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## 7.4 BALANCE OF PLANT SYSTEMS

**Learning Objectives:**

1. State the purposes of the major components of the balance of plant systems.

2. Describe the major differences between the balance of plant systems of the AP1000 and currently operating Westinghouse plants.

### 7.4.1 Main Condenser

The main condenser functions as the steam-cycle heat sink, receiving and condensing exhaust steam from the main turbine and the turbine bypass system.

The main condenser is a three-shell, single-pass, multipressure, spring-supported unit. Each shell is located beneath its respective low-pressure turbine. The condenser is equipped with titanium or stainless steel tubes. Titanium provides good resistance to corrosion and erosion. Freshwater-cooled plants do not require the high levels of corrosion and erosion resistance provided by titanium, so stainless steel tubes may used at those plants if desired.

In a multipressure condenser, the condenser shells operate at slightly different pressures and temperatures. Condensate that is condensed in the low-pressure condenser shell drains through internal piping to the high-pressure (hottest) shell, where it is slightly heated and mixed with condensate from the high pressure shell. Condensate then flows through a single outlet to the suction of the condensate pumps. The condenser shells are located below the turbine building operating floor. Two low-pressure feedwater heaters are located in the neck of each condenser shell. Piping is installed for hotwell level control and condensate sampling.

During normal power operation, exhaust steam from the low-pressure turbines is directed into the main condenser shells. The condenser also receives auxiliary system flows, such as feedwater heater vents and drains and gland sealing steam spillover and drains.

The hotwell level controller provides automatic makeup or rejection of condensate to maintain a normal level in the condenser hotwells. On low level, the makeup control valves open and admit condensate by vacuum draw to the hotwell from the condensate storage tank. On high level, the condensate reject control valves open to divert water from the condensate pump discharge to the condensate storage tank. Rejection or makeup automatically stops when the hotwell level returns to within normal operating range. Rejection to the storage tank can be manually overridden upon an indication of high conductivity in the hotwell to prevent the transfer of contaminants into the condensate storage tank in the event of a condenser tube failure. Air in-leakage and noncondensable gases contained in the turbine exhaust steam are collected in the condenser and removed by the main condenser air removal system.

To protect the condenser shells and turbine exhaust hoods from overpressurization, steam relief blowout diaphragms are provided in the low-pressure turbine exhaust hoods.

The main condenser is capable of accepting up to 40 percent of full-load main steam flow from the turbine bypass system. In the event of high condenser pressure or tripping of the circulating water pumps, the turbine bypass valves are prohibited from opening.

Distribution headers are incorporated to prevent damage to the condenser tubes, feedwater heaters located in the condenser neck, and other condenser components caused by turbine bypass steam or high-temperature drains entering the condenser shell.

The condenser tube cleaning system performs mechanical cleaning of the circulating water side of the titanium tubes. This cleaning, along with chemical treatment of the circulating water, reduces fouling and helps to maintain the thermal performance of the condenser.

### 7.4.2 Main Condenser Evacuation System

Main condenser evacuation is performed by the condenser air removal system (CMS). The system removes noncondensable gases and air from the main condenser during plant startup, cooldown, and normal operation. This action is provided by liquid-ring vacuum pumps.

The air removal system consists of four liquid-ring vacuum pumps that remove air and noncondensable gases from the three condenser shells during normal operation and which provide condenser hogging during startup. One vacuum pump is provided for each condenser shell, and one pump is provided as a standby. The noncondensable gases, together with a quantity of vapor, are drawn through the air cooler sections of condenser shells to the suction of the vacuum pumps. These noncondensable gases consist mainly of air, nitrogen, and ammonia. No hydrogen buildup is anticipated in the system. Dissolved oxygen is present in the condensate and condenser hotwell inventory. Only trace amounts of this oxygen are released in the condenser, and the amounts are negligible compared to the amount of gas and vapor being evacuated by the system. Therefore, the potential for explosive mixtures within the condenser air removal system does not exist.

The circulating water system (CWS) provides the cooling water for the vacuum pump seal water heat exchangers. The seal water is kept cooler than the saturation temperature in the condenser to maintain satisfactory vacuum pump performance.

The noncondensable gases and vapor mixture discharged to the atmosphere are not normally radioactive. However, it is possible for the mixture to become contaminated in the event of primary-to-secondary system leakage. Air in-leakage and noncondensable gases removed from the condenser and discharged by the vacuum pumps are routed to the turbine island vents, drains, and relief system

(TDS) and monitored for radioactivity. Upon detection of unacceptable levels of radiation, appropriate operating procedures are implemented.

Should the condenser air removal system become inoperable, a gradual increase in condenser backpressure would result from the buildup of noncondensable gases. This increase in backpressure would cause a decrease in the turbine cycle efficiency. If the condenser air removal system remains inoperable, condenser backpressure increases to the turbine trip setpoint, and a turbine trip is initiated. The loss of the main condenser vacuum causes a turbine trip, but does not close the main steam isolation valves.

During startup operation, air is removed from the condenser by operating three liquid-ring vacuum pumps. The fourth pump is in standby.

During normal plant operation, noncondensable gases are removed from the condenser by three vacuum pumps. If one pump trips, the condition is alarmed in the main control room, and the standby pump is started.

### 7.4.3 Gland Seal System

The gland seal system (GSS), shown in Figure 7.4-1, consists of the following items and assemblies:

- Steam supply header,
- Steam drains/noncondensable gas exhaust header,
- Two motor-driven gland seal condenser exhaust blowers,
- Associated piping, valves, and controls,
- Gland seal condenser, and
- Vent and drain lines.

The annular space through which the turbine shaft penetrates the turbine casing is sealed by steam supplied to the rotor glands. Where the packing seals against positive pressure, the sealing steam connection acts as a leak-off. Where the packing seals against vacuum, the sealing steam either is drawn into the casing or leaks outward to a vent annulus maintained at a slight vacuum. The vent annulus receives air leakage from the outside. The air-steam mixture is drawn to the gland seal condenser.

Sealing steam is distributed to the turbine shaft seals through the steam-seal header. This sealing steam is supplied from either the auxiliary steam system (ASS), or from the main steam system (MSS), extracted ahead of the high-pressure turbine control valves. Steam flow to the header is controlled by the steam-seal feed valve, which acts to maintain the steam-seal supply header pressure. The low- and high-pressure turbine gland steam pressures are maintained by pressure regulating valves provided in both main and auxiliary steam piping. Excess steam is returned to the No. 1 feedwater heaters via the spillover control valve, which automatically opens to bypass excess steam from the GSS.

During the initial startup phase of turbine-generator operation, steam is supplied to the gland seal system from the auxiliary steam header, which is supplied from the auxiliary boiler. At times other than initial startup, turbine-generator sealing steam is supplied from the turbine stop valve and control valve gland steam leak-off, from the auxiliary steam system, or from the main steam system.

At the outer ends of the glands, collection piping routes the mixture of air and excess seal steam to the gland seal condenser. The gland seal condenser is a shell-and-tube-type heat exchanger where the steam-air mixture from the turbine seals is discharged into the shell side and condensate flows through the tube side as a cooling medium. The gland seal condenser internal pressure is maintained at a slight vacuum by a motor-operated blower. There are two 100-percent capacity blowers mounted in parallel. Condensate from the steam-air mixture drains to the main condenser, while noncondensable gases are exhausted to the turbine island vents, drains, and relief system through a common discharge line shared by the vapor extractor blowers.

The mixture of noncondensable gases discharged from the gland seal condenser blower is not normally radioactive; however, in the event of significant primary-to-secondary system leakage due to a steam generator tube leak, it is possible for the mixture to be radioactively contaminated. The discharge mixture passes through a radiation monitor in the turbine vents, drains, and relief system. Upon detection of unacceptable levels of radiation, appropriate operating procedures are implemented.

### 7.4.4 Turbine Bypass System

The turbine bypass system provides the capability to bypass main steam from the steam generators to the main condenser in a controlled manner to dissipate heat and to minimize transient effects on the reactor coolant system during startups, hot shutdown conditions, cooldowns, and step reductions in generator load. The turbine bypass system, also called the steam dump system, is part of the main steam system.

The turbine bypass system has the capacity to bypass 40 percent of the full-load main steam flow to the main condenser.

The turbine bypass system bypasses steam to the main condenser during plant startup and permits a manually controlled cooldown of the reactor coolant system to the point where the normal residual heat removal system can be placed in service.

The turbine bypass system total flow capacity, in combination with bypass valve response time, reactor coolant system design, and reactor control system response, is sufficient to reduce challenges to the main steam power-operated relief valves, main steam safety valves, and pressurizer safety valves during (1) a reactor trip from 100-percent power, and (2) a 100-percent load rejection or turbine trip from 100-percent power without a reactor trip.

The turbine bypass system is shown in Figure 7.1-2. The system consists of a manifold connected to the main steam lines upstream of the turbine stop valves, and lines with regulating valves connecting the manifold to the condenser shells.

The capacity of the system, along with the NSSS control systems, provides the capability to meet the design-basis requirements. For power changes less than or equal to a 10-percent change in electrical load, the turbine bypass system is not actuated; the total power change is handled by the reactor power control, pressurizer level control, pressurizer pressure control, and steam generator level control systems. For load rejections greater than 10 percent but less than 50 percent, or a turbine trip from 50-percent power or less, the turbine bypass system operates in conjunction with the control systems listed above to meet the design-basis requirements. For load rejections greater than 50-percent power, the rapid power reduction system operates in conjunction with the previously mentioned control systems to meet the design-basis requirements. The rapid power reduction system is designed to rapidly reduce the nuclear power to a value that can be handled by the turbine bypass system.

The turbine bypass valves are electropneumatically operated globe valves. The valves fail to closed positions upon the loss of air or electric signal. A modulating positioner responds to the electric signal from the control system and provides an appropriate air pressure to each valve actuator for modulating the valve open.

Solenoid valves located in the air line to each bypass valve actuator serve as protective interlocks for bypass valve actuation and for tripping the valve open or closed. One of the solenoid valves is energized, when required, to bypass the modulating positioner and provide full air pressure to the actuator diaphragm to quickly trip open the bypass valve. Other solenoid valves, when de-energized, block the air supply to the actuator and vent the actuator diaphragm; this action keeps the bypass valve from opening, or closes the valve if opened.

Two of the blocking solenoid valves for each turbine bypass valve are redundant and block bypass valve actuation upon attainment of low reactor coolant system $T_{avg}$. This interlock minimizes the possibility of excessive reactor coolant system cooldown. However, the low $T_{avg}$ block can be manually bypassed for the bypass valves designated as cooldown valves to allow operation during plant cooldown. Another blocking solenoid valve prevents actuation of the bypass valve when the condenser is not available. This solenoid valve also prevents unblocking the steam dump valve when the condenser is available unless one of the following signals exists:

- High negative rate of change of turbine pressure,
- Reactor trip, or
- Control system in the steam header pressure control mode.

The turbine bypass system has two modes of operation:

- $T_{avg}$ control mode, and
- Pressure control mode.

The $T_{avg}$ control mode is the normal standby at-power control mode. The turbine bypass system is regulated by the difference between the measured reactor coolant system average coolant temperature ($T_{avg}$) and a $T_{avg}$ setpoint derived from turbine first-stage (impulse) pressure. The $T_{avg}$ control mode includes two controllers. The first is the load rejection steam dump controller, which prevents a large increase in reactor coolant temperature following a large, sudden load decrease. Turbine bypass valve control, in conjunction with reactor power control, results in a match between reactor power and turbine load. The second controller is the plant trip steam dump controller, which automatically defeats the load rejection steam dump controller following a reactor trip and provides a controlled rate of removal of decay heat, which in turn decreases reactor coolant system $T_{avg}$.

The pressure control mode is manually selected and is used to remove decay heat during plant startups and cooldowns. The difference between steam header pressure and a pressure setpoint is used to control the turbine bypass flow. The pressure setpoint is manually adjustable and corresponds to the desired reactor coolant system temperature. The turbine bypass system is operated in the pressure control mode when the plant is at no-load conditions, and there is no turbine load reference. There are three pressure control mode operational schemes:

- Header pressure – control derived from the difference between header pressure and pressure setpoint;

- Cooldown – control derived from the manually selected desired reactor coolant system cooldown rate and the target reactor coolant system temperature; and

- Manual – control derived from manual control of valve opening signals.

The bypass valves are divided into two banks. The banks are opened sequentially; the second bank starts to open only after a demand signal that is greater than the full-open demand of the first bank is generated.

The turbine bypass valves have two stroke control modes, modulate and trip open/close. If the demand signal is greater than the full-open demand for the particular bank of valves, a trip open demand signal is generated. When the demand signal decreases below the full-open demand, the trip open demand clears, and the valves return to the modulating mode.

### 7.4.5 Turbine-Generator

#### 7.4.5.1 Component Descriptions

The function of the turbine-generator is to convert thermal energy into electric power.

The turbine-generator is designated as a TC6F 52-in. last-stage blade unit consisting of turbines, a generator, external moisture separator/reheaters, controls, and auxiliary subsystems (see Figure 7.4-2). The major design parameters of the turbine-generator and auxiliaries are presented in Table 7.4-1.

The turbine-generator and associated piping, valves, and controls are located completely within the turbine building. There are no safety-related systems or components located within the turbine building. The orientation of the turbine-generator is such that a high-energy missile would be directed at a 90-degree angle away from safety-related structures, systems, or components. Failure of turbine-generator equipment does not preclude safe shutdown of the reactor. The turbine-generator components and instrumentation associated with turbine-generator overspeed protection are accessible under operating conditions.

The turbine is a 1800-rpm, tandem-compound, six-flow, reheat unit with 52-in. last-stage blades (TC6F 52-in. LSB). The high-pressure turbine element includes one double-flow, high-pressure turbine. The low-pressure turbine elements include three double-flow, low-pressure turbines and two external moisture separator/reheaters (MSRs) with two stages of reheating. The single direct-driven generator is hydrogen and water cooled and rated at 1375 MVA at a 0.90 PF. Other related system components include a complete turbine-generator bearing lubrication oil system, a digital electrohydraulic (DEH) control system with supervisory instrumentation, a turbine steam sealing system, overspeed protective devices, a turning gear, a stator cooling water system, a generator hydrogen and seal oil system, a generator $CO_2$ system, a rectifier section, an excitation transformer, and a voltage regulator.

Steam from each of two steam generators enters the high-pressure turbine through four stop valves and four governing control valves; each stop valve is in series with a separate control valve. Cross-ties are provided between steam chests to provide pressure equalization with one or more stop valves closed. After expanding through the high-pressure turbine, exhaust steam flows through two external moisture separator/reheater vessels. The external moisture separators reduce the moisture content of the high-pressure exhaust steam from approximately 10 to 13 percent at the rated load to approximately 0.5 percent or less.

The AP1000 employs two-stage reheaters. The first stage of reheating is provided with extraction steam from the high-pressure turbine, and the second stage is provided with main steam to reheat the high-pressure turbine exhaust to superheated conditions. The reheated steam flows through separate reheat stop and intercept valves in each of six reheat steam lines leading to the inlets of the three low-pressure turbines.

Turbine steam extraction connections are provided for seven stages of feedwater heating. Steam from the extraction points of the high-pressure turbine is supplied to the No. 6 and No. 7 (high-pressure) feedwater heaters. The high-pressure turbine exhaust supplies steam to the deaerating feedwater heater. The low-pressure turbine third, fourth, fifth, and sixth extraction points supply steam to low-pressure feedwater heaters No. 4, 3, 2, and 1, respectively.

Moisture is removed at a number of locations in the blade path. The no-return drain catchers provided at the nozzle diaphragms (stationary blade rings) accumulate the water fraction of the wet steam, and the accumulated water discharges into each extraction, reheat, or exhaust line directly or through drainage holes drilled through the nozzle diaphragms. A few grooves are provided on the rotating blades near the last stage of each low-pressure turbine to capture the large water droplets of the wet steam and to enhance the moisture removal effectiveness.

The external moisture separator/reheaters use multiple vane chevron banks (shell side) for moisture removal. The moisture removed by the external moisture separator/reheaters drain to a moisture separator drain tank and is pumped to the deaerator.

Condensed reheating steam (tube side) is drained to the reheater drain tank, from which it flows into the shell sides of the No. 7 feedwater heaters.

#### 7.4.5.2 Automatic Turbine Control

The turbine-generator is equipped with a digital electrohydraulic (DEH) control system that combines the capabilities of redundant processors and high-pressure hydraulics to regulate steam flow through the turbine. The control system provides the functions of speed control, load control, overspeed protection, and automatic turbine control (ATC), which may be used, either for control or for supervisory purposes, at the option of the plant operator.

Automatic turbine control provides safe and proper startup and loading of the turbine-generator. The applicable limits and precautions are monitored by the automatic turbine control programs even if the automatic turbine control mode has not been selected by the operator. When the operator selects automatic turbine control, the programs both monitor and control the turbine. The DEH controller takes advantage of the capability of the computer to scan, calculate, make decisions, and take positive action.

The automatic turbine control is capable of automatically:

- Changing speed reference,
- Changing acceleration rates,
- Generating speed holds,
- Changing load rates, and
- Generating load holds.

The thermal stresses in the rotor are calculated by the automatic turbine control programs based on actual turbine steam and metal temperatures as measured by thermocouples or other temperature measuring devices. Once the thermal stress (or strain) is calculated, it is compared to the allowable value, and the difference is used as the index of the permissible first-stage temperature variation. This permissible temperature variation is translated in the computer program as an allowable speed or load or rate of change of speed or load.

Values of some parameters are stored for use in the prediction of their future values or rates of change, which are used to initiate corrective measures before alarm or trip points are reached.

The rotor stress (or strain) calculations used in the program, and its decision-making counterpart, are the main controlling sections. They allow the unit to roll with relatively high acceleration until the anticipated value of stress predicts that limiting values are about to be reached. Then a lower acceleration value is selected and, if the condition persists, a speed hold is generated. The same philosophy is used for load control in order to maintain positive control of the loading rates.

The automatic turbine controls programs are stored and executed in redundant distributed processing units, which contain the rotor stress programs and the automatic turbine controls logic programs. Once the turbine is reset, the automatic turbine controls programs are capable of rolling the turbine from turning gear to synchronous speed.

Once the turbine-generator reaches synchronous speed, the startup or speed-control phase of automatic turbine control is completed, and no further action is taken by the programs. Upon closing the main generator breaker, the DEH control system automatically picks up approximately five percent of rated load to prevent motoring of the generator. At this time, the DEH control system is in load control logic and automatically reverts control to the operator mode.

The operator can also select the automatic turbine control mode. The automatic turbine control selects the loading rate (based on turbine temperature) and allows load changes until an alarm condition occurs. If the operating parameters being monitored (including rotor stress) exceed their associated alarm limit, a load hold is generated in conjunction with the appropriate alarm message. The DEH control system generates the load hold by ignoring any further load increase or decrease until the alarm condition is cleared or until the operator overrides the alarm condition.

The operator may remove the turbine-generator from automatic turbine control. This action places the turbine control in operator auto mode and the automatic turbine control in a supervisory capacity.

### 7.4.5.3 Turbine Protection

Turbine protective trips, when initiated, cause tripping (shutting) of the main stop, control, intercept, and reheat stop valves. The protective trips are:

- Low bearing oil pressure,
- Low electrohydraulic fluid pressure,
- High condenser backpressure,
- Turbine overspeed,
- Thrust bearing wear, and
- A remote trip that accepts external trips.

The emergency trip system also has provisions to trip the turbine in response to a signal from the plant control system or plant safety and monitoring system.

Additional protective features of the turbine and steam system are:

- Moisture separator/reheater safety relief valves,

- Rupture diaphragms located on each of the low-pressure turbine cylinder covers, and
- Turbine water induction protection systems on the extraction steam lines.

**Table 7.4-1**
**TURBINE-GENERATOR AND AUXILIARIES DESIGN PARAMETERS**

| Manufacturer Toshiba | |
|---|---|
| Turbine type | TC6F 52-in. last stage blades |
| No. of elements | 1 high pressure; 3 low pressure |
| Last-stage blade length (in.) | 52 |
| Operating speed (rpm) | 1800 |
| Condensing pressure (in. HgA) | 2.9 |
| Generator rated output (kW) | 1,237,500 |
| Power factor | 0.90 |
| Generator rating (kVA) | 1,375,000 |
| Hydrogen pressure (psig) | 75 |
| Moisture separator | Chevron vanes |
| Reheater | U-tube |
| Number | 2 shell |
| Stages of reheating | 2 |

**Table 7.4-2**
**TURBINE OVERSPEED PROTECTION**

| Percent of Rated Speed (Approximate) | Event |
|---|---|
| 100 | Turbine is initially at valves wide open. Full load is lost. Speed begins to rise. When the breaker opens, the load drop anticipator immediately closes the control and intercept valves if the load at time of separation is greater than 30 percent. |
| 101 | Control and intercept valves begin to close. |
| 108 | Peak transient speed with normally operating speed control system.<br><br>If the power/load unbalance and speed control systems had failed prior to loss of load, then: |
| 110 | A trip signal is sent by the overspeed trip system to actuate closure of the stop,control, intercept, and reheat valves by releasing the hydraulic fluid pressure in the valve actuators. |
| 111 | The emergency electrical overspeed trip system closes the main stop and reheat stop valves based on a two-out-of-three trip logic system. |

| Table 7.4-3<br>MAIN CONDENSER DESIGN DATA | |
|---|---|
| **Condenser Data** | |
| Condenser type | Multipressure, Single pass |
| Hotwell storage capacity | 3 min |
| Heat transfer | 7,540 x $10^6$ Btu/hr |
| Design operating pressure (average of all shells) | 2.9 in.-Hg |
| Shell pressure (design) | 0 in.-Hg absolute to 15 psig |
| Circulating water flow | 600,000 gpm |
| Water box pressure (design) | 90 psig |
| Tube-side inlet temperature | 91°F |
| Approximate Tube-side temperature rise | 25.2°F |
| Condenser outlet temperature | 116.2°F |
| Waterbox material | Carbon Steel |
| **Condenser Tube Data** | |
| Tube material (main section) | Titanium(1) |
| Tube size | 1 in. O.D. – 23 BWG |
| Tube material (periphery) | Titanium |
| Tube size | 1 in. O.D. – 23 BWG |
| Tube sheet material | Titanium or Titanium Clad Carbon Steel(2) |
| Support plates | Modular Design/Carbon Steel |

Notes:
1. For freshwater plants, an equivalent tube material such as 304L, 316L, 904L, or AL-6X may be substituted.
2. If one of the alternate tube materials is used, the tube sheet shall be carbon steel, clad with the same material as the tubes.