5.5 COMPONENT AND SUBSYSTEM DESIGN

5.5.1 Reactor Coolant Pumps

5.5.1.1 Design Bases

The reactor coolant pump (RCP) ensures an adequate core cooling flow rate for sufficient heat transfer in order to maintain a departure from nucleate boiling ratio greater than 1.3 within the parameters of operation. The required net positive suction head (NPSH) is by conservative pump design always less than that available by system design and operation.

Sufficient assembly rotational inertia is provided by a flywheel, motor rotor, and pump rotating parts to provide adequate flow during coastdown. This forced flow following an assumed loss of pump power and the subsequent natural circulation effect provides the core with adequate cooling.

The RCP motor is capable of operation without mechanical damage at overspeeds up to and including 125 percent of normal speed.

The RCP is shown on Figure 5.5-1, and its design parameters are given in Table 5.2-6. Code and material requirements are provided in Tables 5.2-9 and 5.2-27.

5.5.1.2 Design Description

The RCP is a vertical, single-stage, centrifugal shaft seal pump designed to pump large volumes of reactor coolant at high temperatures and pressures. The pump consists of three areas from bottom to top: the hydraulics, the shaft seals, and the motor.

1. The hydraulic section consists of an impeller, a diffuser, casing, thermal barrier, heat exchanger, lower radial (pump) bearing, main flange, motor stand, and pump shaft.

2. The shaft seal section consists of three seals. They are the number 1 controlled leakage, film riding face seal and the numbers 2 and 3 rubbing face seals. These seals are contained within the seal housings.

3. The motor section consists of a vertical solid shaft, a squirrel cage induction-type motor, an oil-lubricated double Kingsbury type thrust bearing, two oil-lubricated radial bearings and a flywheel.

Attached to the bottom of the pump shaft is the impeller. The reactor coolant is drawn up through the impeller, discharged through passages in the diffuser and out through the discharge nozzle in the side of the casing. Above the impeller is a thermal barrier heat exchanger, which limits heat transfer between hot system water and seal injection water. Component cooling water is supplied to the thermal barrier heat exchanger.

High pressure seal injection water is introduced through a connection on the thermal barrier. A portion of this water flows through the seals; the remainder flows down the shaft through and around the bearing and the thermal barrier (where it acts as a buffer to prevent system water from entering the radial bearing and seal section of the unit) and into the Reactor Coolant System (RCS). The thermal barrier heat exchanger provides a means of cooling reactor coolant to an acceptable level in the event that seal injection flow is lost. The water lubricated journal-type pump bearing, mounted above the thermal barrier heat exchanger, has a self-aligning spherical seat.

The RCP motor bearings are of conventional design. The radial bearings are the segmented pad type, and the thrust bearings are tilting pad Kingsbury bearings. All are oil-lubricated. The lower radial bearing and the thrust bearings are submerged in oil, and the upper radial bearing is oil-fed from an impeller integral with the thrust runner. Component cooling water is supplied to the two oil coolers on the pump motor.

The motor is an air-cooled, Class B thermelastic epoxy-insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are located throughout the stator to sense the winding temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

The internal parts of the motor are cooled by air. Integral vanes on each end of the rotor draw air in through cooling slots in the motor frame. This air passes through the motor with particular emphasis on the stator end turns. It is then exhausted to the containment environment.

Each of the RCPs is equipped for continuous monitoring of RCP shaft and frame vibration levels. Shaft vibration is measured by two relative shaft probes mounted on top of the pump seal housing. The probes, one in line with the pump discharge and the other perpendicular to the pump discharge, are mounted in the same horizontal plane near the pump shaft. Frame vibration is measured by two velocity seismoprobes located 90 degrees apart in the same horizontal plane and mounted at the top of the motor support stand. Proximeters and converters convert the probe signals to linear output, which is displayed in the control room. Both units display caution and danger limits of vibration.

All parts of the pump in contact with the reactor coolant are austenitic stainless steel, except for seals, bearings, and special parts.

The pump internals, motor, and motor stand can be removed from the casing as a unit without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the flywheel cover.

5.5.1.3 Design Evaluation

5.5.1.3.1 Pump Performance

The RCPs are sized to deliver flow at rates that equal or exceed the required flow rates. Initial RCS tests confirm the total delivery capability, providing assurance of adequate forced circulation coolant flow prior to initial plant operation. The performance characteristics are shown on Figure 5.1-5.

The reactor trip system ensures that pump operation is within the assumptions used for loss-of-coolant flow analyses, and also assures that adequate core cooling is provided to permit an orderly reduction in power if flow from a RCP is lost during operation.

An extensive test program has been conducted to develop the controlled leakage shaft seal for pressurized water reactor (PWR) applications. Long-term tests were conducted on less than full-scale prototype seals as well as on full-size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the Number 1 seal (seal ring) is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The "spring-rate" of the hydraulic forces associated with the maintenance of the gap is high enough to ensure that the ring follows the runner under very rapid shaft deflections.

Testing of pumps with the Number 1 seal entirely removed, which puts full system pressure on the Number 2 seal, shows that relatively small leakage rates would be maintained for a period of time which is sufficient to secure the pump. Even if the Number 1

seal fails entirely during normal operation, the Number 2 seal would maintain these small leakage rates if the proper action is taken by the operator. The plant operator is warned of Number 1 seal damage by the increase in Number 1 seal leakoff rate. Following warning of excessive seal leakage conditions, the plant operator should close the Number 1 seal leakoff line and secure the pump, as specified in the instrumentation manual. Gross leakage from the pump does not occur if the proper operator action is taken subsequent to warning of excessive seal leakage conditions.

5.5.1.3.2 *Coastdown Capability*

It is important to reactor protection that the reactor coolant continues to flow for a short time after reactor trip. In order to provide this flow in a loss of offsite power condition, each RCP is provided with a flywheel. Thus, the rotating inertia of the pump, motor, and flywheel is employed during the coastdown period to continue the reactor coolant flow. The Pump Motor System is designed for the safe shutdown earthquake (SSE) at the site. Hence, it is concluded that the coastdown capability of the pumps is maintained even under the most adverse case of a blackout coincident with the SSE.

5.5.1.3.3 Flywheel Integrity

Demonstration of integrity of the RCP flywheel is discussed in Section 5.2.6.

5.5.1.3.4 Bearing Integrity

The design requirements for the RCP bearings are primarily aimed at ensuring a long life with negligible wear, so as to give accurate alignment and smooth operation over long periods of time. The surface-bearing stresses are held at a very low value and, even under the most severe seismic transients, do not begin to

approach loads that cannot be adequately carried for short periods of time.

Because there are no established criteria for short-time stress-related failures in such bearings, it is not possible to make a meaningful quantification of such parameters as margins to failure, safety factors, etc. A qualitative analysis of the bearing design, embodying such considerations, gives assurance of the adequacy of the bearing to operate without failure.

Low oil levels in the lube oil reservoirs signal an alarm in the Control Room and require shutting down of the pump if RCP motor bearing temp and/or vibrations are abnormally high. Each motor bearing contains embedded temperature detectors, and initiation of failure, separate from loss of oil, is indicated and alarmed in the Control Room as a high bearing temperature. This again requires pump shutdown. Even if these indications are ignored, and the bearing proceeded to failure, the low melting point of Babbitt metal on the pad surfaces ensures that no sudden seizure of the bearing occurs. In this event, the motor continues to operate as it has sufficient reserve capacity to drive the pump under such conditions. The high torque required to drive the pump, however, demands high current, which leads to the motor being shut down by the Electrical Protection Systems.

5.5.1.3.5 Locked Rotor

It may be hypothesized that the pump impeller might severely rub on a stationary member and then seize. Analysis has shown that under such conditions, assuming instantaneous seizure of the impeller, the pump shaft would fail in torsion just below the coupling to the motor, thereby disengaging the flywheel and motor from the shaft. This would constitute a loss-of-coolant flow in the loop. Following such a postulated seizure, the motor would continue to run without any overspeed, and the flywheel would maintain its integrity, as it is still supported by the motor with two bearings.

There are no other credible sources of shaft seizure other than impeller rubs. Sudden seizure of the pump bearing is precluded by graphite in the bearing. Any seizure in the seals results in a shearing of the anti-rotation pin in the seal ring. The motor has adequate power to continue pump operation even after the above occurrences. Protective relays are provided to trip the supply breaker on an overcurrent condition during startup and normal operation. Indication of pump malfunction is provided by the following alarms: bearing water high temperature, excessive Number 1 seal leakoff, and excessive pump vibration. If a pump malfunction is indicated, the affected pump is taken out of service for investigation.

5.5.1.3.6 Critical Speed

The RCP shaft is designed so that its operating speed is below its first critical speed. This shaft design, even under the most severe postulated transient, gives low values of actual stress.

5.5.1.3.7 Missile Generation

Precautionary measures taken to preclude missile formation from RCP components assure that the pumps will not produce missiles under any anticipated accident conditions. Each component of the pump is analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller, because the small fragments that might be ejected would be contained by the heavy casing.

5.5.1.3.8 Pump Cavitation

The minimum NPSH required by the RCP at best estimate flow is approximately 170 feet (approximately 85 psi). In order for the controlled leakage seal to operate correctly, it is necessary to require a minimum differential pressure of approximately 275 psi across the Number 1 seal. This corresponds to a primary loop

pressure at which the minimum NPSH requirement is exceeded and no limitation on pump operation occurs from this source.

5.5.1.3.9 Pump Overspeed Considerations

For turbine trips actuated by either the Reactor Trip System or the Turbine Protection System, the generator breaker disconnects the generator permitting the RCPs to remain connected to the external network for 30 seconds to prevent any pump overspeed condition.

An electrical fault requiring immediate trip of the generator (with resulting turbine trip) could result in an overspeed condition. However, the Turbine Control System and the turbine intercept valves limit the overspeed to less than 120 percent. As additional backup, the Turbine Protection System has a mechanical overspeed protection trip, usually set at about 110 percent of turbine speed. In case a generator trip deenergizes the pump buses, the RCP motors are transferred to offsite power within six to ten cycles.

5.5.1.3.10 Anti-Reverse Rotation Device

Each of the RCPs is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate, and two shock absorbers.

After the motor has slowed and come to a stop, the dropped pawls engage the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until it is stopped by the shock absorbers. The rotor remains in this position until the motor is energized again. When the motor is started, the ratchet plate is returned to its original position by the spring return.

As the motor begins to rotate, the pawls drag over the ratchet plate. When the motor reaches sufficient speed, the pawls are bounced into an elevated position and are held in that position by friction resulting from centrifugal forces acting upon the pawls. Considerable plant experience with the anti-reverse rotation device has shown high reliability of operation.

5.5.1.3.11 Shaft Seal Leakage

Leakage along the RCP shaft is controlled by three shaft seals arranged in series. Charging flow is directed to each RCP via a seal water injection filter. It enters the pump and is directed to a point between the pump shaft bearing and the pump seals. The flow splits and a portion flows down the shaft through and around the lower radial bearing, down past the thermal barrier heat exchanger and into the RCS; the remainder flows up the pump shaft annulus and provides a back pressure on the Number 1 seal and a controlled flow through the seal. Above the seal, most of the flow leaves the pump via the Number 1 seal leak-off line. Minor flow passes through the Number 2 seal and its leak-off line, and through the Number 3 seal and its leak-off line.

5.5.1.3.12 Seal Discharge Piping

Discharge pressure from the Number 1 seal is reduced to that of the volume control tank. Water from each pump's Number 1 seal is piped to a common manifold, through the seal water return filter and through the seal water heat exchanger, where the temperature is reduced to that of the volume control tank. The Number 2 and Number 3 leak-off line dump Number 2 and Number 3 seal leakage to the reactor coolant drain tank.

5.5.1.3.13 Loss of Offsite AC Power

During normal operation, seal injection flow from the Chemical and Volume Control System (CVCS) is provided to cool the RCP seals and the Component Cooling Water System provides flow to the thermal

barrier heat exchanger to limit the heat transfer from the reactor coolant to the RCP internals. In the event of loss of offsite power, the RCP is deenergized and both of these cooling supplies are terminated; however, the diesel-generators are automatically started and either seal injection flow or component cooling water to the thermal barrier heat exchanger is automatically restored within seconds. Either of these cooling supplies is adequate to provide seal cooling and prevent seal failure due to loss of seal cooling during a loss of offsite power to at least 2 hours.

5.5.1.3.14 Loss of Component Cooling Water

Loss of component cooling water and its effects on the RCP are discussed in Section 9.2.

5.5.1.4 Test and Inspections

Pressure boundary parts of the RCPs can be inspected in accordance with the ASME Code for "Inservice Inspection of Nuclear Reactor Coolant Systems," Section XI.

The pump casing is cast in two pieces, and joined by electroslag welding. Support feet are cast integral with the casing to eliminate a weld region.

The design enables disassembly and removal of the pump internals for usual access to the internal surface of the pump casing.

The RCP quality assurance program is given in Table 5.2-26.

5.5.2 Steam Generators

5.5.2.1 Design Bases

Steam generator design data are given in Table 5.2-5 for Unit 2 and Table 5.2-5a for Unit 1. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation, and the bases for the estimates are given in Section 11. Rupture of a steam generator tube is discussed in Section 15.

The internal moisture separation equipment is designed to assure that moisture carryover does not exceed 0.25 percent by weight for Unit 1 and 0.1 percent by weight for Unit 2 under the following conditions:

1. Steady-state operation up to 105 percent of full-load steam flow, with water at the normal operating level.

2. Loading or unloading at a rate of 5 percent of full-power steam flow per minute in the range from 15 percent to 105 percent of full-load steam flow.

3. A step load change of 10 percent of full power in the range from 15 percent to 105 percent full-load steam flow.

The steam generator tube sheet complex meets the stress, limitations and fatigue criteria specified. Code and materials' requirements of the steam generator are given in Tables 5.2-9 and 5.2-27.

The steam generator design maximizes integrity against hydrodynamic excitation and vibration failure of the tubes for plant life.

The water chemistry in the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces.

5.5.2.2 Design Description

The Unit 2 steam generator shown on Figure 5.1-3 (for Salem Unit 2) is an AREVA NP Model 61/19T, vertical shell and U-tube evaporator with integral moisture separating equipment. The Model-F steam generator for Unit 1 is shown in Figure 5.1-3a. The Model-F is very similar to the original Series 51 generator except in tube dimensions, number of tubes and separators. A specific description of the Model-F steam generator is given in Section 5.5.2.2.2.

5.5.2.2.1 Unit 2 AREVA NP Model 61/19T Steam Generators

The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tube sheet. Manways are provided for access to both sides of the divided head. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. The unit is primarily carbon steel. The heat transfer tubes are Inconel 690 thermally treated and the divider plate is Inconel 690.

The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tube sheet is weld clad with Inconel 600.

Feedwater flows directly into the annulus formed by the shell and tube bundle wrapper before entering the boiler section of the steam generator. Subsequently, water-steam mixture flows upward through the tube bundle and into the steam drum section. A set of centrifugal moisture separators, located above the tube bundle, removes most of the entrained water from the steam. Steam dryers are employed to increase the steam quality to a minimum of 99.90 percent (0.10 percent moisture). The moisture separators recirculate flow mixes with feedwater as it passes through the annulus formed by the shell and tube bundle wrapper.

The steam drum has two bolted and gasketed access openings for inspection and maintenance of the dryers.

5.5.2.2.2 Unit 1 Model-F Steam Generators

The Model-F steam generators are vertical U-tube steam generators that were designed and fabricated in accordance with the ASME Code, 1971 Edition, Summer 1973 Addenda, Class 1, Division 1 for use in a closed cycle pressurizer water reactor system. Unit 1 has Model-F steam generators.

The tube bundle of the Model-F steam generator consists of 5626 thermally-treated U-tubes fabricated from ASME SB-163 (Inconel). The O. D. of each tube is 0.688 inches with a nominal tube wall thickness of 0.040 inches. The ends of the tubes are expanded the full depth of the tube plate, and the tubes are welded to the Inconel cladding on the primary face of the tube plate. Overall height of the Model-F steam generator tube bundle extends approximately 348 inches above the secondary face of the tube plate.

The Model-F steam generators utilize two-stage moisture separators to remove moisture from the wet steam produced by the tube bundle to deliver dry steam to the turbine generator. The first stage separator assembly is located directly above the tube bundle. It is approximately 10 feet high and contains sixteen 20 inch diameter swirl vane assemblies. Steam at the exit end of the first stage separators still contains some entrained moisture and is passed through the second stage separators, containing banks of contoured vanes designed to remove water from steam.

The moisture separator housing consists of two four-sided tiers, one above the other, providing the frames in which the banks of vanes are installed.

The steam outlet nozzle has an I. D. of 29 inches and is located at the apex of the upper elliptical head. The steam outlet nozzle contains a flow limiting device which operates on the venturi principle, to choke flow in the event of a steam line break.

Model-F steam generators are equipped with a blowdown nozzle (2 in. dia.) and a drain nozzle (2 in. dia.). Liquid level connections provide openings for narrow and wide range water level instrumentation used for feedwater control and reactor protection systems. Wide range taps provide a range of 560 inches and narrow range taps provide a range of 128 inches for liquid level measurement. A sampling nozzle (2 inch nominal) is provided in Model-F steam generators used in Unit 1.

5.5.2.3 Design Evaluation

5.5.2.3.1 Natural Circulation Flow

The steam generators (which provide a heat sink) are at a higher elevation than the reactor core (which is the heat source). Thus, natural circulation is assured for the removal of decay heat.

5.5.2.3.2 Secondary System Fluid Flow Instability Prevention

In order to prevent the occurrence of water hammer, the feedwater distribution ring header flow takes place through the top of the headers, rather than out the bottom. This modification has been demonstrated to preclude water hammer as discussed in detail in Section 10.4. The Model-F steam generators in Unit 1 were originally fabricated with this feature to preclude water hammer. The Unit 2 RSG design also incorporates J-tubes and internals that maximize secondary side water inventory above the feed ring with an all-welded thermal sleeve/ring assembly. This eliminates the possibility of steam leakage into the feed ring through a sliding connection.

The limiting case for heat transfer capability is the "Nominal 100 Percent Design" case. The steam generator effective heat transfer coefficient and recirculation ratio are based on the coolant conditions of temperature and flow for this case, and includes a conservative allowance for tube fouling. Adequate tube area is selected to assure that the full design heat removal rate is achieved.

The fouling factor resistance of 0.00005 hr-ft^2-°F/Btu is the value selected to account for the differences in the measured and calculated heat transfer performance as well as provide the margin indicated above. Although margin for tube fouling is available, operating experience to data has not indicated that steam generator performance decreases over a long-term period.

5.5.2.3.3 Tube and Tube Sheet Stress Analyses

Tube and tube sheet stress analyses of the steam generator are given in Section 5.2. Calculations confirm that the steam generator tube sheet will withstand the loading (which is quasi-static rather than a shock loading) caused by loss of reactor coolant.

5.5.2.3.4 Flow-Induced Vibration

In the design of the steam generators, consideration has been given to the possibility of vibratory failure or wear of tubes due to flow-induced excitation. This consideration includes detailed analysis of the tube supporting system based on an extensive research program in both vibration and wear domains. The major cause of tube vibratory failure in heat exchanger components is that due to hydrodynamic excitation by the fluid outside the tube.

Consideration is given to three regions where the possibility of flow-induced vibration may exist:

1. At the entrance of downcomer feed to the tube bundle (cross flow)

2. Along the straight sections of the tube (parallel flow)

3. In the curved tube section of the U-bend (cross flow)

From the description of these regions, it is noted that two types of flow exist, namely, cross flow and parallel flow. For the case of parallel flow, analysis is done to determine the vibratory deflections. Analysis of the steam generator tubes indicates the flow velocities to be sufficiently below that required for damaging fatigue or impacting vibratory amplitudes. The support system, therefore, is deemed adequate to preclude parallel flow excitation.

Cross flow-induced vibration analysis are performed to confirm that the tube bundle is adequately supported to avoid significant levels of tube vibration. Vibration Analysis and a Wear Analysis are established to verify that vibrations do not result in excessive wear or fatigue throughout the tube bundle and U-bend regions.

The three pertinent cross Flow-Induced Vibration mechanisms of the steam generator tubes are (1) fluid elastic instability, (2) vortex shedding resonance, and (3) random turbulence. The FIV analysis verifies that excessive tube vibration from these sources is avoided. Particular areas of emphasis are the tube bundle entrance and the U-bend region as indicated above.

The first mechanism, fluid elastic instability, is a mechanism that may cause the fast rupture of the tubes (vibration amplitudes to increase sharply when a certain critical flow velocity is exceeded). The ratio of the effective crossflow velocity to the critical velocity at any point in the bundle is called the stability ratio. Fluid elastic instability occurs when the stability ratio is greater than or equal to 1.0 so for design, the acceptance criterion for the stability ratio is generally some margin less than 1.0.

The second FIV excitation mechanism is vortex shedding resonance. When fluid flows across a circular cylinder, the wake behind the cylinder contains vortices. The vortices detach from the cylinder in a regular manner, i.e. at a certain frequency, and cause the tubes to vibrate at the same frequency in a direction perpendicular to the flow direction. When, at a critical crossflow velocity, the vortex shedding frequency happens to be close to a tube natural frequency, the vibration of the tube can organize the wake, causing it to synchronize (lock-in) with the tube motion at the tube natural frequency. This phenomenon is called vortex shedding resonance.

In a tube bundle, close spacing of tubes greatly suppresses the formation of organized wakes. For flow in tube bundles, vortex shedding resonance has never been observed in Steam Generator tube bundles having pitch/tube OD ratios lower than 1.46. For the steam generators, the pitch/tube OD ratio is 1.43 for Unit 1 and 1.44 for Unit 2 RSGs, which are less than 1.46.

The third mechanism, random turbulence excitation, is the buffeting of the tubes primarily from the turbulence in the flow. It is the "background" mechanism that accounts for tube vibration below fluid elastic instability and outside regions of vortex shedding resonance. It results in relatively low levels of vibration that increase with increasing flow velocity, with amplitudes and mode shapes varying randomly in time and in direction. Vibration analysis shows that amplitudes are small enough to exclude risks of fatigue due to turbulence response.

Three-dimensional analyses are performed to derive detailed flow distributions in the U-bend area. From this analysis, velocity and density profiles are determined along the tubes. Finite element analysis is then used to predict mode shapes for each U-bend supporting structures (i.e., 3 sets of AVBs) and for various mode types and frequencies.

The FIV computer code, and the finite element code are used to determine if the Fluid Elastic Instability (FEI) threshold velocity is avoided and to analyze random turbulent excitation. The potential for fretting is assessed by FIV wear analysis. The FIV analysis is used to confirm that the tube bundle is adequately supported to prevent excessive tube wear due to FIV excitation mechanisms.

The RSG bundle design parameters that are most important for controlling FIV are:

1. Tube and support materials.

2. Tube outside diameter, thickness and pitch/diameter ratio, and diametric clearance at the tube supports.

3. Bundle height.

4. Bend radius of the outermost tube.

5. Number of tube support plates.

6. Number of Anti-Vibration bar sets.

7. Width of Anti-Vibration bars.

8. Steam flow at full power.

9. Circulation ratio.

Thus, the three pertinent cross-flow induced vibration mechanisms have been analyzed. The results show that all the acceptance criteria are met, and it is concluded that the tube bundle is adequately supported for the prevention of detrimental flow-induced vibration.

Summarizing the results of analysis and tests of steam generator tubes for flow-induced vibration, it can be stated that a check of support adequacy has been made using all published techniques appropriate to heat exchanger tube support design. In addition, the Tube Support System is consistent with accepted standards of heat exchanger design utilized throughout the industry (spacing, clearance, etc.). Furthermore, the design techniques are supplemented with a continuing research and development program to understand the complex mechanism of concern. Service experience of steam generators also shows that flow-induced vibration and cavitation effects do not cause tube thinning.

The effects of vibration, erosion, and cavitation have been given consideration and the stress limitations for each category have been met. Analysis of loss-of-coolant accident (LOCA) blowdown forces on as-fabricated U-tubes has shown that the maximum bending load elastic stress intensity is well below the faulted condition limit. The maximum bending load elastic stress intensity (based on the minimum tube wall thickness) would increase only within the range of 5 to 10 percent and would still be below the faulted condition limit. Therefore, as a minimum, at least 2 1/2 mils (per wall) thinning can be tolerated without exceeding the allowable stress limits. Vibration effects are negligible during normal operation by the supporting system. Under LOCA conditions, vibration is of a short duration and there is no endurance problem.

Further consideration is given to the possibility of mechanically excited vibration, in which resonance of external forces with tube natural frequencies must be avoided. It is believed that the transmissibility of external forces either through the structure or from fluid within the tubes is negligible and should cause little concern.

Finally, it should be noted that successful operational experience with several steam generator designs, including both the Unit 1 and Unit 2 replacement steam generators, has given confidence in the overall approach to the tube support design problem.

Tests and Inspections

The steam generator quality assurance program is given in Table 5.2-26.

Radiographic inspection and acceptance standards are in accordance with the requirements of Section III of the ASME Code.

Liquid penetrant inspection is performed on weld deposited tube sheet cladding, channel head cladding, tube-to-tube sheet weldments, and weld deposit cladding.

Liquid penetrant inspection and acceptance standards are in accordance with the requirements of Section III of the ASME Code.

Magnetic particle inspection is performed on the tube sheet forging, channel head casting (Unit 1), channel head forging (Unit 2), nozzle forgings, and the following weldments:

1. Nozzle to shell

2. Support brackets

3. Instrument connections (primary and secondary)
   (Note: Unit 1 and Unit 2 replacement steam generators have no primary instrumentation connections)

4. Temporary attachments after removal

5. All accessible pressure containing welds after hydrostatic test.

Magnetic particle inspection and acceptance standards are in accordance with requirements of Section III of the ASME Code.

An ultrasonic test is performed on the tube sheet forging, tube sheet cladding, secondary shell and heat plate and nozzle forgings.

The heat transfer tubing is subjected to eddy current test.

Hydrostatic tests are performed in accordance with Section III of the ASME Code.

In addition, the heat transfer tubes are subjected to a hydrostatic test pressure prior to installation into the vessel which is not less than 1.25 times the primary side design pressure multiplied by the ratio of the material allowable stress at the testing temperature.

Manways are provided for access to both the primary and secondary sides.

Steam generator tube inspection will be performed in accordance with Technical Specifications. Due to activity in the channel head and the large number of tubes involved, tube testing is done on a per-plant basis. The extent of tube testing planned in any particular plant will depend on tube performance to date, the channel head activity, and the results of tube sample testing. An eddy current testing method is available if the tubes should require inspection.

5.5.3 Reactor Coolant Piping

5.5.3.1 Design Bases

The RCS piping is designed and fabricated to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. Code and material requirements are provided in Section 5.2.

Materials of construction are specified to minimize corrosion/erosion and assure compatibility with the operating environment.

RCS pressure boundary piping codes for both units are stated in Table 5.2-9.

5.5.3.2 Design Description

Principal design data for the reactor coolant piping for both units are given in Table 5.2-7. The RCS piping is specified in the smallest sizes consistent with system requirements. In general, high fluid velocities are used to reduce piping sizes. This design philosophy results in the reactor inlet and outlet piping diameters given in Table 5.2-7. The line between the steam generator and the pump suction is larger to reduce pressure drop and improve flow conditions to the pump suction.

All piping within the reactor coolant pressure boundary is made of austenitic stainless steel with the main piping being seamless forged. Fittings are one-piece castings with the exception of the RCP inlet 90 degree elbow which is two half castings joined by electroslag welding.

All smaller piping which comprise part of the RCS boundary, such as the pressurizer surge line, spray and relief line, loop drains, and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the pressurizer relief and the pressurizer code safety valves, where flanged joints are used. Thermal sleeves are installed at points in the system where high thermal stresses could develop due to rapid changes in fluid temperature during normal operational transients. These points include:

1. Charging connections at the primary loop from the CVCS.

2. Both ends of the pressurizer surge line.

3. Pressurizer spray line connection at the pressurizer.

4. Safety Injection/Residual Heat Removal System return.

Thermal sleeves are not provided for the remaining injection connections of the ECCS since these connections are not in normal use. All piping connections from auxiliary systems are made above the horizontal centerline of the reactor coolant piping, with the exception of:

1. Residual heat removal (RHR) pump suction, which is 45 degrees down from the horizontal centerline. This enables the water level in the RCS to be lowered in the reactor coolant pipe while continuing to operate the RHR System, should this be required for maintenance.

2. Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.

3. The differential pressure taps for flow measurement are downstream of the steam generators on the first 90 degree elbow.

Penetrations into the coolant flow path are limited to the following:

1. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force.

2. The Reactor Coolant Sample System taps protrude into the main stream to obtain a representative sample of the reactor coolant.

3. The hot leg temperature detectors are located in resistance temperature detector wells that extend into the reactor coolant pipe.

4. The wide range temperature detectors are located in resistance temperature detector wells that extend into the reactor coolant pipes.

5. The differential pressure transmitters are connected to the RCS sample line to monitor RCS level during Mid-Loop operation.

Each reactor coolant loop is provided with RTDs so that individual temperature signals may be developed for use in the Reactor Control and Protection System.

A description of the installation and operation of the RTDs is provided in Sections 5.6.1 and 7.2.3.2.

Signals from these instruments are used to compute the reactor coolant ΔT (temperature of the hot leg, T_{hot}, minus the temperature of the cold leg, T_{cold},) and an average reactor coolant temperature (T_{avg}). The T_{avg} for each loop is indicated on the main control board.

The RCS pressure boundary piping includes those sections of piping interconnecting the reactor vessel, steam generator, and RCP. It also includes the following:

1. Charging line and alternate charging line from the isolation valve up to the branch connections on the reactor coolant loop.

2. Letdown line and excess letdown line from the branch connections on the reactor coolant loop to the isolation valve.

3. Pressurizer spray lines from the reactor coolant cold legs to the spray nozzle on the pressurizer vessel.

4. RHR lines to or from the reactor coolant loops up to the designated isolation or check valve.

5. Safety injection lines from the designated isolation or check valve to the reactor coolant loops.

6. Accumulator lines from the designated isolation or check valve to the reactor coolant loops.

7. Resistance temperature detector thermowells.

8. Loop fill, loop drain, sample, and instrument lines to or from the designated isolation valve to or from the reactor coolant loops.

9. Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel inlet nozzle.

10. Resistance temperature detector scoop element, pressurizer spray scoop, sample connection with scoop, reactor coolant temperature element installation boss, and the temperature element well itself.

11. All branch connection nozzles attached to reactor coolant loops.

12. Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the power-operated pressurizer relief valves and pressurizer safety valves.

13. Seal injection water and labyrinth differential pressure lines to or from the RCP inside reactor containment.

14. Auxiliary spray line from the isolation valve to the pressurizer spray line header.

15. Sample lines from pressurizer to the isolation valve.

Details of the materials of construction of reactor coolant piping and fittings are listed in Table 5.2-26.

5.5.3.3 Design Evaluation

Piping load and stress evaluation for normal operating loads, seismic loads, blowdown loads, and combined normal, blowdown, and seismic loads is discussed in Section 5.2.

5.5.3.4 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

An upper limit of about 50 feet per second is specified for internal coolant velocity to avoid the possibility of accelerated erosion. All pressure containing welds out to the second valve that delineates the reactor coolant pressure boundary are available for examination with removable insulation.

5.5.3.5 Tests and Inspections

Inservice inspection is discussed in Section 5.2.8. The RCS piping quality assurance program is given in Table 5.2-26.

A description of the quality assurance inspections of these components is contained in Section 5.2.3.5.

5.5.4 Main Steam Line Flow Restrictors

Each steam line is provided with a flow restrictor to limit the blowdown rate of steam from the steam generators in the event of a main steam line rupture. The flow restrictors are described in detail in Section 10.3.

In addition to the main steam line flow restrictors, the steam generators have flow restrictors in the steam outlet nozzle each with a flow area of 1.4 ft^2.

5.5.5 Main Steam Line Isolation System

Main steam isolation valves are described in Section 10.3.

5.5.6 Reactor Core Isolation Cooling System

This section is not applicable to PWRs.

5.5.7 Residual Heat Removal System

5.5.7.1 Design Bases

The RHR System is designed to remove residual and sensible heat from the core and reduce the temperature of RCS during the second phase of plant cooldown. During the first phase of cooldown, the

temperature of the RCS is reduced by transferring heat from the RCS to the Steam and Power Conversion System (Section 10).

The RHR System is placed in operation approximately 4 hours after reactor shutdown when the pressure and temperature of the RCS are less than 375 psig and 350°F, respectively. Under normal operating conditions, the RHR System can reduce the temperature of the reactor coolant to 140°F within 22 hours following reactor shutdown. The design residual heat load was based on the residual heat fraction of full core MW (thermal) power level that exists at 20 hours following reactor shutdown from an extended power run near full power (refer to Table 5.5-1).

As a secondary function, the RHR System is used to transfer refueling water between the refueling water storage tank and the refueling cavity at the beginning and end of refueling operations.

In addition, portions of the system are utilized as parts of the ECCS and the Containment Spray System. These functions and the associated analyses are discussed in Section 6.

The RHR System provides sufficient capability in the emergency operational mode to accommodate any single active or passive failure and still function in a manner to avoid risk to the health and safety of the public. Refer to Sections 6 and 15 for a discussion of the operability and capability of the RHR System in an emergency core cooling role.

The system design precludes any significant reduction in the overall design reactor shutdown margin when cooling water is introduced into the core for decay heat removal or during emergency core cooling recirculation mode of operation.

System components whose design pressure and temperature are less than the RCS design limits are provided with redundant isolation means and overpressure protection devices.

All system active components which are relied upon to perform the system functions are redundant and the system design includes provision for hydrostatic testing of system components to applicable code test pressures.

Piping and components of the RHR System are designed to the applicable codes and standards listed in Table 5.5-1. Since the loop contains reactor coolant when it is in operation, austenitic stainless steel piping is employed.

5.5.7.2 System Description

The RHR System (shown on Plant Drawings 205232 and 205332) consists of two residual heat exchangers, two RHR pumps and associated piping valves, and instrumentation.

During system operation, coolant flows from the RCS to the RHR pumps, through the tube side of the residual heat exchangers and back to the RCS. The inlet line to the RHR System loop begins at the hot leg of one reactor coolant loop and the return line is connected to the cold legs of two separate reactor coolant loops. The heat loads are transferred by the residual heat exchangers to the component cooling water.

The cooldown rate of the reactor is controlled by regulating the flow through the tube side of the residual heat exchangers. A bypass line with a remotely-operated control valve around the residual heat exchangers is used to maintain a constant flow through the RHR System.

Coincident with plant cooldown, a portion of the reactor coolant flow may be diverted to the CVCS for cleanup. By regulating diverted flow rate, the RCS pressure may be controlled within the pressure range dictated by the nil-ductility limits of the reactor vessel and the Number 1 seal differential pressure and NPSH requirement of the RCPs.

Design data for the RHR System components described below are listed in Table 5.5-1.

Residual Heat Exchanger

Two residual heat exchangers are installed in the system. Each exchanger is designed to remove one-half of the residual heat load. The installation of two exchangers assures that the heat removal capacity of the RHR System is only partially lost if one exchanger fails or becomes inoperative. Two exchangers also allow maintenance of one exchanger while the other unit is in operation.

The residual heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell. The tubes are welded to the tube sheet to prevent leakage of reactor coolant.

RHR Pumps

Two identical pumps are installed in the RHR System. Each pump is sized to deliver sufficient reactor coolant flow through the residual heat exchangers to meet the plant cooldown requirements. The use of two pumps, installed in parallel, assures that pumping capacity is only partially lost should one pump become inoperative. This also allows maintenance on one pump while the other pump is in operation. In addition to the RHR duty, the pumps are used for transfer of refueling water before and after a refueling operation.

The two RHR pumps are vertical, centrifugal units with mechanical seals to prevent reactor coolant leakage to the atmosphere. All pump parts in contact with reactor coolant are austenitic stainless steel or equivalent corrosion-resistant material.

RHR Valves

The valves used in the RHR System are constructed of austenitic stainless steel or equivalent corrosion-resistant material.

Manual isolation valves are provided to isolate equipment for maintenance. Throttle valves are provided for remote manual control of residual heat exchanger tube side flow, and for remote manual control of bypass flow. Check valves prevent reverse flow through the RHR pumps.

Isolation of the RHR System is achieved with two remotely-operated series stop valves in the line from the RCS to the RHR pump suction and by two check valves in series in each line from the RHR pump discharge to the RCS, plus a remotely-operated stop valve in each discharge line. Overpressure in the RHR System is relieved through a relief valve to the containment sump.

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the Waste Disposal System.

Manually-operated valves have backseats to facilitate repacking and to limit the steam leakage when the valves are open. Leakoff connections are provided where required by valve size and fluid conditions (with exception of MOVs 1RH2, 2RH2 and 2RH26 that are modified from a double to a single packing arrangement with leakoff ports cut and capped, and MOV 1RH26 that is modified from a double to a single packing arrangement with the leakoff port cut and plugged to reduce packing friction loads and thus helping MOV margin recovery under DCPs 80093314 (for Unit 2 valves) and 80095702 (for Unit 1 valves)).

RHR Piping

RHR piping is austenitic stainless steel. Piping joints and connections are welded except where flanged connections are required to facilitate maintenance.

5.5.7.3 Design Evaluation

For RCS cooldown, the unit is provided with two RHR pumps and two residual heat exchangers. If one of the two pumps, one of the two heat exchangers, or one pump and one heat exchanger is not operable, safe cooldown of the plant is not compromised; however, the time for cooldown is extended.

To assure reliability, the two RHR pumps are connected to two separate buses so that each pump will receive power from a different source.

An emergency power source is required to supply essential electrical equipment if a total loss of power should occur while the system is in service. Each pump is connected to a separate emergency power supply.

5.5.7.3.1 Leakage Provisions

The design operating leakage rate of the RHR System is 50 gpm due to a pump seal failure. The RHR pumps are in separate rooms containing two sump pumps, each adequate to provide the minimum capacity of 50 gpm. The sump pumps discharge to the Waste Disposal System. Sump pump reliability is maximized by using submersible type pumps. In the remote event that no sump pumps are operable, there is adequate volume in the RHR rooms to contain the design percentage while the pump is isolated.

Should a large tube-side-to-shell-side leak develop in an RHR heat exchanger, the water level in the component cooling surge tank would rise or fall depending on which system pressure is higher, and the operator would be alerted by a high or low water alarm. In addition, a leak into the Component Cooling System will be detected by a radiation monitor located in each component cooling header.

If the leaking RHR heat exchanger could not be isolated from the Component Cooling System before an inflow completely filled the surge tank, the overflow-vent line would discharge the excess water to the Waste Disposal System. If the leaking RHR heat exchanger could not be isolated from the Component Cooling System before an outflow completely drained the surge tank, remote motor operated valves in the Component Cooling System header cross-tie lines can be closed from the Control Room to split the two safety headers, thus maintaining at least one available header for safe shutdown.

Since the RHR System is required for long-term post-accident removal of decay heat from the reactor core and containment, independent piping systems are provided for the redundant components so that excessive leakage resulting from the deterioration of, or failure in, some passive element in the system can be identified and isolated without complete system loss of function.

Massive failure of piping is not considered credible because long-term operation of the system occurs only at low pressures and temperatures, and the system is protected from environmental conditions by the Class I (seismic) structures.

5.5.7.3.2 RCS Isolation Provisions

The RHR discharge lines are isolated from the RCS by two check valves in series for each line and a remote-operated valve in each line or common header.

There are two motor-operated isolation valves (RH1 and RH2), in series, in the single letdown line connecting the low-pressure RHR System to the high-pressure RCS. Valve RH1 is the upstream valve (closest to the RCS), and RH2 is the downstream valve. The position indication provided for these valves consists of "OPEN-CLOSED" indication on the main control console and valve "OFF-NORMAL" indication in the Auxiliary Alarm System.

The "OPEN-CLOSED" indication for RH1 and RH2 is powered from separate 125-vdc buses. This power is different than the source control power to the valve operators. Using separate power for control and indication ensures that indication will be maintained when control power is locked out.

The Interlock System consists of the following:

1. Valve RH1 is interlocked with a pressure control signal derived from a pressure transmitter to prevent its opening whenever the RCS pressure is greater than the RHR System

design pressure.

2. The pressure transmitter used in Item 1 is connected to the reactor coolant loop which contains the RHR suction

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line. The pressure transmitter is connected into the RHR suction line inside the containment.

3. The control for valves RH1 and RH2 is administratively locked to prevent inadvertent manual opening.

4. A second pressure channel is provided as a pressure control signal to interlock valve RH2 located adjacent to the RHR System. This will be used to prevent its opening whenever the reactor coolant pressure is greater than the RHR System design pressure.

5. This RH2 associated pressure transmitter is connected by a separate connection into the RHR suction line inside the containment. Therefore, the RHR suction line will contain two separate connections, one for each pressure transmitter.

The interlocks are designed to conform to IEEE Standard 279-1971.

Two overhead alarms are provided in the control room for RH1 and RH2:

1. The overhead alarm for RH1 is activated when the RH1 valve is not fully closed in conjunction with high reactor pressure.

2. The overhead alarm for RH2 is activated when the RH2 valve is not fully closed in conjunction with high reactor pressure.

5.5.7.3.3 Failure Analysis

A failure analysis of RHR pumps, heat exchangers, and valves is presented in Table 5.5-2.

5.5.7.3.4 Compliance with Branch Technical Position RSB 5-1

This section addr ses the items contained in Table II of Branch Technical Position (BTP) RSB 5-1 for PWR Class 2 plants. The numbering corresponds to the numbering in Table II.

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1. Double drop line (or valves in parallel) from the RCS.

   A single RHR suction line with two suction isolation valves in series is provided as described in Section 5.5.7.3.2. Compliance is not required since the station can be maintained in a safe hot standby condition while any required manual actions are taken.

2. Safety-grade dump valves, operators, air, and power.

   One safety-grade steam generator power-operated relief valve is provided for each of the four steam generators. Safety-grade remote operators and power supplies are not required since hot standby can be achieved and maintained using the safety-grade steam generator safety valves. The steam generator power operated relief valves are provided with handwheels and can be operated locally to permit plant cooldown. See the cold shutdown scenario and single failure evaluation provided below.

3. Capability to cool down to shutdown assuming most limiting single failure in less than 36 hours.

   Compliance is not required since the station can be maintained in a safe hot standby condition while any required manual actions are taken. The plant is capable of reaching RHR initiation conditions in approximately 36 to 48 hours, including time required to perform any manual actions.

4. Depressurization with only safety-grade systems assuming single failure.

   Compliance is not required since the station can be maintained in a hot standby condition while any required manual actions are taken.

5. Boration with only safety-grade systems assuming single failure.

   Compliance is not required since the station can be maintained in a safe hot standby condition while any required manual actions are taken.

6. Provisions for collection and containment of RHR pressure relief discharge.

   The RHR relief valves discharge to the containment sump.

7. Additional tests to study mixing of the added borated water and cooldown under natural circulation conditions with and without a single failure of an atmospheric dump valve.

   Salem Generating Station is similar to Diablo Canyon Power Station in design, both being Westinghouse PWRs. Due to the similarity of the two stations, no special tests will be conducted by the Salem Unit to establish boron mixing and cooldown capability under natural circulation since Diablo Canyon Station has committed to perform these tests. The results of the tests on Diablo Canyon will be applicable for Salem.

8. Specific operational procedures for cooldown under natural circulation.

   Salem Generating Station will generate specific operational procedures that will enable the operators to bring the station from hot standby condition to cold shutdown status using the systems and operating functions given in Item 9 (Cold Shutdown Scenario).

9. Seismic Category I auxiliary feedwater supply for at least 4 hours at hot shutdown plus cooldown to RHR cut-in based on longest time (for only onsite or offsite power and assuming worst single failure).

   A long-term source of auxiliary feedwater is provided by a connection to the Seismic Category I Service Water System.

Cold Shutdown Scenario (Assuming Loss of All Nonseismic Category I Equipment)

The safe shutdown design basis of the Salem Units is hot standby. The station can be maintained in a safe hot standby condition while manual actions are taken to permit achievement of cold shutdown conditions following an SSE with loss of offsite power. Under such conditions the station is capable of achieving RHR initiation conditions (approximately 350°F, 375 psig) in approximately 36 to 48 hours, including the time required for any manual actions. To achieve and maintain cold shutdown, four key functions must be performed. These are: (1) circulation of the reactor coolant, (2) removal of residual heat, (3) boration and makeup, and (4) depressurization.

Circulation of Reactor Coolant

Circulation of the reactor coolant has two stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F. During this stage, circulation of the reactor coolant is provided by natural circulation with the reactor core as the heat source and steam generators as the heat sink. Steam release from the steam generators is initially via the steam generator safety valves and occurs automatically as a result of turbine and reactor trip. Steam release for cooldown is via the steam generator power-operated relief valves which are operated manually with their handwheels. The steam generator power-operated relief valves are accessible for local operation.

The status of each steam generator can be monitored using Class 1E instrumentation located on the console in the control room. Three separate channels of indications for both steam generator pressure and water level are available.

Feedwater to the steam generators is provided from the Auxiliary Feedwater System which has a 220,000 gallon Seismic Category I auxiliary feedwater storage tank as the primary source, and two separate Seismic Category I piping subsystems. The first subsystem is composed of two motor-driven pumps, each powered from a different emergency power train; the second subsystem incorporates a turbine-driven pump which can receive motive steam from either of two steam generators. There are additional sources of feedwater backup which can be manually accessed. Initial backup is provided by the demineralized water storage tank, the domestic water storage tank, and the fire protection water tank. Additional backup is from the Seismic Category I Service Water System. The operation of the Auxiliary Feedwater System can be monitored using Class 1E instrumentation located on the control console in the Control Room. There is a single indication of the flows into each steam generator, pump operating status lights for the motor-driven pumps, and discharge and suction pressure indication for the turbine-driven pump. There are also two separate indications of the level in the auxiliary feedwater storage tank.

The second stage of reactor coolant circulation is from 350°F to cold shutdown. During this stage, circulation of the reactor coolant is provided by the RHR pumps.

Removal of Residual Heat

Removal of residual heat also has two stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F.

During this stage, the steam generators act as the means of heat removal from the RCS. Initially, steam is released from the steam generators' via the steam generator safety valves to maintain hot standby conditions. When the operators are ready to begin the cooldown, the steam generators' power-operated relief valves are slightly opened by local operation with their handwheels. As the cooldown proceeds, the operators will occasionally adjust these valves to increase the amount they are open. This allows a reasonable cooldown rate to be maintained. Feedwater makeup to the steam generators is provided from the Auxiliary Feedwater System. The Auxiliary Feedwater System has the ability to remove decay heat by providing feedwater to all four steam generators for extended periods of operation.

The second stage is from 350°F to cold shutdown. During this stage, the RHR System is brought into operation. The RHR heat exchangers in the RHR System act as the means of heat removal from the RCS. In the heat exchanger, the residual heat is transferred to the Component Cooling System which ultimately transfers the heat to the Service Water System. The Component Cooling and the Service Water Systems are both designed to Seismic Category I. The RHR System includes two RHR pumps and two RHR heat exchangers. Each pump is powered from different emergency power trains and each heat exchanger is cooled by a different component cooling loop. If any component in one loop becomes inoperable, cooldown of the plant is not compromised; however, the time for cooldown would be extended.

The operation of the RHR System can be monitored using Class 1E instrumentation on the control console in the Control Room. For each loop, there is indication of the pump discharge flow, the pump operation status, and the component cooling flow from the discharge of the heat exchanger.

Boration and Makeup

Boration is accomplished using portions of the CVCS. Boric acid, (3.75 to 4.0 weight percent) from the boric acid tanks is supplied to the suction of the centrifugal charging pumps by the boric acid transfer pumps. The centrifugal charging pumps may inject the borated water into the RCS via the normal charging flow path or the high head safety injection, BIT cold leg flow path. The two boric acid tanks, two boric acid transfer pumps, and the associated piping are of Seismic Category I design. There is sufficient boric acid capacity to provide for a cold shutdown with the most reactive rod withdrawn. The boric acid transfer pumps are each powered from different emergency power trains. The boric acid tank level can be monitored to verify the operability of the boration portion of the CVCS. For this, credit is taken for operator action in using a portable differential pressure indicator which can be connected to the level signal lines from the boric acid tanks.

Makeup, in excess of that provided as 3.75 to 4.0 weight percent boric acid, is provided from the refueling water storage tank (RWST) using centrifugal charging pumps and the same injection flow paths as described for boration. Two motor-operated valves, each powered from different emergency power trains and connected in parallel, will transfer the suction of the charging pumps to the RWST. Makeup from the RWST can be monitored using Class 1E instrumentation on the control console in the control room. Two separate channels of RWST level indication exist for Salem Unit 1 and four separate channels for Unit 2.

Depressurization

Depressurization is accomplished using portions of the CVCS. Either 3.75 to 4.0 weight percent boric acid or refueling water can be used as desired for depressurization with the flow path being from the centrifugal charging pumps to the auxiliary spray valve in the pressurizer. The two centrifugal charging pumps of the CVCS are of Seismic Category I, and are powered from different emergency power trains. The pumps can be operated from, and its operating

status monitored in the control room. The depressurization of the RCS can be monitored using Class 1E instrumentation on the control console in the Control Room. Available to the operator are four channels of pressurizer pressure, three channels of pressurizer level, and two channels of reactor coolant pressure.

Maintaining RCS Temperature and Pressure Without Letdown

In performing the cooldown to cold shutdown, the operator can integrate the function of heat removal, boration and makeup, and depressurization so that these functions can be accomplished without letdown from the RCS.

Without letdown available, boration is done concurrently with the RCS makeup required for cooldown contraction. Pressurizer level is maintained at normal shutdown level. The plant need not be taken water solid to accommodate the borated water. The required shutdown margin is maintained throughout the cooldown if the RCS makeup sequence described below is followed:

1. During the initial phase of the cooldown, the makeup is provided from the boric acid tanks. The boric acid tanks should be used as the sole source of makeup until at least the technical specification minimum volume has been charged.

2. Operators can continue using the boric acid tank if additional volume is required, or shift suction of the charging pumps to the RWST. If the boric acid tanks are used, pure boric acid should be charged until the RCS reaches the desired cold shutdown concentration. The cooldown is completed by using blended makeup at the cold shutdown concentration.

Finally the operators use auxiliary spray from the CVCS to depressurize the plant.

A calculation was performed (Reference 3) to demonstrate that the shutdown margin can be maintained throughout the cooldown without letdown and without taking the plant water solid. Worst case conditions of end-of-life and maximum xenon were assumed.

The assumed initial conditions following plant trip are:

RCS Temperature	= 547°F
RCS Pressure	= 2250 psig
Pressurizer Water Volume	= 500 ft^3
Pressurizer Steam Volume	= 1300 ft^3

The depressurization is performed using auxiliary spray with makeup from the Refueling Water Storage Tank.

Single Failure Evaluation

Circulation of the Reactor Coolant

1. From hot standby to 350°F (refer to Figures 5.1-6C and 10.4-7 and Plant Drawings 205201, 205301, 205203 and 205303) - Four reactor coolant loops and steam generators are provided, any one of which can provide sufficient natural circulation flow to provide adequate core cooling. Even with the most limiting single failure (of a steam generator

power-operated relief valve), three of the reactor coolant loops and steam generators remain available.

2. From 350°F to cold shutdown (refer to Plant Drawings 205232 and 205332) - Two RHR pumps are provided, either one of which can provide adequate circulation of the reactor coolant.

Removal of Residual Heat

1. From hot standby to 350°F (refer to Plant Drawings 205242, 205342 and 205312 and Figure 9.2-2A).

   a. Steam generator power-operated relief valves - Four are provided (one per steam generator), any one of which is sufficient for RHR. In the event of a single failure, three power-operated relief valves remain available.

   b. Auxiliary feedwater pumps - Two motor-driven and one steam-driven auxiliary feedwater pumps are provided. In the event of a single failure, two pumps remain available, either of which can provide sufficient feedwater flow.

   c. Flow control valves - Air-operated, fail-open valves. In the event of a single failure of one flow control valve (which affects flow to one steam generator from either a motor-driven pump or the steam-driven pump) auxiliary feed flow can still be provided to all four steam generators from the other pumps.

   d. Backup source - A backup source of auxiliary feedwater can be provided via a spectacle flange from either train of the Seismic Category I Service Water System.

2. From 350°F to 200°F (refer to Plant Drawings 205232, 205332 and 205312 and Figure 9.2-2A).

a. Suction isolation valves 1RH1 and 1RH2 - These valves are each powered from different emergency power trains. Failure of either power train or of either valve operator could prevent initiation of RHR cooling in the normal manner from the Control Room. In the event of such a failure, operator action could be taken to open the affected valve manually. The mechanical failure of the disc separating from the stem has been investigated (1) and its probability has been found to be in the range of 10^{-4} to 10^{-3} per year. The probability of an earthquake larger than the operating basis earthquake is less than 8×10^{-5} per year. The combined probability of valve stem failure coincident with the earthquake ($<8 \times 10^{-8}$) is so low that it need not be considered in the single failure analysis. In the event of a failure, the station would remain in a safe hot standby condition with heat removal via the steam generators.

b. Isolation valves 11RH4 and 12RH4 - If either of these normally open motor-operated valves, which are powered from different emergency power trains, were to close spuriously, RHR cooling would be provided by the unaffected RHR pump and heat exchanger. The affected valve could be de-energized and opened with its handwheel.

c. Pumps 11 and 12 - Each pump is powered from a different emergency power train. In the event of a single failure, either pump provides sufficient RHR flow.

d. Heat exchangers 11 and 12 - If either heat exchanger is unavailable for any reason, the remaining heat exchanger provides sufficient heat removal capability.

e. Unit 1

Flow control valves 11RH18 and 12RH18 - If either of these normally open-fail open valves should close spuriously, sufficient RHR cooling would be provided by the unaffected RHR train.

Unit 2

Flow control valves 21RH18 and 22RH18 - If either of these normally open - fail as-is valves should close spuriously, sufficient RHR cooling would be provided by the unaffected RHR train.

f. RHR/Safety Injection System Cold Leg Isolation Valves 11SJ49 and 12SJ49 are normally open valves with power locked out. A single failure in the control circuitry can not/will not inadvertently close either of these valves. However, an assumed closure of these valves will put the unit outside of its design basis since three cold legs cannot be fed with flow through a single SJ49 valve during the injection phase. Although such operation is outside of unit's design basis, this type of inadvertent operation may not be a safety significant issue provided an associated PCT penalty of 29°F can be accommodated without exceeding the 2200°F limit. (Westinghouse letter NS-OPLS-OPL-II-89-929), dated 12/20/89). Such a situation, if any, will still require a specific 10CFR50.59 evaluation.

g. Component Cooling Water System - Two redundant subsystems are provided for safety-related loads. Either subsystem can provide sufficient heat removal via one of the RHR heat exchangers.

h. Service Water System - Two redundant subsystems are provided for safety-related loads. Either subsystem can provide sufficient heat removal via one of the component cooling water heat exchangers.

Boration and Makeup (refer to Figure 5.1-6C and Plant Drawings 205201, 205301, 205234, 205334, 205228 and 205328).

1. Boric acid tanks 11 and 12 - Two boric acid tanks are provided. Each tank contains sufficient 3.75 to 4.0 percent boric acid to borate the RCS for cold shutdown.

2. Boric acid transfer pumps 11 and 12 - Each pump is powered from a different emergency power train. In the

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event of a single failure, either pump will provide sufficient boric acid flow.

3. Isolation valve 1CV175 - If valve 1CV175, which is supplied from emergency power and is normally closed, cannot be opened due to power train or operator failure, it can be opened locally with its handwheel. If valve 1CV175 cannot be opened with its handwheel, an alternate flow path is available via air operated, fail open valve 1CV172 and normally closed manual valve 1CV174.

   Although this path may be used as an alternate path, it does not have the full capacity of the boration path through 1CV175 and provides protection in depth only. The credited backup path for boration is from the RWST via 1SJ1 and 1SJ2 to the charging pump suctions.

4. Isolation valves 1SJ1 and 1SJ2 - Each valve is powered from a different emergency power train; only one of these normally closed motor-operated valves needs to be opened to provide a makeup flow path from the RWST to the centrifugal charging pumps.

5. Centrifugal charging pumps 11 and 12 - Each pump is powered from a different emergency power train. In the event of a single failure, either pump provides sufficient boration or makeup flow.

6. Flow control valve 1CV55 - This normally open valve fails open on loss of air or power. If 1CV55 closed spuriously, the charging pumps would operate on their miniflow circuits until operator action could open bypass valves 1CV81 and 1CV82.

7. Flow control valve 1CV71 - This normally open valve fails closed on loss of air or power. Use of a portable nitrogen bottle would allow 1CV71 to be reopened. If 1CV71 was stuck closed as a result of a single failure, manual bypass valve 1CV73 could be opened locally.

8. Isolation valves 1CV68 and 1CV69 - If either of these normally open, motor-operated valves, each of which is powered from a different emergency power train, should

close spuriously, operator action could be used to deenergize the valve operator and reopen the valve with its handwheel.

9. Isolation valve 1CV77 - If the normally open valve should close spuriously, alternate charging valve 1CV79, which fails open, could be used.

10. The alternate, high head safety injection, BIT cold leg flow path to the RCS also provides for the postulated failures in the previous items 7 through 9, which all involve failure of the normal charging path to the RCS.

Depressurization

1. Auxiliary spray valve 1CV75 - This normally closed valve fails closed on loss of air or power. Use of a portable nitrogen bottle would allow 1CV75 to be opened. If 1CV75 was stuck closed as a result of a single failure, the redundant Seismic Category I Overpressure Protection System valves can be used to depressurize the RCS by venting the pressurizer to the pressurizer relief tank.

2. Charging valves 1CV77 and 1CV79 - These valves fail open on loss of air or power. Use of portable nitrogen bottles would allow 1CV77 and 1CV79 to be closed. If either was stuck open, the redundant Seismic Category I Overpressure Protection System valves can be used to depressurize the RCS by venting the pressurizer to the pressurizer relief tank.

Environmental Qualification of the RHR Suction Isolation Valves

The RHR suction isolation valves are qualified for the steam line break environment. Therefore, they are qualified for the less severe environment which would result for venting the pressurizer to depressurize the RCS.

5.5.7.3.5 Hydraulic Performance at Run-Out

An RHR pump was tested for the highest runout flow for the worst hydraulic configuration. This configuration is when one RHR pump

is feeding two charging pumps, two safety injection pumps and also discharging directly into two cold legs. The test indicated that the RHR pump flow exceeded the design runout flow.

The system resistance on the discharge side for the RHR pumps was, therefore, increased by changing the orifices on the flow elements (up and downstream of the RHR heat exchanger) on the 8-inch RHR headers. The resized orifices at both the flow elements together provided the required resistance in the RHR System.

Net positive suction head was evaluated for a pump flow of 4800 gpm (greater than the maximum pump flow). Under this condition, available NPSH exceeds the required NPSH.

5.5.7.4 Tests and Inspections

The RHR pump flow instrumentation is calibrated periodically. Periodic visual inspections and preventive maintenance are conducted during plant operation.

5.5.8 Reactor Coolant Cleanup System

The CVCS provides reactor coolant cleanup and is discussed in Section 9. The radwaste considerations are discussed in Section 11.

5.5.9 Main Steam Line and Feedwater Piping

The main steam line and the feedwater piping are discussed in Section 10.

5.5.10 Pressurizer

5.5.10.1 Design Bases

The general configuration of the pressurizer is shown on Figure 5.1-2. Design data are given in Table 5.2-4. Codes and material requirements are provided in Table 5.2-9.

5.5.10.1.1 Pressurizer Surge Line

The surge line is sized to limit the pressure drop between the RCS and the safety valves with the design discharge flow from the safety valves. Overpressure of the RCS does not exceed 110 percent of the design pressure.

The surge line is designed to withstand the thermal stresses that result from volume surges occurring during operation.

5.5.10.1.2 Pressurizer Volume

The volume of the pressurizer is equal to or greater than the minimum volume of steam, water, or the total of the two that satisfies all the following requirements:

1. The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.

2. The water volume is sufficient to prevent the heaters from being uncovered during a step load increase of 10 percent of full power.

3. The steam volume is large enough to accommodate the surge resulting from 50-percent reduction of full load with automatic reactor control and steam dump without the water level reaching the high level reactor trip point.

4. The steam volume is large enough to prevent water relief through the safety valves following a loss-of-load with the high water level initiating a reactor trip.

5. The pressurizer does not empty following reactor trip and turbine trip.

6. The safety injection signal is not activated during reactor trip and turbine trip.

5.5.10.2 Design Description

5.5.10.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor coolant loop hot leg. The line enables continuous volume pressure adjustments between the RCS and the pressurizer.

The surge line is sized to limit the pressure drop during the maximum anticipated surge to less than the difference between the maximum allowable pressure in the reactor vessel and the loops (at the point of highest pressure) and the pressure in the pressurizer at the maximum allowable accumulation with the code safety valves discharging.

The surge line and the thermal sleeves at each end are designed to withstand the thermal stresses resulting from volume surges of relatively hotter or colder water which may occur during operation.

5.5.10.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant.

The surge line nozzle and electric heaters are installed in the bottom head. The heaters can be removed for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A screen at the surge line nozzle and baffles in the lower section of the pressurizer prevents an insurge of cold water from flowing directly to the steam/water interface and also assists mixing.

The spray line nozzle and relief and safety valve connections are located in the top head of the vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves can also be operated manually by a switch in the control room.

A small, continuous spray flow is provided through a manual bypass valve around the power-operated spray valves to assure that the pressurizer liquid is homogenous with the coolant and to prevent excessive cooling of the spray piping.

During an outsurge from the pressurizer, the flashing of water to steam and the generation of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. During an insurge from the RCS, the Spray System, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the sub-cooled surge water that enters the pressurizer from the reactor coolant loop.

Power-operated relief valves (PORVs) provide the means for pressurizer venting and a procedure for such an application is included within the Station Emergency Instructions for "natural circulation." Pressurizer vent paths have been evaluated and shown not to result in inadvertent opening or failure to close after initial opening.

The PORVs are set to open before the pressurizer safety valves. Relief through the PORVs can limit the pressurizer pressure to levels below the pressurizer safety valve setpressure, and thereby avoid opening (or challenging) the pressurizer safety valves.

Material specifications for the pressurizer, the pressurizer relief tank, and the surge line are provided in Table 5.2-27.

In the list below, several other aspects of the pressurizer are discussed.

Pressurizer Support

The skirt-type support is attached to the lower head and extends for a full 360 degrees around the vessel. The lower part of the skirt terminates in bolting flange with bolt holes for securing the vessel to its foundation. The skirt-type support is provided with ventilation holes around its upper perimeter to assure free convection of ambient air past the heater and connector ends for cooling.

Pressurizer Instrumentation

Refer to Section 7 for details of the instrumentation associated with pressurizer pressure, level, and temperature.

Spray Line Temperatures

Temperatures in the spray lines from the cold legs of two loops are measured and indicated. Insufficient flow in the spray lines results in low spray line temperature. Low alarms from these temperature channels are actuated to warn the operator of low bypass spray flow rate.

Safety and Relief Valve Discharge Temperature

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage or relief through the associated valve. High temperature alarms are actuated if the leakage is abnormal.

5.5.10.3 Design Evaluation

5.5.10.3.1 System Pressure Control

Whenever a steam bubble is present within the pressurizer, RCS pressure is controlled by the pressurizer. Analyses indicate that proper control of pressure is maintained for the normal operating conditions. Twenty banks of "backup" heaters can be powered from the Vital Distribution System. This provides assurance that pressure control for natural circulation can be maintained during a loss of offsite power.

A safety limit has been set to ensure that the RCS pressure does not exceed the maximum transient value allowed under the ASME Code, Section III. Thereby, continued integrity of the RCS components is assured. Evaluation of plant conditions of operation indicates that this safety limit is not reached.

During startup and shutdown, the rate of temperature change is controlled by the operator. Heatup rate is controlled by pump energy and by the pressurizer electrical heater capacity.

When the pressurizer is filled with water (i.e., near the end of the second phase of plant cooldown and during initial system heatup), RCS pressure is controlled by operation of a charging pump. The appropriate letdown flow is provided via the shutdown path from the RHR System.

5.5.10.3.2 Pressurizer Level Control

The normal operating water volume at full-load conditions is approximately 60 percent of the free internal vessel volume. Under part-load conditions, the water volume in the vessel is reduced for proportional reductions in plant load to approximately 25 percent of free vessel at zero power level.

5.5.10.3.3 Pressure Setpoints

The RCS design and operating pressures are listed in Table 5.2-1 together with the safety, power-operated relief and pressurizer spray valves' setpoints. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

5.5.10.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote manual overrides are used to initiate pressurizer spray. In parallel with each spray valve is a manual throttle valve, which permits a small continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open and to help maintain uniform water chemistry and temperature in the pressurizer. Temperature sensors with low alarms are provided in each spray line to alert the operator to insufficient bypass flow. The layout of the common spray line piping to the pressurizer forms a water seal, which prevents the steam buildup back to the control valves. The design spray rate is selected to prevent the pressurizer pressure from reaching the operating setpoint of the power relief valves during a step reduction in power level of 10 percent of full load.

The pressurizer spray lines and valves are large enough to provide adequate spray using as the driving force the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop, so that the velocity head of the reactor coolant loop flow adds to the spray driving force. The spray valves and spray line connections are arranged so that the spray will operate when one RCP is not operating. The spray line also assists in equalizing

the boron concentration between the reactor coolant loops and the pressurizer.

A flow path from the CVCS to the pressurizer spray line is also provided. This additional facility provides an auxiliary spray flow path to the vapor space of the pressurizer during cooldown if the RCPs are not operating. The thermal sleeve on the pressurizer spray connection and the spray piping is designed to withstand the thermal stresses resulting from the introduction of cold spray water.

5.5.10.4 Tests and Inspections

The pressurizer is designed and fabricated in accordance with the ASME Code, Section III, Safety Class 1 vessels.

The pressurizer quality assurance program is given in Table 5.2-26.

5.5.11 Pressurizer Relief Tank

5.5.11.1 Design Bases

Design data for the pressurizer relief tank (PRT) are given in Table 5.2-4. Codes and materials are given in Tables 5.2-9 and 5.2-27.

The tank design is based on the requirement to condense and cool a discharge of pressurizer steam equal to 110 percent of the volume above the full-power pressurizer water level setpoint. The tank is not designed to accept a continuous discharge from the pressurizer.

5.5.11.2 Design Description

The PRT condenses and cools the discharge from the pressurizer safety and relief valves. Discharges from specific relief valves

located inside the containment are also piped to the relief tank. The tank normally contains water and a predominantly nitrogen atmosphere; however, provision is made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen or oxygen.

By means of its connection to the Waste Processing System, the PRT provides a means for removing any noncondensable gases from the RCS that might collect in the pressurizer vessel.

Steam is discharged through a sparger pipe under the water level. This arrangement provides for condensing and cooling the steam by mixing it with water that is near ambient temperature. A flanged nozzle is provided on the tank for the pressurizer discharge line connection to the sparger pipe.

The PRT has pressure, temperature, and level indications and alarms in the control room.

5.5.11.3 Design Evaluation

The volume of water in the tank is capable of absorbing heat from the assumed discharge, assuming an initial temperature of 120°F and increasing to a final temperature of 200°F. If the temperature in the tank rises above 120°F during plant operation, the tank is cooled by spraying in cool water and draining out the warm mixture to the Waste Disposal System.

The spray rate is designed to cool the tank from 200°F to 120°F in approximately 1 hour following the design discharge of pressurizer steam. The volume of nitrogen gas in the tank is selected to limit the maximum pressure following a design discharge to 50 psig.

The rupture discs on the PRT have a relief capacity equal to or greater than the combined capacity of the pressurizer safety valves. The tank design pressure and the maximum rupture disc

burst point are twice the calculated pressure resulting from the maximum design safety valve discharge described above. The tank and rupture disc holders are also designed for full vacuum to prevent tank collapse if the contents cool following a discharge without nitrogen being added.

The PRT rupture disc is the vent path for both the reactor vessel head and the pressurizer vent. The annulus area containing the PRT is well ventilated. With three out of five fan coil units running at reduced speed during an accident condition, the annulus area containing the PRT is adequately ventilated with an air change every hour. A review of possible sources of ignition in the immediate vicinity of interest indicates no concern. Venting through the PRT rupture disc will not adversely affect any system or component essential for safe shutdown.

The discharge piping from the safety and relief valves to the relief tank is sufficiently large to prevent back-pressure at the safety valves from exceeding 20 percent of the setpoint pressure at full flow.

5.5.12 Valves

Valves in contact with the reactor coolant are primarily constructed of stainless steel. For certain applications, such as hard surfacing and packing, design and functional considerations dictate the use of materials other than stainless steel.

All manual and motor-operated valves of the RCS that are 3 inches and larger, (except as listed below), are provided with double-packed packing boxes and intermediate lantern ring leakoff connections. All throttling control valves, regardless of size, are provided with double-packed stuffing boxes and with stem leakoff connections. Leakage to the atmosphere is essentially zero for these valves. RCS valve codes, materials, and quality assurance measures are summarized in Tables 5.2-9, 5.2-27 and 5.2-26, respectively.

The valves listed below have a single set packing configuration and inactive leakoff lines.

	Salem #1			Salem #2	
1PS1	1PS25	1PR6	2PS1	2PS25	2PR6
1PS3	1PS28	1PR7	2PS3	2PS28	2PR7
1PS24	1PS29	1PS59	2PS24	2PS29	2PS59

5.5.13 Safety and Relief Valves

5.5.13.1 *Design Bases*

The capacity of the pressurizer safety valves accommodates the maximum surge resulting from complete loss of load. By the opening of the steam generator safety valves when steam pressure reaches the steam side safety setting, this objective is met without reactor trip or any operator action.

The RCS uses pressure control equipment in addition to the ASME Code safety valves. Although this pressure control equipment is not required by the ASME Code, it is used to assist in maintaining the RCS within the normal operating pressure.

The pressurizer PORVs are designed to limit pressurizer pressure to a value below the high pressure reactor trip setpoint. They are designed to fail to the closed position on loss of air supply. The PORVs are equipped with air accumulators, and will remain operable for some time following loss of the Control Air System, as long as there is sufficient air pressure in the accumulators.

The pressurizer PORVs are not required to open in order to prevent the overpressurization of the RCS. Failure of the PORVs to open results in higher reactor coolant pressures, but does not result in overpressurization of the system. In fact, the opening of the PORVs is a conservative assumption for the departure-from- nucleate-boiling limited transients by tending to keep the primary system pressure down.

The pressurizer spray control valves are also utilized to control pressurizer pressure variations. During an insurge, the Spray System, which is fed from the cold legs, condenses steam in the pressurizer to prevent the pressure from reaching the setpoint of the PORVs.

5.5.13.2 Design Description

The pressurizer safety valves are totally enclosed pop-type valves. The valves are spring-loaded, self-activated and with back-pressure compensation designed to prevent system pressure from exceeding the design pressure by more than 110 percent, in accordance with the ASME Boiler and Pressure Code, Section III. The set pressure of the valves is 2485 psig.

The 6-inch pipes connecting the pressurizer nozzles to their respective code safety valves are shaped in the form of a loop seal. Condensate, as a result of normal heat losses to the ambient will drain back to the pressurizer liquid space through the normally open safety valve drain lines. If the pressurizer pressure exceeds the set pressure of the safety valves, they will start lifting, and the water from the seal will discharge during the accumulation period. A temperature indicator in the safety valve discharge manifold alerts the operator to the passage of steam due to leakage or valves lifting.

The pressurizer is equipped with PORVs, which limit system pressure for a large power mismatch and thus prevent actuation of the fixed high-pressure reactor trip. The relief valves are operated automatically or by remote manual control. The operation of these valves also limits the undesirable opening of the spring-loaded safety valves. Remotely operated stop valves are provided to isolate the PORVs if excessive leakage occurs.

The relief valves are designed to limit the pressurizer pressure to a value below the high pressure trip setpoint for all design transients up to and including the design percent step load decrease with steam dump but without reactor trip.

Design parameters for the pressurizer spray control, safety, and power relief valves are given in Table 5.2-8.

5.5.13.3 Design Evaluation

The pressurizer safety valves prevent RCS pressure from exceeding 110 percent of system design pressure, in compliance with the ASME Code, Section III. Safety valve position is monitored by limit switches which alarm in the Control Room when any valve is not in the fully closed position.

The pressurizer PORVs prevent actuation of the reactor high pressure trip for all design transients up to and including the design step load decreases with steam dump. The relief valves also limit opening of the spring-loaded safety valves. The opening of any pressurizer PORV is annunciated in the control room.

The Salem PORVs, PORV block valves and associated downstream piping have been evaluated for operation under water-solid conditions, and have been found to be adequate. The PORVs can be relied upon to prevent challenges to the pressurizer safety valves when the pressurizer is water-solid. Administrative controls (procedures) are placed upon the PORV block valves to prevent their closure when the pressurizer is water-solid.

Westinghouse has completed a generic study (2) of PORV reliability and concluded that PORVs are adequately reliable so as not to require automatic block valve closure. Public Service Electric & Gas (PSE&G) has determined that the information provided in the generic report is applicable to the Salem Generating Station. Accordingly, automatic isolation of the PORVs is not provided.

5.5.14 Reactor Coolant System Component Supports

5.5.14.1 Description

Reactor vessel supports are assemblages of plates built up to seat the reactor vessel nozzle shoes. There are four shoe supports for each reactor vessel. The support assemblages are air cooled by negative pressure ducts that draw the air away from the space surrounding the vessel through vent holes drilled in the multiple plates. For support details, see Plant Drawing 201194.

The steam generator supports are shown on Plant Drawing 208903. The weight of the steam generator is transferred through four steel columns at its base to the supporting frame. The steam generator penetrates the operating floor of the Containment Building.

The elevation of the operating floor is approximately at the center of gravity of the steam generator. In the original design, the steam generator was supported at the floor by two sets of snubbers and bumper blocks which resist the horizontal forces and overturning moments generated from pipe rupture or earthquake motion. The snubbers have subsequently been deactivated. The two snubbers on the reactor side of each steam generator have been removed. Each of the two backside snubbers has been converted to a rigid, single-acting compression strut via the addition of a compression collar clamped to the snubber body. These compression struts and the bumper blocks resist the lateral forces and moments from pipe rupture or earthquake motion. The supporting frame has its upper bay braced in both directions. The lower bay consists of two parallel planar trusses that are pin-hinged at the top and bottom to allow for thermal displacement. The horizontal forces at the base of the steam generator are transferred through combined truss and frame action to the lower bay of the support structure. The primary loop piping provides lateral support for the frame in the direction normal to the plane of the trusses. Lateral restraint for blowdown is provided at the top of the support structure by two struts connected to the reactor shield wall. The struts are in two bolted sections with gaps for free thermal travel and adjustment. These struts are active for Unit 2 only. On Unit 1, the struts remain in place but are deactivated with the addition of larger gaps.

The RCP supports as shown on Figure 5.5-5 also consist of an upper and lower section. The upper section is a welded steel assembly and is constructed to accommodate the bolts of the feet of the RCP. The lower section is composed of two parallel planar trusses, pin-hinged at the top and bottom to provide for thermal expansion. Lateral support in the direction normal to the plane of the trusses is provided by the primary loop piping. Blowdown restraint is provided at the top of the supporting structure by struts connected to the shield wall. The struts are in bolted sections with gaps for free thermal travel and adjustment.

The steam generator and RCP supports are anchored to the containment base slab by heavy welded steel frames embedded in the concrete and tied to the base mat by 6 and 4 inch diameter bolts, 18.5 feet long. Typical details for the embedded steel for equipment supports are shown on Plant Drawing 208902.

All the statements above are applicable to both the Model 61/19T and the Model-F steam generators, except that the lower support design was modified to accommodate the Model-F steam generator. The Model 61/19T generator was supported from lugs on the channel head while the Model-F generator is supported from the tube sheet elevation so the existing columns had to be replaced by longer ones.

The lower support design for the Unit 1 Model-F generators is shown in Plant Drawing 208903.

The pressurizer also penetrates the operating floor of the reactor containment. Stop lugs are embedded in the floor slab to provide the lateral support for the pressurizer at its mid-height. The vessel skirt is bolted to a steel plate which is in turn welded to the top of the support structure. The support structure frame is braced in both directions. It is further constrained against lateral movement at its top by four short wide flange struts, two in each perpendicular direction, connected to the polar crane support wall. For pressurizer support details, see Plant Drawing 208907.

The control rod drive mechanisms (CRDMs) are supported by the reactor vessel closure head (RVCH) and the integrated head assembly (IHA). The RVCH supports the deadweight of the CRDMs while the IHA seismic platform provides lateral support at the top of each CRDM. The CRDM missile shield, which is permanently attached to the IHA, provides the necessary missile protection for containment if a CRDM were to fracture. The missile shield over the reactor vessel consists of a 181-inch diameter, 2-inch thick steel plate which is permanently attached to the IHA. It is secured to prevent it from becoming a missile. The CRDM ventilation system and ductwork, radiation shielding, and lifting tripod are also permanently attached to the IHA as well and therefore minimal disassembly and reassembly of the IHA is required during refueling outages.

5.5.14.2 Fabrication

For original fabrication, all shop welding was done in accordance with AWS D2.0, "Specification for Welded Highway and Railway Bridges." Detailed joint procedure specifications were submitted by the fabricator for review and approval by PSE&G engineering personnel. The following preheat requirements were specified to minimize residual stress:

1. Material less than 3/4-inch thick shall be preheated to 100°F if the ambient temperature falls below 40°F.

2. Material 3/4 to 1 1/2-inches thick shall be preheated to 150°F prior to welding.

3. Material 1 1/2 to 2 1/2-inches thick shall be preheated to 225°F before welding.

4. Material over 2 1/2-inches thick shall be preheated to 300°F before welding.

Welding of steam generator support modifications for Unit 1 Steam Generator Replacement was done in accordance with AWS D.1.1, Structural Welding Code - Steel, 1996 Edition.

Welding of steam generator support modifications for the Unit 2 Steam Generator Replacement was performed in accordance with AWS D.1.1, Structural Welding Code - Steel, 1994 Edition.

Most intersecting primary members are connected flange to flange by butt welds or are connected to gusset plates by fillet welds. These types of connections are not susceptible to lamellar tearing.

5.5.14.3 Evaluation

Analysis of the RCS supports is discussed in Section 3.9. Steam generator and RCP support load combinations and allowable stress limits are given in Table 5.5-3. The average operating temperature of these supports is approximately 100°F, with a minimum of 70°F. Material for primary component support structures subject to high-intensity impact loads was required to pass a Charpy impact test of 20 foot-pounds at 20°F to verify its fracture toughness characteristics. This fracture toughness assures that brittle behavior will not be exhibited.

5.5.14.4 Inspection

All welds were subject to visual inspection in accordance with American Welding Society requirements. All full penetration shop welds were subject to magnetic particle inspection at four depths supplemented, where practical, by ultrasonic inspection of the finished weld. After original installation, welds on the supports were subject to another magnetic particle inspection. This inspection revealed only minor surface defects on some welds, none critical to the structural integrity of the supports. Nonetheless, these welds were repaired.

In Unit 1 with the Model-F steam generators, the design basis for the lower supports is PSE&G Detail Specification No. 69-7031. The partial penetration welds between the new support columns and the existing support structure were magnetic particle (MT) examined after the root pass and the final pass. The partial penetration welds for the side plates were magnetic particle (MT) examined after the final pass. For the one side plate with full penetration welds, required because of the column offset of 2.203", the welds were MT examined at four thicknesses (Root, 1/3T, 2/3T, and Final) during the process. The stiffener plates were installed using full penetration welds and were MT examined at four thicknesses (Root, 1/3T, 2/3T, and Final) during the process. All new welds were visually examined (VT3) in accordance with Section IWF-3410 of the ASME Code, Section XI, with Addenda through summer 1983.

DCP 80083663, Steam Generator Supports, implemented changes necessary to perform the replacement of the Unit 2 steam generators in 2008. A replacement upper lateral support (ULS) was fabricated and installed on the Replacement Steam Generator (RSG) components. Temporary and permanent modifications were made to the steam generator lower lateral support (LLS) structure.

For the welding fabrication of the replacement ULS components, all full penetration and partial penetration groove welds received either a liquid penetrant (PT) or magnetic particle (MT) examination and a final visual examination (VT) of the completed weld. All other welds require only a final VT of the completed weld. All new welds were visually examined (VT3) in accordance with Section IWF-3410 of the ASME Code, Section XI, with Addenda through summer 1983.

For the welding modifications of the LLS structure, all full penetration welds received am MT examination of the root pass, 1/3T, 2/3T, and the completed weld and a VT examination of the completed weld. All other welds received only a final VT examination of the completed weld. All new welds were visually examined (VT3) in accordance with Section IWF-3410 of the ASME Code, Section XI, with Addenda through summer 1983.

5.5.15 Partial RCS Loop Operation

During partial drain operations of the RCS, adequate RCS inventory, level control, and Net Positive Suction Head (NPSH) must be maintained. If it is required that the RCS water level be lowered to drain the steam generator tubes, the residual heat removal flow rate through each of the RHRS loops should be throttled back to prevent vortexing and possible air entrainment of the pumps.

Draining is to the point where the indicated level is stable and predetermined point (usually at the elevation of the center of the reactor vessel nozzles). At this point, reactor coolant level is monitored continuously to assure that the RHRS inlet lines do not become uncovered. Inventory makeup, if required, is accomplished via the CVCS centrifugal charging pumps.

Should a RHRS inlet line become uncovered, air may be drawn into the suction piping and entrained in the fluid. Factors that minimize the effects of air entrainment on pump performance are as follows:

1. The location of the residual heat removal pumps provides positive head on the pump inlet, and

2. The circulation flow rate is kept low and unnecessary circulation of fluid is avoided (i.e., minimum flow required for core decay heat removal and boron mixing is maintained).

Provisions have been made to minimize the effects of air entrainment. However, should such an event preclude the continued use of the operating train, actions need to be taken to permit the utilization of the alternate train by providing sufficient refill/makeup from the CVCS/charging pumps. Provisions are incorporated to ensure rapid restoration of the RHRS to service in the event that the RHRS pumps become air bound. On identifying this situation, the affected train would be isolated, the reason for the loss of RHR would be identified and corrected, and heat removal accomplished by the redundant train.

Procedures have been developed to address the provision of alternate sources of cooling should loss of RHR cooling occur during shutdown maintenance evolutions. These provisions consider maintenance evolutions during which more than one cooling system may be unavailable, such as loss of steam generators when the RCS has been partially drained for steam generator inspection or maintenance.

The Outage Equipment Hatch may be used to satisfy the requirement for containment closure during modes 5, 6, or undefined. The Outage Equipment Hatch may remain open during mid-loop operations provided that containment closure can be established prior to the onset of core boiling following a loss of RHR. Operating procedures provide administrative controls for operating conditions, which ensure containment closure is achieved prior to core boiling. This satisfies the requirement of NRC Generic Letter 88-17 to establish containment closure prior to core uncovery.

5.5.16 References for Section 5.5

1. Hill, R. A., et al., "Evaluation of Mispositioned ECCS Valves," WCAP-8966 (Proprietary) and WCAP-9207 (Nonproprietary), September 1977.

2. Westinghouse Electric Corp., "Probabilistic Analysis and Operational Data in Response to NUREG-0737, Item II.K.3.2, for Westinghouse NSSS Plants," WCAP-9804, February 1981.

3. ABB Combustion Engineering Report CEN-606, Revision 00, dated 5/21/93, Boric Acid Concentration Reduction Effort, Technical Basis and Operational Analysis for Salem Generating Station Units 1 and 2