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10.0 STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion system for the Perry Nuclear Power Plant is rated at approximately 1,327.6 MW of gross electrical output. An 1,800 rpm, six flow, tandem compound reheat turbine with 43-inch last stage blades will drive a 1,446,700 kVA (with the capability of operating at 1,513,556 kVA at 0.90 power factor), 1,800 rpm, direct connected, 22,000 volt, 3 phase, 60 Hertz, conductor cooled, synchronous generator. Equipment for regenerative feedwater heating, pumping to required pressure, condensate purification, and various auxiliary systems complete the power conversion system.

Main steam from the nuclear boiler system flows to the main turbine generator through four main steam lines. Steam is diverted from the main steam for reheating purposes, seal steam generation, offgas preheaters, reactor feed pump turbines during startup, and steam jet air ejectors. Main steam enters the high pressure turbine, flows through the blade paths and exhausts to the moisture separator reheaters, where moisture is removed and the steam is slightly superheated. Steam then enters the three low pressure turbines, flows through the blade paths and exhausts to the three shells of the condenser.

Steam is extracted at several points in the main turbine cycle for regenerative feedwater heating, for driving the reactor feed pump turbines and for the seal steam evaporator during normal operation.

The condenser condenses the exhaust flows from the turbine as well as other miscellaneous flows from the cycle. Condensate is taken from the hotwell of the intermediate pressure condenser and is pumped by the hotwell pumps through the condensate filter/demineralizer systems, the offgas condenser, the steam packing exhauster, and the steam jet air ejector condensers to the suction of the condensate booster pumps.

These pumps send the condensate through three closed feedwater heaters to the direct contact feedwater heater and hot surge tank. Feedwater is taken from the hot surge tank by the feedwater booster pumps and is pumped through one stage of intermediate pressure feedwater heating to the suction of the reactor feed pumps. These pumps force feedwater through one stage of high pressure feedwater heating to the nuclear boiler system inlet.

Water for condensing the steam in the condenser is circulated in a closed loop system that releases the heat to atmosphere through a natural draft cooling tower <Section 10.4.5>.

A turbine bypass system capable of bypassing 28.8 percent (nominal) of the full load main steam flow directly to the condenser is provided for startup and load changing operation.

The following system diagrams are included:

a.	Main and reheat steam	<Figure 10.1-1 (1)>
		<Figure 10.1-1 (2)>
		<Figure 10.1-1 (3)>
b.	Extraction steam	<Figure 10.1-2>
c.	Feedwater	<Figure 10.1-3 (1)>
		<Figure 10.1-3 (2)>
d.	Condensate (main)	<Figure 10.1-4 (1)>
		<Figure 10.1-4 (2)>
e.	Condensate filters	<Figure 10.1-5 (1)>
		<Figure 10.1-5 (2)>
		<Figure 10.1-5 (3)>

f.	Condensate demineralizers	<Figure 10.1-6 (1)>
		<Figure 10.1-6 (2)>
		<Figure 10.1-6 (3)>
		<Figure 10.1-6 (4)>
g.	Circulating water	<Figure 10.1-7>
h.	High pressure heater drains and vents	<Figure 10.1-8 (1)>
		<Figure 10.1-8 (2)>
		<Figure 10.1-8 (3)>
		<Figure 10.1-8 (4)>
i.	Low pressure heater drains and vents	<Figure 10.1-9>
j.	Steam seal system	<Figure 10.1-10>
k.	Condenser air removal	<Figure 10.1-11>

The following heat balances are included:

a.	Rated power	<Figure 10.1-12>
b.	Designed power (valves wide open)	<Figure 10.1-13>

Design and performance characteristics are listed on the figures for each respective system.

The only portions of the steam and power conversion system (balance of plant) that are safety-related are:

a. For the main steam system - outer containment isolation valve (B21-F028A,B,C,D) to the outermost system isolation valve (N11-F020A,B,C,D).

b. For the feedwater system - from the first system isolation valve (B21-F065A,B) to the reactor.

These portions of the main steam and feedwater systems are Safety Class 1 and 2, and Seismic Category I. Refer to <Section 10.3>, <Section 10.4.7>, and <Section 5.4.9> for further discussion.

System instrumentation is discussed, in general, in <Section 10.2>, <Section 10.3>, and <Section 10.4>. Safety-related instrumentation associated with this system is discussed in <Section 7.2>, <Section 7.3>, and <Section 7.7>.

10.2 TURBINE GENERATOR

10.2.1 DESIGN BASES

The General Electric Model TC6F-43” LSB turbine generators are tandem compound, six flow reheat units. The 1,800 rpm turbine generator produces a gross generator output of approximately 1,327.6 MWe with all feedwater heaters in service and with a nominal plant exhaust pressure of 1 inch Hg (absolute) and zero makeup. Steam conditions at the turbine inlet are 937 psia and 1,190.8 Btu/lb. Normal and upset conditions are shown on <Figure 10.1-1 (1)>.

The unit is expected to operate in the base load mode for the majority of its design life. Normal load swings are limited to the rate of change of the NSSS. Within these limitations, the turbine generator is capable of accepting a load reduction from 100 percent to approximately 71 percent (using the 28.8 percent nominal bypass) and automatically returning to rated power.

Functional limitations imposed by design characteristics of the reactor coolant system are as follows:

a. Turbine Stop Valve

   During any event resulting in turbine stop valve fast closure, turbine inlet steam flow must not be reduced faster than permitted by <Figure 10.2-1>.

b. Turbine Control Valve

   The turbine control valves are capable of full stroke openings of 10 seconds (nominal) and closures in 7 seconds nominal for adequate pressure control performance. During any event resulting in

turbine control valve fast closure, turbine inlet steam flow cannot be reduced faster than permitted by <Figure 10.2-2>.

The turbine generator and associated equipment are designed and manufactured in accordance with the appropriate sections of the ASME Boiler and Pressure Vessel Code (<Table 3.2-1>, Note 12) and the General Electric Company standards and specifications.

10.2.2 DESCRIPTION

10.2.2.1 Turbine Generator

The turbine consists of four casings, a double-flow high pressure section, followed by three double-flow, low pressure casings. The 6 last stages have 43-inch buckets.

The 1,800 rpm generator is 3 phase, 60 hertz, rated 1,446,700 kVA with the capability of operating at 1,513,556 kVA at 0.90 power factor at 22,000 volts, and 75 psig hydrogen pressure.

A shaft driven alternator exciter rated at 3,410 kW provides the necessary dc supply for exciting the field.

An electrohydraulic control system, using electronic computing devices and high pressure fire-resistant fluid, actuates and controls the steam valves. This system is completely separated from the bearing oil supply. During normal operation the turbine control valves act to maintain constant upstream pressure, while the reactor recirculation is controlled according to load demand.

The turbine generator pressure regulator instrumentation and controls are described in <Section 7.7.1> and <Section 7.7.2>. The inservice inspection program for the main steam reheat valves is discussed in <Section 10.2.3.6>.

A set of seven bypass valves with a nominal capacity of 28.8 percent of full load throttle flow is installed immediately upstream of the inlet stop valves. The bypass valves permit rapid load reduction, up to 28.8 (nominal) percent capacity, without requiring that the reactor be tripped. During the PNPP startup program a measurement of the turbine bypass capacity demonstrated that the capacity of each of the seven (7) bypass valves is essentially equal. No direct means are available for measuring total bypass valve flow during startup testing.

Furthermore, analysis was performed to conclude that turbine bypass capacity as low as 25 percent NBR does not affect the bounding ΔCPR results presented in <Table 15.0-2a>.

The heat cycle provides for extraction at six pressure stages for feedwater heating as follows:

a. One on the high pressure turbine cylinder (Heater No. 6).

b. One on the moisture separator (Heater No. 5).

c. Four on each of the three low pressure turbine cylinders (Heater Nos. 4, 3, 2, and 1).

10.2.2.2 Electrohydraulic Control System

The turbine generator uses an electrohydraulic control (EHC) system which, in coordination with the NSSS steam bypass and pressure control system, controls the turbine speed, load, pressure, and flow for startup and normal operations. The EHC system operates the turbine stop valves, control valves and combined stop and intercept valves. Turbine generator supervisory instrumentation is provided for operational analysis and malfunction diagnosis.

Automatic control functions are programmed to protect the nuclear steam supply system with appropriate corrective actions. The turbine EHC system combines the principles of solid state electronics and high pressure hydraulics to control steam flow through the turbine. The control system has the following major subsystems:

a. Speed control unit

b. Load control unit

c. Flow control unit

The speed control unit receives speed signals from the shaft speed pickups, which are compared to a speed reference signal, to produce a speed/error signal. The speed control unit also differentiates the speed signals to produce acceleration signals. These signals are compared to the acceleration reference to produce acceleration error signals that are integrated and combined with the speed/error signal, to produce an output to the load control unit.

The load control unit accepts the speed-acceleration error signal from the speed control unit and compares the signal with the preselected load demand signal, which is provided to the NSSS steam bypass and pressure control system. The load control unit also accepts limit signals (e.g., load limit, pressure limit, power load unbalance limit, etc.) and combines them with the load demand signal to generate flow reference signals, which are provided to the flow control unit.

The flow control unit positions the turbine steam control valves at the required position to satisfy each valve flow reference signal from the load control unit. It consists of the individual valve positioning units, which essentially are electrohydraulic, closed loop, servo-mechanism valve position control systems.

10.2.2.3 Turbine Overspeed Protection System

The turbine overspeed control system is not safety-related. The system has no direct function in the safe shutdown of the reactor in the event of accident. However, a reliable, redundant, fail-safe turbine overspeed system is incorporated for the safety of plant personnel and equipment, and to ensure no mitigation of engineered safety systems employed for safe, orderly shutdown of the reactor system.

To meet the specific requirements of GDC 4, a redundant turbine overspeed control system is provided in addition to the normal speed control function provided by the turbine electrohydraulic control system. Redundancy is achieved by using at least two independent channels from the signal source to the output device which controls the emergency trip system fluid pressure, which actuates the turbine steam valves. <Figure 10.2-3> is a block diagram of the turbine protection system. No specific valve failure can keep the turbine overspeed trip from functioning.

The mechanical overspeed trip is an unbalanced ring which is held concentric with the shaft by a spring. When the speed reaches the trip speed (108 percent to 111 percent of rated), the centrifugal force of the ring overcomes the force of the spring, and the ring snaps to an eccentric position. The ring then strikes the trip finger which operates the mechanical trip valve. This releases the fluid pressure on the disk dump valves for main stop and control valves and intermediate stop and intercept valves, thereby closing the turbine steam valves. The overspeed trip device may be tested by tripping it at normal speed by the application of oil through the oil trip valve.

The electrical backup overspeed trip device consists of a speed trip relay (set at 0.5 percent above the mechanical trip setpoint) that is operated by a signal from a magnetic pickup from the turbine shaft. The signal from the speed trip relay will energize the master trip relay

which will de-energize the coil of the electrical trip solenoid valve. When the coil is de-energized, the electrical trip valve operates to release the fluid pressure on the actuator of the steam valves. Each compartment of the mechanical and electrical overspeed protection systems will be tested at each startup and during normal operation, on a weekly basis, by the following tests:

a. A mechanical overspeed trip test at the EHC Panel to test for operation of the overspeed trip device and mechanical trip valve.

b. A mechanical trip piston test at the EHC panel to test for electrical activation of the trip mechanism.

c. An electrical trip test at the EHC panel to test for operation of the electrical trip valve.

d. A backup overspeed trip test at the EHC panel to test the 2 out of 3 logic circuits.

An air relay dump valve is provided which actuates on turbine trip. The valve controls air to the extraction steam check valves which limit contributions to turbine overspeed from steam and water in the extraction lines and feedwater heaters. The total energy in these steam lines down to the check valves has been included in the turbine overspeed analysis. The extraction steam lines from the turbine to the No. 1 and 2 feedwater heaters are located within the main condensers and do not have any non-return valves provided in them. The turbine overspeed analysis takes into account the total energy in these extraction lines to the No. 1 and 2 heaters down to and including the water and steam in the heater and subcooler shells. This data has been used by General Electric to calculate the maximum potential overspeed. It assumes turbine load is suddenly reduced from maximum to zero, with no restraint of reverse flow in the extraction lines being considered, but all other turbine control and extraction non-return valves operate

normally. This General Electric analysis demonstrates that these bottled-up volumes of steam and water within the turbine and extraction steam system will not cause the turbine speed to rise above a certain maximum value (as established by General Electric steam turbine design rules and code requirements) after a full load rejection or trip.

The closing time for all extraction non-return valves is less than two seconds. The motor-operated stop valves in the extraction steam lines from the turbine are not relied on to provide overspeed protection, but have been included to prevent water damage to the turbine; therefore, their closure times are not relevant to overspeed protection.

Thus, protection against the effects of high or moderate energy pipe failure is not a design requirement since the turbine overspeed control system equipment, electrical wiring and hydraulic lines are not required for safety-related shutdown of the reactor. In the event of a high or moderate energy pipe rupture, failure of the electrohydraulic control system and the hydraulic lines could be postulated. This failure, singly or in combination, would not adversely affect the mechanical overspeed trip or the hydraulic speed control systems. Either the mechanical trip or the pressure loss in the ruptured hydraulic lines would result in closure of the turbine stop valves eliminating any probability of turbine overspeed from any credible source.

The failure analysis for the turbine overspeed protection system is presented in <Table 10.2-1>.

10.2.2.4 Turbine Protection System

In addition to overspeed trip signals discussed above, the emergency trip system closes the main stop and control valves, and the intermediate stop and intercept valves, thereby shutting down the turbine on the trip signals listed in <Section 10.2.2.4.1> and <Section 10.2.2.4.2>.

The sequence of events and response times following a turbine trip are given in <Section 15.2.3>, <Figure 15.2-2>, <Figure 15.2-3>, <Figure 15.2-4>, and <Figure 15.2-5>, and <Table 15.2-2>, <Table 15.2-3>, <Table 15.2-4>, and <Table 15.2-5>.

10.2.2.4.1 Turbine Trip Signals Due to Mechanical Faults

The turbine is shut down due to the following mechanical fault signals:

a. Loss of vacuum trip.

b. Excessive thrust bearing wear.

c. Prolonged loss of generator stator coolant at loads in excess of a preset value.

d. External trip signals, including remote-manual trip on the control panel.

e. Loss of hydraulic fluid supply pressure (loss of emergency trip system fluid pressure automatically closes the turbine valves and then energizes the master trip relay to prevent a false restart).

f. Low bearing oil pressure.

g. Loss of both speed signals when turbine is not in standby control.

h. (Deleted)

i. (Deleted)

j. Loss of 125-volt dc electrohydraulic control power supply when turbine is operating at less than 75 percent rated speed.

k. Loss of 24-volt dc electrohydraulic control power supply.

l. High level in moisture separators.

m. High reactor water level.

n. Low shaft pump discharge pressure when turbine is operating at greater than 75 percent of rated speed.

o. Operation of the manual mechanical trip at the front standard.

p. Low bearing oil pressure to the trip piston.

q. RCIC initiation signal. (This signal may be delayed by a maximum of 5 minutes when steam line flows are ≥ 100 feet/second, as sensed by Main Turbine First Stage Pressure).

10.2.2.4.2 Turbine Trip Signals Due to Generator Electrical Faults

Generator electrical fault signals that trip the turbine are as follows:

a. 345 kV breaker failure.

b. Main transformer differential.

c. Deleted

d. Main transformer 345 kV neutral overcurrent.

e. Unit 345 kV bus differential.

f. Unit auxiliary transformer neutral overcurrent X.

g. Unit auxiliary transformer neutral overcurrent Y.

h. Unit auxiliary transformer sudden pressure.

i. Unit auxiliary transformer differential.

j. Generator volts/Hertz.

k. Generator stator energized with machine at low speed (generator dead machine protection).

l. Underfrequency with generator connected to system.

m. Negative sequence overcurrent with generator connected to system.

n. Generator loss of excitation with voltage balance supervision, generator connected to system.

o. Generator out of step with generator connected to system, current and voltage balance supervision.

p. Sustained generator overexcitation.

q. Generator neutral overvoltage.

r. Generator differential No. 1.

s. Generator differential No. 2.

t. Unit overall differential.

u. Zero sequence overvoltage with voltage balance supervision.

v. Reverse power with voltage balance supervision.

w. Unit auxiliary transformer secondary overcurrent.

10.2.3 TURBINE DISK INTEGRITY

10.2.3.1 Materials Selection

Turbine wheels and rotors for turbines operating with light water reactors are made from vacuum melted or vacuum degassed Ni-Cr-Mo-V alloy steel by processes which minimize flaw occurrence and provide adequate fracture toughness. Tramp elements are controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long life fracture toughness for the environment in which the parts operate. The turbine wheel and rotor materials have the lowest fracture appearance transition temperatures (FATT) and highest Charpy V-notch energies obtainable, on a consistent basis from water quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Since actual levels of FATT and Charpy V-notch energy vary depending upon the size of the part and the location within the part, etc., these variations are taken into account in accepting specific forgings for use in turbines for nuclear application. Charpy tests essentially in accordance with Specification ASTM A-370 are included.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in <Section 10.2.3.1> to produce a balance of adequate material strength and toughness to ensure safety while simultaneously providing high reliability, availability, efficiency, etc., during operation. Bore stress calculations include components due to centrifugal loads, interference fit and thermal gradients, where applicable. The ratio of material fracture toughness, K_{IC} (as derived from material tests on each wheel or rotor), to the maximum tangential stress for wheels and rotors at speeds from normal to 115 percent of rated speed (the highest anticipated speed resulting from a loss of load is 110 percent), is at least 2 $\sqrt{in}$. Adequate material fracture

toughness needed to maintain this ratio is assured by destructive tests on material taken from the wheel or rotor using correlation methods which are more conservative than that presented by J. A. Begley and W. A. Logsdon in Westinghouse Scientific Paper 71-1E7-MSLRF-P1.

Turbine operating procedures will be employed to preclude brittle fracture at startup by ensuring that the metal temperature of wheels and rotors (a) is adequately above the FATT and (b) as defined above is sufficient to maintain the fracture toughness to tangential stress ratio at or above 2 $\sqrt{in}$.

10.2.3.3 High Temperature Properties

The operating temperatures of the high pressure rotors in turbines operating with light water reactors are below the creep rupture range. Creep rupture is, therefore, not considered to be a factor in assuring rotor integrity over the lifetime of the turbines.

Below the creep rupture temperature range, rupture failure is essentially a tensile phenomenon and characterized by the yield and tensile strength of the material. Since the operating temperatures of the high pressure rotor are below the creep temperature range, the yield criterion (0.75 yield stress) governs the material behavior and defines the design stress limits.

10.2.3.4 Turbine Disk Design

The turbine assembly is designed to withstand normal conditions and anticipated transients including those resulting in turbine trip without loss of structural integrity. The design of the turbine assembly meets the following criteria:

a. Turbine shaft bearings are designed to retain structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

b. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20 percent overspeed are controlled in the design and operation so distress to the unit during operation does not occur.

c. The maximum tangential stress in wheels and rotors resulting from centrifugal forces, interference fit and thermal gradients will not exceed 0.75 of the yield strength of the materials at 115 percent of rated speed.

10.2.3.5 Preservice Inspection

The preservice inspection program is as follows:

a. Wheel and rotor forgings are rough machined with minimum stock allowance prior to heat treatment.

b. Each finish machined wheel and rotor is subjected to 100 percent volumetric (ultrasonic), surface and visual examinations using General Electric acceptance criteria. These criteria are more restrictive than those specified for Class 1 components in the ASME Boiler and Pressure Code, Sections III and V, and include the requirement that subsurface sonic indications are either removed or evaluated to assure that they will not grow to a size which will compromise the integrity of the unit during the service life of the unit.

c. All finish-machined surfaces are subjected to a magnetic particle test with no flaw indications permissible.

d. Each fully bucketed turbine rotor assembly is spin tested at or above the maximum speed anticipated following a turbine trip from full load.

10.2.3.6 Inservice Inspection and Maintenance Program

10.2.3.6.1 Turbine Assembly Inspection/Maintenance

The inservice inspection and maintenance program for the low pressure turbine assembly will be performed based on maintaining a combined unit missile probability of less than 1.0 E-5. The turbine will be inspected in stages at different refueling outages such that each low pressure turbine rotor is inspected within its operating interval as required by probabilities of Perry turbine missile generation described in <Section 10.2.3.6.1.1>. The high pressure rotor will be inspected at about 10 year intervals of actual turbine operation. This program will include disassembly of the turbine and complete inspection of all normally inaccessible parts (i.e., couplings, coupling bolts, turbine shaft, low pressure turbine buckets, low pressure rotors, and high pressure rotors).

This turbine assembly inspection will consist of the following visual, surface and volumetric examinations:

a. A thorough volumetric examination of low pressure rotors and high pressure rotors, including areas immediately adjacent to keyways and bores.

b. Visual examination of accessible surfaces of rotors.

c. Visual and surface examination of low pressure buckets.

d. 100% surface examination of couplings and coupling bolts.

10.2.3.6.1.1 External Turbine Missile Generation Probability

The turbine assembly inspection interval was selected on the basis of acceptably low probabilities of Perry turbine missile generation.

Turbine missile generation probabilities are calculated by using either a methodology developed by General Electric or a methodology developed by Siemens-Westinghouse. Either methodology can be used to develop the Perry-specific missile probabilities.

The methodology (General Electric or Siemens-Westinghouse) for determination of missile probability contains three major components:

- The probability of the turbine attaining speeds higher than those occurring during normal operation.

- The estimation of wheel burst probability as a function of speed.

- The probability of a wheel fragment penetrating the turbine casing and thus generating an external missile.

The methodology (General Electric or Siemens-Westinghouse) also indicates that the dominant failure mode would be brittle fracture emanating from a stress corrosion crack which occurs at the axial keyway in the bores of shrunk-on wheels. However, the low pressure rotors utilized at PNPP are a monoblock design, which do not utilize a keyway design. The rotor manufacturer (General Electric) indicates that brittle fracture is no longer a failure mode due to the use of the monoblock rotors <Reference 5>.

The initial Perry turbine calculation results for all three stages of the low pressure turbine showed that the probability of external missile generation was 6.2 E-6 per year after six years of actual turbine operation. Rotor inspection findings and performance of procedures to prewarm the turbine rotors during plant startups altered this probability. Subsequent findings of degraded rotor condition or rotor replacement will again alter the individual and combined unit probability values. The subsequent revised probability values will be used as a basis to schedule inspections such that the combined unit probability will not exceed the NRC annual limit of 1.0 E-5.

10.2.3.6.2 Turbine Steam Valve Inspection/Maintenance

The inservice inspection of turbine steam valves will include the following:

a. Perform dismantled inspections, at no more than ten year intervals for individual valves, within the following valve groups: (1) Main Turbine Stop Valves, (2) Main Turbine Control Valves, (3) Main Turbine Reheat Intermediate Stop Valves, (4) Main Turbine Reheat Intercept Valves and (5) Extraction Steam Valves. This interval, and the periodicity of inspections between components within any group, shall ensure that the annual probability of missile generation is kept below the value discussed in <Section 10.2.3.6.1.1>. Conduct a visual and surface examination of valve seats, disks, and stems. If unacceptable flaws, excessive corrosion, or improper clearances are found in a valve, it will be repaired or replaced and all valves of that type will be inspected. Valve bushings will be inspected and cleaned, and bore diameters will be checked for proper clearance.

b. Turbine stop, turbine control, reheat stop and intercept valves, and the turbine overspeed trip mechanism will be exercised by closing each valve or performing the overspeed trip test and observing, by the valve position indicator, that the valves move

smoothly to a fully closed position. These tests will be made in accordance with Operational Requirements Manual requirements, which further stipulate that online test failures of any one of these steam line subdivisions will require: 1) repair or replacement of failed components within 72 hours, or 2) valve closure in the affected steam line, or turbine isolation from the steam supply until repairs are completed.

c. During normal unit operation, the critical power assisted extraction non-return valves will be tested weekly by partially closing the valves using the solenoid test valves.

There are four (4) critical power assisted valves, specifically the series connected check valves controlling extraction steam flow to/from the steam seal evaporator, and to/from the direct contact heater <Figure 10.1-2> and <Figure 10.1-10>. The power assist feature is required for turbine overspeed protection. Therefore, there should be no 2-way shutoff valves installed in the airlines between the air relay dump valve and the critical power assisted check valves. At initial installation the response time of the actuators on the critical power assisted check valves should be taken. This is the time between turbine trip and full stroking of the power assist actuator. This test should result in response times of less than two second.

10.2.4 EVALUATION

The primary source of activity in the steam and power conversion system is radiation from nitrogen -16, formed by activation of primary coolant water in the reactor. This activity is carried with the steam to the turbine. Fission product noble gases and other activation gases, such as oxygen -19, nitrogen -17 and nitrogen -13, are also carried with the steam to the turbine. Nongaseous fission and activation products are present in the turbine due to moisture carryover in the steam from the NSSS. The maximum anticipated operating concentration of radioactivity

in the high pressure turbine is the same as that indicated in the tables in <Section 11.1>, multiplied by the following appropriate carryover factors:

		Carry Over Factor	
a.	noble gases	1	(100% carry over)
b.	halogens	0.02	
c.	other fission products	0.001	

The activity entering the low pressure turbine is reduced further by moisture separation between the high pressure and low pressure turbines.

Typical turbine component nitrogen -16 inventories are given in <Table 12.2-10>. Resulting radiation dose rates are approximately 6 R/hr for the main steam pipes, 2 R/hr for the high pressure turbine and 4 R/hr for the moisture separator.

As discussed in <Section 11.3>, most of the gaseous activity in the condenser is removed by the steam jet air ejector to the gaseous waste system. The activity that is not removed by the air ejector is reduced significantly by the approximately three minute holdup time in the condenser hotwell. Therefore, the activity entering the condensate and feedwater lines is significantly less than that originally entering the steam and power conversion system.

Biological shielding design is discussed in <Section 12.3.2.2>. The turbine is in an administratively controlled access area.

10.2.5 HYDROGEN AND CARBON DIOXIDE SYSTEMS

10.2.5.1 Power Generation Design Bases

a. The hydrogen and carbon dioxide systems are designed to provide the necessary flow and pressure at the main turbine generator:

   1. During startup when air is purged from the generator by carbon dioxide.

   2. During startup when carbon dioxide is purged from the generator by hydrogen.

   3. During shutdown when hydrogen is purged from the generator by carbon dioxide.

   4. During shutdown when carbon dioxide is purged from the generator by air.

   5. During normal operation where hydrogen can be supplied to the generator as necessary to make up for generator hydrogen leakage.

b. The unit has a hydrogen bulk storage system. Hydrogen supply to the generator is also being provided from the connection to the Hydrogen Water Chemistry supply piping for the plant.

c. (Deleted)

d. Should the carbon dioxide portion of the subject system fail, the plant could continue in normal operation. Should the hydrogen portion of the subject system fail, the plant could continue in normal operation in accordance with the turbine generator manufacturer's requirements.

10.2.5.2 System Description

The hydrogen portion of the system consists of the hydrogen supply station, supply cylinders and piping, together with all necessary valves, pressure reducers, instrumentation and gas purity measuring equipment. The carbon dioxide portion of the system consists of the carbon dioxide vaporizer, carbon dioxide supply piping with all the necessary valves, and instrumentation. The hydrogen and carbon dioxide system components, piping, valves, and instrumentation are shown in <Figure 10.2-4>, <Figure 10.2-5>, and <Figure 10.2-6>. The hydrogen and carbon dioxide bulk storage units are located outdoors. The hydrogen cylinder filling area is near the heater bay. The carbon dioxide tank for generator purge is located near the service building.

10.2.5.3 System Evaluation

The hydrogen and carbon dioxide system serves no safety function. System analysis has shown that failure of the hydrogen and carbon dioxide system will not compromise any safety-related systems or prevent safe shutdown. Nine hydrogen storage cylinders, with a total capacity of 62,424 scf at 2,300 psig, are located in the yard near the heater bay as shown on <Figure 1.2-2>. Hydrogen supply to the generator is expected to be normally provided from the connection to the Hydrogen Water Chemistry supply piping for the plant. The Hydrogen Bulk Storage System may be aligned to provide a hydrogen supply to the generator, as required. This hydrogen supply piping to the generator also provides for connection of a temporary hydrogen supply. Temporary hydrogen storage/handling will continue to maintain the same separation and open space location for precluding adverse effects resulting from the unlikely possibility of any explosions or fires. A fire safety shutoff valve is provided that can be closed to shut off hydrogen to the turbine building in case of fire or high temperature in the plant. A fence is erected around the hydrogen bulk storage unit to

further protect the storage area. “No Smoking” signs and “Danger Regulating Station” signs are posted in accordance with NFPA requirements.

The hydrogen distribution headers inside the turbine building are routed as follows:

1. Headers are located to prevent physical damage to pipe.

2. Headers are located away from equipment that present a fire hazard to hydrogen.

3. Headers are routed through ventilated areas.

The protective measures taken to prevent fires and explosions include the strict observance of the turbine vendor's operating instructions. These protective measures include the following during operation and maintenance:

a. During normal operation, hydrogen is used to cool the generator. To prevent hydrogen from leaking through the generator shaft seal glands into the turbine building, a shaft oil sealing system is provided.

   A carbon dioxide purge is used to avoid having an explosive hydrogen-air mixture in the generator at any time, such as when the generator is being filled with hydrogen prior to being placed in service, or when hydrogen is being removed from the generator for maintenance or inspection. Hydrogen concentrations are controlled with the aid of a gas analyzer.

   Before filling or purging the generator, the carbon dioxide analyzer will be calibrated with air, carbon dioxide and hydrogen.

b. Hydrogen removal from the generator before it is opened for maintenance

   While the generator is at standstill or on turning gear operation and the shaft sealing system is in operation, carbon dioxide is admitted into the generator, maintaining a pressure between specified limits in the generator casing, until the carbon dioxide concentration in the discharge is in excess of 95 percent measured by a gas tester. When hydrogen is being purged from the casing,

all hydrogen supply piping and headers will be disconnected to prevent hydrogen from entering the casing because of possible leakage or faulty operation of valves. The carbon dioxide will be purged from the casing with dry air.

c. Air leakage test of the hydrogen cooled generator

While the generator is at a standstill or on turning gear and the shaft sealing system is in operation, an air leakage test will be performed prior to the initial startup of the hydrogen cooled generator and after the generator has been opened for maintenance.

d. Air removal from the generator before hydrogen fill following maintenance

While the generator is at a standstill or on turning gear operation and the shaft sealing system is in operation, carbon dioxide will be admitted to the bottom of the generator through carbon dioxide distribution piping, and air in the generator will be discharged to atmosphere through the hydrogen feed pipe.

While the generator is being filled with carbon dioxide, the percentage of carbon dioxide in the gas mixture being discharged from the generator to the atmosphere should be measured by the carbon dioxide-air scale of the carbon dioxide analyzer. Carbon dioxide will be admitted to the generator until air has been displaced by carbon dioxide.

e. Filling generator with hydrogen

When the air has been displaced by carbon dioxide as determined by the gas analyzer, hydrogen is admitted to the top of the generator through the sparger and carbon dioxide is vented to atmosphere through the lower sparger, where it was originally admitted. When

hydrogen concentration in the vented gas is above 90 percent hydrogen in carbon dioxide, the vent to atmosphere may be closed and the hydrogen pressure raised to the required operating pressure.

10.2.5.4 Tests and Inspection

The hydrogen and carbon dioxide system is proved operable by its use. System piping and components are pneumatically tested prior to startup.

10.2.6 REFERENCES FOR SECTION 10.2

1. Letter, A. Kaplan (CEI) to U.S. Nuclear Regulatory Commission (NRC), "USAR Appendix 1B Commitment No.4 - Turbine System Maintenance Program," PY-CEI/NRR-0977L, March 20, 1989.

2. Letter, U.S. Nuclear Regulatory Commission (NRC) to A. Kaplan (CEI), "Turbine System Maintenance Program, Perry Nuclear Power Plant Unit No. 1 (TAC No. 72835)," PY-NRR/CEI-0478L, August 23, 1989.

3. "Safety Analysis Report for Perry 5% Thermal Power Uprate," NEDC-32907P, September 1999.

4. Letter, U.S. Nuclear Regulatory Commission (NRC) to S. Dembkowski (Siemens-Westinghouse Power Corporation), 'Safety Evaluation for Acceptance of Referencing the Siemens-Westinghouse Topical Report, "Missile Analysis Methodology for General Electric (GE) Nuclear Steam Turbine Rotors by the Siemens-Westinghouse Power Corporation (SWPC)" (TAC No. MB 5679),' April 2, 2003.

5. Letter, M. Burnett (GE Energy) to FENOC, "Turbine Missile Analysis Statement, FirstEnergy - Perry Nuclear Unit 1, Turbine #170X655, Rebuild #1LX0537," April 19, 2010.

TABLE 10.2-1

TURBINE OVERSPEED PROTECTION SYSTEM

FAILURE ANALYSIS

Component	Malfunction	Comment
Steam Valve (MSV, CV, IV, ISV)	One valve fails to close on overspeed trip	All steam valves are in pairs in series. Thus, failure of one valve to close does not defeat overspeed protection.
Turbine Extraction Non-return Valve	One valve fails to close	The overspeed potential of the feedwater heating system is small. The total energy addition due to any single extraction valve failure can contribute no more than 3 percent to the running speed of the turbine generator.
Mechanical Trip Valve	Fails to drop ETS pressure upon actuation of mechanical overspeed trip	The backup electrical overspeed trip de-energizes the master trip solenoid valve which, in turn, results in a drop in ETS pressure.

TABLE 10.2-1 (Continued)

Component	Malfunction	Comment
Master Trip Solenoid Valve	Fails to drop ETS pressure upon actuation of overspeed trip	The mechanical overspeed trip actuates the mechanical trip valve which, in turn, results in a drop in ETS pressure.
Hydraulic Trip System Piping	Piping fails causing depressurization	All steam valves close as in overspeed trip.
DC Electric Power Supply	Power supply is lost	Loss of two speed signals causes master trip solenoid valve to be de-energized which, in turn, results in a drop in ETS pressure.

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 DESIGN BASES

The main steam system is designed to convey the steam produced in the nuclear boiler system from the outermost containment isolation valves to the turbine stop valves, offgas preheaters, the moisture separator/reheaters, and the condenser steam jet air ejectors. Also provided are valves for bypassing the main turbine to the condenser, a steam supply to the reactor feedpump turbines for the startup and low load operation and a steam supply to the gland steam evaporator. The system is shown on <Figure 10.1-1>.

To prevent a failure that could lead to the release of radioactivity, the main steam system is designed to accommodate the most severe conditions of coincident pressure, temperature and loading. Furthermore, system components are located in a shielded, restricted area to safeguard personnel from radiation.

If a postulated break occurs, radiation levels will not exceed the guideline values discussed in <Chapter 15>.

The main steam system from the outer containment isolation valve (B21-F028A,B,C,D) up to and including the third shutoff valve (N11-F020A,B,C,D) is classified as Safety Class 2, Seismic Category I, and all pressure parts conform to the ASME Boiler and Pressure Vessel Code, Section III, Class 2. The remainder of the system downstream of the third isolation valves is nonsafety class and conforms to ANSI B31.1.0.

Performance requirements, including design pressures and temperatures for pressure parts, are tabulated on the right margin of the system diagram. The "upset" condition tabulated is considered to be the condition existing during safety valve operation and is expected to exist less than one percent of the time.

10.3.2 DESCRIPTION

The principal components of the main steam system are the main steam piping and connected systems. The main steam piping consists of four 28-inch O.D. Schedule 100 lines from the outer containment isolation valves to the main turbine stop valves, and connecting lines to supply steam to the second stage reheater, the condenser steam jet ejectors, offgas preheaters, the main turbine bypass valves, the reactor feedpump turbines, and the seal steam evaporator. All piping in the system is carbon steel.

10.3.3 EVALUATION

The steam flow limiting devices and the flow measurement instrumentation are included in the nuclear boiler system and are discussed in <Section 5.4.4>.

The piping in the main steam system is designed to withstand the maximum upset conditions listed in the tabulation of design requirements. Safety-related equipment and piping located in the auxiliary building portion of the steam tunnel are protected from the effects of postulated phenomena occurring outside this area. Pipe restraints are provided to protect piping and valves from the effects of pipe rupture from any cause. A moment resisting pipe restraint system is provided for both the main steam and feedwater system. The system consists of two restraint locations for each system to provide a couple type moment resistance. Both restraint locations are in the safety-related portion of the steam tunnel in the auxiliary building. One of the two

restraints is located adjacent to the point at which the classification of the steam tunnel changes. Therefore, effects of pipe rupture downstream of the motor-operated stop valves will not be transmitted to the isolation valves <Figure 10.3-1>. Impingement shields are provided where necessary to protect equipment from any postulated water, steam or missile impingement. These accident conditions and their effects on the main steam line are considered in <Section 3.6>. They are classified as faulted conditions and their results are compared with the applicable criteria of the ASME Boiler and Pressure Vessel Code Section III, Class 2.

Under operational basis and safe shutdown earthquake conditions, detailed seismic and stress analyses will be performed on the Safety Class 2 portion of the system; results of these analyses will be compared with the applicable criteria of the ASME Boiler and Pressure Vessel Code Section III, Class 2.

The turbine bypass valves are designed to control excess flow from the nuclear boiler system to the main turbine and are described in <Section 10.4.4>.

The system as described complies with the letter from Mr. Joseph M. Hendrie, Deputy Director for Technical Review, Directorate of Licensing, USAEC, to Mr. John A. Hinds, Manager, Safety and Licensing, General Electric Company, dated April 19, 1974. This letter, and Attachment A to the Hendrie to Hinds letter, outlines a system classification which is an acceptable alternate to the requirements of <Regulatory Guide 1.26>.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

The system boundary subject to inservice inspection extends from the nuclear boiler system (B21-F028A,B,C,D) to include the outer containment

isolation valve in the main steam system (N11-F020A,B,C,D). The design, inservice inspection and testing of the main steam components included in this boundary are described in <Section 5.4.9>.

The main steam components which are not part of the system boundary will not be subjected to inservice inspection.

Preoperational and inservice testing and inspection requirements of the main steam isolation valves are included in <Section 5.4.5.4>.

Valves installed in the main steam system will be hydrostatically tested in accordance with ANSI B16.5 or MSS SP-66. The system when installed will be tested in accordance with Paragraph NC-6100 of Section III of the ASME Boiler and Pressure Vessel Code.

10.3.5 WATER CHEMISTRY (PWR)

This section is not applicable to PNPP, since BWR water is not chemically treated.

10.3.6 STEAM AND FEEDWATER SYSTEM MATERIALS

10.3.6.1 Fracture Toughness

Charpy V notch tests are specified for ferretic materials used in safety-related feedwater and main steam system components where nominal pipe size exceeds 6 inches and material section thickness exceed 5/8 inch. Test methods and acceptance criteria for fracture toughness are in compliance with ASME Code Section III.

10.3.6.2 Material Selection and Fabrication

ASME Class 2 and ASME Class 3 materials used in the main stream and feedwater systems are included in Appendix I to Section III of the ASME Code.

No austenitic stainless steel components are used in safety-related portions of the main steam and feedwater systems.

Cleaning and handling of ASME Class 2 and ASME Class 3 components is performed in accordance with the recommendations of <Regulatory Guide 1.37> and the requirements of ANSI N45.2.1.

Preheat temperatures used for welding of safety-related portions of the main steam and feedwater systems are in accordance with the recommendations of <Regulatory Guide 1.50>, and Section III Article D-1000 of the ASME Code.

Welder qualifications for welds made in areas of limited access are in accordance with the recommendations of <Regulatory Guide 1.71>.

Nondestructive examination of ASME Class 2 and 3 tubular products is performed in accordance with the ASME Code Section III (Winter 1975), Paragraphs NC2550 through NC2569 and Paragraphs ND2550 through ND2569.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

10.4.1.1 General

The main condenser acts as a heat sink for the three low pressure turbine exhausts, limiting the back pressure and thus increasing the amount of available work from the turbines. The main condenser serves as a collection point for turbine bypass steam, moisture separator-reheater relief valve flow and other flows. The main condenser also deaerates and provides storage capacity for the condensate which is reused after a period of radioactive decay.

10.4.1.2 Design Bases

The design bases for the main condenser are as follows:

a. The main condenser is designed to accept the influents specified in <Table 10.4-3> during normal plant conditions without exceeding 5 inches Hg absolute or 200°F at the turbine exhaust to any shell. The main condenser is designed for the following approximate conditions:

Condenser duty	8.1×10^9 Btu/hr
Circulating water inlet temperature (design)	94°F
Circulating water temperature rise	32°F

Air in-leakage	55 scfm
Disassociated H_2 and O_2 from the BWR	H_2 162 scfm O_2 81 scfm

Steam processed through the main condenser normally contains small amounts of radioactive material. Noncondensible gases are removed via the steam jet air ejectors (SJAE) to the offgas processing system. Liquids are processed through the condensate filter/demineralizer systems. Excessive radioactive leakage is detected by the main steam line radiation monitors and the offgas pretreatment monitor.

b. The main condenser is designed to accept 35 percent of the pre-power uprate design main steam flow through the turbine bypass. The turbine bypass connections of the main condenser are designed to minimize tube damage.

c. The main condenser is designed to accept approximately 11.2 x 10^6 pounds per hour of steam from the moisture separator-reheater (MSR) shell side relief valves for a maximum period of one minute. Of all of the relief valves discharging to the main condenser only the reheat steam relief valves, which discharge after inadvertent closure of the reheat stop valves, affect the heat load on the condenser to any extent during a transient condition. For this case the heat load is higher than during normal operation.

   During the operation of the MSR relief valves the turbine bypass system will also be in operation. The combined effect of these two heat loads will not have a detrimental effect on the structural integrity of the condenser or its performance, since the condenser is designed for this total flow for the period specified above.

d. The main condenser hotwell is capable of maintaining a minimum water level corresponding to a retention time of three minutes (approximately 77,000 gallons) at all times for radiation decay.

The expected maximum integrated radiation dose to the condenser over the life of the plant is 10^7 Rad. For control, normal water level is set two feet above minimum water level.

e. Circulating water passes through the three main condenser shells in series. Four separate circulating water circuits and conductivity elements for leakage detection are provided, allowing unit operation without a severe load reduction or trip if one circuit requires removal from service to plug a leaking tube.

f. Internal cleanliness of the Type 304 main condenser tubes is maintained through the use of chemicals and biocide.

g. To prevent tube failure during operation of the turbine bypass, direct steam impingement on the tubes is prohibited by use of spargers to distribute the flow inside the condenser. All other high energy drains are also provided with spargers or baffles inside the condenser.

10.4.1.3 System Description

The main condenser is a three shell, three pressure type with a rubber expansion joint in each neck. Differential water levels are maintained in each of the three condenser hotwells allowing condensate to flow from the lowest pressure to the intermediate pressure, then to the highest pressure hotwell where it is reheated. From there it flows to the hotwell storage located under the intermediate pressure condenser. This hotwell is an extension of the high pressure condenser hotwell and is connected to it by a cross-under pipe. The hotwell storage is isolated

from the IP condenser by a solid divider plate and is vented to the HP condenser. Condensate leaves the hotwell through two outlets. Design information for the main condenser is provided in <Table 10.4-3>.

During normal operation the main condenser receives the following flows:

a. Main turbine exhaust steam.

b. Auxiliary condenser condensate.

c. Drains from low pressure heater No. 1.

d. Steam packing exhauster drains.

e. Steam jet air ejector (SJAE) condenser drains.

f. Offgas condenser drains.

g. Feedwater heater vents.

h. Turbine governor valve leakoffs.

i. Seal steam header flow.

j. Feedpump seal leakoff.

k. Main, reheat, extraction, and miscellaneous drains.

Possible flows during startup or abnormal conditions include:

a. Hotwell pump, SJAE condenser, steam packing exhauster, and condensate booster pump recirculation.

b. Hotwell pump startup vents.

c. Feedwater cleanup flow.

d. Emergency drains from feedwater heaters Nos. 6, 5, 3, and 2.

e. Moisture separator and reheater drains.

f. Condensate makeup.

g. Turbine bypass flow.

h. Feedwater heater vents.

Systems which have relief valves discharging to the condenser include:

a. Reheat steam relief.

b. Heater vents and relief.

c. Offgas condenser.

d. Offgas water separation effluent line.

e. Offgas air preheater.

f. SJAE intercondenser.

g. Steam seal evaporator.

10.4.1.4 Safety Evaluation

Since the main condenser operates at a vacuum, any leakage is into the shell side of the main condenser. Provision is made for detection of circulating water leakage into the shell side of the main condenser. Water leakage is detected by measuring the conductivity of sample water

extracted from a tray located beneath the tube bundles. A leak will allow the circulating water to drain over the tube bundles and collect in the tray. Sampling methods are described in <Section 9.3.2>. Radioactive leakage to the atmosphere cannot occur.

Air inleakage and noncondensible gases, including hydrogen and oxygen gases, contained in the turbine exhaust steam due to dissociation of water in the reactor, are collected in the condenser from which they are removed by the main condenser evacuation system described in <Section 10.4.2>.

Disassociated hydrogen is removed by the steam jet air ejector to the offgas system. Noncondensible gases cascade from the highest to lowest pressure main condenser shell eliminating the possibility of hydrogen buildup in any shell. If one steam jet air ejector set should fail, a standby is available to preclude loss of vacuum.

The main condensers are not required to affect or support the safe shutdown of the reactor, or to support in the operation of reactor safety features.

The influence of the main condenser on the reactor coolant system is reduced by the decoupling effect of the hot surge tank. Pressures, temperatures and flows are influenced by the pumps, heaters and storage tanks downstream of the condenser. The effect it has on the reactor coolant system relates to its contaminant removal and radiation decay capacity. The anticipated inventory of radioactive contaminants during operation and shutdown is discussed in <Section 11.1>. If condenser cooling water leakage into the condensate stream occurs, conductivity elements detect the leakage. The circulating water passes through three main condenser shells in series. Four separate circulating water circuits and conductivity elements are provided, allowing unit operation without a severe load reduction or trip when it is necessary to remove one circuit from service to plug a leaking tube. (Reference 1)

addresses the problem of condenser tube in leakage on the quality of the condensate/feedwater for a plant using seawater for the circulating water. (Reference 1) is used as a conservative guideline (considering the high conductivity of seawater compared to fresh water) for permissible cooling water inleakage and time of operation. The high pressure condenser is equipped with four absolute pressure sensors which will close the main steam isolation valves on loss of condenser vacuum. The effect of a loss of condenser vacuum on reactor operation is provided in <Section 15.2.5>.

Normal deaeration of the turbine exhaust steam in the main condenser controls oxygen to satisfy the feedwater chemistry requirements of a BWR.

Exhaust hood overheating protection is provided by exhaust hood sprays. If these sprays are not effective at mitigating the overheating, alarms alert the operator to manually trip the turbine. Under normal operating, transient and emergency conditions, no detrimental effect is foreseen on the reactor coolant system and no radioactive leakage can be anticipated.

A failure of the main condenser will not cause unacceptable flooding of areas housing safety-related equipment. Flooding analysis is discussed in <Section 2.4.10> and <Section 10.4.5.3.1>.

The loss of main condenser vacuum will cause the turbine to be tripped. The condenser instrumentation interface with the main steam isolation system is described in <Section 7.7.1>.

10.4.1.5 Tests and Inspections

The main condenser is subjected to a shell side hydrostatic test in the field. The pressure is limited to the static head of water at the

turbine flange. The waterboxes and tube circuits are initial service leak tested to normal operating pressure. Visual inspection of pipe weld joints will confirm the exterior condition of the weld joints.

The condenser is provided with access manways to permit entry into the waterboxes (for inspection of tubes and tube joints), into the hotwells and into the condenser shells to permit internal inspection of the condenser. Inspection can be undertaken if there are indications of condenser operating abnormalities (such as tube leaks), or for general inspection purposes. Each condenser inspection will consist of draining the condenser, removing the inspection covers and inspecting for waterbox fouling, impingement erosion, internal structural damage, and cleanliness.

The main condenser will be continually monitored for its performance and tube leakage. If this monitoring reveals condenser operating abnormalities, then the main condenser will be inspected and appropriate corrective action taken. In addition, as a minimum, the steam side of the main condenser will normally be inspected at each refueling.

10.4.1.6 Instrumentation

The following instrumentation is provided for the main condenser:

a. Each condenser shell is provided with local and remote hotwell level and pressure indication.

b. The condensate levels in the condenser hotwell are maintained within proper limits by automatic control. Transfer condensate is passed to and from the condensate storage tank as needed to satisfy the requirements of the system.

c. Turbine exhaust hood temperature is monitored and controlled with water sprays to provide protection from overheating.

d. A high condenser back pressure alarm is set to warn the operator prior to turbine trip. Turbine trip is initiated on loss of condenser vacuum or when condenser back pressure exceeds approximately eight inches Hg absolute. Main steam isolation valve closure is initiated at 21.5 inches Hg absolute (8.5 inches Hg vacuum).

e. Waterbox temperature and level measurements are provided.

f. Conductivity elements detect leakage of circulating water into the condenser.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

10.4.2.1 General

The main condenser evacuation system maintains condenser vacuum by removing noncondensible gases including disassociated hydrogen and oxygen, and air inleakage.

10.4.2.2 Design Bases

Mechanical vacuum pumps are used to draw down the main condenser. The mechanical vacuum pumps have an individual capacity of 3,800 scfm at 20 inches Hg vacuum. Discharge is to the atmospheric vent.

Vacuum is maintained in the main condenser by one steam jet air ejector set; another set is used as a spare. The sets are designed to handle the following capacities:

a.	Air inleakage for main condenser	55 scfm
b.	Disassociated H_2	162 scfm

c. Disassociated O_2 81 scfm

Each steam jet air ejector set is designed to use main steam reduced in pressure by an automatic pressure reducing device. Discharge is to the offgas system for treatment at 8.0 psig and a maximum hydrogen concentration of 4 percent by volume.

Main cycle condensate is used as a cooling medium in each steam jet air ejector condenser.

Anticipated maximum radioactive discharge rates to the environs during normal operation are presented in <Section 11.3>.

10.4.2.3 System Description

The main condenser evacuation system is comprised of mechanical vacuum pumps and steam jet air ejectors with the following functions:

a. Mechanical vacuum pumps are used to evacuate the condenser prior to turbine startup.

b. Noncondensible gases cascade from the highest to lowest main condenser shell and are then removed. Each steam jet air ejector set is a two stage unit with a common condenser after the first stage. Four first stage elements are used for the main condenser and one 100 percent first stage element for each auxiliary condenser. The second stage element is common to all condensers and removes the noncondensibles to the offgas system.

10.4.2.4 Safety Evaluation

The safety evaluation of the main condenser evacuation system follows:

a. An automatic pressure reducing device is used to reduce main steam pressure to steam jet air ejector operating pressure.

b. One steam jet air ejector set is used as a spare. In the event of the failure of one of the steam jet air ejector sets, the remaining set is started.

c. Vacuum pumps operate only for startup to pull a vacuum in the main and auxiliary condenser to establish a vacuum of three inches of Hg.

d. The condenser evacuation system has no direct effect on the reactor coolant system during normal operation.

e. Under normal operating conditions, radioactive leakage is negligible as all leakage up to the steam jet air ejectors is under vacuum and will leak back to the condenser. An analysis of pipe rupture of the discharge pipe to the offgas system from the steam jet air ejector is presented in <Chapter 15>.

f. The system is Quality Group D, as defined by <Regulatory Guide 1.26>, and of non-seismic design.

g. The main condenser air removal system is not designed to withstand the effects of an explosion. If an explosion occurs within the system, continuous leakage paths afterward are prevented by isolating the affected portions of the system from the main condenser and the offgas system. Provisions for the effects of an explosion within the offgas system are discussed in <Section 11.3.2>.

10.4.2.5 Tests and Inspections

The steam jet air ejector condensers are designed and tested in accordance with Section VIII, Division I, of the ASME Boiler and Pressure Vessel Code. Auxiliary steam is available for operational testing.

10.4.2.6 Instrumentation

The inlet isolation valve for the mechanical vacuum pumps closes simultaneously with a pump motor trip upon a main steam line high radiation signal.

The primary instrumentation for the main condenser evacuation system consists of flow switches which trip the isolation valves between the main and auxiliary condensers and the steam jet air ejectors. The steam flow interlocks ensure that adequate dilution flow is supplied to maintain hydrogen concentration below the specified value. Loss of dilution flow alarms in the control room.

10.4.3 TURBINE GLAND SEALING SYSTEM

Main turbine shaft seals, feedpump turbine shaft seals and large steam valve shaft seals are of the injection/labyrinth/leakoff type, and are designed to prevent air leakage into or steam leakage out of the turbine casings.

A separate steam seal system (clean steam) is employed. The gland sealing steam source is from the steam seal evaporator. Nonradioactive steam at approximately 4 psig is supplied to an annulus. This steam leaks inward toward the turbines and goes to a leakoff piped to the condenser. The steam also leaks toward the outside where it goes into the vent annulus which is maintained at a slight vacuum by the steam packing exhauster. A small amount of air is drawn into the vent annulus

and this, together with the nonradioactive steam, goes to the steam packing exhauster where the steam is condensed and the remaining saturated air is discharged by a motor driven blower. The low pressure shaft packing seals against vacuum at all times.

During the early phases of startup, sealing steam is provided directly from the auxiliary steam system. Under startup and low load conditions, heating steam to the steam seal evaporator is from the main steam system. During normal operation the evaporator heating system supply is from extraction steam.

The use of the "clean steam" system eliminates the possibility of radioactive steam escaping to the atmosphere under normal operating conditions. A failure of the system, such as a failure of the clean steam supply to the turbine gland seals which would allow radioactive process steam to leak out to the steam packing exhauster, or a failure in the steam seal evaporator which would cause higher pressure radioactive main or extraction steam to be introduced to the seal steam supply, would allow a small amount of radioactive steam to escape. This would be immediately detected by a radiation monitor in the exhaust pipe and alarmed in the control room.

10.4.3.1 Steam Seal Evaporator

10.4.3.1.1 Design Bases

The steam seal evaporator is a vessel designed to evaporate 45,000 lb/hr maximum (25,000 lb/hr normal) of condensate quality water at 216°F. Design pressure both in the tube side and shell side are 150 psi at 450°F. A major design consideration is to minimize a failure of the vessel components. To this effect, the tubes are made of stainless steel and the vessel is designed, fabricated and tested in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division I.

10.4.3.1.2 System Description

The steam seal evaporator provides the nonradioactive steam for the turbine gland system. It is a shell and tube heat exchanger equipped with suitable controls which is supplied with heat from the main steam line at startup and light loads, and from the eighth stage extraction at higher loads.

Condensate from the evaporator coil is returned to the cycle (No. 4 heater and condenser) through a level control system. Noncondensibles, as well as shell blowdown and pressure relief systems, are vented to the condenser.

The water for the evaporator is clean, nonradioactive condensate. Water flow is controlled automatically to maintain water in the vessel within predetermined levels during all modes of plant operation.

10.4.3.1.3 Safety Evaluation

The steam seal evaporator is nonsafety-related and is not required for the safe shutdown of the reactor. The system is Quality Group D, as defined by <Regulatory Guide 1.26>, and of non-seismic design.

10.4.3.1.4 Tests and Inspections

The steam seal evaporator is hydrostatically tested prior to shipment in accordance with Section VIII, Division I of the ASME Boiler and Pressure Vessel Code.

10.4.3.1.5 Failure Evaluation

The various elements of the steam seal evaporator are designed to do everything reasonably possible to ensure that in the event of a failure

of the barrier between main steam and the seal steam, the leakage to the environment will be detected, monitored and controlled in a safe manner.

The design of the evaporator, in which the radioactive steam flows inside high quality stainless steel tubes, will preclude an uncontrolled leakage to the environment.

It is possible, however, for the tubes to develop pin size holes and for radioactive steam to leak into the evaporator shell and, through the steam packing exhauster, out to the atmosphere. This would be detected by a radiation monitor in the exhaust pipe and alarmed in the control room.

Because of the long path from the NSSS to the exhaust pipe and the small initial leakage rate, it is highly unlikely that the associated activity rate will require a system shutdown.

10.4.3.1.6 Instrumentation

Water level in the shell side of the steam seal evaporator is maintained by level control valves. The tube (steam) side water level is controlled by level control valves which maintain the water level in the steam seal evaporator drain tank. The flow of heating steam is regulated by the steam seal evaporator pressure control. Steam and seal header pressure is regulated by the header pressure control.

Liquid level in the steam packing exhauster is maintained by a trap connected to the main condenser by a level control valve. Pressure and temperature instrumentation is provided to monitor operation of the system.

10.4.4 TURBINE BYPASS SYSTEM

10.4.4.1 Design Basis

The design basis of the turbine bypass system is as follows:

a. The turbine bypass system is designed to control reactor pressure during reactor heatup to rated pressure while the turbine is being brought up to speed and synchronized during power operation when the reactor steam generation exceeds the transient turbine steam requirements; and cool down of the reactor.

b. The turbine bypass system capacity is designed for 28.8 percent (nominal) of the 100 percent rated reactor steam flow. The bypass system will accommodate approximately a 28.8 percent load rejection. The bypass system works in conjunction with the turbine controls (pressure control) <Section 7.7.1>.

c. The turbine bypass valves are capable of remote-manual operation in their normal sequence, during plant startup and shutdown, and for exercising to verify that the valves are operable.

10.4.4.2 System Description

10.4.4.2.1 Operational Function

The turbine bypass system is shown in <Figure 10.4-1>, <Figure 10.4-2>, and <Figure 10.4-3>. The turbine bypass system controls primary steam pressure by sending excess steam flow directly to the main condenser. This permits independent control of reactor pressure and power during reactor vessel heatup to rated pressure as the turbine is brought up to speed and synchronized under turbine speed-load control. Following main turbine generator trips, the turbine bypass will control reactor

pressure to within reactor design limits in accordance with the steam generation rate. The bypass valves are automatically closed whenever vacuum in the main condenser falls below a preset value.

10.4.4.2.2 Bypass Valves

The turbine bypass system consists of seven automatically operated, regulating type bypass valves connected by appropriate piping to the main steamlines upstream of the main turbine stop valves. Each bypass valve outlet is piped directly to the main condenser. The bypass valves have regulation capability and a fast opening response approximately equivalent to the fast closure of the turbine stop and control valves. Each of the bypass valves in the system is individually controlled by a servo loop which drives a double acting hydraulic actuator. The valve is positioned in response to a valve position error signal that represents the difference between current valve position and the bypass valve demand signal generated by the steam bypass and pressure regulation system. Each bypass valve also has mounted on it a fast acting solenoid valve which is fired to open the valve very quickly if the error signal (in the opening direction) becomes excessively large. Bypass valve outline and sectional drawings are provided in <Figure 10.4-3>. Bypass valve design data is presented in <Table 10.4-4>. The valve casing (valve chest) is welded to a branch line coming from the main steam pipes. This connection point to the main steam pipes is downstream of the outboard mainstream isolation valves and upstream of the main turbine admission valves. Mounted in the chest are several bypass valves, each connected to its own hydraulic actuator.

The steam bypass valves receive electronic positioning from the pressure regulator cabinet and are hydraulically powered by an external source of high pressure hydraulic fluid.

When the steam bypass valves are open, steam enters each end of the chest, flows downward between the seat and the stem, and then exits through the discharge casing. The amount of steam passing through each valve is controlled by the lift of the valve. The valve disk and seat are hardsurfaced at their contacting points to improve the ability to maintain adequate seating contact.

The force required to open and position each steam bypass valve is applied to the valve stem by the power actuator which is mounted directly below each valve.

The double acting hydraulic cylinder operator is equipped with an air bleed in both end caps and internal stop tube on the rod side to limit stroke. The piston is fitted with a small leakage plug to allow a small amount of fluid to leak from the high pressure side to the low pressure side of the piston. This small leakage assures a continuous flow of fluid and prevents fluid stagnation.

A hydraulic control manifold is provided with the necessary passages to connect the hydraulic supply and drain to the correct ports on the servovalves, fast acting solenoid valve and cylinder.

The servovalve is mounted on the manifold and controls the fluid flowing to each end of the hydraulic cylinder. The valve receives an analog electrical signal from the pressure regulator cabinet and is used for normal positioning of the steam bypass valve.

In the event that the steam bypass valves must be opened faster than that allowed by the flow capacity of the servovalve, a parallel fluid path to the cylinder is provided by opening of the fast acting solenoid valve. This valve is opened by an electrical current originating in the pressure regulator cabinet. Since considerable time may elapse between the actuations of the solenoid valve, provision is made in the valve test logic to exercise this valve. During valve testing, the steam

bypass valve is slowly stroked open by sending an appropriate electrical signal to the servovalve. After the valve is stroked to approximately the 90 percent open position, the switch rod collar closes a switch in the switchbox. These contacts complete a circuit to the fast acting solenoid valve which allows hydraulic fluid to pass into the hydraulic cylinder at a high rate of flow. Using this scheme, the steam bypass valve slowly strokes open to the 90 percent position and then "snaps" fully open.

10.4.4.2.3 Classification

The steam bypass system is classified as a primary power generation system (i.e., it is not a safety system and its operation is essential to the power production cycle).

10.4.4.3 Safety Evaluation

The turbine bypass system is not essential for turbine operation. Should the bypass system malfunction and inadvertently admit bypass steam to the condenser while the turbine is under load, the steam flow to the turbine would be reduced by action of the pressure controller. If, under these conditions, the condenser heat rejection rate is inadequate and the exhaust pressure becomes excessive, the turbine will be tripped by vacuum trips. In addition, should the turbine exhaust pressure continue to increase, additional redundant vacuum trips are provided to trip the bypass, stop and control valves and MSIVs.

The effects of a malfunction of the turbine bypass system valves and the potential effects of such failures on safety systems and components are evaluated in <Chapter 15>. A pipe break in the turbine bypass system will not have an adverse affect on any safety-related systems and components.

The turbine bypass system can malfunction in either the open or closed mode. The effects of both of these failure modes on the operation of the reactor are discussed in <Appendix 15A>, "Nuclear Safety Operational Analysis." The analyses are system level/qualitative type plant failure mode and effects analyses.

The effects of turbine bypass system malfunctions on the reactor operation are bounded by events presented in <Appendix 15A> as follows:

a. A bypass system line failure is bounded by the pipe break outside containment accident. Refer to Event 38 in <Appendix 15A.6.5.3>.

b. A failure of the bypass system to open is bounded by the turbine trip and load rejection without bypass events. Refer to Events 30 and 31 in <Appendix 15A.6.4.3>.

c. An inadvertent opening of the bypass system, at worst, might cause a high steam line flow or low steam line pressure with a resultant MSIV closure trip. Refer to Event 14 in <Appendix 15A.6.3.3>.

10.4.4.4 Tests and Inspections

The opening and closing of the turbine bypass system valves will be checked during initial startup and shutdown for performance and timing. The bypass steam line upstream of the bypass valves will be hydrostatically tested to confirm leakage tightness. Visual inspection of pipe weld joints will confirm the exterior condition of the weld.

Each of the seven bypass valves is individually cycled through an opening and closing test sequence to check for proper operation, by using the "Bypass Valve Test" pushbutton on the Steam Bypass and Pressure Regulator Control Panel in the control room. The fast acting solenoid is also checked during this test by causing the solenoid to

fire when the valve reaches the 90 percent open position during the opening portion of the test sequence. Each bypass valve will be tested in this manner on a monthly basis.

10.4.4.5 Instrumentation Application

Controls and valves are designed so that the bypass valves steam flow is shut off if the control system loses electric power or hydraulic system pressure. For testing the bypass valves during operation, the stroke time of the individual valves is increased during testing to limit the rate of bypass flow increase and decrease to approximately one percent of reactor rated flow per second.

Upon turbine trip or generator load rejection, the start of the bypass valve steam flow will not be delayed more than 0.1 second after the start of the stop valve or the control valve fast closure motion. A minimum of 80 percent of the rated bypass capacity will be established within 0.3 second after the start of the stop valve or the control valve closure motion. For more detail, refer to <Section 7.7.1>.

10.4.5 CIRCULATING WATER SYSTEM

10.4.5.1 Design Basis

The circulating water system removes thermal energy from the main and auxiliary turbine condensers and dissipates this energy to the atmosphere in a closed system utilizing one natural draft cooling tower. This system was designed to remove 8.35 x 10^9 Btu/hr based on a 76°F wet bulb atmospheric temperature, 30.6°F cooling tower range (average condenser Δt) and an 18°F cooling tower approach to wet bulb. This represents the maximum heat rejection from the cycle (turbine valves wide open) under the most adverse weather conditions (design wet bulb temperature exceeded less than one percent of the time). At power uprate conditions (3758 MWt and turbine VWO), the

system is capable of removing 8.66 x 10^9 Btu/hr based on a 76°F wet bulb temperature. The circulating water system is independent of the emergency cooling facilities.

In the event of perimeter fill degradation, air dams may be installed to minimize impact to heat removal capabilities until repairs can be completed.

The cooling tower basin, pumphouse forebay and forebay flume are capable of containing up to 4,407,000 gallons maximum. The water quantities that could enter the turbine building basement during a design basis accident are listed in <Table 2.4-9>.

It is very unlikely that draining of the cooling tower basin will occur under the conditions postulated in <Section 10.4.5.3.1>. Pumping of the water into the turbine building is also very unlikely to occur since the water level switches located within the turbine building basement would actuate shutdown of the pumps. Pump discharge valve closure would also be actuated by the level switches to break a postulated siphon flow.

A discussion of the design basis accident involving a postulated yard pipe break or flooding of the turbine building via flow through fractured base mat to the underdrain system is contained in <Section 2.4.13.5>.

10.4.5.2 System Description

The closed loop system will consist of one natural draft cooling tower, the main and auxiliary condensers, three circulating water pumps, piping and various valves, and piping specialties required to operate the system, as shown on <Figure 10.1-7>. Typical system operation utilizes all three of the circulating water pumps. When conditions permit, system and plant operation can be fulfilled utilizing less than three

pumps. Water flows from the cooling tower basin through a set of fixed screens to the suction of the circulating water pumps. The pumps discharge water through a 12-foot diameter pipe to the main and auxiliary turbine condensers, condensing the steam therein. From the condensers, water flows out to the cooling tower where it cascades through a set of baffles, is cooled by the air flow and returns to the cooling tower basin. The cooling towers are approximately 411 feet in diameter at the base, and approximately 516 feet high. The distance from any point on the cooling tower to the nearest safety-related structure is in excess of 540 feet.

Winter startup and operation must be carefully controlled to ensure that no excessive ice formation occurs which can lead to reduced tower performance and possible equipment damage. For winter startups, the cooling tower is positioned in the bypass mode which limits the water to the cooling tower basin only. When the basin water temperature reaches a predetermined value, the cooling tower is positioned in the central deicing mode.

The cooling tower is designed with a central deicing system for normal winter operation. The deicing system controls ice formation in the following manner. The central deicing mode limits the cold water through the outer perimeter fill of the tower, i.e., no water is supplied to the center portion of the tower. This results in a greater heat load being applied to the outer perimeter fill, causing the cold water temperature to rise. This hot water melts any ice formed in the outer perimeter fill. As the water temperature continues to rise, the tower will be positioned in the normal operating mode, evenly distributing the hot water over all portions of the tower fill.

Makeup for tower evaporation, wind loss and blowdown is obtained from the service water system. This system will provide the makeup requirements after cooling the various components that use service

water. This water will come from Lake Erie via the intake tunnel into a service water pumphouse. Service water pumps transmit the water to the plant through various heat exchangers in the service water system. It then goes to a weir box from which flow is diverted to the cooling tower basins, with the remainder going directly to the lake by means of the discharge tunnel entrance structure <Figure 9.2-14>. Makeup flow to the cooling tower varies from 16,000 gpm to 25,979 gpm depending on atmospheric conditions.

A blowdown system is provided at the circulating water pump discharge to maintain the concentrated solids in the system at a design level of 2.5 concentrations of makeup water (service water). The blowdown is added to the service water discharge flow and is conveyed to the discharge tunnel entrance structure from which it will flow to the lake by means of the discharge tunnel. Blowdown from the cooling tower varies from 6,000 gpm to 10,332 gpm depending on atmospheric conditions.

Cleanliness of the main condenser tubes is maintained by the use of chemicals and biocide. A mechanical (Amertap) cleaning system was originally installed to maintain condenser tube cleanliness. Although the Amertap system remains installed, it is no longer used for this purpose. Anti-scaling chemicals are added into the circulating water system, on an as-needed basis, to prevent scale deposition on heat exchanger surfaces. A liquid biocide injection system is used, as required, to minimize algae growth in the circulating water and cooling water systems. The circulating water system, as well as the plant effluent water, consisting of cooling water discharge and circulating water blowdown, is monitored to determine biocide concentrations. Discharged effluent water quality will be maintained in accordance with Perry’s National Pollution Discharge Elimination System (NPDES) permit.

All parts of the circulating water system are classified nonsafety.

10.4.5.3 Safety Evaluation

The circulating water system is designed with cross connected discharge piping from the circulating water pumps. The pumps are equipped with separate butterfly valves which permit each circulating water pump to be isolated. Each of the four condenser waterbox circuits is provided with inlet and outlet isolation valves. Therefore, in case of a pump failure or a condenser tube leak, the circulating water system is capable of

operating with two pumps or three trains of condenser water boxes. Operation for extended periods with less than three pumps is also considered a mode of normal operation, when conditions permit.

The cooling tower is located at a minimum of one tower height away from the containment and any other Seismic Category I structure. Since the cooling tower is smaller at the top, the tower would tend to collapse inwardly although collapse of the tower is highly improbable. Therefore, the potential for debris damaging any plant structure is minimal. The cooling tower is made primarily of noncombustible material.

The circulating water system is designed to prevent any injection of radioactive material into the circulating water and its subsequent release to the atmosphere through evaporation in the cooling tower. The circulating water passing through the condenser will be at a higher pressure than the shell or condensing side; therefore, any leakage (such as from a condenser tube) will be from the circulating water into the shell side of the condenser.

The circulating water system serves no safety function. Systems analysis has shown that failure of the circulating water system will not compromise any safety-related systems or prevent safe shutdown.

10.4.5.3.1 Circulating Water Expansion Joint Failure (without a turbine building mat fracture)

In the postulated case that an expansion joint in the circulating water system in the turbine building ruptures causing flooding of the turbine building, heater bay and condensate demineralizer building, the

following precautions have been taken to preclude this flooding from affecting safety-related buildings and components (refer to <Table 2.4-9> and <Table 2.4-10> without mat fracture):

a. Inadvertent flooding of the turbine room basement would be first detected by a level switch located on the turbine room basement wall, which would actuate an alarm in the control room. The unit operator would then investigate the cause of the alarm. If the water level should continue to rise to a second "verification" level switch located three feet above the turbine room basement floor, a second alarm would be sounded in the control room. The operator would immediately shut down all circulating water pumps, close the pump discharge valves and close the condenser waterbox isolation valves. This procedure is incorporated into the Perry alarm response instructions. In the design basis accident analysis, no credit was taken for operator action.

b. A set of three "auto-shutdown" level switches positioned at a higher level (five feet above the turbine room basement floor) would automatically initiate, on a two of three level switch signal, circulating water pump trip, pump discharge valve closure and condenser waterbox isolation valve closure. The flow path between the cooling tower and the condenser waterbox expansion joints is thereby isolated by the two sets of valves: pump discharge and condenser waterbox isolation valves. In the analysis, no credit was taken for the level switches.

c. To reduce the possibility of a water hammer in the circulating water system, slow closing (60 seconds) motor-operated butterfly valves are used for condenser isolation.

d. All rubber expansion joints, valves and piping in the circulating water system are initial service leak tested.

e. Even if interlocks and safeguards failed and the entire water volume in the circulating water system including the cooling tower basin emptied into the turbine building, the water level in the turbine room basement, heater bay and condensate demineralizer building would remain below Elevation 599′-0″. <Table 2.4-9> and <Table 2.4-10> demonstrate that the storage volume to Elevation 599′-0″ within the buildings exceeds with significant margin the potential flooding water volume.

f. In addition to the precautions taken above, no doors are installed between the condensate demineralizer building and the auxiliary building, below Elevation 599′-0″. Water is not permitted to enter Seismic Category I buildings, except for the pipe chase within the auxiliary building. This pipe chase as well as all other openings leading to Seismic Category I Buildings are sealed, thereby protecting safety-related equipment from the effects of flooding. Openings are provided between the turbine room basement and the condensate demineralizer building and the heater bay to permit flooding of this larger "storage area."

g. Makeup water to the cooling tower is supplied by four service water pumps, two of which are operating at one time <Section 9.2.7.2>. If turbine room flooding occurs, the Seismic Category I motor-operated valves in the makeup line to the cooling tower will be automatically closed. The worst case for the circulating water expansion joint failure without mat fracture is the same as the case with mat fracture. For detailed sequence and flows see <Section 2.4.13.5>. This procedure is incorporated into Perry alarm response instructions.

h. To prevent the service water from providing makeup water to the cooling tower basin, two level switches positioned at approximate Elevation 583′-0″ will automatically close the Seismic Category I circulating water makeup isolation valves.

10.4.5.3.2 Circulating Yard Piping Failure

The postulated case of the failure of a circulating water line just outside the turbine building in the Class A fill surrounding these buildings was examined. The case postulated is a crack in the circulating water pipe 18 feet long and 1.2 inches wide. The water will flow out of the crack and into the Class A fill. The rate of water flow through the soil is governed by Darcy's equation for groundwater seepage. The resultant flow into the underdrain system is not greater than 2,000 gpm. A brief summary of the analysis performed is given below.

Distance from bottom of circulating water pipe scour to porous concrete blanket (L) 13 ft

Area of flow (A) 903 ft^2

$Q = kiA$

where:

$k = .074$ ft/min

$i = \frac{h}{L}$

$h = 48'$

$L = 13'$

$i = \frac{48}{13} = 3.7$

$Q = (.074)\ (3.7)\ (903) = 247.2$ cfm

or $(274.2)\ (7.5) = 1{,}849$ gpm

If the maximum normal groundwater system inflow of 80 gpm is added:

$Q = 1{,}929$ gpm

The calculated flowrate of 1,929 gpm conservatively assumes that there will not be any backpressure from water accumulation in the manholes of the underdrain system.

The flow calculated above would be easily handled by the underdrain and gravity discharge system.

10.4.5.4 Tests and Inspections

All active components of the system, except the main condensers, are accessible for inspection during station operation.

Performance, hydrostatic and leakage tests are conducted on the circulating water system components. These are manufacturing tests only and no routine or continuous testing will be undertaken.

10.4.5.5 Instrumentation Application

The circulating water pumps are individually equipped with isolation valves which permit any pump to be isolated.

All isolation valves are operated by remote-manual switches in the control room and automatically close on high-high water level in the turbine basement. Temperature and pressure are measured on each condenser. The water level is automatically maintained in the cooling tower. Necessary level alarms and flow measurements are provided. The cooling tower blowdown system will be automatically modulated proportional to a conductivity measurement to maintain 2.5 times the makeup water concentrations (service water).

10.4.6 CONDENSATE CLEANUP SYSTEM

10.4.6.1 General

A condensate cleanup system is used for scavenging of dissolved solids and suspended matter to maintain high quality condensate.

10.4.6.2 Design Bases

The cleanup system consists of eight filter vessels and six mixed bed demineralizer vessels designed for continuous treatment of full condensate flow. Each vessel is located in an individual shielded area due to the possibility of accumulating significant amounts of radioactive debris removed from the condensate. Condensate is cleaned through the filters and the mixed bed demineralizers in series.

The system design provides maximum removal of both suspended and dissolved impurities. In addition, an extensive condenser sampling and analysis system is provided to ensure prompt detection of small condenser leaks. The condensate demineralizers are provided with conductivity cells to measure water quality in the bed effluent at approximately 93 percent resin depth. The second conductivity cell will provide indication of resin depletion and allow for replacement with fresh resins prior to exceeding chemistry limits. The design features, along with the installed conductivity cells and a regular chemistry monitoring program for specific ions, will ensure dissolved and suspended solids using standard analysis methods are well within the limits recommended by GE. The conductivity cells are set to alarm at or below 0.10 μmho/cm to assure water is maintained within the limits of <Regulatory Guide 1.56>, Revision 1. Upon receipt and validation of an alarming condition, the alarming bed will be removed from service. Prior to returning the demineralizer to service, it will be recharged with fresh resins.

The condensate cleanup system components are designed to meet provisions of ASME Section VIII, Division 1 and/or ANSI B31.1.0 Code for Pressure Piping, Power Piping along with ASME Addenda and applicable code cases in effect at the time of component order.

The cleanup system is designed based on the influent concentrations shown in <Table 10.4-1>. Startup concentrations are defined to occur for periods up to a week. Extended normal operation concentrations are defined as those occurring during full power operation without condenser tube leaks.

The total capacity of condensate demineralizer resin will be measured on each lot of new resin. Total capacity analysis will be performed in accordance with approved chemistry instructions. This testing may be fulfilled by the resin supplier by providing a Certificate of Analysis for each lot, or by an independent testing facility.

Water quality will be tested in accordance with approved chemistry instructions. Analysis will be performed on grab samples for pH and chloride ion using standard industrial practice when conductivity values in the reactor water are elevated. Water conductivity will be monitored and recorded continually on the sampling panel.

The maximum effluent composition from the cleanup system based upon the influent concentrations listed in <Table 10.4-1> is as follows:

Conductivity at 25°C	0.1 μmho/cm
pH at 25°C	6.5 to 7.5
Metallic Impurities	Not measured at condensate effluent. Measured in feedwater
Chloride	Chloride concentration shall be less than 2 ppb

10.4.6.3 System Description

System descriptions for the condensate filters and mixed bed demineralizers are as follows:

a. Condensate Filters

Each condensate filter vessel contains vertical filter elements. These elements will provide acceptable water quality as it relates to suspended solids removal.

The non-precoated filter elements will require only backwashing to remove the captured suspended solids.

The filter system has controls for balancing of flow through each filter and the system pressure differential. The vessels are equipped for monitoring pressure differential and flow.

When instrumentation indicates high differential pressure across a filter vessel it is removed from service and backwashed to remove the filtered impurities to the backwash receiving tank. Backwash waste is pumped to the condensate filter backwash settling tanks and then sent to the liquid radwaste disposal system.

An automatic full flow bypass valve is provided around the filter system and the valve opens on excessive system differential pressure. Controls are provided for manually initiated automatic backwash of a vessel removed from service.

b. Mixed Bed Demineralizers

The mixed bed demineralizer system is operated with resin that is procured in the regenerated form. This fully regenerated resin enters the system via the cation resin regeneration tank and is transferred to the mix and hold tank prior to moving the resin to the empty demineralizer vessel. The demineralizer is then on standby, ready for service.

Normally resin is removed from service prior to exhaustion for use in the radwaste demineralizers. Resin that no longer have sufficient demineralizing capacity is transferred from the demineralizer vessel to the spent resin tanks in the radwaste disposal system.

Water used in the transferring of resin within this system is collected and processed through the liquid radwaste system.

The mixed bed demineralizer system monitors differential pressure. An automatic bypass valve is provided around the mixed bed demineralizer system to open on excessive system differential pressure. Vessels are equipped for monitoring flow and

conductivity. Conductivity is continuously monitored in the effluent and in the resin bed for each demineralizer that is in service. Each demineralizer vessel is equipped with a resin trap, which has a differential pressure monitor. The design is in conformance with the positions of <Regulatory Guide 1.56>, as discussed in <Table 1.8-1>.

10.4.6.4 Safety Evaluation

The condensate cleanup system removes some radioactive material created by corrosion, fission products and carry over from the reactor. While radioactive effects from these sources do not affect the capacity of the resin, the concentration of such radioactive material requires shielding <Section 12.1.2>. Vent gases and other waste water from the condensate cleanup system are sent to the radwaste system for treatment and/or disposal. The addition of new regenerated resin will be done manually. <Chapter 11> describes the activity level and removal of radioactive material from the condensate system. The condensate cleanup system complies with <Regulatory Guide 1.56> as discussed in <Table 1.8-1>.

All condensate cleanup system piping and vessels are located in the nonsafety-related turbine power complex. Therefore, the effects of postulated piping failures are not analyzed.

10.4.6.5 Tests and Inspections

Preoperational tests are performed on the condensate cleanup system to ensure operability, reliability and integrity of the system. Each demineralizer vessel and the resin addition equipment can be isolated during normal plant operation to permit testing and maintenance. Conductivity requirements of the condensate cleanup system are monitored continuously. Refer to <Section 9.3.2> for sampling system points.

10.4.6.6 Instrumentation Application

Conductivity elements are provided for the system influent and for each demineralizer vessel effluent. System influent conductivity detects condenser leakage, whereas, demineralizer effluent conductivities provide indication of resin exhaustion.

Differential pressure is monitored across the demineralizer vessels and each vessel discharge resin trap to detect blockage of flow. The flow rate through each demineralizer is monitored to ensure the even distribution of condensate flow through all operating vessels. The water quality at 93% of bed depth is monitored for each operating demineralizer to warn of impending resin exhaustion. The three tank external resin transfer equipment includes conductivity rinse monitors to ensure the completeness of preservice rinsing. Differential pressure and flow measurement indications are available at the local control panel. Conductivity instrumentation is located at the Turbine Plant Sample Panel for bed and effluent samples for each demineralizer vessel. Conductivity readings are processed by the plant process computer and alarms are generated by the analyzers and/or the process computer to provide remote annunciation in the control room. A multipoint annunciator is included in the local panel to alarm abnormal conditions within the cleanup system. Electrical contacts for the local annunciator provide remote annunciation in the main control room. Other instrumentation includes flow indicators, pressure gauges and timers for automatic supervision of the regeneration cycle. Procedures will prevent the initiation of any automatic operation or sequence of operations which would conflict with any operation or sequence already in progress, whether such an operation is under automatic or manual control.

10.4.7 CONDENSATE AND FEEDWATER SYSTEM

10.4.7.1 Condensate System

10.4.7.1.1 Design Bases

The condensate system transports condensate from the main condenser hotwell to the hot surge tank, maintaining proper water levels in the surge tank for all operating conditions. Condensate quality is maintained by the condensate cleanup system <Section 10.4.6>. The condensate system provides the overall steam cycle water inventory required to accommodate reactor water level variations arising from load changes. The condensate system also serves as a cooling source for the offgas condenser, the steam jet air ejector condenser and the steam packing exhauster.

10.4.7.1.2 System Description

The condensate system is illustrated in <Figure 10.1-4>. The condensate system consists of three 50 percent motor driven hotwell pumps, three 50 percent motor driven condensate booster pumps, three stages of closed low pressure feedwater heaters, a direct contact heater and hot surge tank, and associated piping, valves and instrumentation. Feedwater heaters 1A, 1B, 1C, 2A, 2B, and 2C are located in the main condenser necks.

Equipment interacting with, but not part of the condensate system includes the condensate cleanup system, the offgas condenser, the steam jet air ejector condensers, and the steam packing exhauster.

The hotwell pumps take suction from the hotwell storage area below the IP condenser. The condensate is pumped through the condensate cleanup system, the offgas condenser, the steam jet air ejector condenser, and

the steam packing exhauster, providing sufficient NPSH for the condensate booster pumps during all operating conditions. The hotwell pumps are the vertical-can centrifugal type.

The condensate booster pumps are designed to pump condensate through three stages of closed low pressure feedwater heaters and into the direct contact heater.

System flow requirements at the valves wide open (VWO) condition are met by two 50 percent capacity hotwell pumps and two 50 percent capacity booster pumps operating in series.

The direct contact heater is of the horizontal spray type and is directly mounted on a horizontal hot surge tank. The direct contact heater and hot surge tank are designed in accordance with Section VIII, Division I of the ASME Code and meet the performance criteria of the Heat Exchange Institute (HEI) and ASTM D888-66.

The low pressure feedwater heaters are shell and U-tube heat exchangers designed in accordance with Section VIII, Division I of the ASME Boiler and Pressure Vessel Code. All heaters are two zoned, i.e., each has a condensing zone and an integral drain cooling zone. Heaters No. 1 and No. 2 consist of three parallel streams, any one of which may be isolated for maintenance. Maintenance on either stream of No. 3 heaters is accomplished by isolating that stream and passing the condensate through the hand operated bypass. All condensate system piping is carbon steel, ASTM A-106 Gr. B, and conforms to ANSI B31.1. Flanged connections are provided at the pumps and strainers for ease of maintenance. The majority of the other joints and connections are welded.

10.4.7.1.3 Safety Evaluation

Fifty percent capacity standby pumps are provided for both the hotwell and condensate booster pumps. On loss of pressure in either the hotwell or condensate booster pump discharge header, the appropriate standby pump is manually started. No detrimental effect on the reactor coolant system is realized.

System makeup is provided directly from the condensate storage tank to the highest pressure main condenser shell.

Sentinel type tube side safety relief valves are provided for all closed feedwater heaters.

A feedwater heater tube rupture will precipitate high and very high water level alarms indicating operator action required. If the magnitude of the rupture is such that the heater is flooded, the shell side safety valves will discharge to the condenser. No radioactivity is released to the environment.

The level of radioactivity in the condensate system is low enough that leakage from valve stems, etc. will not create hazards. To further protect the environment, all floor drains from areas where leaks could occur are taken to the radwaste area for processing. Two 100% capacity control valves (1N21F0220 and 1N21F0230) are provided to maintain Hot Surge Tank level. Should the first valve (1N21F0230) fail to provide sufficient flow, redundant control valve 1N21F0220 can be operated manually from the control room console by a selector switch/potentiometer to maintain flow to the Direct Contact Heater and the downstream Hot Surge Tank.

A three-element control loop (condensate flow, feedwater flow and hot surge tank level) is provided to maintain hot surge tank level over the entire plant load range, including load changes and upsets. The loop

executes this function by regulating the condensate flow into the hot surge tank to the value required for replacement of the feedwater leaving the surge tank. This enhances the response of the entire condensate-feedwater-steam cycle.

Any pressure, temperature or flow deviation due to a malfunction in the condensate system will not be immediately felt by the reactor coolant system due to the storage capacity in the hot surge tank, (two minute retention time), and the feedwater system. The storage capacity will allow either corrective actions to be taken or an orderly runback to a compatible load or shutdown.

Conductivity instrumentation is provided to monitor condenser leakage. The condensate demineralizer system is designed to accept condenser leakage during normal operation.

During plant start-up, a 4 inch bypass line is used to fill the Hot Surge Tank. This line is isolated during normal plant operation. This bypass is manually operated and is isolated during normal plant operations.

10.4.7.1.4 Tests

Periodic inspection will be made of all major equipment to ensure proper inservice operation.

The closed low pressure feedwater heaters are given both shell and tube side hydrostatic tests of 1.5 times the respective design pressures.

10.4.7.1.5 Instrumentation

Condensate flow control instrumentation measures the feedwater and condensate flow rates, and hot surge tank level. These measurements are used to regulate the condensate flow to the No. 4 (Direct Contact

Heater) through the 100% capacity condensate control valve 1N21F0230. The condensate control valve, 1N21F0230, controls via signals from surge tank level, feedwater flow, and condensate flow. The redundant 100%

capacity control valve (1N21F0220) has an independent control loop with its own power supply and can be operated manually from the control room console by a selector switch/potentiometer.

Minimum flow requirements for the hotwell pumps, condensate booster pumps, the steam jet air ejector condenser, and the steam packing exhauster are met by a common recirculation line downstream of the condensate booster pumps. Flow through the recirculation line is regulated by a modulating control valve receiving a signal from a flow transmitter upstream of the offgas condenser.

Measurements of pump suction and discharge pressures are provided for all pumps in the system.

Temperature measurements are provided for each stage of feedwater heating. These measurements include the low pressure feedwater flow temperatures into and out of each feedwater heater and drain water temperatures from each heater.

Instrumentation and controls are provided for regulating heater drain flow rate to maintain proper condensate level in each feedwater heater shell. High level alarm, automatic operation of the alternate drain control valve at high level, and automatic isolation on high level of the cascaded drain valve and extraction valve are provided.

10.4.7.2 Feedwater System

10.4.7.2.1 General

The feedwater system is designed to pump condensate from the direct contact heater hot surge tank through two stages of feedwater heating to maintain the reactor vessel water level. Reactor feedwater flow is

automatically controlled to maintain vessel water level within predetermined levels during all modes of plant operation.

10.4.7.2.2 Design Basis

The design requirements of the feedwater system are: for piping, valves, and pressure parts, the design pressures under normal and upset conditions are as tabulated on the right margin of the feedwater system diagrams <Figure 10.1-3> and <Figure 10.1-8>. The upset condition tabulated is considered to be the shutoff head of the feedwater heater or main feed pumps, and is expected to occur less than one percent of the time. Design conditions and requirements of the portion of the feedwater system from the outermost isolation valve to the reactor are covered in <Section 5.4.9>.

Pressure vessels will be designed to Section VIII, Division 1 of the ASME Boiler and Pressure Vessel Code. Piping will be designed to ANSI B31.1.

10.4.7.2.3 System Description

The feedwater system is comprised of: four, one-third capacity motor driven booster pumps, one stage of intermediate pressure heating with external drain cooler, two nominal half capacity horizontal reactor feedwater pumps with variable speed turbine drives, one 20 percent capacity motor driven reactor feedwater pump, one stage of high pressure heating, valves, instrumentation and controls, and associated piping. Three booster pumps take water from the hot surge tank and discharge it through one stage of heating to the reactor feed pump suction. Both feed pumps discharge water through one stage of high pressure heaters into a mixing header before passing through two parallel feedwater shutoff valves to the reactor.

Reactor feedwater flow is controlled automatically to maintain water in the reactor vessel within predetermined levels during all modes of plant operation. The system normally operates as a three element control using reactor vessel water level, steam flow and feedwater flow signals to control feedwater flow by adjusting the speed of the reactor feedwater pump turbines.

Three of the four booster pumps are required for normal operation with the fourth pump on standby. The standby booster pump will be started automatically in the event of a trip of an operating booster pump or low NPSH in the reactor feedwater pump suction header. Booster pumps are manually started from the control room.

Intermediate pressure Heaters 5A and 5B heat the feedwater using steam extracted from the high pressure turbine exhaust. They are shell and U-tube heat exchangers designed to ASME Section VIII, and have a condensing zone only. The drain coolers are horizontal, single pass heat exchangers and are also designed to ASME Section VIII.

Two nominal half capacity reactor feedwater pumps provide the feedwater required at all load points. Minimum flow recirculation for the turbine driven feedwater pumps is provided by lines to the hot surge tank. Individual pump suction flow elements provide flow control for the recirculation valves.

In the case of one inoperative feedwater pump, the remaining pump and a motor driven pump will deliver 80 percent of nuclear boiler rated feedwater flow at no less than 1,060 psia at the reactor vessel feedwater sparger inlet.

Horizontal reactor feed pumps are connected directly to variable speed turbine drives. The dual admission turbines normally take steam from the main turbine crossover steam line after the moisture separators and reheaters. For startup and low load conditions the turbines are driven

by main steam. A control system regulates feedwater flow to maintain reactor water level by controlling the admission of steam to the turbine drives.

Feedwater is heated in Heaters 6A and 6B by high pressure extraction steam. These heaters are shell and U-tube heat exchangers designed to ASME Section VIII, with a condensing zone and an integral drain cooling zone.

10.4.7.2.4 Safety Evaluation

Upon failure of one of the two normally operating reactor feedwater pumps or their turbine drives, a motor driven feed pump will be started automatically in less than ten seconds. The remaining turbine driven pump and the motor driven pump will provide 80 percent of rated flow to prevent reactor scram or actuation of RCIC.

A feedwater heater tube rupture will precipitate high and very high water level alarm, indicating operator action required. The closure of the extraction line valves is automatically initiated. If the magnitude of the rupture is such that the heater is flooded, the shell side safety valves will discharge to the condenser. No radioactivity will be released to the environment.

The level of radioactivity in the feedwater system is low enough that leakage from valve stems, etc. will not create hazards. To further protect the environment, all floor drains for areas where leaks could occur are taken to the radwaste area for processing.

In the event of the loss of feedwater, the reactor is tripped and the RCIC system is actuated. The most severe case is a guillotine break of the feedwater header outboard of the reactor containment vessel. The analysis of the consequences of this postulated incident is discussed in <Chapter 15>.

The reactor can be isolated from the feedwater system by the following three independent valves in each of the two feedwater headers:

a. The first valve from the reactor is a damped check valve located inside containment.

b. The second valve is a damped check valve located outside containment.

c. The third valve is a motor-operated gate valve operated from the control room. The closing time of this gate valve is 100 seconds.

10.4.7.2.5 Tests

The main feedwater and feedwater booster pumps are given complete hydrostatic and performance tests prior to shipment in accordance with Hydraulic Institute Standards. Pump pressure containing parts are tested to ASME Section VIII Division 1.

The feedwater heaters are given both shell and tube side hydrostatic tests at 1.5 times design pressures.

Prior to initial operation, the completed condensate/feedwater system will receive a field hydrostatic test and complete inspection in accordance with applicable codes. The completed system will also be taken through preoperational and startup testing in accordance with <Regulatory Guide 1.68>. Periodic tests and inspections of the feedwater/condensate system are to be performed in conjunction with scheduled maintenance outages.

10.4.7.2.6 Instrumentation

Feedwater flow control instrumentation measures the feedwater flow from the feedwater system and steam flow. These measurements are used by the

feedwater control system to regulate the flow to the reactor to meet system demands. The feedwater control system is described in <Section 7.1.2>, <Section 7.7.1>, and <Section 7.7.2>.

Instrumentation and controls are provided for maintaining feedwater booster pump recirculation flow and for regulating pump recirculation flow rate for the reactor feedwater pumps.

Measurements of pump suction and discharge pressures are provided for all pumps in the system.

Sampling is provided for monitoring the quality of the final feedwater as described in <Section 9.3.2>.

In the heating portion of the system, feedwater temperature measurements are provided for the flow into and out of each heater and at the flow element. Heater drain exit temperatures and steam pressure measurements are provided at each feedwater heater.

Instrumentation and controls are provided for regulating heater drain flow rate to maintain proper condensate level in each feedwater heater shell. High level alarm, automatic operation of the alternate drain valve at high water level and automatic isolation on high level of the cascaded drain valve and extraction valve are provided.

10.4.7.3 Failure Modes and Effects Analysis

The failure modes and effects analysis is presented in <Table 10.4-2>.

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

This section is not applicable to PNPP.

10.4.9 AUXILIARY FEEDWATER SYSTEM

This section is not applicable to PNPP.

10.4.10 REFERENCES FOR SECTION 10.4

1. Licensing Topical Report, NEDO-10899, "Chloride Control in BWR Coolants," June 1973.

TABLE 10.4-1

CONDENSATE CLEANUP SYSTEM INFLUENT CONCENTRATIONS

		Startup	Extended Normal Operation
Iron:	soluble	40 ppb	5 ppb
	insoluble	1,000 ppb[1]	25 ppb
Copper:	(soluble & insoluble)	50 ppb	7 ppb
Other Metals:	(soluble & insoluble)	40 ppb	3 ppb
pH at 25°C		6 to 8	6.5 to 7.5
Conductivity at 25°C		0.5 μmho/cm	0.2 μmho/cm
Chloride		10 ppb	10 ppb[2]

NOTES:

[1] Could be as much as 4,000 ppb for several hours at initial plant startup.

[2] Maximum chloride input during a condenser tube leak will be more than extended normal operation of 10 ppb. The maximum chloride input during a condenser tube leak is equal to the rate where the unit can be kept in service prior to exceeding chemistry limits.

TABLE 10.4-2

FAILURE MODES AND EFFECTS ANALYSIS
FEEDWATER AND CONDENSATE SYSTEMS

Components	Failure	Effects
Hotwell pumps	Pump or motor drive	Reserve pump is started; therefore, no effect on cycle.
Condensate booster pumps	Pump or motor drive	Reserve pump is started; therefore, no effect on cycle.
Heaters	Tube rupture	High level alarm signals operator action is required. If flooded, the shell side relief discharges to condenser. Problem heater can be isolated and bypassed. No release of radioactivity or effect on reactor coolant system.
Condensate control valves	Valve or operator	Valve fails as is to allow continuous flow to the feedwater system to maintain reactor level. If valve should fail closed, due to a tubing failure to the bottom actuator connection, the second control valve is available (opened manually by control room operator) to maintain flow to the direct contact heater.
Feedwater booster pumps	Pump or motor	Reserve pump is started; therefore, no effect on cycle.
Reactor feed pumps	Pump or turbine	A motor driven pump is put into operation. Together with the remaining pump, 80% rated flow is maintained to prevent reactor scram, with a runback to 80% unit load.
Pipe break	Guillotine feedwater line break	Refer to <Chapter 15>.

TABLE 10.4-3

MAIN CONDENSER DESIGN DATA[1]

Manufacturer	Ecolair (Ingersoll-Rand)
Number of Shells	3
Number of tubes:	
Low pressure shell	39,824
Intermediate pressure shell	39,824
High pressure shell	39,824
Tube length:	
Low pressure shell, ft-in.	36'-2 29/32”
Intermediate pressure shell, ft-in.	46'-2 29/32”
High pressure shell, ft-in.	50'-2 29/32”
Surface Area:	
Low pressure shell, ft^2	328,452
Intermediate pressure shell, ft^2	419,689
High pressure shell, ft^2	456,184
Number of passes, per shell	1
Tube size (OD), in.	7/8
Tube gauge	22 BWG
Tube material	ASTM A249, Type 304 Stainless steel
Hotwell capacity at normal water level:	
Low pressure shell	0
Intermediate pressure shell	0
High pressure shell	72,000 gallons

TABLE 10.4-3 (Continued)

Overall approximate dimensions
(height, length, width):

Low pressure shell, ft	45' x 54' x 30'
Intermediate pressure shell, ft	56' x 59' x 30'
High pressure shell, ft	56' x 62' x 30'
Condenser duty (heat transfer), Btu/hr	8.47×10^9

Condenser Guarantee Point (Normal Design Flows):

		Flow (lb/hr)	Enthalpy (Btu/lb)	Pressure (psia)
1.	Turbine exhaust steam	8,959,898	993.8	-
2.	Auxiliary condenser condensate (flows to highest pressure main condenser shell only)	196,130	69.1	1.23 (2.5 in. Hg ABS.)
3.	L.P. 1 heater drain	2,375,452	81.3	-
4.	Steam packing exhauster drains	7,200	180.2	-
5.	Seal steam header bypass flow	14,800	1175.5	-
6.	High pressure turbine gland leakoffs	6,664	1090.5	200.2
7.	Turbine governor valve leakoffs	3,274	1190.8	980.7

TABLE 10.4-3 (Continued)

Intermittent Flows:

In addition to the guaranteed design, the condenser is able to handle other fluids intermittently but not simultaneously. These fluids include the following:

	Flow (lb/hr)	Enthalpy (Btu/lb)	Pressure (psia)	Temp (°F)
1. Turbine bypass steam before throttling and attemperation	5,635,438	1190.8	965	-
2. Moisture-separator drains	891,045	349.7	-	372.1
	360,455	1197.4	-	372.1
3. Reheater Drains	376,020	461.3	555.5	-
	293,966	534.8	950.6	-
4. No. 3 low pressure heater drains	401,067	196.9	-	228.5
5. No. 2 low pressure heater drains	448,820	134.7	-	166.7

6. Moisture Separator-Reheater Relief Valve Flow

The main condenser is also designed to receive steam from the moisture separator-reheater shell relief valves for a maximum period of one minute at the following conditions:

a. Flow, lb/hr 11,243,633

b. Enthalpy, Btu/lb 1278.3

c. Pressure, psia 182.1

Guaranteed free O_2:

a. Plant loads from 10% to 50% 0.010 cc/liter

b. Plant loads from 50% to 100% 0.005 cc/liter

TABLE 10.4-3 (Continued)

Normal Circulating Water Temperature, °F	67 to 86 (varies seasonally)
Maximum Circulating Water Temperature, °F	94 (less than 1% of the time)
Turbine Exhaust (Normal Pressure/Temperature)	
Low pressure shell, in. Hg/°F	2.01 /102
Intermediate pressure shell, in. Hg/°F	2.48 /108
High pressure shell, in. Hg/°F	3.22 /118

NOTE:

(1) This table provides the original design data for the turbine generator system as originally supplied from GE. Steam flows, temperatures, and pressures may vary due to system operating conditions.

TABLE 10.4-4

TURBINE BYPASS VALVE DESIGN DATA

Manufacturer	General Electric
Type	Regulating-Angle globe (grouped in steam chests)
Number of steam chests	2
Number of valves	7 (4 in one chest, 3 in the other chest)
Design flow, per valve, lbm/hr	769,800
Total bypass flow (28.8% of NB rated flow), lbm/hr	5,388,600
Nominal valve size, in.	6-1/2
Steam chest inlet connections	(2) 18” nom. dia
Steam chest outlet connections	(3 or 4) 10” nom. dia
Design pressure/temperature, psig/°F	1250 /575
Valve actuation:	
Time lag from initial electrical signal to the time the bypass valve starts to open	≤0.10 sec
Total time from initial electrical signal to the time the bypass valve is fully open	≤0.30 sec
Deadban, pressure regulator demand to steam bypass valve motion, % Rate Nuclear Boiler Steam Flow (Pressure regulator setpoint, 935 psia)	±≤0.02%