SEABROOK STATION
UPDATED FINAL SAFETY ANALYSIS REPORT

CHAPTER 10
STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion systems are those portions of the plant designed to transmit and convert the thermal energy produced in the reactor into electrical energy. The major components of the steam and power conversion system are located in the Turbine Building, and are not safety related. Design parameters of the steam and power conversion system components are presented in the applicable subsections which describe the major systems and components. The system components are shown on the general arrangement drawings in Section 1.2.

Steam at 1000 psia, 1191.8 H, 0.20 percent moisture is supplied from the outlet of four steam generators to drive a tandem-compound, six-flow exhaust, 1800-rpm turbine. Heat balances at the 100 percent rating and at the turbine design rating are shown in Figure 10.1-1 and Figure 10.1-2.

The turbine nameplate rating is 1,304,003 kW at 1.7 inches Hg absolute back pressure and zero percent makeup; the rating of the generator coupled to the turbine is 1,373,100 kVA at 75 psig H_2 pressure, 25,000 volts, 3 phase, 60 Hz and 0.94 power factor. The heat cycle results in a calculated gross T-G output of 1,305,600 kW at 100 percent load. Allowing for plant loads, the net plant output is approximately 1,254,600 kW.

During normal operation, main steam is taken ahead of the turbine stop valves to supply the single-stage reheaters and the turbine shaft sealing system. Crossover steam from the moisture separator-reheater outlets is supplied to drive two steam generator feedwater pump turbines. During startup or low load operation, main steam can be used to drive the steam generator feedwater pump turbines or the electric driven startup feed pump can be utilized.

Moisture separation with one stage reheat is provided between the high-pressure and low-pressure turbines for all steam entering the low-pressure turbines. Steam from the low-pressure turbines is condensed in a three-shell surface-type, two-pass condenser. Condensate is collected in condenser hotwells which are sized for a minimum of 3-minute storage capacity at full load. The condensate and Feedwater System returns feedwater to the steam generators through six stages of extraction feedwater heaters.

Circulating water (sea water) is pumped through the main condenser and returned to the ocean to dissipate the remaining unusable heat from the steam and power conversion system.

Disposal of heat from the Reactor Coolant System following sudden load rejections or trip of the unit is handled by the Steam Dump System. A detailed description of the Steam Dump System is contained in Subsection 10.4.4. The steam generators are also utilized as the heat sink for reactor heat decay, by absorbing heat from the Reactor Coolant System and producing steam. The steam may be bypassed around the main turbine and condensed in the condenser or vented to atmosphere if the condenser is not available.

The steam and power conversion system provides load-following capability at step load changes of ±10 percent and ramp load changes of ±5 percent per minute over the load range of 15 to 100 percent reactor output. The system can accept a 50 percent load reduction without a reactor trip. The Steam Dump System is capable of bypassing nominally 40 percent of the full-load steam flow. This allows for shutdown from half-load or controlled reactor runback without atmospheric venting of steam through the steam generator relief valves. The Steam Dump System opens automatically to the extent necessary during rapid load reductions to remove excess heat from the Reactor Coolant System and closes as operating conditions stabilize at the new load.

Safety valves are provided on the main steam lines from steam generators, and the steam (shell) side of feedwater heaters and moisture separator-reheaters. Diaphragms are provided in the exhaust sections of the low pressure turbines for overpressure protection of the turbine exhaust sections and the main condensers.

The individual components of the steam and power conversion system are based on proven conventional design, acceptable for use in large central power generating stations. The turbine plant auxiliary equipment is selected to provide the optimum operating economy with maximum safety and reliability. All auxiliary equipment is specified for a design capability corresponding to the turbine design rating. Adequate design margins are included as required for wear and system surges to provide dependable service.

10.2 TURBINE GENERATOR

10.2.1 Design Bases

The Turbine Generator System is designed to receive the steam output of the nuclear steam supply system and convert its thermal energy into electrical energy. When operating at 100 percent of licensed power, the turbine generator has a nameplate output of 1,304,003 kW with throttle steam conditions of 975 psia, 1192 Btu/lb and a back pressure of 1.7" Hg abs.

The turbine generator is intended for base load operation, but is capable of step load changes varying from 20 percent at one-quarter load to 67 percent at full-load, and ramp load changes up to 10 percent/minute increasing and 27 percent/minute decreasing. This is compatible with the nuclear steam supply operation limitations, which are ±10 percent maximum step load changes and ±5 percent/minute ramp load changes, over the load range from 15 percent to 100 percent power.

The turbine generator is equipped with instrumentation to continuously monitor and alarm all significant variables, such as speed, load, pressures, temperatures, valve positions, thermal expansion movements, and shaft eccentricity and vibration.

The Turbine Generator System is a nonnuclear system, with associated piping designed in accordance with either manfacturer's standards or the Power Piping Code, ANSI B31.1. Pressure-containing vessels are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.

10.2.2 Description

The turbine generator and related auxiliary equipment, piping and pressure vessels are shown on the turbine building general arrangement drawings in Section 1.2. Turbine generator general auxiliaries and other equipment in the Turbine Building are cooled by the Secondary Component Cooling Water System (see Figure 10.4-14).

10.2.2.1 Turbine

The turbine is an 1800 rpm, tandem compound with six flow, low pressure stages and 43-inch last stage blades. The turbine consists of one high pressure double-flow section that exhausts into four single-stage reheat MSRs then to three low pressure double-flow sections.

Steam from the main steam header is admitted to the turbine through four angle-body control valves. The main stop valves are welded directly to the inlet nozzles of the control valves. The stop valve below seat chambers are connected by an equalizing line. An internal bypass valve is provided in one of the main stop valves to provide pre-warming steam to the stop and control valves bodies, as well as the turbine. The bypass valve also provides pressure equalization across the stop valve seats, which is required prior to opening the stop valves.

Steam leaving the high pressure turbine has a moisture content of approximately 14 percent. To improve turbine efficiency and reduce low-pressure turbine exhaust moisture, thus minimizing maintenance on the low-pressure blading, the steam exhausted from the high pressure turbine is passed through four moisture separator-reheaters in parallel.

Within the moisture separator-reheater, the moisture is removed from the wet exhaust steam, and the dried steam is reheated to approximately 530°F by condensing high pressure steam in a tube bundle. The reheated steam is admitted to the three low-pressure cylinders of the turbine, from which it exhausts into three individual shells of the main condenser.

The steam and water contained in the moisture separator-heater and cross-around piping would, on loss of load, tend to accelerate the turbine. To prevent this occurrence, combined stop and intercept valves are provided in the cross-around lines, at the inlet of the low pressure turbines. Relief valves which discharge to the condenser are provided on the moisture separator-reheaters to prevent overpressure in the cross-around system.

The turbine and generator bearings are lubricated by a conventional pressurized oil system. A main lubricating oil pump, driven by the turbine shaft, provides the bearing lubricating oil during normal operation. During startup or shutdown, bearing lubricating oil is supplied by AC motor-driven pumps. In addition, a DC motor-driven emergency oil pump provides bearing lubricating oil in case of loss of site power.

The main steam and intermediate reheat valves are opened by a 1600 psig hydraulic fluid system which is totally independent of the bearing oil system. These valves are closed by springs and steam forces upon depressurization of the hydraulic fluid system. The valve actuation system is such that loss of hydraulic fluid pressure for any reason leads to valve closing and consequent unit shutdown.

The turbine valve closure times are as follows:

Turbine main steam stop valve	0.15 seconds
Turbine main steam control valve	0.19 seconds
Intermediate stop valve	0.20 seconds
Intercept valve	0.17 seconds

The turbine valves will be tested for proper operation for overspeed protection at the frequency specified in the Technical Requirements Manual using the following procedures.

a. Fully close main stop valves and intermediate stop and intercept valves in sequence testing at EHC panel.

b. Fully close all main turbine valves and observe travel of the valve stems and linkages.

c. Test trip setting of mechanical overspeed trip device by taking unit up to the trip point.

10.2.2.2 Generator

The generator is sized to accept the gross rated output of the turbine at rated steam conditions. It is a directly coupled, four pole, 1800 rpm, 60 Hz, 3 phase, 25,000 volt, hydrogen and water cooled unit, rated at 1373.1 MVA at 0.94 power factor and 75 psig hydrogen pressure, with a short circuit ratio of 0.52.

All the generator internal components, except the stator winding, are cooled by hydrogen which is contained within the generator frame and circulated in a closed loop by two fans mounted at the end of the rotor (see Figure 10.2-1). The heat absorbed by the gas is removed in two hydrogen coolers mounted directly on the generator frame by secondary component cooling water.

The bulk storage facility for the hydrogen gas will be located in the yard at coordinates 20,700 N and 78,800 E. In accordance with NFPA-50A requirements, this facility is located not less than 50 feet from any occupied building on the site.

All piping from the storage area to the respective buildings, i.e., Waste Processing Building for Reactor Coolant System use and Unit 1 Turbine Building for generator cooling, is routed underground and either enters the building above grade or is encased in a sleeve with a vent to atmosphere upon entering the building below grade (see Figure 10.2-1).

When filling the generator casing, the casing is first purged of air using an inert gas (carbon dioxide) to avoid an explosive hydrogen air mixture. Carbon dioxide is also used during the purging of the casing of hydrogen. During these operations, an analyzer is used to maintain a safe mixture. During normal operations a control panel monitors the generator's hydrogen system status with alarm points for hydrogen purity, high and low temperature.

The stator windings are cooled by de-ionized water circulating in a closed loop between the generator and a generator stator cooling water unit on the ground floor. The heat absorbed by the de-ionized water is removed in a heat exchanger by the secondary component cooling water. Failure of the Stator Cooling Water System initiates a unit power runback which reduces power to 22 percent.

10.2.2.3 Steam Extraction Connections

Turbine steam extraction connections are provided for six stages of feedwater heating. Steam is extracted from one stage of the high pressure turbine, from the high pressure turbine exhaust piping, and from four stages of the low pressure turbines. A combination of positively assisted check valves in the extraction steam lines and automatically controlled heater drain valves protects the turbine against water induction. Check valves are provided in extraction steam lines 3 through 6. There are no check valves in extraction steam lines 1 and 2, since these lines are located within the condenser neck. However, in all cases, the combination of valving and heater drain valve controls is such that no single equipment failure will result in water entering the turbine. The check valves in extraction steam lines 3 through 6 will also provide additional protection against turbine overspeed following a load reduction. The positive-assist action on the check valves is provided by spring-load air actuators. Periodic testing verifies that the operating pistons are free to move under the action of the spring when the air pressure is released.

10.2.2.4 Automatic Controls

The automatic control functions are programmed to protect the Reactor Coolant System with appropriate corrective actions, as explained in Chapter 7. The turbine is tripped every time the reactor is tripped. A reactor trip is initiated upon a turbine trip above approximately 45 percent of full power.

The turbine generator is controlled and protected by an Electro-Hydraulic Control System (EHC) that combines solid-state electronic and high-pressure hydraulic components to control the steam flow through the turbine. Single failure of any component will not lead to destructive overspeed. The probability of multiple failures involving undetected electronic faults and/or stuck valves at the instant of load loss is extremely low due to the high reliability of the control system components and periodic in-service testing and inspection of the main steam and intermediate reheat valves.

The EHC system consists of the following subsystems:

a. Speed Control Unit

   The speed control unit compares the actual control turbine speed and acceleration with the desired speed and acceleration reference signals, and provides a speed error signal to the load control unit. Two redundant speed signals are provided by two magnetic pickups. The acceleration signal is generated by derivation from one of the speed signals. Comparison of the speed and acceleration signals with the respective reference signals results in three speed error signals. The error signal calling for the least valve opening is transmitted to the load control unit.

   The speed control unit with its two redundant speed pickups provides the normal protection of the turbine against overspeed.

b. Load Control Unit

The load control unit combines the speed error signal, a desired load reference, a load increase rate reference and a first-stage pressure feedback signal. It introduces appropriate biases and produces the desired flow signals for the main steam stop control valves and the intercept valves. The first stage pressure feedback consists of a pressure/voltage transducer and a feedback circuit incorporated in the main steam control valve amplifier of the load control unit. The first stage pressure, which is proportional to the actual turbine load, is compared with the reference load signal, and their difference is fed to the amplifier which produces a control valve desired flow signal that tends to make the actual load equal to the desired reference load. Two modes of operation are possible, a manual mode and an auto mode. The manual mode allows the operator to put the circuit into service gradually be means of a motor-operated potentiometer. In the auto mode the stage pressure feedback is automatically activated once the proper permissive conditions are satisfied. The circuit can be simply transferred out of service by the operator from either mode. The purpose of the first stage feedback loop is provide a more linear response of the turbine to the desired load signal. In addition, when in operation, it allows stroke test of each of the control valves at near constant turbine load. In fact, the stage feedback signal tends to maintain the first stage pressure constant and will increase the opening of the control valves not being tested, compensating for the closing of the valve being tested.

c. Flow Control Unit

The flow control unit translates the desired flow signals into valve stem position signals for the hydraulic servo actuators that position the four main steam stop and control valves and the six intermediate reheat intercept and stop valves. This unit introduces corrective functions to compensate for the nonlinearity of the valves. In normal operation, the servo actuators of the main steam control valves gradually adjust the position of the control valve stem in response to variations of a position signal which depends on the flow signal from the load control unit, while the main steam stop valves and the intercept and intermediate stop valves are fully open.

In case of sudden loss of generator load, an overriding nonlinear signal from the load control unit closes, by fast action, directly and simultaneously all main control and intercept valves, and initiates a unit reference load runback toward zero power. The loss of generator load is not detected by an overspeed signal, but as the result of a comparison between the turbine mechanical power and the generator output. If generator load decreases at a rapid rate and load is greater than 40 percent nominal, the power load unbalance circuit will trigger the fast-closing signal. This rapid action will limit the shaft overspeed following a loss of generator load to a level below the setpoint of the emergency overspeed trip. This permits the unit to have a full load rejection and remain running near synchronous speed under control of the speed control system. The speed control circuit is the first line of defense against emergency overspeed. If this fails, when the shaft speed reaches the emergency trip setpoint of 110 percent of rated speed, the emergency trip system will shut down the unit by rapidly closing all steam admission and intermediate valves.

The main line of defense for turbine overspeed protection is the closure of the main steam valves. To further reduce the risk of turbine overspeed following a turbine trip, the sequential trip circuit that normally trips the generator breaker includes main steam valve closed position switches in series with a reverse power relay interlock. This ensures that all steam valves are closed and the generator motors for a set time delay prior to tripping the generator breaker. Refer to Section 8.2.1.3.e.3 for a more detailed description of generator breaker tripping.

The emergency trip system is a high-pressure hydraulic fluid system that when pressurized permits opening of all turbine main steam and intermediate valves by the electro-hydraulic system, and, when depressurized, causes them to be rapidly closed by spring action. Upon reaching the overspeed trip set level (110 percent of rated speed) the depressurization of the emergency trip system is triggered by either or both of the following conceptually redundant devices:

1. Mechanical overspeed trip set at 110 percent speed
2. Electrical backup overspeed trip set one-half percent higher than the mechanical overspeed trip.

The mechanical overspeed trip device consists of a conventional eccentric ring on the turbine shaft which is actuated by centrifugal force during an overspeed condition. As a result of the mechanical trip device's action, a pilot valve will dump the hydraulic fluid pressure from a mechanical trip valve which in turn relieves the hydraulic fluid pressure from the emergency trip system, thereby tripping the turbine.

The mechanical overspeed trip device can be tested during normal operation at rated speed by actuating a mechanical lockout valve. This valve allows hydraulic fluid pressure to be maintained in the emergency trip system while oil is injected into the eccentric ring overspeed device to actuate the overspeed trip. During this test, the electrical backup overspeed trip will provide emergency overspeed protection for the turbine.

The electrical backup overspeed trip consists of three redundant magnetic speed pickups which monitor the turbine speed and provide inputs to a two-out-of-three logic trip circuit. The trip circuit output energizes the mechanical trip solenoid valve and de-energizes the electrical trip solenoid valve. The mechanical trip solenoid valve operates the mechanical trip piston and trips the turbine as previously described. When the electrical trip solenoid valve is de-energized, the hydraulic fluid is dumped from the emergency trip system through the electrical trip valve, resulting in a turbine trip. An electrical lockout solenoid valve is provided to allow testing of the electrical trip valve and electrical trip solenoid valve. When the lockout valve is actuated, hydraulic fluid pressure is maintained while the dumping action of the electrical trip valves is being tested. During this test, the mechanical overspeed trip will provide emergency overspeed protection for the turbine. In addition, test logic is provided to disconnect the trip circuit and to change the trip reference speed setting in order to test the circuit at rated speed in normal operation. A time delay dropout relay returns the circuit to normal after the test pushbutton is released. During this test the mechanical overspeed trip will protect the turbine against overspeed.

In addition to the mechanical and electrical overspeed devices described above, each of the following devices or signals will trip the Emergency Trip System resulting in a turbine shutdown:

1. Manual trip from control room
2. Manual trip handle at the turbine front standard
3. Low bearing lubricating oil pressure
4. Low shaft-driven lubricating oil pump pressure, above 75 percent speed
5. Low condenser vacuum
6. Excessive thrust bearing wear
7. Excessive vibration
8. High exhaust hood temperature
9. Moisture separator high water level
10. Low hydraulic fluid pressure
11. Reactor trip
12. Generator electric trip
13. Loss of generator stator cooling
14. Loss of both electrical speed signals
15. Loss of primary and secondary 24V DC power

16. ATWS mitigation system actuation signal
17. Manual trip of main generator breaker from control room
18. Hi-Hi steam generator level
19. Safety injection actuation

10.2.3 Turbine Disk Integrity

10.2.3.1 Materials Selection

Turbine wheels and rotors were made from electric furnace steel, vacuum poured, with carefully controlled quench and temper heat treatment to provide adequate fracture toughness. Samples from each forging were tested to ensure that detrimental elements such as sulfur and phosphorus are kept to low levels (0.015 max.) to ensure long-life fracture toughness for the environment in which the parts operate. Forgings were also subjected to a thorough ultra-sonic inspection to detect and identify any discontinuities present. All turbine wheel and rotor materials have the lowest fracture appearance transition temperatures (FATT) and highest Charpy V-notch (0°F) 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 were taken into account in accepting specific forgings.

10.2.3.2 Fracture Toughness

The successful operation of a turbine generator depends on proper startup, loading, shutdown, and load-changing procedures to reduce thermal stresses, distortions, vibration and rotor shell differential expansion. These instructions are included in G.E. Company Starting and Loading Instructions.

Suitable material toughness was obtained through the use of materials described under Subsection 10.2.3.1, to produce a balance of adequate material strength and toughness, to ensure safety, while simultaneously providing high reliability, availability and efficiency 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 materials tests on each wheel or rotor), to the maximum tangential stress is at least $2\sqrt{\text{inch}}$ for wheels and rotors at speeds from normal to 115 percent of rated speed, although the highest anticipated speed resulting from a loss of load is 110 percent. 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.

10.2.3.3 High Temperature Properties

The stress-rupture properties of the high-pressure rotor materials and the methods of obtaining these properties are considered to be proprietary information by the turbine manufacturer.

10.2.3.4 Turbine Design

The turbine assembly is designed to withstand normal conditions and anticipated transients including those resulting in turbine trip without loss of structural integrity. A discussion of potential turbine missiles is given in Section 3.5. The design of the turbine assembly meets the following criteria:

a. Turbine shaft bearings are designed to retain their 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 is controlled in the design and operation to avoid distress to the unit during operation.

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

d. The basis for turbine design overspeed is 5 percent above the normal setting of the emergency governor, which is 110 to 111 percent of rated speed. The design overspeed is 115 percent of rated speed.

e. The turbine discs are designed so that in-service inspections can be performed without removal of the discs from the shaft. High stress areas, such as keyways, can be ultrasonically inspected in regions under the wheel hubs as well as under the hub.

10.2.3.5 Pre-Service Inspection

The pre-service inspection program was as follows:

a. Wheel and rotor forgings were rough machined with minimum stock allowance prior to heat treatment, with the finish-machined wheel and rotor then 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 be 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.

b. All finish-machined surfaces were subjected to a magnetic particle test, with no flaw indications permitted.

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

10.2.3.6 <u>In-Service Inspection</u>

a. The in-service inspection program for the turbine assembly includes the following:

Disassembly of the turbine at approximately 10-year intervals, with initial inspection after 6 years of service, during plant shutdown coinciding with the in-service inspection schedule required by the ASME Boiler and Pressure Vessel Code, Section XI, and complete inspection of all normally inaccessible parts, such as couplings, coupling bolts, turbine shaft, low pressure turbine buckets, low pressure wheels, and high pressure rotors.

This inspection will consist of visual, surface, and volumetric examinations, as indicated below:

1. A thorough volumetric examination will be conducted of all low pressure wheels and high pressure rotors, including areas immediately adjacent to keyways and bores. This examination is predicated on the development of suitable remote inspection equipment.
2. Visual examination of all accessible surfaces or rotors and wheels
3. Visual and surface examination of all low pressure buckets
4. 100 percent surface examination of couplings and coupling bolts.

b. The in-service testing and inspection of main steam and reheat valves includes the following:

1. Monthly Testing (31 days):

   Fully close all main turbine valves and observe travel of the valve stems and linkages.

2. Every Refueling Outage (18 months):

   Test trip setting of mechanical overspeed trip device by taking unit up to the trip point.

3. Dismantling of at least one main steam stop valve, one main steam control valve, one reheat stop valve, and one reheat intercept valve during refueling or maintenance shutdowns coinciding with the in-service inspection schedule required by the ASME Code, Section XI, and conducting of a visual and surface examination of valve seats, discs, and stems. If unacceptable flaws or excessive corrosion are found in a valve, all valves of its type will be inspected. Valve bushings will be inspected and cleaned, and bore diameters will be checked for proper clearance.

c. The extraction steam check valves described in Subsection 10.2.2.3 will be subject to monthly testing. The monthly test will check the operation of the power assist actuator and control components and for valve disc integrity.

10.2.4 Evaluation

The turbine-generator and its auxiliary systems are non-Nuclear Safety Class, and there are no safety-related systems, or portions of systems, located close to the turbine-generator. The turbine overspeed control system equipment is located in the front standard on the operating floor. The turbine is tripped by low hydraulic fluid pressure, so a hydraulic line break caused by high or moderate energy pipe failure would have the same result. A mechanical overspeed trip provides additional protection against turbine overspeed, and acts independent of electrical wiring.

There is normally no radioactivity in the secondary system. In the event of a steam-generator tube leak, however, radioactivity can be present in the secondary system. The amount of radioactivity in the secondary system under this condition is a function of the level of activity the Primary Coolant System and the amount of tube leakage. See Chapter 11 for an estimate of the activity level in the secondary steam system due to tube leakage.

The steam-generator blowdown processing system is described in Subsection 10.4.8.

Radiation levels in the Turbine Building are discussed in Chapters 11 and 12.

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 Design Bases

a. The Main Steam Supply System is designed to:

1. Conduct steam from the steam generators to the main turbine, feed pump turbine drives, emergency feed pump turbine drive, reheaters, turbine gland sealing system, Steam Dump System and the Auxiliary Steam System

2. Control steam generator pressure during startup and shutdown and while the condenser is not available

3. Provide over-pressure protection for the steam generators

4. Isolate the Containment from the Main Steam Supply System and provide for main steam line warmup

5. Provide a means to dissipate the heat generated in the Nuclear Steam Supply System, during all modes of normal operation including a turbine trip at full load. Heat removal is discussed in Section 10.4.

b. Safety-related portions of the system will function, as required, during all operating conditions, including adverse environmental occurrences, accidents, and loss of offsite power, in the event of a malfunction or failure of an active component.

c. Pipe cracks or breaks, including pipe whip, in high and moderate energy piping will not preclude essential functions of safety-related portions of the system.

d. The system design provides for functional testing of safety-related components and in-service inspection of safety-related portions of the system.

e. The system has the capability to detect, control and isolate system leakage and preclude accidental release to the environment.

f. The portions of the piping from the steam generators to the five degree restraints downstream of the main steam isolation valve outside of the Containment meet seismic Category I criteria, and are designed in accordance with the ASME Code Section III, Division I (1971), class 2. Piping downstream of the five degree restraints is designed in accordance with the Power Piping Code ANSI B31.1-1967.

g. Other design considerations are discussed in the following sections:

Protection Against Natural Phenomena	Section 3.1
Environmental and Missile Effects	Section 3.1
Quality Group and Seismic Design Classification	Section 3.2
Wind and Tornados	Section 3.3
Flooding	Section 3.4
Missile Protection	Section 3.5
Pipe Rupture	Section 3.6
Seismic Design	Section 3.7
Environmental Design	Section 3.11

10.3.2 Description

10.3.2.1 Piping

The Main Steam System and related piping and instrumentation diagrams are shown in Figure 10.3-1, Figure 10.3-2, Figure 10.3-3, Figure 10.3-4, Figure 10.3-5, Figure 10.3-6, Figure 10.3-7, Figure 10.3-8 and Figure 10.3-9. The extraction steam subsystem is shown on Figure 10.3-10 and Figure 10.3-11. For flow, pressure and enthalpy values at various points in the Main Steam System, see Figure 10.1-1, Heat Balance.

Four 30-inch main steam lines carry steam from each of the four steam generators to the 48-inch main steam header. Each line includes a flow restrictor which is an integral part of the steam generator nozzle, a power-operated atmospheric relief valve, five safety valves and one isolation valve. Two 6-inch lines carry steam from two of the four 30-inch lines to the trip and throttle valve of the emergency feed pump turbine drive.

Four 30-inch turbine supply lines carry steam from the 48-inch main steam header to the turbine stop valve. Two 24-inch turbine supply lines carry steam from the 48-inch main steam header to the Auxiliary Steam System, main feed pump turbine drives, reheaters and steam dump valves.

The entire Main Steam Supply System is designed for 1200 psia at 600°F. The design of the portions of piping with safety valves considers the dynamic forces from the opening of the safety valves. Safety valves settings are shown in Figure 10.3-2. The spacing of the safety valves on the main steam lines is in compliance with Reg. Guide 1.67 and referenced Code Case 1569.

The main steam lines are provided with sufficient drainage for startup and normal operation. Low point drains are valved and returned to the condenser.

All components except the flow restrictors and portions of the 30" lines are located outside of the Containment.

10.3.2.2 Flow Restrictor

The primary function of the flow restrictor is to limit the flow from a steam generator in the event the main steam pipe ruptures downstream of the restrictor (see Section 5.4). Also, the flow restrictors are the primary elements for the steam flow input signal to the Feedwater Control System.

10.3.2.3 Penetrations

Because of the high temperatures involved, and the restraint imposed by the Containment, a separate penetration is provided for each main steam line. The penetrations are manufactured in accordance with the ASME Code, Section III, Class 2 and MC requirements. For a complete description of penetrations see Subsection 3.8.2.

10.3.2.4 Atmospheric Relief Valve

A power-operated atmospheric relief valve (ARV) is provided in the 30-inch line from each steam generator. These valves provide for controlled removal of reactor decay heat during reactor cooldown, plant startup, and after a turbine trip, when the condenser and/or the turbine bypass system are not available.

The atmospheric relief valves are located adjacent to the main steam safety valves described in Subsection 10.3.2.6. The safety valves will operate without plant operator action for an indefinite period, and will maintain the main steam pressure between 1185 psig and 1225 psig during the hot standby condition. When available, the atmospheric relief valves can be used to reduce main steam pressure for both hot and cold shutdown conditions.

Each ARV automatically regulates its respective steam generator outlet header pressure to approximately 1140 psia. The valves are capable of automatic operation over the steam pressure range of 1300 psia to 125 psia, when the Residual Heat Removal (RHR) System is put into operation. Manual operation of the valves' controllers will allow atmospheric relief down to atmospheric pressure. The nominal capacity of each valve is 531,000 lbs/hr at 1140 psia inlet pressure, for a total combined capacity of 10 percent of the maximum steam flow. The maximum capacity of each valve does not exceed 970,000 lbs/hr at 1200 psia inlet pressure, to limit heat release if a valve inadvertently opens.

Operation of the ARV can be either automatic pressure control or manual position control from the main control board. The valve can also be operated from the remote shutdown panel and locally. After a seismic event, the valves can be manually controlled from the control room or the remote shutdown panel. The backup high pressure gas supply is discussed in Subsection 9.3.1.1.

The valve has a stroke time of less than or equal to 70 seconds, and fails in the closed position. "Full open" and "full closed" position indication lights are located in the control room, and on the remote shutdown panel. Each valve is an 8"x10" ANSI Class 900# globe type valve.

A stop valve upstream of each ARV is provided for isolation. Each valve discharges to the atmosphere through a restrictor (silencer) sized and supplied by the ARV manufacturer. The ARVs were designed, fabricated and inspected in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Class 2. The silencer is classified NNS.

10.3.2.5 Emergency Feed Pump Turbine Supply

Two pneumatically operated valves are installed in each of the two branch connections from steam generators E-11A and E-11B. Valves MS-V393 and MS-V394 are containment isolation and EFW steam supply isolation valves. These valves are provided with seismically designed air supplies to ensure closure from the control room in accordance with GDC-57 criteria. These branch valves are redundant, and either branch connection will satisfy the emergency feed pump turbine drive (EFPTD) steam requirements. The branch connections feed a common header that contains a pneumatically operated steam supply isolation valve (MS-V395) located upstream and adjacent to the trip and throttle valve of the EFPTD. For actuation of the steam supply isolation valves and a full description of the Emergency Feed System, see Section 6.8.

10.3.2.6 Safety Valves

Five spring-loaded, self-actuated safety valves on each 30-inch steam generator outlet line provide overpressure protection for the secondary side of the steam generators, and consequently for the main steam piping. The total capacity of the twenty valves is approximately 110 percent of full-load steam flow at a pressure not exceeding 110 percent of the steam generator shell side design pressure. The maximum capacity of any single valve does not exceed 970,000 lbs/hr at an inlet pressure equal to the steam generator shell design pressure, to limit heat release if a valve inadvertently sticks open.

The valves are set at 1185 to 1225 psig with capacities ranging from 893,160 to 922,950 lbs/hr, respectively. These safety valves are designed, fabricated and inspected in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Class 2. These valves may be utilized for safe shutdown of the plant and are classified "active."

10.3.2.7 Main Steam Isolation Valves

One main steam isolation valve (MSIV) with a bypass valve is provided on each steam generator main steam line. The bypass valve is used at startup prior to opening the MSIV for pressure equalization and warming of the main steam piping system. During normal operation, the bypass valves are locked closed with the breakers locked open. The MSIV provides positive shut-off of steam flow in either direction during emergency as well as normal operation. The MSIV is a gate valve actuated by a hydraulic/pneumatic actuator. Hydraulic fluid is pumped into the valve actuator to open the valve against a pressurized pneumatic system. The valve is closed by pneumatic pressure when the hydraulic fluid pressure is relieved. The actuator is a stored nitrogen unit with a hydraulic cylinder coupled directly to a precharged nitrogen accumulator which stores the closing energy. The precharged high pressure nitrogen is stored in an integral, essentially spherical accumulator which is designed as a pressure vessel meeting the requirements of ASME VIII, Div. 1. A dual hydraulic control system is provided to ensure reliability. The MSIV is also capable of being tested online by partial closure of the valve.

For the MSIV (and FWIV) the precharged nitrogen accumulators are integral to the actuator assembly, and are designed to seismic Category I requirements. Separate instrument air accumulators are not required. Compressed air is supplied to air motors to operate the hydraulic pumps to open the MSIVs, but this is not a safety function. Motor-driven pumps perform a similar function for the FWIVs. Pressure switches are provided to alarm on low accumulator gas pressure. The accumulator is designed to minimize gas leakage. If gas pressure does decrease, it is a maintenance function to recharge the accumulator using nitrogen supply.

The MSIV is designed, fabricated and inspected in accordance with the ASME Code Section III, Class 2, and is classified "active." The safety-related electrical components of the actuator are Class 1E.

10.3.2.8 Turbine Stop Valves

A description of these valves in included in Section 10.2.

10.3.3 Safety Evaluation

The main steam cycle provides for heat removal from the NSSS. After a load reduction or turbine trip, this function is provided for by the Steam Dump System, which discharges into the condenser (see Subsection 10.4.4). When the condenser is not available, the atmospheric relief valves permit control of steam generator pressure.

The main steam safety valves are sized to prevent overpressure from load rejection at full power operation.

For a discussion of the increase in heat removal from the Reactor Coolant System, due to inadvertent opening of a main steam dump, relief, or safety valve, see Subsection 15.1.4.

In the event of a main steam line break, the MSIVs will close within five seconds from receipt of signal. The loss of main condenser vacuum has no effect upon the operation or operability of the main steam isolation valves.

Upon a loss of condenser vacuum the turbine stop valves close, the turbine is tripped and the turbine steam bypass valves are prevented from opening.

Reactor coolant system heat removal is accomplished by the steam generator atmospheric steam reliefs or the steam generator safety valves. In this event, the main steam isolation valves would remain open, which is an acceptable condition. For a discussion of increase in heat removal from the Reactor Coolant System due to a rupture of a main steam line, see Subsection 15.1.5.

Safety-related components of the Main Steam System are tested to insure operability under seismic and adverse environmental conditions. Redundant active components are provided to insure the system's safety functions in the event of a component failure.

Pipe restraints and the ability of components to operate under adverse environmental conditions provide protection from pipe breaks or cracks. The main steam and feed water pipe chases are designed to withstand a single-ended rupture of a main steam line.

The capability for testing safety-related components (Subsection 10.3.4) and provision for in-service inspection of the safety-related portion of the system (Section 6.6 and Subsection 3.9.6) are included.

Detection of radioactive leakage is facilitated by the area radiation monitoring system (Section 12.3), the process radiation monitoring system (Section 11.5), the primary coolant leakage detection system (Subsection 5.2.5), and the sampling systems (Subsection 9.3.2).

10.3.4 Inspection and Testing Requirements

An initial hydrostatic test of the main steam system piping is performed to the applicable construction codes. During preoperational testing the operation of the main steam safety valves and main steam isolation valves is demonstrated. Refer to Chapter 14 for further discussion.

Under normal plant operations, a program of in-service inspection of the welds in the safety class portion of the Main Steam System is performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code. Operability of main steam isolation and safety valves is verified in accordance with Technical Specification requirements.

A plant test program performed during initial pre-operational testing verified the ability to achieve plant cooldown using the manual-operated atmospheric relief valves.

10.3.5 Secondary Water Chemistry

10.3.5.1 Description

Secondary side water chemistry is established and maintained within the steam generator supplier's specification by:

a. Using a deaerating condenser that removes oxygen from the condensate

b. Chemical addition

c. Continuous blowdown of the steam generators

d. Cleaning the condenser and the Condensate and Feedwater Systems before startup, or during condenser circulating water inleakage, using the Condensate Polishing System.

When the steam is condensed, undissolved gases are released. These gases, including oxygen, are taken out by the condenser evacuation system. The oxygen content in the condensate leaving the condenser is controlled by procedure to minimize erosion-corrosion in the condensate and feedwater systems.

Additional oxygen control is accomplished by the addition of hydrazine at the condensate pump's discharge header or steam generator feedwater pump discharge piping. This hydrazine, by a chemical reaction, scavenges the oxygen in the feedwater. Maintaining a hydrazine residual near the steam generator feedwater inlet ensures that any dissolved oxygen is removed. Hydrazine also promotes the formation of a protective metal oxide film on carbon steel surfaces.

A combination of amine compounds is used as approved pH additive and added at the condensate pump's discharge header, the effluent of the condensate polishing system, or steam generator feedwater pump discharge piping. It is used to establish and maintain an alkaline pH in the feed train and the steam generator. Alkaline conditions reduce corrosion at elevated temperatures and promote the formation of a protective metal oxide film. The technique of adding hydrazine and volatile amine pH additives is known as All Volatile Treatment (AVT) because these chemicals will not concentrate in the steam generator. Condenser circulating water inleakage is monitored. The monitoring will detect low contaminant levels providing evidence of inleakage. The condensate polishing system may be used to minimize contaminant ingress to the secondary system while preparing to repair identified leaks. Water chemistry monitoring is discussed in Subsection 9.3.2.

The Seabrook Station secondary pH program is based on optimizing the "at" temperature pH (pHt) in various portions of the secondary plant by the use of amines. All amines suitable for use as secondary system pH control agents are classified as weak base compounds. When dissolved in water, these compounds partially ionize forming the hydroxide ion which is responsible for their alkaline properties. Temperature has a marked effect on the ionization constant of each amine depending on the amine itself. As a result the application of a single amine at a constant application rate will result in varying pHt in different regions of the secondary system. It may be necessary to employ a mixture as close as possible to the target pHt for that region in order to maintain the solubility of iron in that region at the lowest level possible.

The concentration of any contaminants that do enter the steam generator is reduced by intermittent and continuous blowdown. This is discussed in Subsection 10.4.8. The plant is equipped with a filtering system that recirculates a portion of the condensate through filters and returns it to the condenser. This procedure removes solid particles from the condenser and the Condensate and Feedwater Systems during low power operation.

10.3.5.2 Effect of Water Chemistry on Iodine Partitioning

The formation of volatile iodine compounds in the steam generator is suppressed by the condition of the secondary water chemistry. The amount of iodine carryover is normally dependent upon the efficiency of the moisture separators within the steam generators.

An approved pH additive is used to regulate the condensate pH. The pH range for effectively eliminating iodine volatility is 8.5-11.0. The "at" temperature pH for condensate is 9-10, maintaining iodine almost completely in its non-volatile state. Thus, only minimal amounts of iodine would be exhausted through the condenser vacuum pumps.

The amount of iodine released to the environment in the event of a steam generator tube rupture is minimal. This is the result of the high degree of iodine partitioning in the steam generator and condenser, and the charcoal filter at the condenser vacuum pump discharge. Refer to Subsection 15.6.3 for further discussion.

10.3.5.3 Control Program

The EPRI Secondary Water Chemistry Guidelines are the basis for the secondary chemistry control program.

A summary of operative procedures which are used for the steam generator secondary water chemistry control and monitoring program is as follows:

a. Procedures are available for sampling for the critical chemical and other parameters and of control points or limits for these parameters for each mode of operation: normal operating, hot startup, cold startup, hot shutdown, cold wet layup. The sampling schedule is expected to closely follow the recommendation of the EPRI Secondary Water Chemistry Guidelines. Critical parameters and specifications for each mode of operation are in accordance with the EPRI Secondary Water Chemistry Guidelines.

b. Procedures for chemical analysis of critical parameters were developed using references such as

    1. American Public Health Association, Standard Methods for Examination of Water and Waste Water

    2. American Society for Testing Materials, Part 31 Water

c. Locations for process instrumentation and sample points are indicted on Updated FSAR Figure 9.3-15. The extensive process instrumentation which monitors critical parameters of the secondary system will result in continuous assessment of the secondary system. Grab samples are taken at critical points (i.e., blowdown, feedwater, condenssate, and makeup) as additional verification of system chemistry control.

d. Procedures for recording and management of data are available. Seabrook Station will have qualified chemistry personnel on station at all times to interpret analysis data of critical parameters on a continuous basis, followed by additional technical review by chemistry department management during normal work hours. All analysis records will be maintained in accordance with station administrative procedures.

e. Procedures for defining corrective action are predicated on the need to maintain condenser integrity by using state-of-the-art techniques for leak detection such as helium-mass spectroscopy to identify air and seawater intrusion. Process instrumentation will result in rapid identification of leaks at Seabrook. Corrective action to identify the location of a verified condenser seawater intrusion in excess of the EPRI chemistry control parameters will be taken promptly. Use of the Condensate Polishing System will limit the chloride concentration in the steam generator blowdown. Actions to minimize degradation of steam generator tubes will be taken as described in the EPRI Secondary Water Chemistry Guidelines.

f. The Seabrook shift chemistry technician is the primary individual responsible to interpret operational chemistry data. Shift chemistry technicians will have completed all training required by the nonlicensed training program for chemistry technicians giving them the expertise to advise the Unit Shift Supervisor on operational chemistry occurrences.

10.3.6 Steam and Feedwater System Materials

10.3.6.1 Fracture Toughness

The test methods and acceptance criteria used to verify the fracture toughness of the ferritic materials used in Class 2 and 3 components of the Steam and Feedwater Systems are in accordance with the applicable requirements of Articles NC-2300 and ND-2300 in Section III of the ASME Boiler and Pressure Vessel Code, 1974 edition.

a. Fracture toughness properties of the steam generator pressure boundary materials are described in Subsection 5.2.3.3 of the Seabrook Updated FSAR. Impact testing of these materials has been performed to verify compliance with ASME III.

b. The main steam and feedwater isolation valves, containment penetrations and the piping between containment penetrations and isolation valves have been reviewed for compliance with General Design Criterion 51, and found to be acceptable. (See SER for Containment Boundary.)

c. The main steam system pipe and fittings inside Containment were fabricated from the materials listed in Subsection 10.3.6.2 below. All welded joints were examined radiographically to ensure minimum weld defects. Impact testing of this material was not considered necessary, since the maximum nil ductility transition temperature for these materials (conservatively taken from NUREG-0577 as 97°F considering the thickness adjustment) was below the minimum service temperature of 100°F established for the hydrostatic test fluid temperature.

The feedwater system pipe and fittings inside Containment and outside Containment up to the check valve beyond the isolation valve were fabricated from the materials listed in Subsection 10.3.6.2 below. All welds were examined radiographically to ensure minimum defects. The piping material, SA-106, was heat-treated to improve impact properties. Impact tests were performed on seven of the eight heats of piping material and met code requirements at the minimum feedwater injection temperature of 50°F.

10.3.6.2 Materials Selection and Fabrication

All Class 2 and 3 pipe, valves and fittings used in the Steam and Feedwater Systems are fabricated from materials that are listed in Appendix I of Section III of the ASME Code.

The following materials are used for Class 2 and 3 service:

Main Steam	Feedwater
SA-106, Grade B and C	SA-106, Grade B (normalized, fine grain)
SA-155, Grade KCF 70	SA-234
SA-234	SA-105
SA-105	SA-193, Grade B7
SA-193, Grade B7	SA-194, Grade 7, 2H, 4 or 3
SA-194, Grade 7, 2H 4 or 3	SA-312, Type 304
SA-216 WCB or WCC (valves)	SA-182, Type 304 SA-403, WP 304

Austenitic stainless steels are used only for the emergency feedwater suction piping. This is a low pressure, ambient temperature, uninsulated section of piping; therefore, Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel," is not applicable.

Regulatory Guide 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal," is applicable to Class 1 and 2 systems. The emergency feedwater piping is Class 3.

The recommendations of Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," were complied with for the fabrication of emergency feedwater suction piping.

The recommendations of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water Cooled Nuclear Power Plants" and ANSI N45.2.1-73, "Cleaning of Fluid Systems and Associated Components for Nuclear Power Plants" were complied with for cleaning and handling of all Class 2 and 3 components.

The preheat temperatures used for welding low alloy steel are in accordance with Regulatory Guide 1.50, "Control of Preheat Temperature for Welding of Low-Alloy Steel." The preheat temperatures used for welding carbon steel materials are in accordance with ASME Code, Section III.

The steam and feedwater system components are provided with sufficient accessibility so that standard welding procedures are utilized. Nondestructive examination procedures used for tubular products conform to applicable requirements of the ASME Code.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEMS

10.4.1 Main Condenser

10.4.1.1 Design Bases

The main condenser is not a safety-related component and has no safety design bases. The following are design criteria which apply to the main condenser:

a. The main condenser is designed to function as a steam cycle heat sink, receiving and condensing exhaust steam from the main turbine and steam generator feedwater pump turbines. It has the capability to condense turbine bypass flows up to 40 percent of full-load main steam flow without exceeding turbine exhaust pressure and temperature limitations.

b. The main condenser is designed to serve as a collection point for vents and drains from various components and systems of the heat cycle.

c. The hotwell of the main condenser is designed to provide approximately three minutes of storage capacity without makeup, for the valves-wide-open flow condition, when operating at the normal water level.

d. The main condenser is designed to de-aerate the condensate.

e. Codes and standards applicable to the condenser design are:

    1. Heat Exchange Institute - Standards for Steam Surface Condensers

    2. American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section VIII, Division I

    3. Tubular Exchangers Manufacturer's Association Standards, Class C

    4. American Society for Testing and Materials - Standards

    5. American National Standards Institute.

10.4.1.2 System Description

a. Component Description

Each condenser shell assembly is comprised of the following sections:

Shell	Tubes
Hotwell	Tube Stakes
Steam dome	Waterboxes
Extension neck	Internal piping to external connections
Tube sheets	Tube support plates

The main condenser system consists of three de-aerating, double pass, single pressure, radial flow type condensers. Each one-third capacity condenser is located beneath one of three low-pressure turbine cylinders. Each condenser shell is floor-mounted and connected to the turbine exhaust flange by means of a rubber-belt expansion joint to accommodate differential thermal expansion between the turbine and condenser.

The condenser shell is carbon steel, welded construction, with $^1/_{16}$" corrosion allowance. Aluminum-bronze tube sheets are bolted to the shell and have provision for allowing thermal expansion of the tubes. The condenser tubes are titanium and are rolled into the holes of the tube sheets.

The condenser tubes are oriented transverse to the turbine-generator axis. Exhaust steam from the turbine discharges down into the condenser from exhaust openings in the bottom of each of the low pressure turbine casings. In addition, the condenser receives steam from the main feed pump turbines.

The condenser tube stakes prevent tube whippage caused by localized sonic steam velocities. The stakes stiffen the titanium tube bundle to reduce vibrational effects which may lead to tube failure. The tube stakes consist of stainless steel Shepard's Crooks for support between tubes, Micarta phenolics for support in the tube lanes, and stainless steel U-clip devices which are installed at certain tube bundle perimeter areas.

The first two stages of feedwater heaters are mounted in the neck of each condenser shell. The extraction steam lines to these heaters are completely enclosed in the condenser neck and dome, while the lines to heaters 3 and 4 pass through the interior of the condenser dome and penetrate the condenser shell.

The waterboxes are coated/lined to prevent corrosion induced by the sea water. The waterboxes are bolted to the condenser shells and are designed for easy removal without disturbing the tube sheets. Design pressure of the waterboxes is 60 psig.

A butterfly valve is provided at the circulating water inlet and outlet nozzles of each shell for isolation. Isolation valves are also provided on all condensate and heater drain lines connecting to each shell, so that each shell can be isolated without shutting down the unit. Though the isolated condenser shell is still exposed to the turbine exhaust steam, it is possible to inspect the tubes and perform minor maintenance and repairs while the unit is operating.

b. System Operation

During normal operation, exhaust steam from the low pressure turbines is directed into the shells of the main condenser. The following auxiliary flows are also discharged into the condenser:

1. Exhaust steam from steam generator feed pump turbines

2. Drains and vents from feedwater heaters

3. Condensate from gland seal system

4. Miscellaneous equipment drains

5. Steam generator blowdown from blowdown flash tank (vapor only) and from the blowdown demineralizers.

In addition to condensing the steam, the condenser also de-aerates the condensate. The noncondensible gases which accumulate in the condenser are removed by the air evacuation system (see Subsection 10.4.2).

Condenser hotwell level is monitored and necessary makeup is provided by the condensate storage tank or discharge to circulating water, respectively (see Subsection 9.2.6). Rejection of condensate normally occurs due to high hotwell level or high contaminant levels. Generally, the condensate storage tank is not used to collect rejected water. Hotwell cation conductivity is also monitored and alarmed in the main control room. The monitoring is arranged so the operator can determine which shell has the inleakage, so that the necessary steps to isolate or plug the leaking tubes can be taken.

The condenser has sufficient capacity to condense 40 percent of the full-load steam flow to the turbine during turbine steam load rejection without exceeding 5" Hg pressure.

Total hotwell capacity is 66,000 gallons at normal water level. This is in excess of three-minute capacity, based on condensate flow at 100 percent load.

There is no provision for control of the circulating water flow except by taking a pump out of service. For a description of the Circulating Water System, see Subsection 10.4.5.

c. System Design Data

Design backpressure	2.0" HgA
Backpressure during full load turbine operation, range	1.5-2.8" HgA
Backpressure during steam dump	5" HgA Max.
Total Heat Load:	
Design	7.90×10^{9} Btu/hr
Steam dump	7.15×10^{9} Btu/hr
Tubes:	Titanium
	55'-3"
Size	1" OD, 22 gage
Circulating water flow (total)	399,000 gpm
Temperature rise	38°F
Water velocity	7 fps
Head loss	27 ft

10.4.1.3 Safety Evaluation

The main condenser has no safety-related design basis. Due to the plant design (PWR) there is negligible influence of condenser control functions on reactor coolant system operation, and negligible potential for hydrogen buildup in the condenser due to continuous gas removal.

In the event of a steam generator tube leak, radioactivity can be present in the secondary side. See Section 11.1 for expected activity due to steam generator tube leakage.

Due to the location of the condenser in the Turbine Building, any flooding resulting from condenser failure will not affect safety-related equipment.

10.4.1.4 Inspection and Testing

The main condenser shell, tubes, and waterboxes are hydrostatically tested to verify integrity prior to initial plant startup.

For service inspection, access manholes are provided on the outlet and turn-around waterboxes, on both ends of the hotwell, and in the steam dome. It is planned to perform a visual inspection of the condenser internals during each refueling outage as part of the normal station preventive maintenance activities.

10.4.1.5 Instrumentation

Condenser vacuum is indicated and recorded in the control room. Condenser vacuum pressure switches are used to (1) alarm pre-turbine trip vacuum, (2) trip the turbine with two-out-of-three coincidence logic and (3) block steam dump to the condenser, also with two-out-of-three coincidence.

Hotwell level indication and high, low and low-low level alarms are provided in the control room. Hotwell level will control the hotwell water inventory by admitting makeup water from the condensate storage facility.

Sea water inleakage to the condenser is monitored by conductivity cells at the catch trough and cation conductivity cells at the hotwell and is recorded and alarmed in the control room and at a local panel. Inleakage is also monitored and alarmed by measuring sodium ion concentration. The instrumentation is sensitive to leakage resulting in ppb concentration.

Monitoring of radioactive contamination is described in Subsection 10.4.2.5.

Additional instrumentation monitors the performance of the condenser by measuring circulating water inlet and outlet temperature and differential pressure. Display of circulating water outlet temperature at the main control board is used for temperature monitoring during backwash operations.

10.4.2 Main Condenser Evacuation System

10.4.2.1 Design Bases

The main condenser evacuation system, Figure 10.4-1, consists of two independent subsystems: the shell side evacuation subsystem and the waterbox priming subsystem.

The Main Condenser Evacuation System has no safety design basis; however, the following design criteria are applicable:

a. The shell side evacuation subsystem removes noncondensible gases and air inleakage from the steam space of the main condenser shells. This system is sized to achieve and maintain shell side vacuum in the condenser to permit plant startup and operation.

b. The waterbox priming subsystem removes the noncondensible gases from the condenser waterboxes (tube side) during startup and normal operation.

Refer to Subsection 10.4.1.1 for the applicable codes and standards for this system.

10.4.2.2 System Description

a. System Components

The air removal equipment consists of three mechanical vacuum pumps serving the three condenser shells, and two mechanical waterbox priming pumps serving the condenser waterboxes.

The vacuum pumps for both subsystems are of the rotary design and electric motor driven, with the shell side pumps being two stage and the waterbox priming pumps being a single stage. Each pump is skid-mounted with its own moisture separator located downstream of the pump discharge and seal water cooler.

The seals to each pump are provided with a closed cooling system using demineralized water. The seal system on the shell side pumps are cooled by circulating water, and on the waterbox pump by service water.

b. Operation

1. Shell Side Evacuation Subsystem

All three pumps will be operated to evacuate the condenser during startup. Condenser pressure can be reduced to approximately 2" HgA in approximately 76 minutes with zero air inleakage. Once vacuum is attained, one pump will be placed on standby to start automatically at approximately 26" Hg vacuum.

During normal plant operation, the noncondensible gases removed by the shell side evacuation system are piped to the Primary Auxiliary Building (PAB) where they are passed through a HEPA and charcoal filter prior to their discharge to the atmosphere. This is done to minimize the possibility of a radioactive discharge to the environment in the event of a steam generator tube leak. For the hogging or startup mode, the noncondensible gases are not expected to be radioactive, and are discharged directly through the Turbine Building vent to atmosphere. See Subsection 10.4.2.5 for discussion on monitoring of shell side discharge. Also, refer to Subsection 11.3.3 for anticipated release rates of radioactive materials.

Vacuum pump discharge flow is directed either to the filter or to the plant stack by diverting valves which are manually positioned by the operator at the main control board.

2. Waterbox Priming Pumps Subsystem

The waterbox priming pumps are used to remove noncondensible gases from the condenser waterboxes during startup, and to remove gases that are released from the circulating water due to temperature rise during normal operation. These gases are discharged directly to atmosphere through the Turbine Building vent.

The two waterbox priming pumps are each sized for full-load operating conditions. During normal operation, one pump is operating with the other on standby or isolated for maintenance.

10.4.2.3 Safety Evaluation

Normally, there is no radioactivity in the condenser evacuation system. A filtering system for treatment of gaseous waste is provided in the event of steam generator tube leakage. The diverting valves in the discharge of the shell side vacuum pumps are arranged so that on loss of electric or pneumatic power, they will fail to the filter position. The radioactivity released from the condenser evacuation system is discussed in Section 11.3.

10.4.2.4 Inspection and Testing Requirements

Initial testing of the system is performed prior to startup to insure the proper functioning and performance of the system and its components.

10.4.2.5 Instrumentation

Local pressure, level and temperature indication are provided to monitor the operation of the Main Condenser Evacuation System. Vacuum switches are provided for automatic operation of the condenser (mechanical) vacuum pumps. Condenser vacuum is indicated and recorded in the main control room; low vacuum condition is also alarmed in the control room. Total condenser vacuum pump flow indication is also provided locally and on the main plant computer.

A radiation monitor is provided at the discharge header of the mechanical vacuum pumps to monitor releases of radioactivity to the environment. Local and remote radioactivity indication and high alarm are provided in the control room. Refer to Section 11.5 for a discussion on process and effluent radiological monitoring and sampling systems. During startup operation (hogging), the gases removed by the evacuation system are discharged to atmosphere via the Turbine Building vent. During normal operation (holding), the gases removed by the evacuation system are piped to the Primary Auxiliary Building ventilation system, where they are passed through HEPA and charcoal filters prior to discharge to atmosphere. Refer to Subsection 9.4.3, for a description of the Primary Auxiliary Building heating and ventilation system.

10.4.3 Turbine Gland Sealing System

10.4.3.1 Design Basis

The turbine gland sealing system provides sealing steam to the main turbine and the two steam generator feed pump turbines. The sealing system prevents the leakage of steam from the turbine packing glands into the Turbine Building and also prevents the leakage of air into the main condenser.

10.4.3.2 Description

The annular space between the turbine shaft and the turbine casing is sealed with conventional steam-sealed labyrinth packing. Each packing box is provided with a steam supply connection and an air-steam exhaust connection to the gland steam condenser, where the steam seal exhaust is condensed. At loads above minimum, the high pressure turbine packing has an excess of steam in which case the steam supply connection serves as a leakoff.

Relief valves are provided to protect the system from malfunctions resulting in overpressure conditions. Air and noncondensible gases are removed from the gland steam condenser by motor-driven exhauster fans. The cooling medium for the gland steam condenser is provided by the condensate system. The steam seal header pressure is maintained slightly above atmospheric. This system and its components are shown on Figure 10.4-2.

10.4.3.3 Safety Evaluation

The mixture of noncondensible gases discharged to the atmosphere by the gland steam condenser exhaust fans is not normally radioactive. Therefore, a component malfunction or failure in this system will not normally result in any release of radiation to the environment. However, in the event of a steam generator tube leak, it is possible for the exhaust fan discharge to be radioactively contaminated. To allow for an assessment of these potential effluents, the exhaust vent is equipped with the capability to obtain grab samples of iodines and particulates.

A full discussion of the radiological aspects of primary-to-secondary system leakage, including anticipated releases from the turbine gland sealing system and limiting conditions for operation, is included in Chapter 11.

10.4.3.4 Tests and Inspection

Before initial startup, the steam seal regulating valves are tested in accordance with the manufacturer's instruction manuals. During operation, the setpoints and steam pressures are checked periodically.

10.4.3.5 Instrumentation

a. Sealing steam pressure in the header is automatically regulated by air-operated diaphragm control valves which control both supply and spillover.

b. Motor-operated stop and bypass valves are manually operated from the local steam seal and drain control panel; open and closed indicating lights show valve position at the local panel.

c. Sealing steam header pressure is indicated locally at the seal steam control panel and in the control room; low header pressure is annunciated in the control room.

d. Low water level in the steam packing exhauster and low vacuum are annunciated in the control room. Both exhauster fans can be manually operated from the control room. Normally one fan is kept running with the second fan standby in auto mode, so that on loss of first fan the second one comes on line automatically. Fan motor high temperature and fan trip are annunciated in the control room.

10.4.4 Steam Dump System

10.4.4.1 Design Bases

The Steam Dump System is designed to reduce the magnitude of nuclear system transients following large turbine load reductions or turbine trips by dumping steam directly to the main condensers, thereby creating an artificial load on the reactor.

The Steam Dump System has the following functional requirements:

a. Permit direct bypass flow to the condensers of nominally 40 percent of rated turbine flow. The reactor is capable of 10 percent step-load reduction, thereby allowing a turbine step-load reduction of 50 percent without a resultant reactor trip.

b. Permit turbine and reactor trip from full power without atmospheric discharge through the steam generator safety valves.

c. Maintain steam header pressure at required pressure during startup, hot standby, cooldown and reactor physics testing periods.

The maximum capacity of any single valve does not exceed 573,000 lb/hr at 1107 psia to limit steam release if any single valve inadvertently sticks open.

If the condenser is not available, the steam dump is isolated to protect the condenser.

The steam dump system piping is designed in accordance with the ANSI B31.1 Power Piping Code.

10.4.4.2 System Description

a. General

The Steam Dump System is shown on Figure 10.3-7. Steam is discharged to the condensers through twelve air-operated, partial capacity, automatically controlled steam dump valves, (PV-3009 through 3020) which are installed in the steam dump lines connected with the steam system. The branch headers to the steam dump valves tie into the main steam headers between the main steam generator isolation valves and the turbine stop and control valves. The steam dump valves are arranged in parallel so that when combined, they will permit the desired bypass flow to pass. This arrangement will limit the steam bypassed to the condenser, should a valve open accidentally or stick open, thereby minimizing the potential for an uncontrolled cooldown of the primary system. This arrangement also permits the steam dump flow to be evenly shared by the turbine condensers, thus preventing uneven turbine exhaust backpressures.

During normal operation, the system is operated in the T_{avg} mode. A control signal obtained from the difference between primary T_{avg} and a $T_{reference}$ signal which is derived from turbine first stage pressure, is used to determine the number of valves and, thus, the amount of steam to be dumped during a transient.

For a large load reduction, either one-half or all of the dump valves are tripped open immediately, depending upon the magnitude of the transient and resulting control signal. The valves are modulated closed as reactor power approaches turbine power (i.e., T_{avg} approaches T_{ref}) so that the valves are fully closed when the reactor power matches the turbine power. For a plant trip the valves will operate to maintain T_{avg} at the no-load value.

During primary plant cooldown, the Steam Dump System is operated in the steam generator pressure control mode. In this mode, the control signal is generated by comparison of steam header pressure with the pressure setpoint. The pressure setpoint is manually reduced to achieve the required cooldown rate.

All dump valves fail closed on loss of control signals, and are prevented from operating on loss of condenser vacuum. During a loss of condenser vacuum transient, excess steam pressure is relieved to the atmosphere through the power-operated relief valves or the safety valves (see Subsection 10.3.2).

The dump lines are normally stagnant and, therefore, collect condensate continuously. This condensate is automatically removed by an upstream drain system to permit proper valve operation.

b. Steam Dump Valves

Twelve steam dump valves are provided, with each valve having a capacity of approximately 510,000 lb/hr. They are designed to fail closed on loss of control signal, and are split into four groups to ensure even distribution of heat into each condenser. The dump valves are capable of a rapid trip actuation or of a modulating operation.

The steam dump valve actuation characteristics are:

1. The valves are capable of going from full-closed to full-open within five seconds after receiving a trip/open signal. This includes the time required to actuate the solenoid valves associated with each dump valve.

2. The valves are capable of going from full-open to full-closed in five seconds after de-energization of the solenoid valves.

3. The valves are capable of being modulated with a maximum full stroke time of 25 seconds.

10.4.4.3 Safety Evaluation

The Steam Dump System is not essential to safe operation of the plant. It is provided, however, to give the plant flexibility of operation. Each valve is provided with an isolation valve to permit maintenance. The flow capacity of each valve is selected to prevent excessive cooldown rate should the valve fail in the open position.

When all the valves are out of service, the steam generator safety valves provide the relieving capacity required to maintain the steam system within the design limits.

No effects of pipe breaks are considered, since all piping is located in the Turbine Building where the effect of pipe breaks will not jeopardize the safe shutdown of the plant.

10.4.4.4 Tests and Inspections

During preoperational and initial startup testing, the Steam Dump System will be tested to verify proper valve performance and overall system dynamic response as described in Chapter 14.

10.4.4.5 Instrumentation Requirements

The Steam Dump System is controlled by a system which compares turbine power to reactor power by means of temperature and pressure inputs. The specific mode of operation (T_{avg} or steam pressure) can be selected through a selector switch mounted at the main control board (MCB). Valve position indications are also available at the MCB. The Steam Dump Control System is discussed in Subsection 7.7.1.8, and is analyzed for the following control modes:

a. Load rejection

b. Plant trip

c. Steam header pressure.

Interlocks are provided to block steam dump operations on low-low T_{avg} to prevent excessive cooldown of the primary plant and to protect secondary plant equipment if the condenser is unavailable, as sensed by the condenser pressure switches and the circulating water pump breaker positions. Figure 7.2-10 shows the functional details and the interlocks pertaining to the Steam Dump Control System.

10.4.5 Circulating Water System

The Circulating Water System provides cooling water to the main condensers to remove the heat rejected by the turbine cycle and auxiliary systems. Discussions pertaining to the interface between the Circulating Water System, the Service Water System and the ultimate heat sink are found in Subsections 9.2.1 and 9.2.5.

10.4.5.1 Design Bases

a. The circulating water system design is based on a maximum ocean water temperature of 65°F, a condenser heat load of 0.79×10^{10} Btu/hr during normal full-load operating conditions, and an average discharge water temperature maximum increase of 39°F for normal operation with both units. During the summer months, extended hot weather combined with ocean current changes can result in minor ocean temperature excursions above the 65°F design temperature threshold. System analysis has been performed to permit continued plant operation up to a maximum ocean temperature of 68.5°F.

b. The design of the system also includes the capability for furnishing cooling water to the Service Water System, and returning it to the circulating water discharge flow.

c. The Circulating Water System is designed to operate safely at extreme high tide and minimum predicted tide (see Subsection 2.4.11.2), and to permit operation of the turbine generator during condenser steam dump conditions without occurrence of a condenser low vacuum trip.

d. Provisions for continuous low-level chlorination (as shown on Figure 10.4-5) and heat treatment of the tunnels are included for control of fouling by marine organisms.

e. The design of the circulating water system structures is nonseismic Category I, with its components also nonseismic Category I and nonsafety-related.

10.4.5.2 System Description

The general arrangements of the various structures and components comprising the Circulating Water System are shown in Figure 1.2-46, Figure 1.2-47, Figure 1.2-48 and Figure 1.2-52, Figure 1.2-53, Figure 1.2-54, and Figure 1.2-55. The Circulating Water System consists of the following principal structures:

a. Two tunnels connecting the plant site with three submerged offshore intakes and a multiport discharge diffuser

b. An intake transition structure

c. A pumphouse

d. A pair of flumes which join the intake transition structure to the pumphouse

e. A discharge transition structure

f. An underground piping system, interconnecting the pumps in the pumphouse, the condensers, and the transition structures.

The flow diagram of the Circulating Water System is shown in Figure 10.4-3 and Figure 10.4-4. During normal operations, the Circulating Water System provides a continuous flow of approximately 390,000 gpm to the main condenser and 21,000 gpm for the Service Water System.

Starting 260 feet below the plant level (240 feet below mean sea level), at the bottom of vertical 19'-0" finished diameter land shafts, two tunnels extend out under the ocean at an ascending grade of about 0.5 percent until they reach their respective offshore terminus locations about 160 feet below the ocean's surface. The tunnels, which are machine bored through bedrock to a 22'-0" diameter, are concrete-lined to provide the finished 19 foot diameter.

The intake tunnel is approximately 17,000 feet long, and is connected to the ocean by means of three 9'-10½" finished diameter concrete-lined shafts, spaced between 103 and 110 feet apart and located approximately 7000 feet off the shoreline in 60 feet of water. A submerged 30'-6" diameter concrete intake structure intake head is mounted on the top of each shaft to minimize fish entrapment by reducing the intake velocity.

The discharge tunnel is approximately 16,500 feet long, and is connected to the ocean by means of eleven, 5'-1" finished inside diameter concrete-lined shafts, spaced about 100 feet apart, located approximately 5000 feet off the Seabrook Beach shoreline in water up to 70 feet deep. A double-nozzle fixture is attached to the top of each shaft to increase the discharge velocity and diffuse the heated water.

The circulating water portion of the pumphouse encloses six 14' wide circulating water traveling screens and three circulating water pumps. A seismic Category I reinforced concrete wall separates the circulating water portion from the service water portion of the pumphouse structure. The water is pumped through two 11-foot diameter pipes (1 per unit) leading to the condensers, and is returned through two 10-foot diameter discharge pipes (1 per unit) connected with the tunnel transition structures. Water to the service water section of the pumphouse is supplied by two pipelines branching off each of the tunnel transition structures.

Fouling by growth of marine organisms is expected to occur from the point where the sea water enters the intake structures up into the condenser. One process used for control of fouling in the intake structures and inlet tunnel will be continuous low-level chlorination with a sodium hypochlorite solution. Three sodium hypochlorite solution storage tanks, surrounded by a concrete spill containment dike, provide a bulk volume supply which may be pumped on demand to selected chlorination injection points within the CW system. The metered rate of injection will be such that a concentration of 0.2 ppm total residual oxidant, measured as Cl_2 equivalent, is not exceeded in the discharge transition structure. In addition, heat treatment, where the direction of flow in the tunnels is temporarily reversed, and the discharge temperature raised by recirculation is also available as a means of controlling marine growth. In this mode, the warm water from the condenser is returned to the ocean through the intake tunnel, while the discharge tunnel is used to supply ocean water to the plant. To heat treat the discharge pipes and tunnel, the temperature of the condenser outlet water is temporarily raised by recirculating some of the discharge water back to the condensers through the pumphouse.

The pumphouse, pipes leading to the condensers, and the condensers can be dewatered, inspected, and cleaned as required to control fouling.

10.4.5.3 Safety Evaluation

Since the Circulating Water System is considered nonsafety-related, the safety evaluation, therefore, concerns itself with the effect of a failure of this system or any of its components on safety-related systems or components.

If the circulating water flow rate falls below the minimum required amount due to a malfunction in the system, the main condenser may no longer be able to adequately condense main steam, but there will be no effect on the safe shutdown capability of the plant.

The safety evaluation of the Circulating Water System, as it relates to the ultimate heat sink and the Service Water System, is presented in Subsection 9.2.1.

Passage of secondary system condensate from the main condenser into the Circulating Water System through a condenser tube leak is not considered possible during power generation, since the Circulating Water System operates at a higher pressure than the condenser, thus preventing possible contamination of the circulating water by potentially radioactive condensate.

The condenser is equipped with vacuum breaker valves which open if a circulating water pump trips, thus preventing the possibility of overpressure from water hammer.

Clogging of a circulating water traveling screen will trip its corresponding circulating water pump, thus preventing collapse of the screen. None of the controls or instrumentation relates to operations which could affect safety-related systems.

The expansion joints used in the CW system are made of fabric reinforced rubber with circumferential steel reinforcing rings. This makes the rupture of a joint in operation a very unlikely occurrence. To evaluate the consequences of a rubber joint failure, they can be divided into four groups as follows:

Group	Number of Joints	Size ID (in)	Pressure Normal Oper. (ft)	Pressure Max (ft)	Location
A	4	102	20	55	Between intake transition structure and pumphouse.
	2	120	20	55	Between discharge transition structure and backwash conduits to the pumphouse.
B	4	120	15	50	At both ends of the discharge pipe section between the two transition structures.

Group	Number of Joints	Size ID (in)	Pressure Normal Oper. (ft)	Max (ft)	Location
C	6	84	50	130	CW pumps discharge.
D	12	84	50	130	Condenser connections.

Group A

Failure of a joint in this group will result in a flood in the valve pit around the transition structure in which the joint is installed, but the water will reach no higher than the water in the pumphouse. The worm gear boxes directly mounted on the butterfly valves will be submerged; however, the electric motors and controls, which are installed above grade, will always be above water. Since the valves remain operational, and no other equipment is affected by this failure, no immediate action will be necessary.

Group B

Failure of a joint in this group will also cause flooding of the valve pit around the transition structure in which the joint is installed, and the water leaking from the joint will drain into the valve pit, eventually fill it, and overflow in the ground unless the CW system of that unit is stopped. It is estimated that the time required to fill the pit will not be less than 45 minutes, even assuming the worst possible failure to be a 2"x24" gap at the lowest side of the joint. A water level alarm will warn the operator of the flooded condition in the valve pit. Failure of a joint in this group will not prevent the Service Water System from providing its function.

Group C

Failure of a joint in this group will flood the pump pit in the Circulating Water Pumphouse between elevations +3' and +20' MSL. A number of openings at elevation 21'-0" of the Circulating Water Pumphouse will prevent the water from building up above the operating floor. The CW pump electric motors and the pump discharge butterfly valve electric motors will always be above water level, and will not be affected by such a failure. Assuming the worst possible failure to be a 2" gap all around, the CW pump pit would fill up in not less than 6.5 minutes. No safety-related equipment is affected by a failure of this equipment.

Group D

Failure of a joint in this group will flood the ground floor pit east of the condensers in the Turbine Building. Assuming the worst possible failure to be a 2" gap all around, the pit would fill up in about 3 minutes, unless prompt action by the operator is taken. There are two level switches in the condenser pit that provide sequential alarms in the control room to warn the operator of the flooded condition. No loss of offsite power is induced by a failure of this equipment provided operator action is taken within 22.2 minutes to mitigate the consequences of the flood.

Summary

The service water pumps are located at ground elevations and their motors are situated above ground elevation. There are no openings in the common wall between the service water pumps and CW pumps. Therefore, flooding which may spread to the open ground has little potential for entering the Service Pumphouse and no potential for interrupting the service water pump safety function.

Flooding caused by a flexible joint failure at the main condenser may spread over the turbine floor and from there to the open ground by passing through Turbine Building doors. However, sufficient physical separation is provided between the areas subject to such a flood and any safety-related equipment whose safety function could be impaired by such a flood.

10.4.5.4 Testing and Inspection

Sufficient manholes and access ways are provided in the circulating water pipes and condenser waterboxes for any necessary inspection or cleaning activities.

10.4.5.5 Instrumentation

Temperature instruments used for condenser performance monitoring and as an upper limit to water temperature for system heat treatment are described in Subsection 10.4.1.5.

Control of heat treatment operation is from the Unit 1 control room. The operator can align all valves (including service water intake valves) for tunnel heat treatment in concert, and adjust the temperature by observing additional discharge water temperature readouts from the computer.

Control and display instrumentation is provided to permit operation of the Circulating Water System from the main control room under all normal and abnormal conditions.

Level instrumentation monitors water level of the intake structure, discharge structure and Circulating Water Pumphouse. The level is indicated at the main control board.

Circulating water pump motor temperatures are monitored and high temperature alarms are provided at the main control board. Once the circulating water pump starts it will be automatically tripped on a loss of offsite power or high pressure drop across the traveling screen.

Controls and position indications are provided on the main control board for the pump operation, motor-operated valves, and condenser vacuum breaker valves.

10.4.6 Condensate Polishing System

10.4.6.1 Design Basis

The Condensate Polishing System (CPS) is an integral part of the Condensate (CO) system. The CPS is intended for standby service and is designed to remove dissolved and suspended impurities from the secondary system. The condensate polishers may be aligned to remove impurities, which could contaminate the secondary system due to a condenser (circulating water) tube leak. The system may also be used during startup to clean the condensate and feedwater systems prior to initiating secondary system flow to the steam generators.

10.4.6.2 System Description

10.4.6.2.1 Operation

The CPS utilizes demineralizers sized to process the equivalent of 100% flow from one of the three condenser hotwells. The CPS is an extension of the condensate system where fluid from a condenser hotwell may be treated to remove contaminants. The CPS removes impurities resulting from condenser tube leakage and corrosion products from the feedwater and condensate systems. The CPS produces a high quality effluent capable of meeting feedwater and steam-side chemistry specifications (see Subsection 10.3.5).

Three lead cation bed (two operating; one spare) demineralizers are utilized to remove system amines prior to processing by the four mixed bed (three operating; one spare) demineralizers. Resin beads are retained in the vessels by a flat, slotted screen underdrain system. Resin bead strainers are located downsteam of each vessel to retain resin in the unlikely event of an underdrain failure.

The CPS is normally in standby. When required for service to mitigate the effects of a condenser leak, the CPS takes the entire flow from the leaking condenser's hotwell, passes this condensate through the demineralizers and returns the condensate to the two clean condenser hotwells. The two clean condenser hotwells remain aligned to the condensate pumps while the leaking condenser hotwell is isolated from the condensate system and aligned to the CPS pump.

The CPS is sized to meet the secondary chemistry requirements for continuous operation as discussed in Subsection 10.3.5 while operating with a condenser leak of 0.04 gpm and to maintain water quality for an orderly unit shutdown with a condenser leak of 0.4 gpm.

The system provides for full flow loop recirculation prior to connection of the CPS to the condensate system. Polisher vessel isolation valves and system interconnection valves are designed to permit a controlled opening and closing to minimize hydraulic surges on the resin bed and within the system piping.

An external resin regeneration and waste processing system is utilized in conjunction with the CPS. The number and sizing of the polisher vessels are such that the functional requirements can be met while permitting the regeneration of resin in one ion exchanger at a time. Sampling of system parameters is provided to ensure correct operation.

Condensate polishing regenerant waste is collected in the low conductivity tank and the water treatment system neutralization tank and sampled prior to release, in accordance with the NPDES permit requirements and the ODCM.

Spent resin will be sluiced to drums for dewatering. The final shipment container and disposal will depend on sampling and whether the resin is determined to require disposal as radioactive waste. The disposal of radioactive resin will meet the requirements as described in Section 11.4. If the waste resin is not determined to be radioactive, then it may be processed as commercial waste in accordance with applicable requirements.

Representative CPS design and operating parameters are listed in Table 10.4-4. The Condensate Polishing System is shown on Figure 10.4-18 and Figure 10.4-19.

10.4.6.2.2 Component Description

a. Cation Demineralizers

The lead cation beds utilize strong acid cation resins to remove dissolved solids from the main condensate stream. The cation beds also remove ammonia, formed in the secondary system as a result of hydrazine degradation, which assists in pH control. The removal of ammonia and other amines allows an extended run length for the mixed beds, which are in series downstream of the cation beds.

Design pressure and temperature for the demineralizer assemblies are 150 psig and 150ºF. The expected temperature for ion exchange resins within the demineralizer is the same as condensate pump discharge temperature, which is less than 125ºF. Design temperatures and pressures are functions of the condensate pump head, condensate system heat balance criteria, and inherent stability of the resin used. Normal operating conditions are 100 psig and 90 - 105ºF.

The sizing of each cation demineralizer is based on adherence to a maximum flow rate of vessel cross section. The final selection of two operating units and one spare unit, each 9 feet-6 inches in outside diameter, provides full CPS flow capability at a unit design flow rate of less than 52 gpm/ft^2.

The cation demineralizer vessels are lined and stainless steel fitted for protection against localized corrosion where ion exchange resins contact internal wetted surfaces. Internal distributors/collectors are stainless steel. The cation demineralizer vessels are designed, fabricated, and code stamped in accordance with ASME Section VIII.

b. Mixed Bed Demineralizers

The mixed beds remove anions and augment the cation beds through further removal of cations.

The design pressure and temperature for the mixed beds are the same as those presented for the cation beds, i.e. 150 psig and 150ºF. The expected temperature for ion exchange resins within each demineralizer is less than 125ºF. Design temperature and pressures are functions of the condensate pump head, condensate system heat balance criteria, and inherent stability of the resin used. Normal operating conditions are 100 psig and 90 - 105ºF.

The sizing of each demineralizer is based on adherence to a maximum flow rate of vessel cross section. The final selection of three operating units and one spare unit, each 8 feet in outside diameter, provides full CPS flow capability at a unit design flow rate of less than 50 gpm/ft^2.

The mixed bed demineralizer vessels are lined and stainless steel fitted for protection against localized corrosion where ion exchange resins contact internal wetted surfaces. Internal distributors/collectors are stainless steel. The mixed bed demineralizer vessels are designed, fabricated, and code stamped in accordance with ASME Section VIII.

c. Condensate Polishing Pump

The condensate polishing pump returns effluent condensate flow from the CPS demineralizers to the CO system. The pump developed head compensates for the losses through the CO system piping, CPS piping, demineralizers, and the CPS control valve.

One 100% condensate polishing pump is provided. The pump is rated for 7,500 gpm at 230 ft. TDH and is driven by a 600 hp motor.

Pump pressure parts are carbon steel; pump shafting and impellers are stainless steel.

d. Condensate Polishing Head Tank

A condensate polishing head tank provides a positive head on the CPS during various operating transients. The tank has a capacity of 7,000 gallons with an approximate normal operating volume of 5,500 gallons.

Design pressure and temperature of the head tank are 150 psig/full vacuum and 150ºF. The vertical carbon steel tank has been designed and fabricated in accordance with ASME Section VIII and is code stamped.

e. Separation Tank

The separation tank is used to separate the anion and cation resins hydraulically. The vessel dimensions are 54-inch diameter in the narrow section, expanding to a cone of twice the cross sectional area or 78 inches in diameter. The narrow section is 17 feet long, and the cone is 6 feet.

Design pressure and temperature of the separation tank are 150 psig and 150ºF. The vertical lined, carbon steel tank has been designed and fabricated in accordance with ASME Section VIII, and is code stamped. For ease of installation, the tank was fabricated in two pieces that are joined by an ANSI 150lb flange midway in the narrow section.

Table 10.4-4 lists details on the design requirements for all the major CPS components.

10.4.6.3 Safety Evaluation

The CPS has no safety-related design basis. All CPS components are contained in non safety related structures. Failure of any portion of this system will not damage any safety-related component or system.

In the event of a steam generator tube leak, radioactivity can be present in the secondary side and could be conveyed to the CPS. Radioactive contamination of the secondary side by steam generator tube leakage is independent of the CPS and is addressed in Section 11.1.

Due to the location of the CPS in the Turbine Building, Administration Building, and Condensate Polishing Facility, any flooding initiated by the CPS or its components will not affect safety-related equipment.

10.4.6.4 Testing and Inspection

Tests and inspections on the CPS are performed to applicable codes and standards. The testing includes functional testing of the system and its components to ensure structural integrity, leaktightness, and the operability/performance of the integrated systems to function and perform during expected operating conditions. Normal operating system performance monitoring detects deterioration in the performance of the system components.

10.4.6.5 Instrumentation

The instrumentation employed for monitoring the CPS performance includes the following:

a. The condensate polishing pump suction and discharge pressure is locally indicated, and discharge header pressure is monitored to ensure correct system operation. The pump is protected from damage by a low flow permissive, a low condenser hotwell level trip and undervoltage, overcurrent and differential protection.

b. The CPS flow control valve regulates system flow downstream of the demineralizers in either auto or manual mode. Flow is modulated based on condensate polishing pump discharge pressure, condenser hotwell level and condensate system flow.

c. The conductivity of the influent condensate to the cation demineralizers, the effluent from each demineralizer, the common cation bed effluent, and the common mixed bed effluent is measured and recorded. An alarm signal is provided to indicate high conductivity.

d. Sodium levels of the influent condensate to the cation demineralizers, the effluent from each demineralizer, the common cation bed effluent, and the common mixed bed effluent can be measured and recorded. An alarm signal is provided to indicate high levels.

e. Silica levels of the effluent from each mixed bed demineralizer, and the common mixed bed effluent can be measured and recorded. An alarm signal is provided to indicate high levels.

f. Dissolved oxygen levels of the common mixed bed effluent can be measured and recorded. An alarm signal is provided to indicate high levels.

g. Flow transmitters are provided to monitor the throughput of each demineralizer.

h. Measurement of the waste stream for any radioactivity both before and during disposal is provided. Presence of a radionuclide concentration exceeding guidelines automatically terminates disposal to the circulating water outfall line.

10.4.7 Condensate and Feedwater Systems

The Condensate and Feedwater Systems return the condensate from the turbine condenser hotwells through the regenerative feed heating cycle to the steam generators while maintaining the water inventories throughout the cycle.

10.4.7.1 Design Bases

a. The Condensate and Feedwater Systems are designed to provide approximately 16.43×10^6 lb/hr of feedwater at 446.7ºF to the steam generators at 100% load. The feedwater system capability is in excess of the turbine control valves wide open (VWO) conditions.

b. The condensate portion of the system is designed to supply approximately 11.22×10^6 lb/hr, with an additional supply of 5.21×10^6 lb/hr from the heater drain pumps to the suction side of the steam generator feedwater pumps at 100% load. The condensate system capability is in excess of the turbine control valves wide open conditions.

c. The feedwater portion of the system is designed to supply the feedwater required for steady-state operation, and to maintain this flow, as required, following a large load reduction. The system is designed to maintain uniform feedwater flow to all steam generators under all conditions and to maintain proper steam generator water levels automatically during steady-state and transient conditions.

d. The Feedwater System from the steam generators, back to and including the check valve upstream of the feedwater isolation valve, is designated as Safety Class 2 and is designed to the requirements of seismic Category I systems. The portion of the system from upstream of the feedwater penetration in the pipe chase, and the Condensate System, is nonseismic Category I, and is designed to ANSI B31.1 requirements. The condensate storage tank is designated Safety Class 3, seismic Category I.

e. The condensate storage tank is designed to store and supply makeup water for the condensate, feedwater, and the Emergency Feedwater Systems (see Subsection 9.2.6).

f. The design parameters for the major components of the Condensate and Feedwater Systems are given in Table 10.4-1.

g. The safety class feedwater lines between the penetrations at the east and west pipe chases and the steam generator nozzles are located in a seismic Category I structure that is tornado, missile and flood protected.

h. The condensate and feedwater system components are designed and constructed in accordance with the following applicable regulations, codes and standards:

   1. Code of Federal Regulations, 10 CFR Part 50

   2. Branch Technical Positions APCSB 3-1 and MED 3-1

   3. ASME Boiler and Pressure Vessel Code

      Section III Nuclear Power Plant Components (Class 2)

      Section XI In-Service Inspection of Nuclear Power Plant Components

      Section VIII Pressure Vessels (Division 1)

   4. NRC Regulatory Guides

      1.26 Quality Group Classification and Standards

      1.29 Seismic Design Classification

5. American National Standards Institute (ANSI)

   B31.1 Power Piping Code

   N18.2 Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants

10.4.7.2 Systems Description

The condensate and feedwater system flow diagrams are shown on Figure 10.4-6, Figure 10.4-7, Figure 10.4-8 and Figure 10.4-9.

a. Condensate System

   Three motor-driven, constant-speed, vertical canned-type condensate pumps are supplied, each designed for approximately 50 percent of the total condensate flow.

   These pumps withdraw condensate from the three condenser hotwells via a common header arrangement which cross-connects the three condenser shells. During normal operation, only two pumps will be operating and one will be on standby. The pumps are vented to the condenser shell to prevent air binding. Seal and priming water are supplied to the condensate pumps from the condensate storage tank or the Demineralized Water System. The condensate pumps discharge into a common header that carries the flow to the steam packing exhauster, which condenses the turbine sealing steam and exhausts noncondensibles through blowers to the atmosphere.

   The total condensate flow rate in the common header is measured after leaving the steam packing exhauster. This measurement is used to ensure that the flow rate does not fall below the minimum flow requirements of the steam packing exhauster and the condensate pumps. This is accomplished by a recirculation valve downstream of the steam packing exhauster which will open to maintain the required flow. Recirculation valves are also provided at each pump to protect the pumps if their discharge valve is closed.

   During plant start-up excess condensate from auxiliary steam used for turbine gland sealing and shell warming is returned to the Auxiliary Steam Condensate System.

The common condensate header flow is routed to three parallel groups of low pressure heaters Nos. 1 and 2 mounted horizontally in the three condenser necks. The outlet flow is manifolded into a common header and conveyed to low pressure heaters Nos. 3 and 4, which are also three parallel groups of heaters, located in the turbine heater bay. The outlet flow is manifolded and routed to two parallel low pressure heaters No. 5, also located in the turbine heater bay.

Low pressure heater No. 1 is a four-pass, and heaters 2, 3 and 4 are two-pass U-tube type with integral drain coolers, while heaters No. 5 are two-pass, U-tube without drain cooler. All feedwater heater strings are provided with block valves and bypass piping to take units out of service for maintenance. All heaters are provided with tube-side safety valves to provide protection against possible overpressurization caused by heating of water trapped between closed isolation valves.

Extraction steam from the main turbine and cross-under piping is the heat source for the heaters (see Figure 10.3-10 and Figure 10.3-11). Automatic nonreturn valves are provided in the extraction steam lines for heaters that are not mounted in the condenser neck. The drains from low pressure heaters Nos. 1, 2, 3 and 4 are cascaded and eventually discharged to the condensers. The drains from low pressure heaters No. 5, which also receive the cascaded drains from high pressure heaters No. 6, are piped to the heater drain tank.

The condensate outlets from low pressure heaters No. 5 are manifolded in a common header, along with the discharge of the two vertical heater drain pumps, which account for about 30 percent of the total feedwater flow at full power. The heater drain pumps take suction from the heater drain tank. A branch line off the common condensate header, before the steam packing exhauster, connects to the individual heater drain pump suction lines to protect the heater drain pumps against low NPSH during transient conditions.

The common condensate header distributes the flow equally to the suction side of the two steam generator feed pumps, after passing through a flow measuring device located in each pump suction line. These are used to control the respective feedwater pump recirculation valves.

Condenser hotwell makeup is provided from either the Condensate Storage Tank or the Demineralized Water Storage Tanks upon receipt of a hotwell low level signal.

Demineralized water from the water treatment system can be introduced into the three condenser hotwells via the condensate storage tank or directly from the Demineralized Water System. The condensate storage tank is protected from freezing by a recirculation system which utilizes a heat exchanger and pump controlled by tank temperature. All condensate system connections to the condensate storage tank which are required for normal system operation are located above the tank level required for emergency plant shutdown (see Subsection 9.2.6).

The Condensate Polishing System (see Subsection 10.4.6) may be used during start-up to clean the condensate and feedwater systems prior to initiating secondary system flow to the steam generators. The system may remain on line during ramp-up to 100% power.

b. <u>Feedwater System</u>

The Feedwater System receives water from the Condensate System and a portion of the Heater Drain System, (specifically, drains from high pressure heaters No. 6, low pressure heaters No. 5, MSR shell drains and MSR reheater drains). The feedwater is pumped through the final stage of feedwater heaters (high pressure heaters No. 6) to the four steam generators.

The flow from the two 50 percent, variable speed, horizontal, turbine-driven steam generator feedwater pumps combines into a common header that feeds two parallel high pressure heaters No. 6. The outlets from the high pressure heaters No. 6 are combined into a common header for temperature equalization. From this common header, an individual feedwater line supplies each steam generator. The flow through each individual feedwater line is controlled automatically using two feedwater regulator valves, one designed for low power operation and one designed for high power operation. The regulator valves are pneumatically operated and are designed to fail closed on loss of air. The feedwater regulator valves are located at the south end of the Turbine Building.

The four feedwater lines exit the Turbine Building; two routed east of the Containment and two routed west, where they enter the east and west pipe chases. The east and west pipe chases house the feedwater isolation valves, which are located just upstream of the containment penetrations and connections to the steam generators. Immediately upstream of the feedwater isolation valve is a check valve and a flow measuring device. The emergency feedwater pump discharge connection to each main feedwater line is located between the containment penetration and the feedwater isolation valve.

An ultrasonic feedwater flow measurement system is installed in the common feedwater header just upstream of the feedwater regulating valves. This system is comprised of a 36-inch in line flow measurement spoolpiece and a local system processor panel. The ultrasonic flow measurement system provides high accuracy mass flow, feedwater temperature and feedwater pressure signals to the Main Plant Computer System via a digital communication link. These signals are utilized as inputs to the secondary power calorimetric calculation performed by the Main Plant Computer System.

Each steam generator feedwater pump has a recirculation control system which protects the pumps from damage at low loads by ensuring minimum flow. A feed pump gland seal water system regulates the flow of condensate from the condensate pump discharge header to the feed pump seals. Leak-off from the seals to the seal water receiver tank is returned to the condenser using a tank level controller which operates a control valve in the outlet line from the tank to the condenser.

Individual steam turbines drive the steam generator feed pumps. The turbine drives are of the dual admission type, and each is equipped with two sets of stop and control valves. One set regulates high pressure steam from the Main Steam System, and the other set regulates low pressure steam extracted from the crossover piping. Gland steam is provided to the turbines from the main turbine gland steam supply system. The exhaust steam from the steam generator feedwater pump turbine drives is condensed in main condenser shells A and C.

One steam generator startup feed pump is provided for each unit to provide normal requirements for startup, cooldown and no-load operation. The pump takes suction from the condensate storage tank and discharges through a startup heater into the high pressure feed water heater discharge piping. (The pump suction may also be aligned to the Demineralized Water Storage Tanks as a backup water source. Startup feedwater flow may also be directed through both high pressure feed water heaters in series. The Startup Feedwater System is described in Subsection 10.4.12. The condensate pumps can also be used for startup by using the steam generator feedwater pump bypass piping. A Sampling System is provided and connected to various points in the Condensate, Feedwater and Heater Drains Systems (see Subsection 9.3.2).

Condensate and feedwater chemistry is controlled as described in Subsection 10.3.5.

The chemical feed for the condensate and steam generator wet layup systems is stored in covered tanks for personnel protection.

Leakage in Condensate and Feedwater Systems through valve packings, pump seals, etc., will be collected by the floor drainage system. Makeup required because of leakage will be automatically controlled from the condensate storage tank or the Demineralized Water System.

10.4.7.3 Safety Evaluation

The requirements of 10 CFR Part 50 for containment isolation are satisfied by one feedwater isolation valve in each main feedwater line, located outside the Containment (see Subsection 6.2.4). These valves isolate the steam generators in the event of a steam generator tube rupture or feedwater line break, and prevent the continued input of feedwater to the Containment and resultant continued pressure increase in the event of a steam line rupture upstream of the main steam isolation valves. For analysis of feedwater system malfunctions that result in a decrease in feedwater temperature, increase in feedwater flow or loss of normal feedwater flow, see Subsections 15.1.1, 15.1.2 and 15.2.7.

With loss of main feedwater flow in the normal direction, the emergency feed pumps will supply sufficient flow to satisfy the primary system's cooling requirements (see Section 6.8). The connection for emergency feedwater on the main feedwater lines is downstream of both the feedwater isolation valve and the check valve which will be held closed by backpressure, to prevent flow in the reverse direction.

The circumstances associated with severe feedwater line water hammer and abnormal pipe movement in some PWR plants show consistently that the steam generator feed ring (where feedwater exits the bottom of the feed ring) was uncovered and drained prior to recovering with cold feedwater.

Seabrook station has a steam generator design (Westinghouse Model F, see Subsection 5.4.2) that enables the feed ring to be uncovered without subsequent drainage because feedwater exits the feed ring from the top through inverted J-tubes. This arrangement insures a flooded feed ring for all level transients within the steam generator, thereby eliminating water hammer. Feedwater piping from the feedwater isolation valve to the steam generator is routed to be self-venting, with the steam generator being the high point of the system.

Any failure in the nonsafety class portion of the Condensate and Feedwater Systems has no effect on the safety of the reactor, which can be shutdown in an orderly manner. A source of feedwater supply to the steam generators is required for decay heat removal from the reactor following a unit shutdown. In the event that the Condensate and Feedwater Systems are not available, the Emergency Feedwater System (see Section 6.8) provides the required emergency supply of feedwater. Normal reactor cooldown is accomplished by dumping steam to the main condenser. When the reactor coolant system temperature and pressure are reduced to or below the design values for the Residual Heat Removal (RHR) System, steam dump can be secured. The RHR design conditions (600 psig and 400°F) correspond to a secondary system pressure of 233 psig.

If for any reason the normal cooldown mode cannot be utilized, the reactor can be cooled down using the Emergency Feedwater System (see Section 6.8) and the power-operated steam generator relief valves.

10.4.7.4 Inspection and Testing

During preoperational testing, the various components of the feedwater, condensate, and associated portion of the heater drain system are functionally tested to verify their performance to the extent practical. The systems are operated during hot functional testing at normal no-load conditions as a final check prior to plant operation. The specific testing is described in Chapter 14.

In-service inspection of the Class 2 feedwater piping will be performed in accordance with ASME B&PV Code, Section XI.

10.4.7.5 Instrumentation

The instrumentation employed for monitoring the Condensate and Feedwater System performance consists of the following:

a. Each condensate pump suction and discharge pressure is locally indicated, and discharge header pressure is indicated at the MCB. Pump controls are at MCB. Normally, two pumps are running with one in standby. The standby pump runs automatically on low discharge header pressure or on trip of any one of the running pumps. Each pump is protected from overheating by being interlocked to pump cooling water flow. Each pump is protected from damage by individual recirculation flow on low pressure. The steam packing exhauster recirculation valve opens on low flow in the condensate discharge header to provide minimum flow protection for the condensate pumps and closes on low header pressure to prevent pump run out and maintain feed pump NPSH.

Pump trip, bearing and motor winding high temperature, and low cooling water flow are alarmed in the control room.

b. The condenser hotwells are interconnected, and each hotwell is equipped with a level transmitter. The level signals from the three hotwells are processed by an auctioneering circuit which selects the lowest value for the hotwell level control system. The level is maintained within a preselected control band by admitting makeup water via the makeup control valve from the condensate storage tank or the Demineralized Water System. Low hotwell level is alarmed in the control room.

c. All feedwater heaters are provided with level controllers and drain control valves for normal drain disposition. High level drain control valves are provided for heaters Nos. 2, 3 and 4 to discharge into the condenser. Low, high and high-high levels are annunciated in the control room. High-high level actuates nonreturn and isolation valves in the extraction steam lines, or condensate isolation valves as applicable, to prevent water carryover to the turbine. Valve position monitoring lights are provided at the MCB for the feedwater heaters spill valves to the condenser and the extraction steam nonreturn and isolation valves.

Gauge glasses are provided for local direct observation of heater liquid levels.

Feedwater heater inlet, outlet and drain temperatures and shell side pressures are monitored and used for the performance computation.

d. The two heater drain pumps are controlled from the MCB. Suction and discharge pressure are indicated locally, and flow to the feed pump suction header is indicated in the control room. Instruments monitor heater drain tank level for indication, control, interlocks, and alarms. The heater drain tank is provided with level controllers which regulate the heater drain pump discharge, recirculation and condenser spill valves. The condenser spill valve is also opened by a high level switch. A high-high level switch initiates turbine water induction protection. Heater drain pump trip, motor bearing, and motor winding high temperatures are alarmed in the control room. The 10-inch spill valve opens on high level.

e. Steam generator feed pumps are provided with local suction and discharge pressure gauges. The indications of these pressures for the steam generator feed pumps are also provided at the MCB.

A flow element is provided in the feedline to each steam generator. Pairs of taps provide for two independent metering measurements from the flow element. The feedwater flow measurements are indicated in the control room and utilized in the steam generator level control system. The details of the safety-related display instrumentation are presented in Section 7.5. The details of the steam generator water level control system are presented in Subsection 7.7.1.7. Manual-auto stations for all the feedwater control valves are provided at the MCB.

For computer trending, separate flow measuring loops utilizing ultrasonic flow transmitters are provided in each feedline to the steam generators.

To ensure that minimum flow requirements are met, a recirculation valve has been provided for each pump, controlled by the suction flow measuring venturi.

f. The steam generator feed pump turbine provides variable speed feed pump operation. The variable speed feed pump control system is described in Subsection 7.7.1.7. Feed pump bearing high temperatures are alarmed in the control room.

10.4.8 Steam Generator Blowdown System

10.4.8.1 Design Bases

The Steam Generator Blowdown System is designed to limit the concentration of dissolved and suspended solids in the shell (secondary) side of the steam generators, which are introduced into the steam generators through the feedwater. Removal of these solids minimizes chemical deposition on steam generator tube surfaces, thus limiting the reduction in heat transfer capability, as well as reducing the rate of steam generator tube corrosion. The potential sources of solids in the steam generators can be any, or a combination of, the following:

a. Chemical additions to the secondary system for corrosion control

b. Reactor coolant boric acid due to primary to secondary leakage through the steam generator tubes

c. Secondary system corrosion products

d. Seawater, due to leakage through the condenser tubes into condensate returning to the steam generator

e. Impurities in condensate makeup water.

The unit has an independent steam generator blowdown and sampling system. Initial processing (depressurization and cooling) of steam generator blowdown liquid is accomplished using the flash tank and bottoms coolers. If the radioactivity in the blowdown liquid is insignificant, then the liquid is returned to the Condensate System after processing through demineralizers, or discharged directly to the Circulating Water System.

The method to process radioactive secondary liquid from the steam generators is to direct steam blowdown flash tank bottoms cooler discharge to the floor drain tanks. If no secondary pressure is available, the steam blowdown and wet lay-up pumps can be used. From the floor drain tanks, processing takes place using the installed vendor system (WL-SKD-135) to the waste or recovery test tanks. (Reference Subsection 11.2.2.1.)

The unit has the continuous blowdown capability of 400 gpm (100 gpm per steam generator). This very high flow rate is used when high feedwater contaminant concentrations require such a blowdown rate. This high rate of blowdown is expected to occur at startup, after a unit shutdown in which maintenance has taken place on the secondary side of the plant. A high rate of blowdown may also be required at other times to control chemistry conditions. In the flash tank, 30 percent of this blowdown is flashed to steam, leaving 70 percent to be processed by the demineralizers, or discharged directly to the Circulating Water System.

Blowdown may be discharged directly to the Circulating Water System when cleanup capabilities are unavailable, as long as the limits of 10 CFR 20 (Appendix B, Table 2, Column 2 - instantaneous release) and 10 CFR 50 Appendix I (average annual release) are not exceeded.

Isolation valves are provided outside the Containment to close all blowdown lines on a "T" signal, Auto emergency feed pump start, or on a HELB signal.

Piping and valves from the steam generator up to and including the containment isolation valves, are Safety Class 2, and are designed to ASME Section III, Code Class 2 (see Section 3.2). Other piping and equipment in the steam generator blowdown systems are nonnuclear safety class, and are designed to ANSI B31.1.B-1971 and ASME Section VIII.

Blowdown water chemistry control parameters are established using the EPRI Secondary Water Chemistry Guidelines.

10.4.8.2 System Description and Operation

a. Normal Operation

Figure 10.4-10, Figure 10.4-11, Figure 10.4-12 and Figure 10.4-13 are flow diagrams of the system. Each of the four steam generators is provided with a bottom blowdown connection on the secondary side above the tube sheet. During normal operation, each steam generator undergoes continuous blowdown with the blowdown water passing through a containment isolation valve, flow meter, and system valves. A small quantity of blowdown is continuously drawn off automatically into the sample system through a sample heat exchanger for monitoring of the activity in the blowdown. If the activity in the blowdown discharge is higher than allowable (see Subsection 9.3.2), blowdown is automatically secured. The blowdown liquid then flows through a manual control valve which establishes the blowdown rate. Some of the liquid flashes upon passing through the control valve, and two-phase flow then enters the flash tank. There, approximately 30 percent of the blowdown flow exits the top of the tank as saturated steam. The remaining 70 percent exits the bottom of the tank as saturated water. The flash tank operates at 70 psia. Steam and water leaving the flash tank are directed as follows depending upon the existence and size of primary to secondary leakage.

1. If No Primary to Secondary Leakage Exists

   Flash tank steam will normally be directed back to the No. 3 feedwater heater or to the main condenser for that unit, or can be exhausted to the atmosphere if the heater and condenser are not available. Liquid from the flash tank will be cooled in the flash tank bottoms cooler and directed through a radiation monitor and flow totalizer into demineralizers. The demineralizers will remove chemical contaminants and radioactivity (as explained later), and the liquid can be transferred back to the condenser. Filters upstream of the demineralizers prevent the transport of corrosion products into the beds. An alternate path to discharge the blowdown liquid to the environment is available, that is, into the service water system discharge line via the Waste Liquid System (see Section 11.2). Flow into the flash tank under these circumstances can vary from 20 gpm (5 gpm per steam generator) to 400 gpm (100 gpm per steam generator).

2. If Primary to Secondary Leakage Exists

The early indication of a primary to secondary leak may be observed as a result of routine grab sampling (at very low leak rates) or on any of the following radiation monitors:

- Condenser air removal, RM 6505
- Blowdown Flash Tank, RM 6519
- Individual Blowdown line, RM 6510-6513 (see Subsection 9.3.2).

Each of the setpoints on these radiation monitors is established, using station procedures, such that plant personnel can detect indications of small leaks, during the early phases of the leak.

If activity in excess of the alarm setpoint is measured on the Flash Tank RM, the blowdown system will automatically isolate. The individual monitors on the blowdown lines will provide indication of which steam generator is leaking. New RM setpoints may be established to continue system operation, once a steady state has been achieved.

EPRI PWR Primary to Secondary Leak Guidelines identifies the significance levels of primary to secondary leaks. The operational plan for how to continue plant operation when leakage exists is located in plant procedures for management overview as well as individual departmental procedures for increased monitoring.

These administrative and operational procedures dictate how the steam generator blowdown liquid will be processed during a primary to secondary leak. The following options are available to operations personnel:

- Continue to use the blowdown demineralizers as in normal operation. This requires additional radiation monitoring in the Demineralizer Building to ensure general area dose rates are within Zone II limits, as well as increased grab sampling frequency to closely monitor the leak rate change.
- Use the Waste Liquid System to treat all or part of the flashed liquid, bottoms or both, from the blowdown flash tank. This may require a reduction in blowdown flow rate.

- Discharge to the environment within the confines of 10 CFR 20 and Appendix I of 10 CFR 50 limits.

If the activity in the flash tank steam is low, the steam may be allowed to return to the No. 3 feedwater heater for reuse in the plant without processing. Flashed steam is not intentionally released to the atmosphere. If significant quantities of radionuclides are contained in the flash tank distillate, the liquid may be processed through the flash steam condenser to the waste test tanks. This limits the flow from the four steam generators to approximately 75 gpm as the cooler capacity is only 25 gpm.

Processing of the steam generator flash tank bottoms liquid through the Waste Liquid System will also necessitate a total blowdown flow limit of 71 gpm for all four steam generators (the vendor-operated Liquid Waste Treatment System capacity for process flow is 50 gpm). The basis for this flow is further discussed in Appendix 11A.

b. <u>Operation With the No. 3 Feedwater Heater or Main Condenser Not Available</u>

When the No. 3 feedwater heater or main condenser for the unit is not available, system flows are realigned as follows:

1. If No Primary to Secondary Leakage Exists

Steam from the flash tank may be directed to the flash steam condenser/cooler and then pumped to the waste test tanks in the Liquid Waste System (see Section 11.2). Although under these conditions this liquid would not contain radioactivity, the contents of the waste test tank would be sampled before discharge to the service water system discharge, since the tanks could contain other processed liquid waste.

If blowdown flow requirements result in steam flow from the flash tank above the capacity of the flash tank condenser/cooler (which can process steam only equivalent to a maximum of 25 gpm of water), an additional path is provided to discharge the flash tank steam via the atmospheric exhaust.

Water from the flash tank will be handled in the same manner as in Subsection 10.4.8.2a.1.

2. If Primary to Secondary Leakage Does Exist

Steam from the flash tank is handled in the same manner as explained in b.1. However, the blowdown capacity is limited as explained in Subsection 10.4.8.2a.2. Radioactive steam is not charged to the atmosphere (see Subsection 10.4.8.2a.2).

Liquid from the flash tank will be handled in the same manner as explained in Subsection 10.4.8.2a.2.

c. Cooling Water Shortage Case

During low heat removal capability of the Primary Component Cooling Water (PCCW) System, steam generator blowdown capacity may be limited. Such circumstances may arise during heat treatment of service water system tunnels and initial phases of plant cooldown for a short duration. Additionally, on a "T" signal, cooling water to the Waste Processing Building is isolated. However, the evaporators are automatically shutdown on a "T" signal.

10.4.8.3 Component Design

a. Flow Control Valves

Initial blowdown liquid flashing will occur due to the pressure drop across the flow control valve associated with each steam generator's blowdown line. The flow control valves are sized to pass zero to 100 gpm flow and are designed to minimize noise, vibration and erosion.

b. Blowdown Flash Tank

The blowdown flash tank is sized to permit 400 gpm (200,000 lbm/hr) two-phase flow. Flow enters the tank through four tangential nozzles. A stainless steel wear plate is used to prevent tank erosion. Steam exiting the tank must pass through a mesh style deentrainment separator (demister pad) to limit carryover. The vessel is carbon steel and will operate at 70 psia with overpressure protection provided to limit any pressure excursion while passing maximum steam flow.

Vessel operating pressure is used to force water flow to the demineralizers, or to the service water system discharge piping. Vessel operating pressure is maintained by pressure control valves in the steam line or cooling water line to the flash tank steam condenser, depending upon mode of system operation. Operating level is maintained by one of two level control valves in the liquid discharge line.

c. Flash Tank Bottoms Coolers

The flash tank bottoms coolers are shell and tube heat exchangers sized so that flashing will not occur downstream under maximum blowdown conditions. Each cooler will handle 50 percent maximum flow.

d. Flash Steam Condenser/Cooler

The flash steam condenser is a shell and tube heat exchanger sized to condense approximately 11,500 lb/hr steam. Cooling water flow (PCCW) through the condenser is regulated to maintain 70 psia in the flash tank. The subcooling section at the bottom of the condenser cools the condensate to approximately 120°F.

e. Flash Tank Distillate Pumps

Two 50 gpm (nominal) centrifugal pumps are provided to pump liquid from the flash steam condenser to the main condenser or waste test tanks depending upon the system mode of operation. These pumps can also be used to evacuate the flash tank through a separate valve (normally kept closed) if necessary.

f. Steam Generator Blowdown Evaporators

Each of the calandria blowdown evaporators has the process liquid on the tube side and heating steam on the shell side. The condensers and coolers with the evaporators subsystem are similar to those with the Boron Recovery System (Subsection 9.3.5) and the Liquid Waste System (Section 11.2). However, the heating element is contained within the evaporators for the Steam Generator Blowdown System, whereas it is separate for the Boron Recovery System.

g. Demineralizers

The unflashed liquid from the flash tank is cooled and directed to demineralizers. The three beds are configured to be compatible with secondary system chemistry. The effluent quality will be in accordance with EPRI Secondary Water Quality Guidelines.

h. Booster Pumps

The booster pumps are required to pump the liquid from the flash tank through heat exchangers and demineralizers into the Condensate System. The booster pumps are especially required to overcome the hydraulic resistance in the downstream circuit at high flow rates.

i. Steam Generator Blowdown Recovery (SGBR) Heat Exchanger

The heat exchanger cools down the unflashed liquid from the flash tank to less than 110°F before it enters the demineralizers. This temperature is required to maintain the characteristics of the demineralizer resins.

j. Iron Filters

The iron filters are located upstream of the demineralizer beds and serve to prevent the transport of corrosion products into the beds, which can reduce bed efficiency. The filters comprise two disposable cartridge housings connected in a duplex piping arrangement. This configuration allows for continuous SB operation during cleaning of a filter.

Table 10.4-2 lists the design and operating conditions of the steam generator blowdown system components.

10.4.8.4 Safety Evaluation

The Steam Generator Blowdown System has no safety function, nor is its performance required during or after an accident. Accordingly, the system is designed as nonnuclear safety (NNS), non-Category I. However, from the connection on the steam generator to the containment isolation valves, just outside the Containment, the system is Safety Class 2 and seismic Category I. Some parts of the system may contain radioactive fluids, depending on the presence of steam generator tube leakage. Closure of the blowdown lines is accomplished by air-operated valves that close on high pressure or level in the flash tank or startup of the emergency feed pumps signal (Refer to Section 6.8). These valves are closed on loss of air pressure or electrical power to the solenoids, thus assuring the performance of the safety function under all failure conditions. Liquid discharge from the flash tank is automatically terminated on a high radiation signal in the discharge line or in the sample withdrawn from each steam generator.

Electrical power is provided at 460 volts, 3 phase, 60 Hz. Emergency electrical power is not provided. Each combination motor-starter incorporates thermal elements to protect against overloads and a magnetic molded case circuit-breaker to protect against faulted conditions.

Monitoring devices are provided to measure conditions of pressure, temperature, radiation, conductivity, flow, and liquid levels to ensure that the system is operated safely and within design limits. The design bases listed in Subsection 10.4.8.1 are met using the flash tank, demineralizer, and Waste Liquid System capabilities. A failure analysis is presented in Table 10.4-3.

10.4.8.5 Test and Inspections

Prior to initial plant startup, the Steam Generator Blowdown System is tested to verify proper operation of system equipment.

During normal plant operation, calibration of the radiation monitors (see Section 11.5) and surveillance testing of the containment isolation valves will be performed in accordance with Technical Specification requirements.

10.4.8.6 Instrumentation and Control

a. Flash Tank Subsystem

1. Containment Isolation Valves

These valves are controlled from the MCB. The outboard valves close automatically on a "T" signal, emergency feed pumps running, or a HELB signal (see Subsection 7.6.10). Flow of individual blowdown lines is indicated at the MCB and locally near the blowdown throttle valves.

2. Flash Tank Instrumentation

Level and pressure are indicated locally and at the MCB. Temperature of the tank is indicated at the MCB. High and low level, as well as hi and hi-hi pressure is alarmed at the MCB.

3. Flash Tank Control

(a) Pressure Control

In normal operation, the pressure of the tank is maintained at 70 psia by throttling the pressure control valve in the steam line to the condenser. During this time the line to the atmosphere is kept closed. When the main condenser or No. 3 feedwater heater is not available, the flash tank is aligned to the flash steam condenser. Pressure control is then achieved by throttling the cooling water valve at the outlet of the flash steam condenser. In case the main condenser, No. 3 feedwater heater, and flash steam condenser are not available, the flash tank steam is processed to atmosphere in a controlled manner.

(b) Level Control

In normal operation, the pressure of the tank is maintained at 70 psia by throttling the pressure control valve in the steam line to the condenser. During this time the line to the atmosphere is kept closed. When the main condenser or No. 3 feedwater heater is not available, the flash tank is aligned to the flash steam condenser. Pressure control is then achieved by throttling the cooling water valve at the outlet of the flash steam condenser. In case the main condenser, No. 3 feedwater heater, and flash steam condenser are not available, the flash tank steam is processed to atmosphere in a controlled manner.

When the flash tank distillate is aligned to the main condenser or waste test tank (WTT), which may be required to drain the steam generators, the level of the tank is controlled by throttling the level control valve at the common discharge header of the flash tank distillate pumps. High level will alarm and then isolate the discharge from the steam generators to the flash tank.

4. Flash Steam Condenser

The level of the flash steam condenser is maintained by throttling the control valve at the common discharge header of the flash tank distillate pumps. Temperature of the distillate is monitored by the plant computer. High and low level are alarmed in the control room.

5. Flash Tank Distillate Pumps

These pumps are used in two different stages of plant operation:

(a) Draining the steam generators via the flash tank, transferring flash tank concentrates to waste test tanks (WTT).

(b) Transferring the distillate from flash steam condenser to WTT or main condenser.

These pumps are controlled from the MCB. In both modes of operation, only one pump is run at a time. In mode (a) the pump is started manually and is stopped automatically on low-low flash tank level. In mode (b), the starting of the aligned pump is automatically initiated by high level in the distillate condenser and stopped manually. When pressure in the flash steam condenser reaches normal operating condition, the distillate circuit is manually aligned to the main condenser (or WTT) and the pump is stopped and isolated. Pump trip is alarmed in the control room. Rotation of pump duty is administratively controlled.

6. Flash Steam Condenser Vent Valve

The valve remains normally closed, and opens automatically at predetermined pressure and closes on high-high pressure to prevent ingress of steam in the vent gas system. The valve can be manually opened from the MCB by overriding pressure interlocks.

7. Radiation Monitoring

The flash tank liquid discharge to the environment is measured continuously and recorded and totalized at the MCB. When the discharge is complete, the totalized flow reading is recorded and forwarded to the chemistry department. Chemistry in turn utilizes this data to satisfy the monthly discharge surveillance requirements of the Technical Requirements Manual. This stream is continuously monitored for radioactivity and is isolated on high radiation and on high flash tank concentrates discharge temperature. High radioactivity is alarmed locally and at MCB. Additionally, high radioactivity in the blowdown sample lines isolates this flash tank liquid discharge stream. All these high radioactivity interlocks, with the exception of high radiation and temperature flash tank concentrate discharge stream, can be manually overridden. This flash tank liquid discharge radiation monitor is reset by flushing the sampling line and draining the trapped liquid to the floor drain tanks. The high temperature interlock is reset by re-establishing cooling water flow through the flash tank bottoms cooler.

b. <u>Evaporator Subsystem</u>

The evaporator subsystem, of the Steam Generator Blowdown System, is not immediately available for use. Prior to any anticipated startup of this subsystem, plant management would be notified to plan for any training, procedure updates, and pre-operational testing required.

Control and instrumentation for all these evaporators are located at the waste management system (WMS) control panel in the Waste Processing Building. Each evaporator can be individually controlled. Normally, the evaporators operate automatically. The initial starting is, however, manual via a master selector switch.

The prime objective of the evaporator control system is to maintain the level constant by manipulating the feed and the auxiliary steam. This is achieved by controllers at the WMS control panel. Controllers also maintain auxiliary control loops, such as evaporator pressure, distillate and concentrates cooling water temperature, at stable values. In case any one of these controllers are lost, a manual control with aid of backup instrumentation maintains evaporator operation. Additionally, instrumentation for feed, temperature, pressure and level of evaporation is provided at the WMS control panel.

The following conditions are alarmed on the local control panel:

1. High, high-high, low pressure and low-low level in the evaporators
2. High and low level in the distillate condensers
3. High vent temperature in the distillate condensers
4. High and low temperature of concentrate outlet at bottoms coolers
5. High distillate cooler outlet temperature and conductivity
6. High auxiliary steam flow
7. Pumps trip
8. Evaporator bottoms pump seal water pressure low.

   All low, low-low level, temperature and pressure alarms are suppressed in shutdown mode.

c. Demineralizer Subsystem

The demineralizer subsystem, along with its regenerative system and controls, is located in a separate room next to the Waste Processing Building. Cooled unflashed liquid is directed to the demineralizer. If the liquid temperature is higher than a predetermined value. The service valve will be closed and the liquid will bypass the demineralizer skid (SB-SKD-95). The influent and effluent conductivities of the demineralizer are measured by conductivity cells to monitor bad performance.

Regeneration is initiated by push-button and carried forward automatically until completed. Units are returned to service manually. Since the acid and caustic systems are the same for all mixed beds, interlocks are provided to allow one unit at a time to go on regeneration. The SG blowdown regenerate will be monitored for radioactivity and may be processed through the Liquid Radwaste System. If the radioactivity in the regenerate solution is determined to be of such low concentration and total quantity that the Technical Specification dose limits for demonstrating compliance with the "As Low As Reasonably Achievable" of 10 CFR Part 50, Appendix I can be met, the regenerate solution may be discharged to the Circulating Water System through the liquid waste discharge header which includes a radiation monitor that will terminate the release if higher than expected activity is detected.

Level loops indicate the levels of the acid and caustic tanks, and control the regeneration process. Low level in the acid or caustic tank prevents regeneration, as does high level in the waste holdup sump.

The contents of the waste holdup sump are sampled to insure that the radionuclide concentration does not exceed the limits of the Offsite Dose Calculation Manual (ODCM). If it does, the contents of the sump are discharged to the chemical drain treatment tanks for processing as radioactive liquid waste. If it does not, the contents of the sump are discharged to the liquid waste systems (LWS) test tank discharge header upstream of the LWS test tank discharge monitor (see Subsection 11.5.2.1).

The following conditions are alarmed on the local control panel:

1. High inlet temperatures to demineralizers

2. High differential pressure on demineralizers

3. High demineralizer influent and effluent conductivity

4. High waste holdup sump level

5. Pumps trip

6. Demineralizer skid service air pressure low.

10.4.9 Auxiliary Feedwater System

A typical pressurized water reactor plant includes an Auxiliary Feedwater System that normally operates during startup, hot standby, and hot shutdown. In addition, it also functions as an emergency heat removal system to transfer heat from the primary system when the Main Feedwater System is not available.

For the Seabrook plant, the functions of the Auxiliary Feedwater System are fulfilled by the startup feed pumps during startup, hot standby and hot shutdown conditions (see Subsection 10.4.12) and the Emergency Feedwater System during loss of normal feedwater flow (see Section 6.8).

10.4.10 Secondary Component Cooling Water System

10.4.10.1 Design Bases

The Secondary Component Cooling Water (SCCW) System is a nonsafety-related system and has no safety design basis. The following design criteria are applicable to this system:

a. The system is designed to remove heat from the turbine-generator accessories and other auxiliary equipment located in, and adjacent to, the Turbine Building. This heat is transported by the recirculating water of the SCCW system to the SCCW heat exchanger or auxiliary SCCW heat exchanger, where it is transferred to the Service Water System.

b. The system is designed for a maximum service water temperature of 80°F. The minimum service water temperature is 35°F. Refer to the Service Water System (Subsection 9.2.1) for further information.

c. The system is designed to provide a maximum secondary component cooling water temperature of 95°F to the equipment coolers. However, the actual cooling water temperature is dependent on the varying SCCW heat loads and the service water inlet temperature.

d. The following codes and standards are applicable for the system:

1. American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section VIII, Division I, Unfired Pressure Vessels

2. Heat Exchanger Institute (HEI) Standards for Heat Exchangers

3. Tubular Exchanger Manufacturers Association (TEMA) Standards, Class "C"

4. American Society for Testing and Materials Standards for Centrifugal Pumps

5. Hydraulic Institute Standards for Centrifugal Pumps

6. American National Standard Institute (ANSI)

7. Power Piping Code B31.1

10.4.10.2 System Description

The Secondary Component Cooling Water System, as indicated on the system flow diagrams, Figure 10.4-14 is designed as a closed loop through the secondary component cooling water pumps, heat exchangers and piping to and from the turbine generator accessories and auxiliary equipment. A head tank is also included to provide makeup water and to act as a surge tank for the system.

The turbine generator accessories and other auxiliary equipment are equipped with auxiliary coolers that have been designed for a maximum cooling water (SCCW) temperature of 95°F. The actual temperature of the water supplied to these coolers will vary from 85°F to 95°F, depending on the SCCW system heat load and service water inlet temperature. This temperature range for the recirculating water will be maintained by a thermally controlled bypass around the SCCW heat exchanger. Uncooled recirculating water will be piped through the bypass and allowed to mix with the SCCW heat exchanger cooled water. A sensor located downstream of the mixing point will be set to maintain a minimum SCCW temperature of 85°F. These temperature controls are on the SCCW side, rather than on the service water side, to avoid interaction with the service water pumps and the Primary Component Cooling Water System.

Each component auxiliary cooler has inlet and outlet valves for isolation and throttling during initial startup. The secondary headers to the various component auxiliary coolers have branch isolation valves to isolate these headers from the main header for maintenance.

The system is filled with demineralized water from the demineralized water makeup system. A corrosion inhibitor is added to the SCCW system through the chemical feed tank, located near the SCCW pumps. In addition the system is provided with a bypass filter to remove foreign particulates from the water.

The system contains three horizontal centrifugal pumps. Only two pumps are required for full load operation, with the third pump on standby. Two main heat exchangers are supplied. These heat exchangers are horizontal, tubular, counterflow, two-pass, shell-and-tube, with fixed tube sheets and removable covers. The shell is constructed of carbon steel; the tube sheets are carbon steel with 90-10 copper nickel cladding. All internal carbon steel surfaces on the tube side of the exchangers will be protected against seawater corrosion by a neoprene lining. Tubes are fabricated of 90-10 copper nickel due to its resistance to seawater corrosion. Two smaller auxiliary heat exchangers are installed in parallel to the main heat exchangers. The auxiliary heat exchangers are sized for very low loads, such as during outages, up to approximately 5 percent power. These heat exchangers are horizontal, shell and tube, counterflow, single pass. The shell is constructed of carbon steel, which will be exposed to the SCCW flow. The tubes and tubesheets are 90-10 CuNi for corrosion resistance from seawater. The channel and cover are coated cast iron.

10.4.10.3 Safety Evaluation

The design and operation of the SCCW system has no safety-related function, and no safety-related evaluation is required. However, since the SCCW system is cooled by the Service Water System, it will be affected to a degree by changes in the Service Water System. The supply of service water to the SCCW heat exchanger will be isolated upon receipt of either a safety injection signal, a cooling tower actuation signal, or a loss of offsite power (see Subsection 9.2.1).

10.4.10.4 Inspection and Testing Requirements

Prior to initial plant startup, the SCCW system is operationally tested to insure that it will perform properly.

10.4.10.5 Instrumentation

a. SCCW Pumps

These pumps are controlled from the MCB. Normally, two pumps are running, with the third pump in standby. A loss of either of the running pumps will automatically start the third pump. Once started, this pump will continue to run until secured by plant personnel.

The pump discharge header pressure is indicated in the control room. Low discharge header pressure, as well as the loss of either pump, is alarmed in the control room. Pump suction and discharge pressure is locally indicated.

b. SCCW Head Tank

Tank level is locally indicated by a level gauge. The low and high level are alarmed in the control room. The level of the head tank is controlled automatically by a level controller that regulates the flow of the demineralized makeup water supply.

c. SCCW Heat Exchangers

Temperature measured at the discharge of the heat exchangers is used to control SCCW temperature by blending the cooled water through the heat exchangers and the warm water through the bypass line. The temperature controller is local. High and low heat exchanger discharge temperatures are alarmed in the control room.

Each heat exchanger's inlet and outlet temperature is locally indicated, and shell pressure of each heat exchanger is also locally provided.

d. Miscellaneous Heat Exchangers

For miscellaneous heat exchangers, outlet temperature and inlet and outlet discharge pressures are locally indicated.

Individual local temperature controllers are provided to control the SCCW flow through the various heat exchangers serviced by the SCCW system. SCCW flow to the air compressor is isolated in the event of a loss of offsite power.

e. Radiation Monitoring

No radiation monitoring is required in the SCCW system, since it does not service any heat exchanger used in systems carrying primary coolant or other radioactive fluid systems.

10.4.11 Auxiliary Steam System

10.4.11.1 Design Basis

The Auxiliary Steam System provides low pressure saturated steam for various plant components and systems, satisfying the following requirements:

a. Building heating and miscellaneous plant requirements.

b. During plant operation and shutdown, auxiliary steam is supplied to the steam generator blowdown evaporator, the boron recovery and waste processing evaporators, letdown and boron recovery degasifiers and various tanks. During plant shutdown, the auxiliary steam requirements for the above systems may exceed the capacity of the auxiliary boilers, requiring the systems to operate at reduced capacity.

c. During plant startup, auxiliary steam is used for turbine gland sealing.

The Auxiliary Steam System is designed in accordance with the Power Piping Code, ANSI B31.1. The auxiliary boilers are designed in accordance with ASME Code Section I, Power Boilers. The deaerator and blowdown tank are designed in accordance with ASME Code Section VIII, Division 1. The Safety Class 3 portion of the system is designed to ASME Code Section III, Subsection ND, Class 3 Components.

10.4.11.2 System Description

The Auxiliary Steam System shown on Figure 10.4-16 is comprised of the following equipment:

a. Two package boilers, each rated at 80,000 lbs/hr of saturated steam at 150 psig, complete with forced draft fans, breeching and common stack

b. One 170,000 lb/hr de-aerating heater with storage tank

c. Three motor-driven boiler feed pumps rated at 180 gpm each (one spare)

d. Triplex fuel oil pumping set (one spare pump)

e. One blowdown tank, one fuel oil storage tank and two skid-mounted chemical feed units

f. Interconnecting piping

g. Safety-related PAB isolation valves.

The Auxiliary Boiler System is shown on Figure 10.4-15 and the Auxiliary Steam Condensate System is shown on Figure 10.4-17.

During plant start-up excess condensate from auxiliary steam used for turbine gland sealing and shell warming is returned to the Auxiliary Steam Condensate System.

Feedwater from the de-aerator is pumped to the auxiliary boilers and evaporated. Steam is piped to building heating units and operating equipment. Building heating system condensate and the equipment steam and/or drains are added to the main cycle or returned to the auxiliary boiler de-aerator.

The boilers are fired by No. 2 fuel oil. Steam atomization is used during normal boiler operation. Air is the atomizing medium for startup.

During normal plant operation, a branch line from main steam lines can supply the required steam to the Auxiliary Steam System. A pressure-reducing valve reduces the main steam pressure to that equivalent to the output of the auxiliary boilers. The pressure reducing station is closed during station startup, when the auxiliary boilers furnish the required steam.

The auxiliary steam PAB isolation valves are operable from the MCB and close automatically on a HELB signal.

10.4.11.3 Safety Evaluation

In the event that any of the systems being supplied with auxiliary steam become contaminated, the auxiliary condensate will in turn become contaminated. To prevent the auxiliary boiler from becoming contaminated, each unit is equipped with a radiation monitor which samples the condensate in the condensate return line. If the radionuclide concentration exceeds a preselected level, the monitor automatically terminates the condensate return. This device is described in greater detail in Subsection 11.5.2.1 and Table 11.5-1.

The operation of the Auxiliary Steam System is not required under emergency conditions. However, on a high energy line break in the PAB, safety-related valves isolate this system.

10.4.11.4 Tests and Inspections

The Auxiliary Steam System is hydrostatically tested in accordance with ANSI B31.1 requirements, and functionally tested to verify control functions. Safety Class 3 portions of the system will be hydrostatically tested in accordance with ASME Code III, Subsection ND, Class 3 Components.

The system is functionally tested to ensure proper operation.

10.4.11.5 Instrumentation and Control

Instrumentation and control associated with the Auxiliary Steam System are located primarily at the auxiliary boiler control (ABC) panel in the Administrative Building. The principal subsystems are identified as follows:

a. Combustion Control: This subsystem provides for automatic control of fuel and combustion air. Automatic correction of fuel-air ratio is provided by O_2 measurement of the flue gas and is used to bias the demand for air flow.

b. Boiler Safety: This subsystem provides for safe operation of the boiler, where a sequence of purging, operation of the fuel system and ignition of burner flame is coordinated in a manner which will preclude any potentially explosive situation, thereby ensuring boiler safety at all times.

c. Auxiliary Boiler: This subsystem utilizes a two-element control system which regulates feedwater flow as a function of steam flow demand. Drum level signal corrects steam-feedwater flow mismatch, and adjusts feedwater flow accordingly. Pressure is indicated locally and remotely at the ABC panel. Flue gas temperature, air velocity, oxygen concentration in flue gas, steam flow and drum level are recorded at the ABC panel. Deviant parameters are alarmed at the ABC panel, and are grouped together in the control room as an "auxiliary boiler trouble" alarm.

d. Boiler Feed Pumps: These pumps are controlled from the ABC panel, are sequenced to start automatically on selected pump, and are interlocked with the de-aerator tank level.

e. Auxiliary Steam Distribution: Auxiliary steam distribution to branch lines is reduced in pressure and fed to the plant for various uses. Local pressure indication is available at each branch line.

10.4.12 Startup Feedwater System

10.4.12.1 Design Bases

The Startup Feedwater System is a nonsafety-related system and, therefore, has no safety design bases. The system is designed to:

a. Provide a supply of feedwater to the steam generators during plant startup to fill and pressurize the steam generators

b. Provide sufficient feedwater flow to the steam generators to allow steam to be utilized for turbine plant warmup and turbine operations up to 5 percent of full load, prior to operation of the main feed pumps

c. Provide sufficient feedwater flow to the steam generators to allow the reactor plant to operate at low load (hot standby) while the turbine plant is not operating

d. Minimize thermal transients in the steam generator feedwater lines

e. The system is designed to the following codes and standards:

   1. ANSI B31.1, Code for Power Piping

   2. Hydraulic Institute Standards.

10.4.12.2 System Description

The Startup Feedwater System consists of a startup feed pump and interconnecting piping. For a diagram of this system, see Figure 10.4-8 and Figure 10.4-9.

The startup feed pump is a horizontal, centrifugal, motor-driven pump which takes suction from the condensate storage tank and discharges into the main feedwater piping at the discharge of the main feed pumps. If the main condenser is not under vacuum, the startup feed pump can also take suction from the condenser hotwell. (If desired, the pump suction may also be aligned to the Demineralized Water Storage Tanks as a backup water source.) Provisions for an auxiliary steam supply to the No. 6 heaters and to the startup heater allow a degree of feedwater heating to minimize thermal transients in the steam generator feedwater lines.

During operation of the Startup Feedwater System, flow to the steam generators is controlled by the feedwater control bypass valves, either manually or automatically, using a steam generator level signal.

The startup feed pump (SUFP) motor can be powered by nonemergency Bus 4 or emergency Bus E5. For additional electrical design details, refer to Subsection 8.3.1.1.b.9.(a).

During no-load and low load plant operations, the SUFP is aligned to non-emergency Bus 4 to provide its startup and shutdown functions. After the SUFP completes its startup function, its power supply will be transferred to emergency Bus E5 as plant power is increased. The SUFP will remain aligned to Bus E5 during 100% power operation. As power is decreased in preparation for a plant shutdown, the SUFP power supply will be transferred back to Bus 4. If the SUFP is required to perform its EFW contingency function while aligned to Bus 4 coincident with a loss of offsite power, it will have to be manually transferred to Bus E5 and manually started.

Valves FW-V163 and FW-V156 are normally closed, but can be opened to permit the startup feed pump to supply SG feedwater via the EFW supply headers. These valves are equipped with motor operators which are powered by a Bus E5 power supply and are controlled from the main control board.

10.4.12.3 Safety Evaluation

The Startup Feedwater System is not part of the Engineered Safety Systems, and is not required for maintenance of plant safety in the event of an accident.

10.4.12.4 Tests and Inspection

The system will be performance tested prior to initial plant startup.

10.4.12.5 Instrumentation

Control of feedwater flow to the steam generators during startup feedwater operation uses a portion of the same narrow-range steam generator level channels used during normal feedwater operation.

The startup feed pump is started from the main control room for startup operations. The startup feed pump motor can be powered from non-emergency Bus 4 or emergency Bus E5. The status of Bus 4 and Bus E5 is monitored in the main control room. While aligned to Bus 4, the startup feed pump will automatically start if both steam-driven feed pumps trip. Automatic starting of the startup feedpump is blocked if an "S" signal or hi-hi steam generator level signal is generated to trip the feed pumps. This blockage of the startup feed pump is not safety-related, but takes place because the feedwater control bypass and isolation valves are also closed. While aligned to Bus E5, the SUFP control switch will be maintained in pull-to-lock to prevent inadvertent start on Bus E5. The SUFP will only be manually started on Bus E5 to perform its EFW contingency function, for quarterly SUFP surveillance testing, to support shutdown after a plant trip, or as needed to support maintenance retest. The SUFP will only be manually started, while the emergency diesel generator (EDG) is supplying Bus E5, to perform its EFW contingency function or for 18 month EDG surveillance testing. The startup feed pump motor bearing and motor winding high temperature are alarmed in the main control room.

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CHAPTER 10
STEAM AND POWER CONVERSION SYSTEM

TABLES

TABLE 10.3-1 Deleted

TABLE 10.4-1 CONDENSATE AND FEEDWATER SYSTEM COMPONENT DESIGN DATA

1. Condensate Pumps

Number	3
Type	Vertical, multistage
Capacity, per pump	11,300 gpm
Total developed head @ design capacity	1,065 feet
Temperature of condensate	100°F
Motor rating	3,500 hp

2. Steam Packing Exhauster

Number	1
Tube material	304 SS
Channel design pressure	600 psig
Channel design temperature	125°F

3. Feedwater Heaters

Number	16
Type	Closed, horizontal U-tube
Tube Material	304 SS

Heater No.		Channel Design Pressure (psig)	Channel Design Temperature (°F)
1.	3	600	370
2.	3	600	370
3.	3	600	370
4.	3	600	370
5.	2	600	425
6.	2	1500	600

4. Steam Generator Feedwater Pumps

Number	2
Type	Horizontal, single stage
Capacity, per pump	18,662 gpm*
Total developed head @ design capacity	2,196 ft*
Temperature of feedwater	373ºF*

5. Steam Generator Feedwater Pump Turbines

Number	2
Turbine drive rating	12,417 hp

6. Heater Drain Pumps

Number	2
Type	Vertical, multistage
Capacity, per pump	5,917 gpm*
Total developed head @ design capacity	691 ft*
Temperature of condensate	373ºF*
Motor rating	1,250 hp

7.	Startup Heater	Tubeside Design Pressure (psig) 1500	Tubeside Design Temperature (°F) 400
		Shellside Design Pressure (psig) 225	Shellside Design Temperature (°F) 250

* Reflects post-uprate design heat balances.

TABLE 10.4-2 STEAM GENERATOR BLOWDOWN SYSTEM COMPONENT DATA

Flash Tank

Number	1
Design Pressure	150 psig to full vacuum
Operating Pressure	55 psig
Design Temperature	366°F
Operating Temperature	303°F
Capacity (Input)	200,000 lb/hr
Capacity	2700 gal.
Materials	Carbon Steel (Shell), Type 304 SS (Internals)
Design Code	ASME Sec. VIII, Div. 1
Safety Class	NNS

Flash Tank Bottoms Cooler

Number	2
Heat Exchange Rate	7,220,000 Btu/hr
Design Code	ASME Sec. VIII and TEMA C
Safety Class	NNS

	Shell Side	Tube Side
Design Temperature, °F	366	366
Design Pressure, psig	150	150 to full vacuum
Operating Pressure	85	55
Design Flow, lb/hr	240,300	70,000
Fluid	Cooling Water	Blowdown
Temperature in, °F	102 (max.)	303
Material	Carbon Steel	304L SS

Flash Steam Condenser/Cooler

Number	1	
Heat Exchange Rate	12,520,000 Btu/hr	
Design Code	ASME Sec. VIII and TEMA C	
Safety Class	NNS	
	Shell Side	Tube Side
Design Temperature, °F	366	366
Design Pressure, psig	150 to full vacuum	150
Operating Pressure, psig	55	85
Design Flow, lb/hr	11,500	417,000
Fluid	Steam	Cooling Water
Temperature in, °F	303	102
Temperature out, °F	130	132
Material	304L SS	Carbon Steel with 304L tubes SS

Flash Tank Distillate Pumps

Number	2
Design Flow	50 gpm
Design TDH	110 ft
Material	316 SS
Design Pressure	250 psig
Design Temperature	366°F
Design Code	Mfg. Standard
Safety Class	NNS

Vapor Body (Evaporator)

Number	2
Design Throughput	13,511 lb/hr (Feed)
Reflux Rate	2,574 lb/hr
Volume Holdup	1300 gals.
Safety Class	NNS
Design Pressure	50 psig to full vacuum
Operating Pressure	15 psig
Design Temperature	300°F
Material	Incoloy 825 (Tower 316L SS)

Heating Element (Evaporator)

Heat Transfer Rate	17,153,000 Btu/hr
Design Code	ASME Sec. VIII and TEMA C

	Shell Side	Tube Side
Design Temperature, °F	375	300
Design Pressure, psig	150 to full vacuum	150 to full vacuum
Operating Pressure, psig	125	15
Design Flow	20,618 lb/hr	16,085 lb/hr
Fluid	Steam/Condensate	Process Liquid
Temperature in, °F	353	200
Temperature out, °F	353	253
Material	Carbon Steel	Incoloy 825

Evaporator Distillate Condenser

Number	2	
Heat Exchange Rate	15,200,000 Btu/hr	
Design Code	ASME Sec. VIII, Div. 1 and TEMA C	
Safety Class	NNS	
	Shell Side	Tube Side
Design Temperature, °F	300	200
Design Pressure, psig	150 to full vacuum	150
Operating Pressure, psig	15	85
Design Flow	16,085 lb/hr	1,022 gpm
Fluid	Distillate	Cooling Water
Temperature in, °F	250	85
Temperature out, °F	250	115
Material	304 LSS	Carbon Steel with 304L SS Tubes

Evaporator Distillate Accumulator

Number	2
Capacity	300 gals.
Material	304L SS
Design Pressure	Full Vacuum to 50 psig
Operating Pressure	15 psig
Design Temperature	300°F
Operating Temperature	250°F
Design Code	ASME Sec. VIII, Div. 1
Safety Class	NNS

Evaporator Distillate Pump

Number	2
Design Flow	35 gpm
Design TDH	210 ft
Material	316 SS
Design Pressure	150 psig
Design Temperature	300°F
Design Code	Manufacturer's Standards
Safety Class	NNS

Evaporator Distillate Cooler

Number	2
Heat Exchange Rate	1,762,200 Btu/hr
Design Code	ASME Sec. VIII, Div. 1, and TEMA C
Safety Class	NNS

	Shell Side	Tube Side
Design Temperature, °F	200	300
Design Pressure, psig	150	150
Operating Pressure, psig	85	50
Design Flow	177 gpm	13,511 lb/hr
Fluid	Cooling Water	Distillate
Temperature in, °F	85	253
Temperature out, °F	105	120
Material	Carbon Steel	304L SS

Evaporator Bottoms Pump

Number	2
Design Flow	15 gpm
Design TDH	35 ft.
Material	Gould-Alloy
Design Pressure	150 psig
Design Temperature	300°F
Design Code	Manufacturer's Standards
Safety Class	NNS

Evaporator Bottoms Cooler

Number	2
Heat Exchange Rate	463,560 Btu/hr
Design Code	ASME Sec. VIII, Div. 1
Safety Class	NNS

	Shell Side	Tube Side
Design Temperature, °F	200	300
Design Pressure, psig	150	150
Operating Pressure, psig	85	50
Design Flow	47 gpm	15 gpm
Fluid	PCCW	Concentrate
Temperature in, °F	85	253
Temperature out, °F	105	180
Material	Carbon Steel	Incoloy 825

Piping

Material	Austenitic and High Nickel Stainless Steel
Design Code	ANSI B31.1
Safety Class	NNS

Demineralizer

Number	3
Type	Mixed bed
Orientation	Vertical
Size	4'-0" diameter x 8'-0" straight
Resin Volume/Manufacturer	
Cation	22 cu. ft/Diamond Shamrock (Duolite) No. C-26TR
Anion	22 cu. ft/Diamond Shamrock (Duolite) No. A-161TR
Inert	6 cu. ft/Diamond Shamrock (Duolite) No. S-3TR
Bed Depth	4 ft
Design Flow	50 gpm normal, 280 gpm maximum
Backwash Flow	31 gpm
Rinse Flow	75 gpm
Design Pressure	300 psig
Design Temperature	150°F
Materials	316 SS vessel & internals
Design Code	ASME Sect. VIII
Safety Class	NNS

Booster Pump

Number	1
Design Flow	350 gpm (includes 60 gpm min. circulation flow)
Design TDH	200 feet
Material	316 SS
Design Pressure	150 psig
Design Temperature	300 °F
Design Code	Manufacturer's Standards
Safety Class	NNS

SGBR Heat Exchanger

Number	1
Heat Exchange Rate	11,200,000 Btu/hr.
Design Code	ASME Sect. VIII & TEMA BFU
Safety Class	NNS

	Shell Side	Tube Side
Design Temperature, °F	200	300
Design Pressure, psig	150	300
Operating Pressure, psig	85	150
Design Flow, lb/hr.	280,000	140,000
Fluid	Cooling Water	Blowdown
Temperature in, °F	85	185
Temperature, out, °F	125	110
Material	Carbon Steel	Steel with Stainless Tubes

Resin Traps	Process Flow	Waste Flow
Number	1	1
Design Flow	50 to 280 gpm	75 gpm
Design Pressure	300 psig	(Later)
Design Temperature	300 °F	100 °F
Differential Pressure Clean/Dirty	4/5 psi	4/5 psi
Size	0.01 slots	0.05 slots
Material	304 SS	304 SS
Design Code	Manufacturers Std.	Manufacturers Std.
Safety Class	NNS	NNS

Iron Filters	
Number	2
Design Flow	280 gpm
Design Pressure	240 psi
Design Temperature	100°F
Material	Carbon Steel
Design Code	ASME Sect. VIII
Safety Class	NNS

TABLE 10.4-3 STEAM GENERATOR BLOWDOWN SYSTEM MALFUNCTION/FAILURE ANALYSIS

Component	Accident or Malfunction	Comments and Consequences
System	LOCA/LOOP**	The system does not have to be operational during accident conditions. Therefore it can be shutdown.
Pressure Vessels	Overpressure	Automatic controls and safety relief valves are provided.
System	Failure to Function	If the flash tank is out of service for repairs, the blow-down will have to be stopped. Evaluation of secondary chemistry will need to be used for outage time; this might eventually result in a unit shutdown
Tanks & Piping	Rupture	The safety relief valves on the pressurized systems are set at pressures below the design pressures considering reasonable transients in the system. In spite of this, should a rupture occur, safety related structures and equipment will not be flooded. The portion of the piping within the Containment is designed to safety class 2 and is designed/supported for the corresponding seismic and other loads.
Instrumentation	Malfunction	Two level instruments, one for process control and indication and the other for indication and the other for indication and alarm, are provided on all the essen-tial equipment of the process. Moreover, the I&C are located outside the boron concentration areas to provide easy access during operation.

Component	Accident or Malfunction	Comments and Consequences
Containment Isolation Valves	Air or Electrical power failure to solenoid valve	Valves are designed to fail closed.
	Failure of one train "T" signal	Dual solenoid valves are provided. Each independently receive a "T" signal from the A and B Train respectively.

**OP = Loss of Offsite Power.

TABLE 10.4-4 CONDENSATE POLISHING SYSTEM COMPONENT DATA

Cation Bed Demineralizer

Number	3
Orientation	Vertical
Size	9' 6" diameter x straight
Resin Volume	212 cu ft
Design Flow, cross-sectional	52 gpm/ft^2
Design Pressure	150 psig
Design Temperature	150ºF
Materials	Carbon steel, lined, with stainless steel internals
Design Code	ASME Section VIII
Safety Class	NNS

Mixed Bed Demineralizer

Number	4
Orientation	Vertical
Size	8' diameter x straight
Resin Volume	38 cu ft cation; 113 cu ft anion
Design Flow, cross-sectional	50 gpm/ft^2
Design Pressure	150 psig
Design Temperature	150ºF
Materials	Carbon steel, lined, with stainless steel internals
Design Code	ASME Section VIII
Safety Class	NNS

Cation Bed Resin Strainer

Number	3
Design Differential Pressure	165 psig
Design Temperature	150ºF
Design Flow	3,750 gpm
Particle Retention	100 mesh
Material, vessel	Stainless steel, with stainless steel element

Mixed Bed Resin Strainer

Number	4
Design Differential Pressure	165 psig
Design Temperature	150ºF
Design Flow	2,500 gpm
Particle Retention	100 mesh
Material, vessel	Carbon steel, with stainless steel element

Low Conductivity Tank

Number	1
Design Pressure	Atmospheric
Design Temperature	120ºF
Capacity	32,000 gal
Materials	Carbon steel, lined
Design Code	ANSI/AWWA D100
Safety Class	NNS

Condensate Polishing Head Tank

Number	1
Design Pressure	150 psig/Full vacuum
Design Temperature	150ºF
Capacity	7,000 gal
Materials	Carbon steel
Design Code	ASME Section VIII
Safety Class	NNS

Condensate Polishing Pump

Number	1
Design Flow	7,500 gpm
Design TDH	230 ft
Material	Carbon steel with stainless steel shaft and impeller
Design Pressure	150 psig
Design Code	Manufacturer's Standard
Safety Class	NNS

Recycle Pump

Number	2
Design Flow	3,000 gpm
Design TDH	116 ft
Material	Carbon steel, with stainless steel shaft and impeller
Design Pressure	275 psig
Design Code	Manufacturer's Standard
Safety Class	NNS

Low Conductivity Pump	
Number	2
Design Flow	300 gpm
Design TDH	60 ft
Material	Carbon steel, with stainless steel shaft and impeller
Design Pressure	150 psig
Design Code	ANSI B73.1M
Safety Class	NNS
Acid Pump	
Number	2
Design Flow	10 gpm
Material	Alloy 20
Design Pressure	150 psig
Design Code	Manufacturer's Standard
Safety Class	NNS
Caustic Pump	
Number	2
Design Flow	10 gpm
Material	316 stainless steel
Design Pressure	150 psig
Design Code	Manufacturer's Standard
Safety Class	NNS
Separation Tank	
Number	1
Design Pressure	150 psig
Design Temperature	150ºF
Materials	Carbon steel, lined
Design Code	ASME Section VIII
Safety Class	NNS
Anion Regeneration Resin Mix and Storage Tank	
Number	1
Design Pressure	150 psig
Design Temperature	150ºF
Materials	Carbon steel, lined
Design Code	ASME Section VIII
Safety Class	NNS

Mixed Bed Cation Regeneration Tank

Number	1
Design Pressure	150 psig
Design Temperature	150ºF
Materials	Carbon steel, lined
Design Code	ASME Section VIII
Safety Class	NNS

Cation Regeneration Tank

Number	1
Design Pressure	150 psig
Design Temperature	150ºF
Materials	Carbon steel, lined
Design Code	ASME Section VIII
Safety Class	NNS

Cation Storage Tank

Number	1
Design Pressure	150 psig
Design Temperature	150ºF
Materials	Carbon steel, lined
Design Code	ASME Section VIII
Safety Class	NNS

Sulfuric Acid Tank

Number	1
Design Pressure	Atmospheric
Design Temperature	110ºF
Capacity	4,170 gal
Materials	Carbon steel, lined
Design Code	ASME Section VIII, not stamped
Safety Class	NNS

Sodium Hydroxide Tank

Number	1
Design Pressure	Atmospheric
Design Temperature	110ºF
Capacity	4,170 gal
Materials	Carbon steel, lined
Design Code	ASME Section VIII, not stamped
Safety Class	NNS

Cation Dilution Water Heater Tank

Number	1
Design Pressure	150 psig
Design Temperature	250ºF
Capacity	4,000 gal
Materials	Carbon steel, lined
Design Code	ASME Section VIII, Div. 1
Safety Class	NNS

SEABROOK STATION
UPDATED FINAL SAFETY ANALYSIS REPORT

CHAPTER 10
STEAM AND POWER CONVERSION SYSTEM

FIGURES

See 1-NHY-B202116

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Heat Balance - 100% Load	
		Figure 10.1-1

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Heat Balance - Valves Wide Open	
		Figure 10.1-2

See PID-1-HG-B20888

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Hydrogen Gas System	
		Figure 10.2-1

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Main Steam System Overview	
		Figure 10.3-1

See PID-1-MS-B20580

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Main Steam System - Main Steam Headers Detail	
		Figure 10.3-2 Sh. 1 of 2

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Main Steam System - Main Steam Headers Detail	
		Figure 10.3-2 Sh. 2 of 2

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Main Steam System - Emergency Feedwater Pump Supply Detail	
		Figure 10.3-3

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Main Steam System - Main Steam Manifold and HP Turbine Piping Detail	
		Figure 10.3-4

See PID-1-MS-B20584

Main Steam System - Low Pressure Steam Piping Detail

Figure 10.3-5

See PID-1-MS-B20585

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Main Steam System - High Pressure Steam Piping Detail
	Figure 10.3-6

See PID-1-MS-B20586

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Main Steam System - Steam Dump Piping Detail	
		Figure 10.3-7

See PID-1-MS-B20587

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Main Steam System - Main Steam Drains Detail	
		Figure 10.3-8

See PID-1-MS-B20588

See PID-1-EX-B20324

See PID-1-EX-B20328

See PID-1-AR-B20744

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Condenser Air Evacuation System P&ID	
		Figure 10.4-1

See PID-1-SSS-B20759

See PID-1-CW-B20672

See PID-1-CW-B20673

See PID-1-CW-B20674

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Circulating Water Detail	
		Figure 10.4-4 Sh. 2 of 2

See PID-1-CL-B20680

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Chlorination System Overview	
		Figure 10.4-5

See PID-1-CO-B20420

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Condensate System Detail [5 Sheets]	
		Figure 10.4-7 Sh. 2 of 5

See PID-1-CO-B20424

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See PID-1-FW-B20684

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Feedwater System Overview	
		Figure 10.4-8

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Feedwater System Detail	
		Figure 10.4-9 Sh. 1 of 2

See PID-1-FW-B20687

See PID-1-SB-B20625

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Steam Generator Blowdown Overview	
		Figure 10.4-10

See PID-1-SB-B20626

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Steam Generator Blowdown Blowdown Evaporation Detail [3 Sheets]	
		Figure 10.4-12 Sh. 3 of 3

See PID-1-SB-B20627

See PID-1-SB-B20628

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See PID-1-AB-B20012

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Auxiliary Boiler Overview	
		Figure 10.4-15

See PID-1-AS-B20564

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Auxiliary Steam Overview	
		Figure 10.4-16

See PID-1-ASC-B20900

See PID-1-ASC-B20901

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Auxiliary Steam Condensate System Overview,	
		Figure 10.4-17 Sh. 2 of 2

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SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Condensate Polishing System Condensate Polishing Pump	
		Figure 10.4-19