10.1 DESIGN BASIS

The steam and power conversion system is designed to receive steam from the NSSS and convert the steam thermal energy into electrical energy. A closed regenerative cycle condenses the steam from the main turbine and returns the condensate as heated feedwater to the steam generators.

The turbine generator has a maximum expected capacity of 845 MWe when operating with 6 stages of feedwater heating and the steam exhausting to a pressure of 1.8 inches Hg absolute.

Components from the steam generators up to and including the main steam isolation valves and main and auxiliary feedwater header isolation check valves were designed to CP Co Design Class l requirements. The main steam piping between the main steam isolation valve and various steam takeoff block valves is designed to CP Co Design Class 2 requirements. The remainder of the components and piping is designed to CP Co Design Class 3 requirements. See Section 5.2 for a discussion of classes.

10.2 SYSTEM DESCRIPTION AND OPERATION

10.2.1 SYSTEM GENERAL DESCRIPTION

The main steam, extraction steam, feedwater, condensate and steam generator blowdown systems are shown on Figures 10-1, 10-2, 10-3 and 10-4.

1. Main Steam System (Figures 10-1 and 10-2)

   Steam generated in the steam generators passes through two 36-inch headers and main steam isolation valves to the turbine stop valves. Each main steam header is provided with 12 spring-loaded safety valves and 2 atmospheric dump valves upstream of the main steam isolation valves (MSIVs). The safety valves discharge to the atmosphere and are in accordance with the requirements of the ASME B&PV Code, Section III. In addition, there is a steam bypass to condenser valve downstream of the MSIVs. The main steam line also supplies steam for the steam jet air ejectors, the heating steam for the reheaters, the secondary steam supply to the steam generator feed pump turbine drivers, and steam supply to the turbine-driven auxiliary feed pump turbine driver which is connected upstream of the MSIVs.

2. Moisture Separator-Reheaters

   Steam exhausted from the high-pressure turbine goes to the low-pressure turbines by way of four moisture separator-reheaters in which moisture in the wet exhaust steam is removed and drained to the moisture separator drain tank and the steam is reheated by main steam. The primary steam supply to the steam generator feed pump turbine drivers is extracted from the moisture separator-reheaters.

   Cycle steam flow through the moisture separator-reheater units is not controlled and is a function of load with all auxiliaries operating normally. Wet steam from the high-pressure turbine enters the reheater shell via the cycle steam inlet connection and flows through the shell. Moisture is removed from the wet steam when it flows upward through the chevron vanes and perforated plates.

   The condensate removed from the wet cycle steam by the chevron vanes and perforated plates is collected in the lower connection and drained to the moisture separator reheater drain tank.

   The dry cycle steam then passes over the finned tubes of the reheater bundle where it is superheated. This superheated steam continues upward and out the reheater through the cycle steam outlet connection.

Heating steam taken from upstream of the turbine stop valve enters the upper portion of the tube bundle hemispherical channel head via the heating steam inlet connection. This steam circulates through the U-tubes, relinquishing its heat to the cycle steam flowing over the tubes before the majority of the heating steam exits the lower section of the channel head as liquid through the heating steam condensate outlet connection.

Condensate from the 2nd pass tubes discharges from the 2nd pass tubeside drain outlet nozzle to the respective reheater drain tank located below the turbine operating floor. Excess steam from the 2nd pass continues to the 3rd and 4th passes. Steam and condensate from the 4th pass tubes discharges from the 4th pass drain outlet nozzles to the extraction steam inlet to the respective feedwater heater.

A 4th pass heater drain control valve is installed in the 4th pass discharge line upstream of the respective feedwater heater. This control valve is used to optimize the terminal temperature difference across the MSR in order to optimize the heating efficiency of the moisture separator-reheaters and minimize the vented steam to the respective feedwater heaters.

3. Main Steam Dump and Bypass System (Figures 10-4 and 10-1, Respectively)

The main steam dump and bypass system consists of four automatically actuated atmospheric dump valves which exhaust to atmosphere and a turbine bypass valve which exhausts to the main condenser; the total capacities of the atmospheric steam dump and turbine bypass valves are 30% and 4.5%, respectively, of steam flow with reactor at full power. The capacity of the atmospheric steam dump valves is adequate to prevent lifting of the main steam safety valves following a turbine and reactor trip. The turbine bypass to the main condenser provides for removal of reactor decay heat following reactor shutdown. Although the steam dump system is arranged for automatic operation, the atmospheric dump valves may be manually controlled from either control room or engineered safeguards control panels.

The atmospheric steam dump valves have a back up nitrogen supply to allow steam generator pressure control during station blackout. This meets 10 CFR 50.63 requirements for coping without AC power by complying with Reg Guide 1.155, Station Blackout.

4. Main Steam Line Isolation

One main steam isolation valve is provided on each main steam header. The main steam isolation valves are closed on either a low steam generator pressure signal or a containment high-pressure signal. Closure of these valves will also result in a turbine-generator trip. Manual closure of one valve will cause automatic closure of the other valve. Each valve consists of a swing disc held open against flow by a pneumatic cylinder. The valves are provided to isolate the steam generators, in the unlikely event of a steam generator tube failure following a main steam line break accident, to prevent the uncontrolled release of radioactivity. Closure of these valves also prevents a rapid uncontrolled cooldown of the Primary Coolant System.

An auxiliary function of the main steam isolation valves is to prevent the release to the containment of the contents of the secondary sides of both steam generators in the event of the rupture of one main steamline inside containment. The valves are normally open, and close in five seconds upon receipt of a low steam generator pressure signal in a no-flow condition. When flow does exist, the valve is expected to close in less than one second. An accumulator is provided to hold the valve open in case of a loss of air supply to the valve operator.

Four pressure transmitters on each steam generator actuate contacts in indicating meter relays which are connected in a two-out-of-four logic to close both main steam isolation valves. On low steam generator pressure only, automatic closing of the main steam isolation valves can be blocked by pushing both of two isolation block push buttons as the steam pressure is decreasing toward the isolation set point. The isolation block is automatically removed by a two-out-of-four logic when the steam generator pressure rises to 50 psi above the isolation set point pressure. Refer to Section 7.2 for further details on system controls.

5. Steam Generator Blowdown System (Figures 10-3 and 10-4)

The steam generator blowdown system is designed to process steam generator blowdown water. A minimum continuous blowdown of 5,000 lb/h per steam generator is required for effective steam generator chemistry control. During periods of severe condenser leakage, it is necessary to increase the blowdown rate considerably. Accordingly, the steam generator blowdown system is designed for continuous operation at up to 30,000 lb/h blowdown per steam generator with occasional higher flow rates such as during low power operation following multi-day shutdowns (per EAR-2001-0233). Other functions of the system include the capability to clean up the condenser hotwell prior to start up by recirculating the water through the blowdown demineralizers, and the capability to recirculate steam generator secondary side water, for treatment purposes, during cold shutdown conditions.

The steam generator blowdown system consists of flash tank, blowdown tank, two blowdown pumps, blowdown heat exchanger, blowdown filter, three blowdown demineralizers, piping, valves and instrumentation. The system is continuously monitored by a process monitor which detects radioactivity which may have leaked into the steam generator from the primary system.

During normal operation, the flash tank, blowdown tank, blowdown demineralizers, blowdown heat exchanger, blowdown filter, and one of the blowdown pumps will be in service. Under this condition, one pump is in "standby" and the other is in continuous service. The standby pump starts automatically on high blowdown tank level. The blowdown tank is vented to the main condenser or to the stack. The flash tank is vented to the plant heating/evaporator steam system or to the stack. Blowdown water is pumped through the blowdown heat exchanger and filter (filter is optional) to the blowdown demineralizers and into the condenser. Alternate modes of operation include:

1. The ability to direct the blowdown through the blowdown demineralizers to the condensate storage tank;

2. The ability to direct the blowdown to the mixing basin while isolating the blowdown demineralizers;

3. The ability to direct the blowdown to the condenser while isolating the blowdown demineralizers;

4. And the ability to recycle the blowdown through the miscellaneous waste system and to the utility water storage tank.

A radiation monitor on the effluent of the blowdown tank detects radioactivity which may have leaked into the blowdown water through the steam generators. High activity is annunciated in the main control room. If the radioactivity level in the system reaches a preset level above normal background as detected by the radiation monitor, the recirculation and blowdown containment isolation valves and the mixing basin discharge valve all close. The blowdown vent monitor provides an alarm in the control room.

10.2.2 STEAM TURBINE

The turbine is an 1,800 r/min tandem compound, 3 cylinder, quadruple flow, indoor unit. Saturated steam is supplied to the turbine from the steam generators through four stop valves and four governing control valves. The steam flows through a double-flow, high-pressure turbine and then through four combination moisture separator-reheaters in parallel, and then to two double-flow, low-pressure turbines that exhaust to the main condenser.

Turbine control is accomplished with a rapid response electrohydraulic control system (see Section 7.5). In the event of turbine trip initiated from a solenoid trip, overspeed, low bearing oil pressure, low condenser vacuum or a manual trip, a signal is supplied from the turbine auto-stop oil system to the Reactor Protective System to trip the reactor.

The turbine lubricating oil system supplies oil for lubricating the bearings. A bypass stream of turbine lubricating oil flows continuously through coalescing filters to remove water and other impurities.

10.2.2.1 High-Pressure Turbine

The high-pressure turbine element is of a double-flow design; therefore, it is inherently thrust balanced. Steam from the four control valves enters at the center of the turbine element through four inlet pipes, two in the base and two in the cover. These pipes feed four double-flow nozzle chambers flexibly connected to the turbine casing. Each nozzle chamber is free to expand and contract relative to the adjacent chambers.

Steam leaving the nozzle chambers passes through the nozzle flow guides and flows through the reaction blading. The reaction blading is mounted in blade rings which, in turn, are mounted in the turbine casing. The blade rings are center line supported to ensure center alignment while allowing for differential expansion between the blade ring and the casing. This design reduces casing thermal distortion and, thus, seal clearances are more readily maintained.

Steam exhausts from the high-pressure turbine base, through cross-under piping, to the four combined moisture separator steam reheater assemblies.

The high-pressure rotor is made of NiCrMoV alloy steel. The main body of the rotor weighs approximately 120,920 pounds. The approximate values of the transverse center line diameter, the maximum diameter (including blades) and the main body length (generator coupling face to extension shaft coupling face) are 36 inches, 82 inches and 301 inches, respectively.

The blade rings are made of stainless steel and the casing cover and base are made of carbon steel castings. The specified minimum mechanical properties are shown in Table 10-1.

The bend test specimen shall be capable of being bent cold through an angle of 90° and around a pin 1 inch in diameter without cracking on the outside of the bent portion.

The approximate weights of the four blade rings, the casing cover and the casing base are 97,000 pounds, 115,000 pounds and 115,000 pounds, respectively.

The casing cover and base are tied together by means of more than 100 studs. The stud material is an alloy steel having the mechanical properties shown in Table 10-2.

The studs have lengths ranging from 17 inches to 66 inches. About 90% of them have diameters ranging between 2.5 inches and 4 inches. The total stud cross-sectional area is about 900 square inches and the total stud free-length volume is about 36,000 cubic inches.

10.2.2.2 Low-Pressure Turbine

Each low pressure turbine is a double flow element employing reaction blading. Steam enters at the center of the blade path, flows through the blading to an exhaust opening at each end, then downward to the condenser.

Each low pressure turbine consists of a fabricated outer casing. The outer casing forms the housings for the low pressure turbine bearings. The outer casing base of the No. 1 low pressure turbine provides the support for the generator end of the high pressure turbine generator end bearing. The thrust bearing is supported in the governor end of the No. 2 low pressure turbine outer casing base.

The structural shapes of the casings and their methods of support are carefully designed to obtain free but symmetrical movements resulting from thermal changes, and thereby reduce to a minimum the possibility of distortion.

The rows of stationary blading in each end of the low pressure turbines are carried in blade rings or the inner cylinders. These blade rings and inner cylinders are each supported in the outer cylinder just below the horizontal centerline. Guide pins on the vertical centerline are supplied to maintain the position of blade rings axially.

Each low pressure turbine casing is supported by a continuous foot (or skirt) extending around the cylinder base. The foot of each casing rests on a separate seating plate which is grouted to the foundation. The location of the low pressure turbines is maintained by eight taper dowels through the foot and six keys between the foot and the seating plate.

The low pressure rotors, consisting of a series of alloy steel discs shrunk on a shaft and keyed in position, are also machined from alloy steel forgings. The outer discs are held in place by split rings, fitted in grooves in the rotor and retained by shrink rings.

All rotors are finished machined and after completely bladed, are given a running test and an accurate dynamic balance test.

Flanged, rigid type couplings are used to connect the rotors of the high pressure, No. 1 low pressure, No. 2 low pressure and the generator. The rotating element thus formed is supported by eight journal bearings and is located axially by the thrust bearing mounted at the governor end of the No. 2 low pressure turbine.

In the late 1970s, Westinghouse turbines developed a history of cracks forming in the disc bores and keyways of low-pressure turbines in nuclear plants. As a result of this generic problem, Westinghouse along with Westinghouse turbine owners and the NRC worked together to arrive at an acceptable solution. In order to minimize the possibility of disc rupture, it was necessary to periodically inspect the critical disc bore region. To arrive at a safe rational procedure for determining inspection intervals, a fracture mechanics approach for calculating the critical crack size was used. The crack's growth rate was predicted from disc yield strength and temperature using the regression equation derived from field data. Details for calculating the critical crack sizes, growth rates and criteria for inspection intervals were discussed in a proprietary Westinghouse Report MSTG-1-P, Criteria for Low Pressure Nuclear Turbine Disc Inspection, submitted to the NRC in June 1981. Refer to Section 5.5 for a discussion of turbine missiles.

The Westinghouse low pressure rotors were later replaced with Siemens Westinghouse rotors in 1999.

Refer to Section 5.5 for a discussion of turbine missiles.

10.2.2.3 Electrical Generator

The generator is made up of a housing, stator, rotor and shaft with sleeve bearings and ventilation blower, see Figure 10-5. The generator is a hydrogen inner cooled unit connected directly to the turbine and rated at 0.85 power factor. It is rated for 955 MVA and has the capability to accept the gross output of the turbine at rated steam conditions. Generator operation is supported by a hydrogen gas system, a seal oil system and a signal system.

1. Hydrogen Gas System - This system provides a safe means for transferring hydrogen to and from the generator, using carbon dioxide as a scavenging medium. In addition, this system maintains the desired gas pressure, cools the gas and dries the gas should moisture get into the machine from the seal oil system.

2. Seal Oil System - This system serves to lubricate the gland seals and to prevent hydrogen leakage from the generator, without introducing an excessive amount of air and moisture into the generator. The same oil is used in the seal oil system and the turbine bearing oil system. The turbine bearing oil system serves as a seal oil backup should the seal oil pump stop or if the seal oil pressure should drop below 8 psi above the generator gas pressure.

3. Signal System - This system provides the operator with signals on the operating conditions present in Table 10-3.

10.2.2.4 Exciter

The exciter is of the brushless type and is driven from the generator shaft. The exciter consists of a permanent magnet generator, an ac generator and a rectifier assembly mounted on a common shaft. The exciter is totally enclosed with suitable heat exchanger and means for circulating the air within the housing.

The high frequency power generated in the stator of the permanent magnet generator is used to supply power to the static Trinistat voltage regulator. The regulator output supplies excitation for the stator of the ac exciter. The rotor of the ac exciter is made with a multiphase winding and supplies high frequency power to the rectifier assembly. The dc output of the rectifier constitutes the main excitation power and is fed directly to the field winding of the generator by means of leads which pass through the coupling to the generator shaft.

10.2.3 CONDENSATE AND FEEDWATER

10.2.3.1 Condensate System

The condensate/feedwater cycle (Figure 10-4) is a closed system with deaeration accomplished in the main condenser. Steam is discharged from the low-pressure turbine and passes around the tube bank area (shell side) of the single pass main condenser to be condensed and deaerated. The main condenser originally contained 511,490 square feet of surface provided by 26,550, 1-inch, 70-foot-long Admiralty tubes, and by 1,426, 1-inch, 304 stainless steel tubes in the air cooler and impingement sections. In 1974, due to tube leakage problems, the entire Admiralty tube section was retubed with 90-10 copper-nickel tubes. In 1990, the main condenser, feedwater heaters E-5A/B & E-6A/B, and drain coolers E-7A/B were replaced to eliminate copper materials of construction in the secondary water/steam cycle. The new condenser contains 24,594 one inch, 70 ft long, 439 stainless steel tubes with an effective surface area of 449,282 square feet. The new heaters and drain coolers contain 304 stainless steel tubes. Other sources of steam and/or water which enter the condenser are:

1. High level dump from the feedwater heater tanks

2. High level dump from the reheater drain tanks

3. Drains from the air ejector

4. Drains from the gland seal condenser

5. Exhaust from the feed pump turbines

6. High level dump from the moisture separator reheater drain tanks

7. Bypass dump steam

8. Makeup from the condensate storage tank

9. Moisture separator-reheater scavenging steam vent chamber (on start-up only)

10. Gland seal steam spillover

11. Miscellaneous vents, steam traps and drains

12. Blowdown from the steam generators

Minimum condensate storage tank inventory is 94,280 gallons (See Section 9.7.2.1). This ensures that sufficient inventory is available to meet a Station Blackout Rule requirement to have 57,100 gallons available to cope with loss of all AC power for 4 hours.
Noncondensible gases are removed from the main condenser during operation by the steam jet air ejectors, and during start-up by the condenser vacuum pump, hogging air ejector and the steam jet air ejectors. The condenser vacuum pump is used to establish a partial condenser vacuum during start-up and to allow testing of the main condenser for leakage while the Plant is shut down.

The deaerated condensate is transferred from the condenser hot well through a common header to the suction of two half-capacity, electric motor-driven condensate pumps. The two pumps discharge to a common line then diverge in two passes in parallel through the air ejector condenser and the gland seal condenser. The flow from each joins into a common line and is routed through two identical trains of drain coolers and low-pressure feedwater heaters. The condensate flows from the low-pressure heaters to the suction (crosstied) of the two variable speed, turbine driven steam generator feed pumps. These pumps pump the feedwater through the high-pressure feedwater heaters to the steam generators.

10.2.3.2 Condensate Demineralizer System

In 1973, leaks developed in the steam generator tubes. Investigations showed that the problem was tube wastage caused by using phosphates for secondary water chemistry control. In 1974, it was decided to install a full flow condensate demineralizer system and institute a program of steam generator flushing to remove phosphates, continuous steam generator blowdown, start-up recirculation and volatile secondary water chemistry control. Consumers Power Company concurred with studies and tests performed during 1979 and 1980 that the Condensate Demineralizers would be of more detriment than help. Use of the Condensate Demineralizer System ceased in 1981. This system is currently considered as "retired in place."

The Condensate Demineralizer System was isolated from the Condensate System by replacing the inlet and outlet valves with blind flanges. The Condensate Demineralizer bypass valve was removed to avoid inadvertent closures.

10.2.3.3 Feedwater Regulating System

Two half-capacity feedwater pumps (Figure 10-4) are used to furnish the feedwater flow. Each turbine driver and pump must be started locally and brought up to speed before the driver can be controlled from the main control room. The suction and discharge pressures of the feedwater pumps are indicated and annunciated in the main control room. If the suction pressure falls (2 out of 3 logic) below a preset critical value, the pump will be automatically tripped. The turbine drivers will also be tripped from thrust bearing failure, overspeed, and low bearing oil pressure. A manual trip is also available. Steam flow to each turbine driver is indicated and recorded in the main control room. The turbine speed is also indicated in the control room. Three modes of control are provided as follows:

1. Automatic Control in Conjunction With Feedwater Regulating Valves

   Each steam generator's three-element control unit will produce a demand signal for feedwater flow which is a function of the steam generator downcomer level error, trimmed by the difference between feedwater flow and compensated steam flow. The feedwater flow demand signal for each steam generator will be sent to the corresponding feedwater regulating valve controller and to the turbine driver speed control system. The feedwater regulating valve controller in combination with the turbine driver speed control system will function to control the level in each steam generator by modulating the feedwater flow. The regulating valve controller will automatically adjust the position of the regulating valves. The speed control system will select the signal from the steam generator requiring the higher feedwater flow. The selected feedwater demand which represents a speed demand for both turbine drivers is compared to a feedback signal from turbine speed in the speed controller of each driver. Any difference between the two signals will cause the speed controllers to produce a change in turbine speed in the appropriate direction. At low power levels (< 25% power) a single element control unit is normally used. See Section 7.5 for details.

   In 1980, additional automatic controls were placed on the feedwater regulating and bypass valves such that they would close on receipt of a low steam generator pressure (500 psia) signal. This modification was needed to prevent, in the event of a main steam line break, the possibility of a condensate pump supplying water to a depressurized steam generator causing overcooling of the Primary Coolant System. Overpressurization of containment was also a concern if the additional mass of feedwater were released as steam into containment through the broken steam line.

In 1990 additional automatic controls were placed on the main feedwater regulating valves and bypass valves such that they would also close on Containment High Pressure (CHP). This modification was needed when it was discovered that a small steam line break would result in high containment pressure, but not reduce steam generator pressure fast enough to close the valves in time to prevent exceeding containment design pressure.

2. Fixed Speed Control

The turbine driver speed control system can be divorced from the feedwater regulating system and operated automatically to maintain parallel operation of each turbine driver at a manually set speed. The feedwater regulating valve system will then function to control steam generator level by automatically throttling the discharge of the feed pumps as in 1. above.

3. Manual Control

The speed of each turbine driver may be manually adjusted from the control room.

The preceding operational modes consider simultaneous operation of both pumps. The system is designed to permit operation with one feed pump under all modes at reduced unit load.

If the turbine driver speed controllers are in Control Mode 1 or 2 at the time of a main turbine trip, the feedwater pump turbine drivers will be automatically ramped down to a low fixed speed corresponding to approximately 5% of full load feedwater flow. Due to the slow rampdown, operators manually control main feedwater flow or initiate auxiliary feedwater flow as necessary to restore and maintain steam generator levels. At the same time, the feedwater regulating valves will be locked in place at their respective existing positions.

With the loss of offsite power, the main feed pumps will be tripped from low suction header pressure which will result from loss of power to the condensate pumps from their supply buses. The auxiliary feedwater pumps will be available for service at the operator's discretion.

10.2.4 CIRCULATING WATER SYSTEM

Initially, the Plant was designed for a once-through condenser cooling Circulating Water System. The circulating water was taken from the lake through a submerged crib and a 3,300-foot-long pipe tunnel into the intake structure and pumped by two half-capacity motor-driven pumps through the condenser tubes to the discharge canal.

In 1974, the Circulating Water System was converted to a closed cycle system (Figure 10-6) using two mechanical draft cooling towers. The system consists of two essentially independent closed loops. Each loop supplies one-half of the main condenser with cooling water.

10.2.4.1 Cooling Towers

Cooling water is supplied to the main condenser by gravity flow from two SPX Marley induced draft cross-flow cooling towers, one with 16-cells (E-30A), and one with 18-cells (E-30B). The cooling towers (Table 10-4) are designed for a 32°F range (inlet temperature minus outlet temperature). The cooling towers are erected to the south of the Plant (Figure 2-2) over concrete basins. The basin water level elevation is approximately 20 feet above the condenser inlet. Each tower basin supplies one-half of the condenser through a 90-inch pipe which connects to a 96-inch condenser inlet piping at the intake structure.

At the outlet of each cooling tower are screens to remove any debris which collects in the basin. Cooling tower E-30A has two sets of removable screens, while cooling tower E-30B has two traveling water screens. Provisions for stop logs are also provided at the basin outlet.

The two cooling towers are located approximately 500 feet and 1,000 feet, respectively, from the Plant and 300 feet from the nearest transmission lines in order to minimize icing potential. They are spaced approximately 500 feet apart to prevent warm air recirculation between the towers.

Two half-capacity vertical wet pit cooling tower pumps (Table 10-5) are installed in the cooling tower pump building. The pumps receive heated circulating water from the condenser via the 96-inch condenser discharge piping and pump suction spillway provided to reduce velocity head. The cooling tower pumps return the circulating water to the cooling tower distribution headers through two 96-inch pipes. Motor-driven butterfly valves are provided in both the pump discharge and condenser inlet piping. The valves are provided for throttling during pump start-up and for maintenance isolation. The valves are interlocked with their corresponding pump motor breakers.

10.2.4.2 Makeup and Blowdown

Makeup water is normally provided by the dilution water pumps, which discharge directly into each cooling tower's return line. The dilution water flow is approximately 40,000 gpm per pump. Full load tower evaporation rates range from a maximum in the Summer at an estimated 6,000 gpm each to a Winter low of approximately 4,500 gpm each. The makeup water surplus is directed to the makeup basin where it combines with the Plant service water effluent, then over the overflow weirs and into the mixing basin for discharge to the lake. The service water flow ranges from 14,200 gpm to 15,600 gpm and serves as a makeup source backup, should both dilution water pumps become unavailable.

Organic antiscalant and sodium hypochlorite can be added to the Circulating Water System to prevent scaling and biological growth in the condenser tubes. The NPDES permit limits the amount of total sodium hypochlorite that can be discharged to surface water systems. In order to meet the discharge limit and at the same time use sodium hypochlorite at an effective biocide concentration, sodium bisulfite is injected to the overflow weirs of the north and south make-up basins. Sodium Bisulfite is used as a de-chlorinator agent to reduce a total residual oxidant in the Lake out flow, to levels acceptable to the NPDES Permit.

10.2.4.3 Dilution

As stated above, dilution water is the primary source of circulating water system makeup. Dilution water is added to the circulating water on each cooling tower return line. Flow is supplied by two 40,000 gpm vertical wet pit pumps. The pumps are located in the screenhouse (intake structure) and supplied with lake water. In addition, dilution water may be directed directly to the mixing basin as-needed.

10.2.5 CODES AND STANDARDS

All components in the system are designed and fabricated in accordance with applicable codes; eg, the moisture separators-reheaters and the closed feedwater heaters are in accordance with the ASME B&PV Code, Section VIII, and the piping and valves are to ASA B31.1-1955, Code for Pressure Piping.

The components are similar to those which have experienced extensive service in operating power plants. Adequate protective devices and controls are provided to assure reliable and safe operation.

10.3 SYSTEM ANALYSIS

10.3.1 REACTOR AND/OR TURBINE TRIP

Following a reactor and/or turbine trip, the feedwater flow to the steam generator is ramped down to approximately 5% of full flow. Due to the slow rampdown, operators manually control main feedwater flow or initiate auxiliary feedwater flow as necessary to restore and maintain steam generator levels. Once the system transient has terminated, the operator, while monitoring the primary coolant temperature, can restore and maintain the steam generator level. The feedwater temperature will decrease to that of the stored condensate.

10.4 TESTS AND INSPECTIONS

Equipment, instruments and controls are regularly inspected in order to ensure proper functioning of systems.

The turbine governor and stop valves, reheat stop and intercept valves, bleeder trip valves and auxiliary feedwater pump may be tested while the turbine is in operation.

In addition, during the Plant shutdown period for refueling, equipment, instruments and controls can be checked and inspected.

In-service inspection of ASME Class 1, 2, and 3 components is conducted in accordance with Section XI of the ASME B&PV Code.

In-service testing of ASME Class 1, 2, and 3 components is conducted in accordance with ASME Code for Operation and Maintenance of Nuclear Power Plants.

10.4.1 PIPE WALL THINNING INSPECTION PROGRAM

In response to Generic Letter 89-08, the pipe wall thinning inspection program was initiated to meet or exceed the requirements of NUREG-1344, Appendix A.

A component susceptibility ranking has been broken down into 14 systems/ subsystems for ease of tracking. These systems are:

1. Main steam
2. Condensate
3. Feedwater
4. Steam generator blowdown
5. Heater drain pump discharge
6. Reheater drain tank
7. Numbers 5 and 6 heater drains
8. Moisture separator drain tanks
9. Numbers 1-4 heater drains
10. Heater vents
11. Extraction steam to Number 6 heater
12. Extraction steam to Number 5 heater
13. Extraction steam to Number 3 heater
14. Extraction steam to Numbers 1-2 heaters

Components in these systems are ranked according to projected wear rates obtained by modeling. Modeling factors for single-phase systems include piping material, fluid velocity, piping configuration, oxygen concentration, pH and temperature. Factors for two-phase systems include percent moisture, piping material, temperature, oxygen concentration, pH, piping configuration and fluid velocity.

Components were selected in a three-stage process. First, systems were selected based on material, velocity and temperature. Second, subsystem selection used temperature and velocity, water/steam quality and pH/chemistry. And last, component selection considered geometry, walkdowns and experience.

By letter dated April 19, 1990, the NRC accepted this program on the basis that it complied with NUREG-1344, Appendix A.