REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

CHAPTER 5

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5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

This chapter was originally prepared to describe the reactor coolant system during the initial fuel cycle. Much of the original text is retained for historical record. However, where applicable, changes have been made to reflect the uprating of the unit to a stretch power rating of 2700 Mwt and then to an EPU power rating of 3020 MWt. The corresponding EPU normal operating NSSS power is 3034 MWt, which accounts for net heat addition to the NSSS from other sources, such as the reactor coolant pumps. This increase has a negligible impact on the structural evaluations of the RCS. Consequently the EPU does not have a significant impact on the design bases of the RCS. Where information associated with the higher power level is not available the existing information is identified as Cycle 1. Replacement Steam Generators of type 89/19TI were installed in Unit 2 in the fall of 2007.

5.1 SUMMARY DESCRIPTION

The reactor is a pressurized water reactor with two coolant loops. The Reactor Coolant System (RCS) circulates water in a closed cycle, to remove heat from the reactor core and transfers it to a secondary (steam generating) system. The steam generators provide the interface between the Reactor Coolant (primary) System and the Main Steam (secondary) System. The steam generators are vertical U-tube heat exchangers in which heat is transferred from the reactor coolant to the Main Steam System. Reactor coolant is prevented from mixing with the main steam by the steam generator tubes and the steam generator tube sheet. The RCS is a closed system thus forming a barrier to the release of radioactive materials.

The arrangement of the RCS is shown on Figures 5.1-1 and 5.1-2. The major components of the system are the reactor vessel; two parallel heat transfer loops, each containing one steam generator and two reactor coolant pumps; a pressurizer connected to one of the reactor vessel outlet pipes; and associated piping. All components are located inside containment.

Reactor Coolant System pressure is controlled by the pressurizer, where steam and water are maintained in thermal equilibrium. Steam is formed by energizing immersion heaters in the pressurizer, or is condensed by the pressurizer spray to limit pressure variations caused by contraction or expansion of the reactor coolant. The average temperature of the reactor coolant varies with power level and the fluid expands or contracts, changing the pressurizer water level.

The charging pumps and letdown control valves in the Chemical and Volume Control System (CVCS) are used to maintain a programmed pressurizer water level. A continuous but variable letdown purification flow is maintained to keep the RCS chemistry within prescribed limits. Two charging nozzles and a letdown nozzle are provided on the reactor coolant piping for this operation. The charging flow is also used to alter the boron concentration or correct the chemical content of the reactor coolant.

Other reactor coolant loop penetrations are the pressurizer surge line in one reactor vessel outlet pipe; the four safety injection inlet nozzles, one in each reactor vessel inlet pipe; two outlet nozzles to the Shutdown Cooling System, one in each reactor vessel outlet pipe; two pressurizer spray nozzles; vent and drain connections; and sample and instrument connections.

Overpressure protection for the reactor coolant pressure boundary is provided by three spring-loaded ASME Code pressurizer safety valves connected to the top of the pressurizer. Two power operated relief valves are provided to minimize the opening of the pressurizer safety valves. All these valves discharge to the quench tank where the steam is released under water to be condensed and cooled. If the steam discharge exceeds the capacity of the quench tank, it is relieved to the containment atmosphere via the quench tank relief valve and/or a rupture disc installed in the tank.

Overpressure protection for the secondary side of the steam generators is provided by 16 spring-loaded ASME Code safety valves located in the Main Steam System upstream of the steam line isolation valves (see Section 10.3).

Components and piping in the RCS are insulated with a material compatible with the temperatures involved to reduce heat losses and protect personnel from high temperatures.

Design parameters of the RCS are listed in Table 5.1-1. Table 5.1-2 lists RCS volumes.

Shielding requirements of the surrounding concrete structures are described in Chapter 12. Reactor Coolant System shielding permits limited personnel access to the containment during power operation. The reactor vessel is enclosed by a primary shield wall. This and other shielding reduces the dose rate within the containment and outside the shield wall during full power operation to acceptable levels.

5.1.1 SCHEMATIC FLOW DIAGRAM

The principal pressures, temperatures, and flowrates at major components are listed in Table 5.1-3. These parameters are referenced to Figures 5.1-3 and 5.1-4, the piping and instrument diagram, by numbered locations. Instrumentation provided for operation and control of the RCS is described in Chapter 7 and is indicated on Figures 5.1-3, 5.1-4, 5.1-4a and 5.1-4b.

5.1.2 PIPING AND INSTRUMENT DIAGRAM

Figures 5.1-3, 5.1-4, 5.1-4a and 5.1-4b comprise the piping and instrumentation diagram of the RCS. Figures 5.1-3 and 5.1-4 depict the reactor coolant pressure boundary and illustrate the use of the isolation design features utilized between the RCPB and connected systems. The entire RCS is located within the containment. Fluid systems which are connected to the RCS and which include the limits of the reactor coolant pressure boundary (as defined in 10 CFR 50.2 (V)) are identified and the appropriate piping and instrumentation diagrams are referenced. Figure 5.1-6 is the piping and instrumentation diagram for the reactor coolant pumps. Figure 5.1-6A illustrates the charging pump line to the reactor cooler pumps. This line was previously for seal injection. Seal injection was removed and the lines to each reactor coolant pump were capped.

5.1.3 ELEVATION DRAWINGS

Reactor Coolant System plan and elevation drawings are provided as Figures 5.1-1 and 5.1-2.

Major components of the RCS are surrounded to the extent possible by concrete structures which provide support, shielding and missile protection. Elevation drawings illustrating principal dimensions of the RCS and its relationship to the surrounding concrete structures are provided as Figures 1.2-8 through 1.2-11.

5.1.4 OPERATION WITH THE RCS AT REDUCED INVENTORY OR MID-LOOP CONDITIONS

Background

Following reactor shutdown ($k_{eff} < 1.0$) irradiated fuel continues to produce substantial quantities of heat due to the decay of fission products, primarily through the emission of gamma (γ) rays. Most of this decay heat is deposited in the reactor coolant and is subsequently removed from the RCS by the shutdown cooling heat exchangers. Sometimes routine reactor maintenance, such as the replacement of a reactor coolant pump seal, can require opening the cold leg while the RCS is partially drained. For this work, the RCS is drained to approximately the mid-plane of the hot leg piping; this condition is referred to as "mid-loop". Reducing the RCS water inventory has the effect of decreasing the system response time to any loss of decay heat removal capability. The plant is considered to be in mid-loop conditions when the reactor vessel water level is below the top of the hot leg and at or above the mid-plane of the hot leg piping. The term "reduced inventory" refers to a water level beginning 3 feet below the reactor vessel flange and continuing down to the top of the hot leg. This definition is consistent with that used by the NRC in Generic Letter 88-17, Loss of Decay Heat Removal (Reference 1).

In the event of a loss of shutdown cooling while at a reduced inventory or mid-loop condition, the deposited γ-ray energy would heat the core coolant inventory to saturation and begin to boil-off the water remaining in the reactor vessel above the core. If this boiling condition persists, reactor fuel will be uncovered from the loss of inventory. Substantial quantities of steam will be evolved during any inventory boil-off.

EPU calculations have shown that the boil-off of RCS inventory at low pressures is a relatively slow evolution that requires two hours or more to reduce the RCS water level below the top of the active fuel. However, if the steam generated by the boil-off process is not effectively vented from the system, the pressure within the reactor vessel upper plenum may increase, depressing the reactor vessel water level such that active fuel is exposed. This scenario, which also requires the presence of an opening in the RCS cold leg and installation of both hot leg nozzle dams, leads to a more rapid core uncovery than does the low pressure boil-off scenario.

For example, if the pressurizer manway is open and the reactor vessel water level is below the top of the hot leg piping, a direct steam vent pathway is available. However, water levels above the mid-plane of the hot leg increase the k_{90} loss factor, leading to an increase in the loss (or resistance) coefficient K and lower steaming rates, until pressurization forces additional inventory into the cold legs.

To preclude rapid core uncovery following any loss of shutdown cooling, the timing of the RCS drain down to mid-loop conditions is constrained by the following factors: 1) sequencing of nozzle dam installation; 2) the available RCS vent area; 3) the steam production rate due to inventory boil-off; and 4) the containment closure capability. The steam production rate after a loss of shutdown cooling is proportional to the decay heat generation rate. The relationship between hot side vent area and the steam evolution rate is critical to maintaining a stable (and acceptably small) pressurization of the core and upper plenum region in the event of a loss of shutdown cooling when steam generators are not available for heat removal. The ability to close containment openings quickly aids in minimizing offsite radiological dose.

Reference 4 derives the vent area required to avoid excessive pressurization of the RCS following any loss of shutdown cooling.

REGULATORY BASIS

Initially, concerns related to operation while at reduced inventory arose following a loss of shutdown cooling event at the Diablo Canyon site in 1987. As a result of the event, the NRC prepared regulatory guidance in the form of Generic Letters (GL), including GL 88-17, Loss of Decay Heat Removal to discuss a number of phenomena recognized as affecting nuclear plant operation when these plants are operating in a non-power condition. Some of the phenomena identified in GL 88-17 can cause the time between the loss of decay heat removal and the onset of severe core damage to be as short as one hour. The common industry understanding prior to issuance of GL 88-17 was that core damage required a loss of shutdown cooling of about 4 hour duration. Enclosure 1 of GL 88-17 went on to discuss the six areas of concern listed below:

1) Pressurization
2) Vortexing
3) Draining the S/G U-tubes
4) RCS level differences
5) Design characteristics of decay heat removal systems
6) Instrumentation

Of these six items, the NRC's principal concern was that pressurization could occur as a result of conditions unique to operation with a reduced RCS inventory – and that excessive pressurization could adversely affect plant safety. After shutdown cooling was lost at Diablo Canyon, the inventory of core coolant began to boil in 30 to 45 minutes. More importantly, the boiling led to pressurization of the RCS, which was an unanticipated outcome. As previously noted, in the presence of a cold leg opening co-incident with installed hot leg nozzle dams pressurization of the RCS can depress the water level in the reactor vessel, leading to a loss of inventory and an early core uncovery.

These areas of concern formed the basis for the expeditious and programmatic action requirements imposed on licensees, including St. Lucie. Section 2.2.2 of Enclosure 2 to GL 88-17 provided guidance for licensees on establishing interim restrictions for draining the RCS. The goal of the interim guidance was to have licensees implement procedures and administrative controls that would reasonably assure containment closure prior to a core uncovery resulting from a loss of decay heat removal (DHR) and the coincident failure of alternate makeup capability. The NRC anticipated that this interim guidance would later be supplanted by site-specific guidance developed by licensees and industry owners groups. NRC also envisioned that periodic updates and revisions to this guidance would be developed using 10 CFR 50.59 criteria.

For reduced inventory and mid-loop operations with irradiated fuel present in the reactor vessel, an open vent path through the pressurizer manway is required. Under some conditions it requires opening an additional vent pathway through ICI Quickloc assemblies. The RCS venting calculation quantifies the available ICI vent capacity with and without upper flange thread protection devices installed. The available ICI vent capacity without thread protectors installed is slightly greater than the ICI vent capacity available when thread protectors are installed. To credit this ICI vent path, removal of the ICI Quickloc seal assemblies is required prior to entry into reduced inventory conditions. With a vent pathway available through the pressurizer manway and at least six ICI Quickloc assemblies, adequate venting is present for all times after shutdown greater than 81 hours.

Time to Boil

Based on revised EPU decay heat loads, times to boil and the time required to boil-off enough coolant inventory to uncover the core have been determined. The input assumptions used will bound both current and future operating cycles.

When the RCS is drained to mid-loop and the initial coolant temperature is 120°F, the time to boil is 10.2 minutes at 72 hours after shutdown and 11.2 minutes at 90 hours after shutdown. Both of these values assume an equivalent operating cycle length of 16000 EFPH for previous fuel cycles. If the initial coolant temperature is assumed to be 110°F, the time to boil increases to 11.3 minutes at 72 hours after shutdown and 12.4 minutes at 90 hours after shutdown. At RCS temperatures above ~90°F, the time to boil from mid-loop conditions is less than 26.4 minutes for the first 360 hours after reactor shutdown.

Increasing the water level in the reactor vessel above the core has a minor effect on the time to boil. At 90 hours after shutdown, increasing the RV water volume by 100 ft^3 (748 gallons) delays the onset of core boiling by 0.857 minutes, if the initial temperature is 120°F.

Time to Core Uncovery

Assuming the RCS pressure remains at approximately 15 psia (i.e. depressurized), the time to core uncovery from mid-loop conditions as a function of initial coolant temperature and time after shutdown has been evaluated for EPU conditions. No inventory makeup is assumed available. At 72 hours after shutdown and with an initial temperature of 120°F, core uncovery occurs 110 minutes (1.83 hours) after a loss of shutdown cooling. Decreasing the initial temperature to 110°F increases the time to core uncovery by 2 minutes to 112 minutes. At 90 hours after shutdown the corresponding the corresponding values are 121 minutes (2.02 hours) and 123 minutes, respectively. If the reactor has been shutdown for only 60 hours, water level in the core will drop below the top of the active fuel 103 minutes (1.72 hours) after shutdown cooling is lost from mid-loop conditions when the initial temperature is 120°F.

Steaming Rates and Required Vent Area

The rate of steam generation following any loss of shutdown cooling has been determined for EPU conditions for reduced inventory and mid-loop conditions. Steam production rates in the range of 10.2 lbm/sec to 13.9 lbm/sec could be expected following a loss of shutdown cooling from hot mid-loop conditions at Unit 2.

The upper limit on acceptable pressurization can be determined by considering the elevation difference between the RCS cold legs and the top of the core. Pressurization that will raise a water column by more than this amount could fill the cold legs with liquid inventory that should be covering the core and lead to a loss of inventory through any hole in the cold leg.

For Unit 2, the maximum permissible pressurization of the core/upper plenum region that avoids inventory loss to the cold legs is on the order of 3.0 psig. This is the basis for the 17.7 psia value (14.7 + 3.0) discussed in Reference 6.

Vent Area and Time after Reactor Shutdown

The cross sectional area of the pressurizer surge line is the limiting dimension constraining steam flow through an open pressurizer manway. The Unit 2 pressurizer surge line has a cross-sectional area of 0.5592 ft^2. The EPU analysis uses a K-factor of 3.38 for the surge line/pressurizer manway combination. Results from the orifice flow equation used to calculate the steaming rate through the open manway are sensitive to the flow resistance (K) factor used. The K-factor used in the EPU analysis is explicitly calculated through review of the appropriate drawings. This was utilized in the analysis that determined the required hot side vent area as a function of cycle length and time after shutdown.

The analysis determined a required cooling time of 110 hours after shutdown if the equivalent operating cycle length for past operation was ≤16000 EFPH (this bounds 18 month fuel cycles) and 114 hours if the equivalent operating cycle length for past operation was characterized by 24-month cycles. These cooling times will ensure that the pressurizer manway vent path alone has sufficient capacity to maintain the core and upper plenum region pressure not greater than 3.0 psig.

To reduce these required cooling times, an additional vent path on the reactor head must be opened.

Each ICI Quickloc flange assembly through which a vent path is opened provides an additional 0.286 lbm/sec of steam venting capacity at an assumed 3.0 psid. The venting capacity of an ICI assembly is greater if the upper flange thread protector is not installed. If a vent path is established through any six of the ICI Quickloc assemblies and the pressurizer surge line/manway during mid-loop operations, then the combined vent capability is 12.41 lbm/sec. Therefore, removing the pressurizer manway and removing at least six of the ICI Quickloc seal assemblies will provide a vent path adequate to prevent pressurization above 3.0 psig in the event of a complete loss of shutdown cooling for times of 81 hours or greater after shutdown.

Containment Closure

The undesirable containment environment that will rapidly ensue following a loss of shutdown cooling requires that containment closure be promptly initiated on any loss of shutdown cooling. The containment closure requirements for St. Lucie Unit 2 ensure that potentially adverse environmental factors present in the containment atmosphere do not effect the closure evolution.

Radiological Consequences

The radiological consequences of a sustained loss of shutdown cooling with an open containment equipment hatch have not been evaluated for either St. Lucie unit. This event is not a design basis event at St. Lucie.

A qualitative assessment of the dose consequences inside and outside containment was performed for Ft. Calhoun in 1988 by the CEOG (see Reference 7). These calculations used conservative inputs, such as a 1% failed fuel fraction, and concluded the site boundary whole body doses would be in the tens of millirem range. This analysis also concluded that the in-containment isotopic concentrations of many species would exceed 10 CFR Part 20 limits once core boil-off has begun.

Pump Makeup to Compensate for Inventory Boil-off

An EPU analysis determined that two charging pumps can provide sufficient makeup capability to compensate for inventory boil-off if the reactor has been shutdown for at least 72 hours. In addition to charging pumps other makeup sources, including a high pressure safety injection (HPSI) pump, are available. HPSI pump makeup capability is greater than the boil-off rate from any credible mid-loop condition, so depending on the location of any RCS openings the added makeup will either flow out through a hole or increase the level of the RCS. If makeup flow is not required at a time when low elevation openings are present on the hot side of the RCS, it may be desirable to throttle HPSI pump flow some time after initiation to match the boil-off rate so to avoid spilling injection flow on the containment floor.

PLANT RESTRICTIONS

St. Lucie Unit 2 Plant procedures include the required restrictions and operational guidance for reduced inventory and mid-loop conditions.

REFERENCES FOR SECTION 5.1.4

1) Loss of Decay Heat Removal (Generic Letter No. 88-17, including Enclosures), U.S. Nuclear Regulatory Commission, October 17, 1988.

2) Deleted

3) Deleted

4) Attachments to CEOG letter CEOG-88-599, Task 555 Draft Final Report, "Loss of RHR Scenarios, Detailed Qualitative Assessment", CE-NPSD-421, Revision 01, October 17, 1988.

5) NRC Generic Letter 87-12, Loss of Residual Heat Removal (RHR) While the Reactor Coolant System (RCS) is Partially Filled, July 9, 1987.

6) Deleted

7) Engineering Evaluation of Fort Calhoun Station, Loss of SDC at Mid-Loop Conditions, prepared for the Omaha Public Power District, Final Report, September 1988.

TABLE 5.1-1

DESIGN PARAMETERS OF REACTOR COOLANT SYSTEM

	Cycle 1	EPU
Design Thermal Power, Mwt (Including net heat addition from RCPs)	2570	3050
Thermal Power, Btu/hr	8.77×10^9	1.03×10^{10}
Design Pressure, psia	2500	2500
Design Temperature (except Pressurizer), °F	650	650
Pressurizer Design Temperature, °F	700	700
Reactor Coolant System Design Flow Rate, lb/hr	122×10^6	140.8×10^6
Cold Leg Operating Temperature, °F	550	551
Coolant Average Operating Temperature, °F	577	578.5
Hot Leg Operating Temperature, °F	604	606
Normal Operating Pressure (psia)	2250	2250

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY (RCPB)

5.2.1 COMPLIANCE WITH CODES AND CODE CASES

5.2.1.1 Compliance with 10 CFR 50.55a

The code class, edition and addenda for the RCPB are listed in Table 5.2-1 and are in accordance with the provisions of 10 CFR 50.55a.

5.2.1.2 Applicable Code Cases

The Code Cases applied in the construction of the reactor coolant pressure boundary components and those used for modifications to instrument nozzles are listed in Table 5.2-2. Except as noted, all of the code cases listed have been included in Regulatory Guides 1.84, "Code Case Acceptability ASME Section III Design and Fabrication," March 1977 (R9) or 1.85, "Code Case Acceptability ASME Section III Materials," March 1977 (R9) as approved cases.

The original Reactor Vessel Closure Head and the original CEDMs have been replaced. The Code Cases used in the replacement components are listed in Table 5.2-2.

5.2.2 OVERPRESSURIZATION PROTECTION

5.2.2.1 Design Bases

Appendix 5.2A presents the design bases for sizing the overpressurization protection system. The loss of load transient which is used to size the pressurizer safety valves is not a design transient for any other component in the reactor coolant pressure boundary.

5.2.2.2 Design Evaluation

Section 15.2 provides an evaluation of the functional design of the overpressure protection system. In this analysis, the capability of the overpressure protection system to maintain secondary and primary operating pressures within 110 percent of design is clearly demonstrated.

The analytical model and assumptions used in the analysis are discussed in Section 15.2.

The analysis demonstrates that sufficient relieving capacity has been provided so that when acting in conjunction with the Reactor Protective System the safety valves prevent exceeding 110 percent of the design pressure.

5.2.2.3 Piping and Instrumentation Diagram

The piping and instrumentation diagram showing the primary safety valves and their associated discharge lines are shown on Figures 5.1-3 and 5.1-4. The secondary safety valves are shown on Figure 10.1-1.

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Pressurizer Safety Valves

See Subsection 5.4.13 for a description on pressurizer safety valves. The pressurizer safety valves discharge into the pressurizer quench tank. The pipe diameter, pipe length and routing is shown on Figure 5.2-1.

5.2.2.4.2 Main Steam Safety Valves

See Subsection 10.3.2 for a description of main steam safety valves.

5.2.2.5 Mounting of Pressure-Relief Devices

Mounting of the pressurizer safety valves and main steam safety valves are described in Subsections 5.4.13 and 10.3.2 respectively.

5.2.2.6 Applicable Codes and Classification

The applicable codes and classification for the overpressure protection system are contained in Subsections 3.2.1 and 3.2.2. Additional component information can be found in Subsections 5.2.1, 5.4.11, 5.4.13 and Section 10.3.

5.2.2.7 Material Specification

Material specifications for the overpressure protection system are given in Subsections 5.2.3, 5.4.13, and 10.3.6.

5.2.2.8 Process Instrumentation

Process instrumentation for the overpressure protection system is shown on Figures 5.1-3 and 5.1-4 and described in Chapter 7. Instrumentation associated with pressurizer relief discharge is described in Subsection 5.4.11.

5.2.2.9 System Reliability

Reliability of the main steam safety valves is discussed in Subsection 10.3.3. The pressurizer safety valves are spring actuated mechanisms, and cannot close when setpoint pressure is exceeded. The operational reliability of the pressurizer safety valves is assured by:

a) Compliance with ASME Code, Sections III and XI for safety valves

b) Conservative design criteria

c) Selection of a vendor with proven experience and expertise

d) Accounting for thermal cycling during valve operation

e) Technical Specifications

5.2.2.10 Testing and Inspection

Each safety valve undergoes initial testing by the valve vendor. Subsequent testing and inspection of the pressurizer safety valves is governed by ASME Code, Section XI, Subsection IWV. Testing and inspection of the main steam safety valves is discussed in Subsection 10.3.4.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIAL

5.2.3.1 Material Specifications

A list of specifications for the principal ferritic materials, austenitic stainless steels, bolting and weld materials, which are a part of the reactor coolant pressure boundary is given in Tables 5.2-3 and 5.2-4.

To reduce sensitivity to neutron-induced changes in service, low residual requirements for copper, phosphorous, and vanadium are imposed on plate and weld materials in the reactor vessel belt-line. The core beltline region as defined by Appendix G of 10 CFR 50 includes the intermediate and lower shell courses and their longitudinal weld seams. Also included is the girth seam joining the intermediate to lower shell courses. The chemical content of the reactor vessel beltline plate and weld material as determined by chemical analysis is given in Tables 5.2-5 and 5.2-6.

5.2.3.2 Compatibility With Reactor Coolant

5.2.3.2.1 Reactor Coolant Chemistry

Controlled water chemistry is maintained within the Reactor Coolant System. Control of the reactor coolant chemistry is the function of the Chemical and Volume Control System which is described in Subsection 9.3.4. Water chemistry limits applicable to the Reactor Coolant System are given in Subsection 9.3.4.

5.2.3.2.2 Materials Compatibility

The materials of construction used in the reactor coolant pressure boundary and for modifications to instrument nozzles which are in contact with reactor coolant are designated by an "a" in Tables 5.2-3 and 5.2-4. These materials have been selected to minimize corrosion and have previously demonstrated satisfactory performance in other existing operating reactor plants.

5.2.3.2.3 Compatibility with External Insulation

5.2.3.2.3.l NSSS Components

The possibility of leakage of reactor coolant onto the parts of the reactor coolant pressure boundary causing corrosion of the pressure boundary has been investigated for reactors similar to St Lucie Unit 2. Tests have shown that Reactor Coolant System leakage onto surfaces of the reactor coolant pressure boundary does not affect the integrity of the pressure boundary.

The reactor vessel closure head dome and lower portion of the reactor vessel are insulated with stainless steel reflective insulation to minimize insulation contamination in the event of a spillage. Metal encapsulated fiberglass insulating wool blanket is used to insulate the reactor vessel closure head flange.

The steam generators are insulated with stainless steel reflective insulation in response to NRC Generic Letter 2004-02 “Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors,” which satisfies the requirements provided in the guidance report, NEI-04-07, “Pressurized Water Reactor Sump Performance Evaluation Methodology.”

The quantity of leachable halogens is in accordance with Regulatory Guide 1.36, "Non-metallic Thermal Insulation for Austenitic Stainless Steel," February, 1973 (R0).

The other NSSS components are insulated with non-metallic insulation which is in accordance with the requirements of Regulatory Guide 1.36 (R0).

5.2.3.2.3.2 AE-Supplied Components

The piping within the RCPB is insulated for thermal, personnel or anti- sweat requirements. All insulation used inside the containment consists primarily of fiberglass or metallic reflective insulation. The quantities and locations of each type of insulation are provided in Table 6.2-40; the materials of construction of each type of insulation are listed in Table 6.2-39.

The insulation on stainless steel components is in accordance with the requirements of Regulatory Guide 1.36 (R0).

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

The tests and acceptance requirements of 10 CFR 50, Appendix G, are applied to the reactor coolant pressure boundary ferritic materials, bolting and weld materials used for fabrication of the reactor vessel, steam generators (primary side), pressurizer, and the reactor coolant piping.

An alternate procedure is used for tributory nozzles (spray and let down/ drain) in the reactor coolant piping. This material is tested in accordance with the ASME Code, Section III, 1971 edition through Winter 1972 addenda to, Paragraph NB-2332.a, which requires three Charpy V-notch specimens tested at a single temperature for pumps, valves, and fittings with pipe connection of nominal wall thickness 2-1/2 inches or less. The material must exhibit a minimum of 40 mils lateral expansion at or below the lowest service temperature. Drop weight specimens are not required, therefore no T_{NDT} has been determined for this material. However, the lateral expansion requirement is more severe than that required by 10 CFR 50 Appendix G and a conservative RT_{NDT} has been estimated by use of the Branch Technical Position MTEB 5-2, "Fracture Toughness Requirements for Older Plants," as shown in Table 5.2-12. These RT_{NDT} values were estimated using the CVN values presented in Table 5.2-12A. The lowest service temperature for these nozzles is 40°F.

The material for bolting and other fasteners greater than one inch diameter is purchased to the ASME Code Edition and Addenda specified for the component in which they are used. Table 5.2-1 lists Code Editions and Addenda for the components of the reactor coolant pressure boundary. These materials meet the requirements of the Code Edition and Addenda to which they are ordered.

Although these materials are ordered prior to the publication of 10 CFR 50 Appendix G, sufficient testing to demonstrate compliance with Appendix G is performed in all but two cases. The acceptability of these two cases can be demonstrated, however, as follows:

a) The 2-3/8 inch hex bar of SA-193 Gr. B7 used for pressurizer manway nuts, material ID No. C-5364, displays 25-53 ft-lbs absorbed energy and 18-33 mils lateral expansion at 10°F (see Table 5.2-13a). Since full curves are not required for this material, testing over a range of temperatures is not normally done. Examination of the percent shear results show that the tests were done in the transition region of the Charpy curve; the range of shear values was 40-80 percent and two of the three specimens exhibited over 50 percent shear. At the 10°F test temperature two specimens met the 25 mils lateral expansion requirement. At a temperature 30°F higher (40°F), it is expected that all specimens would exceed 25 mils lateral expansion. The data for SA-193 Gr. B-7 material, given in Table 5.2-13c, exhibits in excess of 30 mils lateral expansion at a minimum of 66 percent shear. Thus, had testing been done at 40°F, the requirements of 10 CFR 50 Appendix G would have been met.

   The heat treatment for material ID. No. C-5364 is given in Table 5.2-13b; the heat treatment for the Table 5.2-13c data is given in Table 5.2-13d. Each of these heat treatments produce similar metallurgical structures in this alloy.

   The preload temperature for these fasteners, equivalent to their lowest service temperature, is 70°F.

b) No data on lateral expansion are reported for material ID. No. C-5365, SA540 Gr. B-24, a 1.656 inch diameter bar used for pressurizer manway studs. This material exhibited absorbed energy values of between 54 and 58 ft-lbs 10°F, well in excess of the required 45 ft-lbs. WRC Bulletin 175, "PVRC Recommendations on Toughness Requirements for Ferritic Materials," August 1972, contains energy (ft-lbs) versus lateral expansion (mils) data for bolting steels of the 4340 (SA-540 Gr. B-23 and B-24) composition. Based on this data, at least 30 mils lateral expansion was obtained for bolting steels exhibiting a minimum of 54 ft-lbs absorbed energy. Therefore, the lateral expansion requirement (25 mils) for the SL2 material (ID. No. C-5365) would be met at 10°F.

Fracture toughness data as required by 10 CFR 50, Appendix G is presented in Tables 5.2-7 through 5.2-13. Charpy V-notch test results are shown on Figures 5.2-2 through 5.2-23c.

All ferritic reactor coolant pressure boundary (RCPB) welds were made using submerged arc or covered electrode weld process. The fracture toughness data for the beltline welds are included in Table 5.2-7a. Impact test data for all weld materials used in the beltline region were taken from the weld metal certification tests of NB-2400. The highest RT_{NDT} for the beltline region weld materials is -40°F. In all cases RT_{NDT} is fixed by the NDT temperature.

The test specimens for core beltline welds are made with the same pre, interpass, and post-weld temperature requirements as the reactor vessel welds. The specimens receive a 40 hour, 1150 ± 25°F stress relief treatment equivalent to the stress relief given to the vessel. The test specimens are in the same metallurgical condition as are the welds in the core beltline region.

Testing and measuring equipment for fracture toughness tests for the reactor vessel, steam generators, pressurizer, reactor coolant pumps and piping are calibrated in accordance with Paragraphs NA-4600 and NB-2360 of the 1971 ASME Code Section III, through Summer 1972 Addenda (Winter 1972 Addenda for piping).

The personnel performing impact testing were qualified in accordance with the ASME Boiler and Pressure Vessel Code. Compliance with the ASME B&PV Code is verified by Combustion Engineering quality assurance procedures, and reviewed by ASME and NRC audits.

As required by the Code, the personnel performing impact testing are certified by qualified supervisory personnel. Records of this certification are maintained in accordance with NA-4900, "Records and Data Reports," and are available for review at Combustion Engineering's Chattanooga facility. Combustion Engineering training methods comply with the revision of 10 CFR 50 Appendix G published November 14, 1980 "for comment".

All of the ferritic pressure retaining materials used in the fabrication of the replacement Reactor Vessel Closure Head (RVCH) have been tested to demonstrate compliance with the fracture toughness requirements of 10 CFR 50, Appendix G as required by the Code. All aspects of the fracture toughness (impact) testing were performed in compliance with SUBARTICLE NB-2200 and SUBARTICLE NB-2300 of ASME Code Section III, Division 1, 1989 Edition No Addenda.

5.2.3.3.2 Control of Welding

5.2.3.3.2.1 Avoidance of Cold Cracking

5.2.3.3.2.1.1 NSSS Components

St. Lucie Unit 2 components conform to NRC Regulatory Guide 1.50, "Control of Preheat Temperature for Welding of Low-Alloy Steel," May 1973 (R0) except for Part C, Paragraphs 1.b and 2.

The strict interpretation of Paragraph 1.b would imply that the qualification plates are an infinite heat sink that would instantaneously dissipate the heat input from the welding process. The procedure qualification consists of starting the welding at the minimum preheat temperature. Welding is continued until the maximum interpass temperature is reached. At this time, the test plate is permitted to cool to the minimum preheat temperature and the welding is restarted. Preheat temperatures utilized for low alloy steels are in accordance with Appendix D of Section III of the ASME Code. The maximum interpass temperature utilized is 500°F. This position applies to the steam generators, reactor vessels, 42 inch and 30 inch Reactor Coolant System piping and pressurizer.

The Paragraph 2 requirement is considered an unnecessary extension of present NSSS vendor procedures, which continue to produce low-alloy steel welds meeting ASME Code Sections III and IX requirements. The requirements of Regulatory Guide 1.50 (R0) are met by compliance with Paragraph 4. The soundness of all welds is verified by ASME Code acceptable examination procedures.

With regard to Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low Alloy Steel Components," May 1973 (R0), major Reactor Coolant System components are fabricated with corrosion resistant cladding on internal surfaces exposed to reactor coolant. The major portion of the material protected by cladding from exposure to reactor coolant is SA-533, Grade B, Class 1 plate which, as discussed in the Regulatory Guide, is immune to underclad cracking. Cladding performed on SA-508, Class 2 forging material is performed using low-heat-input welding processes controlled to minimize heating of the base metal.

Moisture Control for low hydrogen covered arc welding electrodes is consistent with Subparagraph NB-2440 of ASME Code, Section III and the requirements of SFA 5.1, "Specification for Mild Steel Covered Arc Welding Electrodes," of ASME Code, Section II.

The replacement Reactor Vessel Closure Head is SA-508, Class 3 forging material. All high heat input welding procedures used to apply the cladding were first qualified by undergoing Intergranular Separation Test as part of the weld procedure qualification. The base materials for the procedure qualification were of the same specification and grade as were used in the cladding of the Reactor Vessel Closure Head.

5.2.3.3.2.1.2 AE-Supplied Components

Low-alloy steels are not utilized in any AE-Supplied RCPB components, therefore, Regulatory Guides 1.50 and 1.43 are not applicable.

5.2.3.3.2.2 Conformance to Regulatory Guide 1.34

Regulatory Guide 1.34, "Control of Electroslag Weld Properties," December, 1972 (R0), addresses controls to be applied during welding using the electroslag process. The electroslag process has not been used in the fabrication of any reactor coolant pressure boundary components. Therefore, the recommendations of this guide are not applicable.

5.2.3.3.2.3 Conformance to Regulatory Guide 1.71

5.2.3.3.2.3.1 NSSS Components

St. Lucie Unit 2 does not comply with the specific requirements of Regulatory Guide 1.71, "Welder Qualification for Areas of Limited Accessibility," December, 1973 (R0). Performance qualifications, for personnel welding under conditions of limited accessibility, are conducted and maintained in accordance with the requirements of ASME Code, Sections III and IX.
A requalification is required when (1) any of the essential variables of Section IX are changed, or (2) when authorized personnel have reason to question the ability of the welder to satisfactorily perform to the applicable requirements. Production welding is monitored for compliance with the procedure parameters and welding qualification requirements are certified in accordance with Sections III and IX. Weld quality is verified by the performance of the required nondestructive examination.

5.2.3.3.2.3.2 AE-Supplied Components

Conformance to Regulatory Guide 1.71 (R0) is provided in Subsection 5.2.3.4.2.1.2.

5.2.3.3.3 Nondestructive Examination of Tubular Products

5.2.3.3.3.1 NSSS Components

All tubular products used for components of the reactor coolant pressure boundary are nondestructively examined in accordance with the requirements of the ASME Code, Section III, Division 1, with the applicable edition and addenda as listed in Table 5.2-1. In addition the non-destructive examination requirements of all these tubular products (except the two components noted below) are consistent with the recommendations of Regulatory Guide 1.66, "Nondestructive Examination of Tubular Products," October 1973 (R0).

The two components (pressurizer heater tubing and heater sleeve tubing) are ultrasonically tested in accordance with the requirements of the ASME Code Addenda for the 1971 Edition Summer 1972 Addendum.

Reactor vessel instrument tubing and CEDM nozzle housings for the replacement RVCH were ultrasonically examined in accordance with NB-2552.2, in addition to the examinations required by NB-2551(b) of ASME Code Section III, Division 1, 1989 Edition, No Addenda.

5.2.3.3.3.2 AE-Supplied Components

Class 1 and 2 tubular products of the reactor coolant pressure boundary are examined in accordance with the requirements of ASME III, NB 2552 and NB 2560. See Table 5.2-1 for code dates. All pressure retaining forgings associated with inlet piping connections of 2-1/2 inches nominal size and over, are 100 percent liquid penetrant examined. All bevelled weld ends and longitudinal welds are liquid penetrant examined.

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

5.2.3.4.1 Avoidance of Stress Corrosion Cracking

5.2.3.4.1.1 Avoidance of Sensitization

5.2.3.4.1.1.1 NSSS Components

St. Lucie Unit 2 is consistent with the recommendations of Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," May 1973 (R0), as described in items a) through e), except for the criterion used to demonstrate freedom from sensitization. The ASTM A708 Strauss Test was used in lieu of the ASTM A262 Practice E, Modified Strauss Test, to demonstrate freedom from sensitization in fabricated, unstabilized, stainless steel.

a) Solution Heat Treatment Requirements

All raw austenitic stainless steel material, both wrought and cast, used in the fabrication of the major NSSS components in the reactor coolant pressure boundary, was supplied in the annealed condition as specified by the pertinent ASTM or ASME Code; viz, 1900-2050°F for 1/2 to one hour per inch of thickness and water quenched to below 700°F. The time at temperature was determined by the size and type of component.

Solution heat treatment was not performed on completed or partially-fabricated components. Rather, the extent of chromium carbide precipitation is controlled during all stages of fabrication as described below.

b) Material Inspection Program

Extensive testing on stainless steel mockups, fabricated using production techniques, was conducted to determine the effect of various welding procedures on the susceptibility of unstabilized 300 series stainless steels to sensitization-induced intergranular corrosion. Only those procedures and/or practices demonstrated not to produce a sensitized structure were used in the fabrication of these reactor coolant pressure boundary components. The ASTM standard A708 (Strauss test) was the criterion used to determine susceptibility to intergranular corrosion. This test has shown excellent correlation with a form of localized corrosion peculiar to sensitized stainless steels. As such, ASTM A708 was utilized as a go/no-go standard for acceptability.

As a result of the above tests, a relationship was established between the carbon content of 304 stainless steel and weld heat input. This relationship is used to avoid weld heat affected zone sensitization as described below.

c) Unstabilized Austenitic Stainless Steels

The unstabilized grades of austenitic stainless steels with carbon contents of more than 0.03 percent used for components of the reactor coolant pressure boundary are Type 304 and 316. These materials are furnished in the solution annealed condition. Exposure of completed or partially fabricated components to temperatures ranging from 800°F to 1500°F is prohibited.

Duplex, austenitic stainless steels, containing more than 5 FN delta ferrite (weld metal, cast metal, weld deposit overlay), are not considered unstabilized since these alloys do not sensitize, that is, form a continuous network of chromium-iron carbides. Specifically, alloys in this category are:

CF8M CF8	Cast Stainless Steel	Delta ferrite controlled to 5 FN-28 FN
308 309 312 316	-	Single and combined stainless steel weld filler metals. Delta ferrite controlled to 5 FN-18 FN as deposited.

In duplex austenitic/ferritic alloys, chromium-iron carbides are precipitated preferentially at the ferrite/austenite interfaces during exposure to temperatures ranging from 800°F to 1500°F. This precipitate morphology precludes intergranular penetrations associated with sensitized 300 series stainless steels exposed to oxygenated or fluoride environments.

d) Avoidance of Sensitization

Exposure of unstabilized austenitic 300 series stainless steels to temperatures ranging from 800°F to 1500°F results in carbide precipitation. The degree of carbide precipitation or sensitization depends on the temperature, the time at the temperature, and also the carbon content.

Weld heat affected zone sensitized austenitic stainless steels were avoided by careful control of weld heat input to less than 60 kJ/inch, interpass temperature to a maximum of 350°F and carbon content.

Homogeneous or localized heat treatment in the temperature range 800 °F to 1500 °F was prohibited for unstabilized austenitic stainless steel with a carbon content greater than 0.03 percent used in components of the reactor coolant pressure boundary. When stainless steel safe ends were required on component nozzles or piping, fabrication techniques and sequencing required that the stainless steel piece be welded to the component after final stress relief. This is accomplished by welding an Inconel overlay on the end of the nozzle. Following final stress relief of the component, the stainless steel safe end is welded to the Inconel overlay, using Inconel weld filler metal.

PC/M 09078M implemented during SL2-19, mitigated cold leg spray and intermediate drain nozzles alloy 600 dissimilar metal (DM) welds by repair and replacement of the DM welds and safe ends. The replacement materials are 304L/316L stainless steel with welding materials of 309L and 316L. Prior to welding the safe end to the nozzle, two layers of ER309L were deposited on the ID and face of the weld prep, followed by two layers of ER316L. Once the nozzle buttering is complete, the 316L safe end was welded to the buttering using a groove weld of ER316L filler.

e) Cleanliness and Contamination Protection

The procedures and practices followed for cleaning and contamination protection of the Reactor Coolant Pressure Boundary components during fabrication, shipment and storage, construction, testing and operation are discussed in Subsection 5.2.3.4.1.2.

5.2.3.4.1.1.2 AE-Supplied Components

The conformance with Regulatory Guide 1.44 (R0) for AE-supplied components is provided in Subsection 6.1.1.

5.2.3.4.1.2 Avoidance of Contamination Causing Stress Corrosion Cracking

5.2.3.4.1.2.1 NSSS Components

Specific requirements for cleanliness and contamination protection are included in the equipment specifications for components fabricated with austenitic stainless steel. The provisions described below indicate the type of procedures utilized for NSSS supplied components to provide contamination control as required by Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," March, 1973 (R0). (See Section 17.2)

Contamination of austenitic stainless steels of the 300 type by compounds which can alter the physical or metallurgical structure and/or properties of the material was avoided during all stages of fabrication. Painting of 300 series stainless steels was prohibited. Grinding was accomplished with resin or rubber-bounded aluminum oxide or silicon carbide wheels which were not previously used on materials other than austenitic alloys. Outside storage of partially fabricated components was avoided and in most cases prohibited. Exceptions were made with certain structures provided they were dry, completely covered with a waterproof material, and kept above ground.

Internal surfaces of completed components were cleaned to produce an item which is clean to the extent that grit, scale, corrosion products, grease oil, wax, gum, adhered or embedded dust or extraneous materials were not visible to the unaided eye. Cleaning was effected by either solvents (acetone or isotropyl alcohol) or inhibited water (30-200 ppm hydrazine or 0.5-0.75 weight percent trisodium phosphate). Cleaning water conformed to the following requirements:

the following requirements:

Halides	
Chloride (ppm)	< 0.60
Fluoride (ppm)	< 0.40
Conductivity (μmhos/cm)	< 5.0
pH	6.0 - 8.0
Visual clarity	No turbidity, oil or sediment

Prior to shipment, reactor coolant pressure boundary components were packaged in such a manner that they were protected from weather, dirt, wind, water spray, and any other extraneous environmental conditions encountered during shipment and subsequent site storage. The environment within the package and/or component was maintained clean and dry. In some instances, use of a desiccant-breather system was utilized. The shipment package was employed for site storage and was not removed until the component was installed within the containment.

To prevent halide-induced intergranular corrosion, which could occur in aqueous environment with significant quantities of dissolved oxygen, solutions were inhibited via additions of hydrazine or phosphate. Results of tests have proven these inhibitors to be completely effective. Operational chemistry specifications restrict concentrations of halide and oxygen, both prerequisites of intergranular attacks (refer to Subsection 9.3.4).

5.2.3.4.1.2.2 AE-Supplied Components

The specific cleanliness requirements and contamination protection are in accordance with the Regulatory Guide 1.37 (R0).

5.2.3.4.1.3 Characteristics and Mechanical Properties of Cold-Worked Austenitic Stainless Steels for Reactor Coolant Pressure Boundary Components

Cold-worked austenitic stainless steel is not utilized for components of the reactor coolant pressure boundary.

5.2.3.4.2 Control of Welding

5.2.3.4.2.1 Avoidance of Hot Cracking

5.2.3.4.2.1.1 NSSS Components

In order to preclude microfissuring in austenitic stainless steel welds, reactor coolant pressure boundary components are consistent with the recommendations of the Interim Position (Branch Technical Position MTEB 5-1) Regulatory Guide 1.31, Control of Stainless Steel Welding, except for the differences noted below.

a) Major Reactor Coolant Pressure Boundary Components, Excluding Reactor Coolant Pumps

The delta ferrite content of A-No. 8 austenitic stainless steel filler metal, except for 16-8-2, in the fabrication of components of the reactor coolant pressure boundary has been controlled to 5-18 FN. Delta ferrite content was determined by magnetic measurement or chemical analysis in conjunction with the Schaeffler or McKay Diagram, performed on undiluted weld deposits. In the case of filler metal used with a non-consumable electrode process, the delta ferrite content may have been determined by chemical analysis of the rod, wire or consumable insert in conjunction with the stainless steel constitution diagram.

The ferrite requirements were met for each heat, lot, or heat/lot combination of weld filler material.

b) The quality and structural adequacy of welds in the reactor coolant pumps were assured by the use of controls on materials, procedures, and personnel. These controls were selected to be pertinent to the component functional safety level required and generally, were imposed through the appropriate ASME Code referenced in Table 5.2-1.

Conformance to Regulatory Guide 1.34, "Control of Electroslag weld Properties," December 1972 (R0) is discussed in Subsection 5.2.3.3.2.2.

Conformance to Regulatory Guide 1.71, "Welder Qualification for Areas of Limited Accessibility," December, 1973 (R0) is discussed in Subsection 5.2.3.3.2.3.

5.2.3.4.2.1.2 AE-Supplied Components

Conformance to Interim Position MTEB 5-1 on Regulatory Guide 1.31 is provided in Subsection 6.1.1.

Regulatory Guide 1.34, (R0) does not apply since electroslag welding is not utilized on non-NSSS Components.

Conformance to Regulatory Guide 1.71 (R0) is as follows:

Welder qualification under simulated limited-access conditions is not performed. However, the objective of the Regulatory Guide is adhered to by using welding supervisors to monitor welders and place an experienced welder(s) at limited-access locations.

5.2.3.4.3 Nondestructive Examination

Nondestructive examination of tubular products is discussed in Subsection 5.2.3.3.3.

5.2.4 INSERVICE INSPECTION AND TESTING OF REACTOR COOLANT PRESSURE BOUNDARY

An inservice inspection program is provided for the examination of the Quality Group A reactor coolant pressure boundary (RCPB) components and supports as defined by Code Class 1 in ASME Code, Section XI. The purpose of the inservice inspection program is to periodically monitor the systems or components requiring inservice inspection program in order to identify and to repair those indications which do not meet acceptance standards. The acceptance standards are provided in the ASME Code Section XI. The initial inservice inspections conducted during the first 120 month period following commercial plant operation will be developed to the requirements of 10 CFR 50.55a(g), to the extent practical. Where it becomes impractical to meet this criteria, relief from requirements, on a case-by-case basis, will be requested. References 1, 2, 3, 4. A list of these relief requests is provided in the inservice inspection program.

5.2.4.1 <u>System Boundary Subject to Inspection</u>

The system boundary subject to inspection is defined in 10 CFR 50, Section 50.2(v). The reactor pressure vessel, pressurizer, primary side of the steam generator and associated piping, pumps, valves, bolting, and component supports are subjected to inspection.

5.2.4.2 <u>Arrangement of Systems and Components to Provide Accessibility</u>

Provisions are made in the plant design for access to permit the conduct of preoperational and inservice inspections as specified in the ASME Code, Section XI. The inservice inspection program shall be updated periodically to meet the 10 CFR 50.55a(g) requirements. The design and arrangement of the components are such that space is provided to conduct examinations either from the interior or the exterior or a combination of both.

The use of conventional nondestructive, and visual test techniques, both direct and remote, can be applied to the Reactor Coolant System components. The high radiation levels and remote underwater accessibility of the reactor vessel present special problems. In order to facilitate an inservice inspection of the vessel from the internal surfaces during refueling, the vessel internals and the core barrel are removable. During refueling, the reactor vessel head, closure seal surfaces and studs may be examined. This allows the internal parts of the vessel which are visible, including the cladding and components, to be visually checked, as well as allowing access to the vessel wall for volumetric examinations.

The design considerations which have been incorporated into the system and plant layout to permit the required examinations are as follows:

a) Storage space is provided for the reactor vessel internals and core barrel in the refueling cavity, which permits internal and external examinations of these components.

b) The reactor vessel head is stored dry on the containment operating floor during refueling to facilitate direct visual inspection.

c) Reactor vessel studs, nuts and washers can be removed to dry storage during refueling.

d) Limited clearance is provided around the reactor coolant piping penetrating the primary shield which permits access to at least one of the reactor vessel cold leg nozzle welds.

e) Limited access is provided to the external surface of the reactor vessel lower head through the reactor cavity drain tunnel.

f) Access is provided via manways into the primary water box side of the steam generator. An access opening in the support skirt provides for inspection of the staywell welds.

g) A manway is provided in the pressurizer to allow access for internal inspection.

h) The reactor coolant pumps can be disassembled and inspected internally. Also, access is provided for the volumetric examination of the motor flywheels.

i) Insulation on Reactor Coolant System components and piping is removable where necessary.

j) Portions of the auxiliary systems piping, and Emergency Core Cooling System piping are arranged for maximum accessibility inside the containment. Access is not available to the segments of these systems where the piping penetrates the Reactor Coolant System shield wall.

k) Portions of the auxiliary system piping and emergency core cooling piping external to the containment are accessible for inspection at any time except where the piping penetrates the concrete floors and walls.

l) The piping supports and restraints are designed to facilitate accessibility for examination to the maximum practicable extent commensurate with other design requirements. Certain welds in pipe restraint structures will not be available for inspection after installation. An example of this inaccessibility is the welds attaching shear keys to the base or anchor plates. The shear keys are embedded in cement grout during installation and are therefore inaccessible for visual examination.

m) Safety and relief valves are flanged and can be removed from the system for disassembly and internal inspection.

5.2.4.3 Examination Techniques and Procedures

Examinations include liquid penetrant or magnetic particle techniques when surface examination is specified, ultrasonic, eddy current or radiographic techniques when volumetric examination is specified, and visual inspection techniques are used to determine surface condition of components and for evidence of leakage. Specific techniques, procedures, and equipment are defined in the inservice inspection program.

5.2.4.4 Inspection Intervals

The inspection interval for the examination program is in accordance with the ASME Code, Section XI requirements and is defined in the inservice inspection program.

5.2.4.5 Categories and Requirements

The inservice inspection program category and examination requirements for the reactor coolant pressure boundary components, including their supports, comply with the ASME Code, Section XI.

5.2.4.6 Evaluation of Results

The evaluation of nondestructive examination results, acceptance standards and documentation is in accordance with the ASME Code, Section XI.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

Code Class 1 systems and components are subjected to (a) a system leakage test prior to startup following each reactor refueling outage, and (b) a system hydrostatic pressure test at or near the end of each inspection interval. The system temperature-pressure relationship is in agreement with Section XI requirements except as limited by the Technical Specifications. Operational limitations during heatup, cooldown, and system hydrostatic pressure testing, are provided in the Technical Specifications.

Table 5.2-15 shows the pressure isolation valves under the scope of Generic Letter 87-06, "Periodic Verification of Leaktight Integrity of Pressure Isolation Valves." The test frequency and leakage limits of these pressure isolation valves are provided in the Technical Specifications.

As an alternative to hydrostatic testing for welded repairs or installation of replacement items by welding in Class 1, 2, and 3 piping systems, a system leakage test using the 1992 edition of Section XI, paragraph IWA-5000, is acceptable when the rules of code case N-416-1 are applied to the repair or replacement activity. Reference 4 grants approval. Also, see Table 5.2-2.

5.2.5 DETECTION OF LEAKAGE THROUGH REACTOR COOLANT PRESSURE BOUNDARY

The reactor coolant pressure boundary (RCPB) leakage detection system is designed to detect and identify abnormal leakage within the limits given in the Technical Specifications. The RCPB leak detection system is capable of detecting unidentified leakage as low as 1.0 gpm within a reasonable time period. The instruments in the RCPB leakage detection system are calibrated at least once per 18 months.

The RCPB leakage detection system meets the intent of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973 (R0). Reference 5 documents NRC acceptance of the containment radiation monitoring system with respect to leak-before-break and Regulatory Guide 1.45.

5.2.5.1 Leakage Detection Methods

The means provided for leak detection consists of instrumentation which can detect general leakage from the reactor coolant pressure boundary. Through changes in liquid level, flow rate or radioactivity level, specific sources of leakage can frequently be identified. The various methods of detecting leakage (unidentified and identified) are discussed in the following subsections.

5.2.5.1.1 Sump Level Monitoring

Collection of water in the reactor cavity sump indicates possible reactor coolant leakage. Reactor Building floor drains and containment fan cooling unit condensate drains are routed to the sump so that water does not accumulate in areas of the containment other than the sump.

All drains entering the sump are routed first to a measurement tank. A triangular notch weir is machined on the side of the measurement tank. The level of the flow through the weir corresponds to the flow of water into the tank. A water level switch is installed on the tank at the level that corresponds to a flow of one gpm into the tank; an alarm is annunciated whenever the flow rises to one gpm. A water level transmitter with a recorder in the control room is used to monitor the actual flow through the weir. The recorder has a range of 0 to 12 gpm.

5.2.5.1.2 Containment Airborne Particulate, Iodine and Gaseous Radioactivity Monitoring.

As described in Subsection 12.3.4.2.3.1, redundant seismic Category I containment atmosphere radiation monitors are designed to provide a continuous indication in the control room of the particulate, iodine and gaseous radioactivity levels inside the containment. Radioactivity in the containment atmosphere indicates the presence of fission products due to a Reactor Coolant System leak.

The monitor draws a sample of containment air through a continuous sampler assembly located outside the containment (see Figure 12.3-14). The sampler assembly is described in Subsection 11.5.2.1.2. The sampler assembly contains a three stage gas, particulate and iodine monitor as described in Subsection 11.5.2.1.3c. Alarms, data display and recorder are located on a seismic panel in the control room.

High radiation level and alert status alarms are provided in the control room. Leakages occurring under conditions having smaller percentages of failed fuel are better detected by the particulate detector. Listings of time rate of change in noble gas concentration and time for 10 percent deviation from normal are shown in Table 5.2-14 which are based on a postulated step increase in direct leakage from 0.1 gpm to one gpm at 85 percent thermal rating, 0.1 percent failed fuel, at the end of a 90 day purge cycle. The response times indicated represent the worst case.

5.2.5.1.3 Pressurizer Power Operated Relief Valves and Pressurizer Safety Valve Leakage

Leakage through the pressurizer power operated relief valves and pressurizer safety valves is detected by an increase in temperature in the valve discharge lines (Figure 5.1-4) and rising water level in the quench tank. These parameters are monitored as follows:

a) Discharge Line Temperature - Each of the pressurizer safety valve discharge lines contain a temperature detector (TE-1107, 1108, 1109) for monitoring valve leakage. The discharge lines from the power operated relief valves also contain temperature detectors (TE-1106 and 1110). Control room temperature monitoring instrumentation consist of indicator/alarm units (TIA-1107, 1108, 1109, 1106 and 1110) for each of these detectors.

b) Acoustic Monitor – Each pressurizer safety and PORV discharge line contain an accelerometer used for detection of flow noise through the valve. The noise signal is converted to a voltage proportional to the flow detected and is indicated in the control room. A common control room annunciator will alarm beyond a specific threshold. The control room operator will confirm the alarm by checking the individual monitors.

c) Quench Tank Water Level - Since the pressurizer safety valve or power operated relief valves discharge to the quench tank, steam leaking through the valves eventually condenses in the quench tank and causes increasing water level and temperature. Level indicator alarm unit LIA-1116 detects this increasing water level change and TIA-1116 detects corresponding increase in water temperature due to steam entry into the tank.

   Pressure does not significantly increase due to leakage of steam into the quench tank. Pressure measurement is used to measure quench tank pressure after a valve discharge.

5.2.5.1.4 Safety Injection Tank Check Valves

Leakage of reactor coolant through the safety injection tank check valves (V3215, 3225, 3235, 3245) shown on Figure 6.3-1c can be detected by:

a) Safety Injection Tank Water Level - In-leakage of reactor coolant to the safety injection tank produces a rising water level in the tank. This is detected by the tank level indicator/high-low alarm (LIA-3311, 3321, 3331 and 3341) and the level indicator/high high low low alarm (LIA-3312, 3322, 3332 and 3342) which actuate high water level alarms.

b) Safety Injection Tank Pressure - Since the safety injection tank is a relatively small closed volume with a nitrogen cover gas, the rising water level due to reactor coolant in-flow is accompanied by an increasing tank pressure. Pressure indicator alarm units (PIA-3311, 3321, 3331 and 3341) on the control board monitor the tank pressure and annunciate alarms on high tank pressure as well as pressure switches PIS-3313, -3323, -3333 & -3343 which also actuate a high-high pressure alarm.

c) Safety Injection Tank Sample - RCS inleakage can be confirmed by sampling.

The Safety Injection Tank check valves are within the Scope of Generic Letter 87-06, "Periodic Verification of Leaktight Integrity of Pressure Isolation Valves." The test frequency and leakage limits of these pressure isolation valves are provided in the Unit 2 Technical Specifications.

5.2.5.1.5 Heat Exchanger Leakage

Leakage of reactor coolant through the letdown heat exchanger, reactor coolant pump seal heat exchanger, or sample heat exchangers can be detected by either of the following:

a) Component cooling system radiation - Heat exchanger leaks produce leakage of reactor coolant and fission products into the Component Cooling Water System. Such leakage increases radiation levels in the system and can be detected by the two component cooling water monitors described in Subsection 11.5.2.2.1. These monitors alarm and indicate in the control room.

   Complete dispersion of only one gallon of reactor coolant throughout the volume of the Component Cooling Water System is sufficient to cause early detectable rapid change in detector scale provided there is no residual radioactivity already present in the component cooling water. In this case the limit on detection is the transport time around the Component Cooling Water System loop. The true detection time however is based both on component cooling water radiation being directly proportional to the product of percent failed fuel and leak rate, and the amount of residual radiation already in the system.

b) Component cooling surge tank water level - Inleakage of reactor coolant increases the inventory in the Component Cooling Water System, causing a rising surge tank water level. A one gpm leak into the component cooling water surge tank can be detected and alarmed within eight hours. Level switch LS-14-5 and local gage glasses (LG-14-2 A and B) mounted on the surge tank provide control room high water level alarms and local indication of tank water level, respectively.

5.2.5.1.6 Steam Generator Tube Leakage

Leakage of reactor coolant through the steam generator tubing is indicated by secondary side radioactivity. The following are methods for detecting the resulting radiation levels.

a) Blowdown line radiation - Increasing radiation levels due to dissolved and estrained fission products in the secondary side water can be detected by the radiation monitors in the steam generator blowdown lines. Remote readout and high radiation alarms are provided. These monitors are described in Subsection 11.5.2.2.4.

b) Off gas radiation - Increasing off gas radiation due to gaseous and volatile fission products in the Main Steam System can be detected by the radiation monitor in the condenser air ejector discharge or the atmospheric steam dump exhaust monitor. These monitors are described in Subsections 11.5.2.2.7 and 11.5.2.2.12.

c) Blowdown sample analysis Steam generator water samples are taken periodically. The sample is analyzed for dose equivalent I-131 and gross activity. The analyses provide the capability of detecting reactor coolant leakage into the steam generator secondary side.

The time to detect a one gpm leak depends on reactor coolant activity and previous leakage. A change from 0.1 gpm to one gpm leak can be detected in approximately two hours by the steam generator blowdown radiation monitor. A one gpm leak with no previous leakage can be detected in less than 20 minutes.

Calculation PSL-2FJI-99-001 (Ref. 6), Steam Generator Blowdown Radiation Monitor Response Time St. Lucie Unit 2, determined that the time to reach the activity concentration corresponding to the radiation monitor alarm setpoint of two times background is approximately 4 seconds. These results confirmed the validity of the value listed in Table 5.2-14. However, since this response time was calculated assuming different conditions than those assumed in Table 5.2-14, Table 5.2-14 was not revised to reflect the calculated value. Calculation PSL-2FJI-99-001 also determined the transit time from the steam generator to the radiation monitor to be 500 seconds, for a total radiation monitor response time of approximately 9 minutes which confirms the validity of the value cited above of less than 20 minutes to detect a one gpm leak with no previous leakage.

5.2.5.1.7 Reactor Coolant Makeup

An important means of detecting abnormal leakage from the Reactor Coolant System is through measurement of the net amount of makeup flow to the system. Since all normal sources of outflow from the system such as letdown flow and reactor coolant pump controlled bleedoff are collected and recycled back into the Reactor Coolant System by the Chemical and Volume Control System described in Subsection 9.3.4, the net inventory in the Reactor Coolant System and Chemical and Volume Control System under normal operating conditions is constant. Transient changes in letdown flow rate or Reactor Coolant System inventory can be accommodated by changes in the volume control tank water level. The net makeup to the system under zero leakage steady state conditions should be essentially zero. The makeup flow rates from the makeup water system and boric acid makeup tanks are continuously monitored and recorded. Any increasing trend in the amount of makeup required indicates a leak which is increasing in rate. Suddenly occurring leaks are indicated by a step increase in the amount of makeup which does not decrease as would be the case for a purely transient condition. Additionally, a RCS inventory balance is performed per Technical Specifications using the makeup volume as input.

The maximum capacity of the Chemical and Volume Control System for reactor coolant makeup is 132 gpm (three 44 gpm charging pumps) which gives a ratio of maximum allowable leakage to makeup to 1/132.

5.2.5.1.8 Reactor Coolant Pump Seals

Instrumentation shown on Figure 5.1-6 detects abnormal seal operation. The reactor coolant pumps are equipped with three stages of seals plus a vapor backup seal as described in Subsection 5.4.1. During operation the Reactor Coolant System operating pressure is decreased through the three seals to approximately volume control tank pressure. The vapor seal prevents leakage to the containment atmosphere and allows sufficient pressure to be maintained to direct the controlled seal leakage to the volume control tank. The vapor seal is designed to withstand full Reactor Coolant System pressure in the event of failure of any or all of the three primary seals, provided the pump is not rotating.

Referring to Figure 5.1-6, the reactor coolant pump P&ID, there is sufficient instrumentation on the reactor coolant pump to detect seal degradation and leakage. All these reactor coolant pump control grade instruments have appropriate high or low range alarms to alert the operator to seal malfunction. The DCS was expanded to include the reactor coolant pump monitoring and display system. A more detailed discussion of the DCS can be found in Subsection 7.5.1.4a. The flat panel display was installed to integrate the RCP monitoring and display system into the DCS in addition to the equipment discussed in Subsection 7.5.1.4a.

5.2.5.1.9 Reactor Vessel Head Closure Leakage

Reactor Vessel Head Closure Flange sealing is accomplished by a double-seal arrangement utilizing two silver jacketed Ni-Cr-Fe alloy spring-energized O-ring seals. The space between the double O-ring seal is monitored by a local pressure gage (PI-1118) and pressure switch (PS-1118) shown on Figure 5.1-3 to detect an increase in pressure which indicates a leak past the inner O-ring. A high pressure alarm actuated by pressure switch PS-1118 alerts the operator to the presence of leakage past the inner seal.

5.2.5.1.10 Reactor Coolant Pump Flange Closure Leakage

This system is essentially the same as the one for the reactor vessel head closure described in Subsection 5.2.5.1.9. The local indicators (PI-1150, 1160, 1170 and 1180) and pressure switches (PS-1150, 1160, 1170 and 1180), shown on Figure 5.1-6, provide the leak detection monitoring system with control room via the annunciator window and a Distributed Control System (DCS) driven Flat Panel Display annunciation for the reactor coolant pump closures.

5.2.5.1.11 Containment Atmosphere Temperature Indication

Temperature indication is not an absolute method of detecting leakage. However, temperature indication is provided for monitoring the containment after a leak has occurred.

5.2.5.1.12 Safety Injection and Shutdown Cooling Isolation and Check Valves

Certain Safety Injection and Shutdown Cooling Valves as identified in Table 5.2-15 are within the scope of Generic Letter 87-06, "Periodic Verification of Leaktight Integrity of Pressure Isolation Valves." The test frequency and leakage limits of these pressure isolation valves are provided in the Unit 2 Technical Specifications.

5.2.5.2 Indication in Control Room

The primary indications of reactor coolant leakage are:

a) Containment sump flow indication and alarm
b) High containment particulate radioactivity indication and alarm
c) High containment gaseous radioactivity indication and alarm
d) High containment iodine radioactivity indication and alarm

Other control room instrumentation used in detecting and identifying reactor coolant leakage includes:

a) Temperature indication downstream of power operated relief valve and pressurizer safety valves and high temperature alarm.
b) Acoustic monitoring downstream of Pressurizer safeties & PORVs.
c) Quench tank temperature and water level indication and alarm.
d) Safety injection tank water level indication.
e) High and high-high safety injection tank levels alarm.
f) Safety injection tank pressure indication and high pressure alarm.
g) Component cooling water radiation indication.

g) Component cooling water surge tank high and low water level alarms
h) Steam generator blowdown radiation indication and alarm
i) Condenser steam jet air ejector exhaust radiation indication
j) Atmospheric steam dump exhaust monitor

5.2.5.3 Limits for Reactor Coolant Leakage

The limits for both identified and unidentified leakage are described in the Technical Specifications.

5.2.5.4 Differentiation Between Identified and Unidentified Leaks

Reactor Coolant System leakage is categorized as identified and unidentified leakage. Identified leakage is:

a) leakage (except seal water flow from the RCP seals) into closed systems, such as pump seal or valve packing leaks that are captured, and conducted to a sump or collecting tank, or

b) leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary leakage, or

c) reactor coolant system leakage through a steam generator to the secondary system.

All other leakage is unidentified leakage. Since identified leakage is known, its effect upon the various leakage detection systems also is known. An increase in leakage, resulting from unidentified leakage, is detected by the leakage detection systems. The systems are capable of responding to a one gpm leakage in one hour or less (refer to Table 5.2-14).

The containment air particulate and radioactive gas monitors provide the primary means of remotely identifying the source of leakage within the Reactor Building. If sump flow indicators detect leakage above normal without a corresponding increase in airborne activity level, the indicated source of leakage probably is from a nonradioactive system.

In order to identify leaks from the RCPB to the shell side of the steam generators, each steam generator has a sampling system. The sampling system is tapped off the blowdown line of each steam generator. Samplings from each steam generator are analyzed for radioactivity and chemistry to determine the integrity of the primary to secondary boundary within the steam generators.

Leakage from the Reactor Coolant System into the Component Cooling Water System is identified by an increase in water level in the component cooling water surge tanks and radioactivity in the system.

5.2.5.5 Testing and Inspection

Preoperational testing consists of calibrating the instruments, testing the automatic controls for activation at the proper set points and checking the operability and limits of alarm functions. Radiation detectors can be remotely checked against a standard source during normal operation.

h) Component cooling water surge tank high and low water level alarms
i) Steam generator blowdown radiation indication and alarm
j) Condenser steam jet air ejector exhaust radiation indication
k) Atmospheric steam dump exhaust monitor

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The limits for both identified and unidentified leakage are described in the Technical Specifications.

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b) leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary leakage, or

c) reactor coolant system leakage through a steam generator to the secondary system.

All other leakage is unidentified leakage. Since identified leakage is known, its effect upon the various leakage detection systems also is known. An increase in leakage, resulting from unidentified leakage, is detected by the leakage detection systems. The systems are capable of responding to a one gpm leakage within a reasonable time period (refer to Table 5.2-14).

The containment air particulate and radioactive gas monitors provide the primary means of remotely identifying the source of leakage within containment. If sump flow indicators detect leakage above normal without a corresponding increase in airborne activity level, the indicated source of leakage probably is from a nonradioactive system.

In order to identify leaks from the RCPB to the shell side of the steam generators, each steam generator has a sampling system. The sampling system is tapped off the blowdown line of each steam generator. Samplings from each steam generator are analyzed for radioactivity and chemistry to determine the integrity of the primary to secondary boundary within the steam generators.

Leakage from the Reactor Coolant System into the Component Cooling Water System is identified by an increase in water level in the component cooling water surge tanks and radioactivity in the system.

5.2.5.5 Testing and Inspection

Preoperational testing consists of calibrating the instruments, testing the automatic controls for activation at the proper set points and checking the operability and limits of alarm functions. Radiation detectors can be remotely checked against a standard source during normal operation.

Normal leakage rates are identified at the early stages of plant operation by the makeup water data. The normal operating levels are compared with the identified leakage and used to verify the sensitivity of the instrumentation.

5.2.5.6 Leakage Checks During Shutdown

Leakage of reactor coolant is checked during shutdowns in the following manner:

a) Prior to reactor startup following each refueling outage, pressure retaining components of the reactor coolant pressure boundary are visually examined for evidence of reactor coolant leakage while the system is under a test pressure of not less than the nominal system operating pressure.

b) The visual examinations above are conducted in conformance with the requirements of Section XI of the ASME Boiler and Pressure Vessel Code, subject to the modifications established by 10 CFR 50.55a.

   The source of any reactor coolant leakage detected by the examinations of (a) above will be located and evaluated for corrective measures as described in the ASME Code, subject to the modifications established by 10 CFR 50.55a.

5.2.6 LOW TEMPERATURE OVERPRESSURE PROTECTION (LTOP)

Overpressure protection of the Reactor Coolant System (RCS) during low temperature conditions is provided by power operated relief valves (PORVs) V1474 and V1475 connected to the pressurizer steam space and when the shutdown cooling system (SDCS) is in operation also by the SDCS relief valves. During hot standby and power operations, the PORVs open at a high pressure setpoint of 2370 psia. When the RCS is at low temperatures the operator realigns the PORV setpoints to a low pressure value of 490 psia for low temperature overpressure protection. The PORVs are shown on the piping and instrumentation diagram of Figure 5.1-4a and described in Subsection 5.4.13. The protection provided by the PORVs and SDCS relief valves precludes any overpressurizing transient from exceeding the technical specification pressure-temperature (P-T) operating limits.

Each PORV solenoid is supplied from a separate IE electrical source. For high pressure service the actuating signal is provided from the Reactor Protection System (RPS) high pressure trip. A separate-train signal is supplied to each PORV. For LTOP service the actuation of each PORV is provided by separate Class 1E channels of RCS temperature and pressure instrumentation.

The low temperature overpressure protection provided by the relief valves is required during heatup and cooldown and during extended periods of cold shutdowns. The low pressure setpoint of 490 psia is incorporated in the LTOP mode since each PORV is designed to accommodate the most limiting transients as described in Subsection 5.2.6.2.1. Per the Technical Specifications, the PORVs are used for LTOP during heatup when any RCS cold leg temperature is in the range from 80-246°F and during cooldown when any RCS cold leg temperature is 224°F and below to 132°F. For temperatures below 132°F during cooldown, the SDCS relief valves are the only means of LTOP. In addition to administrative controls and procedures, a low temperature alarm is provided to alert the operator to align the LTOP system. To maintain RCS overpressure protection, the relief valves are aligned at all temperatures below the P-T curve limits corresponding to the pressurizer safety valve setpoint of 2,500 psia. At temperatures above the temperature limit which corresponds to the pressurizer safety valve setpoint, the "normal" PORV setpoint of 2370 psia is selected. The PORVs provide backup overpressure protection for the pressurizer safety valves as described in Subsection 5.4.13.

5.2.6.1 Design Criteria

A discussion follows the criteria considered in determining the adequacy of the PORVs and the SDCS relief valves to provide low temperature overpressure protection (LTOP) of the RCS.

5.2.6.1.1 Credit for Operator Action

No credit is taken for operator action to terminate an overpressurization transient until 10 minutes after the operator is made aware that a transient is in progress.

5.2.6.1.2 Single Failure Criteria

In the LTOP mode, the PORV overpressure protection system and the SDCS relief valves are designed to protect the reactor vessel given a single failure in addition to a failure that initiated the pressure transient. The event initiating the pressure transient is considered to result from either an operator error or equipment malfunction. The PORV system has redundancy in actuation channels and functions during a loss of offsite power. When the PORVs are used to limit safety valve opening, at the high setpoint, redundancy is not required; therefore, only one PORV is aligned to the RCS, since this is an equipment protective rather than a safety-related function. When the SDCS relief valves are the means of LTOP protection, redundancy is provided by the system containing two relief valves.

5.2.6.1.3 Testability

To assure operational readiness in the LTOP mode, the PORV protection system is tested in the following manner:

a) A test is performed to assure operability of the system electronics prior to each shutdown.

b) A test for valve operability is, as a minimum, conducted as specified by the ASME Code, Section XI.

c) Subsequent to system, valve, or electronics maintenance, a test on those portion(s) of the systems maintained is performed prior to declaring the system operational.

The SDCS relief valves are passive components of the shutdown cooling system and have surveillance and operability requirements designated in the Unit 2 Technical Specifications.

5.2.6.1.4 Seismic Design and IEEE 279 Criteria

The PORVs, isolation valves, associated interlocks and instrumentation are designed to Quality Group A, seismic Category I requirements. The interlocks and instrumentation associated with the PORVs satisfy the appropriate portions of IEEE 279-1971 criteria.

The SDCS relief valves are Quality Class B, they are included as Class 2 equipment and meet the specifications of ASME Code Section XI.

5.2.6.1.5 Reliability

The use of the PORVs and SDCS relief valves for RCS overpressure protection does not reduce the reliability of the ECCS or SDCS.

5.2.6.2 <u>Design and Analysis</u>

In demonstrating that use of the LTOP system meets the criteria listed in Subsection 5.2.6.1, the following additional information is provided.

5.2.6.2.1 Limiting Transients

Transients during the low temperature operating mode are more severe when the RCS is operated in the water-solid condition. Addition of mass or energy to an isolated water-solid system produces increases in system pressure. The severity of the pressure transient depends upon the rate and total quantity of mass or energy addition. The choice of the limiting LTOP transients was based on evaluation of potential transients for St. Lucie Unit 1. These transients are shown on Figure 5.2-26 and are applicable to St. Lucie Unit 2.

The most limiting transients initiated by a single operator error or equipment failure are:

a) An inadvertent safety injection actuation (mass input).

b) A reactor coolant pump start when a positive steam generator to reactor vessel ΔT exists (energy input).

The transients were determined as most limiting by conservative analyses which maximize mass and energy additions to the RCS. In addition, the RCS is assumed to be in a water-solid condition at the time of the transient; such a condition has been noticed to exist infrequently during plant operation since the operator is instructed to avoid water-solid conditions whenever possible. (Note: water-solid conditions may exist during normal plant heatup and cooldown.)

The mass addition due to the simultaneous operation of two HPSI and three charging pumps was considered, along with the simultaneous addition of energy from decay heat and the pressurizer heaters.

The energy addition due to a reactor coolant pump start when a steam generator to reactor vessel ΔT of 40°F exists was considered. In addition to considering the energy addition to the RCS from the steam generator secondary side, energy addition from decay heat, reactor coolant pump, and pressurizer heaters was also included.

LTOP transients have not been analyzed for the simultaneous startup of more than one reactor coolant pump (RCP). Such operation is procedurally precluded since the operator starts only one RCP at a time and a second RCP is not started until system pressure is stabilized. RCP motor amperage is used to establish nominal pump performance and operation prior to starting a second RCP. Additionally, there is an LTOP transient alarm that indicates that a pressure transient is occurring.

A Technical Specification requires that the operator not start an RCP if the ΔT exceeds 40°F. However, administrative procedures will ensure that the ΔT is maintained below 30°F. A separate Technical Specification ensures that the appropriate action is taken if one PORV or one SDCS relief valve is out of service during the LTOP mode of operation.

An analysis of P/T limits and LTOP protection for the period ending at 55 EFPY was performed. The LTOP enable temperatures were determined by following the guidance of the ASME Boiler and Pressure Vessel Code Section XI, Appendix G. They were calculated to be less than or equal to 246°F during heatup and less than or equal to 224°F during cooldown. Since the 55 EFPY pressure-temperature limits are less restrictive than the 21.7 EFPY limits, the PORV setpoint was raised to 490 psia from 470 psia for increased operational flexibility. A change to the SDCRV setpoint of 350 psia was not practical or required.

The P/T limits, LTOP requirements, setpoints and controls were evaluated for operation at EPU conditions. The only update for EPU conditions was a reduction in the period of applicability to approximately 47 EFPY from 55 EFPY.

5.2.6.2.2 Provision for Low Temperature Overpressure Protection

During heatup, RCS pressure is maintained below the PORV pressure setpoints until after the PORVs are re-set to the "normal" high setpoint. The PORVs can be re-set to the normal setpoint when cold leg temperature increases above the maximum temperature for LTOP during heatup (nominally T_c = 246°F), defined in the Technical Specifications.

During cooldown, RCS pressure is decreased to below the PORV low pressure setpoint before cooling the plant to below the maximum temperature for LTOP during cooldown (nominally T_c = 224°F), defined in the Technical Specifications. Once temperature is lowered, the PORV control switch must be aligned in the LTOP mode.

The LTOP mode applies for all temperatures within the maximum LTOP temperature range. The PORVs will remain in the LTOP mode until the RCS is opened during refueling. The LTOP system is designed to be aligned during all heatup and cooldown operations.

5.2.6.3 <u>Equipment Parameters</u>

Each PORV is actuated from a 90-140v dc solenoid valve which is energized automatically from a pressurizer pressure transmitter. Each PORV is designed to close on interruption of power to the solenoid valve.

Pertinent PORV operational and design requirements are presented in Table 5.4-9. The PORVs are sized based on a transient (simultaneous operation of two HPSI pumps and three charging pumps) initiated from a water-solid condition. The analysis of the Subsection 5.2.6.2.1 limiting transients for the period ending 55 EFPY demonstrated that the PORV water relieving capacity is adequate to prevent violation of the pressure-temperature limits for the temperature ranges where a PORV can be relied upon for LTOP protection, in accordance with the Technical Specifications. Moreover, this analysis assumed that only one of the two available PORVs was in operation. Therefore, both PORVs together are designed to have more than twice the capacity needed to mitigate the most severe expected transient.

The flow capacity requirement for steam (153,000 lb/hr) was chosen to avoid unnecessary lifting of the safety valves, based on an analysis of the control rod withdrawal transient. Analysis has shown that each PORV, sized for LTOP as described above, will have approximately twice the required steam flow capacity. For at-power operation (PORV setpoint of 2370 psia) only one PORV need be in service to provide the required flow capacity. However, it is noted that design criteria on reactor coolant system pressure would still be met if the PORVs were not in service. The pressurizer safety valves have sufficient relieving capacity to mitigate the most severe event (see Appendix 5.2A).

The PORVs are not specifically designed for two-phase conditions at the PORV inlet since it is expected that either steam or subcooled water conditions will exist, but not a two-phase mixture. (See Appendix 1.9A [item II.D.1]) and Subsection 5.4.13.4 for further discussion of PORV testing.

The SDCS relief valves are sized for a flow capacity of 2300 gpm at a lift set pressure of 350 psia. Each of the two SDCS relief valves is sufficient to provide LTOP during low temperature operation when the SDCS relief valves are aligned to the RCS during modes 4-6.

5.2.6.4 Administrative Controls

Administrative controls necessary to provide LTOP are limited to those controls that align the PORVs when Reactor Coolant System parameters are satisfied. Before entering the low temperature region for which overpressure protection is necessary, RCS pressure is decreased to below the maximum pressure required for LTOP operation. The technical specifications define when the PORVs are required to be operable, when used for LTOP, and the number of block valves required to be open. The PORVs will remain in the LTOP mode while the RCS is at low temperature and the reactor vessel head is secured. Control room indication is provided to give the operator PORV position indication and mode of operation.

Unit 2 Technical Specifications define the configuration of the Shutdown Cooling System for cooldown and heatup in modes 4-6.

5.2.6.4 Summary of Electrical Controls and Circuitry

This section summarizes the electrical controls and circuitry for the PORVs. The SDCS relief valves are passive devices which have no indication or control features.

PORV Actuation

Each PORV is actuated from a 90-140V dc solenoid pilot valve. This valve is energized automatically from a pressurizer pressure transmitter for LTOP; normal actuation is from the RPS high pressure trip. Each PORV is designed to close on loss of power to the solenoid valve. Figure 5.2-27 illustrates the PORV actuation logic.

PORV Switches

Each PORV is provided with a mode selector switch which is a two position manual control switch with a "NORMAL" AND "LTOP" position. Each PORV is also provided with a three position "Off/Override/Test" Selector Switch. The "OFF" position of this switch is used normally when PORV control circuitry testing is not desired. The "OVERRIDE" position shuts the PORV if it is open and overrides any signal to open the valve. The "TEST" position simulates an open signal to the PORV without physically opening the valve.

LTOP Interlock

An LTOP interlock is provided to prevent PORV actuation when the cold leg temperature is greater than 246°F and the mode selector switch is inadvertently positioned to "LTOP". A "PORV Normal Condition" Alarm will actuate in the control room alerting the operator to select "NORMAL" on the Mode Selector Switch when cold leg temperature is greater than 246°F. The interlock will reset when cold leg temperature drops below 246°F.

LTOP System Alarms (see Figure 5.2-28)

a) PORV LTOP Condition Alarm

During cooldown when the "Mode Selection Switch" is in the "Normal" position a "PORV LTOP Condition" alarm will alert the operator to select "LTOP" on the "Mode Selector Switch" prior to the cold leg temperature reaching a value 224°F. Thus, changing the PORV actuation setpoint from 2370 psia to 490 psia for both PORVs (V1474 and V1475). This alarm will not reset unless the PORV mode selector switch is in the "LTOP" position and the motor operated isolation valves of both PORVs are "OPEN".

b) PORV Normal Condition Alarm

During heatup when the "Mode Selector Switch" is in the "LTOP" position a "PORV Normal Condition" alarm will alert the operator to select "Normal" on the "Mode Selector Switch" after the cold leg temperature reaches a value greater than 246°F. Thus, changing the PORV actuation setpoint from 490 psia to 2370 psia for both PORVs (V1474 and V1475). This alarm will not reset unless the PORV Mode Selector Switch is in the "Normal" position and at least one of the PORV isolation valves is "OPEN".

c) LTOP Transient Alarm

When RCS temperature (cold leg) is less than or equal to 224°F or the mode selector switch is in "LTOP" and pressurizer pressure is greater than or equal to 490 psia, a potential LTOP transient is sensed, actuating the "LTOP Transient" alarm. Alarm values may be set conservative to these values. The LTOP B pressure measurement channel has separate alarm and actuating devices, and the alarm may be set conservative to the actuating device.

d) PORV Test Condition Alarm

A "PORV Test Condition" alarm will alert the operator whenever the PORV protective system is in the "Override" or "Test" position, bypassing all setpoints. The PORV will remain closed in this condition until the selector switch is placed in the "OFF" position at which time the alarm will reset.

e) Indicating Lights

Open and close position indicating lights have been located in the control room, informing the operator of the actual stem position of each PORV. Indicating lights are not energized or deenergized from the solenoid valve circuitry. Indicating lights are controlled from the valve stem position.

Each isolation valve is provided with a two-position open-close switch for valve operation. Open and close position indicating lights are also provided for each motor operated isolation valve.

A test indicating light will be provided for each PORV and lit whenever the PORV protective system control circuitry has been bypassed (in "OVERRIDE") or has been tested satisfactorily (see Figure 5.2-29).

NOTE: Each PORV (V1474 and V1475) and actuation channel (channel A and B) will have their own independent alarms as indicated by parentheses on Figure 5.2-28.

Section 5.2: REFERENCES

1) Letter, A. C. Thadani (NRC) to C. O. Woody (FPL), "Relief from Parts of ASME Code Section XI," dated January 13, 1986.

2) Letter, A. C. Thadani (NRC) to C. O. Woody (FPL), "Relief from Parts of ASME Code Section XI," dated October 10, 1986.

3) Letter, H. N. Berkow (NRC) to J. H. Goldberg (FPL), "St. Lucie Unit 2 - Reliefs from Parts of ASME Code Section XI," dated October 2, 1989.

4) Letter, Eugene V. Imbro (NRC) to Thomas F. Plunkett (FPL), "St. Lucie Units 1 and 2 - Request for Approval of ASME Code Case N-416-1 As An Alternative to the Required Hydrostatic Pressure Test," dated April 29, 1996.

5) Safety Assessment by Plant Systems Branch Division of Systems Safety and Analysis Office of Nuclear Reactor Regulation Region II Concerns (TIA 96-019) Regarding the Containment Radiation Monitoring Systems at St. Lucie Units 1 and 2, and Turkey Point Units 3 and 4, May 27, 1999.

6) Calculation PSL-2FJI-99-001, "Steam Generator Blowdown Radiation Monitor Response Time St. Lucie Unit 2," Rev. 0.

TABLE 5.2-1

REACTOR COOLANT SYSTEM PRESSURE BOUNDARY CODE REQUIREMENTS

Component	Codes and Classes
Reactor Vessel, Pressurizer	1. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1971 Edition through Summer 1972 Addenda.
Replacement Reactor Vessel Closure Head	1. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Div. 1 Class 1, 1989 Edition, No Addenda.
Steam Generator	1. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components Class 1 and 2, 1998 Edition through 2000 Addenda.
Reactor Coolant Pump	1. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1971 Edition through Summer 1973 Addenda.
Pressurizer Spray, Safety, Power Operated Relief, and Power operated relief isolation valves	1. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1971 Edition through Winter 1972 Addenda.
	2. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components Class 1, 1974 Edition.
	3. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components Class 1, 1974 Edition through Winter 1974 Addenda.
	4. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components Class 1, 1974 Edition through Summer 1974 Addenda.
	5. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1977, Edition Through Summer 1979 Addenda.

TABLE 5.2-1 (Cont'd)

Component		Codes and Classes
Reactor Coolant Piping	1.	ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1971 Edition through Winter 1972 Addenda. (NSSS)
RCPB Piping	2.	ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, 1971 Edition through Summer 1973 Addenda (A/E).
Miscellaneous NSSS Valves	1.	ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1971 Edition through Winter 1972, Summer 1973, Winter 1973 Addenda.
	2.	ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1974 Edition through Summer 1974, Winter 1974 and Summer 1975 Addenda.
	3.	ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1977 Edition through Summer 1978 Addenda.
Control Element Drive Mechanisms	1.	ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1 1998 Edition through 2000 Addenda.
Miscellaneous Non-NSSS Valves	1.	ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, 1974 Edition (Summer 75 Addenda).

Codes listed above are construction codes. In addition, all these components are designed and constructed to permit the performance of the tests and inspections required by Section XI, Rules for In-Service Inspection.

TABLE 5.2-2

CODE CASE INTERPRETATIONS

Code Case Number	Title	Component(s) Affected
1141-1	Foreign Produced Steel; Annulled 7/23/76	Reactor Vessel, Pressurizer
1332-6	Requirements for Steel Forgings	Reactor Vessels, Reactor Coolant Pipe
1334-3 (N-2)	Requirements for Corrosion Resisting Steel, Steel Bars and Shapes, Section III	CEDM's
1361-2	Socket Welds	Pressurizer
1492	Post-Weld Heat Treatment; Annulled 3/3/75	Reactor Vessel, Reactor Coolant Pipe, Pressurizer
1519*	Use of A 105-71 in lieu of SA-105 The ASTM A 105-71 material provided for more desirable chemistry than SA-105. This code case was incorporated into the Code in the Summer 1973 Addenda.	Reactor Coolant Pipe
1553-1	Pressure temperature ratings of SA-351 Grades CF8A, CF3 and CF3M, Section III.	Miscellaneous Valves
1580-1	Buttwelded alignment tolerance and acceptable slopes for concentric centerlines for Section III, Class 1, 2 and 3 construction.	Miscellaneous Valves
1581	Power operated pressure relief valves, Section III.	Pressurizer power operated Relief Valve
1590	Chemical analysis variations Section III, construction	Miscellaneous Valves

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1492	Post-Weld Heat Treatment; Annulled 3/3/75	Reactor Vessel, Reactor Coolant Pipe, Pressurizer
1519*	Use of A105-71 in lieu of SA-105 The ASTM A105-71 material provided for more desirable chemistry than SA-105. This code case was incorporated into the Code in the Summer 1973 Addenda.	Reactor Coolant Pipe
1553-1	Pressure temperature ratings of SA-351 Grades CF8A, CF3 and CF3M, Section III.	Miscellaneous Valves
1580-1	Buttwelded alignment tolerance and acceptable slopes for concentric centerlines for Section III, Class 1, 2 and 3 construction.	Miscellaneous Valves
1581	Power operated pressure relief valves, Section III.	Pressurizer power operated Relief Valve
1590	Chemical analysis variations Section III, construction	Miscellaneous Valves

TABLE 5.2-3

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Component	Material Specification
Reactor vessel	
Shell	SA-533 Grade B, Class 1 Steel
Forgings	SA-508 Class 1 and 2
Cladding[(a)]	Weld deposited austenitic stainless steel with greater than 5% delta ferrite (Equivalent to SA-240,Type 304) or NiCrFe alloy (equivalent to SB-168)
Replacement Reactor Vessel Closure Head (RVCH)	
Forging	SA-508, Class 3
Replacement RVCH Cladding	Weld Deposited austenitic stainless steel:
	First layer is 309L with delta ferrite number acceptable range of 5FN to 20FN. Subsequent layers are 308L with delta ferrite number acceptable range of 5FN to 17.6FN.
CEDM Nozzles	Nozzle: SB-167 (Alloy 690)
	Adapter: SB-166 (Alloy 690)
	Weld Filler: 52 or 52M (Alloy 690)
Instrument Nozzle	Nozzle: SB-167 (Alloy 690)
	Adapter: SA-479 Type 304 Stainless Steel
	Weld Filler: 52 or 52M (Alloy 690)
Vessel Internals[(a)]	Austenitic Stainless Steel and NiCrFe alloy
Fuel Cladding[(a)]	Zircaloy-4
Control element drive mechanism housings	
Lower	SA-182 Type 403 Modified stainless steel Special Code Case N-4-11 with end fittings to SB-166 (Alloy 690)
Upper	SA-479 and SA-213 Type 316 stainless steel with end fitting of SA-479 and vent valve seal of Type 440 stainless steel seat to SA-479
Closure head bolts & Nuts	SA-540 B23 and B24, Class 3
Support (on Nozzles)	SA-508, Class 2
Pressurizer -	
Shell	SA-533 Grade A Class 1
Upper Head Instrument Nozzle	SA-533 Grade B Class 1
Penetration Bore[(a)]	
Cladding[(a)]	Weld deposited austenitic stainless steel with greater than 5% delta ferrite or NiCrFe alloy (equivalent to SB-168)

(a) Materials exposed to reactor coolant

(b) Special weld wire with low residual elements of copper and phosphorus is specified for the reactor vessel core beltline region.

(c) The four (4) one-inch instrument nozzles in the upper head have SA-182, Type 316L safe ends.

TABLE 5.2-2 (Cont'd)

Code Case Number	Title	Component(s) Affected
1649	Modified SA453-GR660 for class 1, 2, 3 and CS construction	Miscellaneous Valves
1661	Post-Weld Heat Treatment for P-1 Materials	Pressurizer, Reactor Coolant Pipe
1698	Waiver of Ultrasonic Transfer Method This case is used for ferritic safe-end and piping welds. It permits elimination of the transfer method which is ineffective in compensating for attenuation differences between the calibration block and the component materials. The transfer methods used comply with the condition of acceptance given in Regulatory Guide 1.85.	Reactor Coolant Pipe
1731*	Basic Calibration Blocks for Section IX, Division 1, Ultrasonic Examination of Welds 10 inches to 14 inches thick. This case is used for reactor vessel upper shell calibration blocks, since the basic Code does not provide for thicknesses greater than 10 inches.	Reactor Vessel
1769	Qualification of NDE Level III Personnel, Section III, Division I	Miscellaneous Valves
N-432**	Repair Welding Using Automatic or Machine Gas Tungsten-Arc Welding (GTAW) Temperbead Technique Section XI, Division I	Reactor Coolant Pipe and Pressurizer
N-474-1***	Design Stress Intensities and Yield Strength Values For UNS N06690	Pressurizer and Reactor Coolant Pipe Instrument Nozzles
2142*	F-Number Grouping for Ni-Cr-Fe, Classification UNS N06052 Filler Metal, Section IX	Pressurizer and Reactor Coolant Pipe Instrument Nozzles
N-416-1	Alternative Pressure Test Requirements For Welded Repairs or Installation of Replacement Items By Welding Class 1, 2, and 3 Section XI, Division 1	Class 1, 2, and 3 Piping Systems
N-20-4	SB-163, Cold Worked UNS N08800, and SB-163 UNS N06600, UNS N06690, and UNS N08800 to Supplementary Requirements S2 of SB-163, Section III, Division 1, Class 1.	Steam Generator
N-740-1**** (DRAFT)	Dissimilar Metal Weld Overlay for Repair of Class 1, 2, and 3 Items Section XI, Division 1	Class 1, 2 and 3 Piping Systems

TABLE 5.2-2 (Cont'd)

* Not included in Regulatory Guides 1.84 or 1.85

** Included in Regulatory Guide 1.147 Rev. 6 dated May, 1988 and 1.85, Rev. 25, dated May, 1988

*** Included in Regulatory Guide 1.85, Rev. 28 dated April, 1992

**** Not listed in Regulatory Guide 1.147, Rev. 14, dated August 2005

For the Reactor Vessel Head Penetrations (CEDM) nozzle and weld repairs, the following Code Cases were used as permitted by NRC Regulatory Guides 1.85 and 1.147:

Code Case Number	Title
N-416-1, -2	Alternative Pressure Test Requirements for Welded Repairs or Installation of Replacement Items By Welding Class 1, 2, and 3 Section XI, Division 1
N-2142-1	F-Number Grouping for Ni-Cr-Fe, Classification UNS W06052 Filler Metal Section IX
N-2143-1	F-Number Grouping for Ni-Cr-Fe, Classification UNS W86152 Welding Electrode Section IX
N-474-2	Design Stress Intensities and Yield Strength Values for UNS N06690 with Min. Specified Yield Strength of 35 ksi
N-638	Similar & Dissimilar Metal Welding Using Ambient Temperature Machine GTAW Temper Bead Technique

The original Reactor Vessel Closure Head has been replaced. The Information above, concerning the Reactor Vessel Head Penetrations (CEDM) nozzle and weld repairs is historical.

For the replacement Reactor Vessel Closure Head the following Code Cases were used as permitted by NRC Regulatory Guide 1.84:

Code Case Number	Title
N-2142-1	F-Number Grouping for Ni-Cr-Fe, Classification UNS W06052 Filler Metal Section IX
N-2143-1	F-Number Grouping for Ni-Cr-Fe, Classification UNS W86152 Welding Electrode Section IX
N-474-2	Design Stress Intensities and Yield Strength Values for UNS N06690 with Min. Specified Yield Strength of 35 ksi
N-416-1	Alternative Pressure Test Requirements for Welded Repairs or Installation of Replacement Items By Welding Class 1, 2, and 3 Section XI, Division 1

TABLE 5.2-3 (Cont'd)

Component	Material Specification
Pressurizer (Cont'd)	
Forged nozzles	SA-508 Class 2
Instrument nozzles[a]	SB-166
Surge and PORV	
nozzle safe ends[a]	SA-351, Gr CF8M
Spray and instrument	SA-182, Type 316, except upper head
nozzle safe ends[a][c]	instrument nozzles have Type F316L
Studs and nuts	SA-540 Grade B24 and SA-193 Gr. B7
Steam generator	
Primary head, nozzles and manways	SA-508 Grade 3, Class 2
Primary divider plate	SB-168 UNS N06690
Primary nozzle safe ends	SA-105
Primary head cladding[a]	Weld deposited austenitic stainless steel (Type 308L and 309L)
Tubesheet	SA-508 Grade 3, Class 2
Tubesheet cladding	Weld deposited NiCrFe (Alloys 52 / 152)
Tube[a]	NiCrFe Alloy (SB-163 UNSN 06690)
Secondary shell and head	SA-508 Grade 3, Class 2
Secondary nozzles	SA-508 Grade 3, Class 2
Steam nozzle venturis	SB-166 UNS N06690
Secondary instrument nozzles	SA-105
Studs / Nuts	SA-193 B16 / SA-194 Grade 7
Support Skirt	SA-508 Grade 3, Class 2
Sliding base support studs and nuts	SA-540 Grade B23 Class 2

TABLE 5.2-3 (Cont'd)

Component	Material Specification
Reactor coolant pumps	
Casing[a]	A-351 Grade CF8M
Internals[a]	Austenitic stainless steel (SA-351 Grade CF8M ASTM A79 Type 316 ASTM A240 Type 316, SA-182 GR F 304)
Studs and Nuts	SA-540 B23 Cl. 4 and SA-194 Gr. 2H
Reactor coolant piping	
Pipe (30 in. and 42 in.)	SA-516 Grade 70
Cladding[a]	SA-240 - 304L
Surge Line (12 in.)[a]	SA-351 - CF8M
Spray Line Pipe	SA-312, Type 316
	SA-312, 304L
Spray Line Fittings	SA-403, Type WP 316 SA-182, F 316 SA-376, TP 316 SA-182(M), TP 316/316L SA-182, F304L SA-182, F316/F316L
Piping safe ends (30 in.)[a]	SA-351 - CF8M
Surge nozzle forging	SA-105 Grade II
Surge nozzle safe end[a]	SA-351 - CF8M
Shutdown cooling outlet nozzle forgings	SA-105 Grade II
Shutdown cooling outlet[a] nozzle safe ends	SA-351 - CF8M
Safety injection nozzle forgings	SA-182 - F1
Safety injection nozzle[a] safe ends	SA-351 - CF8M
Charging inlet nozzle forging	SA-182 - F1
Charging inlet nozzle[a] safe end	SA-182 - F316
Spray nozzle forgings	SA-105 Grade II
Letdown and drain pipe	SA-312, 304L

TABLE 5.2-3 (Cont'd)

Component	Material Specification		
Reactor coolant piping (Cont'd)			
Spray nozzle safe ends [(a)]	SA-182 - F316		
Letdown and drain or drain nozzle forgings	SA-105 - Grade II		
Letdown and drain or drain nozzle safe ends[(a)]	SA-182 - F316		
Sampling or pressure[(a)] measurement nozzles	SB-166		
Sampling or pressure measurement nozzle safe ends[(a)]	SA-182 - F316 or SA-479 TP-316		
RTD nozzles[(a)]	SB-166		
Hot Leg RTD Split Nozzle Penetration Bore[(a)]	SA-516 Grade 70		
Sampling nozzle (surge line)[(a)]	SA-182 - F316		
RTD nozzle (surge line)[(a)]	SA-182 - F316		
Nozzle Thermal Sleeves[(a)]	SB-166 or SB168		
Valves[(a)]	SA-351 - CF8M, SA-182-F316		
AE - Supplied Components			
Valves	ASME	SA-182 SA-479	(F-316), SA-564 (Type-630) (Type-347, 348, 316L)
Pipes	ASME	SA-312	(GR TP 304)
Fittings	ASME	SA-182 SA-403 SA-351	(F-304) (GR-WP 304W) (GR CF8)
Flanges	ASME	SA-182 SA-351	(F-304) (GR-CF8)
Restrictors	ASME	SA-182	F-316
Bolts, Nuts	ASME	SA-193 SA-194	GR B7 GR 2H

TABLE 5.2-4

REACTOR COOLANT PRESSURE BOUNDARY WELDING MATERIAL

Material Specification	Base Material	Weld Material
1. SA-533 Gr. B C1.1	SA-533 Gr. B C1.1	a. SFA 5.9, E-8018, C3 b. MIl-E-18193, B-4
2. SA-508 C1.2	SA-533 GR. B C1.1	a. SFA 5.5, E-8018, C3 b. MIL-E-18193, B-4
3. SA-508 C1.1	SA-508 C1.2	a. SFA 5.5, E-8018, C3
4. SA-516 Gr. 70	SA-516 Gr. 70	a. SFA 5.1. E-7018[(e(3))]
5. SA-182 FI	SA-516 Gr. 70	a. SFA 5.1, E-7018
6. SA-105 Gr.II	SA-351 CF8M	a. SFA 5.14, ERNiCr-3 c. ErNiCrFe-7A
7. SA-182 FI	SA-351 CF8M	a. SFA 5.11, ENiCrFe-3
8. SA-105 Cr. II	SA-182 F316	a. SFA 5.14, ERNiCr-3 c. ErNiCrFe-7A
9. SB-166	SA-182 F316	a. SFA 5.14, SFA 5.11, Root ERNiCr-3 Remaining ENiCrFe-3
10. SA-167	SA-182 F304	a. Root SFA 5.14, ERNiLCr-3 Remaining 5.11, ENiCrFe-3
11. SA-516 Gr. 70	SA-351 CF8M	a. SFA 5.11, ERNiCr-3
12. SA-182 F1	SA-182 F316	a. SFA 5.11, ENiCrFe-3
13. SB-166	SA-533 GR. B C1.1	a. SFA 5.11, ENiCrFe-3
14. SA-182 Code Case 1334	SB-167	a. SFA 5.14, ERNiCr-3
15. SA-516 Gr. 70	SA-508 C1.2	a. SFA 5.5, E-8016, C3

TABLE 5.2-4 (Cont'd)

Material Specification	Base Material	Weld Material
16. Austentic[a] stainless steel cladding		a. SFA 5.9, ER-308[e(2)] SFA 5.9, ER-309[e(1)] SFA 5.9, ER-312
17. Inconel	Inconel	a. ENiCrFe-3 ERNiCr-3
18. Inconel	SA-516 Gr. 70	a. ERNiCr-3 UNS N06052 Ni-Cr-Fe
19. Inconel	SA-533 Gr. B C1.1	a. ERNiCr-3
20. SB-166 Alloy[a] 690 (Inconel)	UNS N06052 Ni-Cr-Fe (Inconel Pad)	UNS N06052 Ni-Cr-Fe
21. Inconel Pad[a]	SA-533 GR. B C1.1	UNS N06052 Ni-Cr-Fe
22. SA 508 Gr 3 Cl 2	SA 508 GR 3 Cl 2	covered electrode: SFA-5.5 E9018-G wire/flux: SFA 5.23 F9P4-EG-G
23. SA 105	SA 508 GR 3 Cl 2	covered electrode (repair): SFA-5.1 E7018 wire/flux: SFA 5.23 F10P2-EG-G
24. Inconel 690 Clad[a]	SA 508 GR 3 Cl 2	wire: SFA-5.14 ERN:CrFe-7 covered electrode: SFA-5.11 ENiCrFe-7
25. Austenitic SS clad[a][c]	SA 508 GR 3 Cl 2	strips - trade designation: WEL ESS 309L and WEL ESS 308L flux - trade designation: WEL BND F-8 covered electrode: SFA-5.4 E309L-16 and E308L-16 wire - SFA-5.9 ER309L and ER308L
26. Austenitic SS clad[a][c]	SA 105	strips - trade designation: WEL ESS 309L and WEL ESS 308L flux - trade designation: WEL BND F-8 covered electrode: SFA-5.4 E309L-16 and E308L-16

TABLE 5.2-4 (Cont'd)

	Material Specification	Base Material	Weld Material
27.	SB 163 Alloy 690 (tubes)[(a)(d)]	Inconel 690 Clad	wire (repair): SFA 5.14 ERNiCrFe-7
28.	Inconel 690 Partition Plate[(a)]	Austenitic SS clad and Inconel 690 Clad	wire: SFA-5.14 ERNiCrFe-7 covered electrode: SFA-5.11 ENiCrFe-7
	The original Reactor Vessel Closure Head and CEDMs have been replaced. The following weld materials were used in fabricating the pressure boundary of the replacement RVCH:		
29.	SB-166 (Alloy 690)	SA-479, F-304	ERNiCrFe-7
30.	SA-508, Class 3	SB-167 (Alloy 690)	ERNiCrFe-7 or EniCrFe-7
31.	SB-167 (Alloy 690)	SB-166 (Alloy 690)	ERNiCrFe-7 or EniCrFe-7
32.	Austentic SS Cladding	SA-508, Class 3	SFA-5.9, ER-308L SFA-5.11, ER-309L

Note: (a) Materials exposed to reactor coolant

(b) Deleted

(c) Filler materials are not classified.

(d) Current welding is performed without filler material but wire may be used for repair.

(e) During replacement of the steam generators, the following welding materials were used for attachment of the RCS piping to the RSG nozzles.

(1) ER309L / E309L
(2) ER308L / E308L
(3) ER70S-6 / E-7018

(f) PC/M 07003M applied ErNiCrFe-7A UNS N06054 Structural Weld Overlay (SWOL) material to the following nozzle to safe-end welds - Hot Leg (HL) Shutdown Cooling Nozzles A&B, HL Surge Nozzle and HL Drain Nozzle.

TABLE 5.2-5

CHEMICAL ANALYSES OF PLATE MATERIAL IN ST. LUCIE UNIT 2
REACTOR VESSEL BELTLINE

	Lower Shell Plate			Intermediate Shell Plate		
Heat #	B-8307-2	A-3131-1	A-3131-2	A-8490-2	B-3416-2	A-8490-1
Code #	M-4116-1	M-4116-2	M-4116-3	M-605-1	M-605-2	M-605-3
Element	(wt. %)					
Si	0.24	0.26	0.26	0.23	0.23	0.23
S	0.010	0.009	0.008	0.012	0.014	0.017
P	0.007	0.007	0.008	0.008	0.008	0.009
Mn	1.37	1.44	1.47	1.39	1.40	1.39
C	0.20	0.23	0.23	0.23	0.24	0.23
Cr	0.02	0.03	0.03	0.08	0.13	0.08
Ni	0.57	0.60	0.60	0.61	0.62	0.61
Mo	0.55	0.60	0.61	0.56	0.55	0.57
B	0.001	<.001	<.001	<.001	<.001	<.001
Cb	<.01	<.01	<.01	<.01	<.01	<.01
Ti	<.01	<.01	<.01	<.01	<.01	<.01
Co	0.011	0.011	0.012	0.015	0.016	0.015
Cu	0.06	0.07	0.07	0.11	0.13	0.11
Al	0.025	0.019	0.018	0.028	0.025	0.027
N_2	0.007	0.008	0.008	0.009	0.008	0.009
V	0.004	0.004	0.004	0.004	0.004	0.003
W	<.01	<.01	<.01	<.01	<.01	<.01

Notes: ND = Not Detected
NA = Not Analyzed

TABLE 5.2-5 (Cont'd)

	Lower Shell Plate			Intermediate Shell Plate		
As	0.003	0.004	0.005	0.007	0.006	0.008
Sn	0.003	0.003	0.004	0.011	0.013	0.012
Zr	<.001	<.001	<.001	<.001	<.001	<.001
Sb	NA	NA	NA	0.0032	0.0036	0.0030
Pb	ND	ND	ND	<0.001	<0.001	<0.001

Notes: ND = Not Detected
NA = Not Analyzed

TABLE 5.2-6

CHEMICAL ANALYSES OF WELD MATERIAL
IN ST. LUCIE 2 REACTOR VESSEL BELTLINE

Weld	Lower Shell Long. Welds			C1. Girth Seam Weld	Inter. Shell Long. Welds		
Seam #	101-142	101-142B	101-142C	101-171	101-124A	101-124B	101-124C
Element (Wt. %)							
Si	0.15	0.16	0.13	0.43	0.14	0.10	0.14
S	0.009	0.009	0.008	0.011	0.010	0.014	0.011
P	0.008	0.008	0.008	0.009	0.009	0.011	0.009
Mn	1.37	1.40	1.44	1.30	1.14	0.98	1.19
C	0.13	0.13	0.13	0.10	0.12	0.12	0.12
Cr	0.02	0.02	0.02	0.09	0.03	0.03	0.03
Ni[(a)]	0.10	0.09	0.09	0.08	0.06	0.06	0.07
Mo	0.58	0.56	0.60	0.53	0.54	0.33	0.58
B	<.001	<.001	<.001	.001	.0005	.0005	.0005
Cb	<.01	<.01	<.01	<.01	<.01	<.01	<.01
Ti	<.01	<.01	<.01	<.01	<.01	<.01	<.01
Co	0.005	0.005	0.005	0.009	0.012	0.012	0.012
Cu[(a)]	0.04	0.05	0.04	0.07	0.04	0.03	0.04
Al	0.005	0.002	0.002	0.003	0.001	<0.001	0.001
N_2	0.004	0.005	0.005	0.011	0.004	0.006	0.006
V	0.006	0.006	0.006	0.004	0.004	0.002	0.005
W	<.01	<.01	<.01	<.01	0.01	0.01	0.01
As	0.010	0.010	0.010	0.003	0.013	0.012	0.013
Sn	0.005	0.005	0.005	0.003	0.004	0.004	0.004
Zr	<.001	<.001	<.001	<.001	0.002	0.002	0.002
Sb	NA	NA	NA	0.0012	NA	NA	NA

TABLE 5.2-6(Cont'd)

Weld Seam #	Lower Shell Long. Welds 101-142	101-142B	101-142C	C1. Girth Seam Weld 101-171	Inter. Shell Long. Welds 101-124A	101-124B	101-124C
Pb	ND	ND	ND	<.001	ND	ND	ND

ND = Not Detected

NA = Not Analyzed

(a) The weld metal copper and nickel chemical analyses represents a single test result and should be maintained for historical purposes. Embrittlement predictions should be based on the "best estimate" copper and nickel values for a specific weld wire heat using all industry available data. These "best estimate" values were determined in response to NRC GL 92-01, Rev. 1, Supplement 1 and were submitted to the NRC in FPL Letter L-97-233.

TABLE 5.2-7
REACTOR VESSEL TOUGHNESS PROPERTIES

Location	Place Number	Code Number	Material	Drop Weight NDTT(°F)	RT_{NDT} (°F)	Minimum Transverse Charpy USE(1) (ft+lb)
Upper Shell Plate	122-102A	M-604-1	SA 533B C1 1	0	+50	-
Upper Shell Plate	122-102B	M-604-2	SA 533B C1 1	+10	+50	-
Upper Shell Plate	122-102C	M-604-3	SA 533B C1 1	-10	+10	-
Intermediate Shell Plate	124-102B	M-605-1	SA 533B C1 1	0	+30	105
Intermediate Shell Plate	124-102C	M-605-2	SA 533B C1 1	-10	+10	113
Intermediate Shell Plate	124-102A	M-605-3	SA 533B C1 1	-20	0	113
Lower Shell Plate	142-102C	M-4116-1	SA 533B C1 1	-30	+20	91
Lower Shell Plate	142-102B	M-4116-2	SA 533B C1 1	-50	+20	105
Lower Shell Plate	142-102A	M-4116-3	SA 533B C1 1	-40	+20	100
Closure Bead (3)	102-101	M-4110-1	SA 533B C1 1	-10	+30	-
Closure Bead Flange (3)	106-101	M-4101-1	SA 508 C1 2	0	0	-
Inlet Nozzle	128-101A	M-4102-1	SA 508 C1 2	-20	-20	-
Inlet Nozzle	128-101D	M-4102-2	SA 508 C1 2	-20	-20	-
Inlet Nozzle	128-101B	M-4102-3	SA 508 C1 2	-	0	-
Inlet Nozzle	128-101C	M-4102-4	SA 508 C1 2	-10	-10	-
Outlet Nozzle	128-301B	M-4103-1	SA 508 C1 2	-20	-20	-
Outlet Nozzle	128-301A	M-4103-2	SA 508 C1 2	-30	-30	-
Vessel Flange	126-101	M-602-1	SA 508 C1 2	-30	-10	-
Inlet Nozzle Safe End	131-102A	M-4104-1	SA 508 C1 1	-20	+20	-
Inlet Nozzle Safe End	131-102D	M-4104-2	SA 508 C1 1	-20	+20	-
Inlet Nozzle Safe End	131-102B	M-4104-3	SA 508 C1 1	-20	+20	-
Inlet Nozzle Safe End	131-102C	M-4104-4	SA 508 C1 1	-20	+20	-
Outlet Nozzle Safe End	131-101B	M-4105-1	SA 508 C1 1	-10	0	-
Outlet Nozzle Safe End	131-101A	M-41105-2	SA 508 C1 1	-10	0	-
Bottom Head Dome	152-101	M-4112-1	SA 533B C1 1	-50	-40	-
Bottom Head Torus	104-102 (A to F)	M-4111-1	SA 5335 C1 1	-40	+40	-
Closure Head Torus (3)	104-102 (A to D)	M-4109-1	SA 533B C1 1	-60	-10	

(1) Reported only for beltline region plates

(2) Not Used

(3) This is historical data for the original Closure Head. The Closure Head has been replaced. The replacement Closure Head Forging is SA 508, Class 3 Low Alloy Steel. From six Charpy Impact tests conducted at Tndt +60 degree F (20 deg F), the minimum absorbed energy was 139 ft-lbs, which is above the required 50 ft-lbs and the minimum lateral expansion was 79 mils, which is above the required 35 mils minimum. Based on these requirements, RTndt = -40 degree F.

TABLE 5.2-7a

IMPACT TEST DATA FOR ST. LUCIE 2 BELTLINE WELD MATERIALS

Wire Heat No.	Electrode or Flux Lot No.	NDT °F	Temp. °F	CVN Data Absorbed Energy ft-lbs	Shear %	Lat. Exp.	
101-124A	83642	3536 (Type 0091)	-80**	-20	96		66
			-56**		81		58
					72		51
				+10	118		78
					116		79
					115		78
		E8018-LOHB	-60	0	140		73
					135		71
					122		70
				+10	143		78
					137		73
					142		77
		E8018-IAOCE	-80	-100	8	0	3
					6	0	1
					8	0	3
				-80	21	15	12
					26	20	17
					15	15	8
				-40	45	30	30
					65	40	42
					87	50	52
				-20	100	60	60
					87	50	55
					60	40	40
				+60	127	90	70
					136	90	75
					142	90	79
				+100	150	100	81
					165	100	89
					149	100	80
		E8018-BABEF	-70	-80	13	0	6
					8	0	5
					11	0	5
				-40	83	30	52
					87	30	54
					50	20	33

**Note: The conservative generic value of the initial RT(NDT) of -56°F for weld heat 83642 is used for future predictions of adjusted RT(NDT) at the suggestion of the NRC, due to scatter in the available industry initial RT(NDT) data for this non limiting heat as noted in evaluation ENG-PSL-SESJ-97-026 and FPL letter L-97-136.

TABLE 5.2-7a (Cont'd)

Seam No.	Wire Heat No.	Electrode or Flux Lot No.	NDT °F	CVN Data Temp. °F	Absorbed Energy ft-lbs	Shear %	Lat. Exp. Mils.
				-10	114	60	73
					83	40	51
					116	60	69
				+60	145	80	80
					148	80	80
					163	100	83
				+160	167	100	84
					161	100	88
					153	100	87
		E8018-HABJC	-70	-10	127		72
					129		75
					132		76
				+10	158		73
					167		82
					160		85
		E8018-FAAFC	-60	0	107		68
					103		66
					124		75
				+10	121		75
					118		69
					117		71
		E8018-HAGB	-40	+10	180		90
					146		83
					157		86
				+20	196		87
					210		88
					177		81
101-124B	83642	3536 (Type 0091)	see seam	101-124A			
		E8018 HABJC	see seam	101-124A			
		E8018 GACJC	-80	-30	66		44
					68		43
					53		37
				+10	109		78
					118		81
					112		75

TABLE 5.2-7a (Cont'd)

Seam No.	Wire Heat No.	Electrode or Flux Lot No.	NDT °F	CVN Data Temp. °F	CVN Data Absorbed Energy ft-lbs	CVN Data Shear %	CVN Data Lat. Exp. Mils.
101-124C	83642	3536 (Type 0091)	see seam	101-124A			
		E8018-IAOCE	see seam	101-124A			
		E8018-BABEF	see seam	101-124A			
		E8018-HABJC	see seam	101-124A			
		E8018-FAAFC	see seam	101-124A			
		E8018-HAGB	see seam	101-124A			
	83637	1122 (Type 0091)	-50	+10	153		85
					131		81
					125		77
		E8018 JAHB	-40	+10	165		86
					138		82
					139		76
				+20	157		86
					137		82
					157		85
		E8018 BAOED	-50	+10	156		84
					149		79
					145		77
		E8018 AACJD	-60	0	119		73
					101		62
					152		90
				+10	126		74
					149		91
					127		77
101-142A	83637	1122 (Type 0091)	see seam	101-124C			

TABLE 5.2-7a (Cont'd)

Seam No.	Wire Heat No.	Electrode or Flux Lot No.	NDT °F	CVN Data Temp. °F	CVN Data Absorbed Energy ft-lbs	CVN Data Shear %	CVN Data Lat. Exp. Mils.
101-142B	83637	1122 (Type 0091)	see seam	101-124C			
		E8018 FAOED	-60	-80	9	0	4
					19	5	10
					16	5	7
				-40	76	40	52
					70	40	44
					89	50	55
				0	98	60	60
					102	60	61
					86	50	52
				+100	157	100	90
					152	100	86
					153	100	86
		E8018 EACAE	-80	-100	21	5	12
					19	0	11
					27	5	16
				-20	83	40	52
					89	50	55
					85	40	54
				+100	123	100	78
					124	100	81
					136	100	91
101-142B		E8018 GABID	-50	+10	104		65
					105		64
					101		64
				+100	153		89
					156		91
					136		86
101-142C	83637	1122 (Type 0091)	see seam	101-124(			
101-171 *See surveillance weld seam 101-194, representative of 101-171	83637	0951 Type 124	-70	-10	82	60	61
					99	80	72
					94	70	66
				+100	112	100	83
					116	100	84
					116	100	85

TABLE 5.2-7a (Cont'd)

Seam No.	Wire Heat No.	Electrode or Flux Lot No.	NDT °F	CVN Data Temp. °F	Absorbed Energy ft-lbs	Shear %	Lat. Exp. Mils.
	3P7317	0951 Type 124	-80	-20	51	30	41
					50	30	39
					52	30	41
				+100	94	100	64
					93	100	63
					100	100	70
		E8018 IAOCE	see seam	No. 101-124A			
		E8018 FAAFF	-70	-10	66	30	43
					52	25	37
					74	35	48
				+160	127	100	81
					132	100	80
					122	100	80
		E8018 KABIF	-50	+10	97	50	62
					93	50	57
					96	50	60
				+160	132	100	75
					139	100	79
					156	100	85
101-194*	83637	0951 Type 124	-50	-40	10	20	16
				-30	41	30	31
*Surveillance weld					19	30	16
representative of					62	50	49
seam 101-171				-25	62	40	54
					38	20	29
*Full Charpy curve					29	30	27
from baseline testing				-20	50	30	45
with Capsule W-83				-1	93	80	73
BAW 1880				+20	61	50	53
				+40	69	60	60
				+70	74	80	67
				+85	118	100	96
				+105	95	90	88
				+150	124	100	93
				+200	106	100	91
				+250	123	100	92
				+300	98	100	80
				+350	127	100	88
				+400	117	100	86
				+450	108	100	87

TABLE 5.2-8a

STEAM GENERATOR (PRIMARY SIDE) TOUGHNESS PROPERTIES (SG A)

Name of Part	Part Number	Heat Number	Material	Drop Weight NDTT (°F)	RT_{NDT} (°F)
Channel Head	GV/SL313 FS/001	04W81-1-1	SA 508 Gr 3 Cl 2	-20	-20
Tubesheet	GV/SL313 PT/001	04W24-1-1	SA 508 Gr 3 Cl 2	-10	-10
Inlet Nozzle Safe End	GV/SL313 ERP1	51049	SA 105	-18	-18
Outlet Nozzle Safe End - 1	GV/SL313 ERP2-1	51049	SA 105	-18	-18
Outlet Nozzle Safe End -2	GV/SL313 ERP2-2	51049	SA 105	-18	-18
Partition Plate	GV/SL313 PLPA		SB-168 UNS N06690	N/A	N/A

TABLE 5.2-8b

STEAM GENERATOR (PRIMARY SIDE) TOUGHNESS PROPERTIES (SG B)

Name of Part	Part Number	Heat Number	Material	Drop Weight NDTT (°F)	^{RT}NDT (°F)
Channel Head	GV/SL314 FS/001	04W84-1-1	SA 508 Gr 3 Cl 2	-20	-20
Tubesheet	GV/SL314 PT/001	04W25-1-1	SA 508 Gr 3 Cl 2	-40	-40
Inlet Nozzle Safe End	GV/SL314 ERP1	51049	SA 105	-50	-50
Outlet Nozzle Safe End - 1	GV/SL314 ERP2-1	51049	SA 105	-50	-50
Outlet Nozzle Safe End -2	GV/SL314 ERP2-2	51049	SA 105	-50	-50
Partition Plate	GV/SL314 PLPA		SB-168 UNS N06690	N/A	N/A

TABLE 5.2-9

PRESSURIZER TOUGHNESS PROPERTIES

Location	Piece Number	Code Number	Material	Drop Weight NDTT (°F)	$^{RT}NDT^{(0F)}$
Upper Shell	622-102A	M-8906-1	SA 533B C1 1	-40	-30
Upper Shell	622-102B	M-8906-2	SA 533B C1 1	-40	-30
Lower Shell	642-102B	M-8906-3	SA 533B C1 1	-40	-40
Lower Shell	642-102A	M-8906-4	SA 533B C1 1	-30	-30
Manway Cover	676-102	M-2137-1	SA 533B C1 1	-10	-10
Surge Nozzle	658-101	M-8902-1	SA 508 C1 2	-40	-40
Spray Nozzle	608-101	M-8920-1	SA 508 C1 2	-30	-30
Bottom Head	650-101	M-8901-1	SA 533B C1 1	+10	+10
Closure Head	601-102	M-8901-2	SA 533B C1 1	+10	+10

TABLE 5.2-10

STEAM GENERATOR (SECONDARY SIDE) TOUGHNESS PROPERTIES (SG A)

Name of Part	Part Number	Heat Number	Material	Drop Weight NDTT (°F)	^{RT}NDT (°F)
Lower Shell	GV/SL313 VI/001	04D358-1-1	SA 508 Gr 3 Cl 2	-20	-20
Middle Shell	GV/SL313 VI/002	04D477-1-1	SA 508 Gr 3 Cl 2	-20	-20
Conical Shell	GV/SL313 VI/003	04W110-1-1	SA 508 Gr 3 Cl 2	-10	-10
Intermediate Shell	GV/SL313 VI/004	04D593-1-1	SA 508 Gr 3 Cl 2	-20	-20
Upper Shell	GV/SL313 VI/005	04W92-1-1	SA 508 Gr 3 Cl 2	-10	-10
Elliptical Head	GV/SL313 FE/001	04W92-1-2	SA 508 Gr 3 Cl 2	-20	-20
		04D518-1-1		-10	-10
Feed Water Nozzle	GV/SL313 TE/001	5-0025	SA 508 Gr 3 Cl 2	0	0
Recirculation Nozzle	GV/SL313 TE/002	5-0025	SA 508 Gr 3 Cl 2	-18	-18
Secondary Manways	GV/SL313 TE/003	5-0025	SA 508 Gr 3 Cl 2	-9	-9

TABLE 5.2-11

STEAM GENERATOR (SECONDARY SIDE) TOUGHNESS-PROPERTIES (SG B)

Name of Part	Part Number	Heat Number	Material	Drop Weight NDTT (°F)	^{RT}NDT (°F)
Lower Shell	GV/SL314 VI/001	04D359-1-1	SA 508 Gr 3 Cl 2	-10	-10
Middle Shell	GV/SL314 VI/002	04D478-1-1	SA 508 Gr 3 Cl 2	-10	-10
Conical Shell	GV/SL313 VI/003	04W111-1-1	SA 508 Gr 3 Cl 2	-20	-20
Intermediate Shell	GV/SL314 VI/004	04D663-1-1	SA 508 Gr 3 Cl 2	0	0
Upper Shell	GV/SL314 VI/005	04W144-1-1	SA 508 Gr 3 Cl 2	-20	-20
Elliptical Head	GV/SL314 FE/001	04W144-1-2	SA 508 Gr 3 Cl 2	-20	-20
		04D515-1-1		-10	-10
Feed Water Nozzle	GV/SL314 TE/001	5-0025	SA 508 Gr 3 Cl 2	0	0
Recirculation Nozzle	GV/SL314 TE/002	5-0025	SA 508 Gr 3 Cl 2	-18	-18
Secondary Manways	GV/SL314 TE/003	5-0025	SA 508 Gr 3 Cl 2	-9	-9

TABLE 5.2-12

PIPING-TOUGHNESS PROPERTIES

Location	Piece Number	Code Number	Material		Drop Weight NDTT (°F)	$^{RT}NDT^{(0F)}$
Spray Nozzle	728-401	M-9213-1	SA 105		NA	+20^A
Spray Nozzle	728-401	M-9213-2	SA 105		NA	+20^A
Let Down Drain Nozzle	728-601	M-9214-1	SA 105		NA	+20^A
Let Down Drain Nozzle	728-601	M-9214-2	SA 105		NA	+20^A
Let Down Drain Nozzle	728-601	M-9214-3	SA 105		NA	+20^A
Let Down Drain Nozzle	728-601	M-9214-4	SA 105		NA	+20^A
Charging Inlet Nozzle	728-501	M-9217-1	SA 182	Gr F1	+10	+10
Charging Inlet Nozzle	728-501	M-9217-2	SA 182	Gr F1	+10	+10
Safety Injection Nozzle	728-301	M-9218-1	SA 182	Gr F1	+20	+20
Safety Injection Nozzle	728-301	M-9218-2	SA 182	Gr F1	+20	+20
Safety Injection Nozzle	728-301	M-9218-3	SA 182	Gr F1	+20	+20
Safety Injection Nozzle	728-301	M-9218-4	SA 182	Gr F1	+20	+20
Surge Nozzle	728-101	M-9211-1	SA 541	-1	-10	0
Shutdown Coolant Outlet Noz.	728-201	M-9212-1	SA 541	-1	-10	-10
Shutdown Coolant Outlet Noz.	728-201	M-9212-2	SA 541	-1	-10	-10
Drain Nozzle	728-701	M-9215-1	SA 105	-1	NA	+20^A
Straight Segment	722-102A	M-9201-1	SA 516	Gr 70	-10	+60
Straight Segment	722-102B	M-9201-2	SA 516	Gr 70	-10	+60
Straight Segment	722-102A	M-9201-3	SA 516	Gr 70	-30	+30
Straight Segment	722-102B	M-9201-4	SA 516	Gr 70	-30	+30
Straight Segment	722-106A	M-9202-1	SA 516	Gr 70	-30	0
Straight Segment	722-106B	M-9202-2	SA 516	Gr 70	-20	+20

NA - Not Available

A-MTEB position 5-2, "Fracture Toughness Requirements for Older Plants," Paragraph 1.1(3)(b)

TABLE 5.2-12 (Con't)

Location	Piece Number	Code Number	Material	Drop Weight NDTT (°F)	$^{RT}NDT^{(0F)}$
Straight Segment	722-106A	M-9202-3	SA 516 Gr 70	-20	+20
Straight Segment	722-106B	M-9202-4	SA 516 Gr 70	-30	0
Straight Segment	722-108A	M-9203-1	SA 516 Gr 70	-30	0
Straight Segment	722-108B	M-9203-2	SA 516 Gr 70	-20	-10
Straight Segment	722-110A	M-9204-1	SA 516 Gr 70	-20	+40
Straight Segment	722-110B	M-9204-2	SA 516 Gr 70	-20	+40
Straight Segment	722-110A	M-9204-3	SA 516 Gr 70	-10	+30
Straight Segment	722-110B	M-9204-4	SA 516 Gr 70	-10	+30
Straight Segment	722-104A	M-9205-1	SA 516 Gr 70	-20	+30
Straight Segment	722-104B	M-9205-2	SA 516 Gr 70	-20	+30
Straight Segment	722-104A	M-9205-3	SA 516 Gr 70	-40	+20
Straight Segment	722-104B	M-9205-4	SA 516 Gr 70	-10	+30
Elbow	742-102A&B	M-9206-1	SA 516 Gr 70	-30	+20
Elbow	742-108A&B	M-9207-1	SA 516 Gr 70	-30	+30
Elbow	742-108A&B	M-9207-2	SA 516 Gr 70	-10	+40
Elbow	742-104A&B	M-9208-1	SA 516 Gr 70	-20	+20
Elbow	742-110A&B	M-9209-1	SA 516 Gr 70	-30	-30
Elbow	742-110A&B	M-9209-2	SA 516 Gr 70	-30	+20
Elbow	742-112A&B	M-9209-3	SA 516 Gr 70	-30	+30
Elbow	742-106A&B	M-9210-1	SA 516 Gr 70	-30	0

TABLE 5.2-12a

CHARPY V-NOTCH IMPACT DATA FOR NB-2332.a COMPONENTS

		CVN DATA									
Component Code No.	Heat No.	Temp °F	Energy Absorbed (ft-lb)			Lat. Exp. (Mils)			Shear (%)		
			1	2	3	1	2	3	1	2	3
M-9213-1		-100	2	3	2	2	4	1	1	1	1
M-9213-2		-40	40	12	11	44	11	9	1	1	1
M-9214-1	A422QT	0	21	30	33	20	30	30	10	20	20
-2		+20	240	240	65	90	88	46	100	100	30
-3		+40	133	240	240	88	86	90	80	100	100
-4		+100	240	240	240	81	88	88	100	100	100
M-9215-1											

All seven nozzles were manufactured from three forgings taken from the same heat.

TABLE 5.2-13

BOLTING MATERIALS TOUGHNESS PROPERTIES

Component	Piece Number	Code Number	Location	Material	Temperature for 45 ft-lb and 25 mils Lat. Exp. (°F)
Reactor Vessel	179-101	M-4114-1	Studs	SA 540 Gr B-24	+10
Reactor Vessel	179-102	M-4115-1	Nuts	SA 540 Gr B-23	+10
Reactor Vessel	179-103	M-4115-1	Washers	SA 540 Gr B-23	+10
Steam Generator A	GV/SL313 GJTHP	Heat 28853	Pri. Manway Studs	SA 193 Gr B16	+60
Steam Generator A	GV/SL313 BL/120	Heat 3093	Pri. Manway Nuts	SA 194 Gr B7	+60
Steam Generator B	GV/SL314 GJTHP	Heat 28853	Pri. Manway Studs	SA 193 Gr B16	+60
Steam Generator B	GV/SL314 BL/120	Heat 3093	Pri. Manway Nuts	SA 194 Gr B7	+60
Pressurizer	676-108	C-5364	Manway Nuts	SA 193 Gr B-7	+60 [A]
Pressurizer	674-106	C-5365	Manway Studs	SA 540 Gr B-24	+10 [A]
Pressurizer Safety Valves	674-106	C-5365	Flange Bolts	SA 193 Gr B-7	+40
Power Operated Relief Valves	676-106	C-5365	Flange Bolts	SA 193 Gr B-7	+40

A - Estimated based on extrapolation of available data (reference Subsection 5.2.3.3.1)

TABLE 5.2-13a

CVN DATA FOR PRESSURIZER MANWAY NUTS, CODE NO. C-5364

Temp F	Ft-lbs	% Shear	Mils Lat Exp
+10	53	80	33
+10	25	40	18
+10	41	60	27

TABLE 5.2-13b

HEAT TREATMENT MOR PRESSURIZER MANWAY NUTS, CODE NO. C-5364

Austenitized	1550F, oil quenched
Tempered	1000F
Stress Relieved	1000F

TABLE 5.2-13c

IMPACT DATA FOR SA-193 GR. B-7 MATERIAL

Heat No.	Piece No.	Temp.	Absorbed Energy (ft-lb)			Shear (%)			Lateral Exp. (Mils.)		
			1	2	3	1	2	3	1	2	3
85689	876	+10	69	68	69	100	100	100	45	45	46
	876-1	+10	69	69	70	100	100	100	48	48	46
	831	+10	65	65	65	100	100	100	44	46	43
	831-1	+10	66	68	68	100	100	100	43	43	45
	832	+10	60	60	59	100	100	100	41	38	37
	832-1	+10	60	60	60	100	100	100	39	38	38
	907	+10	59	60	61	100	100	100	36	38	38
	907-1	+10	64	66	65	100	100	100	43	45	45
42540		+10	65	66.5	53	62	64	53	47	50	37
215272		+40	61	74	64	100	100	100	38	44	45
			63	59	61	100	100	100	43	33	36
			59	68	49	100	100	73	31	30	34
216276		+40	60	63	61	100	100	100	42	37	39
215272		+40	75	90	86	100	100	86	40	73	54
215272		+40	64	55	53	79	66	69	39	32	30

TABLE 5.2-13d

HEAT TREATMENT FOR SA-193 GR. B-7 MATERIALS

Heat No.				
85689	Austenitized	1550 F, 1-1/2 hrs at heat	,	water quenched
	Tempered	1100 F, 8 hrs.	,	air cooled
	Stress Relieved	1100 F, 5 hrs.	,	air cooled
42540	Austenitized	1550 F, 2-1/2 hrs.	,	oil quenched
	Tempered	1100 F, 5 hrs.		
215272	Austenitized	1580 F, 8 hrs.	,	oil quenched
	Tempered	1120 F, 6 hrs.		
215276	Austenitized	1570 F, 6 hrs.	,	water quenched
	Tempered	1140 F, 7 hrs.		
215272	Austenitized	1560 F, 5 hrs.	,	oil quenched
	Tempered	1130 F, 7 hrs.		
215272	Austenitized	1580 F, 8 hrs.	,	oil quenched
	Tempered	1170 F, 8 hrs.		

TABLE 5.2-13e

STEAM GENERATOR PRIMARY MANWAY STUD AND BOLT MATERIAL IMPACT AND HEAT TREATMENT DATA

Part Number	Heat Number	Material	Temp.	Absorbed Energy (ft/lb)			Lateral Expansion (Mils.)			Austenitized (°F)	Tempering (°F)	Quenching
				1	2	3	1	2	3			
GV/SL313 GJTHP	28853	SA 193 Gr B16	+60	86	93	87	62	64	62	1706	1238	Oil
GV/SL313 BL/120	3093	SA 194 Gr B7	+60	89	90	92	62	65	67	1562	1202	Water
GV/SL314 GJTHP	28853	SA 193 Gr B16	+60	86	93	87	62	64	62	1706	1238	Oil
GV/SL314 BL/120	3093	SA 194 Gr B7	+60	89	90	92	62	65	67	1562	1202	Water

TABLE 5.2-14
REACTOR COOLANT LEAK DETECTION SENSITIVITY

Leakage Source	Detection Instrumentation	Instrument Range(1)	Normal Reading	Average Rate of Change for 1.0 gpm Leak	Time for Scale to Move 10% from Normal Reading for 1.0 gpm Leak
1. Direct	Sump input flow alarm		NA	NA	NA
	Monitoring Recorder		0	10 min for first 1 gpm indication	NA
	Containment Radiation		1.8E-10μCi/cc 9.5E-5 μCi/cc	1.5E-7μCi/cc/min	>62 min
2. Safety Valves and	Discharge Line Temperature		90-120° F	-	NA
	Quench Tank Water Level		29 in.	-	NA
PORV	Acoustic Monitoring Alarm		NA	NA	NA
3. S.I. Tank Check Valves	S.I. Tank Water Level		80-88%	0.0083%/min.	17.7 hr.
	S.I. Tank Pressure		579-621 psi	0.36 psi/min.	2.87 hr.
4. Heat Exchanger	CCW Radiation		2.1E-6μCi/cc	2.0E-6μCi/cc/min	<1 min.
	CCW Surge Tank Water Level Alarm		NA	NA	NA
5. Steam Generator Tubing	Blowdown Line Radiation		5.3E-6μCi/cc	2.0E-7μCi/cc/min	<1 min.
	Condenser vacuum pumps exhaust Radiation		5E-6μCi/cc	2.0E-7μCi/cc/min	<1 min.
6. Reactor Vessel Closure Head	O-Ring Space Pressure		0 psig	-	NA
7. Reactor Coolant Pump Closure Cover	Flange Gasket leak of pressure		0 psig	-	Less than 1 min
8. Steam Generator Tube Rupture	Main steam line radiation detectors		Background		NA

APPENDIX 5.2A

OVERPRESSURE PROTECTION FOR ST. LUCIE UNIT 2 - PRESSURIZED WATER REACTOR

ABSTRACT

This Appendix documents the original sizing procedure and the EPU overpressure protection for the St. Lucie Unit 2 Reactor Coolant System and steam generators. The values presented for original sizing represent Cycle 1 conditions.

Overpressurization of the Reactor Coolant System and steam generators is precluded by means of pressurizer safety valves, main steam safety valves and the Reactor Protection System. Pressure relief capacity for the steam generators and Reactor Coolant System is conservatively sized to satisfy the overpressure requirements of the ASME Code, Section III. The safety valves in conjunction with the Reactor Protection System, are designed to provide overpressure protection for a loss-of-load incident with a delayed reactor trip.

This appendix documents the standard sizing procedure for both primary and secondary safety valves during the design phase. The ability for this equipment to provide overpressure protection from EPU operating conditions is also documented in this appendix. The analyses demonstrating the ability of these valves to provide adequate overpressure protection is documented in Section 15.2.

Because of the procurement lead times, the valves must be sized quite early in the design process since this information is required to prepare interface requirements and valve specifications. The type of analysis required by Section 5.2.2 of the USNRC Standard Review Plan can only be performed once the design has been finalized and the exact operating limits are known. The EPU overpressure protection analyses demonstrate the initial sizing methodology provides sufficient margin for the valves to continue to provide the required overpressure protection.

1. INTRODUCTION

Overpressure protection for the reactor, steam generators, and Reactor Coolant System is in accordance with the requirements set forth in the ASME Code, Section III. Overpressure protection is ensured by means of pressurizer safety valves, main steam safety valves, and the Reactor Protective System. Analysis of all reactor and steam plant transients causing pressure excursions is conducted. The worst case transient, loss-of-load, in conjunction with a delayed reactor trip is the design basis for the pressurizer safety valves. The pressurizer safety valves, main steam safety valves, and Reactor Protective System maintain the Reactor Coolant System below 110 percent of design pressure during worst case transients. The main steam safety valves are sized to pass a steam flow equivalent to a power level of 2750 Mwt, which is greater than the initial licensed power level of 2570 Mwt. Steam generator pressure is limited to less than 110 percent of steam generator design pressure during worst case transients.

2. ANALYSIS

2.1 METHOD

CE performed the original parametric study to determine the design basis incident for sizing the pressurizer safety valves. The design basis incident was a loss-of-load with a delayed reactor trip. The analysis was performed using digital computer codes which have been verified by transient data from operating plants and accurately models the thermal, hydraulic, and nuclear performances of the Reactor Coolant and steam system. The digital codes used in the transient analysis include reactor kinetics, thermal and hydraulic performance of the Reactor Coolant System, and the thermal and hydraulic performance of the steam generators. The computer simulation includes effects of reactor coolant pump performance, elevation heads, inertia of surge line water and friction drop in the surge line. Worst case initial conditions and nuclear parameters were assumed for the parametric analysis. The reactor was assumed to trip at a RCS pressure of 2420 psia, with the pressurizer safety valves assumed to lift at a pressure of 2525 psia, which is 25 psi above the system design pressure. During the analysis, the throat area associated with these valves was increased parametrically until the above design basis incident analysis indicates that a further increase in throat area does not result in a significant decrease in RCS peak pressure.

The EPU overpressure analysis uses the EPU Safety Analysis results in Chapter 15 to demonstrate the overpressure protection requirements set forth in ASME Code Section III are met with the current safety valves.

2.2 ASSUMPTIONS

The following are the assumptions used for the original (pre-EPU) valve designs:

a) At the onset of the loss-of-load transient, the Reactor Coolant and Main Steam Systems are at maximum rated output plus a two percent uncertainty. By choosing the highest possible power output, the heatup rate of the reactor coolant loop is maximized, hence the rate of pressurization is also maximized.

b) Moderator coefficient is 0.0. Analytical studies supported by core data show that the moderator coefficient can vary between 0.0 and -3.5×10^{-4} for various phases of core life. Therefore, a coefficient of 0.0 is chosen to maximize the power/pressure transient.

c) Doppler coefficient of -.8 x 10^{-5} ΔK/K/F is used in the loss-of-load analysis. By choosing a relatively small Doppler coefficient, the reduction in reactivity with increasing fuel temperature is minimized thereby, maximizing the rate of power rise. Actual operating coefficients can be expected to range from -1.4 x 10^{-5} at zero power to -1. x 10^{-5} ΔK/K/F at full power.

d) No credit is taken for letdown, pressurizer spray, secondary bypass, or feedwater addition after turbine trip in the loss-of-load analysis. Letdown and pressurizer spray both act to reduce reactor coolant system pressure. By not taking credit for these systems, the rate of pressurization and peak pressure are increased. By not taking credit for the addition of feedwater, the steam generator secondary inventory is depleted at a faster rate. This in turn reduces the capability of the steam generator to remove heat from the reactor coolant loop, thereby maximizing the rate of Reactor Coolant System pressurization.

e) The analysis reflects consideration of plant instrumentation error and safety valve setpoint errors. For example, all safety valves are assumed to open at their maximum popping pressure. This extends the period of time before energy can be removed from the system. The reactor trip setpoint errors are always assumed to act in such a manner that they delay reactor trip, again resulting in maximum pressurization.

f) Pressurizer pressure at the onset of the incident is 2200 psi. By using the lower limit of the normal plant operating pressure, the time required to trip the plant on high pressure is increased.

The EPU analysis maintains the same assumptions with the following adjustments to account for EPU conditions:

1) The power uncertainty has been revised from 2% to 0.3%. The Doppler coefficient has been revised from -.8 x 10^{-5} ΔK/K/F to -.9 x 10^{-5} ΔK/K/F.

2) The initial pressurizer pressure is 2180 psia. The secondary side peak pressure analysis conservatively accounts for pressurizer spray to delay the time to the high RCS pressure reactor trip.

3) The Loss of Condenser Vacuum case analyzed is consistent with SRP Section 5.2.2 in that the trip signal generated is the second reactor trip signal (first safety grade trip). An additional case was performed that considers a reactor trip on the third reactor trip signal (second safety grade trip).

2.2.1 MAIN STEAM SAFETY VALVE SIZING

The discharge piping serving the main steam safety valves is designed to accommodate rated relief capacity without imposing unacceptable backpressure on the main steam safety valves.

The main steam safety valves were sized to pass a steam flow equivalent to a power level of 2750 Mwt. This limited steam generator pressure to less than 110 percent of steam generator design pressure during worst case transients. The EPU secondary side peak pressure Safety Analysis demonstrates the steam generator pressure will remain less than 110 percent of the steam generator design pressure with an initial power level of 3030 MWt (3020 MWt plus 0.3%). The main steam safety valves consist of two banks of valves with staggered set pressures. The valves are spring loaded type safety valves procured in accordance with ASME Code, Section III.

Figure 5.2A-1 depicts the pre-EPU steam generator pressure transient for this worst case loss-of-load incident. As can be seen on Figure 5.2A-1, the steam generator pressure remained below 110 percent of design pressure during the incident. Figure 5.2A-5 is the steam generator pressure transient for the EPU conditions. Figure 5.2A-5 shows the pressure remains below 110% of the steam generator design pressure.

2.2.2 PRESSURIZER SAFETY VALVE SIZING

The quench tank and pressurizer safety valve discharge piping are sized to preclude unacceptable pressure drops and backpressure which would adversely affect valve operations. The discharge piping pressure drops and backpressure have been evaluated for EPU conditions and found to be acceptable.

Pressurizer safety valve backpressure is limited by the design pressure of the valve bellows. These bellows prevent any accumulated backpressure from being imposed on the valve spring, thus allowing valve operation at its design setpoint rather than at its setpoint plus backpressure.

The design basis incident for sizing the pressurizer safety valves is a loss of turbine generator load during which the reactor trip on turbine trip is not operable. The reactor can be tripped on one of the following:

a) High pressurizer pressure trip;

b) Steam generator low level trip;

c) High reactor power trip;

d) Manual trip

The first of these to occur is the high pressurizer trip.

If the high pressure trip were to become inoperative, other reactor trips would proceed to shut the reactor down as their setpoints are exceeded.

The original pressurizer valve sizing was based on a series of loss-of-load studies run with various sizes of pressurizer safety valves. As can be seen on Figure 5.2A-2 after the pressurizer safety valve capacity increases to a certain size, additional increase in capacity has negligible effect in reducing the maximum system pressure experiences during the loss-of-load transient. The pressurizer safety valves are chosen so as to minimize the maximum pressure experienced during the loss-of-load transient. The minimum specified pressurizer safety valve capacity is identified on Figure 5.2A-2.

Figures 5.2A-1, 5.2A-3, and 5.2A-4 present curves of steam generator pressure, maximum Reactor Coolant System pressure and core power versus time for the worst case loss of turbine generator load used to evaluate the pre-EPU plant response. As can be seen on Figures 5.2A-1 and 5.2A-3 the maximum steam generator pressure and reactor coolant loop pressures remain below 110 percent of design during this worst case transient. Figures 5.2A-5 and 5.2A-6 present the EPU peak pressure analyses for the loss of load cases. Figures 5.2A-5 and 5.2A-6 show that the maximum steam generator pressure and the RCS maximum pressure remain below 110% of design pressure.

Figure 5.2A-1 shows the first and second banks of main steam safety valves open at approximately 5.6 and 8.8 seconds, respectively. The main steam safety valves remove energy from the Reactor Coolant System and thus mitigate the pressure surge. The pressurizer safety valves are conservatively assumed to open at one percent above the normal Reactor Coolant System design pressure. Figure 5.2A-3 shows that the pressurizer safety valves open 7.9 seconds after the initiation of the upset condition.

2.2.3 ACCEPTABILITY OF SAFETY VALVE BLOWDOWN

An evaluation[1] of the EPRI test results for the St. Lucie Unit 2 pressurizer safety valve showed that the valve ring adjustments which assure stable valve operation resulted in blowdowns of approximately 10 percent. An analysis was performed, as outlined below, to demonstrate that the extended blowdown would not adversely affect overpressure protection or plant operation, per ASME Code requirements.

An extended blowdown of the safety valves could result in swelling of the pressurizer liquid level due to flashing and possible liquid carryover through the safety valves. Since the safety valve design specification specifies dry saturated steam flow conditions, it is desirable to show that these conditions are maintained during the extended blowdown. It is also desirable to verify that the RCS remains in a subcooled condition in order that steam bubble formation in the RCS is precluded.

A computer analysis was performed of the loss-of-load event with delayed reactor trip, similar to that used in safety valve sizing, except that a conservative 20 percent safety valve blowdown and initial conditions biased to maximize pressurizer liquid level were assumed. The purpose of this analysis was to determine the pressurizer liquid level response and the RCS subcooling under these conservative conditions. In order to introduce additional conservatism, into the results, an additive adjustment was made to the computer-calculated pressurizer levels on the basis of a very conservative pressurizer model. This model assumed that the initial saturated pressurizer liquid did not mix with the cooler insurge liquid, that the initial liquid remained in equilibrium with the pressurizer steam space, and that the steam which flashed during blowdown remained dispersed in the liquid phase and caused the liquid level to swell. The adjusted pressurizer water level vs. time curve showed a maximum of 95.5 percent (expressed as the percentage of the distance from the lower level nozzle to the upper level nozzle; corresponds to 1395 ft^3), below the safety valve nozzle elevation of 107 percent, so that dry saturated steam flow to the safety valves is assured throughout the blowdown. The computer analysis also showed that adequate subcooling was maintained in the RCS during the blowdown, so that steam bubble formation is precluded.

In addition, the licensing safety analyses of the St. Lucie Unit 2 Chapter 15 pressurization events were re-evaluated to determine the impact of assuming a 15 percent blowdown for the pressurizer safety valves in lieu of the five percent generally assumed. The evaluation indicated that, for the FWLB event analysis, which produces the greatest increase in pressurizer level, the increased blowdown would not result in the pressurizer liquid level reaching the safety valve nozzle elevation and thus normal safety valve operation would be assured. It is therefore concluded that a 15 percent safety valve blowdown does not adversely affect the conclusions of the St. Lucie Unit 2 Chapter 15 safety analyses.

In summary, the evaluation of the 10 percent blowdown of the St. Lucie Unit 2 pressurizer safety valves shows that plant overpressure protection is not adversely impacted and that the conclusions of the St. Lucie Unit 2 Chapter 15 safety analyses are not changed.

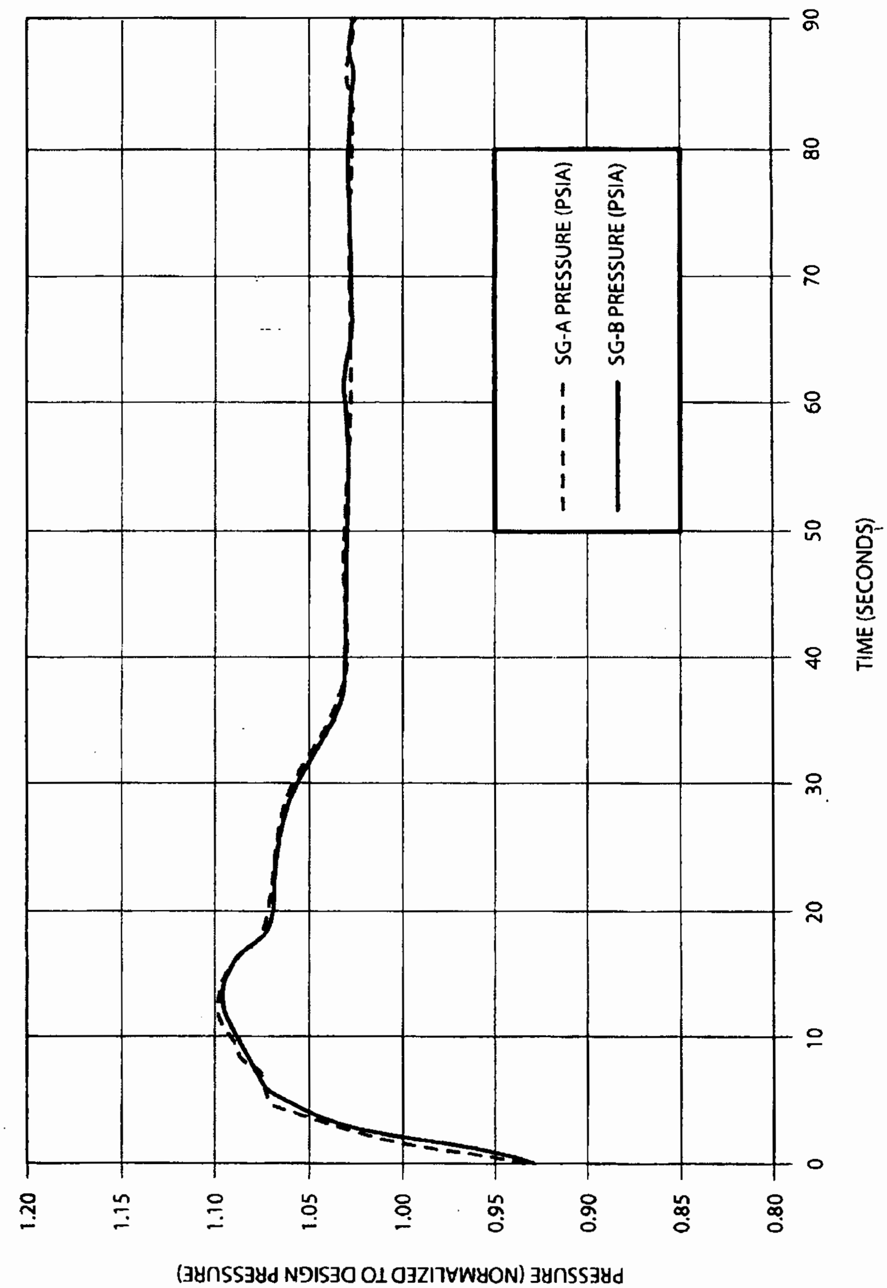
PCM 96139M replaced the relief valves with a more rigid forged steel valve body design which has an actual blowdown of 4%. This 10% blowdown evaluation is not relevant to EPU operations.

3. CONCLUSIONS

The steam generators and RCS are protected from overpressurization in accordance with the guidelines set forth in the ASME Boiler and Pressure Vessel Code, Section III. The maximum RCS pressure is shown as a function of time on Figure 5.2A-6 for the loss of turbine-generator load. As can be seen on Figure 5.2A-6, the maximum pressure remains below 110 percent of design pressure during this worst case transient. Figure 5.2A-5 depicts the steam generator pressure transient for this worst case loss-of-load accident. As can be seen on Figure 5.2A-5, the steam generator pressure also remains below 110 percent of design pressure during the incident. Both primary and secondary safety valves satisfy the requirements per Subsection NB7421 of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, regarding the required number and capacity of pressure relief devices. Also, in accordance with code requirements, the 10 percent blowdown of the St. Lucie 2 pressurizer safety valves was shown to be acceptable.

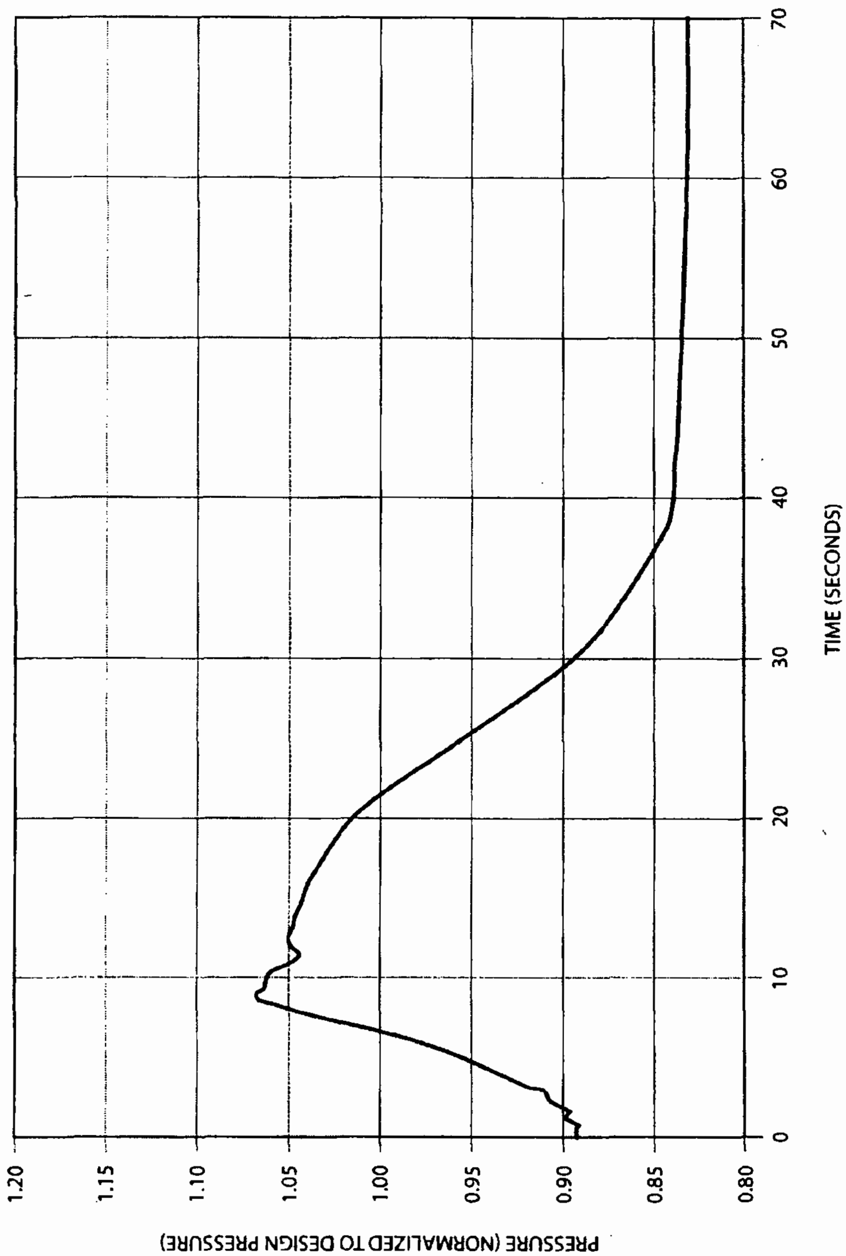
Furthermore, the analysis of a complete loss-of-load incident is described in Section 15.2. In the event that a complete loss-of-load occurs without a simultaneous reactor trip, this analysis reveals that the protection provided by the high pressurizer pressure trip, pressurizer safety valves and main steam safety valves is sufficient to assure that the integrity of the RCS and Main Steam System is maintained.

The analysis in the above section was repeated without taking credit for reactor trip on high pressurizer pressure (the first safety grade trip signal). The resulting primary-side and secondary-side pressures are within the acceptance criteria of Standard Review Plan Section 5.2.2.



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2
STEAM GENERATOR PRESSURE
LOSS OF CONDENSER VACUUM
(LOSS OF LOAD WITH DELAYED REACTOR TRIP)
FIGURE 5.2A-5

Amendment No. 21 (11/12)



FLORIDA POWER & LIGHT COMPANY **ST. LUCIE PLANT UNIT 2**
MAXIMUM REACTOR COOLANT SYST. PRESSURE VS. TIME FOR LOSS OF CONDENSER VACUUM (LOSS OF LOAD WITH DELAYED REACTOR TRIP) **FIGURE 5.2A-6**

INTRODUCTION

An analytical evaluation of natural circulation cooldown to shutdown cooling system entry conditions without formation of voids was performed for St. Lucie Unit 1 in 1980. The analytical evaluation was performed with a detailed thermal hydraulic model utilizing the RETRAN computer code. This code uses for inputs the RCS fluid volumes, flow junctions and heat conductors.

The 1980 St. Lucie Unit 1 analysis is applicable to St Lucie Unit 2. St. Lucie Unit 2 "is essentially the same design as St. Lucie Unit 1" (Subsection 1.3.1).. Because of this similarity, the fluid volumes, flow junction and heat conductors for Unit 2 are virtually identical to the St. Lucie Unit 1. Therefore, if the analysis was to be performed on Unit 2 the numerical values of the nodal points, would be very similar to the ones used for Unit 1. The differences in the numerical values would be mainly caused by the 16 x 16 fuel geometry used in Unit 2. However, these differences would not appreciably change the end result.

Additionally, the selection of auxiliary equipment, associated with this analysis, have caused some physical arrangements to differ between the two Units. These physical differences, however, have not caused any significant changes in the flow conditions.

The reactor coolant system pressure must be reduced to 275 psia for shutdown cooling initiation. Consequently to prevent the formation of voids the upper 1-lead fluid must be cooled to a value less than the corresponding saturation temperature of 409.5°F. After that time de-pressurization to shutdown cooling system entry conditions can occur without void formation in the reactor coolant. Hot Leg temperature cooldown rates of 30°F/hr and 50°F/hr to 325°F were investigated to determine the cooldown time required for the fluid temperature in the reactor vessel upper head to reach shutdown cooling entry conditions without void formation.

THERMAL-HYDRAULIC MODEL

The analysis was performed with a detailed thermal-hydraulic model utilizing the RETRAN (Reference 1) computer code. Figure 5.2B-1 presents a schematic drawing of the fluid volume, flow junctions and heat conductors used in the model. Table 5.2B-1 provides a description of these volumes junctions, and conductors. Specific features of the model include: a detailed nodalization of the upper portion of the reactor vessel including a representation of the reactor vessel walls and internals; a number of automatic control systems including those for charging pumps, the letdown flow control valve and the pressurizer heaters; and a non-equilibrium thermal-hydraulic model for the pressurizer.

PRE-EPU ANALYSIS RESULTS

The St. Lucie Unit 2 SGs have been replaced. The natural circulation capability of the RSGs has been verified (Reference 4). Therefore, the original responses, as they applied to the OSGs, remain appropriate following the SG replacement.

An analysis of a St. Lucie Unit 1 natural circulation cooldown from full power for a hot leg temperature cooldown rate of about 30°F/hr to 325°F demonstrates that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 16.1 hours. The results are presented in Figure 5.2B-2. The condensate supply required for this cooldown is 218,500 gallons.

The analysis for a hot leg temperature cooldown rate of about 50°F/hr to 325°F demonstrates that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 14.2 hours. The results are presented in Figure 5.2 B-3. The condensate supply required for this cooldown is 193,000 gallons.

The analysis for a hot leg temperature cooldown rate of about 50°F/hr to 325°F was repeated using very conservative assumptions regarding fluid mixing in the upper reactor vessel in order to determine a bounding cooldown time for operating guidelines. The results demonstrate that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 25.7 hours. The condensate supply required for this cooldown is 270,500 gallons.

In addition, FP&L has investigated the amount of water required to bring St. Lucie Unit 2 through four hours of hot standby followed by a Natural Circulation Cooldown without upper head voiding. Table 5.2B-2 indicates the amount of condensate water required to meet a variety of different cooldown rates. The maximum conservative value of 330,900 gallons is composed of 60,400 gallons required for hot standby coupled with 270,500 gallons needed for natural circulation cooldown. The condensate requirement of 330,900 gallons will be met via revising FP&L procedures to require the operator to follow a hot standby Natural Circulation Cooldown procedure to establish makeup to the condensate storage tank and to maintain the volume of the tank continuously above the technical specification Limit. The makeup supply of condensate water can be supplied from the two 500,000 gallon city water storage tanks located on the St. Lucie Unit 1 site. Pumping capabilities can be provided by the St. Lucie Unit 1 diesel generators.

We have concluded that this approach adequately accomplishes the goal of bringing the plant to shutdown conditions in a safe manner.

RECOMMENDATION

The above results show that for a hot leg temperature cooldown rate of 50°F/hr to 325°F, the upper head fluid can be cooled to shutdown cooling system entry conditions without void formation in approximately 14.2 hours.

In order to provide additional conservatism, it is recommended that for natural circulation cooldown to shutdown cooling system entry conditions without void formation, the hot leg temperature cooldown rate be about 50°F/hr to 325°F followed by a soak at 325°F for 20.4 hours for a total cooldown time of approximately 25.7 hours from cooldown initiation. Figure 5.2B-4 shows the recommended plant cooldown rate. The condensate supply required for this cooldown is 270,500 gallons.

OTHER ANALYSIS

The NRC staff indicated that the St. Lucie Unit 1 natural circulation cooldown event would not, by itself, provide sufficient basis to satisfy the boron mixing and natural circulation cooldown test requirements associated with Reactor System Branch, Branch Technical Position 5-1. Therefore, St. Lucie

Unit 2 was required to: 1) provide a report on the San Onofre Unit 2 Natural Circulation Cooldown and Mixing Test, and 2) justify that the test data is applicable to St. Lucie Unit 2. The information from the San Onofre report was used on a comparison basis for NRC approval and provides the similarities of the results and the applicability to St. Lucie Unit 2. (2)

Based on San Onofre Nuclear Generating Station Report CEN-259, the estimated cooling water requirement for St. Lucie Unit 2 is 276,000 gallons. Therefore, St. Lucie Unit 2 has a sufficient amount of water in the CST to meet the requirements of BTP RSB 5-1[(3)].

EFFECT OF UPRATE TO 3020 MWT

To evaluate the natural circulation capability of St. Lucie Unit 2 at an EPU power level of 3020 MWt, the CENTS computer Code (Reference 5) was used to simulate the plant response to a loss of offsite power followed by a natural circulation cooldown from hot standby conditions to shutdown cooling system entry conditions. The CENTS code is an NRC approved code that is acceptable for referencing in licensing applications for Combustion Engineering designed pressurized water reactors.

The previously analyzed scenarios were simulated. The resulting total cooldown time and condensate volume required can be compared to the 1980 St. Lucie Unit 1 analysis values.

At an EPU power level of 3020 MWt, the simulations demonstrate that the plant can be cooled down to SDC entry conditions using the same equipment the plant has prior to EPU operation while maintaining pressure control (no voids in the RCS) for a loss of offsite power event.

The 3020 MVW uprate at St. Lucie Unit 2 will not adversely impact the natural circulation cooldown capability of the plant for the following reasons:

- The maximum core ΔT during the 30°F/hour and the 50°F/hour cooldown Is lower than the normal full power ΔT of 55°F.
- The reactor coolant system pressure is reduced to 275 psia for SDC initiation and the upper head fluid is cooled to a value less than the corresponding saturation temperature of 409.5°F.
- The condensate volume requirement established in the historical evaluation is bounding for the 3020 MWt uprate.

The EPU analysis also shows:

- Acceptable results were determined for natural circulation cooling during the hot standby period for expected residual heat rates immediately following reactor shutdown from the 3020 MWT EPU conditions.
- The ADVs are adequate to achieve cooldown to the SDC entry point in a reasonable time period. SDC entry conditions can be achieved In less than 10 hours at a cooldown rate of 30°F/hour and less than 15 hours at a cooldown rate of 50°F/hour which Includes four hours In hot standby.

The results of the CENTS simulation for the 30°F/hour cooldown show that it will take about 9.3 hours to bring the RCS to shutdown cooling entry conditions (325°F and a pressure of 275 psia). The condensate supply required for this cooldown is about 117,000 gallons.
The results of the CENTS simulation for the 50°F/hour cooldown show that it will take about 14.5 hours to bring the RCS to shutdown cooling entry conditions. The condensate supply required for this cooldown is abut 164,200 gallons.

The most limiting cooldown simulation required cooling down at a 50°F/hour rate to 325°F and then maintaining the hot leg temperature at 325°F for 5.1 hours in order to allow the SDC pressure to be reached without flashing of the upper head fluid. The condensate supply required for this cooldown is about 281,000 gallons. The total cooldown time is 23.6 hours.

REFERENCES:

(1) RETRAN-A Program For One-Dimensional Transient Thermal-Hydraulic Anlysis of Complex Fluid Flow Systems, Volumes 1, 2, 3 and 4, EPRI CCM-5, December 1978.

(2) FPL Letter L-84-68 from J W Williams to D G Eisenhut dated March 13, 1984.

(3) NRC Letter from E G Tourigny to W F Conway dated April 12, 1988.

(4) AREVA NP Inc. Document 77-5069878-001, "Replacement Steam Generator Report for Florida Power and Light St. Lucie Unit 2."

(5) Westinghouse Owners Group Topical Report WCAP-15996-P-A, Rev. 1, "Technical Description Manual for the CENTS Code," dated March 2005.

TABLE 5.2B-2

NATURAL CIRCULATION COOLDOWN

CONDENSATE STORAGE TANK REQUIREMENTS FOR PRE-EPU OPERATION

Condition	Length of Condition (hours)	C.S.T. Req't (gal)	Reference
1. Case 1			
Hot standby	4.0	60,400	Ref Table 10.4-2
Cooldown (@30°F/HR)	16.1	218,500	Ref App. 5.2B
Total	20.1	278,900	
2. Case 2			
Hot standby	4.0	60,400	Ref Table 10.4-2
Cooldown (@50°F/HR)	14.2	193,000	Ref App. 5.2B
Total	18.2	253,400	
3. Case 3*			
Hot standby	4.0	60,400	Ref Table 10.4-2
Cooldown (@50°F/HR)	25.7	270,500	Ref App. 5.2B
Total	29.7	330,900	

* Case 3 - Extreme conservative assumptions regarding fluid mixing in the upper reactor vessel

TABLE 5.2B-3

NATURAL CIRCULATION COOLDOWN

CONDENSATE STORAGE TANK REQUIREMENTS FOR EPU OPERATION

Condition	Length of Condition (hours)	C.S.T. Req't (gal)	Reference
1. Case 1			
Hot standby	4.0	74,000	Ref Table 10.4-2
Cooldown (@30°F/hr)	9.3	117,000	Ref App. 5.2B
Soak to SDC Entry Pressure	9.5	74,000	
Total	22.8	265,000	
2. Case 2			
Hot standby	4.0	76,300	Ref Table 10.4-2
Cooldown (@50°F/HR)	14.5	164,200	Ref App. 5.2B
Soak to SDC Entry Pressure	5.1	40,500	
Total	23.6	281,000	

* Case 2 - Extreme conservative assumptions regarding fluid mixing in the upper reactor vessel head

Specimens are prepared from three metallurgically different materials, including base metal, weld metal and heat-affected zone (HAZ) materials. In addition, material is included from a standard heat of ASTM A533-B.

Class I manganese-molybdenum nickel steel made available by the USNRC sponsored Heavy Section Steel Technology (HSST) program. This standard reference material (SRM) is used as a monitor for Charpy impact tests permitting comparisons among the irradiation data from operating power reactors and experimental reactors. Compilation of data generated from post-irradiation tests of these correlation monitors is carried out by the HSST program.

5.3.1.6.1.1 Base Metal

Base metal test material is manufactured from a section of intermediate shell plate M-605-1 which is found to have the combination of RT_{NDT}, chemical composition (Cu and P) and neutron fluence during service, which would first appear to limit the vessel operating lifetime.

The section of shell plate used for the base metal test material is adjacent to the test material used for ASME Section III tests and is at a distance of at least one plate thickness from any water-quenched edge. This material is heat-treated to a metallurgical condition which is representative of the final metallurgical condition of the base metal in the completed reactor vessel.

5.3.1.6.1.2 Welded Plates

Weld metal and heat affected zone material are produced by welding together sections from the selected base metal plate and another plate from the reactor vessel beltline. The HAZ test material is manufactured from a section of the same shell plate used for base metal test material.

The sections of shell plate used for weld metal and HAZ test material are adjacent to the test material used for ASME Code, Section III tests and are at a distance of at least one plate thickness from any water-quenched edge. The procedure used for making the intermediate-to-lower shell girth weld in the reactor vessel is followed in the manufacture of the weld metal and HAZ test materials. The welded plates are heat-treated to metallurgical conditions that are representative of the final metallurgical conditions of similar materials in the completed reactor vessel.

5.3.1.6.1.3 Archive Material

Representative stock (archive material) to provide two additional sets of test specimens for each material for encapsulation are provided with full documentation and identification.

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 REACTOR COOLANT PUMPS

5.4.1.1 Design Bases

The reactor coolant pumps provide sufficient forced circulation flow through the Reactor Coolant System to assure adequate heat removal from the reactor core during power operation. A low limit on the reactor coolant pump flowrate is established to assure that specified fuel design limits are not exceeded. Design flow is derived on the basis of the thermal-hydraulic considerations presented in Section 5.1.

The reactor coolant pump and motor assembly, in conjunction with the flywheel, provide sufficient coast down flow following loss of power to the pumps to assure adequate core cooling.

The reactor coolant pump pressure boundary is designed for the transients given in Subsection 3.9.1.1 so that the ASME Code, Section III allowable stress limits are not exceeded for the specified number of cycles.

The reactor coolant pump parameters and design requirements are listed in Table 5.4-1.

5.4.1.2 Description

The reactor coolant is circulated by four vertical, single bottom suction, horizontal discharge, centrifugal, motor driven pumps as shown in Figure 5.4-1. The design parameters for the pumps are given in Table 5.4-1. The piping and instrumentation diagram for the reactor coolant pump is shown in Figure 5.1-6. The pump performance curve is shown in Figure 5.4-2.

5.4.1.2.1 Reactor Coolant Pump Assembly

The reactor coolant pump assembly consists of the following:

a) Pump Case and Motor Mount

b) Rotating Assembly
(Containing the impeller with a welded impeller locknut)

c) Shaft Seal Assembly

d) Motor Mount

e) Motor Assembly

5.4.1.2.1.1 Pump Case and Motor Mount

The reactor coolant pump motor is connected to and supported by the pump case through the motor mount. There are two openings on opposite sides of the motor mounts that provide access for assembly of the flanged rigid coupling between the motor and pump and for seal cartridge replacement. This assembly includes the seal heat exchanger, which cools the seal cartridge assembly.

5.4.1.2.1.2 Rotating Assembly

The pump rotating assembly consists of impeller, water lubricated radial hydrostatic bearing, rotor, seal coolant recirculating impeller and rotating elements of the seal cartridge assembly. The radial bearing, one of three used for pump motor shaft support, is located just above the pump impeller. The upper radial bearing and the axial thrust bearing are located on the motor shaft. The seal cartridge and recirculating impeller are located above the thermal barrier formed by the close clearance between the pump shaft and the pump case cover.

5.4.1.2.1.3 Shaft Seal Assembly

The seal cartridge consists of four-multiface type mechanical seals; three full pressure seals mounted in tandem and a fourth low pressure vapor seal designed to withstand system design pressure when the pumps are not operating. A controlled bleedoff flow through the seals is used to cool the seals and to equalize the pressure drop across each seal. The controlled bleedoff flow is collected in the volume control tank of the Chemical and Volume Control System. Leakage past the vapor seal is collected in the Waste Management System through drainage via floor drains to the containment sump.

The seal cartridge assembly is cooled by circulating the controlled leakage through a coiled tube heat exchanger cooled by component cooling water and integral with the pump case cover. The seal coolant recirculation is done by the recirculating impeller located directly below the seal cartridge. The seal cartridge concept reduces the time required for seal maintenance thereby lowering personnel radiation exposure time. The seal cartridge can be removed without draining the pump case. Details of the seal cartridge are shown in Figure 5.4-3.

The seal design life is at least two years. Each seal is designed to accept the full operating pressure of the Reactor Coolant System. The first three seals of the cartridge assembly normally operate with a pressure differential equal to one-third of the operating pressure and with only a slight pressure differential across the vapor seal. The seal rotors are titanium carbide operating against a hard carbon faced stator.

5.4.1.2.1.4 Motor Assembly

The motor assembly includes the following:

a) Air Cooler

b) Motor Bearing Lubrication

c) Oil Lift Pumps

d) Motor Shaft

e) Upper and Lower Radial Guide Bearings

f) Axial Thrust Bearing

g) Flywheel

h) Anti-Reverse Rotation Device

i) Motor

The heat exchanger cooling water is supplied from the Component Cooling Water System. Two 10 hp ac oil lift pumps are used to support the pumpmotor shaft assembly during startup and shutdown of the reactor coolant pumps. The motor-pump hearing support system includes a Kingsbury double acting thrust bearing, upper and lower radial bearings in the motor and a radial hydrostatic bearing located above the pump impeller. The piping and instrumentation diagram for the lube oil and cooling system of the pumps is shown on Figure 5.1-6. The flywheel and motor-pump rotating assembly has a minimum total moment of inertia of 100,000 $lb\text{-}ft^2$ to improve pump coastdown characteristics in order to meet system requirements during a loss of pump power condition.

Each pump-motor assembly is equipped with an anti-rotation device shown in Figure 5.4-4 to preclude reverse rotation caused by backflow through the impeller. The device stops the pump when it decelerates from normal speed (900 rpm) to zero speed while the remaining reactor coolant pumps continue to operate. The anti-reverse device consists of a rotating disc keyed to the motor shaft, and a stationary disc which is bolted to the motor frame. The stationary disc contains several detents each with ramped sides and flats on top of the detents and in the troughs between them. The rotating elements contain several holes in which the retaining pins are located. When reactor coolant pump rotation stops, each pin drops to the flat between detents, and reverse rotation is prevented by the pin which bears against the vertical side of a detent. When motor rotation is started in the normal direction, the pins ride up the ramped sides of the detents and are locked against the sides of the holes in the rotating disc by centrifugal force. No parts are in contact when the motor is operating at rated speed and no lubrication is required for the device. One pin is capable of holding the pump stationary against the torque produced by reverse flow or by the application of 100 percent voltage in reversed phase rotation.

The reactor coolant pump motor is sized for continuous operation at the flows resulting from four-pump operation or partial pump operation with 0.74 specific gravity water. The motor service factor is sufficient to allow 500 heatup cycles. The motors are designed to start and accelerate to speed under full load when 80 percent or more of normal voltage is applied. The motors are contained within NEMA Standard 1-1.20 drip-proof enclosures and are equipped with electrical insulation suitable for a zero to 100 percent humidity and radiation environment of 30R/hr of gamma. The motor cross section is shown in Figure 5.4-5.

5.4.1.2.1.5 Reactor Coolant Pump Lube Oil Collection System

A Reactor Coolant Pump Lube Oil Collection System is provided to meet the following criteria:

a) Capable of collecting lube oil from all potential pressurized and unpressurized leakage sites in the reactor coolant pumps' lube oil systems,

b) Capable of draining lube oil from the collection system at the pumps to a safe location at a rate in excess of the largest anticipated leak in the lube oil systems,

c) Seismically analyzed to insure the system will remain on the reactor coolant pump motors during design basis earthquake conditions, and

d) Capable of collecting 225 gallons of lube oil. This quantity is in excess of the quantity which would require pump shutdown (approximately 15 gallons for each pump). Also, the capacity is in excess of the entire volume of the lube oil contained in one reactor coolant pump (190 gallons).

5.4.1.3 Evaluation

The reactor coolant pumps are sized to deliver flow that equals or exceeds the design flowrate used in the thermal hydraulic analysis of the Reactor Coolant System Analysis of steady state and anticipated transients is performed assuming the minimum design flow rate. Tests are performed to evaluate reactor coolant pump performance during the post core load hot functional testing to verify adequate flow.

Leakage from the reactor coolant pump past the pump shaft is controlled by the shaft seal assembly. Reactor coolant entering the seal chambers is cooled and collected in closed systems so that reactor coolant leakage to containment is essentially zero. In the event of a seal malfunction, instrumentation in the form of pressure transmitters, a flow meter, and a temperature detector is provided to alert the operator to a potential problem.

Component cooling water to the reactor coolant pumps is not required to ensure (1) the integrity of the reactor coolant pressure boundary, (2) the capability to shutdown the reactor and maintain it in a safe shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite doses comparable to the guidelines established for design basis accidents. Low component cooling water flow to each pump is indicated and alarmed in the control room. The component cooling water flow from the reactor coolant pumps is sensed by four separate redundant transmitters and low flow is indicated and alarmed in the control room. If the component cooling water flow from the reactor coolant pumps is not restored in 10 minutes, the system automatically trips the reactor and the reactor coolant pumps could be tripped by the operator manually, allowing the system to be cooled down by natural circulation flow.

The reactor coolant pumps, by design and field experience, are not susceptible to seal failure resulting from loss of seal cooling water. The reactor coolant pumps are equipped with four series-arranged face seals, all of which are designed for 2500 psid. The P across any one of the three main seals during normal operation is 750 psi. The loss of any single seal would result in a P of approximately 1100 psi. A seal leakage chamber structurally designed for 2500 psia is provided to collect controlled seal leakage and conduct it to a closed system. The fourth face seal is provided as an integral part of the seal leakage chamber to prevent liquid or gaseous leakage from escaping to the atmosphere. This seal is designed to operate normally against a backpressure of 25 to 250 psia and is capable of holding against 2500 psia in the static condition and during coastdown following failure of the three series-arranged main seals. When holding against 2500 psia in the static condition, the seal leakage should not exceed the normal operating seal leakage.

The seals have been specified and tested for 10 minutes of RCP operation without cooling water to the RCP seals without incurring seal damages. See Subsection 9.2.2.3.1

In the event of an actuation of containment isolation and subsequent isolation of CCW, the reactor coolant pumps are tripped, as discussed above, resulting in no requirement for component cooling water.

In the event of a break in the reactor coolant pump suction piping, a high reverse flow through the pump is prevented by the anti-reverse rotation device, as described in Subsection 5.4.1.2.1.4. In the event of a discharge line break, increased flow through the pump tends to accelerate the pump impeller and flywheel in the forward direction. A detailed evaluation of this incident relating to the integrity of the flywheel is presented in Subsection 5.4.1.4.

5.4.1.4 Reactor Coolant Pump Flywheel Integrity

The following design conditions and material specifications for the flywheels are consistent with the recommendations of Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity," October 1971 (R0). Technical Specifications require a program for the inspection of each reactor coolant pump flywheel per the recommendation of Regulatory Position c.4.b of Regulatory Guide 1.14, Revision 1, August 1975.

5.4.1.4.1 Flywheel Material Specification

The material used to manufacture the flywheel was produced by a process that minimizes flaws by a commercially acceptable process such as the vacuum melt and degassing process which provides adequate fracture toughness properties. The acceptance criteria for flywheel design is compatible with the safety philosophy of the reactor coolant pressure boundary criteria as appropriate considering the inherent design and functional requirement differences between the pressure boundary and the flywheel.

a) The nil-ductility transition temperature (NDTT) of the material, as obtained from the dropweight tests (DWT) performed in accordance with the Specification ASTM E208-66T was no greater than 10°F.

b) The Charpy V-Notch (Cv) upper shelf energy level, in the "weak" (WR) direction, as obtained per ASTM A370 was no less than 50 ft.-lbs. A minimum of three Cv specimens were tested from each plate or forging.

c) The minimum fracture toughness of the material at the normal operating temperature of the flywheel is equivalent to a dynamic stress intensity factor K_{Ic} (dynamic) of at least 100 Ksi $\sqrt{in}$. Compliance was demonstrated by either of the following:

    1) Testing of the actual material of the flywheel to establish the K_{Ic} (dynamic) value at the normal operating temperature.

2) Use of a lowerbound fracture toughness curve obtained from tests on the same type of material. The curve was translated along the temperature coordinate until the K_{Ic} (dynamic) value of 45 Ksi$\sqrt{in}$ is indicated at the NDTT of the material, as obtained from dropweight tests.

d) Each finished flywheel was subjected to a 100 percent volumetric ultrasonic inspection from the flat surface per ASME Code, Section III. This inspection was performed on the flywheel after final machining and overspeed test.

e) The flywheel is flame cut; at least 1/2 in. of stock was left on the outer and bore radii for machining to final dimensions.

f) The flywheel was subjected to a magnetic particle of liquid-penetrant examination per ASME Code, Section III before final assembly. The inspection was performed on finished machine bores, key ways, and on both flat surfaces to a radial distance of eight in. minimum beyond the final largest machined bore diameter but not including small drilled holes. There are no stress concentrations such as stamp marks, center punch marks, or drilled or tapped holes within eight in. of the edge of the largest flywheel bore.

5.4.1.4.1.2 Flywheel Design Criteria

The flywheel is designed to withstand normal operating conditions, anticipated transients, and the design basis loss of coolant accident loadings combined with the safe shutdown earthquake loadings.

The following criteria are satisfied:

a) The combined stresses, both centrifugal and interference, at normal operating speed do not exceed 1/3 of the minimum specified yield strength for the material selected in the direction of maximum stress.

b) The design speed of the flywheel is 125 percent of normal operating speed.

c) The combined centrifugal and interference stresses at design speed are limited to 2/3 of the minimum specified yield strength where design overspeed is 125 percent of normal operating speed.

d) The motor and pump shaft and bearings can withstand any combination of normal operating loads, anticipated transients, and the design basis loss of coolant accident combined with the safe shutdown earthquake.

e) Each flywheel was tested at design speed, 125 percent of normal operating speed, as defined in 2.b above.

f) The flywheel is accessible for 100 percent in-place volumetric ultrasonic inspection. The flywheel motor assembly is designed to allow such inspection with a minimum of motor disassembly.

5.4.1.5 Reactor Coolant Pump Instrumentation

The reactor coolant pumps and motors are equipped with the instrumentation necessary for proper operation and to warn of incipient failures. A description of the major channels follows (see Figure 5.1-3). Measurement channels are typical for each reactor coolant pump.

5.4.1.5.1 Temperature

5.4.1.5.1.1 Motor Stator Temperature

Each reactor coolant pump motor is provided with six thermocouples embedded in the stator windings. Indication of stator temperature is provided in the control room. During initial reactor coolant pump testing, the highest reading thermocouple is selected for this temperature measurement channel. High temperature is detrimental to motor winding insulation life, and may be caused by high ambient temperature, reduction in the cooling air flow to the stator, or inadequate time delay between successive starts of the motor.

5.4.1.5.1.2 Motor Bearing Temperatures

Temperature indication for the following oil lubricated bearings is provided in the control room.

a) Motor upper guide bearing

b) Upper and lower thrust bearings

c) Motor lower guide bearing

High temperature is indicative of bearing or oil supply problems. The thrust bearings are also provided with high temperature alarms.

5.4.1.5.1.3 Pump Controlled Bleedoff Temperature

The temperature of the controlled bleedoff flow is provided. A high temperature condition is an indication that the seal assembly or seal water cooler is not operating properly.

5.4.1.5.1.4 Seal Water Heat Exchanger Outlet Temperature

Temperature sensors (TE-1151, 1161, 1171, 1181) are provided at the seal water outlet. A high temperature condition is an indication that the cooler has developed a leak or that the component cooling water flow has decreased. High temperatures are alarmed.

5.4.1.5.2 Pressure

5.4.1.5.2.1 Reactor Coolant Pump Seal Pressures

The middle seal, upper seal and controlled bleedoff cavities in each reactor coolant pump are provided with pressure transmitters that generate a signal proportional to the pressure within the cavity. High and low pressure alarms for the upper seal cavity and the controlled bleedoff cavity are provided. Pressure indication of all three is also provided.

5.4.1.5.2.2 High Pressure Oil Lift Pump Discharge Pressures

Pressure switches at each high pressure oil lift pump discharge actuate indicating lights and alarms on low pressure in the control room. In the event of a failure of one of the oil lift pumps, the second oil lift pump must be started. A separate measurement channel provides a control signal to the respective reactor coolant pump circuit; which prevents the starting of the reactor coolant pump if insufficient oil lift pressure exists. Another separate measurement channel provides local indication of pressure in the oil lift pump discharge header.

5.4.1.5.2.3 Reactor Coolant Pump Differential Pressure

Two independent differential pressure transmitters are provided on each reactor coolant pump. The differential pressure signal is indicated in the control room. The pump performance curve (Figure 5.4-2) relates pump differential pressure to pump flow.

5.4.1.5.2.4 Casing Main Closure Gasket Leakage Pressure

A pressure indicator and pressure switch are provided on each reactor coolant pump to monitor the pressure between the double casing main closure gaskets. High pressure in the cavity between the gaskets indicates leakage of the inboard gaskets and is alarmed in the control room.

5.4.1.5.3 Flow

5.4.1.5.3.1 Reverse Rotation Indicator Switch

A flow switch in the lube oil system mounted near the main thrust bearing bracket provides an indication that the reactor coolant pump motor is turning in the reverse direction. This switch causes an alarm in the control room. This feature has been removed from 2B1 RCP motor.

5.4.1.5.3.2 Pump Controlled Bleedoff Flow

A flowmeter is used to measure the controlled bleedoff flow from the bleedoff seal cavity to the CVCS. This instrument provides an indication of the flowrate and annunciates high and low flow alarms.

5.4.1.5.3.3 Motor Circulating Oil System Flow

A lube oil flow switch is provided at the outlet from the lube oil cooler. Should the lube oil flow to the cooler fall below a predetermined setpoint, a low flow alarm is actuated. This feature has been removed from 2B1 RCP motor.

5.4.1.5.4 Level

Each RCP upper lower oil reservoir has a bubbler type level measurement system. A level transmitter is used to measure the air backpressure from each bubbler which is equivalent to the oil level in the reservoir. The excess flow valve in the bubbler limits the excess air flow to the oil reservoir. The transmitter transmits a signal for level indication and high and low alarms in the control room.

5.4.1.5.5 Vibration

Reactor coolant pump motor vibration and axial shaft position is sensed by proximity probes arranged around the motor and pump shaft. These probes are noncontacting. The probes are used to determine axial shaft position relative to the motor case (one probe), provide phase angle information (one probe) and to determine X-Y vibration at the upper motor bearing and the top of the pump mechanical seal (four probes). Pumps 2A1, 2A2 and 2B1 are provided with an additional set of X-Y probes which are installed at the lower motor bearing. These are available for maintenance and troubleshooting and are not normally indicated in the control room.

Excessive X-Y vibration at the upper motor bearing and mechanical seal is alarmed in the control room.

The vendor supplied cables are routed such that they are separated from other plant cables.

5.4.1.6 <u>Testing and Inspection</u>

The reactor coolant pressure boundary is nondestructively inspected as required by ASME Code, Section III for Code Class 1 components. The reactor coolant pump casing inspections include complete radiography and liquid penetrant or ultrasonic testing. The reactor coolant pump receives a hydrostatic pressure test in the vendor's shop and with the Reactor Coolant System. In-service inspection of the reactor coolant pump pressure boundary is performed during plant life in accordance with ASME Code, Section XI.

The reactor coolant pump assembly is performance tested in the vendor's shop over at least the normal operating range in accordance with the Standards of the Hydraulic Institute. Tests also demonstrate the ability of the reactor coolant pump to function under various operating conditions specified. Tests commonly performed are hot and cold performance and start-stop cycling. Vibrations are monitored at several places on the reactor coolant pump during shop testing.

The reactor coolant pump motors undergo a "routine" test in accordance with NEMA MG-1. This test also confirms that the motors are within their vibration limits. Each motor is tested further by being used as the driver for the reactor coolant pump assemblies during the pump manufacturer's shop testing.

To the greatest extent practicable, all conditions of normal operation of the reactor coolant pumps are duplicated during testing.

The reactor coolant pump flywheel inspections and testing are described in Subsection 5.4.1.4.

5.4.2 STEAM GENERATORS

5.4.2.1 Design Bases

The two steam generators are designed to transfer 2710 MWt from the Reactor Coolant System to the Main Steam System, producing approximately $11.8x10^6$ lb/h of 896.9 psia saturated steam, when provided with 435°F feedwater. With implementation of the extended power uprate (EPU), it has been verified that the two steam generators have the capability to transfer 3034 MWt, producing approximately 13.3×10^6 lb/h of 886.2 psia saturated steam, when provided with 436°F feedwater. Moisture separators and steam driers in the shell side of the steam generator limit the moisture content of the steam to 0.10 wt% during normal operation at full power. The steam generator design parameters are listed in Table 5.4-2. The steam generators, including the tubes, are designed for the Reactor Coolant System transients listed in Subsection 3.9.1.1 so that the code allowable stress limits are not exceeded for the specified number of cycles. All transients have been established based on conservative assumptions of operating conditions in consideration of supportive system design capabilities. The steam generators are capable of sustaining the following additional design transients without exceeding code allowable stress limits: (Note: differences exist between the cycles and transients assumed in the design of Unit 1 and those assumed in the design of Unit 2. Further, there may also be unit differences with respect to those cycles and transients required by plant procedure to be tracked).

a) Ten secondary side hydrostatic tests with secondary side pressurized to 1250 psia with the primary side at atmospheric pressure. The minimum shell side temperature for this test is 70°F.

b) Two hundred secondary side leak tests with the secondary side pressurized from 820 psia to design pressure, with the primary side pressurized so that the tube differential pressure (secondary to primary) does not exceed 820 psi (test condition). The secondary side temperature shall be 70-200°F.

c) Fifteen thousand cycles of adding 70°F feedwater at 600 gpm to each of the steam generators through the main feedwater nozzle when at hot standby conditions (normal condition). The basis is nominal operating conditions assuming intermittent feeding of the steam generators.

d) Eight cycles of adding 32°F feedwater at 650 gpm to each of the steam generators after a loss of normal feedwater. This feedwater flow may be introduced while the secondary side is dry: at 610°F and atmospheric pressure.

e) Four thousand pressure transients of 85 psi across the primary divider plate in either direction caused by starting and stopping reactor coolant pumps (normal condition).

5.4.2.1.1 Steam Generator Materials

The pressure boundary materials used in the construction of the steam generator are listed in Table 5.2-3. These materials are in accordance with the ASME Code, Section III plus code case interpretations as specified in Subsection 5.2.1.

The Code Class 1 components of the steam generator meet the fracture toughness requirements of the ASME Code and 10 CFR 50, Appendix G as discussed in

Subsection 5.2.3.3.1. Fracture toughness data for the steam generator materials is presented in Tables 5.2-8, 5.2-10, and 5.2-11.

During final assembly and shipment, the steam generator primary and secondary sides are brought to a state of cleanliness consistent with the rest of the fluid system in interfaces with as described in Subsection 5.2.3. In addition, the interior of the steam generator is protected by pressurizing with an inert gas during shipment and interim storage. Cleanliness during construction is discussed in Subsection 5.2.3.4.1.2.1.

The chemistry control and corrosion control effectiveness of the secondary side water is discussed in Subsection 10.3.5.

5.4.2.1.2 Steam Generator Description

The nuclear steam supply system utilizes two steam generators (Figure 5.4-6) to transfer the heat generated in the Reactor Coolant System to the secondary system. The design parameters for the steam generators are given in Table 5.4-2.

The steam generator is a vertical U-tube heat exchanger with the reactor coolant on the tube side and the secondary fluid on the shell side.

Reactor coolant enters the steam generator through the 42 inch ID inlet nozzle, flows through 3/4 inch OD 0.0429 inch wall U-tubes, and leaves through two 30 inch ID outlet nozzles. Divider plates in the lower head separate the inlet and outlet plenums. The plenums are carbon steel with stainless steel clad. The reactor coolant side of the tube sheet is Ni-Cr-Fe clad. The U-tubes are Inconel 690 composition.

The steam generator contains 8999 U-tubes for heat transfer for primary to secondary water. Each tube is expanded into the tube sheet so that there is no voids or crevices occurring along the entire length of the tube sheet interface. The tubes are also welded to the Ni-Cr-Fe alloy clad on the reactor coolant surface of the tubesheet. The tube to tubesheet welding conforms with the requirements of the ASME Code, Sections III and IX. Support for the tube bundles are by stainless steel broached tube support plates. Additional support is provided by stainless steel anti-vibration bars to prevent excessive flow-induced vibration.

Feedwater enters the steam generator through the feedwater nozzle where it distributed via a feedwater distribution ring. The feedwater ring is constructed with discharge nozzles which are configured in the form of a "J". These nozzles are welded to the top of the ring and direct the feedwater flow away from the shell. This construction greatly reduces the rate at which the ring drains, helping to provide assurance that the feedwater ring remains full of water as long as there is feedwater flow when the level in the steam generator drops below the feedwater ring (refer to Figures 5.4-6, 16, and 17).

The downcomer in the steam generator is an annular passage formed by the inner surface of the steam generator shell and the cylindrical shell that encloses the vertical U-tubes. Upon exiting from the bottom of the downcomer, the secondary flow is directed upward over the vertical U-tubes. Heat transferred from the primary side converts a portion of the secondary flow into steam.

Upon leaving the vertical U-tube heat transfer surface, the steam-water mixture enters the cyclone-type separators. These impart a centrifugal motion in the mixture and separate the water particles from the steam. The water exists from the perforated separator housing and combines with the feedwater to repeat the cycle. Final drying of the steam is accomplished by passage of the steam through the double pocket, chevron-type dryers.

The steam generators are mounted on bearing plates which allow controlled lateral motion due to thermal expansion of the reactor coolant piping. Key stops embedded in the concrete base limit this motion in case of a reactor coolant pipe rupture. The top of each unit is restrained from sudden lateral movement by keys and hydraulic snubbers mounted rigidly in the concrete structure.

The steam generators are located at a higher elevation than the reactor vessel. The elevation difference created natural circulation capability sufficient to remove core decay heat following coast down of all reactor coolant pumps.

Overpressure protection for the shell side of the steam generators and the main steam line up to the inlet of the turbine stop valve is provided by 16 flanged spring loaded ASME Code safety valves which discharge to atmosphere. Overpressure protection is discussed in Subsection 5.2.2.

5.4.2.1.3 Steam Generator Tubes

The steam generator are tubed with 0.750 inch OD by .0429 wall tubes. The tubes are fabricated from Inconel 690 to insure compatibility with both the primary and secondary waters. The design incorporates a general corrosion allowance that provided for reliable operation over the plant design lifetime.

Localized corrosion has led to steam generator tube leakage in some operating plants. Examination of tube defects that have resulted in leakage has shown that two mechanisms are primarily responsible. These localized corrosion mechanisms are referred to as (1) stress assisted caustic cracking, and (2) wastage or beavering. Both of these types of corrosion have been related to steam generators that have operated on phosphate chemistry. The caustic stress corrosion type of failure is precluded by controlling feedwater chemistry to the specification limits shown in Subsection 10.3.5. Removal of solids from the secondary side of the steam generator is discussed in Subsection 10.4.8. Localized wastage or beavering has been eliminated by removing phosphates from the chemistry control system.

Volatile chemistry (discussed in Subsection 10.3.5) has been successfully used in all CE steam generators that have gone into operation since 1972.

a) Tube Degradation Mechanisms

   The design steady state and transient conditions specified in the design of the steam generator tubes are discussed in Subsection 3.9.1.1.

Alloy 690 tubes are less susceptible to various forms of the degradation.

NRC Information Notice 90-49, "Stress Corrosion Cracking of PWR Steam Generator Tubes," identified conditions of similar steam generators, where circumferential cracks were observed near the tube expansion transition at or near the top of the tubesheet.

Should a circumferential crack be detected the tube may have a stabilizer and tube plug installed. If the plugged tube severs, the stabilizer is designed to reduce the possibility of tube-to-tube contact. The stabilizers the plugs and their installation are designed to function under all operating, transient or test conditions of the steam generator. This installation takes into consideration maintaining integrity under vibrating loads and material compatibility with tube material subject to both reactor coolant and feedwater system environments.

A number of operating plants have experienced a corrosion phenomenon known as "denting".

Denting is caused by the uncontrolled corrosion of carbon steel support structure surfaces surrounding a tube. As the uncontrolled corrosion of carbon steel takes place, the original base metal (iron) is converted to nonprotective magnetite (Fe_3O_4) resulting in a doubling of volume (i.e., twice the volume of the original base metal is occupied by the metal oxide). Because the magnetite is nonprotective, the base metal continues to corrode, producing large localized concentrations of metal oxide. The expanded metal oxide exerts pressure on the steam generator tube and the support. Then pressure in the tube/tube support annulus becomes sufficient to produce yielding in the tube wall, denting results.

Experience from operating steam generators and laboratory testing has demonstrated that two conditions are required to initiate denting:

1) The original clearance between the tube and the support must have become blocked with a porous deposit in which bulk water can enter and be concentrated.

2) The bulk water being concentrated must have impurities that produce chloric acid solutions, which in corroding the carbon steel of the support result in the formation of a nonprotective form of magnetite.

The potential for tube denting has been reduced in the St. Lucie Unit 2 steam generators by the installation of tube support plates and antivibration bars system that are stainless steel with a high chromium content that forms a tight adherent oxide layer. This combination eliminates the potential for denting.

b) Tube Plugging

If tube damage or degradation has been detected, or should preventative measures warrant, a steam generator tube plug may be inserted to block tube flow and provide a reactor coolant system pressure boundary function. Mechanical or welded tube (or tubesheet) plugs are used for this purpose.

A tube stabilizer may be used in conjunction with plugging the tube ends to stabilize a tube where tube severance or wear due to fluid induced vibration is a concern. The stabilizer is designed to reduce the possibility of tube-to-tube contact and the possibility of a second tube sever in the subject tube.

Tube plugs and stabilizers are designed to function under all operating, transient or test conditions of the steam generator. Their design and installation takes into consideration maintaining integrity under vibrating loads and material compatibility with the tube and tubesheet clad materials subject to both reactor coolant and feedwater system environments.

c) Potential Effects of Tube Rupture

The steam generator tube rupture incident is a penetration of the barrier between the RCS and the Main Steam System. The integrity of this barrier is significant from the standpoint of radiological safety in that a leaking steam generator tube allows the transfer of reactor coolant into the Main Steam System. Radioactivity contained in the reactor coolant would mix with water in the shell side of the affected steam generator. This radioactivity would be transported by steam to the turbine and then to the condenser or directly to the condenser via the Steam Dump and Bypass System. Noncondensible radioactive gases in the condenser are removed by the Main Condenser Evacuation System and discharged to the plant vent. Analysis of a steam generator tube rupture incident, assuming complete severance of a tube, is presented in Section 15.6.

Experience with nuclear steam generators indicates that the probability of complete severance of a tube is remote. The material used to fabricate the vertical U-tube is a Ni-Cr-Fe alloy. A double-ended rupture has never occurred in a steam generator of this design. The more probable modes of failure, which result in smaller penetrations, are those involving the occurrence of pinholes or small cracks in the tubes, and of cracks in the seal welds between the tubes and tube sheet. Detection and control of steam generator tube leakage is described in Subsection 5.2.5.

d) Composition of Secondary Fluid and Radiological Considerations

Radioactivity concentration in the secondary side of the steam generator is dependent upon the activity level of the Reactor Coolant System, the primary to secondary leak rate, and the operation of the Steam Generator Blowdown System. An evaluation of shell side radioactivity concentration is given in Section 11.1.

The recirculation water within the steam generators contains volatile additives necessary for proper chemistry control. These and other chemistry considerations of the Main Steam System are discussed in Subsection 10.3.5.

Materials used in fabrication of the steam generator are not affected by the radiation levels and doses resulting from operation. Although radiation levels are significant for any internal maintenance operations, procedures and equipment have been developed to minimize individual personnel exposure during these operations by allowing rapid completion of individual maintenance operations.

5.4.2.2 Steam Generator In-service Inspection

a) Preservice and periodic inservice inspections of the steam generators will be performed. These programs are developed to comply with the ASME Code, Section XI requirements as appropriate, to permit examinations of the steam generator Code Class 1 and 2 component parts, including the steam generator tubes (refer to Subsection 5.2.4 and Section 6.6).

b) The parameters of the preservice and inservice inspection programs comply with the guidelines recommended in Regulatory Guide 1.83, "In-service Inspection of Pressurized Water Reactor Steam Generator Tubes," July 1975 (R1)

c) The preservice and inspection program examination method, equipment and reporting requirements comply to Appendix IV of the ASME Code, Section XI. The program parameters governing the criteria used for tube inspection, tube sample sizes, inspection intervals, and acceptance criteria (including plugging limits) are included in Technical Specifications.

5.4.3 REACTOR COOLANT PIPING

5.4.3.1 Design Basis

The reactor coolant piping is designed and analyzed for normal operation and all transients discussed in Subsection 3.9.1. Loading combinations and stress criteria associated with faulted conditions are presented in Subsection 3.9.1. In addition, certain nozzles are subjected to local transients that are included in the design and analysis of the areas affected. Thermal sleeves are installed in the surge nozzles, safety injection nozzles, and charging nozzles to accommodate these additional transients. Principal parameters are listed in Table 5.4-3. The ASME Code and Addenda the piping is designed to is specified in Subsection 5.2.1. The safety injection nozzles have been re-evaluated for the stated transients, and thermal sleeves are not required.

In addition to being specified as seismic Category I, the following additional vibratory requirement is specified in the engineering specification. The various piping assemblies are designed so that no damage to the equipment is caused by the frequency ranges 14 to 15 Hz and 70 to 75 Hz. The frequency ranges account for mechanical vibratory excitation of the reactor coolant pump and impeller vane passing pressure variations.

5.4.3.2 Description

Each of the two heat transfer loops contains five sections of pipe; one 42 inch internal diameter pipe between the reactor vessel outlet nozzle and steam generator inlet nozzle, two 30 inch internal diameter pipes from the steam generator's two outlet nozzles to the two reactor coolant pump suction nozzles, and two 30 inch internal diameter pipes from the reactor coolant pump discharge nozzles to the reactor vessel inlet nozzles. These pipes are referred to as the hot leg, the suction legs, and the cold legs, respectively. The other major section of reactor coolant piping is the surge line, a 12 inch schedule 160 pipe between the pressurizer and the hot leg in Loop 2B, and the spray line, a 4 inch Schedule 160 pipe at the pressurizer reduced to two 3 inch schedule 160 pipes between the 4 inch pipe and each cold leg in Loops 2B1 and 2B2. Arrangement of this piping is further described in Subsection 5.1.1.

To minimize the possibility of stress corrosion cracking, the reactor coolant piping is fabricated from SA-516 GR 70 base material mill clad with SA-240, Type 304L stainless steel. The surge line, spray lines, and other small lines are totally made of stainless steel. Nozzles are shop fabricated with safe ends to preclude dissimilar field welds.

Where stainless steel or Ni-Cr-Fe nozzle or safe end material is used, the safe ends are welded to the assembly after final stress relief to prevent furnace sensitization. Other precautions used in the shop and during field assembly of the piping are described in Subsection 5.2.3. In addition, to ascertain the integrity of the piping during plant life, necessary inservice inspections required by Section XI of the ASME Code are performed where required on the reactor coolant piping. To facilitate such inspections, longitudinal weld seems have been oriented at the 90 degrees and 270 degrees locations where feasible.

The 42 inch and 30 inch pipe diameters are selected to obtain reactor coolant velocities that provide a reasonable balance between erosion-corrosion, pressure-drop, and system volume. The surge line is sized to limit the frictional pressure loss through it during the maximum in-surge so that the pressure differential between the pressure and the heat transfer loops is no more than five percent of the Reactor Coolant System design pressure. The spray line sizing is discussed in Subsection 5.4.10.

To reduce the amount of field welding during plant fabrication, the 42 inch and 30 inch pipes are supplied in major pieces, complete with shop installed instrumentation nozzles and connecting nozzles to the auxiliary systems. Where required, the nozzles are supplied with safe ends to facilitate field welding of the connecting piping.

5.4.3.3 Evaluation

It is demonstrated by analysis that the reactor coolant piping is adequate for all normal operating and transient conditions of Subsection 3.9.1 during the life of the plant. In addition, the fully assembled RCS is subjected to the required hydrostatic tests and post hydrostatic nondestructive testing. Fracture toughness of the reactor coolant piping is discussed in Subsection 5.2.3

During the design, driving frequencies are accommodated by proper location of piping spring characteristics. The dynamic effects of system operation are also considered and piping restraints sized accordingly.

Further assurance of the continued structural integrity of the system during plant life is obtained from the in-service inspections performed in accordance with ASME Code, Section XI, and described in detail in Subsection 5.2.4

A discussion of the radiological considerations for the reactor coolant piping is provided in Section 12.3.

5.4.3.4 Tests and Inspections

Prior to and during fabrication of the reactor coolant piping, nondestructive testing, based on the requirements of the ASME Code (see Table 5.2-1) is applied. Subsections 5.2.3.3.3 and 5.2.3.4.3 discuss the nondestructive examination program used during fabrication and construction. In-service inspections of the Reactor Coolant System piping are discussed in Subsection 5.2.4. Tests for Reactor Coolant System integrity following normal opening, modification, or repair are specified in the Technical Specifications.

5.4.4 MAIN STEAM LINE FLOW RESTRICTIONS

The main steam line, venturi type, flow elements located in each main steam line and within the containment are components of the feedwater control system and also act as flow restrictors to impede the discharge of steam into the containment in the event of a steam line break accident downstream of the flow element. Further information is found in Section 10.3 and Table 10.3-1.

5.4.5 MAIN STEAM ISOLATION SYSTEM

The Main Steam Isolation System is discussed in Section 10.3.

5.4.6 REACTOR CORE ISOLATION COOLING SYSTEM

This subsection is not applicable to St. Lucie Unit 2.

5.4.7 RESIDUAL HEAT REMOVAL SYSTEM

5.4.7.1 Design Bases

5.4.7.1.1 Summary Description

The Shutdown Cooling System (SDCS) is used in conjunction with the Main Steam and Main or Auxiliary Feedwater Systems to reduce the temperature of the Reactor Coolant System (RCS) in post shutdown periods from normal operating temperature to the refueling temperature. The initial phase of the cooldown is accomplished by heat rejection from the steam generators to the condenser or atmosphere. For a normal cooldown the reactor coolant hot leg temperature is reduced to 325°F and the pressurizer pressure is reduced to 276 psia*. Then, the SDCS can be put into operation to reduce the reactor coolant temperature to the refueling temperature of 140°F, or less, and to maintain this temperature during refueling. During refueling, a portion of the shutdown cooling flow is directed to the CVCS and is processed by the CVCS ion exchangers and filters for purification of the RCS. This purified flow is then returned to the RCS.

The SDCS is used in addition to the atmospheric dump valves and the Auxiliary Feedwater System to cooldown the Reactor Coolant System following a small break LOCA (see Section 6.3). Operating plants with similar designs (with some generic differences due to necessary requirements) are St. Lucie Unit 1 and Millstone 2.

Assuming a loss of offsite power (LOOP), the plant cooldown process to reach cold shutdown conditions is comprised of two phases of heat removal. The initial phase is accomplished by controlling heat rejection to the atmosphere through the secondary atmospheric dump valves. The Reactor Coolant System (RCS) is depressurized by the main or auxiliary spray system or manual control of letdown and/or charging pumps throughout the RCS cooldown while maintaining RCS pressure temperature requirements in accordance with the St. Lucie Unit 2 Technical Specifications and subcooled margin limitations. Safety Injection tanks may be isolated when depressurizing to reach shutdown cooling entry pressure condition. With offsite power available, forced RCS flow is maintained during a plant cooldown. However, for a LOOP, natural circulation flow is used during the plant cooldown until the reactor coolant pumps are restarted after offsite power is restored.

Once the RCS has been adequately cooled down and depressurized, the Shutdown Cooling System (SDCS) is aligned and the cooldown proceeds by rejecting heat to the SDCS heat exchangers. Assuming loss of offsite power, the most limiting postulated single failure is a failure of one emergency power train. A loss of one DC emergency train would effectively prevent AC power off one diesel generator, even if operating, from being transferred to the onsite electrical system. The single failure disables one train of components associated with the atmospheric dump valves, chemical and volume control systems, auxiliary feedwater system, and shutdown cooling systems. However, the plant can be cooled down to cold shutdown conditions with one emergency power train and one train of system components within 36 hours as shown in Subsection 5.4.7.5.

5.4.7.1.2 Functional Design Bases

The following functional design bases apply to the Shutdown Cooling System:

* The operating limit for SDC entry has been conservatively established at 275 psia.

a) No single active failure prevents at least one complete train of the SDCS from being brought on line, whether this is during normal plant cooldown or following a design basis event.

b) The post LOCA functional requirements defined in Subsection 5.4.7.1.1 are met assuming the failure of a single active component during the short-term immediately after a LOCA, or a single active or limited leakage passive failure of a component during the long-term cooling phase following a LOCA. Additional analysis of passive failures in the SDCS can be found in Appendix 3.6F.

c) No single failure allows the SDCS to be overpressurized by the Reactor Coolant System. Shutdown Cooling System components are provided with overpressure protection by use of interlocks, valve arrangement, and relief valves (see Subsections 5.4.7.2.2 and 5.4.7.2.3).

d) The SDCS lowers the Reactor Coolant System temperature as follows:

   1) two train emergency cooldown (based on Reactor Coolant System cooldown to 350 F, hot leg temperature, in 3.5 hours after shutdown.)

      350F - 200F - approximately 5.5 hours after shutdown

2) One train cooldown (Emergency Condition)

350° F - 200° F: approximately 10.5 hours after activation of the SDCS

Emergency cooldown curves are shown on Figures 5.4-7 and 5.4-8.

e) The components of the Shutdown Cooling System are designed in accordance with Subsection 5.4.7.2.4.

f) Materials are selected to preclude system performance degradation due to the effects of short and long term corrosion.

g) In the event of a single active failure and to assure availability of the system when required, redundant components are provided. Instrumentation to assure proper system operation is described in Subsection 5.4.7.2.2, item (e).

h) The system design provides for inspection and testing of components to ensure availability and proper operation.

i) Pressure relief valves in the SDCS suction lines protect the system from overpressurization during system operation when the suction valves are open and the system is not isolated from the Reactor Coolant System. The valves are sized considering transients due to inadvertent operation of charging pumps, HPSI pumps, and pressurizer heaters. Additional pressure relief valves are provided to protect isolated sections of piping from thermal overpressure (see Subsections 5.4.7.2.3 and 6.3.2.2.6).

j) The SDCS is designed against the effects of internally and externally generated missiles as described in Section 3.5, and designed against the dynamic effects of pipe rupture as outlined in Section 3.6.

k) The motor operators for valves V3480, V3481, V3545, V3651, and V3652 are located above the maximum water level expected during the recirculation phase of Safety Injection System operations.

l) The design location, arrangement, and installation of the system and its components are such that it withstands the effects of earthquakes and other natural phenomena, without loss of capability of performing its safety function as specified in General Design Criterion 2. Operability requirements and analysis of this system and components relative to Regulatory Guides 1.29, "Seismic Design Classification," February 1976 (R2) and 1.48 "Design Limits and Loading Combinations for Seismic Category I Fluid System Components," May 1973 (R0) are described in Section 3.2 and Section 3.9.

m) No components of the SDCS for St. Lucie Unit 2 are shared by St. Lucie Unit 1, thereby satisfying GDC 5.

n) The SDC operation is a closely monitored mode of operation. In the event of a closure of a SDC suction line isolation valve, the operator sees indications on the instruments in the control room and shuts the LPSI pump off avoiding overheating and damage. Adequate cooling of the core is provided by the redundant SDC train. The cooling curve for a one train cooldown is shown on Figure 5.4-8.

5.4.7.2 System Design

5.4.7.2.1 System Schematic

The SDCS piping and instrumentation diagram, shutdown cooling mode diagram, and flow point data are shown on Figures 6.3-1a, b, c and 6.3-2d, and Table 6.3-4d, respectively. For a two train cooldown, the pressurizer pressure and hot leg temperature of the reactor coolant system vary from 276 psia* and 325°F at initiation of shutdown cooling to atmospheric pressure and less than 140°F at refueling conditions.

The SDCS contains two shutdown cooling heat exchangers and employs one or both low pressure safety injection pumps throughout shutdown cooling. During initial shutdown cooling, a portion of the reactor coolant flows out the shutdown cooling nozzles located on the reactor vessel outlet (hot leg) pipes and is circulated through the shutdown cooling heat exchangers by the LPSI pumps. The return to the reactor coolant system is through the safety injection nozzles in reactor coolant pump discharge (cold) legs.

The SDCS suction line isolation valves are interlocked to prevent overpressurization of the SDCS by the reactor coolant system. These interlocks are described in Subsection 5.4.7.2.3 and Section 7.6.

Shutdown cooling and LPSI flow are measured by orifice meters FT-3301 and 3306 installed in each LPSI header or by flow instruments FT-3312, 3322, 3332 and 3342 installed in the individual injection headers. The information provided by these flow elements is used to manually maintain total flow control during shutdown cooling operation.

The cooldown rate is controlled by adjusting the flow rate through the heat exchanger(s) with the throttle valves (HCV-3512, HCV-3657) on the discharge of the heat exchangers in conjunction with valves FCV-3301 and FCV-3306. The injection header motor-operated isolation valves, HCV-3615, 3625, 3635 and 3645 are manually controlled to maintain the required total shutdown cooling flow rate to the core.

During initial cooldown the temperature differential for heat transfer is large, thus only a portion of the total shutdown flow is diverted through the heat exchangers. As cooldown proceeds, the temperature differentials become less and the flow rate through the shutdown cooling heat exchangers is increased to the maximum achievable.

* The operating limit for SDC entry has been conservatively established at 275 psia.

At this time, full shutdown cooling flow (with the exception of any bypass valve leakage and purification flow) is through one or both of the shutdown cooling heat exchangers. A portion of the shutdown cooling flow from either of the loops through connections on the discharge side of the Low Pressure Safety Injection (LPSI) pumps is diverted to purify Reactor Coolant inventory during periods of shutdown. The flow is directed to the Chemical and Volume Control System (CVCS) just upstream of flow element FE-2202 and is processed by the CVCS ion exchanger and filters. The flow is then returned to the suction of the LPSI pumps via the shutdown cooling lines (Figure 6.3-1a,b and 9.3-5a).

5.4.7.2.2 Component Description

a) Low-Pressure Safety Injection Pumps

The Low Pressure Safety Injection (LPSI) pumps are used jointly as part of the SDCS and SIS. During all periods of plant operation, when SIS operability is required, the LPSI pumps are manually aligned for emergency core cooling operation.

During shutdown cooling. LPSI pump 2A takes flow from the Reactor Coolant System hot leg 2A and discharges through the shutdown cooling heat exchanger 2A. Train A shutdown cooling flow is returned to the Reactor Coolant System through the LPSI header A to the Reactor Coolant System cold legs 2A1 and/or 2A2. Likewise, LPSI pump 2B takes flow from the Reactor Coolant System hot leg 2B and discharges through the shutdown cooling heat exchanger 2B. Train B shutdown cooling flow is returned to the Reactor Coolant System cold legs 2B1 and/or 2B2. Thus, two completely independent shutdown cooling trains are provided.

The LPSI pump design flowrate of 3000 gpm was based on maintaining a core ΔT (approximately equal to the full power ΔT) at shutdown cooling 3 1/2 hours after shutdown for the pre-stretch core decay heat. The LPSI pump characteristics are further discussed in Section 6.3.2.2.2. Note that the SDC flow required to maintain full power ΔT at 3 ½ hours after shutdown with post-stretch core decay heat is approximately 4000 gpm which is beyond the capacity of a single SDC train. However, this ΔT would only be approached during a natural circulation cooldown without RCPs available. For a natural circulation cooldown, a soak period of at least 20 hours is maintained to preclude voiding in the reactor head prior to initiating SDC. At this time, the SDC flow required to maintain a full power core ΔT is less than 2300 gpm.

b) Shutdown Cooling Heat Exchangers (SDCHX)

The shutdown cooling heat exchanger removes core decay heat, sensible heat, and LPSI and reactor coolant pump heat during plant cooldown and cold shutdown. The shutdown cooling heat exchangers are sized to lower the reactor coolant to the refueling water temperature (140°F) 27 1/2 hours after shutdown, assuming two shutdown cooling heat exchangers and two LPSI pumps are operating.

A conservative fouling factor is assumed, resulting in an additional area margin for the shutdown cooling heat exchangers. The shutdown cooling heat exchanger characteristics for the shutdown cooling mode are given in Table 5.4-4.

The design pressure of the shutdown cooling heat exchanger is based on the maximum operating pressure of the LPSI pump suction piping plus the shutoff head of the LPSI pump. The design temperature of the shutdown cooling heat exchanger is based on the SDC initiation temperature.

c) Piping

All SDCS piping is austenitic stainless steel. All piping joints and connections are welded except for a minimum number of flanged connections that are used to facilitate equipment maintenance or accommodate component design.

d) Valves

1) Motor Operated Valves

Design pressures and temperatures for the SDCS motor operated valves are provided in Table 6.3-5.

Throttle valves HCV-3512, HCV-3657, FCV-3301 and FCV-3306 are provided for remote control of the shutdown cooling heat exchanger tube side and bypass flow.

The two SDCS suction lines are equipped with three remotely controlled isolation valves in each line. A remotely controlled valve (V3545) serves as a crossover valve between the two SDCS suction lines. Five of the suction line isolation valves are located inside containment, and two valves are located outside containment. The shutdown cooling suction valves power and control diagram is shown on Figure 7.6-1.

All motor operated valves in the ECCS are equipped with Limitorque motor operators. These operators allow disengagement of the motor for handwheel operation, but are automatically re-engaged when the motor is activated. As a result, it is not possible for the motor operated valves to be disabled from automatic operation due to a prior manual handwheel operation.

The following SDCS motor operated valves are subject to the requirements of NRC Generic Letter 89-10: FCV-3301, FCV-3306, V3456, V3457, V3480, V3481, HCV-3512, V3517, V3536, V3539, V3651, V3652, HCV-3657, V3658, V3664, V3665.

As a result of evaluations performed to address NRC Generic Letter 95-07 "Pressure Locking and Thermal Binding of Safety Related Power-Operated Gate Valves", valve V3545 is maintained "Locked Open" during normal operation to eliminate susceptibility to pressure locking, V3651, V3652, V3480 and V3481 have a 3/16" hole drilled on the RCS side of the disk to prevent pressure locking.

The LPSI pump suction isolation valves (V3432 and V3444) are motor operated, to facilitate SDCS alignment from the control room.

2) Manual

Manual isolation valves are provided to isolate equipment for maintenance.

Manual valves exist in the flow paths of the SDCS trains which, if improperly aligned, could prevent flow from that train. These valves are V3206 and V3207, which are just downstream of the LPSI pumps. These are "locked open" and administrative procedures are used to assure their proper position. There is no single manual valve which, if misaligned, would disable both SDCS trains.

3) Relief Valves

Protection against overpressure of components within the shutdown cooling system is provided by relief valves. A description of relief valves, their set pressures and capacities is provided in Subsection 6.3.2.2.6.

4) Check Valves

Check Valves prevent reverse flow through the system during shutdown cooling.

5) Power Supplies

In addition to the preferred sources of offsite power, independent onsite standby electrical power supplies are provided for the SIS equipment by the diesel generators. A detailed description of the onsite standby power sources is given in Section 8.3. Diesel generator load sequencing is provided in Section 8.3.

e) Instrumentation

Operation of the SDCS is controlled and monitored through the use of installed instrumentation. The instrumentation provides the capability to determine heat removal, cooldown rate, shutdown cooling flow, and the capability to detect degradation in the flow or heat removal capacity. The instrumentation provided for the SDCS consists of:

1) Temperature measurements - Shutdown cooling heat exchanger inlet and the temperature of the shutdown cooling flow to the low pressure header. All temperatures are indicated in the control room. The shutdown cooling heat exchangers inlet temperature, and the low pressure header temperatures are recorded to facilitate control of the Reactor Coolant System cooldown rate.

2) Pressure Measurements - LPSI header pressure and shutdown cooling heat exchanger inlet pressure. These pressures are indicated in the control room, and, when used with the low-pressure pump performance curves, provide an alternate means of measuring system flow rate.

3) Flow Measurements - Total shutdown cooling flow rate is measured by flow indicators FI-3301 and 3306 or alternatively by FI-3312, 3322, 3332, and 3342.

The instrumentation is discussed further in Sections 7.4 and 7.6.

5.4.7.2.3 Overpressure Control

Protection against overpressure of the SDCS is provided by relief valves and interlocks. A description of relief valves is provided below and in Subsection 6.3.2.2.6.1.

There are six relief valves in the SDCS suction lines. These valves are sized to protect the components and piping from overpressure due to thermal expansion of the fluid. Valves V3482 and V3469 have a set pressure of 2485 psig and a capacity of five gpm. Relief fluid from these valves is collected in the quench tank. These valves are designed to 1974 ASME, Section NB, Quality Group A (see Figure 6.3-1b).

Valves V3483 and V3468 have a set pressure of 335 psig and a capacity of 155 gpm. Relief fluid from these valves is collected in a holdup tank in the Waste Management System. These valves are designed to 1974 ASME, Section NC, Quality Group B (see Figure 6.3-1b).

In addition to protecting the components and piping from overpressure due to the thermal expansion of the fluid, valves V3666 and V3667 are sized to protect the components and piping from overpressure due to inadvertent starting of the charging pumps, HPSI pumps, and pressurizer heaters. These valves have a set pressure of 335 psig and a capacity of 2300 gpm. Relief fluid collected from these valves is collected in the containment sump. These valves are designed to 1974 ASME, Section NC (to 1975 summer addenda) Quality Group B (see Figure 6.3-1b). When calculating the capacity of valves V3666 and V3667, the capacity of each valve was taken to be greater than the combined flow rate of two HPSI pumps, three charging pumps and the fluid forced out of the pressurizer when the backup heaters are actuated. This is a very conservative sizing, as the inadvertent actuation of the HPSI pumps, the charging pumps, and simultaneous energization of the pressurizer heaters is an unlikely coincidence. The largest flow rate which would be expected is from two safety injection pumps delivering approximately 1100 gpm at the Reactor Coolant System at 335 psig.

For the Shutdown Cooling mode, the LPSI pump suction is aligned to the hot leg of the RCS. The flow from the discharge side of the pump goes to the cold leg of the RCS. Due to this arrangement, the LPSI pump would not be dead headed by an RCS pressure surge. Relief valves in the shutdown cooling suction lines prevent isolation of the line from any anticipated overpressure events.

Valves V3666 and V3667 are located inside containment in close proximity of the containment sump. The discharge fluid from these relief valves is routed directly to the containment sump in order to prevent the accidental spread of Reactor Coolant System inventory outside the containment. The discharged liquid, which is collected and contained in the containment sump, will then be transported to the Liquid Waste Management System for processing. The containment sump is a large collecting reservoir provided to supply water to the Containment Spray and Safety Injection System for long term recirculation. The design of the containment sump is described in FSAR Subsection 6.2.2.2.3.

The use of the containment sump as an atmospheric collection tank minimizes the possibility of introducing any backpressure on the relief valve discharge piping. The relatively short piping runs in the discharge piping reduces the potential for any downstream pressure buildup or pressure fluctuations. This design assures maximum relief valve capacity at design conditions.

Since the SDCS is not designed to accommodate full Reactor Coolant System pressure, isolation of the system suction lines is assured by interlocks on the four suction line isolation valves inside containment. An independent interlock, utilizing pressurizer pressure is provided for each of the valves. For each SDCS train, power is supplied to the interlocks on these valves by two independent power supplies (one power supply for each interlock). This ensures isolation of the SDCS from the Reactor Coolant System should a spurious signal inadvertently open one of these valves. Each interlock is designed to prevent opening of its associated valve whenever pressurizer pressure is greater than 276 psia. An audible alarm sounds in the control room whenever any of the valves are off the full closed position. The interlock also provides automatic closure of the valves prior to an actual or simulated pressurizer pressure signal exceeding 515 psia. When power to an interlock is removed, the interlock fails as is. This precludes the loss of LPSI pump suction flow and, thereby, damage to the pump is avoided. As there are two isolation valves with interlocks in each LPSI pump suction train it is still possible to close off the LPSI pump line, as required, by both automatic and manual means. It should be noted that the basic purpose of the interlock is to provide double barrier protection between the Reactor Coolant System and the SDCS before the Reactor Coolant System returns to normal operating temperature and pressure. Each of the seven suction line isolation valves is equipped with open/close position indication in the control room.

Valve control circuitry is covered in Section 7.6. Interlocks are discussed further in Section 7.6. Interlocks are provided on the safety injection tank isolation valves for overpressure protection of the SDCS. The SIT interlocks are discussed in Section 7.6 and Subsection 6.3.2.2.1.

5.4.7.2.4 Applicable Codes and Classifications

Table 5.4-4 and Section 6.3 provides the applicable codes for system components. Refer to Section 3.2 for safety and seismic classifications.

5.4.7.2.5 System Reliability

The SDCS is designed to perform its design function assuming a single failure, as described in Subsection 5.4.7.1.2.

To assure availability of the SDCS when required, redundant components and power supplies are utilized. The Reactor Coolant System can be brought to refueling temperature utilizing one of two LPSI pumps and one of two shutdown cooling heat exchangers. However, with the design heat load, the cooldown would be considerably longer than the specified 27 1/2 hour time period.

Inadvertent overpressurization of the SDCS is precluded by the use of pressure relief valves and interlocks installed on the shutdown cooling suction line isolation valves and safety injection tanks isolation valves (see Subsections 5.4.7.2.3, Sections 6.3, and 7.6).

The instrumentation, control, and electric equipment pertaining to the SDCS are designed to applicable portions of IEEE Standards. See Section 7.5 for further details.

In addition to normal offsite power sources, physically and electrically separated and redundant onsite emergency power supply systems are provided to power safety related components. See Chapter 8 for further details.

Since the SDCS is essential for a safe shutdown of the reactor, it is a seismic Category I system and designed to remain functional in the event of a safe shutdown earthquake (see Section 3.10).

For a long-term performance of the SDCS without degradation due to corrosion, only materials compatible with the pumped fluid are used.

Environmental conditions are specified for system components to ensure acceptable performance in normal and applicable accident environments (see Section 3.11).

5.4.7.2.6 Manual Actions

Plant shutdown is the series of operations which bring the reactor from a hot standby condition to cold shutdown. The Shutdown Cooling System is used in conjunction with the Main Steam, and Main or Auxiliary Feedwater Systems to reduce the temperature of the Reactor Coolant System to the refueling temperature. The initial phase of the cooldown is accomplished by heat rejection from the Steam Generators to the condenser. In the case of no condenser vacuum, the atmospheric dump valves may be used.

For a normal cooldown, the reactor coolant hot leg temperature is reduced to 325F and the pressurizer pressure is reduced to 276 psia*. The Shutdown

* The operating limit for SDC entry has been conservatively established at 275 psia.

Cooling System is then put into operation to reduce the reactor coolant temperature to the refueling temperature.

The SDCS is a manually aligned and actuated system. Alignment to the shutdown cooling mode is accomplished via remote (from the control room or from the local control station outside the reactor containment) operated valves with the exception of the minimum flow isolation valves which are manually aligned in the plant. These valves also have a handwheel for local operation. Once system alignment to the shutdown cooling mode is accomplished, the SDCS system, and hence plant cooldown, can be controlled remotely from the control room during normal plant conditions.

Required manual actions for normal two train SDCS alignment and operation are listed below (Functionally, these actions allow for SDCS alignment and are not intended to provide appropriate sequencing of steps). All actions are performed from the control room, except as noted:

a) The containment spray isolation valves for the shutdown cooling heat exchangers (MV-07-03, MV-07-04) are closed.

b) The safety injection tank isolation valves (V3614*, V3624*, V3634, V3644) may be closed or the tanks depressurized. Note: In order to close these valves, power must be restored to the valves at the motor control center.

c) The shutdown cooling heat exchanger (SDC HX) flow control valves (HCV-3657*, HCV-3512) are operated as required to control cooldown and the SDC HX inlet valves (V3517*, V3658) are opened.

d) The SDC HX bypass valves (FCV-3306*, FCV-3301) and the SDC warm-up valves (V3536*, V3539) are operated as required to initiate and control SDC operation.

e) The SDC HX outlet valves (V3456*, V3457) are opened.

f) The LPSI pumps are operated as required.

g) The LPSI Recirculation valves (V3767*, V3205) are locked closed locally at the valves.

h) The LPSI pump suction valves (V3444*, V3432) from the RWT and the containment sump are locked closed.

i) The hot leg suction valves (V3480*, V3481*, V3664*, V3651, V3652, V3665) are opened (the normal position for the hot leg suction cross-tie V3545 is locked open). Note: In order to operate valves V3480, V3481, V3545, V3651 and V3652, power must be restored to the valves at the motor control center outside the control room.

j) CCW is established to the SDC HXs by opening valves HCV-14-3A and HCV-14-3B. The LPSI header isolation valves (HCV-3615*, HCV-3625*, HCV-3635, HCV-3645) are opened as required.

k) The shutdown cooling throttle valves (HCV-3657*, HCV-3512) are adjusted as necessary to maintain the RCS cooldown rate at 75°F/hr. or less. The total SDCS flow is maintained greater than or equal to 3000 gpm through one or both shutdown cooling trains when required by Technical Specifications. At other times, SDC flow is maintained as required to meet the heat removal requirements. The SDCS bypass flow control valves (FCV-3306, FCV-3301) are manually controlled by the operator.

A graph of Reactor Coolant System temperature vs. time after shutdown for a typical cooldown is presented on Figure 5.4-7.

Shutdown cooling is continued throughout the entire period of plant shutdown to maintain a refueling water temperature of 140°F or less. When RCS pressure is reduced to atmospheric and shutdown cooling is in operation, shutdown purification flow may be initiated to purify the circulating reactor coolant in the chemical and volume control system by using the connection between the SDCS and the chemical and volume control system.

The shutdown cooling function is used during the early stages of plant start up to control reactor coolant temperature. Heat generated by the reactor coolant pumps and by core decay is removed as required by the shutdown cooling system. Prior to continuing plant heatup above SDC design conditions, the interconnections to the reactor coolant system are isolated and the safety injection system is aligned for emergency operation. The six isolation valves (V3480*, V3481*, V3664*, V3651, V3652 and V3665) in the shutdown cooling suction lines are closed, the cross connect, V3545 is opened. After reactor coolant pump operation is allowed (reactor coolant system pressures $\geq$ 265 psia) and prior to reaching 325°F (reactor coolant system hot leg temperature) or 276 psia**, the LPSI pumps are stopped and the shutdown cooling heat exchangers are aligned for their containment spray function.

Initiation of shutdown cooling with the most limiting single failure (loss of one shutdown cooling train) can be accomplished using the procedures under plant cooldown for the operable train (i.e., operating the valves with (*) for train A, or the valves without (*) for train B). The SDC isolation valves are unique in that one of the two valves inside containment on each physical train is powered from separate electrical trains (i.e. V3480 and V3651 are powered by the B bus, and V3481 and V3652 are powered from the A bus).

In the event of a loss of a power (emergency or normal) supply, the SDCS suction line crossover valve (V3545) may be utilized to provide at least one complete shutdown cooling train. The operator selects the system flow path with an active available power supply (emergency or normal), and since the SDCS suction line crossover valve (V3545) is a normally Locked Open valve, the SDC function can continue. At times of reduced RCS inventory, the cross-tie valve can be closed to guard against the simultaneous loss of both trains resulting from an inadvertent loss of RCS level. Closure of the cross-tie valve is procedurally controlled to ensure that it is opened prior to pressurizing the RCS.

Following certain accidents, (feedwater line break, small break LOCA, steamline break, or loss of offsite power), it may become necessary to initiate shutdown cooling with reactor coolant system hot leg conditions which exceed the normal shutdown cooling initiation temperature (325F

* Indicates valves on shutdown cooling train 'A'.

** The operating limit for SDC entry has been conservatively established at 275 psia.

Reactor Coolant System hot leg temperature). However, shutdown cooling is not initiated at conditions which exceed the design temperature of the SDCS components (350F Reactor Coolant System hot leg temperature).

5.4.7.3 Performance Evaluation

The design point of the SDCS is taken at 27 1/2 hours after plant shutdown. At this point, the design heat load is to maintain a refueling temperature of 140F with 100F component cooling water. Two shutdown cooling heat exchangers and two LPSI pumps are assumed to be in operation at the design flow of 3000 gpm per shutdown cooling heat exchanger train. The SDCHX size is determined at this point, since it demands the greatest heat transfer area due to the relatively small ΔT between reactor coolant and component cooling water. The cooldown rate is limited to a maximum of 75° F/hr throughout the cooldown. The emergency cooldown curve is shown on Figure 5.4-7.

For the most limiting single active failure (see Table 5.4-5) in the SDCS, pressurizer pressure and Reactor Coolant System hot leg temperature are reduced to 276 psia and 325° F by other heat rejection means (atmospheric vent valves, steam bypass through the condenser). From these initial conditions, Reactor Coolant System temperature can be brought to 200° F in approximately 20.8 hours following shutdown cooling initiation using one LPSI pump and one shutdown cooling heat exchanger. The cooldown curve for an emergency one train cooldown is shown on Figure 5.4-8.

A failure modes and effects analysis (FMEA) for the SDCS is presented in Table 5.4-5. The analysis demonstrates that the SDCS can withstand any single active failure and still perform its design function. Analysis of passive failures in the SDCS is summarized in Appendix 3.6F.

On December 5, 1980, the Davis-Besse Nuclear Power Station experienced an inadvertent actuation of the emergency core cooling system (ECCS) in the recirculation Mode. At the time, the system was in the Hot Shutdown Mode, as repairs were being made to the electrical system. An electrical short circuit or ground caused the Safety Injection System to be actuated. As the Reactor Coolant System (RCS) was at a higher pressure than the Safety Injection pumps' shut off head (2100 vs. 1600 psig) the water from the Refueling Water Storage Pool did not enter the RCS. The electrical failure also caused a change to the Recirculation Mode. During the mode changeover period (1-1/2 minutes) the piping was aligned such that water from the RWSP drained into their SIS Recirculation Sump (about 15,000 gallons drained). After this switchover time, the High Pressure and Low Pressure Pumps (HPSI and LPSI Pumps) were aligned to a dry sump (save for the 15,000 gallons mentioned above). The major concern here is that the Safety Injection Pumps could become air bound, which could result in significant damage to the pumps, causing them to become inoperable.

If an electrical failure of the type that occurred at Davis-Besse could take place at St. Lucie Unit 2, the following fluid system response would occur. The LPSI and HPSI pumps are aligned with the RWT during normal plant operation. For this event no flow would be delivered to the RCS because the RCS pressure exceeds the shut off head of the LPSI and HPSI pumps. After the SIAS, but before the RAS, the only flow through the pumps would be mini-flow back to the RWT. This is done to prevent damage to the pumps when no flow can be delivered to the RCS.

Upon initiation of the RAS, the LPSI pumps are automatically shut off and the mini-flow valves are closed. This stops all flow through the HPSI pumps. The operator must take manual action to stop the HPSI pumps. Any degradation to the HPSI system as a result of this would have no effect on the decay heat removal abilities of the unit.

At this point Davis-Besse's piping layout allowed flow from the RWSP to the containment sump during the valve transition period. The St. Lucie Unit 2 Design prevents this flow with a pair of check valves (one in each train) just downstream from the containment sump isolation valves. Because the outlet nozzle on the RWT is approximately 12 feet above these check valves, a pressure of about 5 PSI holds them closed.

The April 19, 1980 event which occurred at Davis Besse inadvertently aligned the decay heat removal (DHR) pumps to the recirculation mode (and a dry containment sump) while the RCS was in a quasi-refueling mode. This resulted in air in the suction line of the system. As a result, the DHR system was down for approximately 2 1/2 hours while the lines were vented. During this delay the temperature limit for the refueling mode was exceeded.

Should this unlikely combination of events occur at the St. Lucie Unit 2 plant, no damage would occur to the DHR system. After the SIAS and before the RAS, the LPSI pumps would be aligned to their suction lines, which is the condition they were in prior to the event. After the RAS, the LPSI pumps would not be connected to the dry containment sump due to two conditions: the suction lines are isolated from both the RWT and the sump by valves V3444 and V3432 which do not receive an RAS; also the RAS automatically turns off the LPSI pumps. However, the HPSI pumps will be connected to the dry sump and could become damaged by becoming airbound if the operator does not shut them off soon enough. This damage will not affect the decay heat removal capabilities of the DHR system.

The preceding discussions compared the vulnerability of the St. Lucie Unit 2 fluid system to two similar events that occurred at Davis-Besse. It is concluded that the results for St. Lucie Unit 2 would be much less severe and could be handled by operator action.

5.4.7.4 Preoperational and In-Service Testing

Preoperational tests were conducted to verify proper operation of the SDCS. The preoperational tests included testing of the automatic flow control,(automatic control was subsequently removed in favor of manual control), verification of adequate shutdown cooling flow, and verification of the operability of all associated valves. In addition, a preoperational hot functional performance test was made on the installed shutdown cooling heat exchangers.

For availability of the SDCS, components of the system are periodically tested as part of the Safety Injection System testing, as described in the Technical Specification. As discussed in NRC Generic Letter 2008-01, the presence of unanticipated gas voids within the Shutdown Cooling System can challenge the ability of the system to perform its design functions due to issues such as gas binding, water hammer, injection delay times, etc. Pending development of a formal Gas Accumulation Management Program to augment control of these issues, interim acceptance criteria for maintaining the Shutdown Cooling System operability is contained within Model Prompt Operability Determinations attached to Engineering Evaluation PSL-ENG-SEMS-08-030. Periodic testing confirms that the Shutdown Cooling System is maintained in accordance with Gas Accumulation Management Program criteria. The heat exchanger bypass valves leakage is tested on a frequency determined by historical test data. The system and component tests are sufficient to demonstrate the continued operability of the SDCS.

In addition to flow tests, the SDCS also undergoes a series of preoperational and in-service hydrostatic tests. Preoperational hydrostatic tests were conducted in accordance with Section III of the ASME Code while in-service hydrostatic tests are carried out as required by Section XI of the ASME Code.

ASME Boiler and Pressure Vessel Code Case N-416, "Alternative Rules for Hydrostatic Testing or Replacement of Class 2 Piping," may be used within the limitations stated in the "Inquiry" and "Reply" sections of the Code Case to satisfy the inservice pressure testing requirements of the ASME Code, Section XI.

St. Lucie Unit 2 had RSGs installed in Fall 2007. The RSGs have been evaluated with respect to natural circulation (see AREVA Doc. 77-5069878-01), and have been shown to have natural circulation capabilities equal to or better than the OSGs. Additionally, the RSGs impact on the Condensate Storage Tank, Shutdown Cooling System, and Auxiliary Feedwater was evaluated. It was considered that the OSGs requirements bound the RSGs, and no modifications to these systems is required. (Reference 8)

5.4.7.5 Compliance With Branch Technical Position RSB 5-1

(See Appendix 5.2B for additional analysis related to natural circulation cooldown.)

This section contains information which is historical in nature in that it documents FPL's response to the Branch Technical Position; however, compliance with RSB 5-1 is still required and update of this section should occur, as appropriate.

BRANCH POSITION

A. Functional Requirements

The system(s) which can be used to take the reactor from normal operating conditions to cold shutdown shall satisfy the functional requirements listed below.

1. The design shall be such that the reactor can be taken from normal operating conditions to cold shutdown using only safety-grade systems. These systems shall satisfy General Design Criteria 1 through 5.

RESPONSE:

Cooldown to cold shutdown conditions employ the auxiliary feedwater system, the main steam system, the chemical and volume control system, the component cooling water system, and the shutdown cooling system. The initial plant cooldown is accomplished by heat rejection to the atmosphere by the steam generator atmospheric dump valves. Four safety grade atmospheric dump valves, two per steam generator, are provided at St. Lucie Unit 2. The atmospheric dump valves, valve operators, and power supplies are all built in accordance with seismic Category I, Quality Group B requirements. Two atmospheric dump valves are supplied from vital dc bus SA; the other two atmospheric dump valves are supplied from vital dc bus SB. The valves are also supplied with handwheels to allow them to be operated manually. Should a single failure occur making two atmospheric dump valves inoperable from the control room, the other two valves are sufficient for plant cooldown.

During loss of offsite power the reactor coolant system is depressurized using auxiliary spray. The auxiliary spray is safety grade and has vital power supplied by emergency onsite power (4160 volt ac bus, diesel generator). Redundant auxiliary spray valves are provided.

Boration is accomplished using the chemical and volume control system. This system incorporates redundant charging pumps, boric acid makeup tanks and charging pump suction and delivery paths. This system satisfies the single failure criterion and can function without offsite power.

When the plant reaches the appropriate temperature and pressure, the shutdown cooling system is aligned, and the cooldown proceeds by rejecting heat to the shutdown cooling system heat exchangers.

BRANCH POSITION

A.2 The system(s) shall have suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities to assure that for onsite electrical power system operation (assuming offsite power is not available) the system function can be accomplished, assuming a single failure.

RESPONSE:

Assuming loss of offsite power, the most limiting single failure associated with the thirty-six hour criterion is the failure of a dc bus and associated diesel generator. This failure disables the auxiliary spray valve and one train of components associated with the chemical and volume control system, the auxiliary feedwater system, the component cooling water system, and the shutdown cooling system. The sequence of operator actions described below is required to cool down to the shutdown cooling system entry conditions.

1. Secondary Steam Removal

The steam generated for decay heat removal and for system cooldown after a loss of offsite power is discharged through the atmospheric dump valves (ADVs). The two steam generator dump valves, operators, and power supplies are safety grade. There are two dc operated ADVs located on each of the two main steam lines. The ADVs are capable of automatic modulating service using ac control power and are capable of open/close service from the control room using dc power only. Each ADV is sized to pass 50 percent of the steam flow required to hold the Reactor Coolant System at hot standby for two hours followed by a 75F/hr cooldown to the shutdown cooling system entry temperature of 350F during natural circulation conditions, assuming that only 125,000 gallons of condensate are available from the condensate storage tank (see Appendix 5.2B for analysis of natural circulation cooldown at lower cooldown rates). The ADVs are ASME Code Class 2, seismic Category I with Class IE qualified electrical components and a single valve capacity of 54,000 lb/hr at 40 psig. Should a single failure of an emergency power train occur making one ADV on each steam generator inoperable, the remaining two ADVs are capable of releasing the design basis required steam flow.

In addition to the ADVs, the following means are also available for dumping secondary steam.

- Steam may be released from either or both of the steam generators through the auxiliary feedwater pump turbine steam supply lines which are also safety grade (seismic Category 1, Quality Group B).
- Steam may be bypassed to the condenser if it is available.

- Steam traps may be bypassed, if necessary, to relieve steam.

- Vent valves and drain valves may be used, if necessary, to relieve steam.

In summary, four 50 percent capacity safety grade (seismic Category I, Quality Group B) atmospheric steam dump valves with multiple, diverse backup means of relieving steam are provided. See FSAR Section 10.3 for more information.

2. Primary Depressurization

All or a portion of the charging flow may be used for auxiliary spray flow to cool and depressurize the pressurizer in the event that reactor coolant pumps and thus main spray flow are not available. Auxiliary spray flow can be provided by operating one or more of the three safety grade charging pumps (Seismic Category I, ASME Class 2) after opening one or both of the two safety grade auxiliary spray isolation valves, SE-02-3 and SE-02-4 (seismic Category I, ASME Class 1), and after closing both safety grade charging line isolation valves, SE-02-1 and SE-02-2 (seismic Category I, ASME Class 1). The charging pumps are powered from the emergency onsite power sources while the auxiliary spray valves are dc powered. Only one charging pump and one auxiliary spray isolation valve need be operable in order to provide adequate auxiliary spray system operation. However, both charging line isolation valves must be closed to ensure that adequate charging flow is diverted through the auxiliary spray line. Three alternatives are available for plant depressurization if both offsite and one emergency power train fails. Plant shutdown without letdown and without auxiliary spray is addressed in Subsection 9.3.4.3.1.3.4. The second alternative involves manual action inside containment to close the fail-open charging line isolation valve. With the failed charging line isolation valve closed, adequate auxiliary spray and normal charging flow can be obtained throughout a plant cooldown with one charging pump, one auxiliary spray valve and one charging line isolation valve operable from the available emergency power train. (Note: The charging line isolation valves would not require manual action inside the containment since the current plant design uses 125V DC valves powered from a battery backed electrical bus; therefore, the valves would be available for use during this scenario). The third alternative involves operation of the safety grade pressurizer power operated relief valves (PORVs) to cool and depressurize the pressurizer (within the 36 hour cooldown criterion). The PORVs provide a redundant diverse means of pressurizer depressurization in addition to the use of the pressurizer auxiliary spray system. See Subsection 9.3.4 for more information.

As the RCS pressure is being reduced to the shutdown cooling entry pressure, the safety injection tanks (SITs) have their pressure reduced in accordance with operating procedures. An interlock with pressurizer pressure prevents the SIT isolation valves from being closed until RCS pressure drops to shutdown cooling entry pressure. Isolation of the tanks requires restoring power to the valve operators at the motor control center, in order to close the isolation valves from the control room. However, the tanks can be depressurized from the control room by using the vent valves. Two vent valves are provided on each tank. Each valve on a tank is powered from a separate emergency power source.

To initiate shutdown cooling, the SDC isolation valve breakers (for V3480, V3481, V3545, V3651 and V3652) must be manually closed at the Motor Control Center to allow for remote operation from the control room.

3. Primary Boration and Inventory Makeup

The St. Lucie Unit 2 design incorporates three safety grade charging pumps (seismic Category I, ASME Code Class 2), redundant safety grade charging pump borated water sources (two seismic Category I, ASME Code Class 2 boric acid make-up tanks and one seismic Category I, ASME Code Class 2 refueling water tank), redundant charging pump suction paths, and redundant charging pump delivery paths. The charging pumps and all related automatic control valves are connected to vital power if the normal power supply system should fail. During the plant cooldown, the Chemical Volume and Control System (CVCS) borates the RCS to cold shutdown boron concentration and accommodates the reactor coolant shrinkage, taking suction from the boric acid makeup and refueling water tanks. The minimum amount of stored boric acid solution that is maintained in either boric acid makeup tank is sufficient to bring the RCS to the required cold shutdown boron concentration.

Since the original response, and according to the implemented Boric Acid Concentration Reduction Program (Licensing Amendment #40), sufficient boric acid is added from the boric acid makeup tanks to the RCS to achieve a condition where the cooldown can be concluded using inventory and boric acid concentration from the refueling water tank.

Should offsite power be unavailable, letdown flow will be isolated and the normally closed motor-operated valve, V2504, will be operated manually to provide suction for the charging pumps from the refueling water tank. This valve is powered from vital MCC 2B5, but no credit is taken for its remote operation because its operator is not class IE. The capability of the CVCS to borate and to makeup is not compromised as a result of this event. A single failure of one emergency power train would leave at least one charging pump and one borated water source operable for RCS injection off the available emergency dc bus. One charging pump will allow the RCS to be borated to a cold shutdown boron concentration within the period that the plant is initially held at hot standby. Borated makeup water from the refueling water tank becomes available upon the opening of valve V2504 manually via the handwheel at the valve location within the Reactor Auxiliary Building. The procedure to bring the plant from hot standby to cold shutdown conditions is identical to that described in Subsection 9.3.4.3.1.3.4 for a shutdown without letdown and without auxiliary spray.

As a result of the Boric Acid Concentration Reduction Program, the boron concentration needed to maintain the required shutdown margin was calculated for each temperature during cooldown. Throughout the cooldown, the RCS boron concentration is maintained above the concentration needed to maintain the required shutdown margin.

4. Secondary Makeup

During cooldown, the auxiliary feedwater system (AFWS) and atmospheric dump valves provide a means to bring the reactor coolant system temperature down to the shutdown cooling system entry temperature. The auxiliary feedwater pump(s) are started and the safety grade auxiliary feed isolation valves are opened by an auxiliary feedwater actuation signal (AFAS). The auxiliary feedwater system is designed such that no single active failure coupled with a loss of offsite power prevents plant cooldown. A failure modes and effects analysis is provided in the St. Lucie Unit 2 FSAR Table 10.4-3.

The AFWS contains one steam driven and two motor driven auxiliary feedwater pumps. Each pump by itself is capable of maintaining the RCS in hot standby. Also, the steam driven or either of the motor driven auxiliary feedwater pumps is capable of delivering enough feedwater condensate for a plant cooldown. The AFWS is designed to safety grade requirements (seismic Category I, Safety Class 3, ASME Code Section III). Each of the motor driven auxiliary feedwater pumps utilize a Class IE ac safety related power supply and the turbine driven pump train relies strictly on dc power supply. If the motor driven auxiliary feedwater pumps were operating due to an AFAS when offsite power was lost, the pumps would automatically restart using diesel generator power. If one diesel generator were to fail, the remaining motor driven pump or the turbine driven pump can be used to provide full capacity auxiliary feedwater flow. Auxiliary feedwater system valves required for cold shutdown have control switches in the control room and locally as well.

The 400,000 gallon condensate storage tank (CST) provides the water supply for the AFWS. When no tornado warnings are in effect, 297,800 gallons are available for St. Lucie Unit 2. The remaining usable portion of the condensate storage volume is provided for the St. Lucie Unit 2 secondary system makeup during normal plant operations. The CST is designed as seismic Category I, ASME Code Class 3, and is enclosed in a concrete protective barrier in order to withstand any tornado and/or missile effects.

Each ADV is sized to pass 50 percent of the flow required to bring the Reactor Coolant System to the SDCS entry temperature with reactor coolant pumps off, assuming that only 125,000 gallons of condensate is available from the CST. The quantity of water needed for St. Lucie Unit 2 cooldown is determined assuming a case wherein the unit is brought to hot standby and held there for two hours and then cooled down at the maximum rate of 75°F/hr until the shutdown cooling window of 350 F is reached. This requires 129,000 gallons, as indicated in Table 10.4-2. During emergency conditions (except the hypothetical tornado missile which drains the St. Lucie Unit 1 CST) there is sufficient water in the CST to allow hot standby operation for 23 hours and a subsequent cooldown to 350F over four hours. See UFSAR Subsections 9.2.6 and 10.4.9 for further information. Also see UFSAR Appendix 5.2B for additional analysis of natural circulation cooldown and CST requirements.

For EPU operation, two cases were evaluated. For one case the unit is held at hot standby for two hours and then cooled down to shutdown cooling entry conditions. The other case is held at hot standby for four hours and then cooled down to shutdown cooling entry conditions. Both cases are evaluated at a cooldown rate of 75°F/hr. If the plant is held at hot standby for two hours before cooldown, the quantity of water needed is 139,000 gallons. If the plant is held at hot standby for four hours before cooldown, the quantity of water needed is 154,000 gallons.

BRANCH POSITION

A.3 The system(s) shall be capable of being operated from the control room with either only onsite or only offsite power available. In demonstrating that the system can perform its function assuming a single failure, limited operator action outside of the control room would be considered acceptable if suitably justified.

RESPONSE:

All systems used for cooldown to hot shutdown are capable of being operated from the control room. Operator action outside the control room resulting from single failure assumptions are identified in the response to position A.2 above.

Cooldown to cold shutdown using SDCS can be accomplished with limited operator action from outside the control room as described in Subsection 5.4.7.2.6.

BRANCH POSITION

A.4 The system(s) shall be capable of bringing the reactor to a cold shutdown condition, with only offsite or onsite power available within a reasonable period of time following shutdown, assuming the most limiting single failure.

RESPONSE:

The initial phase of cooldown is accomplished by heat rejection to the atmosphere from the atmospheric dump valves (see Position A.2). Once the Shutdown Cooling System (SDCS) is aligned, the cooldown proceeds by rejecting heat to the SDCS heat exchangers. Assuming loss of offsite power, the most limiting postulated single failure is that of one vital dc bus and associated diesel generator. This single failure disables one train of components associated with the ADVs, CVCS, Auxiliary Feedwater System and Shutdown Cooling System. However, the plant can be cooled down to cold shutdown conditions with one diesel generator and train of system components within 36 hours.

BRANCH POSITION

B. RHR System Isolation Requirements

The RHR system shall satisfy the isolation requirements listed below.

1. The following shall be provided in the suction side of the RHR system to isolate it from the RCS.

   (a) Isolation shall be provided by at least two power-operated valves in series. The valve positions shall be indicated in the control room.

   (b) The valves shall have independent diverse interlocks to protect against one or both valves being opened during an RCS increase above the design pressure of the RHR system.

RESPONSE:

The SDCS is designed to provide adequate isolation between the SDCS and the safety injection tanks or the RCS when the RCS is above the design pressure of the SDCS (350 psig) as follows:

There are two parallel paths with two isolation valves per path inside containment on the suction line to the SDCS pumps. Each valve has a separate, independent power source and each valve is interlocked with a separate and independent pressurizer signal. Valve opening is prevented until the RCS pressure falls to a value of 276 psia. The setpoint for automatic closure of the SDCS suction line isolation valves is 500 psia to preclude premature isolation of the SDCS*.

Each isolation valve is equipped with open/close position indication in the control room.

It should also be noted that there is a cross connect between the two LPSI pump trains. This cross connect is situated between the two isolation valves on each train. This cross connect piping is opened and closed via valve V3545 (key locked opened). Power is supplied to the valve from either electrical Train A or B via the swing Bus. This cross connect valve can be operated from the control room and also from another control station. Open and closed positions are shown by corresponding lights. These lights are powered from electrical Bus A. In addition, there is 0-100 percent indication for this valve.

Thus, if one of the valves failed or if one of the diesel generators failed, there would still be one functioning LPSI pump train. For example, if valve V3481 failed closed, the piping line to LPSI pump 2A would no longer be

* The requirement is prior to an actual or simulated pressurizer pressure signal exceeding 515 psia.

available; however, the line to LPSI pump 2B would still be open and operable. As a second example; electrical Train A failed - the diesel generator - failed to start - these valves V3652, V3481 and V3664 would not open. Electrical Train B is functional and is used to open the SDC isolation valves (V3480 and V3651). Water flows through the LPSI pump 2A train (up to the cross connect point), flows through the cross connect piping and into the LPSI pump 2B piping train, thus supplying LPSI pump 2B with the necessary flow. Plant procedures ensure that the cross connect valve (V3545) will be opened when both SDC trains are operating.

At times when the SDC system is being operated at reduced levels in the RCS and the suction pressure valve interlock is defeated with the pressurizer manway removed, a pressurizer safety valve removed or the reactor head removed, the suction cross-tie valve, V3545, may be closed to gain additional heat removal performance from the SDC system. In addition, at times when a rapid loss of RCS level could cause air ingestion into the SDC system, such as operation at hot leg mid-loop level, the closed cross-tie valve could preclude the failure of both trains and allow continuation of, or expeditious recovery of, the SDC function.

BRANCH POSITION

B.2. One of the following shall be provided on the discharge side of the RHR system to isolate it from the RCS:

(a) The valves, position indicators, and interlocks described in item 1 (a)-(c).

(b) One or more check valves in series with a normally closed power operated valve. The power-operated valve position shall be indicated in the control room. If the RHR system discharge line is used for an ECCS function, the power-operated valve is to be opened upon receipt of a safety injection signal once the reactor coolant pressure has decreased below the ECCS design pressure.

(c) Three check valves in series, or

(d) Two check valves in series, provided that there are design provisions to permit periodic testing of the check valves for leak tightness and the testing is performed at least annually.

RESPONSE:

Two check valves are within the containment barrier.

Design features permit leak testing of each check valve separately during plant operation to fulfill staff requirements for high/low pressure isolation.

In addition, normally closed motor operated valves are provided outside the containment. These valves will automatically open on SIAS.

NOTE:

Subsequent to initial plant operation, the technical specifications have been revised to allow testing at intervals greater than annual.

BRANCH POSITION

C. Pressure Relief Requirements

The RHR system shall satisfy the pressure relief requirements listed below.

1. To protect the RHR system against accidental overpressurization when it is in operation (not isolated from the RCS), pressure relief in the RHR system shall be provided with relieving capacity in accordance with the ASME Boiler and Pressure Vessel Code. The most limiting pressure transient during the plant operating condition when the RHR system is not isolated from the RCS shall be considered when selecting the pressure relieving capacity of the RHR system. For example, during shutdown cooling in the PWR with no steam bubble in the pressurizer, inadvertent operation of an additional charging pump or inadvertent opening of an ECCS accumulator valve should be considered in selection of the design bases.

2. Fluid discharged through the RHR system pressure relief valves must be collected and contained such that a stuck open relief valve will not:

    a. Result in flooding of any safety-related equipment.

    b. Reduce the capability of the ECCS below that needed to mitigate the consequences of a postulated LOCA.

    c. Result in a non-isolatable situation in which the water provided to the RCS to maintain the core in a safe condition is discharged outside of the containment.

3. If interlocks are provided to automatically close the isolation valves when the RCS pressure exceeds the RHR system design pressure, adequate relief capacity shall be provided during the time period while the valves are closing.

RESPONSE:

Overpressure protection of the SDCS is provided by relief valves in the suction lines and valves in the LPSI pump discharge header. There are six relief valves in the SDCS suction lines. These valves are sized to protect the components and piping from overpressure due to thermal expansion of the fluid. Valves V3482 and V3469 have a set pressure of 2485 psig and a capacity of five gpm. Relief fluid from these valves is collected in the quench tank and are designed to 1974 ASME, Section NB, Quality Group A (see Figure 6.3-1b).

Valves V3483 and V3468 have a set pressure of 335 psig and a capacity of 155 gpm. Relief fluid from these valves is collected in a holdup tank in the Waste Management System. These valves are designed to 1974 ASME, Section NC, Quality Group B (see Figure 6.3-1b). Further protection is provided by relief valves V3666 & V3667 between the inside and outside containment isolation valves. The relief valves protect the SDCS from inadvertent RCS pressurization during SDCS operation. The valves are sized and designed to provide protection against water-solid overpressure transients. The setpoint and valve capacity for V3666 & V3667 are 335 psig and 2300 gpm, respectively. The valves are capable of passing full safety injection flow. The relief valves at discharge of the LPSI pumps protect the header from pressure developed by temperature changes to the trapped water. The setpoint for the relief valve is 500 psig with a capacity of five gallons per minute (Ref. FSAR 6.3.2.2.6.1). See Subsection 5.4.7.2.3 for more information.

BRANCH POSITION

D. Pump Protection Requirements

The design and operating procedures of any RHR system shall have provisions to prevent damage to the RHR system pumps due to overheating, cavitation or loss of adequate pump suction fluid.

RESPONSE:

The shutdown cooling system mode is a closely monitored manual mode of operation. Control room indication of the RCS pressure (PI-1103), the pressure in each LPSI header (PI-3304 (Train B) and PI-3307 (Train A)), each LPSI pumps flow rate (F-3312 (Train A), F-3322 (Train A), F-3332 (Train B), and F-3342 (Train B), and the position of each remotely actuated suction line isolation valve (V3480 (Train A), V3481 (Train A), V3651 (Train B), and V3652 (Train B) permits the operator to take the necessary steps to prevent damage to the pumps resulting from overheating, cavitation, or a loss of adequate suction fluid. If evidence of pump cavitation appears; manual control of LPSI flow can be used to maintain adequate available NPSH. Should the operator determine it necessary to secure one shutdown cooling train, adequate cooling of the core can be provided by the redundant train. Also, the existing design permits a single failure of the A or the B bus to close a suction valve in each train of the SDCS. To avoid a loss of suction to the LPSI pump, plant procedures ensure that the cross connect valve (V3545) will be opened when both SDC trains are operating or that the closure interlock is defeated whenever the cross connect valve is closed.

Low flow alarms aid the operator in evaluating pump performance. The *ultrasonic flow sensors are located in the miniflow lines (FE-03-1-1 (Train A) and FE-03-21 (Train B)) and the discharge lines (FE-03-1 (Train A) and FE-03-2 (Train B)) for the LPSI pumps, with alarm annunciators in the Control Room.

*Note: The ultrasonic flow sensors and alarms were subsequently deleted by PC/M 104-294, due to sensor obsolescence and procedural improvements.

BRANCH POSITION

E. Test Requirements

The preoperational and initial startup test program shall be in conformance with Regulatory Guide 1.68. The program for PWRs shall include tests with supporting analysis to (a) confirm that adequate mixing of borated water added prior to or during cooldown can be achieved under natural circulation conditions and permit estimation of the times required to achieve such mixing, and (b) confirm that the cooldown under natural circulation conditions can be achieved within the limits specified in the emergency operating procedures. Comparison with performance of previously tested plants of similar design may be substituted for these tests.

RESPONSE:

The preoperational and startup test programs conform to Regulatory Guide 1.6 (R2). Boron mixing under natural circulation conditions, has been demonstrated in a prototypical test at the San Onofre Nuclear Generation Station (SONGS). The results of this SONGS test have been reported to the NRC under separate correspondence.[1]

A natural circulation test and simulator training will be performed for St. Lucie Unit 2 to demonstrate the capability of cooling the plant. A detailed plan is included in Subsection 14.2.12.42 in a separate correspondence. St. Lucie Unit 1 submittals to the NRC concerning Natural Circulation cooldown have been reviewed with respect to their applicability to St. Lucie Unit 2. It is FPL's opinion that the submittals provided to the staff for Unit 1 are directly applicable to Unit 2. In summary, Unit 2 has revised emergency operating procedures which reflect a more stringent cooldown rate than the existing 75°F/hr rate. However, it is our position that the more stringent cooldown rate is not required to preclude safe cooldown or plant shutdown. All evaluations completed by our NSSS Vendor (CE) concur with our position. The St. Lucie Unit 2 response is covered by the St. Lucie Unit 1 analysis which is addressed in FP&L letters L-80-343 dated October 17, 1980 and L-80-431 dated December 30, 1980. See also Appendices 5.2B and 5.2C which contain the St. Lucie Unit 1 analysis. Appendix 5.2B has also been updated with the St. Lucie Unit 2 analyses for operation at EPU conditions.

(1) FPL letter L-84-68 dated March 13, 1984

BRANCH POSITION

F. Operational Procedures

The operational procedures for bringing the plant from normal operating power to cold shutdown shall be in conformance with Regulatory Guide 1.33. For pressurized water reactors, the operational procedures shall include specific procedures and information required for cooldown under natural circulation conditions.

RESPONSE:

The operational procedures will be in conformance with Regulatory Guide 1.33. Generic guidance for cooldown under natural circulation conditions developed in conjunction with the CE Owner's Group will be included in the procedures.

BRANCH POSITION

G. Auxiliary Feedwater Supply

The seismic Category I water supply for the auxiliary feedwater system for a PWR shall have sufficient inventory to permit operation at hot shutdown for at least 4 hours, followed by cooldown to the conditions permitting operation of the RHR system. The inventory needed for cooldown shall be based on the longest cooldown time needed with either only onsite or only offsite power available with an assumed single failure.

RESPONSE:

Subsection 10.4.9 of the St. Lucie Unit 2 UFSAR states that the quantity of water stored in the condensate storage tank for St. Lucie Unit 2 cooldown is determined assuming a case wherein the unit is brought to hot standby conditions and held there for two hours followed by a cooldown at the maximum rate of 75°F/hr until the shutdown cooling window of 350°F is reached. The total hot standby and cooldown time is 6.5 hours (see Table 10.4-2). This evolution results in about 43,000 gallons of condensate to cool the plant from hot standby to 350°F and about 86,000 gallons of condensate to remove 6.5 hours of decay heat.

A cooldown scenario which involves maintaining hot standby conditions for four hours followed by a cooldown at the maximum rate of 75°F/hr until the shutdown cooling entry conditions are reached is basis for condensate storage per Branch Technical Position RSB 5-1. Pre-EPU calculations show that 49,600 gallons of condensate is required to cool the plant from hot standby to 350°F. However, 100,000 gallons of condensate is now needed to remove 8 hours of decay heat.

Thus 149,600 gallons of condensate storage was required for pre-EPU operation in order to accommodate an initial hold at hot standby for four hours followed by a cooldown. For EPU operation, at a cooldown rate of 75°F/hr to shutdown cooling entry conditions following an initial hold at hot standby for four hours, 154,000 gallons of condensate are needed. The condensate storage tank minimum available volume of water (297,600 gallons) is above the volume needed for a four hour initial hot standby scenario (see Subsection 10.4.9.3).

As indicated in Subsection 10.4.9 (Table 10.4-2, Figure 10.4-10) there is sufficient water in the condensate storage tank during emergency blackout conditions (except when an assumed tornado missile ruptures the Unit 1 storage tank) to remove a total of 27 hours of decay heat plus the sensible heat (stored energy). This volume of water would support a scenario of 23 hours in hot standby followed by a 4 hour cooldown.

See UFSAR Appendix 5.2B for additional analysis of natural circulation cooldown and CST requirements.

5.4.7.6 Generic Letter 88-17 Commitments

Generic Letter 88-17 was issued to address concerns related to the loss of decay heat removal capability during non-power operations based on several industry incidents. The generic letter required the implementation of expeditious actions as well as programmed plant enhancements to address this issue. FPL provided commitments to implement these requirements in letters to NRC (L-88-552 and L-89-38). The commitments made by FPL were in the following areas: 1) personnel training on the events; 2) availability of instrumentation to verify state of RCS and cooling systems performance; this includes the use of core exit thermocouples and SDC supply/return line temperature for core exit conditions and RCS water level indicators for reduced inventory; 3) procedures for normal and off-normal reduced inventory SDC operation and administrative controls for containment closure prior to core uncovery; 4) at least one HPSI pump and charging pumps available to maintain RCS in stable and controlled condition; 5) the performance of time to RCS boiloff, core uncovery and vent area analyses to supplement design information and support procedures/instrumentation; 6) guidelines to ensure perturbation-causing operations are minimized; and 7) controls to avoid RCS pressurization when hot leg nozzle dams are in place simultaneously. In addition, licensees were required to identify and submit appropriate changes for Technical Specifications that restrict or limit the safety benefit of the actions identified in the generic letter.

5.4.8 REACTOR WATER CLEANUP SYSTEM

This section of Regulatory Guide 1.70 (R3) is for boiling water reactors and is not applicable to St. Lucie Unit 2.

5.4.9 MAIN STEAM LINE AND FEEDWATER PIPING

The main steam piping is discussed in Section 10.3. The Feedwater System piping is discussed in Subsection 10.4.7. The main steam and feedwater piping materials are discussed in Subsection 10.3.6.

5.4.10 PRESSURIZER

5.4.10.1 Design Bases

The pressurizer is designed to:

a) Maintain Reactor Coolant System (RCS) operating pressure such that the minimum pressure observed during operation transients is above the setpoint for the safety injection actuation signal (SIAS) and that the maximum pressure is below the high pressure reactor trip.

b) Compensate for changes in reactor coolant volume during the design transients specified in Subsection 3.9.1.1.

c) Provide sufficient water volume to prevent draining the pressurizer as a result of a reactor/turbine trip.

d) Contain a total water volume such that the total mass and energy released to the containment during a LOCA is minimized.

e) Provide sufficient water volume to prevent the pressurizer heaters from being uncovered during a pressurizer outsurge following a 10 percent step decrease or a five percent per minute ramp decrease.

f) Provide sufficient steam volume to allow acceptance of an insurge without the pressurizer water level reaching the primary safety or power operated relief valve nozzles.

g) Provide sufficient steam volume to yield an acceptable pressure response to normal system volume changes during design load change transients.

h) Provide sufficient pressurizer heater capacity to heat up the pressurizer, filled with water at the zero power level, at a rate that ensures a pressurizer temperature (and thus pressure) which maintains an adequate degree of subcooling of the water in the reactor coolant loops as it is heated by core decay heat and/or pump work from the reactor coolant pumps.

5.4.10.2 Description

The pressurizer, as shown on Figure 5.4-10 is a vertically mounted, bottom supported, seismic Category I, cylindrical pressure vessel. Replaceable direct immersion electric heaters are vertically mounted in the bottom head. The pressurizer is furnished with nozzles for spray, surge, safety valves, relief valve and pressure, temperature and water level instrumentation. A manway is provided in the top head. Principal design parameters are listed in Table 5.4-6.

The pressurizer is designed and fabricated in accordance with the ASME Code listed in Table 5.2-1. The interior surface is clad with weld deposited stainless steel.

The total volume of the pressurizer is established by consideration of the factors given in Subsection 5.4.10.1. To account for these factors and to provide adequate margin at all power levels the water level in the pressurizer is programmed as a function of average reactor coolant temperature (See Figure 4.4-10). High or low water level error signals result in the control actions shown on Figure 5.4-11. The pressurizer surge line is sized to accommodate the flow rates associated with the RCS expansion and contraction due to the transients specified in Subsection 3.9.1.1.

The pressurizer maintains Reactor Coolant System operating pressure and, in conjunction with the Chemical and Volume Control System (CVCS), Subsection 9.3.4, compensates for changes in reactor coolant volume during load changes, heatup, and cooldown. During full power operation, slightly more than one half the pressurizer volume is occupied by saturated water, and the remainder by saturated steam. Reactor Coolant System pressure may be controlled automatically or manually by maintaining the temperature of the pressurizer fluid at the saturation temperature corresponding to the desired system pressure.

During load changes, the pressurizer limits pressure variations caused by expansion or contraction of the reactor coolant. The average reactor coolant temperature is programmed to vary as a function of load (See Figure 4.4-10). A reduction in load is followed by a decrease in the average reactor coolant temperature to the programmed value for the lower power level. The resulting contraction of the reactor coolant lowers the pressurizer water level, causing the Reactor Coolant System pressure to decrease. The pressure reduction is partially compensated by flashing of pressurizer water into steam. Pressurizer heaters are automatically energized on low system pressure, generating steam and further limiting pressure decrease. Should the water level in the pressurizer drop below the setpoint, the letdown control valves close to minimum value, and additional charging pumps in the CVCS are automatically started to add coolant to the Reactor Coolant System and restore pressurizer water level. A redundant Class 1E Low-Low Level Heater Cutoff with alarms is installed to assure that all heaters are deenergized on a pressurizer low-low level signal. Therefore, no single failure in the protection system can cause them to be energized while uncovered.

Some of the heaters are connected to proportional controllers, which adjust the heater input to account for steady-state losses and to maintain the desired steam pressure in the pressurizer. The remaining backup heaters are connected to on-off controllers. These heaters are normally deenergized but are automatically turned on when needed. The pressure control program is shown on Figure 5.4-12.

When steam demand is increased, the average reactor coolant temperature is raised in accordance with the reactor coolant temperature program. The expanding reactor coolant from the reactor coolant piping hot leg enters the bottom of the pressurizer through the surge line, compressing the steam and raising system pressure. The increase in pressure is moderated by the

condensation of steam during compression and by the decrease in bulk temperature in the liquid phase. Should the pressure increase be large enough, the pressurizer spray valves open, spraying reactor coolant from the reactor coolant pump discharge (cold leg) into the pressurizer steam space. The relatively cold spray water condenses some of the steam in the steam space, limiting the system pressure increase. The programmed pressurizer water level is a power dependent function. A high water level error signal, produced by an in-surge causes the letdown control valves to open, releasing reactor coolant to the CVCS and restoring the pressurizer to the programmed level. Small pressure and reactor coolant volume variations are accommodated by the steam volume that absorbs flow into the pressurizer and by the water volume that allows flow out of the pressurizer. During certain transients which result in RCS inventory increases, a safety grade Class 1E Pressurizer high level alarm alerts the operator and allows sufficient time to terminate excess charging. This action functions to keep peak RCS pressure below 2370 psia, thus avoiding a reactor and turbine trip.

The pressurizer spray is supplied from each of the reactor coolant pumps associated with steam generator 2B as shown on Figures 5.1-3 and 5.1-4. Automatic spray control valves control the amount of spray as a function of pressurizer pressure; both of the spray control valves function in response to the signal from the controller. These valves are sized to use the differential pressure between the reactor coolant pump discharge and the pressurizer to pass the amount of spray required to prevent the pressurizer steam pressure from opening the power operated relief valves during normal load following transients. A small continuous flow is maintained with the pressurizer spray bypass valves through the spray lines at all times to keep the spray lines and the surge line warm to reduce thermal shock during plant transients. An auxiliary spray line is provided from the charging pumps to permit pressurizer spray during plant heatup, or to allow cooling if the reactor coolant pumps are shut down.

In the event of an abnormal transient which causes a sustained increase in pressurizer pressure, at a rate exceeding the control capacity of the spray, a high pressure trip level is reached. This signal trips the reactor and opens the two power operated relief valves. The steam discharged by the power operated relief valves goes to the quench tank where it is condensed.

5.4.10.3 Evaluation

It is shown by analysis, made in accordance with the requirements for ASME Code, Section III, Code Class 1, that the pressurizer is adequate for all normal operating and transient conditions expected during the life of the plant.

Overpressure protection of the Reactor Coolant System is provided by three ASME Code spring-loaded pressurizer safety valves. Refer to Subsection 5.4.13 for more information on safety valves.

A discussion of the radiological considerations for the pressurizer is provided in Section 12.3.

5.4.10.4 Tests and Inspections

Following shop fabrication, the pressurizer is subjected to the hydrostatic test required by ASME Code, Section III, Code Class 1. Upon completion of field erection of the Reactor Coolant System, the system is hydro-tested to verify the pressure retaining capability of the field piping welds.

Prior to plant startup, the transient performance of the pressurizer is evaluated by determining system normal heat losses, and maximum pressurization and depressurization rates. This data is used to set the pressure controllers and verify the adequacy of the pressurizer water level control system, heaters and spray valves.

Further assurance of the structural integrity of the pressurizer during plant life is obtained from inservice inspections performed in accordance with ASME Code, Section XI and described in Section 5.2.

5.4.10.5 Pressurizer Surge Line Thermal Stratification

Design basis cyclic transients were revisited for the pressurizer surge line and nozzles to address thermal stratification and thermal stripping concerns raised by NRC Bulletin 88-11. This Bulletin required licensees to visually inspect the surge line; to perform analyses to demonstrate that the surge line meets applicable design codes and other UFSAR/regulatory requirements for the design life of the plant; to obtain data on thermal stratification, thermal striping and line deflection; and to perform detailed stress and fatigue analyses on the line to ensure compliance with applicable code requirements. As a result of this analysis which is documented in Reference 6, the NRC concluded (Reference 7) that the results of the analysis performed by the Combustion Engineering Owner's Group (CEOG) for this task may be used for FPL as the basis to update the plant specific code stress reports to demonstrate compliance with applicable Code requirements as requested in NRC Bulletin 88-11. The analysis developed a new set of design basis transients based on the collected data. The new set of design basis transients are provided in Reference 6. The total number of heatup-cooldown cycles remained unchanged at 500. However, the number of stratification cycles that occur during a heatup-cooldown cycle was changed.

The structural integrity of the surge line is maintained for EPU operation and existing pipe support loads remain applicable. The results from the existing pre-EPU analysis of record (Reference 9) are applicable for EPU normal operation and transients.

5.4.11 QUENCH TANK (Pressurizer Relief Discharge System)

5.4.11.1 Design Bases

The quench tank is designed to receive and condense the normal discharges from the pressurizer safety and power operated relief valves and to prevent the discharge from being released to containment.

The quench tank is sized to contain the 567 lbm steam calculated to be discharged by the pressurizer safety valves during the worst case anticipated operating occurrence (loss of load event, see Appendix 5.2A) followed by 575 lbm steam calculated to be discharged by the power operated relief valves during CEA withdrawal accident as the plant returns to power following the loss of load trip.

The quench tank is mounted on a structural steel frame which is designed to seismic Category I requirements. The pressure relief discharge system is designated Quality Group D and non-seismic per ANSI N18.2. Furthermore, the piping system from the pressurizer in the quench tank, although designated non-seismic, has been seismically analyzed to ensure that it withstands safe shutdown earthquake loadings without failure.

A loss of load event immediately followed by an uncontrolled rod withdrawal event is unrealistic given that each result in a reactor trip. Thus, it is sufficient to ensure that the tank volume is such that the tank is capable of accepting and condensing steam released to the quench tank in the limiting event (uncontrolled rod withdrawal). The steam released in an uncontrolled rod withdrawal is 450 lbm for 3020 MWt operation, well below the limit the tank was sized for as stated above. The current quench tank water level and temperature limits can be maintained.

5.4.11.2 System Description

The quench tank, shown on Figure 5.4-13, is an austenitic stainless steel vessel suitable for prolonged contact with borated water. The quench tank is located in the containment at elevation 62 ft which is lower than the pressurizer safety or power operated relief valves to ensure that any leakage or discharge from the valves drains to the quench tank. Nozzles are provided for the safety/relief valve discharge line, vent, drain, instrumentation, makeup water and a manway and rupture disc. The tank prevents the steam released from the pressurizer safety/relief valves from being released to the containment atmosphere. The steam is discharged under water by the sparger and condensed. A 1/2 inch hole in the sparger prevents a vacuum from forming in the safety/relief valve discharge piping following a steam release. Primary water is manually added to cool the tank water after a steam discharge and the pressure is manually relieved to the Waste Management System. Normal operating level can then be reestablished by draining to the reactor drain tank located at elevation 7.58 ft. A relief valve and a rupture disc venting to the containment atmosphere are provided for overpressure protection. The rupture disc is also provided with a stainless steel vacuum support.

The tank normally contains water under a three psig nitrogen overpressure. The quench tank normal water volume of 127 cubic feet covers the sparger and is sufficient to condense the steam released from the pressurizer safety and power operated relief valves as a result of the design basis transient. The water temperature in the quench tank is limited to 281° F based on initial water temperature of 120° F. The tank gas volume is based on limiting the maximum tank pressure to 70 psig after the steam release produced by this sequence of events.

The quench tank design parameters are given in Table 5.4-7. The quench tank and piping connections are shown on the Reactor Coolant System Piping and Instrumentation Diagram, Figures 5.1-3 and 5.1-4. The nitrogen supply piping and the piping from the quench tank to the reactor drain tank is shown on Figures 11.3-1 and 11.2-1, respectively.

The sparger, spray header, nozzle and rupture disc fittings are stainless steel.

5.4.11.3 Safety Evaluation

The quench tank is designed and fabricated to the requirements of the ASME Code, Section III, Code Class 3. Although the quench tank is designated non-seismic, seismic Category I supports have been provided. Furthermore, the piping system from the pressurizer to the quench tank, although designated non-seismic, has been seismically analyzed to ensure that it withstands safe shutdown earthquake loadings without failure. Besides these evaluations, the quench tank sparger is analyzed for both seismic forces and blowdown forces. These additional evaluations ensure that the quench tank would withstand these accident related conditions. The quench tank rupture disc minimum capacity is greater than the combined maximum capacities of the pressurizer power operated relief and safety valves at the maximum allowed ASME Code quench tank pressure. Thus the build-up backpressure does not exceed the valve design backpressure for the pressurizer safety valves. Criteria for design against pipe whip are discussed in Section 3.6. Compliance with Regulatory Guide 1.67, "Installation of Overpressure Protection Devices," October, 1973 (R0) is discussed Subsection 3.9.3.

Failure of any of these components in no way compromises the integrity of the reactor coolant pressure boundary or safe shutdown of the plant.

5.4.11.4 Instrumentation Requirements

The quench tank is equipped with water level, pressure and temperature Instrumentation as described below. The location of each of the sensors are indicated on Figure 5.1-4.

5.4.11.4.1 Temperature

The temperature measurement channel consists of a resistance temperature detector (RTD), a temperature transmitter and associated indicator and alarms. Quench tank temperature indication and high-temperature alarm are provided in the control room. A high temperature alarm may be indicative of a safety/relief valve leakage or discharge to the quench tank.

5.4.11.4.2 Water Level

Water level instrumentation consists of a level transmitter and associated indicating and alarming equipment. Quench tank level indication and high and low level alarms are provided in the control room. A low level alarm is indicative of the sparger being uncovered or of insufficient tank fluid volume to quench the design basis steam release. A high level alarm alerts the operator of insufficient gas volume in the quench tank to accept a pressurizer steam release without becoming overpressurized and causing the rupture disc to burst.

5.4.11.4.3 Pressure

The pressure measurement instrument consists of a pressure transmitter and associated indicators and alarms. Quench tank pressure indication and high pressure alarm are provided in the control room. The high pressure alarm alerts the operator to the situation prior to the bursting of the rupture

5.4.11.5 Inspection and Testing Requirements

Inservice inspection of the applicable portions of the pressurizer relief discharge system is performed in accordance with ASME Code, Section XI.

5.4.12 VALVES

5.4.12.1 Design Basis

The safety related valves within the reactor coolant pressure boundary act as pressure retaining vessels and leak tight barriers during normal plant operation, accidents and seismic disturbances. The valves associated with the Reactor Coolant System pressure boundary are shown on Figures 5.1-3 and 5.1-4. These valves are designed in accordance with ASME Code, Section III, Code Class 1 requirements and withstand the effects of the system design transients (see Subsection 3.9.1.1) plus other transients associated with the valve location or service requirements. The valves meet seismic Category I requirements. Backseats are specified on manual and motor-operated gate and globe valves to further minimize potential leakage. Functional requirements for each valve are detailed in the individual valve specifications.

Materials of construction are specified to assure compatibility with the environment and contained fluids.

5.4.12.2 Design Description

All valves in the Reactor Coolant System are constructed primarily of stainless steel. Other materials in contact with the reactor coolant, such as hard facing and packing, are compatible materials. Fasteners, packing, gland assemblies and yoke fasteners are constructed of stainless steel or equal to eliminate corrosion problems. Valves, over 2 inches which are not constructed with diaphragms, bellows, or not normally backseated, are provided with either two independent sets of packing, separated by a lantern ring and leak-off connections piped to the reactor drain tank or provided with the EPRI recommended five ring packing stack-up, with capped leakoff connections, to control valve stem leakage.

5.4.12.3 Design Evaluation

All valves within the reactor coolant pressure boundary are stress analyzed in accordance with ASME Code, Section III, Code Class 1, refer to Section 3.9

5.4.12.4 Tests and Inspections

The valves are hydrostatically tested and leak tested across the seats and across the packing in accordance with the ASME Code, Section III as indicated in Table 5.2-1. Valves greater than one inch nominal pipe size are dimensionally checked, including measurements to determine minimum wall thickness.

In-service inspection is performed in accordance with ASME Code, Section XI.

5.4.13 PRESSURIZER SAFETY AND RELIEF VALVES

5.4.13.1 Design Basis

The pressurizer safety and power operated relief valves are designed to the requirements of the ASME Code, Section III, Code Class 1 (refer to Table 5.2-1 for code date). Their location in the RCS, flow paths, and associated instrumentation are shown on Figure 5.1-4.

The design basis for establishing the relieving capacity of the pressurizer safety valves is presented in Appendix 5.2A. The relieving capacity of the pressurizer safety valves are designed to provide overpressure protection for the postulated transients presented in Chapter 15. No credit is taken for power operated relief valves (PORVs) in the Section 15.2 analysis or in the sizing of the safety valves.

The PORVs prevent opening of the pressurizer safety valves during hot standby or power operations based upon the design transient which is a control rod withdrawal accident. This design basis transient assumes the main steam safety valves (described in Subsection 10.3.3) are operational and the reactor is scrammed on high pressure by the Reactor Protective System. The PORVs are also designed to provide the RCS with Low Temperature Overpressure Protection (LTOP) as described in Subsection 5.2.6.

5.4.13.2 Description

The RCS is protected against overpressure by protective and control devices such as the pressurizer spray system, PORVs and the high-pressure reactor trip. In addition to these features, three ASME Code safety valves ensure that RCS piping and components are protected from overpressure in accordance with ASME Code requirements. The pressurizer safety valve is illustrated on Figure 5.4-14. The design parameters are listed in Table 5.4-8. A flanged connection is used to secure these valves to the top of the pressurizer. They are direct acting, spring-loaded safety valves with an enclosed bonnet and a balanced bellows to compensate for backpressure variations.

The RCS has two power operated relief valves connected to the top of the pressurizer as shown on Figures 5.1-4 and 5.1-4a. During certain transient conditions, the RCS pressure will increase at a rate that exceeds the control capacity of the pressurizer spray system. The PORVs are provided to prevent such excursions from unnecessarily lifting the safety valves.

The PORVs are designed to open at the reactor high-pressure trip setpoint (2370 psia). When the plant is at power, one PORV is isolated from the RCS by closure of the upstream motor operated gate valve to avoid an excessive discharge of reactor coolant due to both PORVs lifting.

In the startup and cooldown mode of operation, both PORVs are aligned to the pressurizer. While in the Low Temperature Overpressure Protection (LTOP) mode, the PORV setpoints are at low pressures. The power operated relief valve is illustrated on Figure 5.4-15. The design parameters for the power operated relief valves are given in Table 5.4-9.

Downstream temperature and flow instrumentation actuate their respective alarms in the control room, notifying the operator of PORV leakage.

5.4.13.3 Evaluation

Low temperature overpressure protection by the PORVs is discussed in Subsection 5.2.6. Overpressure protection by the pressurizer safety valves is discussed in Subsection 5.2.2 and the ASME Code Report on safety valve overpressure Protection is included as Appendix 5.2A.

The NRC Staff per GL 90-06 identified actions to enhance the reliability of the PORVs and PORV block valves that perform safety related functions. For St. Lucie the PORV's (V1474 & V1475) perform the safety related function of providing low temperature overpressure protection for the reactor coolant pressure boundary as discussed in Section 5.2.6. The PORVs are not credited with performing any accident mitigation function, nor are they relied upon to cooldown the plant.

5.4.13.4 Tests and Inspections

Both the safety valve and the PORVs are inspected and tested during fabrication in accordance with ASME Code, Section III requirements. The following four paragraphs describe the original safety valves and are maintained as-is for historical purposes.

The inlet and outlet portions of the pressurizer safety valves are hydrostatically tested with water at the appropriate pressures required by the ASME Code. Using a prorated spring to permit valve operation with the available steam supply, each valve is cycled; set pressure and seat leakage tests are performed, and adjustment is made for blowdown. The actual operating spring is then installed and set pressure and seat leakage tests are performed using air at room temperature. Another seat leakage test is then performed using air at 650°F (+25°F, -0°F). Final set pressure and leakage tests are performed in the field at operating temperatures. On the basis of the results of the EPRI PWR Safety and Relief Valve Test Program, which included full scale testing of a St. Lucie 2 model pressurizer safety valve, valve ring adjustments for the St. Lucie 2 pressurizer safety valves were selected to assure stable operation. The resulting valve blowdown is approximately 10 percent (2250 psia blowdown pressure). Note: 10% represents the blowdown of the originally installed safety valves. PCM 96139 installed new valves with a specified blowdown of 4%.

The inlet and outlet portions of the PORVs are hydrostatically tested with water at the appropriate pressures required by the ASME Code. Each valve is cycled at LTOP pressure using room temperature water and at normal steam service pressure using air at 650°F (+25°F, -0°F). Cycling is done by manually energizing and deenergizing the solenoid. During the cycling, the operation of the position indicators on the main valve disc and on the solenoid is checked. Total leakage tests which include main seat leakage and solenoid leakage are performed using room temperature water at LTOP pressure and air at 650°F (+25 °F, -0°F) at normal steam service pressure.

St. Lucie 2, along with other PWR utilities, participated in the EPRI program for the performance testing of PWR safety and relief valves. The EPRI program was conducted in response to NUREG-0578 Section 2.12, "Performance Testing for BWR and PWR Safety and Relief Valve Operability." Models of the St. Lucie 2 pressurizer safety valves and power operated relief valves were tested in the program. The EPRI test program results demonstrated satisfactory operability for the St. Lucie 2 pressurizer safety and power operated relief valves. Results were reported in Combustion Engineering reports CEN-213 (June 1982)[1] for power operated relief valves and CEN-227 (December 1982)[2] for safety valves.

Reference 3 documents NRC acceptance of the Relief and Safety Valve Test Program designed to qualify the operability of prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. NRC review of NUREG-0737 items including relief and safety valve testing is discussed in FSAR Appendix 1.9A.

Per GL 90-06 (Ref. 4 & 5), the following requirements apply to the PORV's and PORV block valves (V1474, V1475, V1476 and V1477):

1) These valves are Class 1 valves and are to be included in its QA program for maintenance and procurement.
2) Include the PORVs and block valves within the scope of ASME Section XI, Subsection IWV for inservice testing.
3) Include the block valves in the Motor Operated Valve (MOV) test program, GL 89-10, "Safety Related Motor Operated Valve Testing and Surveillance".

In-service testing of PORVs for the LTOP mode is discussed in Subsection 5.2.6.1.3.

5.4.14 COMPONENT SUPPORTS

The structures supporting Code Class 1 components are also discussed in Subsection 3.8.3.

5.4.14.1 <u>Design Bases</u>

The criteria applied in the design of the reactor coolant system supports are that the specific function of the supported equipment be achieved during all normal, earthquake, and LOCA conditions. Specifically, the supports are designed to support and restrain the reactor coolant system components under the combined design basis earthquake and LOCA loadings in accordance with the stress and deflection limits listed in Subsection 3.9.3.1.

5.4.14.2 <u>Description</u>

The Reactor Coolant System support points are illustrated in Figures 3.8-41, 3.8-42, 3.8-43, 3.8-44, and 3.8-52.

a) Reactor Vessel Supports

The reactor vessel is supported by three integral pads at an elevation below the centerline of the vessel nozzles. The integral pads provide vertical vessel support and allow for unrestrained thermal expansion of the vessel.

Keyways located alongside the vertical support pads guide the vessel during thermal expansion and contraction of the Reactor Coolant System and maintain the vessel centerline.

b) Steam Generator Supports

The steam generator is supported at the bottom of a sliding base bolted to an integrally attached conical skirt. The sliding base rests on low friction bearings which allow unrestrained thermal expansion of the Reactor Coolant System. Two keyways within the sliding base guide the movement of the steam generator during the expansion and contraction of the reactor coolant system and, together with a stop and anchor bolts, prevent excessive movement of the bottom of the steam generator during seismic events and following a LOCA.

A system of keys and snubbers located on the upper end guide the top of the steam generator during expansion and contraction of the Reactor Coolant System and provide restraint during seismic events and following a LOCA or a steam line break.

c) Reactor Coolant Pump Supports

Each reactor coolant pump is provided with four vertical spring-type hangers which provide support for normal operation and seismic conditions. In addition each pump has a horizontal hydraulic snubber to dampen torsional oscillation of the pump on the main coolant piping under seismic conditions. The support system is designed to accept the piping and pump movements resulting from the normal and abnormal transient operating conditions described in Subsection 3.9.3.1.

For the case of pipe break in the pump suction line, one structural stop is provided on each suction line to limit the pump horizontal motion.

d) Pressurizer Supports

The pressurizer is supported by a cylindrical skirt welded to the pressurizer and bolted to the support structure. The skirt is designed to withstand dead weight and normal operating loads as well as the loads due to earthquakes and LOCA.

5.4.14.3 Evaluation

The Reactor Coolant System supports are designed to the criteria for load combinations and stresses which are presented in Subsection 3.9.3.1. The criteria are used to determine the loads the supports must consider as a result of the effects of pipe rupture and seismic conditions.

5.4.14.4 Testing and Inspection

Tests were conducted on materials similar to that being used for the reactor vessel and steam generator sliding supports to demonstrate that the maximum static coefficient of friction does not exceed 0.15 at a design loading of 5000 psi. Sliding supports for the steam generator were 100 percent liquid penetrant inspected and machined sockets were 100 percent magnetic particle inspected at the vendor's shops. The steam generator base plate was 100 percent ultrasonic inspected per ASME III Subsection NF.

The steam generator snubbers were tested in the vendor's shop at the rated load capacity in both tension and compression. The piston creep velocities were measured during these tests for compliance with specification limits. Tests were also conducted for initiation of snubber action on both the tension and compression directions.

SECTION 5.4: REFERENCES

1) "Summary Report on the Operability of Power Operated Relief Valves in CE Designed Plants," CEN-213, Combustion Engineering, Inc., June, 1982.

2) "Summary Report on the Operability of Pressurizer Safety Valves in CE Designed Plants," CEN-227, Combustion Engineering, Inc., December, 1982.

3) Letter, from J.A. Norris (NRC) to C.O. Woody (FPL), "NUREG-0737 Item II.D.1 Performance Testing of Relief and Safety Valves," dated May 11, 1989.

4) Generic Letter 90-06, "Resolution of Generic Issue 70, Power-Operated Relief Valve and Block Valve Reliability, and Generic Issue 94, Additional Low-Temperature Overpressure Protection for Light Water Reactors"

5) NRC Letter, St. Lucie Units 1 & 2 - Response to Generic Letter 90-06 dated August 20, 1993

6) ABB Combustion Engineering Report CEN-387-P, "Pressurizer Surge Line Flow Stratification Evaluation," Rev. 1-P-A, C-E Owners Group, May 1994.

7) NRC Letter to C-E Owners Group, "Safety Evaluation for CEOG Report CEN-387-P, Revision 1, (Bulletin 88-11)," July 14, 1993.

8) AREVA NP Document 77-5069878-01, "Replacement Steam Generator Report for Florida Power and Light St. Lucie Unit 2".

9) CE Design Report F-MECH-DR-006, Rev. 0, "Addendum to the Piping Analytical Reports for FPL St. Lucie Units 1 and 2," January 17, 1994.

TABLE 5.4-1

REACTOR COOLANT PUMP PARAMETERS

Cycle 1

Number	4
Type	Vertical, Limited Leakage, Centrifugal
Shaft Seals	Mechanical (4)
Stationary Face	Carbon CCP-72
Rotating Face Body	ASTM A351 Gr CF8
Rotating Face Ring	Titanium Carbide, Kenna-Metal K 162-B

Note: shaft seals were replaced during the 1998 refueling outage with the N-9000 design, which incorporates the following materials:

Stationary Face	NMCC CNFJ
Rotating Face	Kennametal KZ-801
Design Pressure, psig	2485
Design Temperature, °F	650
Normal Operating Pressure, psig	2235
Normal Operating Temperature, °F	550*
Design Flow, gpm	81,200
Total Dynamic Head, feet	310
Maximum Flow (one-pump operation), gpm	120,000
Dry Weight, pounds	161,750
Flooded Weight, pounds	168,750
Reactor Coolant Volume, cubic feet	112
Material	
Shaft	ASTM A182 Type F-304
Casing	ASTM A351 Gr CF8M
Casing Wear Ring	ASTM A351 Gr CF8
Hydrostatic Bearing	
Bearing	ASTM A351 Gr CF8
Journal	ASTM A351 Gr CF8
Flywheel	ASTM A543 Cl 1 Type B
Motor	
Voltage, volts	6600
Frequency, hz/phase	60/3
Horsepower/Speed, Hot, hp/rpm	5700/883
Horsepower/Speed, Cold, hp/rpm	7200/883
Horsepower/Speed, Rated	6500/881
Service Factor	1.15

* For EPU operation, normal operating temperature is 551°F.

TABLE 5.4-1 (Cont'd)

Instrumentation	
Seal Temperature Detectors	1
Pump Casing Pressure Taps	2
Seal Pressure Detectors	3
Controlled Bleedoff Flow Detectors	1
Controlled Bleedoff Temperature Detectors	1
Motor Oil Level Detectors	2
Motor Bearing Temperature Detectors	4
Motor Stator Temperature Detectors	6
Reverse Rotation Detectors	2 (Removed from 2B1 RCP motor)
Vibration Monitors	6
Oil Lift Pressure Switches	5 (*)
Oil Lift Pressure Gage	1
Total Seal Assembly Leakage	
Three Pressure Seals Operating, gpm	1.00
Two Pressure Seals Operating, gpm	1.35
One Pressure Seal Operating, gpm	1.90

Note (*): Four pressure switches in operation and one is an installed spare.

The spare pressure switch has been removed from 2B1 RCP motor.

TABLE 5.4-2

STEAM GENERATOR PARAMETERS

Parameter	Cycle 1[(a)] Value	RSG[(b)] Value	EPU[(b), (d)] Value
Number of units	2	2	
Heat transfer rate, each, Btu/h	4.386×10^9	4.623×10^9	5.179×10^9
Primary side:			
Design pressure/temperature (psia/°F)	2500/650	2500/650	
Coolant inlet temperature, °F	604	595.5	602.4
Coolant outlet temperature, °F	550	549.0	551
Coolant flow rate, each, lb/h	61×10^6	75.8×10^6	
Coolant volume at 68 °F each, ft^3	1629	1900	
Tube size, OD inches	3/4	3/4	
Tube thickness, nominal inches	0.048	0.0429	
Secondary side:			
Design pressure/temperature (psia/°F)	1000/550	1000/550	
Steam pressure, psia	815	896.9[(c)]	886.2[(c)]
Steam flowrate each, lb/h	5.6×10^6	5.9×10^6	6.6×10^6
Feedwater temperature at full power, °F	435	435	436
Moisture carryover, weight maximum, %	0.20	0.10	
Reactor Coolant inlet nozzle, No./ID inches	1/42	1/42	
Reactor Coolant outlet nozzle, No./ID inches	2/30	2/30	
Steam Nozzle, No./ID inches	1/34	1/34	
Feedwater nozzles, No./size/schedule	1/16/80	1/18 (16" ID)	
Overall heat transfer coefficient (estimated), Btu/h-Ft^2 - °F	933	1458	1416

(a) Performance parameters are based on full power Cycle 1 operation.

(b) Parameters are based on no fouling, no plugging and continuous blowdown of 1% of total steamflow.

(c) Static steam pressure.

(d) Only the values that change with implementation of EPU are shown.

TABLE 5.4-5 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
9.	SIT Isolation Valve V3614, V3624, V3634, or V3644	a) Fails open	Electrical malfunction, Mechanical binding	Inability to isolate one safety injection tank from the RCS during shutdown cooling. Possible inadvertent draining of one SIT.	Valve position indicator in control room, periodic testing.	Reduce pressure in affected tank using vent valves.	During shutdown cooling these valves are closed. However, if a LOCA occurs an SIAS will automatically open these valves. Prior to the actuation of shutdown cooling, the SIT pressure is periodically lowered below the RCS pressure to preclude discharging of their contents. Pressure reduction is achieved by bleeding off nitrogen or draining liquid to RWT.
		b) Fails closed	Electrical malfunction, Mechanical binding	None during shutdown cooling.	Valve position indicator in control room, periodic testing	None required.	
10.	LPSI Suction Isolation Valves V3432 , V3444	a) Fails open	Electrical malfunction, Mechanical binding	Inability to double isolate one LPSI pump suction from the RWT during shutdown cooling operation; loss of one shutdown cooling train.	Periodic testing, position indicator in control room.	Redundant LPSI train is unaffected	These valves are normally locked open and are closed just prior to initiation of shutdown cooling. Valves are opened from the control room.
		b) Fails closed	Electrical malfunction, Mechanical malfunction	None during shutdown cooling.	Periodic testing position indicator in control room.	None required	These valves are required to be closed during shutdown cooling operation. Valves are opened from the control room.
11.	SDCS Cross Connect Valve V3545	a) Fails open	Electrical malfunction, Mechanical binding	None during system operation.	Periodic testing, position indicator in control room	None required	This valve is required to be open when both SDC trains are in operation.
		b) Fails closed	Electrical malfunction, Mechanical binding	Inability to establish a crossover flow path between the SDCS trains (inside containment).	Periodic testing, position indicator in control room	The valve is capable of being powered from either diesel generator.	This valve is an FAI and locked open in the control room during power operation. This valve assures operation of at least one SDCS train if one emergency diesel generator fails.

TABLE 5.4-3

REACTOR COOLANT PIPING PARAMETERS

Parameter	Value	
Number of loops (steam generators)	2	
Flow per loop, lb/h	See Table 5.1-1	
Pipe Size		
Reactor Outlet ID/Wall, in		
Elbow	42/4-1/8	W/O Clad
Pipe	42/3-3/4	W/O Clad
Reactor Inlet ID/Wall, in		
Elbow	30/3	W/O Clad
Pipe	30/2-1/2	W/O Clad
Pump Suction ID/Wall, in		
Elbow	30/3	W/O Clad
Pipe	30/2-1/2	W/O Clad
Surge Line, Nominal (in.)/Schedule	12/160	
Spray Line, Nominal (in.)/Schedule	4/160 & 3/160	
Design pressure, psia	2500	
Design temperature, F	650	
Surge Line Design Temperature F	700	
Spray Line Design Temperature F	650	

TABLE 5.4-4

SHUTDOWN COOLING HEAT EXCHANGER DATA

Parameter	Value
Quantity	2
Type	Shell and tube horizontal U-Tube
Manufacturer	Tubular Exchangers Manufacturing Association (TEMA)
Service transfer rate (Btu/h-F-ft^2)	277
Heat transfer area per heat exchanger, ft^2	5790
Tube side:	
Fluid	Reactor
Design Pressure, psig	500
Design Temperature, F	400
Material	Austenitic stainless steel
Shell Side:	
Fluid	Component Cooling Water
Design Pressure, psig	150
Design Temperature, F	250
Material	Carbon Steel
At 27-1/2 hours after shutdown:	
Tube Side	
Flow, million lb/h	1.5
Inlet Temperature, F	135.00
Outlet Temperature, F	116.3
Shell Side	
Flow, million lb/h	2.41
Inlet temperature, F	100.0
Outlet temperature, F	111.6
Heat load (million Btu-h-HX)	280
Code	ASME Section III, 1974 Edition, Class 2 and 3

TABLE 5.4-5

FAILURE MODES AND EFFECTS ANALYSIS - SHUTDOWN COOLING SYSTEM

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
1.	SDCS Suction Isolation Valves (Inside containment) V3480, V3481, V3651, or V3652	a) Fails open	Electrical malfunction, Mechanical malfunction	Loss of redundancy for isolating one shutdown cooling train if the RCS pressure should rise above the SDCS isolation valve interlock setpoint during shutdown cooling operation.	Periodic Testing Alarm in control room	The redundant series valve ensures that the SDCS is protected from high RCS pressure.	These valves are interlocked to prevent inadvertent opening and to automatically close whenever the RCS pressure exceeds the SDCS isolation valve interlock setpoint.
		b) Fails closed	Electrical malfunction, Mechanical malfunction	Partial loss of decay heat-removal capability. Loss of one shutdown cooling train.	Periodic testing, Alarm. ("valve closure initiated") in control Room	Redundant shutdown cooling train ensures adequate cooling although the cooling time will be extended.	These valves are FAI and locked closed in the control room during power operation.
2.	LPSI Pump 2A or 2B	Fails to start ,or fails during operation	Electrical malfunction, Bearing failure, seal failure	Loss of flow through one shutdown cooling train to RCS cold leg.	No flow indication from FIC3306 or FIC3301, no discharge pressure Indication from PI3314 or PI3315, Periodic testing, pump "Run" light	Redundant shutdown cooling train will not be affected.	The reactor coolant system can be brought to refueling temperature using one LPSI pump and one shutdown cooling heat exchanger, but the cooldown process would be extended beyond the specified 24 hour time period.
3.	Minimum recirculation flow line isolation valve V3659, V3660, V3495 or V3496	a)Fails open	Electrical malfunction, Mechanical binding	None during shutdown cooling. Loss of redundancy to prevent pumping of primary coolant to RWT during SDC.	Periodic testing	Redundant series isolation valve provides backup.	These valves are locked open and are required to be closed during shutdown cooling.
		b)Fails closed	Electrical malfunction	Loss of mini-flow protection against operating one LPSI pump dead headed if pump is spuriously act.	Periodic testing	Redundant LPSI train is unaffected.	

TABLE 5.4-5 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
4.	SDC Hx Inlet Isolation Valve V3517, V3658	a) Fails open	Electrical mal-function, Mechani-ical binding	Inability to isolate shutdown cooling heat exchanger for maintenance.	Valve position indication, periodic testing	Redundant containment spray train.	These valves are locked closed in cont-rol room during, power operation and are required to be open dur-ing shutdown cooling opera-tion.
		b) Fails closed	Electrical mal-function, Mechan-ical binding	Inability to align one shutdown cooling heat exchanger for shutdown cooling operation.	Periodic testing, abnormal pressure indication from PI3303X or PI3303Y, abnormal temperature indication from TI3303X or TI3303Y	Redundant shutdown cooling train.	----
	SDC Hx Outlet Isolation Valve V3456 or V3457	a) Fails open	Electrical mal-function, Mechanical bind-ing	Inability to isolate SDC Hx for maintenance.	Valve position indication, periodic testing	None required.	These valves are tucked closed in the control room during power operation and are required to be open during shutdown cooling.
		b) Fails closed	Electrical mal-function, Mechan-ical binding	Isolating of one shutdown cooling Hx during shutdown cooling operation.	Periodic testing, no ΔT indication from TIR3351 or TIR3352.	Redundant shutdown cool-ing train will not be affected.	----
	LPSI/SDC Hx Bypass Flow Control Valve FCV3301 or FCV3306	a) Fails open	Electrical mal-function, Mech-anical binding	Excessive shutdown cooling flow will bypass the SDCS Hx. Inability to increase the cooldown cooling rate in affected train.	Valve position indica-tor, periodic testing, low ΔT indication from TIR3352 or TIR3351	Redundant shutdown cool-ing train will assure shutdown cooling time will be extended.	These valves are locked open during power operation and power to the valve operators are racked out. The valves are manually adjusted.
		b) Fails closed	Electrical mal-function, Mech-anical binding	During early states of shutdown cooling, excessively cooled water would be pumped through one shutdown cooling, train to the reactor core.	Valve position in-dicator, periodic test-ing, abnormal ΔT indication from TIR3351 or TIR3352	Operator can manually operate the associated throttle valve. Redun-dant shutdown cooling train will not be affected.	Operator manually controls these valves during the shutdown cooling mode.
		c) Excessive Seat Leakage	Seat wear or damage	Excessive shutdown cooling flow will bypass the SDCS Hx	Periodic testing, low ΔT indication from TIR3351 or TIR3352	Redundant SDC train will not be affected. Use of injection Header isolation valves for flow control minimizes impact of excessive leakage.	-------

TABLE 5.4-5 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
	SDC Hx Flow Control Valve HCV3512 or HCV3657	a) Fails open	Electrical mal-function, Mech-anical binding	Inability to regulate and main-tain cooldown rate. See 6b.	Valve position indicator in control room, Periodic testing, Ab-normal flow indication from FR3301 or FR3306	Same as 6a.	These valves are locked closed during power operation. These valves are opened by the operator to initiate SDC flow to the Hxs and are manually adjusted by the operator to main-tain cooldown.
		b) Fails closed	Electrical mal-function, Mech-anical binding	Reduction in core cooling capability. Isolation of one shutdown cooling Hx.	Valve position indicator in control room, periodic testing, no delta t indication from TIR3351 or TIR3352	Redundant shutdown cooling train will not be affected.	During the final stages of shut-down cooling, the SDCS bypass val-ves are almost completely closed so that a substantial amount of reactor coolant passes through the shut-down cooling heat exchangers.
	LPSI Valve HCV3615, HCV3625, HCV3635, or HCV3645	a) Fails open	Electrical mal-function, Mech-anical binding	Inability to gradually warm up the associated shutdown cooling line during the shutdown cooling alignment procedure.	Valve position indicator in control room, periodic testing.	Redundant shutdown cooling trains will not be affected.	The safety in-jection piping is designed for a limited number of Thermal cycles such as could result from Operating the Shutdown cooling trains without prior warmup.
		b) Fails closed	Electrical mal-function, Mech-anical binding	Inability to inject cooled reactor coolant into one of the RCS cold legs.	Valve position indicator in control room, periodic testing, no flow indication from testing, no flow F13312, F13322, FI3332, of F13342	Redundant LPSI valve - and shutdown cooling train are not affected.	----

TABLE 5.4-5 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
9.	SIT Isolation Valve V3614, V3624, V3634, or V3644	a) Fails open	Electrical malfunction, Mechanical binding	Inability to isolate one safety injection tank from the RCS during shutdown cooling. Possible inadvertent draining of one SIT.	Valve position indicator in control room, periodic testing.	Reduce pressure in affected tank using vent valves.	During shutdown cooling these valves are closed. However, if a LOCA occurs an SIAS will automatically open these valves. Prior to the actuation of shutdown cooling, the SIT pressure is periodically lowered below the RCS pressure to preclude discharging of their contents. Pressure reduction is achieved by bleeding off nitrogen or draining liquid to RWT.
		b) Fails closed	Electrical malfunction, Mechanical binding	None during shutdown cooling.	Valve position indicator in control room, periodic testing	None required.	
10.	LPSI Suction Isolation Valves V3432 , V3444	a) Fails open	Electrical malfunction, Mechanical binding	Inability to double isolate one LPSI pump suction from the RWT during shutdown cooling operation; loss of one shutdown cooling train.	Periodic testing, position indicator in control room.	Redundant LPSI train is unaffected	These valves are normally locked open and are closed just prior to initiation of shutdown cooling. Valves are opened from the control room.
		b) Fails closed	Electrical malfunction, Mechanical malfunction	None during shutdown cooling.	Periodic testing position indicator in control room.	None required	These valves are required to be closed during shutdown cooling operation. Valves are opened from the control room.
11.	SDCS Cross Connect Valve V3545	a) Fails open	Electrical malfunction, Mechanical binding	None during system operation.	Periodic testing, position indicator in control room	None required	This valve is required to be open when both SDC trains are in operation.
		b) Fails closed	Electrical malfunction, Mechanical binding	Inability to establish a crossover flow path between the SDCS trains (inside containment).	Periodic testing, position indicator in control room	The valve is capable of being powered from either diesel generator.	This valve is an FAI and locked open in the control room during power operation. This valve assures operation of at least one SDCS train if one emergency diesel generator fails.

TABLE 5.4-5 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
12.	SDCS Warmup Valve V3536 or V3539	a) Fails open	Electrical malfunction, Mechanical binding	Diversion of some flow from the discharge leg to the suction leg of one SDCS train without passing through the reactor core during shutdown cooling.	Position indicator in control room Periodic testing	The redundant shutdown cooling train will not be affected.	If this valve fails open, there will be a minimal effect on the shutdown cooling time.
		b) Fails closed	Electrical malfunction, Mechanical binding	Inability to gradually warm LPSI pump, SDCHX, and shut-down cooling piping (one train) during the shutdown cooling alignment process.	Periodic testing, position indicator in control room	Redundant shutdown cooling train will not be affected	Gradual warming of the shutdown cooling trains minimize thermal shock at initiation of shutdown cooling. These valves are gradually closed once warm up and flow rate stability have been achieved.
13.	SDCS Suction Isolation Valve (outside containment) V3664 or V3665	a) Fails open	Electrical malfunction, Mechanical binding	No effect on normal or emer-gency SDCS operation.	Periodic testing	None required	
		b) Fails closed	Electrical malfunction, Mechanical binding	Inability to align one shut-down cooling train for shut-down cooling operation.	Periodic testing	Redundant shutdown cooling train will not affected	These valves are FAI and locked closed in the control room during operation.

* The method of Detection column is used to show that it is possible to detect the failure during or before Shutdown Cooling System Operation.

TABLE 5.4-8

PRESSURIZER SAFETY VALVE PARAMETERS

Property	Parameter
Design Pressure, psia	2500
Design Temperature, °F	700
Fluid	Saturated steam, 2000 ppm H_3BO_3, pH=5.0
Set Pressure, psia	2500 $\pm$ 1% (Note 1)
Minimum Capacity, lb/hr at 3% accumulation	200,000
Orifice Area, square inches	1.838
Accumulation, %	3
Backpressure	
Max buildup/max superimposed, psig	500/300
Approx. Dry Weight, pounds	792
Minimum Blowdown Pressure, psia	2125
Materials	
Body	ASME SA 182 GRF316, ASTM A351, GR. CF8M OR EQUIVALENT
Disc Insert	ASTM A637 GR 718
Nozzle	ASME SA 182 GR F316
Bonnet	ASME SA 105
Spring	ASTM A689
Code	ASME Section III, Class 1, 1974 Edition

Note 1: As -found setpoint is 2500 psia +/-2% for operability. Values are reset to 2500 psia +/-1% during surveillance to allow for drift.

TABLE 5.4-6

PRESSURIZER PARAMETERS

Property	Parameter
Design pressure, psia	2500
Design temperature, °F	700
Normal operating pressure, psia	2250
Normal operating temperature, °F	653
Internal free volume, minimum, ft^3	1500
Normal (full power) operating water volume, ft^3	800
Minimum (zero to 15% power) operating water volume, ft	450
Spray flow, maximum, gpm	450
Spray flow, continuous, gpm	1.5
Heater type	Immersion
Heater capacity total, kW	1500*
Proportional, kW	300*
Backup, kW	1200*

* Operation with a reduced pressurizer heater capacity of 700 kW is acceptable. This permits up to 16 pressurizer heaters, a total of 800 kW, to be removed from service, as described below:

One proportional pressurizer heater (50 kw), and;

Fifteen backup pressurizer heaters (750 kW). Diesel backed heater banks should be maintained at full capacity to provide margin over the Technical Specification heater requirement of 150 kW.

Heaters available from backup banks (non diesel backed) can be utilized to replace heaters removed from service from the proportional heater banks and diesel backed banks.

TABLE 5.4-7

QUENCH TANK PARAMETERS

Design Pressure (Int./Ext.)	100/15 psig
Design Temperature	350 F
Normal Operating Pressure	3 psig
Normal Operating Temperature	120 F
Internal Volume	209 ft^3
Normal Water Volume	127 ft^3
Normal Gas Volume	82 ft^3
Blanket Gas	Nitrogen
Nozzles	
Pressurizer line inlet, (1)	10 inches, sch 40
Demineralized water inlet, (1)	2 inches
Manway and rupture disc, (1)	18 inches
Vent/relief, (1)	1.5 inches
Drain (1)	2 inches
Temperature instrument, (1)	1 inch
Level instrument (2)	1 inch
Rupture Disc Set Pressure @ 350 F	85 psig @ 350 F
Relief Valve	
Set pressure	70 psig
Accumulation, % of set pressure	10%
Blowdown, % of set pressure	10%
Capacity	500 scfm
Vessel Material	ASME-SA-240-Tp-304
Code	ASME Section III, Class 3 1974 Edition

TABLE 5.4-9

POWER OPERATED RELIEF VALVE PARAMETERS

(Valves 1474 and 1475)

I. Operational Requirements	Normal Service	LTOP Service
Fluid	Saturated Steam*	Water*
Operating Pressure, psia	2250	300
Operating Temperature, °F	653	417
Set Pressure, psia	2370	490 (see Note 1)
Backpressure, Buildup, psia	500	150
Minimum Capacity @ Set Pressure	153,000 lb/hr	1420 gpm (see Notes 1 & 2)

*Service: Pressurizer pressure relief of saturated steam and water with 2000 ppm H_3BO_3 pH 5.

II. Design Requirements		
Design Pressure, psia	2500	
Design Temperature, °F	675	
Valve Type	Solenoid Operated Relief Valve	
Seismic Class	I	
Quality Group	A	
Code	ASME Section III	(refer to Table 5.2-1 for code date)
Active	Yes	
Inlet Line Size, Inches	3	
Outlet Line Size, Inches	8	
Body Material	ASME SA 182, Grade F 316	
Failure Position	Fail close on loss of Electrical Power	

TABLE 5.4-9 (Cont'd)

Safety Related Function	Open/Close
Solenoid Voltage Requirement	90-140 V D.C.

Notes:

1. Valve capacity corresponds to a nominal setpoint of 465 psia.

2. The valve manufacturer demonstrates via a combination of testing and analysis that the saturated steam and water flow capacity requirements are met.

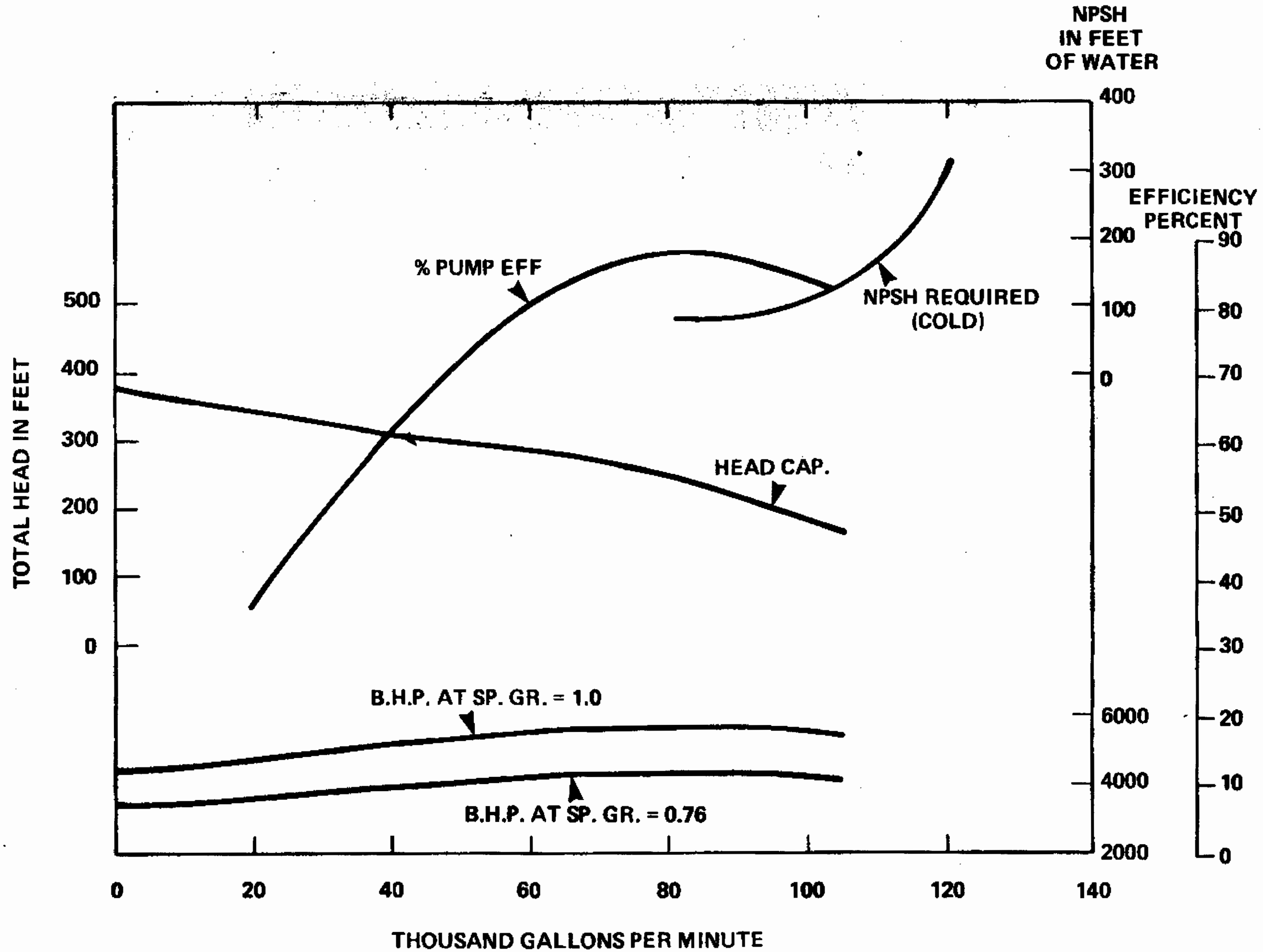
Refer to Drawing
2998-455

Amendment No. 18 (08/08)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

SECTIONAL ASSY REACTOR PRIMARY COOLANT PUMPS

FIGURE 5.4-1



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

REACTOR COOLANT PUMP
PERFORMANCE
FIGURE 5.4-2

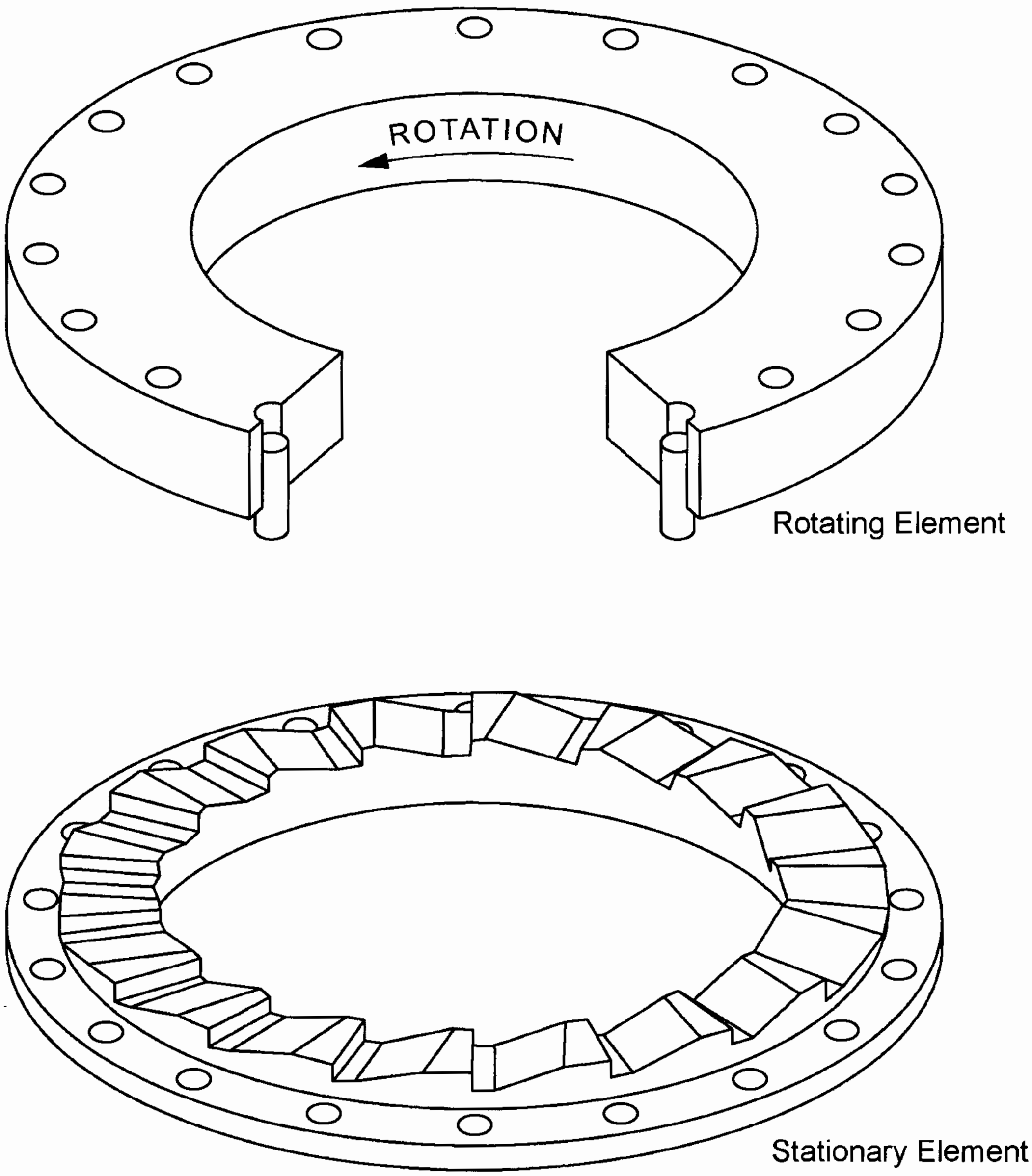
Refer to Drawing
2998-19778

Amendment No. 18 (01/08)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

REACTOR COOLANT PUMP SHAFT
SEAL ARRANGEMENT N-9000 SEAL

FIGURE 5.4-3

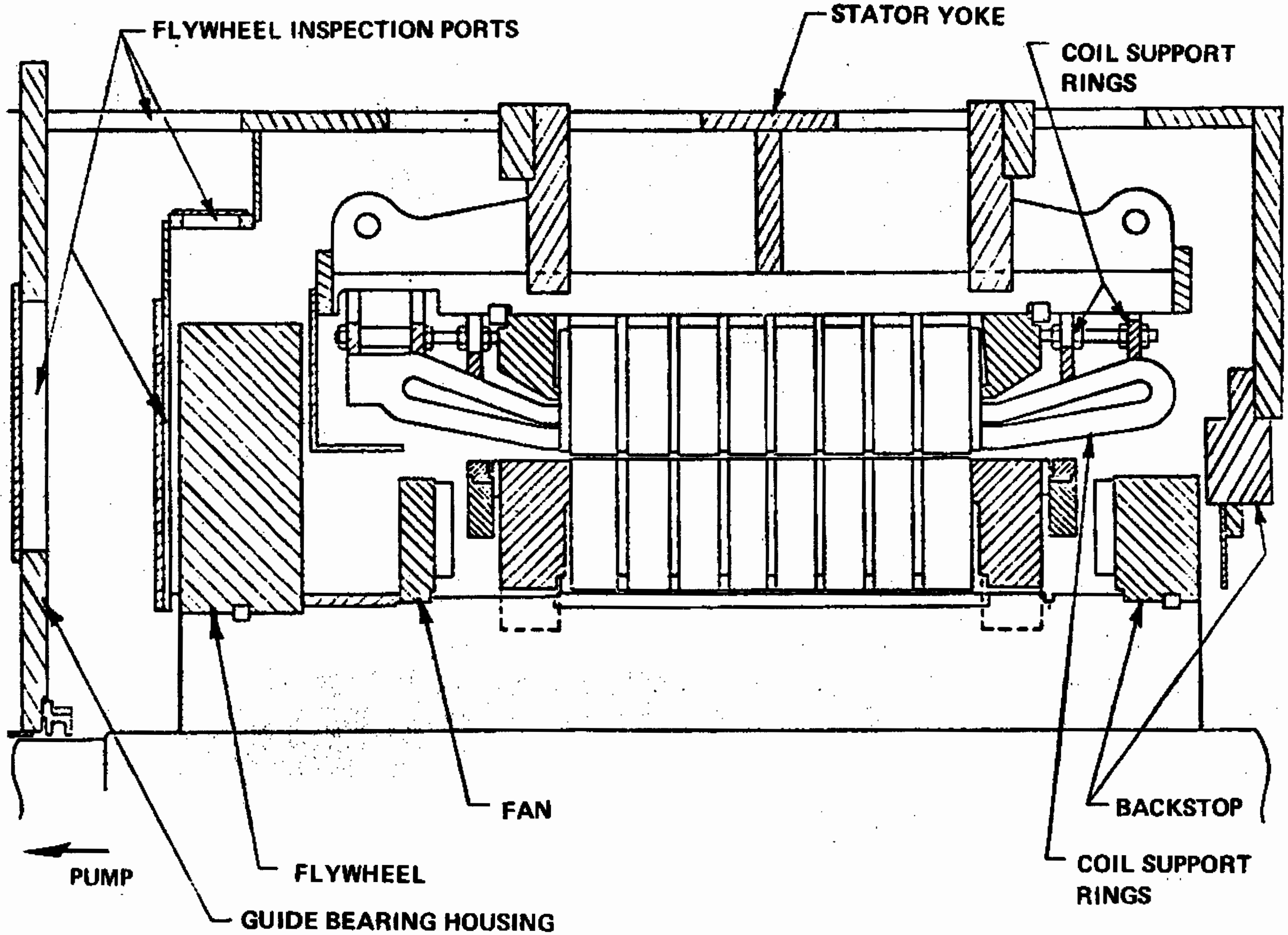


Amendment No. 18 (01/08)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ANTIROTATIONAL DEVICE

FIGURE 5.4-4



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MOTOR FLYWHEEL ASSEMBLY

FIGURE 5.4-5

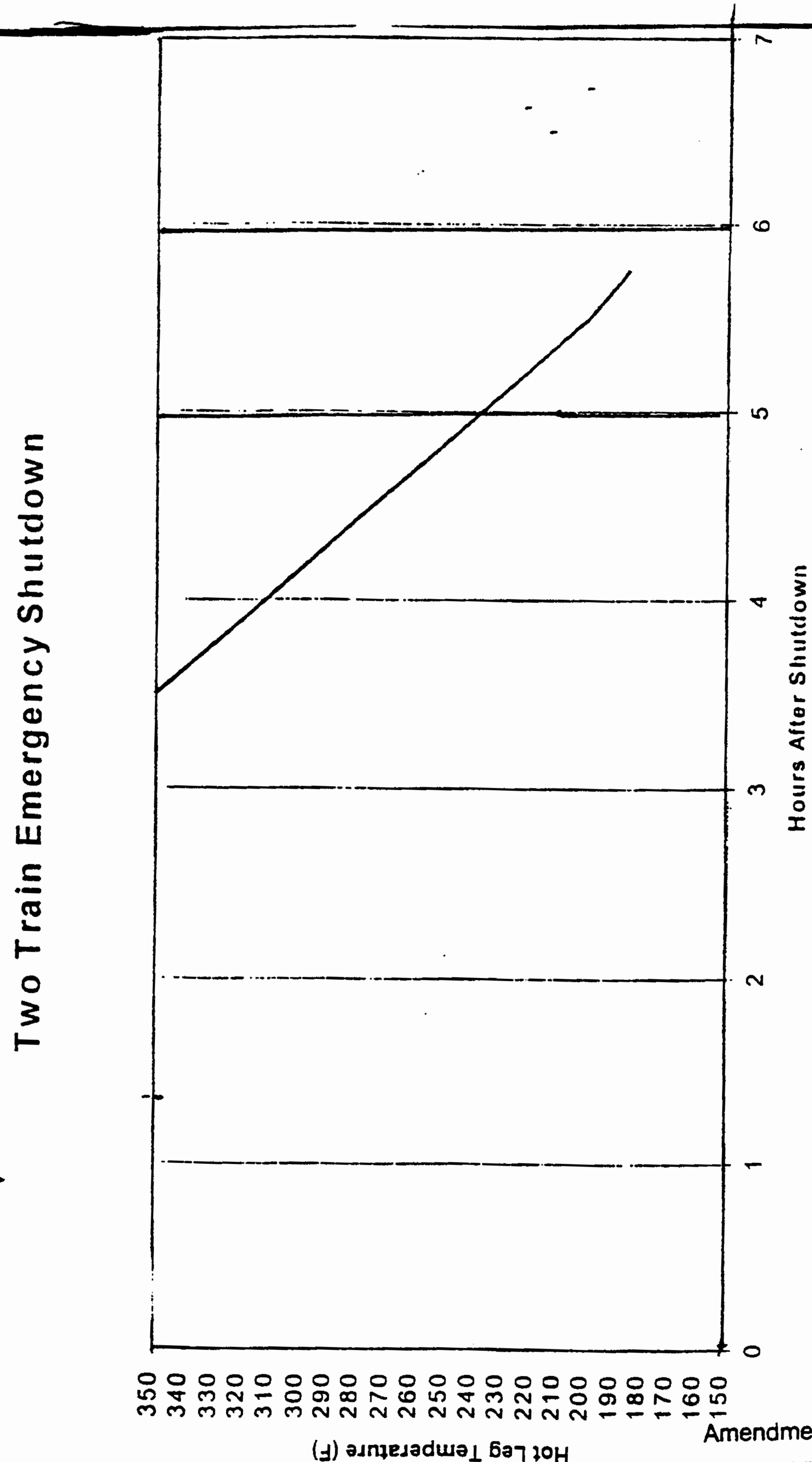
Refer to Drawing
2998-205

Amendment No. 18 (01/08)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

STEAM GENERATOR
ELEVATION

FIGURE 5.4-6

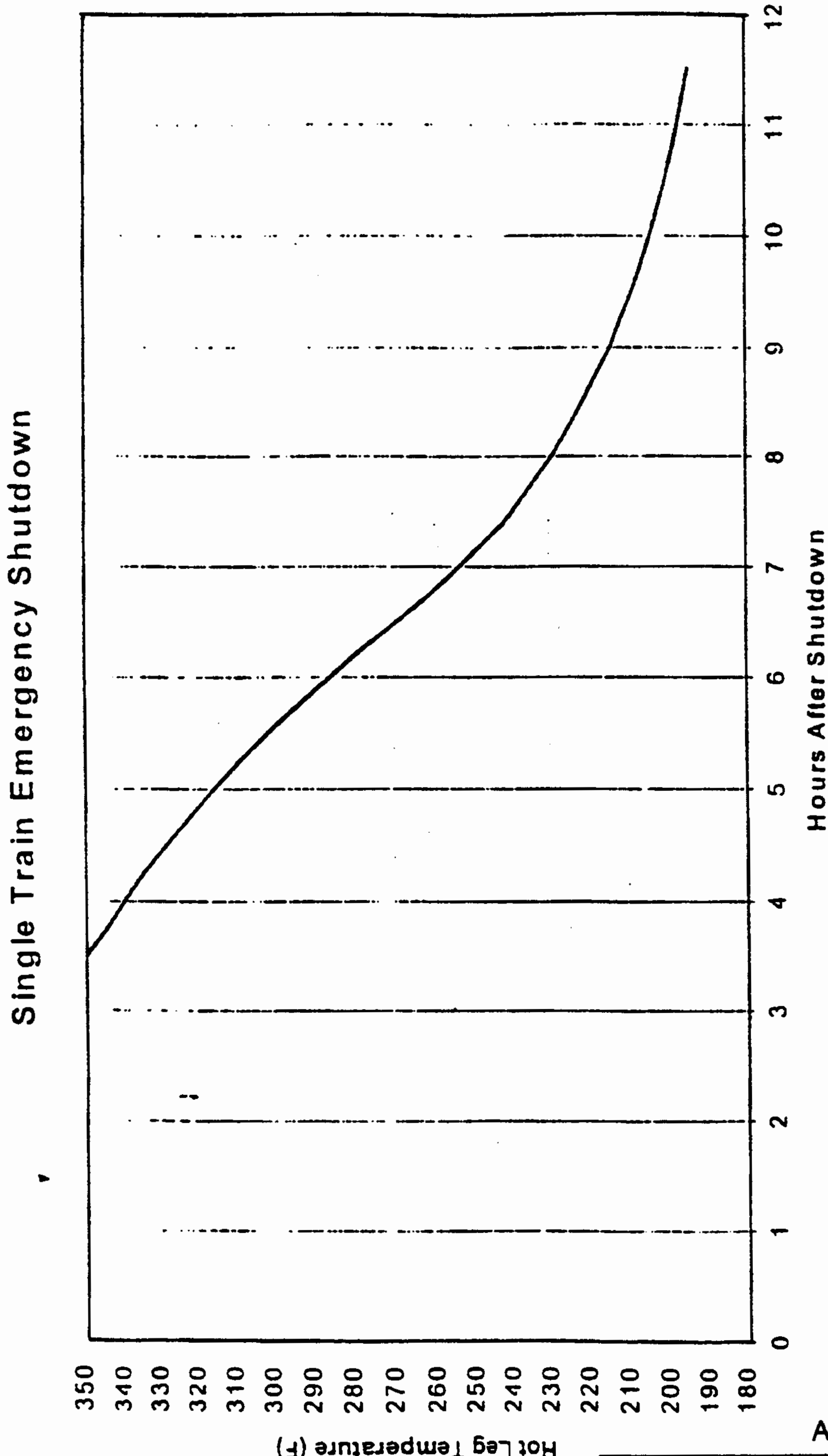


Amendment No. 13 (05/00)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

TWO TRAIN COOLDOWN
FROM 300 F

FIGURE 5.4-7

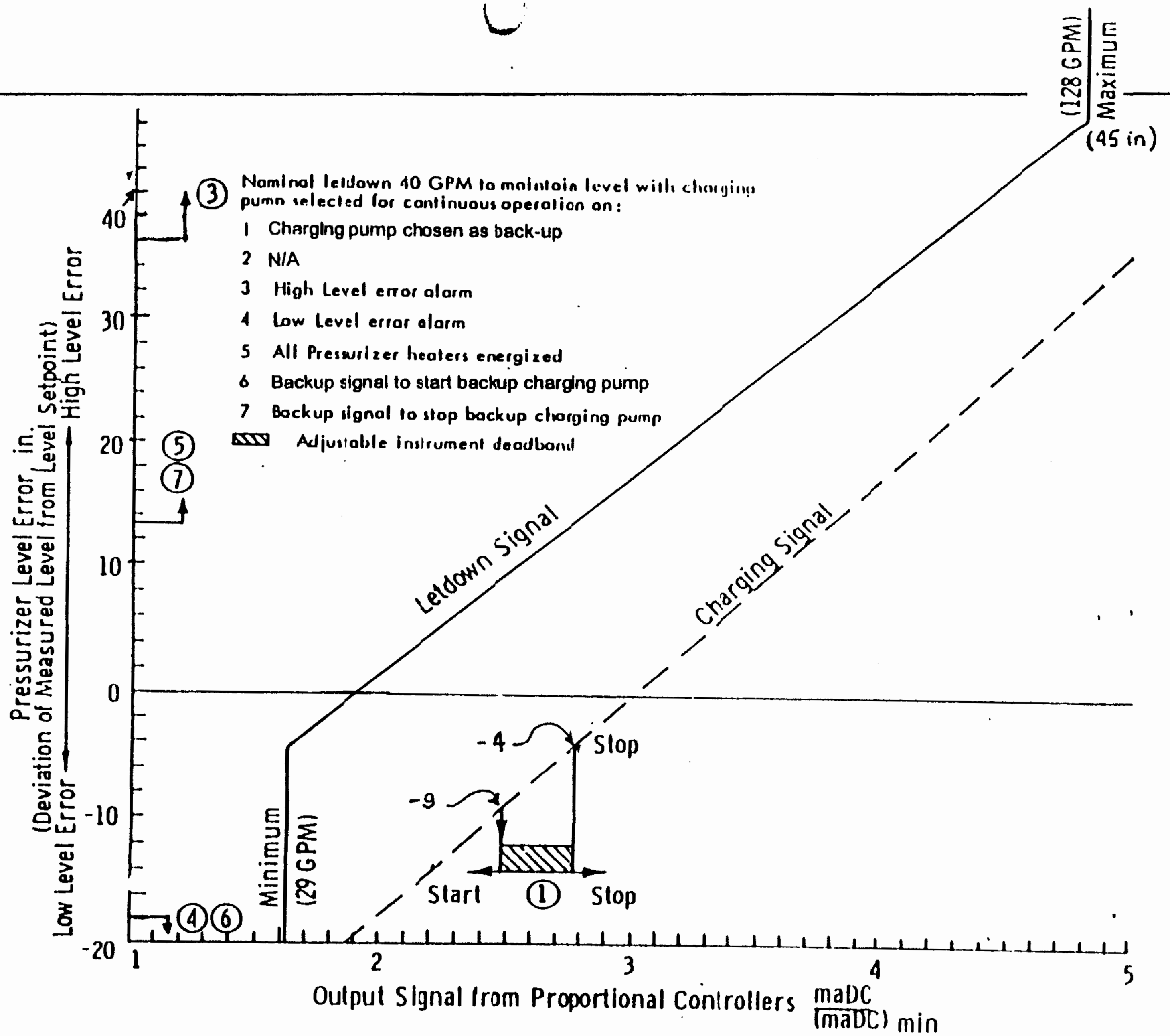


Amendment No. 13, (05/00)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ONE TRAIN COOLDOWN
FROM 350 F

FIGURE 5.4-8

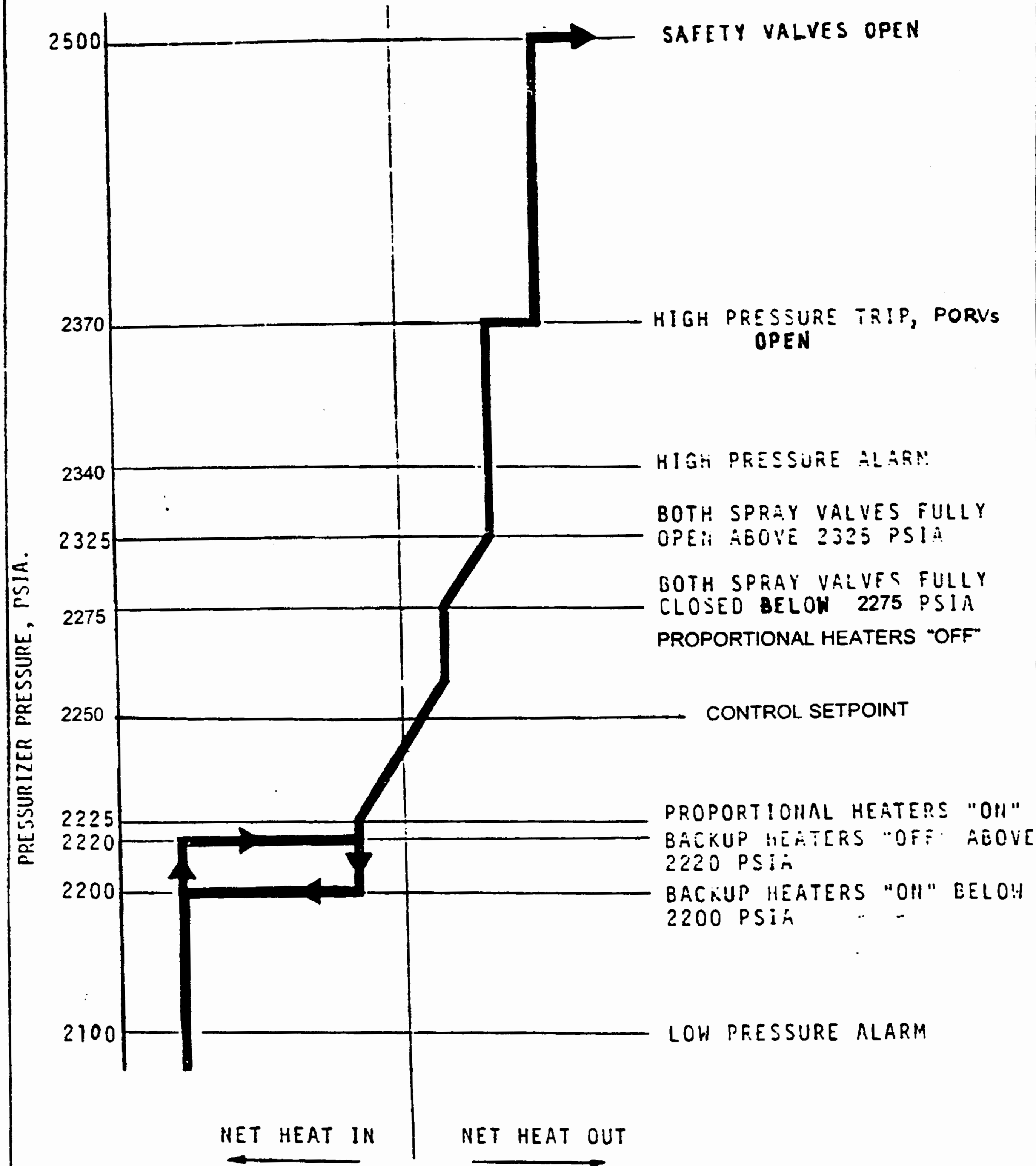


Amendment No. 14 (12/01)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PRESSURIZER LEVEL CONTROL PROGRAM

FIGURE 5.4-11

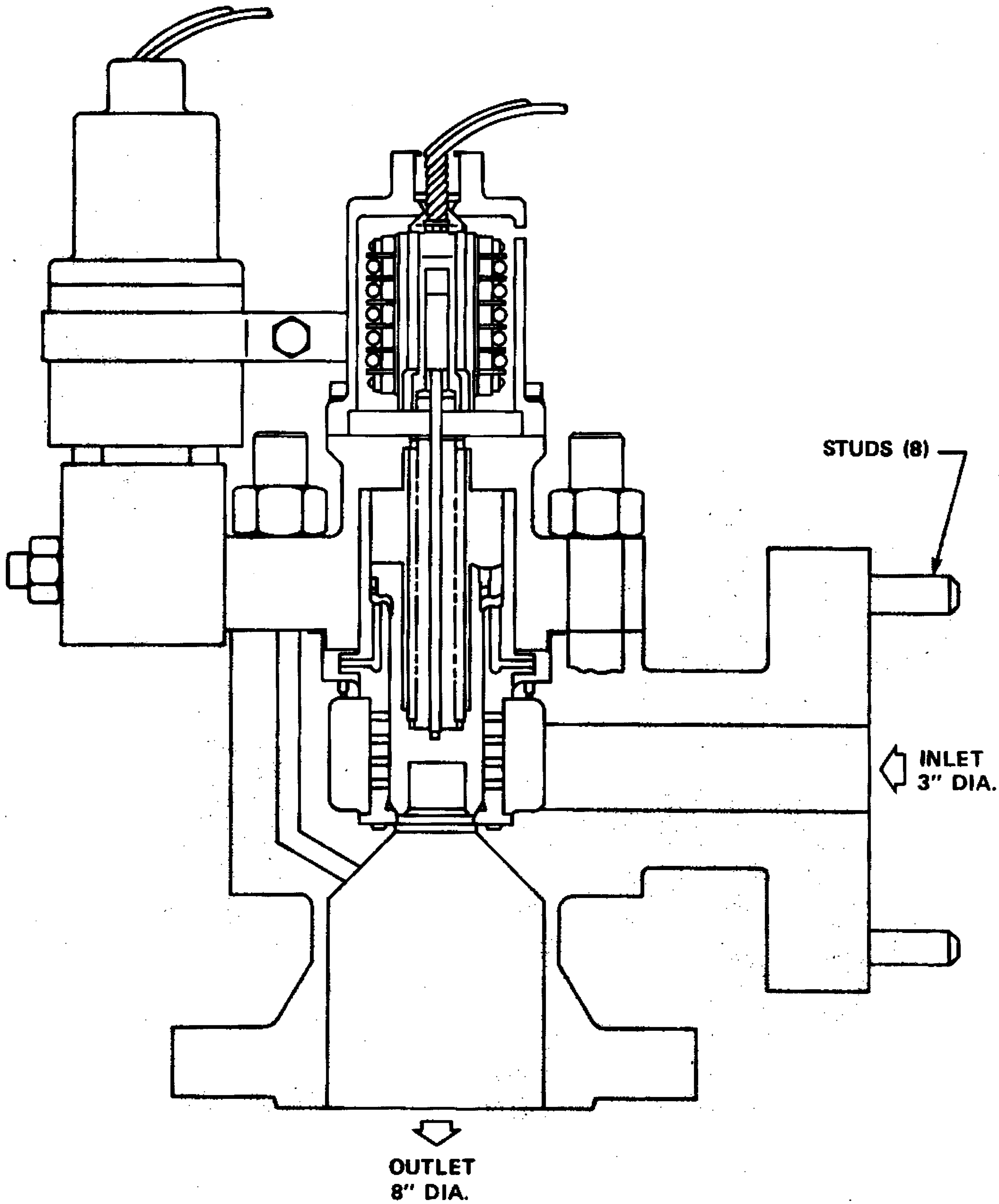


Amendment No. 13, (05/00)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

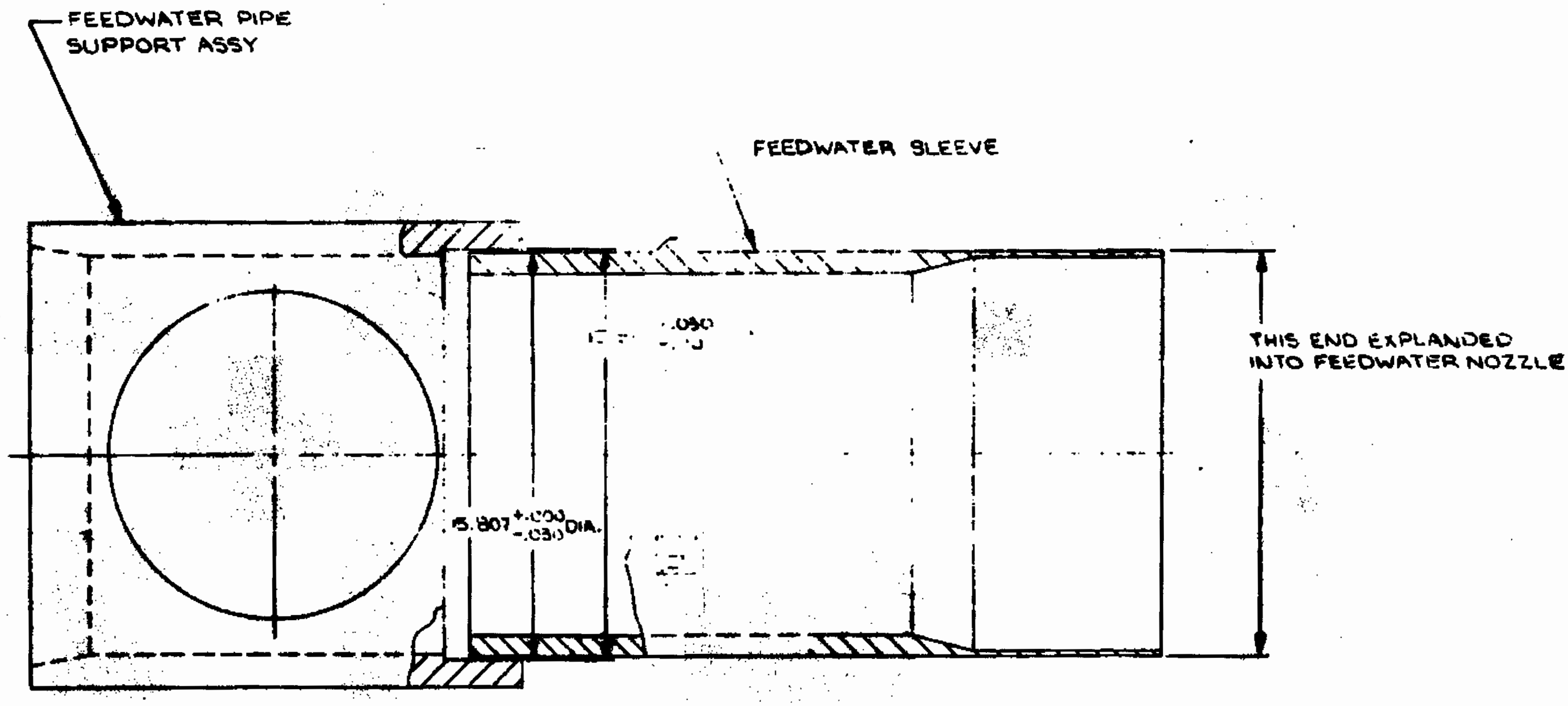
PRESSURIZER PRESSURE CONTROL PROGRAM

FIGURE 5.4-12



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

POWER OPERATED RELIEF VALVE
FIGURE 5.4-15

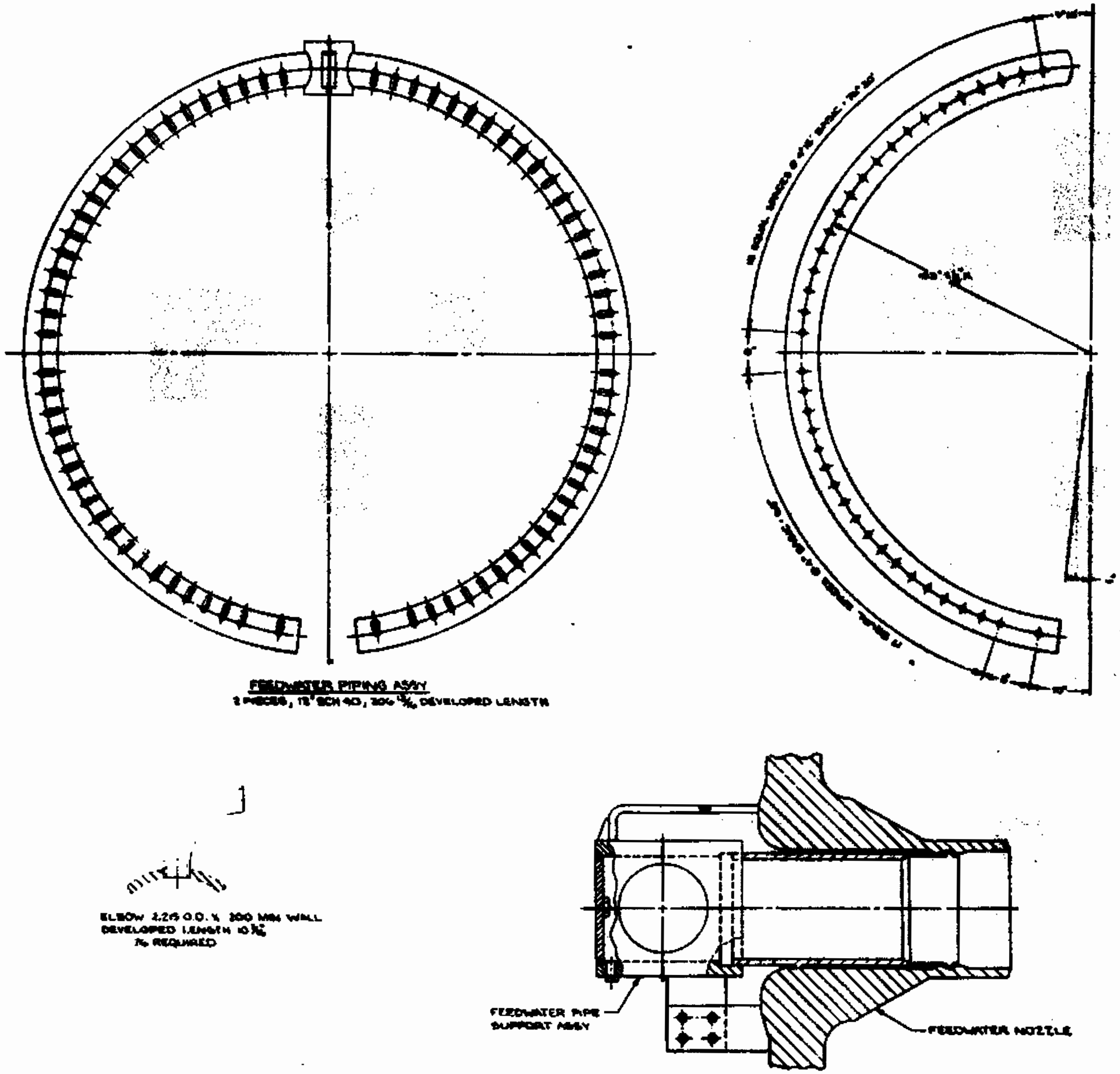


LEAK PATH-FEEDWATER PIPE SUPPORT ASSY/FEEDWATER NOZZLE SLEEVE

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

STEAM GENERATOR
FEEDWATER SPARGER
SHEET 1

FIGURE 5.4-16



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

STEAM GENERATOR
FEEDWATER SPARGER
SHEET 2

FIGURE 5.4-17