CHAPTER 10
STEAM AND POWER CONVERSION SYSTEM

10.1 DESIGN BASIS

10.1.1 Performance Objectives

The turbine-generator systems consist of components of conventional design acceptable for use in large power stations. The equipment is arranged to provide high thermal efficiency without sacrificing safety. The component design parameters are given in Table 10.1-1.

The steam and feedwater system is designed to remove heat from the reactor coolant in the four steam generators and produce steam for use in the turbine-generator. It can receive and dispose of, in its cooling systems and through atmospheric relief valves, the total heat existent or produced in the reactor coolant system following an emergency shutdown of the turbine-generator from a full-load condition.

The heat balance diagram at 1,078,200 kWe, maximum calculated; is shown on Figure 10.1-1. The stretch rating heat balance diagram, Figure 10.1-2A for 1,007,838 kWe incorporates the new electrical generator, uprated HP element and ruggedized LP element.

The system design monitors and restricts radioactivity discharge to normal heat sinks or the environment so that the limits of 10 CFR 20 are not exceeded under normal operating conditions or in the event of anticipated system malfunctions.

One steam turbine- and two electric motor-driven auxiliary feedwater pumps are provided to ensure that adequate feedwater is supplied to the steam generators for removing reactor decay heat under all circumstances, including loss of power and normal heat sink (e.g., condenser isolation, loss of circulating water flow). Feedwater flow can be maintained until either power is restored or reactor decay heat removal can be accomplished by other systems. Auxiliary feedwater pumps and piping are designed as seismic Class I components.

10.1.2 Load Change Capability

Load changes up to step increases of 10-percent and ramp increases of 5-percent per min within the load range of 15 to 100-percent and with manual rod control can be accommodated without reactor trip subject to possible xenon limitations late in core life. Similar step and ramp load reductions are possible within the range of 100 to 15-percent of full load. The reactor coolant system will accept a complete loss of load from full power with reactor trip. In addition, the turbine bypass and steam dump systems make it possible to accept a turbine load decrease of up to 25- to 50-percent of full power at a maximum turbine unloading rate of 200%/minute without reactor trip (see Section 7.3.3.1). The plant is normally in base-loaded operation.

10.1.3 Functional Limits

The system design incorporates backup means (power relief and code safety valves) of heat removal under any loss of normal heat sink (e.g., condenser isolation, loss of circulating water flow) to accommodate reactor shutdown heat rejection requirements. System atmospheric discharges under normal operation are made only if the releases are within the acceptable limits of 10 CFR 20. All discharges to the atmosphere that may contain non-negligible contributions to the offsite radiation environment are monitored to ensure acceptable radiation levels.

10.1.4 Secondary Functions

The steam and power conversion system provides steam for the turbine-driven auxiliary feedwater pump and for the operation of the air ejectors. The turbine bypass system is designed to dissipate the heat in the reactor coolant following a full-load trip. This heat is removed by the steam bypass of the turbine generator to the condenser circulating water and by the steam dump through the atmospheric power relief valves and safety valves in the event of loss of vacuum in the condenser.

TABLE 10.1-1

Steam and Power Conversion System
Component Design Parameters

Turbine Generator	
Turbine type	Four-element, tandem-compound, six-flow exhaust
Turbine capacity (MWe)	
Initial license application	906.6
At current licensed Reactor Power	1078.2
Generator rating (kVA)	1,439,200 (0.91pf; 75 psig H_2)
Turbine speed (rpm)	1,800
Condensers	
Type	RADIAL FLOW, SINGLE-PASS, DIVIDED WATER BOX, DEAERATING
Number	3
Condensing capacity (pounds of steam per hour, total)	7,243,971 (plus BFPT)
Condensate pumps	
Type	Eight-stage, vertical, pit-type, centrifugal
Number	3
Design capacity, each (gpm)	7,860
Motor type	Vertical, induction
Motor rating (hp)	3,000
Feedwater pumps	
Type	High-speed, barrel casing, single-stage, centrifugal
Number	2
Design capacity, each (gpm)	15,300
Pump drive	Horizontal steam turbine
Drive rating, each (hp)	8,350
Auxiliary feedwater pumps	
Number	3 (one steam-turbine- driven, two electric- motor-driven)
Design capacity (gpm)	800 (turbine-driven) 400 (each, motor-driven pump)
Auxiliary feedwater source	360,000-gal ensured reserve in 600,000-gal condensate tank Alternate supply from 1,500,000-gal city water tank

10.1 FIGURES

Figure No.	Title
Figure 10.1-1	Deleted
Figure 10.1-1a	Uprate PEPSE Model with New HP Turbine High Pressure Turbine Expansion
Figure 10.1-1b	Uprate PEPSE Model with New HP Turbine Moisture Separator Reheater Train A
Figure 10.1-1c	Uprate PEPSE Model with New HP Turbine Moisture Separator Reheater Train B
Figure 10.1-1d	Uprate PEPSE Model with New HP Turbine Low Pressure Turbine Expansion
Figure 10.1-1e	Uprate PEPSE Model with New HP Turbine Main Condensers
Figure 10.1-1f	Uprate PEPSE Model with New HP Turbine Notes and Significant Results
Figure 10.1-2	Deleted
Figure 10.1-2a	Deleted
Figure 10.1-3	Deleted
Figure 10.1-4	Deleted
Figure 10.1-5	Deleted
Figure 10.1-6	Deleted
Figure 10.1-7	Load Heat Balance Diagram at 1,034,072 kWe

10.2 SYSTEM DESIGN AND OPERATION

10.2.1 Main Steam System

The main steam system, which is designed for a pressure of 1085 psig at 600°F, conducts steam from the four steam generators, which are located inside the containment structure, to the turbine generator unit, located in the Turbine Generator Building. The system, shown in Plant Drawings 227780, 9321-2017, and 235308 [Formerly UFSAR Figure 10.2-1, sheets 1, 2 and 3], has four 28-inch main steam pipes, one from each steam generator to the turbine stop and control valves. The four lines are interconnected local to the turbine. Each steam pipe has a swing disk type main steam isolation value (MSIV) and a swing disk type nonreturn valve located outside the containment. The MSIVs were redesigned to better withstand the dynamic forces associated with rapid closure in the event of a steam line rupture and thus reduce the likelihood of damage. The material for the valve discs was upgraded to stainless steel and the design of the disc arms was improved to reduce valve strains. In their Safety Evaluation Report (SER) dated September 15, 1976, the NRC determined that these modifications would satisfy General Design Criteria 4 of 10 CFR 50, Appendix A. A flow venturi upstream of the isolation valve measures steam flow, providing flow signals used by the automatic feedwater control system (see Section 7.3.3.3). The venturi also limits the steam flow rate in the event of a steam line break downstream of the venturi. Steam pressure is also measured upstream of the isolation valve.

The MSIVs each contain a free-swinging disk that is normally held out of the main steam flow path (valve open) by a solenoid controlled air piston. On receipt of a signal from the steam line break protection system described in Section 7.2.3.2.3.7, the solenoid valves are energized, releasing air from the piston and thereby allowing the MSIV to close. The MSIVs are designed to close in 5 seconds or less.

The non-return valves are activated on reverse flow of steam in case of accidental pressure reduction in any steam generator or its piping.

The system is classified as Class I for seismic design up to and including the isolation valves.

The steam line break incident is analyzed in Section 14.2.5.

10.2.1.1 Turbine Steam Bypass System

Excess steam generated by the reactor coolant system is bypassed, during conditions described below, from the four 28-in. main steam lines ahead of the turbine stop valves directly to the condensers by two 20-in. main steam bypass lines that run on either side of the turbine. From each 20-in. line, six 8-in. lines are taken, each with an 8-in. bypass control valve installed. Each bypass valve discharges into a 10-in. pipe that is connected by a manifold with one other 8-in. bypass valve and discharges into a 12-in. manifold. Each 12-in. manifold is taken to a separate section of the condenser where it discharges into the condenser through a perforated diffuser. Each bypass valve has a maximum capacity of 505,000 lb/hr and is rated at 442,000 lb/hr with 650 psia inlet pressure. The total capacity of all 12 bypass valves when operated with 765 psia in the steam generators (stretch rated load of 1078.2 MWe) is approximately 5,561,500 lb/hr (40-percent of the steam generator steam flow). The large number of small-size valves installed limit the uncontrolled steam flow to less than that of a steam generator/main steam safety valve should one valve stick open. Thus, a stuck open bypass valve will not result in a plant cooldown in excess of the steam line rupture/malfunction cases analyzed in UFSAR section 14.2.5. Additionally, local manually operated isolation valves are provided at each control valve.

On a turbine trip with reactor trip, the pressure in the steam generators rises. To prevent overpressure without main steam safety valve operation, the 12 turbine steam bypass valves open and discharge to the condenser for several minutes. The operation of the valves is initiated by a signal from the reactor coolant average temperature instrumentation. In the event of a turbine trip, all valves open fully in 3 sec. After the initial opening, the valves are modulated by the T_{avg} signal to reduce the average temperature and to maintain it at the no-load value. This is described further in Section 7.3.3.

After a normal orderly shutdown of the turbine generator leading to plant cooldown, the operator may select pressure control for more accurate maintenance of no-load conditions using the bypass valves to release steam generated by the residual heat. Plant cooldown, programmed to minimize thermal transients and based on residual heat release, is effected by a gradual manual adjustment of this pressure setpoint until the cooldown process is transferred to the residual heat removal system.

During startup, hot standby service, or physics testing, the bypass valves may be controlled manually from the pressure controllers located on the main control board.

The 12 bypass valves open on temperature control on turbine trip or large load rejection. All 12 valves are prevented from opening on loss of condenser vacuum. They are also blocked on trip of the associated condenser circulating water pump.

10.2.1.2 Steam Dump to Atmosphere

If the condenser heat sink is not available during a turbine trip, excess steam, generated as a result of reactor coolant system sensible heat and core decay heat, is discharged to the atmosphere.

There are four 6-in. by 10-in. and one 6-in. by 8-in. code safety valves located on each of the four 28-in. main steam lines outside the reactor containment and upstream of the isolation and nonreturn valves. Discharge from each of the 20 safety valves is carried to the atmosphere through individual vent stacks. The five safety valves in each main steam line are set to relieve at 1065, 1080, 1095, 1110, and 1120 psig. The total relieving capacity of all 20 valves is 15,108,000 lb/hr.

In addition, four 6-in. power-operated relief valves are provided, which are capable of releasing steam to the atmosphere to dissipate the sensible and core decay heat. These valves are automatically controlled by pressure or may be manually operated from the main control board and are capable of releasing 10-percent of the equivalent rated steam flow (1,390,375 lb/hr of steam at 1020 psig pressure). One power-operated relief valve is located on each main steam line upstream of the swing disk isolation valve. Discharge from each of the four power relief valves is carried to the atmosphere through individual muffled (silencer-fitted) vent stacks. In addition, the power-operated relief valves may be used to release the steam generated during reactor physics testing and plant hot standby operation if the main condenser is not available.

10.2.1.3 Low-Pressure Steam Dump System

A low pressure steam dump system is provided to bypass steam from the exhaust lines from the high-pressure turbine directly to the condenser. The system is provided to minimize turbine speedup immediately following a turbine trip or generator breaker opening.

The low-pressure steam dump system consists of six dump valves, which connect the high-pressure turbine exhausts to the condensers through individual breakdown orifices. An isolation valve is provided for each dump valve. At any generator breaker opening, turbine trip, or overspeed trip with the isolation valves open and dump valves closed, the dump valves would be activated. This would divert approximately 25-percent of the steam available to overspeed the turbine to the condensers, thus reducing the potential maximum turbine speed.

10.2.1.4 Steam for Auxiliaries

The steam for the turbine-driven auxiliary feedwater pump is obtained from two of the 28-in. steam-generator outlet mains upstream of the swing disk isolation valves. A pressure-reducing control valve reduces the steam to 550 psig for the auxiliary turbine.

Auxiliary steam for the turbine gland steam supply control valve, the three steam-jet air ejectors, the reheater section of the six moisture separator-reheaters, the three priming ejectors, and supplementary steam for the main feed pump turbines is obtained from branches on the steam lines ahead of the turbine stop valves. Pressure-reducing stations are used for the priming and main air ejectors. Reheater temperature control valves are located in the steam line to the reheaters. The design pressure and temperature for this system are 1085 psig and 600°F. Steam from six extraction openings in the turbine casings is piped to the shells of the three parallel strings of feedwater heaters. The first extraction point originates at the high-pressure turbine casing and supplies steam to the shells of the No. 26 A/B/C (high-pressure) feedwater heaters. The second extraction point originates in the moisture preseparators located in the high-pressure turbine exhaust piping ahead of the moisture separators and supplies steam to the No. 25 A/B/C (low-pressure) feedwater heaters. The third, fourth, fifth, and sixth extraction points all originate at the low-pressure turbine casings and supply steam to the Nos. 24 A/B/C, 23 A/B/C, 22 A/B/C, and 21 A/B/C (all low-pressure) feedwater heaters, respectively.

Non-return valves are provided in all but the two lowest pressure extraction steam lines to prevent turbine overspeed from the backflow of flashed condensate from the heaters after a turbine trip. All of these valves are air-cylinder operated and close automatically on turbine trip. Two of these valves are installed in each of the steam lines to heater Nos. 25 and 26 and also in the extraction line from each moisture pre-separator. One of these valves is installed in the steam lines to heater Nos. 23 and 24. The low-pressure fifth and sixth point extraction lines are located entirely in the condenser shells and do not contain non-return valves.

10.2.1.5 Steam Generator Blowdown

Each steam generator is provided with two 2½ in. bottom blowdown connections to control the shell solids concentration. The two connections are at the same level but are on opposite sides of the shell. Piping from 2½ to 2 in. reducing inserts at each of the two connections join to form a 2-in. blowdown header for each steam generator. The bottom of each steam generator is also provided with a drain connection, except in the case of the steam-generator No. 21 drain, which has been blanked off.

Each blowdown line has two diaphragm-operated trip valves acting as isolation valves and a hand shutoff valve. The isolation valves are solenoid controlled and open when their individual solenoid is energized. The isolation valves will fail shut on loss of air or power. Each valve is provided with position indicating lights in the control room. In addition to the isolation valves, each line includes a manually operated needle-type flow control valve for blowdown flow or sample flow adjustment and an air-operated valve acting as a fluid trap valve. The steam-generator sample line is taken off from the blowdown line outside containment downstream of the isolation valves. A small flow from each sample line is combined and is monitored for radiation. In the event of a high-radiation signal, both isolation diaphragm valves in the blowdown lines close automatically. They also shut on a phase A containment isolation signal and on an automatic start signal for the motor-driven auxiliary feedwater pumps. The two isolation valves and the fluid trap valve are electrically interlocked to preclude water hammer during closure of the valves on an isolation signal. On an open signal, the isolation valves open prior to the fluid trap valve.

Blowdown from all four steam generators passes to the blowdown flash tank. The flashed vapor is discharged to the atmosphere while the condensate drains by gravity through a service water discharge line into the circulating water discharge canal.

If drains from the blowdown flash tank become contaminated, or in the event of primary to secondary coolant leakage in one or more of the steam generators, the blowdown may be manually diverted to the support facilities (Unit 1 site) secondary boiler blowdown purification system flash tank. This system cools the blowdown and either stores it in the support facilities waste collection tanks or purifies it.

The normal full-load blowdown rate from four steam generators is approximately 57,455 lb/hr or 0.41-percent of feedwater flow. The design basis blowdown flow for four steam generators is 265,200 lb/hr. The maximum limit for blowdown flow is 198,900 lb/hr per steam generator for short periods of operation, not to exceed one year cumulative over the life of the steam generator. This provides for occasionally higher blowdown rates should they be required to reduce solids concentration, and/or sodium carry over via the feedwater system in case of small condenser leaks.

10.2.2 Turbine Generator

The original turbine generator had a guaranteed capability of 1,021,793 kWe at 1.5-in. Hg absolute exhaust pressure with zero percent makeup and six stages of feedwater heating. The unit currently operates at 1800 rpm with steam supplied ahead of the main stop valves at 737 psia, 509°F, and enthalpy of 1200 BTU/lb. Steam is admitted to the turbine through four stop valves and four control valves. The expected throttle flow at 1078 MWe is 12,971,500 lb of steam per hour.

The turbine (TC6F-45) is a four-casing, tandem-compound, six-flow exhaust unit with 45-in. last row blades and consists of one double-flow high-pressure element in tandem with three double-flow low-pressure elements. The low pressure rotors are of the fully-integral design, which eliminates the separate discs (with their bores and keyways) of the earlier design. Steam, after passing through the stop and control valves, passes through the high-pressure turbine, then through the moisture preseparators, through the moisture separator reheaters, and then to the low-pressure turbines as shown in Plant Drawings 227780, 9321-2017, and 235308 [Formerly UFSAR Figure 10.2-1, sheets 1, 2 and 3].

There are four moisture preseparators and six horizontal-axis, cylindrical shell, combined moisture separator/steam reheater assemblies. Steam from the exhaust of the high-pressure turbine element passes through the preseparators and enters each reheater assembly at one end. Internal manifolds in the lower section distribute the wet steam. The steam then rises through a chevron moisture separator where the moisture is removed and drained to a drain tank. The steam leaving the chevron separator flows over a tube bundle where it is reheated. This reheated steam leaves through nozzles in the top of the assemblies and flows to the low-pressure turbines. The tube bundle is supplied with main steam from ahead of the turbine throttle valves, which condenses in the tubes and leaves as condensate. Condensate from the reheater assemblies flows to the high-pressure heaters. The turbine-generator building general arrangement, operating floor, and cross section are shown in Plant Drawings 9321-2004 and 9321-2008 [Formerly UFSAR Figures 10.2-2 and 10.2-3].

The turbine oil system consists of a high-pressure hydraulic control system and a low-pressure lubrication system. Oil is also used to seal the generator shaft seals to prevent hydrogen leakage from the generator into the turbine building. The oil pump mounted on the main turbine shaft normally supplies all oil requirements. A motor-driven auxiliary oil pump supplies the oil required during turbine startup and whenever there is low pressure in the bearing oil header. The auxiliary unit is a centrifugal pump driven by a 150-hp motor. Oil is supplied to the hydraulic control mechanisms at 300 psig. A motor-driven bearing oil pump is also provided to supply oil whenever there is a low pressure in the bearing oil header. This is a centrifugal-type pump with a 75-hp motor. During startup, these auxiliary oil pumps supply all the oil while the main pump acts against a closed check valve. An alternating current motor-driven oil pump is provided for turning gear and emergency operation. A direct current motor-driven oil pump, operated from a station battery, provides additional backup to ensure a supply of lubricating oil to the machine. An alternating current motor-driven generator seal oil pump is furnished for normal operation with a direct current motor-driven backup pump to ensure confinement of the hydrogen within the generator.

A continuous bypass turbine oil purification system removes contaminants from the oil.

To maintain shaft alignment while the unit is down, a motor-driven turning gear is provided.

In 1987, the original generator was replaced with a generator of larger capacity. The new generator has a hydrogen cooled rotor and a water cooled stator, and is rated at 1,439,000 kVA at 75 psig hydrogen pressure. It has sufficient capability to accept the gross kilowatt output of the steam turbine with its control valves wide open, at a reactor power of 3216 MWt.

10.2.3 Turbine Controls

High-pressure steam enters the turbine through four stop valves and four governing control valves. The four main stop valves are designed for the specific operating conditions. Each stop valve is a single-seated, oil-operated, spring-closing valve controlled primarily by the turbine overspeed trip device. The turbine overspeed trip pilot is actuated by one of the following to close the stop valves:

1. Turbine thrust bearing trip.
2. Low bearing oil pressure trip.
3. Low condenser vacuum.
4. Solenoid trip.
5. Overspeed trip.
6. Manual trip.

Each stop valve has limit switches that operate position lights on the main control board.

Test switches on the main control board permit test closure of each valve. The valve position can be observed at the turbine. Periodic tests exercise the stop valves and ensure their ability to close during an emergency. The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525 “Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency,” and in accordance with established NRC acceptance criteria for the probability of a missile ejection incident at IP-2. In no case shall the test interval for these valves exceed one year.

Before a stop valve can be opened, the pressure across the valve must be equalized. This is done by opening a small bypass valve around each of the stop valves.

Electrical interlocks (e.g. circuit breaker position contacts, instrument contacts, relay contacts, valve limit switch contacts) are utilized in control circuits that actuate the turbine trip auxiliary relays. This will initiate a reactor trip.

Four hydraulically operated control valves of the single-seated plug type open and close in sequence to control steam admission to the turbine. They are actuated by the turbine speed governor, which is responsive to turbine speed.
It includes:

1. A speed changer or synchronizing device.
2. A load limit device that must be reset after operation of the overspeed trip before the control valves can be opened.

3. A second load limit device without reset, furnished to give redundancy of load cutback following a rod drop.
4. The governing emergency trip valve, actuated by loss of low pressure auto stop oil pressure.
5. An auxiliary governor, responsive to the rate of turbine speed increase to close the control valves.

Each control valve has a motor-controlled hydraulic pilot valve to test the operation of the valve. Test switches with indicating lights are provided on the main control board turbine section. Removable strainers are located in each control valve body to protect the valves and turbine from foreign material in the steam.

The normal governing devices that operate through hydraulic relays to operate the control valves are as follows:

1. The governor handwheel at the unit.
2. The governor synchronizing motor, which is controlled by a switch on the electrical section of the main control board and is used for raising or lowering turbine speed or load.
3. The load limit handwheel at the unit.
4. The load limit motor, which is controlled by a switch on the turbine section of the main control board and by a reactor control rod drop runback signal (this is described further in Chapter 7).

The pre-emergency device functions similarly to the normal governing devices by operating the control valves in case of abnormal operating conditions in the auxiliary governor. This pre-emergency device closes the control valves on rapid increase in turbine speed. The control valves will be actuated by either the speed governor or load limit. The device delivering the lowest oil pressure will be in control. Pressure gauges on the main control board indicate the oil pressure from these devices.

The emergency devices that will trip the stop valves, the control valves, and the air relay dump valves are as follows:

1. Solenoid trip.
2. Low condenser vacuum trip.
3. Low bearing oil trip.
4. Thrust bearing trip.
5. Manual trip at the unit.
6. Overspeed trip.

The solenoid trip is produced directly by the following:

1. Reactor trip breakers opening.
2. Turbine generator primary lockout relay.
3. Turbine generator backup lockout relay.
4. Manual trip push button at control board.
5. Vibration.
6. Main steam isolation valve closure.
7. Steam generator high-high level.
8. [Deleted]

9. Safety injection.
10. [Deleted]
11. AMSAC trip
12. [Deleted by EC-20569]
13. Loss of stator cooling

The solenoid trip signals and logic are shown in Plant Drawing 225096 [Formerly UFSAR Figure 7.2-3].

The mechanical overspeed trip mechanism consists of an eccentric weight mounted in the end of the turbine shaft that is balanced in position by a spring until the speed reaches the point at which the trip is set to operate.

The centrifugal force overcomes the restraining spring and the eccentric weight flies out striking a trigger that trips the overspeed trip valve and releases the autostop fluid to drain. The resulting decrease in autostop pressure causes the governing emergency trip valve to release the control oil pressure.

This closes the main stop and control valves. An air pilot valve used to control the extraction lines non-return valves is also actuated by the autostop pressure.

The independent electrical overspeed protection system (IEOPS),has been disabled and is out of service. IEOPS is not required by the Technical Specifications, and is redundant to the Turbine Mechanical Overspeed Protection and it was not credited for Turbine Overspeed Protection.

The autostop valve is also tripped when any one of the protective devices is actuated. The protective devices include low bearing oil pressure, solenoid, thrust bearing, and low vacuum trips. These devices are all included in a separate assembly, but they are connected hydraulically to the overspeed trip valve. An additional protective feature includes a turbine trip following a reactor trip.

When the unit load is at or above P-8, trip of the turbine generator requires a reactor trip.

A loss of one main feedwater pump initiates automatic turbine load cutback. This is described further in Chapter 7.

10.2.4 Circulating Water System

Hudson River water is used for the condenser circulating water. River water flows under the floating debris skimmer wall, through traveling screens, and into six separate screenwells. The traveling screens, which operate continuously, are designed to reduce the potential for fish and debris from entering the circulating water pumps. Each screenwell is provided with stop logs to allow dewatering of any individual screenwell for maintenance purposes.

The water from each individual screenwell flows to a motor-driven, vertical, mixed flow condenser circulating water pump. Each of the six condenser circulating water pumps provides 140,000 gpm and 21-ft total dynamic head when operating at 254 rpm and 84,000 gpm and 15-ft total dynamic head when operating at 187 rpm. Each pump is located in an individual pump well, thus tying a section of the condenser to an individual pump. The circulating water is piped to the condensers and is discharged back into the river far enough away from the intake to minimize recirculation. To protect the traveling screens against ice during freezing water conditions, bar grates with ice shields are installed upstream of the traveling screens at the inlet of the intake bays. Heating elements located in the traveling screen head section prevents ice from forming on the screens.

Sodium hypochlorite, is available for injection into the circulating water to prevent the buildup of bacterial slime on the traveling water screens, condenser tubes, and piping. Sodium hypochlorite may be stored in two 4000-gal tanks in the hypochlorite room of the Unit 1 screenwell house. These tanks supply the 500 gallon day tank for the Unit 2 sodium hypochlorite feed pump skids and the Unit 3 sodium hypochlorite storage tank via the Unit 3 transfer pump.

10.2.5 Condenser and Auxiliaries

Three surface-type, single-pass, radial flow condensers with bolted divided water boxes at both ends are provided. Fabricated steel water boxes and shell construction is used. Hotwell design is for at least 4-min storage while operating at maximum turbine throttle flow with free volume for condensate surge protection. The hotwells are longitudinally divided to facilitate the detection of condenser tube leakage. Each half is provided with separate conductivity measurement devices. In the event of high conductivity (high salinity) in a hotwell, it will be manually isolated. The condensate will be dumped overboard instead of being used to provide suction for the condensate pumps. The deaerating hotwells reduce the residual oxygen in the condensate to less than 0.01 cm^3/l. Condensers 21, 22 and 23 use titanium tubes and tube sheets. Water box manholes are provided for access. Provision is made steam turbine bypass condensing arrangements to condense turbine bypass steam for controlled startup and to condense residual and decay heat steam following a shutdown.

Three motor-driven, eight-stage, one-third capacity, vertical, pit-type, centrifugal condensate pumps are provided, each taking suction from the condenser hotwells. The condensate pumps discharge into three separate parallel streams of feedwater heaters and provide the suction supply to the feedwater pumps.

Each condenser has one four-element, two-stage air ejector with separate intercondensers and common aftercondensers as shown in Figure 10.2-4. The ejectors function by using steam from the main steam system supplied through a pressure-reducing valve. Motor driven vacuum pumps are also provided. Air removed from the condenser is monitored for radioactivity. In the event of a steam-generator leak and the subsequent presence of radioactive contaminated steam in the secondary system, the radioactive noncondensable gases that concentrate in the air ejector effluent will be detected by this radiation monitor. A high activity level signal automatically diverts the exhaust gases from the vent stack to the containment.

For initial condenser shell side air removal, three noncondensing priming ejectors are provided. Each has a capacity of 900 cfm. This apparatus may be used during periods of plant shutdown where decay heat is involved. The main ejectors will also be operated at the same time to ensure that the effluent is monitored for radioactivity.

Examinations of condensers are conducted regularly during scheduled outages in accordance with engineering recommendations. Examinations typically include visual inspections and eddy current tests.

For startup operation two full size motor driven vacuum pumps with all ancillary equipment are installed to reduce oxygen levels in the feedwater and condensate prior to and during start-up. The pumps are also capable of being used for the normal holding operation in lieu of the air ejector system or as a backup to the air ejector system. For the start-up operation steam from the house boiler is used for turbine gland sealing.

10.2.6 Condensate and Feedwater System

The condensate and feedwater system is designed to supply a total of 13,957,950 lb of feedwater per hour to the four steam generators at a turbine load of 1078 MW(e). This system is composed of:

1. A condensate system that collects and transfers condensed steam and the drains from five feedwater heaters through five stages of feedwater heating to the suction of the main feedwater pumps.

2. A condensate makeup and surge system that maintains a normal water level in the condenser hot wells.

3. A heater drain system that collects and transfers the drains from Nos. 25 and 26 feedwater heaters, the moisture preseparators and the six moisture separator/reheaters to the suction of the main feedwater pumps.

4. A feedwater system that delivers the condensate and heater drains through the final stage of feedwater heating to the steam generators.

5. An auxiliary feedwater system that provides a flow of water from the condensate storage tank to the steam generators when the main feedwater pumps are unavailable. The flow is equivalent to that required for makeup because of reactor core decay heat removal requirements.

10.2.6.1 Condensate System

The condensate system transfers condensate and low-pressure heater drains from the condenser hotwell through five stages of feedwater heating to the suctions of the main feedwater pumps. The system flow diagram is shown in Plant Drawings 9321-2018 and 235307 [Formerly UFSAR Figure 10.2-5].

Three one-third size condensate pumps, arranged in parallel, take suction from the bottoms of the condenser hotwells. The pumps discharge into a common header that carries a portion of the condensate through three steam jet air ejector condensers, arranged in parallel, and through one gland steam condenser. The remaining portion flows in parallel with the first flow path, bypassing the steam jet air ejectors and the gland steam condenser. The second flow path rejoins the first in the header downstream of the gland steam condenser.

The condensate pumps are eight-stage, vertical, pit-type pumps. Each pump is rated at 7860 gpm and 1150-ft total dynamic head when operating at 1185 rpm. A standard packed stuffing box is used for shaft sealing. The pump bearings are lubricated by the pumped liquid. Each pump is driven through a solid coupling by a 3000-hp, vertical, solid shaft, induction motor that has an open drip-proof enclosure. The condensate pumps are operated by manual control on the main control board. To maintain the condenser vacuum and turbine steam seals during startup, shutdown, and at very low loads, an 8-in. condensate recirculation line, containing a diaphragm-operated valve, is provided to maintain minimum flow through the air ejector condensers and gland steam condenser. The recirculation line originates at the condensate header downstream of the gland steam condenser and terminates at the condenser hotwell. The diaphragm-operated recirculation valve is automatically controlled by the minimum flow required by the air ejector condensers.

The 24-in. header divides into three 14-in. lines downstream of the gland steam condenser. From these lines, the condensate passes through the tube sides of three parallel strings of two low-pressure feedwater heaters. The flow from these heaters is combined in another 24" pipe, and then divided to go to the remaining three strings of three low-pressure heaters. After the No.25 feedwater heater, the three condensate lines join into a common header. The heater drain pump discharge enters this header and then continues on to the suction of the main feedwater pumps.

Each parallel string of feedwater heaters may be taken out of service by closing a manual gate valve at the inlet to the string of heaters and at the outlet of the string of heaters.

The condensate makeup and surge systems maintain normal water level in the condenser hotwell.

The makeup system connects the 600,000-gal capacity condensate storage tank to a diffusing pipe in the condenser shell. This line contains a diaphragm-operated valve that can automatically open on low level in the condenser hotwell to pass makeup water from the tank to the condenser. This valve may be operated manually or automatically. An isolating valve will close the condenser makeup before the condensate storage tank level reaches its Technical Specification minimum capacity. This will ensure a reserve of condensate for the auxiliary feedwater pumps that will hold the plant at hot shutdown for 24 hr following a trip at full power.

The condensate surge system connects the condensate pump discharge header to the condensate storage tank. This line contains a diaphragm-operated valve that automatically opens on high level in the condenser hotwell to pass excess condensate from the condensate pump discharge header to the condensate storage tank.

Hotwell levels are indicated on the main control board. Should the automatic makeup valve or the surge valve become inoperative, it may be isolated from its respective system and the hotwell level controlled from the control room by remote manual positioning. The condenser hot-wells contain 114,000 gal, which is equal to approximately 5.63-min condensate flow at 1078 MWe load.

The drains from the No. 26 A/B/C feedwater heaters flow to the heater drain tank. Normal condensate level is maintained in the No. 26 heaters by diaphragm-operated level control valves.

The drains from the No. 25 A/B/C feedwater heaters flow by gravity directly to the heater drain tank. There are no level control valves in the drains from these heaters.

Two half-size heater drain pumps pump the drains from the drain tank into the condensate header upstream of the main feedwater pumps. Both pumps discharge through diaphragm-operated level control valves.

The heater drain pumps are 14-stage, vertical, enclosed suction-type pumps. Each pump is rated at 4150 gpm and 720-ft total dynamic head when operating at 1170 rpm. Each pump is driven through a solid coupling by a 1000-hp, vertical, solid shaft, induction motor that has an open drip-proof enclosure.

The heater drain pumps are operated by manual controls on the main control board. A heater drain pump is automatically stopped on low drain tank level or if the flow falls below a set minimum. After the pump has stopped, the water level in the heater drain tank will increase. An alarm sounds in the control room on both tank low level and pump low flow.

When a high level occurs in the heater drain tank, diaphragm-operated valves open to discharge the excess condensate from the heater drain tank directly to the shell of a condenser. An alarm sounds in the control room. The heater drain tank has a 5660-gal storage capacity at normal water level or approximately 0.64-min storage of drains at the normal full load of 1078 MWe.

Drains from the Nos. 24, 23, and 22 feedwater heater strings normally flow through diaphragm-operated level control valves to the shells of the next lowest pressure feedwater heater. On high level in any heater, a separate high-level drain from the heater discharges directly to the condenser.

Drains from the No. 21 feedwater heaters normally flow through diaphragm-operated level control valves to the condenser. When a high level occurs in the heaters, a separate high-level drain for each heater discharges to the condenser.

10.2.6.2 Main Feedwater System

Two half-size steam-driven main feedwater pumps increase the pressure of the condensate for delivery through the final stage of feedwater heating and then the feedwater regulating valves to the steam generators. The system flow diagram is given in Plant Drawing 9321-2019 Figure 10.2-7.

The main feedwater pumps are single-stage, horizontal, centrifugal pumps with barrel casings. Each pump is rated at 15,300 gpm and 1700-ft total dynamic head when operating at 4740 rpm. Seal-water injection is used for shaft sealing. Bearing lubrication for both the pump and its turbine drive is accomplished by an integral lubricating oil system. Normal circulation of the lubricating oil is by a motor-driven pump. The lubricating oil system includes a reservoir, a cooler, and two motor-driven oil pumps. Each main feedwater pump is driven through a flexible coupling by an 8350-hp horizontal steam turbine that uses steam from the discharge of the three reheater moisture separators on one side of the turbine hall. The main feedwater pumps are operated automatically by the feed control system. Manual controls are also provided on the main control board for remote operation and testing during normal operation. During normal startup of the plant, these pumps are started locally. A minimum flow control system is provided to ensure that each pump is handling at least a 3000-gpm flow at all times.

Above a preset turbine power, the operator may arm the condensate pump auto-start circuit (MBFP trip or MBFP low suction pressure or running condensate pump trip).

Low suction pressure starts any idle condensate pumps (if armed) and reduces the feed pump turbine speed to maintain suction pressure. Normal speed is regained when the suction pressure and flow is reestablished. High discharge pressure reduces turbine speed to prevent excessive pressure in the feed piping.

In the original design, a bypass was provided around the low pressure heaters, which was to be used to provide sufficient suction pressure at the feed pumps during a transient when flashing might occur in the heater drain tank and affect the performance of the heater drain pumps. The bypass valve was retired in place when operating experience proved that it was not required to perform this function.

High main feedwater pump bearing temperatures are alarmed in the main control room. However, they do not automatically stop the pump.

The two parallel main feedwater pumps operate in series with the condensate pumps and discharge through check valves and motor-operated gate valves into a common header. The feedwater then flows through the three parallel, high-pressure feedwater heaters into a common header. Four parallel 18-in. lines containing the feedwater metering and regulating stations feed the four steam generators.

Shutoff valves at the inlets and outlets of the feedwater heaters permit a heater to be taken out of service. Bypass lines are provided around the heaters to allow operation when a heater is out of service for maintenance.

A long loop recirculation line, from the high pressure feedwater header, leading back through an installed particulate removal filter and portable demineralizers to the condenser, is available for secondary coolant cleanup during plant outages.

The steam-generator feedwater metering and regulating stations measure, indicate, record, and control the water level in each of the four steam generators. A conventional three-element system receives flow and load signals from the reactor protection system through isolation amplifiers and compares the difference between steam and feedwater flows to adjust the level setpoint. The deviation of level measurement from this setpoint positions the feedwater control valve accordingly. Totalized steam flow controls the speed of the main feedwater pump turbines.

Low-flow feedwater regulating valves bypass the main control valves for the control of low-load feedwater flow.

On trip of one main feedwater pump above a preselected turbine power, the following actions are automatically initiated to prevent a trip of the reactor and turbine-generator.

a. The turbine load limit is run back to reduce the steam demand.
b. Any idle condensate pumps are started. (if armed)
c. Non tripped pump to pick up additional load.

A reactor trip is actuated on a coincidence of steam flow-feedwater flow mismatch, coupled with a low level in the corresponding steam generator. A reactor trip is also initiated on a coincidence of two-out-of-three low-low water-level signals from any one steam generator. Whenever this reactor trip occurs, the main feedwater valves move to the fully open position in response to an increased level demand signal from the feedwater control system. This provides an additional heat sink for the reduction of reactor coolant temperature to the no-load average temperature value. The feedwater regulating valves close on one of the following conditions:

1. High-high steam generator water level.
2. Reactor trip coincident with low T_{avg} signal.
3. Safety injection signal.

In the case of reactor trip coincident with low T_{avg} signal, the low flow feedwater bypass valve closure may be delayed by means of an installed timer to allow main feedwater to moderate the cooler auxiliary feedwater before it enters the steam generators. The feedwater control system is an electronic analog instrumentation system.

Readout and control equipment is as follows:

1. Wide and narrow range level shown on recorder calibrated for cold conditions in the steam generator, permits observation of the level essentially over the full height of each steam-generator shell.

2. Visual indication is provided in the main control room of feedwater flows in pounds per hour for each steam generator.

3. A leading edge flow meter in each steam-generator feedline provides feedwater flow data for thermal power calculations.

4. Each flow channel and each narrow-range level channel is indicated on the main control board.

5. Each feedwater controller has one manual control station. The unit consists of an auto/manual transfer switch and an analog output control, which serves as the valve position signal when in "Manual." The "Automatic" setpoint is preset, but adjustable in the instrument rack.

6. Other manual control stations are used to position auxiliary feedwater regulating valves.

10.2.6.3 Auxiliary Feedwater System

This system is used for normal startup. The auxiliary feedwater system supplies high-pressure feedwater to the steam generators to maintain a water inventory. This is needed to remove decay heat energy from the reactor coolant system by secondary-side steam release in the event that the main feedwater system is inoperable. The head generated by the pumps is sufficient to deliver feedwater into the steam generators at safety valve pressure. Diverse auxiliary feedwater supplies are provided by using two pumping systems using different sources of motive power for the pumps. The system flow diagram is given in Figure 10.2-7.

The capacity of each system is set so that all four steam generators can be supplied with auxiliary feedwater. Under limiting conditions, at least two steam generators will not boil dry nor will the primary side relieve water through the pressurizer relief/safety valves following a loss of main feed-water flow. Further details are given in Section 14.1.9.

One system uses a steam-turbine-driven pump with the steam capable of being supplied from two of the steam generators. This system is designed to supply up to 800 gpm of feedwater (200 gpm to each steam generator). The estimated (expected) design performance characteristic of the pump is given in Figure 10.2-8. The technical specification requirement is that this pump be capable of supplying at least 380 gpm.

Steam to drive the turbine is supplied from two of the main steam lines upstream of the isolation valves at steam-generator outlet pressure and is reduced to within the 550-psig turbine design pressure by a pressure-reducing control valve (PCV-1139). The turbine is started by opening the pressure-reducing valve between the turbine supply steam header and the main steam lines. The turbine sleeve journal bearings are ring oil-lubricated, water cooled. The pump uses oil slinger lubricated ball bearings. The drive is a single-stage turbine, capable of quick starts from cold standby, and is directly connected to the pump.

The speed of the turbine can be adjusted manually via a remote pneumatic speed controller (HC-1118). It is normally set at zero percent (i.e., minimum setting of approximately 3200 rpm). Upon generation of an automatic start signal for the turbine-driven pump, PCV-1139 will open, and the turbine will start and run. The pump itself will only operate on recirculation flow since the auxiliary feedwater regulating valves in its discharge are normally closed. In order to deliver flow to the steam generators using this pump, the operator must open one or more of the associated auxiliary feedwater regulating valves, and manually adjust the speed controller for the turbine. Both of these actions can be performed from the central control room control board or locally at the valves. The auxiliary feedwater regulating valves are pneumatically operated. PCV-1139 opens fully on loss of control air. All pneumatic instruments and valves associated with the auxiliary feedwater system requiring instrument air for their safety function have automatic nitrogen back-up.

Since the single failure criterion for loss of normal feedwater events can be satisfied by one motor-driven auxiliary feedwater pump providing flow for a sufficiently long period of time before an operator action is taken to align the turbine-driven auxiliary feedwater pump, manual alignment of the turbine-driven pump is acceptable. Further details are given in Section 14.1.9.

The other system uses two motor-driven pumps with lubricated ring oiled ball bearings. Each pump has a design capacity of 400 gpm, and the discharge piping is arranged so that each pump supplies two of the four steam generators. The estimated design performance characteristic for these pumps is given in Figure 10.2-9. The technical specification requirement is that each pump be capable of supplying at least 380 gpm.

The motors are of open drip-proof design with ball bearings. In the event of complete loss of power, electrical power is automatically obtained from the diesel generators. Each motor-driven pump is provided with a discharge pressure sustaining control system to prevent the pump from "running out" on its curve. The Regulating valves are pneumatically operated and have an automatic nitrogen bottle backup system to maintain operability in the event that control air is lost. A recirculation line and control system are provided for each pump to maintain a minimum flow when it is running.

Upon generation of an automatic start signal for the motor-driven auxiliary feedwater pumps, both pumps will start and each will deliver at least 380 gpm. The regulating valves for each motor-driven pump are controlled such that each steam generator receives approximately 190 gpm. An additional restriction on auxiliary feedwater flow when a steam generator feed ring has been uncovered for an extended period of time provides added assurance against a potentially damaging water hammer upon initiation of cold auxiliary feedwater to the steam generators. This restriction limits auxiliary feedwater flow to the affected steam generator(s) until an increase in steam generator level can be seen. The accident analyses in Sections 14.1.9 (Loss of Normal Feedwater) and 14.1.12 (Loss of All AC Power to the Station Auxiliaries) assume that only one motor-driven pump starts one minute after accident initiation and delivers 380 gpm (nominal 190 gpm to each of two steam generators). Further, operator action is credited at 10 minutes after reactor trip to start the second motor-driven pump or to align the steam-driven-turbine pump.

The auxiliary feedwater pumps are located in an enclosed room in the auxiliary feedwater building, which houses the area of the main steam and feedwater penetrations immediately outside the reactor containment.

Safety-grade flow measurement devices are installed in the feedwater supply to each steam generator with indicators on the main control board. In addition, wide-range and safety-grade narrow-range steam-generator level indications are provided in the main control room. These provide the operator with the information necessary to route auxiliary feedwater discharge flow through the remote manual discharge regulating valves.

The distribution piping is seismic Class I throughout. It is designed to ensure that a single fault will not restrict the system function.

The overall seismic qualification of the auxiliary feedwater system was reviewed and found acceptable by NRC Safety Evaluation Reports issued September 7, 1982 and September 29, 1987.

The water supply source for this system is redundant. The main source is by gravity feed from the condensate storage tank. This tank is sized to meet the normal operating and maintenance needs of the turbine cycle systems. However, a minimum water level will be maintained, equivalent to the steam generation from 24 hr of residual heat generation at hot shutdown conditions. The condensate storage tank is considered the safety grade source for the auxiliary feedwater system.

The auxiliary feedwater pumps can draw from an alternative supply of water to provide for long-term cooling. This alternative supply is from the 1.5 million gal city water storage tank. This supply is manually aligned to the auxiliary feedwater pumps in the event of unavailability of the condensate storage tank.

The auxiliary feedwater pumps are automatically started on receipt of any of the following signals:

1. Steam-driven auxiliary feedwater pump:
   a. Low-low water level in any two of the four steam generators.
   b. Loss of offsite power concurrent with a unit trip and with no safety injection signal present.

2. Motor-driven auxiliary feedwater pumps:
   a. Low-low water level in any steam generator.
   b. Automatic trip of main feedwater pumps [*Note - One main feedwater pump trip automatically sends a demand start signal to both motor-driven auxiliary feedwater pumps*.] as indicated by loss of main feed pump control oil pressure after manual control switch was last operated to the "start" position.
   c. Safety injection signal.
   d. Loss of outside power concurrent with a unit trip.

The auxiliary feedwater system automatic initiation signals and circuits meet safety-grade requirements. Interfacing AMSAC signals and circuits which are not safety-grade are provided with Class 1E isolation devices.

In the event of a complete loss of offsite power, the electrical power is supplied by the diesel generators as described in Chapter 8.

The pneumatically powered flow control valves associated with the three AFW pumps are supplied by instrument air with a nitrogen supply as backup (for accident analyses the non-safety grade instrument air is not credited). Lack of the nitrogen backup supply (and instrument air) would cause the motor driven and turbine driven pump flow control valves to fail open and the turbine governor control valve to fail open. The nitrogen backup supply is adequate to permit remote (CCR) positioning of the flow control valves for 30 minutes, following which local manual operator action would be taken. If AFW was actuated due to an event such as a Loss Of Normal Feedwater (LONF) when the backup nitrogen supply is not available, the AFW function is available as follows:

- With offsite electrical power supplying the motor driven pumps, they would start on low-low steam generator level in any generator (see above start signals). However, the overcurrent protection logic could result in breaker amptector actuation if there is a reduced bus voltage and the pumps are providing high flow because the flow control valves are full open. These pumps are considered unavailable in this condition. The turbine driven pump would also start when a low-low steam generator level signal from two steam generators is received (see above start signals). Calculations have shown that the pump would provide adequate flow from that point to maintain steam generator level.

- With a loss of offsite power, the motor driven and turbine driven AFW pumps would get a start signal. The two motor-driven AFW pumps will provide their required function since they would be loaded on the emergency diesel generators but would not trip on breaker amptector operation since the low voltage condition would not exist on the diesels. The turbine-driven AFW pump will perform its required AFW function when the flow control valves and the turbine governor control valve fail open since the pump design speed at the nominal mechanical governor setting is adequate to provide the required flow.

Posting of the operator dedicated to pump control will restore operability to all pumps and allow maintenance on the nitrogen backup system.

In addition, the steam-driven and the motor-driven auxiliary feedwater pumps can be started manually from the control room and locally at the pumps.

In the event of a loss of the condensate storage tank supply (e.g., one or both condensate storage tank discharge valves are closed), immediately place the auxiliary feedwater pump controls in the manual mode. Within 1 hour either the valve(s) shall be reopened or the valves from the alternate city water supply shall be opened and the auxiliary feedwater pump controls restored to the automatic mode.

10.2.6.4 System Chemistry

Steam-generator water chemistry is maintained within the required water quality limits. A nitrogen blanket in the condensate storage tank minimizes oxygen ingress. During outages, as part of the wet lay-up process, nitrogen is introduced as a sparging gas to displace air from the steam generators. Hydrazine is added to the condensate for oxygen control and ammonium hydroxide and/or volatile amines are added to maintain the pH at the optimum value for the materials of construction for the system.

No radiation shielding is required for the components of the steam and power conversion system. During normal operation, continuous access to the components of this system outside of containment is possible.

Under normal operating conditions, no radioactive contaminants are present in the steam and power conversion system. It is possible for this system to become contaminated through steam-generator tube leaks. In this event, any contamination is detected by monitoring the steam-generator shell-side blowdown sample points and the condenser air ejector discharge. Operation with a steam-generator tube leak is discussed in Chapter 14. Radiation monitors are installed in the main steam lines outside of the containment wall to provide continuous readout on recorders in the control room.

Steam generator feedwater is monitored at the main condensers. The condensate is analyzed for the major chemical constituent of river water (sodium) and is monitored for total dissolved solids.

10.2.7 Codes and Classifications

The pressure-retaining components or compartments of components comply, as a minimum, with the codes detailed in Table 10.2-1.

TABLE 10.2-1
Codes and Classifications

System pressure vessels and[3] pump casing	ASME Boiler and Pressure Vessel Code, Section VIII
Steam-generator vessel (shell side)	ASME Boiler and Pressure Vessel Code, Section III, Class C[1] (required)
System valves, fittings, and piping[2]	USAS Section B31.1 Power Piping Code (1955) ASA, USAS, ANSI
Pressure Testing of Repairs and Modifications	USAS Section B31.1 Power Piping Code (1992)

Notes:

1. The shell side of the steam generator conforms to the requirements for Class A vessels (Actual) and is so stamped as permitted under the rules of Section III.
2. Except piping supplied by Westinghouse as part of the Turbine generator package, which was designed and fabricated to Westinghouse proprietary standards. This includes crossover, crossunder and lube oil piping.

3. Nos. 26A and 26B feedwater heater extraction steam inlet nozzles were modified in 1995 under the provisions of ASME Section VIII and were inspected and accepted under the provisions of the licensee's 10 CFR 50 Appendix B Quality Assurance Program.

10.2 FIGURES

Figure No.	**Title**
Figure 10.2-1 Sh. 1	Main Steam Flow Diagram, Sheet 1, Replaced with Plant Drawing 227780
Figure 10.2-1 Sh. 2	Main Steam Flow Diagram, Sheet 2, Replaced with Plant Drawing 9321-2017
Figure 10.2-1 Sh. 3	Main Steam Flow Diagram, Sheet 3, Replaced with Plant Drawing 235308
Figure 10.2-2	Turbine Generator Building General Arrangement, Operating Floor, Replaced with Plant Drawing 9321-2004
Figure 10.2-3	Turbine Generator Building General Arrangement, Cross Section, Replaced with Plant Drawing 9321-2008
Figure 10.2-4	Condenser Air Removal and Water Box Priming - Flow Diagram, Replaced with Plant Drawing 9321-2025
Figure 10.2-5 Sh. 1	Condensate and Boiler Feed Pump Suction - Flow Diagram, Sheet 1, Replaced with Plant Drawing 9321-2018
Figure 10.2-5 Sh. 2	Condensate and Boiler Feed Pump Suction Flow Diagram, Sheet 2, Replaced with Plant Drawing 235307
Figure 10.2-6 Sh. 1	Deleted
Figure 10.2-6 Sh. 2	Deleted
Figure 10.2-7	Boiler Feedwater Flow Diagram, Replaced with Plant Drawing 9321-2019
Figure 10.2-8	Steam Turbine-Driven Auxiliary Feedwater Pump Estimated Performance Characteristics
Figure 10.2-9	Motor-Driven Auxiliary Feedwater Pump Estimated Performance Characteristics

10.3 SYSTEM EVALUATION

10.3.1 Safety Features

Trips, automatic control actions, and alarms will be initiated by deviations of system variables within the steam and power conversion system. Appropriate corrective action is taken as required to protect the reactor coolant system. The more significant malfunctions or faults that cause trips, automatic actions, or alarms in the steam and power conversion system are:

1. Turbine trip (see Section 10.2.3 for further discussion of trip actions):
   a. Generator/electrical faults.
   b. Low condenser vacuum.
   c. Thrust bearing failure.
   d. Low lubricating oil pressure.
   e. Turbine overspeed.
   f. Reactor trip.
   g. Manual trip.
   h. Main steam isolation valve closure.

2. Automatic control actions (see Chapter 7 for a further discussion of trip actions):
   a. High level in steam generator stops feedwater flow.
   b. Normal and low level in steam generator modifies feedwater flow by continuous proportional control.

3. Principal alarms:
   a. Low vacuum in condenser.
   b. Thrust bearing failure.
   c. Low lubricating oil pressure.
   d. Turbine overspeed.
   e. Low level in steam generator.
   f. High level in steam generator.
   g. Condenser hotwell high and low levels.

A reactor trip from power requires the removal of core decay heat. Immediate decay heat removal requirements are satisfied by the steam bypass to the condensers. Thereafter, core decay heat can be continuously dissipated by the steam bypass to the condenser as feedwater in the steam generator is converted to steam by heat absorption.

Normally, the capability to return feedwater flow to the steam generators is provided by the operation of the turbine-cycle feedwater system. In the unlikely event of a complete loss of offsite electrical power to the station and concurrent reactor trip, decay heat removal would be ensured by the single turbine-driven and two motor-driven (by emergency diesel-generator power) auxiliary feedwater pumps, and steam dump to atmosphere by the main steam safety and/or power relief valves. Further details are given in Section 14.1.12. In this case, feedwater from the condensate storage tank is available by gravity feed to the auxiliary feedwater pumps. The minimum 360,000 gal of water in the condensate storage tank is adequate for decay heat removal at hot shutdown conditions for at least 24 hr. A backup source of feedwater is available from the city water storage tank.

The analysis of the effects of loss of full load on the reactor coolant system is discussed in Section 14.1.8.

10.3.2 Secondary-Primary Interactions

Following a turbine trip, the control system reduces reactor power output immediately by a reactor trip. Steam is bypassed to the condenser, and there is no lifting of the main safety valves. In the event of failure of a main feedwater pump, a motor-driven auxiliary feedwater pump is automatically started and the second main feedwater pump remaining in service will carry approximately 65-percent of full-load feedwater flow. If both main feedwater pumps fail, the reactor will be tripped as a result of steam-generator low-low level or steam-feedwater flow mismatch and the auxiliary feedwater pumps will start. Not withstanding the anticipatory reactor trip on turbine trip, if reactor coolant system conditions reach trip limits, the reactor will trip.

Pressure relief is required at the main steam system design pressure of 1085 psig. The first safety valve is set to relieve at 1065 psig. Additional safety valves are set at pressures up to 1120 psig (see Section 10.2.1.2), as allowed by the ASME Code. The pressure relief capacity is greater than the steam generation rate at maximum calculated conditions.

The evaluation of the capability to isolate a steam generator to limit the release of radioactivity in the event of a steam-generator tube leak is presented in Section 14.2.4. The steam break accident analysis is presented in Section 14.2.5.

10.3.3 Single Failure Analysis

Table 10.3-1 presents the results of a single failure analysis of selected components in the system.

TABLE 10.3-1
Single-Failure Analysis

Component or System	Malfunction	Comments and Consequences
Auxiliary feedwater system	Auxiliary feedwater pump fails to start (following loss of main feedwater)	The auxiliary feedwater system comprises one turbine-driven and two motor-driven pumps. The turbine pump has twice the capacity of a motor-driven pump. A single motor-driven pump has sufficient capacity to allow time for an operator action to align the turbine-driven train and prevent relief of water through the primary side safety/relief valves. Thus adequate redundancy of auxiliary feedwater pumps is provided, as described in UFSAR 14.1.9.
Steam line isolation system	Failure of steam line isolation valve to close (following a main steam line rupture)	Each steam line contains an isolation valve and a non-return check valve in series. Hence, a failure of an isolation (or non-return) valve will not permit the blowdown of more than one steam generator irrespective of the steam-line rupture location, as described in UFSAR section 14.2.5.
Turbine bypass system	Bypass valve sticks open (following operation of the bypass system resulting from a turbine trip)	The turbine bypass system comprises 12 bypass valves, each with a steam flow capacity less than a steam generator/main steam safety valve. Thus, the uncontrolled steam flow from a stuck open bypass valve will not result in a plant cooldown in excess of the bounding steam line rupture / malfunction cases analyzed in UFSAR section 14.2.5.

10.4 TESTS AND INSPECTIONS

The main steam isolation valves are tested at least at refueling intervals and a maximum closure time of 5 sec is verified.

The main steam isolation valves serve to limit an excessive reactor coolant system cooldown rate and resultant reactivity insertion following a main steam break incident. Their ability to close upon signal is verified at periodic intervals. A closure time of 5 sec from receipt of closing signal was selected as being consistent with expected response time for instrumentation as detailed in the steam line break analysis. Further details are given in Section 14.2.5.

The auxiliary feedwater pumps are tested at regular intervals. Verification of correct operation is made both from instrumentation within the main control room and by direct visual observation of the pump. In addition, during reactor startup and shutdown, the auxiliary feedwater pumps (normally the motor-driven pumps) are used to deliver water from the condensate storage tank through its feedwater control valves to the feedwater line to the steam generators.

In response to NRC IE Bulletin 87-01, an inspection program has been established for piping and fittings in the extraction steam, turbine crossunder, heater drain pump discharge, condensate, feedwater and auxiliary feedwater systems. UT inspections are utilized to evaluate wall thickness at locations considered to be most susceptible to erosion/corrosion. Additional information is given in reference 1.

REFERENCES FOR SECTION 10.4

1. Letter from Murray Selman (Con Edison), to William Russell, NRC, dated 9/11/87.