling water is about 55 times the flow of the exhaust steam to be condensed.

If an air condenser is used, the closed-circuit cooling water system becomes much smaller, because the amount of water needed in the rest of the plant is a relatively small percentage of that needed for the water condenser. The air condenser is usually equipped with 2–20 double-speed fans, as a function of the steam flow that is to be condensed, to the required vacuum and to the ambient temperature. In other installations, variable-speed fans are used, which are provided with frequency converters capable of modulating their loading between 50 and 100%.

FIG. 8.33l
The control room of a power plant consisting of four 380 MW groups of generators, located at La Casella, Italy. (Courtesy of ENEL.)

CONTROL EQUIPMENT

Central Control Room

The control system in a combined cycle power plant having one generating group normally consists of a DCS system, provided with two operator stations, each with two CRTs, plus a keyboard, trackball or mouse, and printers.

When more groups are installed, each group can be equipped with three CRTs and possibly with large screens on the wall (Figure 8.33l). The operator stations can be PC-based in a client/server configuration. According to the size and criticality of the plant, the server can be simple or redundant. In general, the cost of controls is small in comparison to the mechanical equipment costs or the costs associated with plant shutdowns, loss of production, and expenses associated with restarting. For these reasons and for increased safety, usually redundant or voting systems are used.

The multiloop controllers are used in redundant or fault-tolerant configurations, and serial gateways should be provided to connect the GT and ST governors, the AVRs, the demineralization water plant, and possibly the electrical protections. In some instances, the ST governor can be part of the DCS itself with a dedicated redundant multiloop controller similar to the ones used to control the HRSG and the cycle. In other cases, the GT governor and the ST governor can be in separate hardware packages.

DCS and I/O Configuration Integration and properly designed interfacing between the DCS, PLC, and other digital control packages is essential. The serial links should be redundant to ensure the maximum operating continuity. If not all external devices are available with redundant links, it is recommended that they be provided. The system bus and the I/O buses should also be redundant, with the goal of guaranteeing the maximum uptime.

The number of continuous and discrete (on/off) I/O points used is in the range of 5000, and the discrete I/O outnumbers the analog. The input signals are often duplicated for control purposes or tripled in a voting system for safety functions, and this requires careful attention in point assignments to the input cards and of the input cards to the multiloop controllers (see Reference 2). If the sequence of events control function is carried out in the DCS, the appropriate input cards have to be correctly anticipated or a dedicated system must be installed and connected to the DCS via a serial link (see Reference 3).

In recent years, the connection of the plant DCS to the company intranet has become common practice, in order to allow for a remote overview of the plant's behavior and to remotely view the main operating parameters and to assist in correctly managing plant maintenance. However, no commands can be issued from the overview location.

When a company owns or operates several power production plants, this configuration allows for the gathering of information for further processing by management or by the engineering support team in real time. Adequate firewalls must be included to prevent unwanted access from hackers or the injection of viruses.

In a few cases, power plants are mechanically designed for operation from a remote location and are unattended. This means that the control room in the plant is equipped as if the plant were attended in order to allow for temporary operation mainly during precommissioning, commissioning, start-up, and tuning, and in case there is a plant upset.

Furthermore, there can be additional redundant links to other control room(s), located a few miles away. Of course, extensive additional information systems serve the goal of plant safety. These systems utilize the fire- and gas-detection and -protection systems and gate control, flooding, and so on. The fire-detection and fire-fighting system cabinets are located in the control room behind or to the sides of the operator's control desks, in order to allow for immediate response to any dangerous situation.

The software packages supplied with the DCS, in addition to the standard operating controls, also include such data sources as the steam tables, the sequence of event (SOE) module, post-trip review modules, and possibly the performance evaluators and stress evaluators.

Control Desks, Operator's Displays Operators find it very useful to have one CRT on the control desk directly connected to the GT governor and another one directly connected to the ST governor, in order to eliminate the transmission delays mainly during start-up and shutdown, or during plant upsets.

The control desk also houses the PC dedicated to continuous emission monitoring system (CEMS) plus the remote direct reading level gauges for the steam drums, where they are required by local regulations.

The engineering station can be located on the same control desk or in a separate room, according to the company policies and also as a function of the available space. It is, however, to be noted that the operations team is very small, has only a couple of operators per shift, a few other maintenance specialists, plus the plant manager. For example, in a power plant with four combined cycle units, the operating team is composed of two operators per shift, each running two units, and a common supervisor.

The control system is also used for the management of spare parts inventory and maintenance of both main machinery and the smart transmitters. The aim is to perform the maintenance on a predictive basis, i.e., when the behavior of a component shows a degradation that could result in a fault. In this case, the use of fieldbus technology connecting field devices is very useful, because of the large volume of diagnostic information to be processed and conveyed to maintenance engineers.

The control system sometimes also has the task of storing technical bulletins and documentation pertinent to the various components of the plant in order to facilitate the finding of information as required.

Monitoring and Control Loops

In a combined cycle power plant, these functions are quite simple and are similar to the boiler and the steam turbine controls that are covered in Sections 8.6 and 8.38 in this chapter. In contrast to boiler controls, HRSG controls do not have air/fuel ratio, steam pressure, furnace draft, and so on, so they are relatively simpler. In the paragraphs below, those measurements and controls will be discussed that are typical to combined cycle controls, or are different from the ones used on boilers and steam turbines.

Fuel Gas Heating Value The heating value of the gas delivered to the users is variable with time, and in several countries the heating bill reflects not only the quantity of fuel delivered, but also its higher heating value. The gas distributors provide average daily values of the upper heating value, which the users should check.

In addition to the commercial issues, this measurement, related to the lower heating value, is very important from an operational point of view, especially when the GT is the aeroderivative type. An increase in the fuel gas heating value increases the flame temperature and can overheat the first row of turbine blades, causing a sudden shutdown of the GT, if the firing rate is not decreased. The consequence of a shutdown is the loss of at least 1 hr of electric production, and if the plant is cogenerative, the steam production is also disrupted.

To prevent this kind of shutdown, a chromatograph or a calorimeter (or both) are installed on the fuel gas. For a detailed discussion of calorimeters and chromatographs, refer to Sections 8.8 and 8.12 of the first volume of this handbook, respectively. If the fuel gas heating value increases, the set point of the GT governor is automatically lowered to reduce the combustion temperature and, thereby, protect the system from a shutdown.

HRSG Start-Up Vent Valve The main purpose of this valve, which is installed downstream of the HP superheater (see item 1 in Figure 8.33k), is to control the pressure in the steam drum during start-up and to let it rise slowly so that the corresponding rate of rise in steam drum temperature will be acceptable. To perform this task, the HP vent valve works in combination with the ST bypass valves.

For large steam drums with a wall thickness > 4 in. (100 mm) operating at 1500 psi (100 bar) and over, the acceptable temperature gradient is 6–11°F/min (3–6°C/min), while for smaller drums operating at 900 psi (60 bar), the temperature gradient can be 15°F/min (8°C/min). The lower figures are used when the HRSG is subject to frequent starts and stops.

The problem that is typical of the HRSG is that during the start-up phase, the heat delivered to the HRSG is quite high even though the GT runs at its minimum capacity, i.e., at FSNL or minimum technical load. The start-up vent valve should be capable of operating with an upstream pressure from nil to the design pressure, with temperature varying from 212°F (100°C) to the superheated steam temperature at the nominal working pressure. The valve has critical pressure drop and should be designed to abate the noise pressure level down to 80–85 dB(a), according to most contractual specifications.

For the purpose of noise abatement, this valve cannot be considered as operating in emergency only, like safety valves, because it operates for long periods of time during all start-ups, and the start-ups can be relatively frequent, at least for the need of off-line washing the air compressor blades. For detailed information on control valve sizing and valve noise calculation, refer to Sections 6.14 and 6.15 of this volume.

Because this valve operates with both variable upstream pressure and variable flow, as a function of HRSG operation and of the requirement to keep the temperature gradient within the allowable limits, it is not easy to prepare sizing data of process conditions describing the pressurization operation in order to size the valve.

The sizing of this valve is dependent upon a number of factors, only one of which is the start-up condition.

It is possible that the plant should be designed to maintain the GT output in case of ST failure or in case of ST condenser failure. In this case, the valve should be sized for 100% unfired duty because the possible supplementary firing is shut down if the vent valve opens. If the plant can be started up by using the ST bypass valves only, because auxiliary steam is available to bring the condenser on-line, then this vent valve can be omitted. Experience has shown that this valve works properly to cope with the start-up needs, if it is sized for at least 30–35% of the boiler steam capacity at nominal conditions.

In some cases this valve can be a motor-operated (inching type) globe valve. An additional requirement for this valve often is to prevent the blowing of the safety valves that are protecting the drum and superheater coils from overpressuring in case of ST trip or load rejection. To be able to do this, the start-up vent valve should be fast opening (opening time of 2–3 sec) and stay open for about 5 sec until the ST bypass valves (if sized for 100% flow) can handle the upset caused by the ST trip.

If there are no ST bypass valves, as in smaller plants or process steam generators, the valve should be able to handle the full steam generating capacity. For high-pressure boilers, the flow can be split into two valves, one suitable for the controlling the start-up conditions up to a pressure of 30% of the nominal one, and the other, used for emergency only, to prevent the blowing of the safety valves. When operating at full pressure, the start-up valve is inhibited in order to prevent uncontrollable level upsets. Whatever valve size is selected, it is essential to consider the amount of make-up water required.

Steam Drum Level Control

The level control of the steam drum of an HRSG is very similar to that of fired boilers. Up to 30% of nominal steam flow, usually a single-element controller (level only as shown in Figure 8.6ww), is used. There have been cases where the level control of large HRSGs was stable, while its load was over 30% and the level was controlled with a single element controller.

Above 30%, the loop usually is bumplessly transferred to three-element control (water level, steam, and water flow as shown in Figure 8.6yy). The phrase *three-element* is used to define a mass balance between input and output flows to/from the steam drum, which are feedback-corrected by the level measurement. In more elaborate algorithms, more than three measurements can also be used.

The feedwater control valve can be located upstream or downstream of the economizer, as a function of the designs of the various HRSG manufacturers. Several HRSG manufacturers do not allow the economizer to steam, and therefore the control valve is installed downstream of the economizer. This solution is very effective in preventing steaming but imposes a higher design pressure on the economizer itself with the associated costs.

The valve in these installations is quite critical because it can be subject to flashing and cavitation. The installation of the control valve at ground level can help reduce this problem, provided the piping layout allows for it. Furthermore, during start-up, due to the water trapped in the economizer, an overpressure builds up, because the boiler feedwater valve is closed due to the minimal amount of steam generation in the steam drum, and the check valve on the BFW pump discharge is closed.

This overpressure needs to be relieved without opening the safety valve through an antiflash valve that should open on the pressure threshold. Some units are designed to maintain a minimum flow through the economizers to prevent this, and the excess water is dumped from the steam drums to a condensate-recovery system.

Some HRSG suppliers accept a little steaming in the economizer and install the control valve upstream of the economizer with an accurate heat-transfer design to reduce steaming during some transient conditions. The valve, in this case, is much less critical as it handles "cold" water without flashing or cavitation problems.

Mainly on the HP circuit, the BFW control valve sometimes requires a smaller valve in parallel for start-up. This start-up valve should be sized for a flow equal to approximately 20–35% of the nominal flow (in order to handle the water flow required during start-up). It should be sized to operate at a pressure drop that is much higher than the one during normal operation through the main control valve. This is because the flow is very low, the BFW pump is practically working at its shut-off pressure, while the friction losses in the line and coils are minimal, and the pressure in the steam drum is much lower than during normal operation.

As the power station can operate under several conditions, it is suggested that the suppliers who bid on the BFW control valve be provided with data on all the different operating conditions. This way they should be able to check the

TABLE 8.33m
Illustration of the Process Data Required for the Proper Sizing of an HP Boiler Feedwater Control Valve

Case	Q Steam (lb/s)	Q Blowdown 2%	Q Sizing (lbs/s)	T (°F)	P Pump (psia) Delivery el. 3 ft.	Dp Line and Head (psi)	P Upstream Valve (psia) el 100 ft.	P Downstream Valve (psia) Pin-eco (psia)	DP (psi) Operation
1	171.3	3.4	174.7	348	2143.6	60	2083.6	1856	227.6
2	169.8	3.4	173.2	348	2146.5	60	2086.5	1813	273.5
3	166.6	3.3	169.9	348	2156.7	60	2096.7	1755	341.7
4	146.0	2.9	148.9	348	2255.3	60	2195.3	1552	643.3
5	146.1	2.9	149.0	348	2265.5	60	2205.5	1581	624.5
6	127.2	2.5	129.7	348	2346.7	60	2286.7	1378	908.7
7	97.0	1.9	98.9	348	2459.8	60	2399.8	1233	1166.8
8	167.4	3.3	170.7	348	2156.7	60	2096.7	1784	312.7
9	146.2	2.9	149.1	348	2264.0	60	2204.0	1566	638.0
10	126.9	2.5	129.4	348	2349.6	60	2289.6	1363	926.6
11	94.2	1.9	96.1	348	2467.0	60	2407.0	1233	1174.0
12	160.2	3.2	163.4	348	2230.7	60	2170.7	1769	401.7
13	228.7	4.6	233.3	348	2290.1	60	2230.1	1552	678.1
14	122.1	2.4	124.5	348	2371.4	60	2311.4	1349	962.4
15	96.1	1.9	98.0	348	2464.2	60	2404.2	1233	1171.2
16	167.8	3.4	171.2	348	2126.3	60	2066.3	1842	224.3
17	166.7	3.3	170.0	348	2065.3	60	2005.3	1784	221.3
18	167.7	3.4	171.1	348	2058.1	60	1998.1	1842	156.1
19	31.4	0.6	32.0	348	2554.1	60	2494.1	377	2117.1
20	169.9	3.4	173.3	348	2135.0	60	2075.0	1827	248.0
21	166.5	3.3	169.8	348	2135.0	60	2075.0	1755	320.0
22	145.9	2.9	148.8	348	2249.6	60	2189.6	1552	637.6

performance of the proposed valve over the complete range of operating conditions (Table 8.33m). The valve body size is frequently determined not only on the basis of the required valve capacity (C_v), but also by considering the maximum acceptable flow velocity [approximately 30 ft/s (9 m/s)]. Additional information can be found in ISA standards (Reference 4).

Steam Temperature Control

Steam temperature is usually controlled with desuperheating valves installed between the first and second superheaters, similarly to the arrangement in regular boilers (Figure 8.33n). If the superheaters are split into more banks in parallel, good practice requires a desuperheating valve per each bank.

The control function is normally implemented by a cascade loop in which the master controller (TIC-111 in Figure 8.33n) senses the final steam temperature and the slave senses the temperature after the desuperheater, before the steam enters the second superheater. The set point of the slave controller has a low limit of roughly 28–30°F (15–16°C) above the saturation temperature obtained by characterizing the steam drum pressure to prevent moist steam in the second superheater, as well as poor temperature control.

The temperature used as the measurement of the slave controller (TT-112) should be located about 60 ft (20 m) downstream of the desuperheater to allow the water droplets to vaporize, which is necessary to obtain a correct measurement and to prevent mechanical damage to the protecting thermowell. Sometimes a feedforward action by steam flow is added (FY-102) to the control system.

Very often, the piping is also protected with internal sheathing to prevent erosion. If the thermal design is correct, in some operating conditions (mainly under base loading) the desuperheaters are not in operation, while in other operating conditions the desuperheating BFW flow can be highly variable. It is suggested that the suppliers who bid on the desuperheater be provided with data on all of the different operating conditions (Table 8.33o).

When a desuperheating valve is not in use, it is isolated by a pneumatically or electrically operated on/off valve that is installed upstream of the desuperheater in the BFW line. This valve is closed a few seconds after the desuperheating valve is closed (or when it is less than 2% open) and is opened

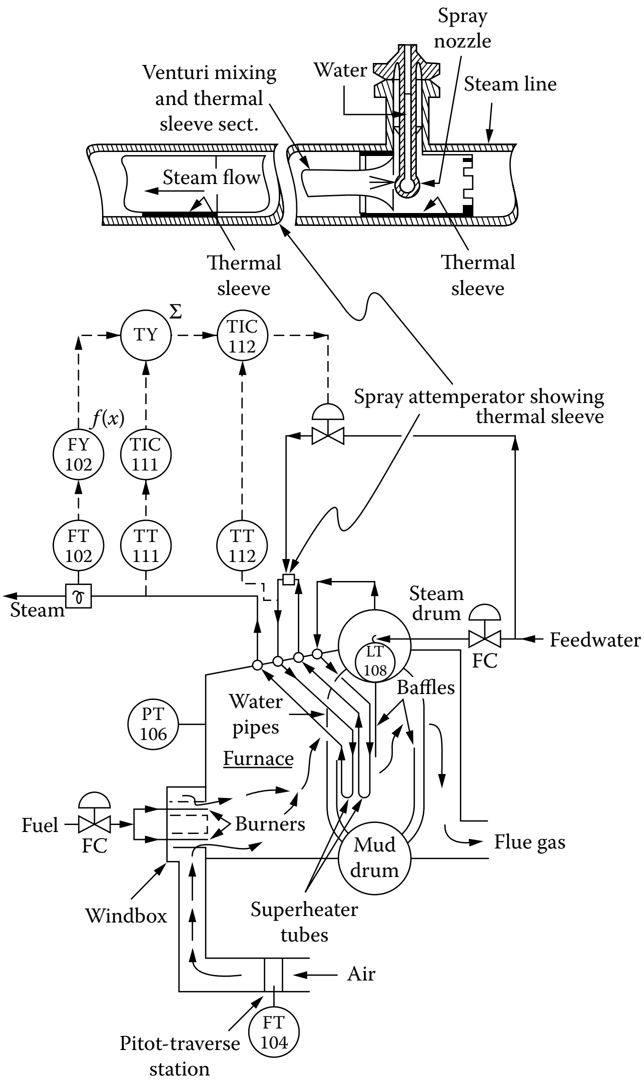

FIG. 8.33n

Cascade configuration for controlling the desuperheater control valve.

when control signal setting the desuperheater valve opening exceeds approximately 4%.

If the desuperheater is of the insertion type, its rating should be determined by considering the design pressure of the BFW and the design temperature of the steam. With today's high pressures [up to 3500 PSIG (241 barg)] and temperatures [up to 1075°F (580°C)], this is not always achievable. This creates serious problems when desuperheaters are selected. Additional information can be found in ISA standards (Reference 5).

Pegging Steam Control

Pegging steam is required to deaerate the boiler feedwater during start-up, when no low pressure (LP) steam is yet available and if no steam is available from an auxiliary boiler or from other HRSGs. The purpose of this control system is to start deaerating the boiler feedwater as soon as possible during start-up.

If the deaerating tower is located on top of the LP drum, then during normal operation, the steam needed for deaeration is generated in the LP drum. Under start-up conditions, the steam first becomes available in the HP section, then in the IP section, and finally in the LP section of the HRSG. If an auxiliary boiler is not available, in order to start degassing as early as possible, a connection can be made between the IP or HP drum and the deaerating head. In this connecting pipe, a motor-operated on/off valve and a throttling control valve are installed.

The control valve serves to reduce the HP or IP pressure to the LP level for the deaerator during start-up. Once the LP section is generating enough steam to be self-sufficient to ensure good deaeration, this start-up phase can be terminated. This happens when the pressure in the deaerator reaches a pressure of about 25 psia (1.7 bara). At this point, the pegging steam line is closed. This is done by closing both the control valve and the on/off isolating valve.

On fired units it is possible that pegging steam is also required during normal operation at high loads, because the LP section does not generate sufficient steam.

Condensate Preheater (Economizer) Temperature Control

This control system is unique to HRSGs and is not used on conventional fired boilers. Its dual purpose is to 1) prevent external condensation on the tubes of the preheater, which could cause external corrosion, and 2) obtain the correct inlet temperature to the deaerator.

The first objective is met by taking some of the hot condensate leaving the preheater and mixing it with the cold condensate entering the preheater (TIC-1 in Figure 8.33p). The hot condensate is recirculated by recirculation pumps, and the flow rate of recirculated hot condensate is throttled by TIC-1, which detects the temperature of the (mixed) condensate stream entering the preheater and keeps that temperature high enough to prevent external condensation.

The correct inlet temperature for the deaerator is obtained by mixing the hot condensate downstream of the preheater with cold condensate. This inlet temperature is maintained by TIC-2, which detects the mixed condensate's inlet temperature to the deaerator and is set a little lower [15°F (8°C)] than the boiling temperature. If large amounts of the hot condensate are recirculated by TIC-1, this could cause TIC-2 to lose control and cause a low temperature at the condensate inlet to the deaerator, thus the need for pegging steam.

A less sophisticated control configuration that has been used to remove sulfur from flue gas is shown in Figure 8.33q. Here, the cascade master TIC-2 maintains the required deaerator inlet temperature by modulating the set point of TIC-1, the slave controller. In this configuration, however, there is no positive protection of the preheater coil against condensation on its external surface.

TABLE 8.33o
Illustration of the Process Data Required for the Proper Sizing of an HP Steam Desuperheater

4 valves per boiler—one for each superheater bank in parallel

Case	Q Steam (lb/s) (total)	Q Steam (lb/s) Per Line	T Steam Upstream °F	T Steam Downstream °F	P Steam (psia)	Q Water (total) lb/s	Q Water Valve lb/s	T Water °F	P Water (psia) el. 100 f.	Dp Water Steam (psi)
1	0.0	0.0	921	921	1182.1		0.000	288	1472.1	290.0
2	19.8	5.0	979	842	1241.5	19.832	4.958	293	1472.1	230.6
3	9.3	2.3	961	878	1187.5	9.264	2.316	284	1472.1	284.6
4	32.0	8.0	1022	797	1245.9	32.023	8.006	271	1472.1	226.2
5	32.6	8.2	1044	775	1208.2	32.625	8.156	273	1472.1	263.9
6	0.0	0.0	905	905	1167.6		0.000	297	1472.1	304.5
7	0.0	0.0	912	912	1166.1		0.000	295	1472.1	306.0
8	9.2	2.3	954	882	1211.1	9.231	2.308	295	1472.1	261.0
9	18.1	4.5	973	849	1241.5	18.105	4.526	293	1472.1	230.6
10	21.1	5.3	993	829	1215.4	21.161	5.290	291	1472.1	256.7
11	7.2	1.8	952	889	1179.2	7.208	1.802	293	1472.1	292.9
12	25.0	97.3	1008	813	1212.5	25.000	6.250	286	1472.1	259.6

In some HRSGs, block valves are provided so that the LP preheater can be temporarily valved off (isolated), if water leakage occurs.

If the fuel has a high sulfur content, the primary concern is to keep the inlet temperature of the condensate to the preheater above the dew point of flue gas by proper recirculation of some of the hot condensate.

Supplementary Firing Control

In some plants, the fuel flow to the burners is set manually by the load dispatcher, but errors can cause transient overfiring and overheating the superheater tubes. Therefore, a burner management system, complete with accessories such as flame scanners, purging, and cooling, shall be provided to ensure the boiler safety.

Supplementary firing should limited to a fraction of the GT load. The applicable safety codes in the area of the HRSG depend on the presence of fuel gas in the proximity. It is possible to reduce the area classification by a careful study of the piping layout and by the adoption of some precautions. These would include he use of double stuffing glands with bleeds in between the glands on the fuel gas valves. The intermediate bleeds from such valves are collected and vented to the atmosphere at safe location.

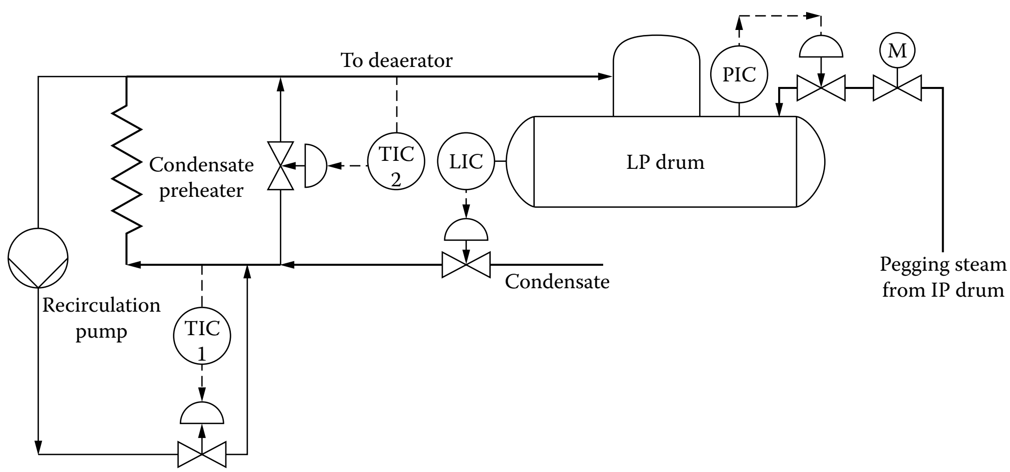

FIG. 8.33p
TIC-1 keeps the condensate preheater surface temperature high enough to prevent external condensation, while TIC-2 keeps the deaerator inlet temperature below the boiling point. Under certain conditions, the two loops can fight each other.

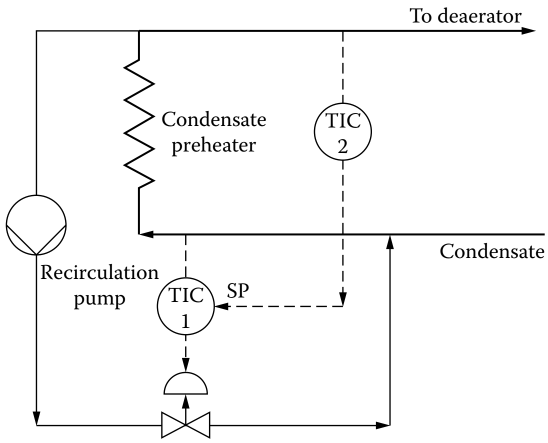

FIG. 8.33q
Cascade control of preheater does not give positive protection against flue gas condensation on the external surface of the preheater.

The firing could also pose some problems with emission control, especially at reduced GT loads, and may require the use of flue gas recirculation (FGR).

Steam Turbine Bypass Control

The bypass valves (Figure 8.33k) around the steam turbine (ST) are closed during normal operation and are throttling during the start-up, after an ST trip, or in the case of load rejection. A pressure controller PIC (with antireset windup) is throttling the bypass valve, so as to keep the upstream (inlet) pressures at the desired HP, IP, and LP settings and to make sure that they do not reach the settings of the corresponding safety valves.

In addition, the pressure control valves in the turbine bypasses should be provided with a quick-opening capability (a solenoid can be used on pneumatic valves) that will be triggered by an ST trip and remain open for a duration of approximately 5 sec.

When the boiler operates in sliding (floating) pressure, the set point of the bypass PICs should track the operating pressure to prevent sudden transients. In these conditions, the purpose of the bypass is to prevent the safety valves from blowing when the steam pressure suddenly increases due to a trip of the ST. Alternatively, if the valves have a hydraulic actuator capable of following the controller output with very little delay (a few seconds), the opening can be proportional to the steam flow prior to the ST trip, thus avoiding any pressure upset.

During start-up, after the vacuum has been established in the condenser, the set points of the bypass PICs are set to follow the acceptable heating curve of the steam drum until the steam turbine is warmed up and can handle the superheated (SH) steam. A desuperheater should be provided to reduce the steam temperature to the value that is compatible with the downstream steam conditions. This desuperheater can be integral with the pressure reducing valve or separate from it.

The bypass valves can be sized to pass partial or full flow at the operating pressure conditions. In combined cycle power plants, the bypass valves are normally sized to pass the full steam flow. If the HRSG can operate on sliding pressure, the sizing is still based on the maximum operating pressure and flow. During the operation in the sliding pressure mode, because the GT is not at base load, the pressure drop across the valve is reduced, and an ST trip can cause a rise in the upstream steam pressure, but always within the normal operating values.

If the plant configuration is 2 + 1 (Figure 8.33f), during plant start-up or if GT is out of service, only one GT and HRSG are feeding the ST. In such cases, the HP pressure is lower than the normal one even though the operating GT is running at base load. A trip of the ST under these conditions will cause a sudden opening of the bypass, and the pressure in the operating HRSG will rise up to a value close to the nominal operating pressure. Additional information can be found in ISA standards (Reference 6).

Load/Frequency Control

The purpose of this control system is to keep the frequency variations within preset limits when the load and the generated power are unbalanced. The system guarantees that each generator unit can automatically and autonomously participate in the frequency control by gradually modifying the generated power in order to keep the frequency constant.

This is completely true if the unit is running at partial loading and is somewhat less so as the loading approaches 95%. If the unit is running at base load, it can only decrease its load if the frequency is in excess of the nominal one but it cannot increase the load in the case of an underfrequency episode.

Due to the offset that is caused by the proportional-only mode of frequency regulation, even when the generated power is balanced with the load, there could still be an offset in the frequency that needs to be corrected. This correction is provided by an external controller (at grid level) that acts as a primary or master of a cascade control loop whose slave is the turbine governor. In such a case, a command is likely to be received from the grid dispatcher to vary the generated power of the units that have spare capacity, in order to restore the nominal frequency of the grid or the correct exchange of power with other grids.

The variation in total generating capacity is split between the GT and ST into 2/3 in the GT and 1/3 in the ST. This means that if the electric power generation should change by x MW, the total change almost immediately (within a few seconds) affects the GT, and then, a few minutes later, there will be an increasing contribution by the ST with simultaneous decreasing contribution by the GT. When the new steady state is reached, the contribution of the GT will be about

2/3x and the incremental power contribution of the ST will be about 1/3 x.

Running Permissives

Each machine component is provided with its own internal safety instrumented functions (SIFs) that are defined and often implemented by the manufacturers, because they are inside their scope of responsibility for supply and are also proprietary systems.

As the components of the total plant are very much interconnected from both from the process and from the electrical perspective, it is necessary to provide reliable interconnections with the objective of minimizing the partial or total plant shutdowns that they can cause. These functional interconnections are very much dependent on the arrangement of the plant (single shaft or multiple shaft, 2 +1 configuration, and so on) and the response to the failure of all major pieces of equipment must be planned in advance. Therefore, it is good practice to prepare both a cause–effect table/matrix (sometimes called a shutdown key) and an overall diagram of running permissives, which are also useful to the plant operators during normal operation.

A steam turbine trip causes the sudden temporary opening of the bypass valves around the STs and possibly the opening of the HRSG vent valves (Figure 8.33k). This allows the plant to run at reduced electrical capacity with the GT only, yet retaining the possibility of restarting the ST if the causes for the trip can be quickly removed.

If the condenser is not available, the GT is forced to operate under FSNL condition and either vent valves on the HRSG are opened or the GT must be shut down. This choice is dependent on the design of start-up vents and on the availability of water, as was discussed earlier. If the HRSG is provided with a diverter, the possibility of exhausting the GT to the atmosphere should also be considered, particularly if it is expected that the restarting of the ST will be delayed beyond a certain time period.

An HRSG trip due to unsafe conditions (too low a level, or a "low-low" condition in the drums, or sometimes too high a temperature, or a "high-high" condition of the SH or RH steam) should either open the diverter (if such exists), or otherwise the GT should be shut down. If a high level condition is detected ("high-high"), the ST bypass system can be opened and the ST tripped. In the case of abnormal conditions in the post-firing (flame failure) section, only the burner trip should be considered.

A gas turbine trip causes the trip of the complete train, unless complementary firing is available in the HRSG. In this case, the ST should be tripped, the diverter should be switched, the air fan started, and the burners lit after purging, to avoid disruption of the steam being generated for industrial use.

An electric generator trip should cause the trip of the pertinent driving turbine or of the complete train, in case of single-shaft configuration. In some cases, if the fault is electric, it is possible to try to prevent the trip by opening the circuit breaker of the machine. This way, the GT can be kept in operation at FSNL, with the possible benefit of reducing the time to restart and of reducing the equivalent hours of GT operation.

A step-up transformer fault causes the trip of the pertinent generator, if it is directly connected, and also the opening of the line breaker. If there is a circuit breaker between the generator and the transformer, then it too is opened.

A fault in the bus bar system causes the isolation of the faulty bus bar, possibly without interfering with the generation set.

A fault in the grid causes the opening of the line breakers, the trip of the ST, and the running of the GT in "island mode" (or at minimum load sufficient to feed the pertinent loads in the power house). This kind of electric trip with sudden load loss is claimed to be tolerated by the GT, but sometimes keeping the GT in operation requires a time-consuming fine-tuning.

Safety Functions and Integrity Levels

The manufacturer-supplied GT and ST governors usually include the control and safety systems for the turbines. In fault-tolerant configurations containing a high level of diagnostics, they normally include separate processors at least for safety functions. However, detailed diagnostics are usually not provided by the GT manufacturers, and the safety integrity level (SIL) "capability" of the governors is not guaranteed, either, by their architecture alone. The attainment of the SIL capability also requires the proper selection of the sensors, wiring, final elements, maintenance, and testing.

The turbine suppliers are very reluctant to accept any modification or inclusion of additional functionality to their controls, even if it is strictly correlated with their supplied controls and is external to the GT. This is because the turbine package is provided with control functions inside the governor (designed around the turbine it protects). The supplied packages usually do include several architectures of the furnished control functions, from which the user can select.

Most safety-related controls that are required for turbines in a cycle with an unfired HRSG are furnished within the manufacturer's package. The unsafe conditions that are usually not covered are those of the levels in the steam drums of the HRSG and the fuel gas intercept valves to the GT.

Often the specifications call for a safety integrity level of 3 (SIL 3) for all SIFs, and this could be due to inadequate analysis. Such specifications could result in overengineering of the complete safety instrumented system (SIS) with its associated costs in maintenance, for the whole life cycle of the plant. For the proper selection of SIL levels, see References 7 and 8.

START-UPS AND SHUTDOWNS

Start-Up Procedures

The combined cycle power plants, even if they are operated at base load, are subject to starts and stops more frequently than other industrial plants or power plants. The frequency of start/stop requirements dramatically increases if the combined cycle operates in an intermittent way.

In order to operate the plants with reduced crews of operators, it is necessary to be able to implement a start-up procedure from the control room without people having to walk around the plant. Hence, all valves that need to be operated during the start-up should be motor-operated.

The main concern in starting up a combined cycle power plant is to avoid thermal stresses to the machinery that would shorten its life and produce unsafe conditions. This consideration results in extending the time for start-up, while economics would require that start-up take place in the minimum possible time and with minimum fuel consumption.

For the ST and the HRSG, different starting conditions can be defined depending on their status at the beginning of the start-up (i.e., if they are cold or hot). Of course, a cold start up requires a more cautious and longer procedure to avoid stressing the machinery. However, the cold and hot conditions are different for the HRSG and the ST, so that a start-up can be considered cold for one machine and hot for the other. For large HRSGs, a warm start-up condition is often considered.

Each manufacturer of the main plant equipment sets the requirements for its machine, and then it is up to the process design engineers to combine these requirements with their own to arrive at start-up procedures that will minimize the overall start-up time.

Sometimes, the normal start-up procedure needs to be modified to cope with the environmental constraints as dictated by local regulations. This could involve a long warming period at low load followed by a quick ramp-up, or starting with the GT at high load (even 70–80%) plus a lot of steam being bypassed to the condenser, in order to maintain the proper temperature gradient in the HRSG. This unusual situation can have an impact on the last stages of the ST and needs to be thoroughly investigated with the manufacturers in order to avoid dangerous operating conditions.

The start-up sequences are resident both in the DCS that acts as the overall coordinator, and in the turbine governors that are interfaced with the DCS. As previously mentioned, in several instances the governors are parts of the DCS.

Permissive Conditions The start-up can take place only if some permissive conditions are satisfied, such as the availability of instrument air, cooling water, demineralized water, fuel gas, and electricity to feed all motors (HV and LV) and the DCS. All these permissives should be listed in detail as prerequisites for the start-up procedure.

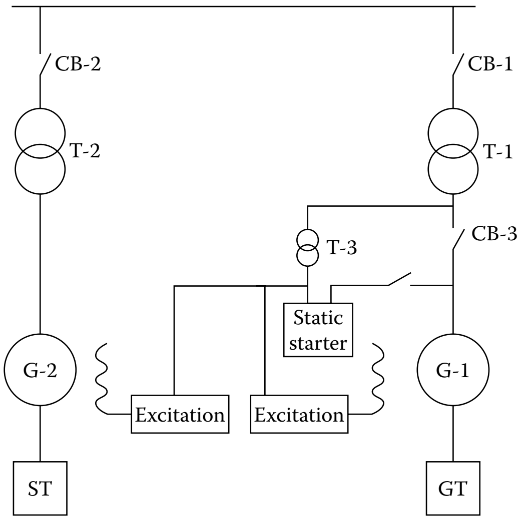

FIG. 8.33r
Simplified one-line electrical diagram of a dual-shaft power station of 250 MW capacity.

The document describing the overall sequence should start with the required position of all valves, status of all controllers (auto, manual, forced to XX value, and so on) and conditions of all pumps (running, standby, available/unavailable) at the beginning of the start-up procedure. The hot, warm, or cold condition of each machine should also be determined.

According to the mechanical and electrical configuration of the plant, the start-up procedure can vary to follow specific requirements. Therefore, each plant has to be designed individually. In other words, each plant is unique and its start-up procedure should also be developed to suit the unique requirements of the GT, HRSG, ST, and condenser manufacturers and, possibly, also of the electrical grid and plant operators. In the case of cogeneration, the requirements of the steam user operators should also be taken into account.

As an example, a typical cold start-up procedure is provided below for a unit designed for 250 MW, dual-shaft, unfired HRSG with three steam pressure levels, a water-cooled condenser, and a GT generator also acting as launching motor, in which the main steps correlating the different equipment are highlighted (Figure 8.33r). In this case, no black starting was required and no steam was available from an auxiliary boiler or other units.

Cold conditions mean that the boiler has an HP temperature lower than 212°F (100°C) and the first-stage metal temperature of the ST is less than 245°F (120°C). Some suppliers also recommend that the shafts of the turbines be cranked for few hours before starting up, with the lubrication system in operation.

For a power plant unit of this size, skin thermocouples are installed on the HP drum, on the final HP superheater, and on the IP reheater, mainly to monitor the metal temperature gradients during the start-up phases.

If all permissives are satisfied and the equipment is ready to be energized, the start-up sequence proceeds as follows:

The Start-Up Sequence

1. Close the line circuit breaker CB-1 in order to energize backwards to the gas turbine step-up transformer T-1 and the unit transformer T-3. The generator circuit breaker CB-3 is open.
2. On the operator's start-up command, the GT governor will put in operation the lube oil system, if it was not in operation because the turbine was cranking. For heavy-duty turbines a slow cranking (few rpm) is necessary for several hours before starting. The temperature of the lube oil shall be higher than the minimum required by the manufacturer.
3. The lubricating oil circuit of the steam turbine is put in operation as well as the jacking oil circuit of the generator.
4. The shaft turning gear of the steam turbine is started, unless it was already operating.
5. All cooling circuits are put in operation.
6. The level of the condensate storage tank is to be at a normal value.
7. The condenser hot well level is to be at a normal value.
8. The condensate extraction pumps are put into operation.
9. The LP drum level is filled to the required start-up value.
10. The IP and HP drums are filled to the required start-up level (minimum level).
11. The boiler blow-down system is started and put in auto; the sampling system is started as well.
12. One main boiler feedwater pump is started.
13. The steam turbine bypass system is prepared for automatic operation.
14. The HRSG configuration is set and checked.
15. The superheater drain valves are open and shall be kept open until a pressure of approximately 30 psig [2 bar(g)] is reached.
16. The steam line drains are open to warm up the piping and shall be kept open until the correct temperature has been obtained.
17. The boiler setup sequence is performed either automatically or manually, step by step. The automatic ramp-up sequence of the HRSG is selected for start.
18. The excitation system of the GT generator and the static starting system of the GT are energized.
19. The block and bleed valves on the fuel gas supply are put in operation in order to deliver fuel gas to the gas turbine inlet valve.
20. Under the control of the GT governor, the gas turbine is now ready to start, waiting for the start command from the operator that can be given through the DCS or directly via governor HMI.
21. When the correct lube oil pressure is established, the static starter will rotate the gas turbine and run it at a preset value without firing during the time needed for the proper purge of the turbine and of the HRSG. It should be noted that the purging time is longer on the combined cycle than on the open cycle, as the volume of the HRSG must be purged as well. The time for the purge (typically, 15–20 min) is calculated on the basis of five air changes with the airflow produced by the compressor running at launching motor speed.
22. At the end of the purge, the GT governor will light the burners, the static starting system will be switched off and the gas turbine will ramp up to the synchronization speed in 15–20 min (for heavy-duty GTs) or a couple of minutes (for aeroderivative GTs). The excitation system regulates the generated voltage to the correct value. The speed gradient of the gas turbine is controlled by the GT governor. The gas turbine is kept at full speed no load, exhausting to the HRSG with the generator disconnected from the grid. For some turbines, it is required that a minimum load be connected; in case the power station auxiliaries are not large enough, the paralleling of the GT generator to the grid shall be performed. Some turbines even at FSNL have an exhaust temperature higher than an acceptable value [usually 770°F (410°C)] for the HP superheater coils (abnormal thermal expansion due to very low steam flow), and therefore it is necessary to activate the exhaust temperature limitation function.
23. The HRSG will start steaming, and the pressure is controlled by actuating the vent valves so that the temperature gradient in the HP drum remains within the limit indicated on the relevant diagrams by the HRSG manufacturer for cold conditions in order to prevent stress to the pressure parts. The vent valves are initially kept at a minimum opening, then switched to automatic control with an automatic ramp of the controller set point. If the vacuum in the condenser can be obtained because some steam is available, the steam pressure is controlled by means of the turbine bypass valves.
24. The HRSG is kept at the warming up condition [HP 800 psig (55 barg), IP 300 psig (20 barg), LP 50 psig (3 barg), approximately] for at least 15 min, while the steam lines are preheated via the main stop bypass valves, line vents, and drains, or alternatively, with the main stop valves fully open.
25. As soon as the differential pressure across the main stop valves and the temperature of the steam lines are acceptable, the main stop valves of the HRSG are opened. If the start-up takes place with the stop valves fully open, this step is skipped.
26. The generated steam from HP or alternatively from IP is conveyed to pressurize the steam glands of the

steam turbine. If auxiliary steam is available, this step takes place much earlier.

27. The start-up ejector is started as soon as steam is available at suitable conditions and is operated until the condenser pressure reaches 4.5 psia [300 mbar(a)]. After that the main ejectors are started in order to reach the proper vacuum 0.4 psia [30 mbar(a)].
28. When the pressure in the condenser reaches 4 psia [280 mbar(a)], the turbine drains to the condenser are opened and the generated steam is desuperheated and dumped to the condenser. The pressure reducers (bypass valves and desuperheaters) in the main steam system are put in operation with an initial set point of approximately 870 psig [60 bar(g)] for the bypass from HP to the cold reheat (CRH), while 200 psig [14 bar(g)] or less is required for the bypass from the hot reheat (HRH) to the condenser and 45 psig [3 bar(g)] from LP to the condenser. The operation is performed by acting through the DCS, starting from the HP to the CRH bypass (sometimes this bypass is opened before the vacuum at the condenser is established in order to flush the RH coils) and ending with the IP and LP to the condenser.
29. At this point, the gas turbine is still running at FSNL (or at minimum load) and the HRSG (HP) stays at 870 psig [60 bar(g)] and 735°F (390°C).
30. When the correct control fluid pressures are established, the ST is started under control of the turbine governor. The turbine increases its velocity with a gradient defined by the governor and is gradually warmed up according to the sequence defined by the manufacturer. It is possible that the acceleration is increased in a range around the first critical velocity of the steam turbine and of the generator. When the turbine velocity is about 90% of the nominal speed, the excitation system will regulate the generated voltage to the correct value.
31. The steam lines' vents and drains are closed.
32. As soon as the steam turbine has warmed up to an acceptable point under control of the synchronizing equipment and on request of the operator, the gas turbine generator is put in parallel with the grid by closing the circuit breaker CB-3.
33. The GT governor ramps up the generated load at least to the minimum allowable working value (about 55%).
34. The gas turbine output is raised up at a rate of about 2%/min. This operation can be done either through the DCS or directly by the GT governor HMI.
35. Meanwhile, the set points of the pressure regulators of the bypass valves are gradually raised, so as to pressurize the boiler, always keeping in mind that the temperature gradient in the steam drums shall not exceed the value stated by the boiler manufacturer.
36. When the boiler reaches a load of 30% the level control is switched to three-element control with the normal operational set point.
37. Drains and chemical dosing system of the boiler are put into normal operation.
38. When the warm-up procedure of the ST is finished, the steam turbine generator is synchronized with the grid, and the circuit breaker CB-2 is closed.
39. The power plant is now ready for ramping up to nominal power; when pressure in the HP drum reaches 1150 psig [80 bar(g)], the ramp limitation for the gas turbine is increased to 5%/min.

The complete cold start-up procedure of such a group of equipment requires about 4–6 hr or even more because of the low acceptable gradients and of the suggested stabilizing time in the HRSG and ST heating. In practice, the GT remains at FSNL or at minimum load for almost the whole start-up period, except the last 1/2–3/4 hour.

The hot and warm start-ups differ from the cold one mainly because several steps in the early stage of the sequence can be skipped and because higher gradients are acceptable in the limits on temperature/pressure rise. On the other hand, some additional precautions must also be taken. For example, it is necessary to protect from the steam becoming cooler than the ST metal by synchronizing the GT and raising the load until a proper steam temperature is reached. It may be necessary to lower the pressure of the reheater (RH) by opening the bypass and possibly also the vent valve, because the bypass is sized to pass the full flow at nominal conditions.

As a result, for the group of equipment considered in the example, the hot or warm start-up time is shortened to 2–3 hr.

Short-Term Planned Stop

A planned shut-down of the complete unit has the purpose of stopping the operation of the group of equipment with minimum stress to the machinery. It is also a goal to keep the electrical system alive to the maximum extent, so as to be able to restart the plant as soon as possible, in the hot start-up conditions. It is advisable to verify with equipment suppliers if there are any process variable limits or constraints that must be obeyed to avoid damaging the equipment itself. In particular, there could be the temperature of the RH steam that should be lowered in a predetermined way to prevent abnormal axial elongation of the ST rotor.

Short Stop Sequence

1. Reduce the generated power with a predetermined gradient through the GT governor by reducing the fuel gas admitted to the gas turbine.
2. The GT governor starts the auxiliary lube oil pump of the GT unless lubrication is obtained by means of separate pumps.

3. Consequential to the reduced power generated in the gas turbine, the steam turbine reduces its generated power. It is necessary to decrease the pressure of the RH beyond the natural pressure decrease by assigning variable set points to the bypass and vents, based on pressure/power curves defined by the ST manufacturer.
4. When the power generated by the steam turbine is close to 30%, the steam turbine bypass valves are opened and shortly after the turbine is tripped. The circuit breaker CB-2 opens, actuated by the minimum load relay. The vacuum in the condenser and the steam to the glands should be maintained as long as possible, at least until the steam turbine is stopped and restarted under turning gear (a sudden inlet of fresh air inside the hot portion of the turbine might generate distortions and thermal stress both on rotor and casing).
5. Once the minimum allowable load is reached, the GT governor shuts the gas admission valves, opens the circuit breaker CB-3, and excludes the excitation circuit.
6. Close the block and open the bleed valves on fuel gas inlet to the gas turbine package.
7. Immediately after the turbines are stopped, the steam turbine jacking oil pump is automatically started and the turbine turning gear is put into service, keeping the AC lubrication oil pumps in service until the journal temperature is reduced to a value compatible with the babbit metal of the bearing.
8. The operator activates the automatic bottling procedure of the HRSG, by which all valves around the HRSG and the damper in the stack (if present) are closed. If the stop is very short, then a couple of minutes after the TG stops, a very slow depressurization procedure is activated by slightly opening the start-up vents, thus keeping the superheaters flushed as to prevent condensation.

At the end of the short planned stop, turbines of the power station are still hot and turning under the turning gear and the HRSG is still pressurized and hot, ready to start in the shortest possible time (a couple of hours).

Long-Term Planned Stop

The long-term planned stop of the complete power generating unit has the purpose of stopping the group of equipment with minimum stress to the machinery and to reach the cold conditions in the shortest time. This has to be done in a manner compatible with the allowable temperature gradients that are needed to perform maintenance by means of internal inspection of the HRSG, or maintenance of the steam turbine.

In case of the long-term stop, the short planned stop is modified by running the ST at minimum load to stabilize its temperature at low values. In addition to the steps listed for the short-term planned stop, the sequence required in this case is as listed below:

Long Stop Sequence

1. Open the vent valves.
2. Break the vacuum in the condenser and take out the sealing steam from the turbine gland, following ST manufacturer instructions.
3. When the pressure in the steam drums reaches about 30 psig [2 bar(g)], open the drain valves in the superheaters.
4. Bring the level in the steam drums to minimum value and close the BFW control valves.
5. Stop the BFW pumps, depending on the pressure in the steam drums.
6. The jacking pump and the lube oil pump of the ST must be kept in operation until the rotor is cold enough to be sure that the bearing shall not be damaged by temperature. This operation takes several days. Following manufacturer instructions, the ST turbine rotor shall be rotated under turning gear periodically to avoid unelastic permanent deformation. During this rotation, the oil system shall be in operation, jacking oil pumps included.

After such a stop the boiler needs cooling down before one can enter the flue gas side. This is accomplished by opening the inspection doors and allowing the air to circulate inside the casing. The boiler is, however, still full of water. If the inside of the steam drums is to be inspected, the blowdown valves should be opened to empty the steam drums. If the boiler must be completely emptied, it is done by also opening all the drains.

Emergency Shutdown

Depending on its cause, the emergency shutdown can be partial or total.

An example of a partial shutdown is a cause requiring the shutdown of the steam turbine. If the exhaust gas from the GT can be diverted to a bypass stack (Figure 8.33i) or if the generated steam is dumped to the condenser, the gas turbine can continue generating electric power, even though in an uneconomical manner.

A fault in the gas turbine or in the HRSG causes a complete stop of the power generating unit, unless a flue gas diverter exists and the fault is in the HRSG. A fault in the utilities can generate partial or total shutdown or lead to a runback of the gas turbine. The emergency shutdown can also be caused by the electric grid, resulting in partial or complete shutdown of the unit.

The operator can also initiate total or partial emergency shutdowns, but this operation should be avoided as much as possible to prevent stresses to the machinery. In terms of equipment life, an emergency shutdown of the GT is considered to be equivalent to at least 50 hours of operation and can exceed 150 hours, according to the formulas of some GT manufacturers. As a rule of thumb, for an emergency shutdown, the equivalent number of hours of operation is equal to the load percentage at the moment of the turbine trip (e.g., if the turbine trips at 75% of the load, the equivalent hours are 75).

A load rejection is accounted as 50% of the corresponding equivalent hours due to an emergency trip. If the causes for the shutdown are external to the generating set, its shutdown should be avoided as much as practical. This can be achieved by operating the gas turbine in an island mode, i.e., disconnected from the grid and feeding the electric loads of the power station only.

The operator can then decide whether to stop the gas turbine or to keep it in island operation. Sometimes, in the case of a sudden load rejection, the gas turbine is unable to go into the island mode of operation, because of the intervention of its overspeed protection interlocks.

PERFORMANCE TESTS

The performance tests are normally carried out in accordance with ANSI-ASME Performance Test Codes (PTCs), namely PTC 22 for Gas Turbines (Reference 9), PTC 4.4 for Gas Turbine Heat Recovery Steam Generators (Reference 10), and PTC 6 for Steam Turbines (Reference 11). For gas turbines see also ISO 2314 (Reference 12).

As part of the performance test, temperature measurements should be made in the HRSG inlet duct, as required by the code. These requirements call for a minimum of 24 temperature sensors in small ducts (up to 48 ft^2 in cross-sectional area). These thermocouples should be supported, mineral insulated, and provided with external stainless steel sheathing, and be without protecting wells.

The thermocouples should be located at the center of the individual areas of a grid, with the number of rows and columns selected according to the ANSI/ASME PTC 4.4. These thermocouples serve a temporary purpose and should be removed after the test is completed. The difference between temperature readings in the section of the flue gas duct can reach 15–20°F (8–12°C). A suitable method of temperature averaging has to be developed in order to correctly evaluate the performances of large units.

It is also necessary to test the BFW flow to the various steam drums (HP, IP, LP) of the HRSG, as the water flow measurement is more accurate than that of the steam flow. The steam flow, therefore, is measured as a reference. During the HRSG performance test, the blow-down valves and the sampling lines to the steam and water analyzers are closed.

The water flow measurement tends to be a little unstable even during steady-state operation, which is required for the performance test. It is, therefore, recommended to prepare a DCS screen page on which the various flows are totalized. This allows the operator to simultaneously start and stop all the totalizations, using software pushbuttons on the page (Table 8.33s).

TABLE 8.33s
Tabulation Allowing the Operator to Compare the Total Flows of Water and Steam In and Out of the Steam Drums

Service	*Total Flow*	*Units*	*Service*	*Total Flow*	*Units*
LP BFW	8 digits	Lbs	LP Steam	8 digits	Lbs
IP BFW	8 digits	Lbs	IP Steam	8 digits	Lbs
HP BFW	8 digits	Lbs	HP Steam	8 digits	Lbs
IP Dsh W	8 digits	Lbs			
HP Dsh W	8 digits	Lbs			
CURRENT TIME		PRESET DURATION		ELAPSED TIME	
hh/mm/ss		hh/mm/ss		hh/mm/ss	
RESET		START		STOP	
ν		ν		ν	

The totalized flows should cover 3- to 4-hr periods of flow integration as a minimum, because the corresponding ANSI standard (PTC4.4) requires that the test should last at least 2 hr. If there are reheat coils and the steam flow through them is not direcly measured, it should be calculated by mass balance around the steam drums.

CONCLUSIONS

In this section, the traditional basic controls used in power plants have been discussed. The potentials for optimizing these processes are somewhat limited, but should still be considered.

For example, when the plant is operated in an intermittent manner, the start-up period should be minimized. The corresponding savings in fuel and production can be substantial if during the design stage and during the subsequent tuning of the system in field, attention is focused on the goal of decreasing the start-up time. To reach this goal, the start-up sequences of the individual equipment should be well coordinated, and when necessary, some of the steps of the start-up sequence should be modified, postponed, or anticipated during commissioning.

Another potential for optimization is noise silencing. This is because if the steam venting during start-up is too noisy, it restricts the times at which the plant can be started up in built-up areas. This consideration can limit the acceptable time period and result in a need to put the power plant on-line well in advance of the required time.

In terms of the potentials for improving equipment efficiency through optimization, keeping the air compressor blades of the GT clean is an important goal. The frequency of the on-line washing required should be determined in the field, based on both the turbine characteristics and on environmental pollution. The off-line washing should be done when the GT performance drops substantially.

The goal of optimization can be served by evaluating the trade-off between the recovery in performance after a maintenance-related shutdown and the loss of production due to that plant shutdown. Computerized control systems can be useful in optimizing the maintenance practices of the plant.

ABBREVIATIONS

AVR	Automatic voltage regulator
bara	Bar absolute
BFW	Boiler feedwater
BMS	Burner management system
CEMS	Continuous emissions monitoring system
CRH	Cold reheat
CRT	Cathodic ray tube
DCS	Distributed control system
FGR	Flue gas recirculation
FSNL	Full speed no load
GT	Gas turbine
HP	High pressure
HRH	Hot reheat
HRSG	Heat recovery steam generator
HV	High voltage
IGV	Inlet guide vanes
IP	Intermediate pressure
KJ	Kilojoule
KW	Kilowatt
LP	Low pressure
LV	Low voltage
MP	Medium pressure
MW	Megawatt
PC	Personal computer
OTSG	Once through steam generator
RH	Reheater or reheated
SCR	Selective catalytic reduction
SFC	Static frequency converter
SH	Superheater or superheated
SIF	Safety instrumented function
SIL	Safety integrity level
SOE	Sequence of event recorder
ST	Steam turbine
STIG	Steam injection gas turbine
TOC	Total organic carbon
1oo2D	One out of two with diagnostic
2oo3	Two out of three

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