Entergy

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December 12, 2013

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
Docket No.: 50-293
License No.: DPR-35

FSAR Update Revision 29, Technical Specifications Bases Changes, 10 CFR 50.59(d) Report, and Regulatory Commitment Changes

LETTER NUMBER: 2.13.085

This letter submits Final Safety Analysis Report (FSAR) Revision 29 update pages for Pilgrim Nuclear Power Station. This update is submitted in accordance with 10 CFR 50.71(e) requirements and includes changes implemented during Fuel Cycle 19, ending with refueling outage 19 as contained in Attachments 1 & 2.

Additionally, a description of a new and subsequently revised 10 CFR 50.59 Safety Evaluation performed during Fuel Cycle 19 is summarized in Attachment 3. There were no Regulatory Commitment changes or Technical Specification (TS) Bases changes performed during Fuel Cycle 19.

There are no new regulatory commitments contained in this letter.

If you have any questions regarding the information contained in this letter, please contact Joseph R. Lynch, Licensing Manager at (508) 830-8403.

I declare under penalty of perjury that the foregoing is true and correct; executed on December 12, 2013.

Sincerely,

John A. Dent Jr.
Site Vice President

JAD/rmb

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NRR

Attachment 1: Filing Instructions for FSAR Revision 29, Change-out pages (7 Pages)
Attachment 2: FSAR Revision 29 Change-out pages (See Filing Instructions)
Attachment 3: Description of 10 CFR 50.59(d) Evaluation (3 Pages)

cc:

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ATTACHMENT 1

Filing Instructions for FSAR Revision 29, Change-out pages

(7 Pages)

Filing Instructions

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ATTACHMENT 2

FSAR Revision 29 Change-out pages

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1.2 DEFINITIONS

The following definitions apply to the terms used in the Safety Analysis Report.

1. Radioactive Material Barrier - A radioactive material barrier includes the systems, structures, or equipment that together physically prevent the uncontrolled release of radioactive materials. The barriers are identified as follows:

   a. Reactor Fuel Barrier - Uranium dioxide sealed in metal cladding

   b. Nuclear System Process Barrier - The systems of vessels, pipes, pumps, tubes, and similar process equipment that contain the steam, water, gases, and radioactive materials coming from, going to, or in communication with the reactor core. The actual boundaries of the nuclear system process barrier depend upon the status of plant operation

      For example, process system isolation valves, when closed, form part of the barrier. The steam jet ejector offgas path forms a planned process opening in the barrier during power operation

      Because the nuclear system process barrier is designed to be divided by isolation valve action into two major sections under certain conditions, this barrier is considered in two parts as follows:

      (1) Nuclear System Primary Barrier - The reactor vessel and attached piping out to and including the second isolation valve in each attached pipe. In various codes and standards used in the industry, this barrier is sometimes referred to as the "primary system pressure boundary"

      (2) Nuclear System Secondary Barrier - That portion of the nuclear system process barrier not included in the nuclear system primary barrier

c. Primary Containment - The drywell in which the reactor vessel is located, the pressure suppression chamber, and process lines out to the first isolation valve outside the containment wall. Portions of the nuclear system process barrier may become part of the primary containment, depending upon the location of a postulated failure. For example, a closed main steam line isolation valve is part of the primary containment barrier when the postulated failure of the main steam line is inside the primary containment.

d. Secondary Containment - The Reactor Building, which completely encloses the primary containment, the Standby Gas Treatment System, and the main stack, constitute this barrier

2. Radioactive Material Barrier Damage - Radioactive material barrier damage is defined as an unplanned, undesirable breach in a barrier, except that the operation of a relief or safety valve does not constitute barrier damage.

3. Nuclear System - The nuclear system generally includes those systems most closely associated with the reactor vessel which are designed to contain, or be in communication with the water and steam coming from or going to the reactor core. The nuclear system includes the following:

   Reactor vessel
   Reactor vessel internals
   Reactor core
   Main steam lines from reactor vessel to the isolation valves outside the primary containment
   Neutron Monitoring System
   Reactor Recirculation System
   Control Rod Drive System
   Residual Heat Removal System
   Reactor Core Isolation Cooling System
   Core Standby Cooling Systems
   Reactor Water Cleanup System
   Feedwater System piping between the reactor vessel and the first valve outside the primary containment safety and relief valve system

4. The word safety, when used to modify such words as objective, design basis, action, and system, indicates that the objective, design basis, action, or system is related to concerns considered to be of primary safety significance, as opposed to the plant mission - to generate electrical power. Thus, the word safety is used to identify aspects of the station which are considered to be of primary importance with respect to safety.

5. Power Generation - The phrase power generation, when used to modify such words as objective, design basis, action and system, indicates that the objective, design basis, action, or system is related to the mission of the station - to generate electrical power - as opposed to concerns considered to be of primary safety importance. Thus, the phrase power generation is used to identify aspects of the station which are not considered to be of primary importance with respect to safety.

6. Operational - The objective operational, along with its noun and verb forms, is used in reference to the working or functioning of the station, in contrast to the design of the station.

7. Scram - Scram refers to the automatic rapid insertion of control rods in response to the detection of undesirable conditions.

8. Safety Limit - A safety limit is an established limit above normal operational limits on the value of a nuclear system process or analytical variable, or an established limit specifying an allowable degree of barrier damage.

9. Planned Operation - Planned operation is normal station operation under planned conditions in absence of significant abnormalities. Operations subsequent to an incident (transient, accident, or special event), are not considered planned operations until the actions taken in the station are identical to those which would be used had the incident not occurred. The established planned operations can be considered as a chronological sequence:

   refueling outage -->achieving criticality -->heatup --> power operation -->achieving shutdown --> cooldown -->refueling outage.

   The following planned operations are identified:

   a. Refueling Outage - Refueling outage included all of the planned operations associated with a normal refueling outage:

      (1) Planned, physical movement of core components (fuel, control rods, etc.)

      (2) Refueling test operations

      (3) Planned maintenance

b. Achieving Criticality - Achieving criticality includes all the actions which are normally accomplished in bringing the station from a condition in which all control rods are fully inserted to a condition in which nuclear criticality is achieved and maintained

c. Heatup - Heatup begins where achieving criticality ends and includes all actions which are normally accomplished in approaching nuclear system rated temperature and pressure by using nuclear power (reactor critical). Heatup extends through warmup and synchronization of the turbine-generator

d. Power Operation - Power operation begins where heatup ends and includes continued operation of the station at power levels in excess of heatup power

e. Achieving Shutdown - Achieving shutdown begins where power operation ends and includes all actions normally accomplished in achieving nuclear shutdown (more than one rod subcritical) following power operation

f. Cooldown - Cooldown begins where achieving shutdown ends and includes all actions normally accomplished in the continued removal of decay heat and the reduction nuclear system temperature and pressure

10. Incident - An incident is any event - abnormal operational transient, or accident - not considered as part of planned operation.

11. Abnormal Operational Transient - An abnormal operational transient includes the events following a single equipment malfunction or a single operator error that is reasonably expected during the course of planned operations. Power failures, pump trips, and rod withdrawal errors are typical of the single malfunctions or errors initiating the events in this category.

12. Abnormal Occurrence - Abnormal occurrence refers to the occurrence of any station condition that:

a. Exceeds a Limiting Safety System Setting as established in the Technical Specifications

b. Violates a Limiting Condition for Operation as established in the Technical Specifications

c. Causes any abnormal operational transient

d. Causes any uncontrolled or unplanned release of radioactive material from the site

13. Accident - An accident is a single event, not reasonably expected during the course of station operations, that has been hypothesized for analysis purposes or postulated from unlikely but possible situations, and that causes or threatens a rupture of a radioactive material barrier. A pipe rupture qualifies as an accident; a fuel cladding defect does not.

14. Design Basis Accident - A design basis accident is a hypothesized accident the characteristics and consequences of which are utilized in the design of those systems and components pertinent to the preservation of radioactive material barriers, and the restriction of radioactive material release from the barriers. The potential radiation exposures resulting from a design basis accident are greater than any similar accident postulated from the same general accident assumptions.

15. Special Event - A special event is an event which neither qualifies as an abnormal operational transient nor an accident but which is postulated to demonstrate some special capability of the system or its systems.

16. Safety Action - A safety action is an ultimate action in the station which is essential to the avoidance of specified conditions considered to be of primary safety significance. The specified conditions are those that are most directly related to the ultimate limits on the integrity of the radioactive material barriers or the release of radioactive material. There are safety actions associated with planned operation, abnormal operational transients, accidents, and special events. Safety actions include such actions as the indication to the operator of the values of certain process variables, reactor scram, core standby cooling, and reactor shutdown from outside the control room. See Figures 1.2-1 through 1.2-3 and Table 1.2-1.

17. Power Generation Action - A power generation action is an action in the station which is essential to the avoidance of specified conditions considered to be of primary significance to the station mission - the generation of electrical power. The specified conditions are those that are most directly related to the following:

    a. The ability to carry out the station mission - the generation of electrical power - through planned operation

    b. The avoidance of conditions which would limit the ability of the station to generate electrical power

c. The avoidance of conditions which would prevent or hinder the return to conditions permitting the use of the station to generate electrical power following an abnormal operational transient, accident, or special event. There are power generation actions associated with planned operation, abnormal operational transients, accidents, and special events. See Figure 1.2-3.

18. Protective Action - A protective action is an ultimate action at the system level which contributes to and is essential to the accomplishment of a safety action. System level actions which are essential to accomplishing reactor scram, reactor vessel isolation, containment isolation, pressure relief, automatic depressurization, and core standby cooling are some of the protective actions. See Figures 1.2-1, 1.2-2, and 1.2-3

19. Protective Function - A protective function encompasses the monitoring of one or more station variables or conditions and the associated initiation of intra system actions which eventually result in protective action. See Figure 1.2-2.

20. Safety System - A safety system is any system, group of systems, component, or group of components, the actions of which are essential to accomplishing a safety action. See Figure 1.2-3 and Table 1.2-1.

21. Process Safety System - A process safety system is a safety system the actions of which are essential to a safety action required during planned operation. See Figure 1.2-3 and Table 1.2-1.

22. Nuclear Safety System - A nuclear safety system is a safety system the actions of which are essential to a safety action required in response to an abnormal operational transient. See Figure 1.2-3 and Table 1.2-1.

23. Engineered Safeguard - An engineered safeguard is a safety system the actions of which are essential to a safety action required in response to accidents. See Figure 1.2-3 and Table 1.2-1.

24. Protection System - Protection system is a generic term which may be applied to nuclear safety systems and engineered safeguards. See Figure 1.2-3 and Table 1.2-1.

25. Special Safety System - A special safety system is a safety system the actions of which are essential to a safety action required in response to a special event. See Figure 1.2-3 and Table 1.2-1.

26. Power Generation System - A power generation system is any system the actions of which are not essential to a safety action, but which are essential to a power generation action. Power generation systems are provided for any of the following purposes:

    a. To carry out the mission of the station - generate electrical power - through planned operation

    b. To avoid conditions which would limit the ability of the station to generate electrical power

    c. To facilitate and expedite the return to conditions permitting the use of the station to generate electrical power following an abnormal operational transient, accident, or special event. See Figure 1.2-3 and Table 1.2-1

27. Safety Objective - A safety objective describes in functional terms the purpose of a system or component as it relates to conditions considered to be of primary significance to the protection of the public. This relationship is stated in terms of radioactive material barriers or radioactive material release. The only systems which have safety objectives are safety systems. See Figure 1.2-3.

28. Power Generation Objective - A power generation objective describes in functional terms the purpose of a system or component as it relates to the mission of the station. This includes objectives which are specifically established so the station can fulfill the following purposes:

    a. The generation of electrical power through planned operation

    b. The avoidance of conditions which would limit the ability of the station to generate electrical power

    c. The avoidance of conditions which would prevent or hinder the return to conditions permitting the use of the station to generate electrical power following an abnormal operational transient, accident, or special event. See Figure 1.2-2

    A system or piece of equipment has a power generation objective if it is a power generation system. A safety system can have a power generation objective, in addition to a safety objective, if parts of the system are intended to function for power generation purposes.

29. Analytical Objective - An analytical objective describes the purpose or intent of a portion of the Safety Analysis Report presenting an analysis.

30. Safety Design Basis - The safety design basis for a safety system states in functional terms the unique design requirements which establish the limits within which the safety objective shall be met. A power generation system may have a safety design basis which states in functional terms the unique design requirements that ensure that neither planned operation nor operational failure by the system results in conditions for which station safety actions would be inadequate.

31. Power Generation Design Basis - The power generation design basis for a power generation system states in functional terms the unique design requirements which establish the limits within which the power generation objective shall be met.

    A safety system may have a power generation design basis which states in functional terms the unique design requirements which establish the limits within which the power generation objective for the system shall be met.

32. Safety Evaluation - An evaluation of a change in the design or operation of systems, structures, and components to determine if an unreviewed safety question will result, specifically to determine if:

    a. The probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the Final Safety Analysis Report may be increased; or

    b. The possibility for an accident or malfunction of a different type than any evaluated previously in the Final Safety Analysis Report may be created; or

    c. The margin of safety as defined in the basis for any Technical Specification is reduced.

33. Power Generation Evaluation - A power generation evaluation is an evaluation which shows how the system satisfies some or all of the power generation design bases. Because power generation evaluations are not directly pertinent to public safety, they are generally not included. However, where a system or component has both safety and power generation objectives, a power generation evaluation can be used to clarify the safety versus power generation capabilities.

34. Operational Nuclear Safety Requirements - An operational nuclear safety requirement is a limitation or restriction on either the value of a process variable or the operability of a station system. Such operational nuclear safety requirements must be observed in the operation (not necessarily at power) of the station to satisfy specified operational nuclear safety criteria. The aggregate of all operational nuclear safety requirements defines an operational framework within which actual station operations must remain.

35. Operational Nuclear Safety Criteria - A set of standards which are used to select operational nuclear safety requirements.

36. Design Power - The stated design power in megawatts thermal is the result of a heat balance for a particular plant design. For the Pilgrim Nuclear Station, design power is 1,998 MWt.

37. Single Failure - A single failure is a failure that can be ascribed to a single causal event. Single failures of active components are considered in the design of certain systems, and are presumed in the evaluations of incidents to investigate the ability of the station to respond in the required manner under degraded conditions.

38. Operable, Operability - A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified functions(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal or emergency electrical power sources, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s).

39. Operating - Operating means that a system or component is operating when it is performing its intended function in its required manner.

40. Shutdown - The reactor is shut down when the effective multiplication factor (K_{eff}) is sufficiently less than 1.0, that the full withdrawal of any one control rod could not produce criticality.

41. Shutdown Mode - The reactor is in the shutdown mode when the reactor is shut down, the reactor mode switch is in the shutdown mode position, and all operable control rods are fully inserted.

42. Cold Shutdown Condition - The reactor is in the cold shutdown condition when the reactor is in the shutdown mode, the reactor coolant is maintained at less than 212°F, and the reactor vessel is vented to the atmosphere.

43. Place in Shutdown Mode - Place in the shutdown mode means conduct an uninterrupted normal station shutdown operation until the shutdown mode is attained.

44. Place in the Cold Shutdown Condition - Place in the cold shutdown condition means conduct an uninterrupted normal station shutdown operation until the cold shutdown condition is attained.

45. Refuel Mode - The reactor is in the refuel mode whenever the reactor mode switch is in the refuel mode position.

46. Startup Mode - The reactor is in the startup mode whenever the reactor mode switch is in the startup mode position.

47. Run Mode - The reactor is in the run mode whenever the reactor mode switch is in the run mode position.

48. Place in Isolated Condition- Place in isolated condition means conduct an uninterrupted normal isolation of the reactor from the main (turbine) condenser including the closure of the main steam line isolation valves.

49. Primary Containment Integrity - Primary containment integrity means that the drywell and suppression chamber are intact and all of the following conditions are satisfied:

    a. All manual containment isolation valves on lines connected to the reactor coolant system or containment which are not required to be open during plant accident conditions are closed.

    b. At least one door in the airlock is closed and sealed.

    c. All automatic primary containment isolation valves and all instrument line flow check valves are operable or at least one containment isolation valve in each line having an inoperable valve shall be deactivated in the isolated position.

    d. All containment isolation check valves are operable or at least one containment valve in each line having an inoperable valve is secured in the isolated position.

50. Secondary Containment Integrity - Secondary containment integrity means that the reactor building is intact and the following conditions are met:

    a. At least one door in each access opening is closed

    b. The standby gas treatment system is operable

c. All automatic ventilation system isolation valves are operable or secured in the isolated position

51. Core Fuel to Water Total Power - The core fuel to water total power is the sum of (a) the instantaneous integral, over the entire fuel clad outer surface, of the product of heat transfer area increment and position dependent heat flux, and (b) the instantaneous rate of energy deposition by neutron and gamma reactions in all the water and core components except fuel rods in the cylindrical volume defined by the active core height, and the inner surface of the core shroud.

52. Refueling Outage (as applicable to surveillance frequency requirements) - For the purpose of designating frequency of testing and surveillance, a refueling outage shall mean a regularly scheduled refueling outage.

53. Core Alteration - Core Alteration shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed, and fuel in the vessel. The following exceptions are not considered to be Core Alterations:

    a. Movement of source range monitors, local power range monitors, intermediate range monitors, traversing incore probes, or special movable detectors (including undervessel replacement); and

    b. Control rod movement, provided there are no fuel assemblies in the associated core cell.

54. Risk - Risk is the product of the probability of an event and the adverse consequences of the event.

55. Reliability - Reliability is the probability that an item will perform its specified function without failure for a specified time period in a specified environment.

56. Unreliability - Unreliability is the probability that a component or system will fail to perform its specified action for a specified time period in a specified environment. (The sum of reliability and unreliability equals unity.)

57. Availability - Availability is the probability that an item will be operable when called upon to perform its specified function.

58. Unavailability - Unavailability is the probability that a component or system will be inoperable when called upon to perform its specified action. (The sum of availability and unavailability equals unity.)

59. Repair Rate - The repair rate is the number of repairs completed per unit time.

60. Failure Rate - The failure rate is the number of failures per unit time.

61. Test Duration - The test duration is the elapsed time between test initiation and test termination.

62. Test Interval - The test interval is the elapsed time between the initiation of identical tests.

63. Active Component - A device characterized by an expected significant change of state or discernible mechanical motion in response to an imposed design basis load demand upon the system. Examples are: switch, relay, valve, pressure switch, turbine, transistor, motor, damper, pump, analog meter, etc.

64. Passive Component - A device characterized by an expected negligible change of state or negligible mechanical motion in response to an imposed design basis load demand upon the system. Examples are: cable, piping, valve in stationary position, resistor, capacitor, fluid filter, indicator lamp, cabinet, case, etc.

65. Nuclear Safety Operational Analysis - A systematic identification of the requirements for and the limitations on station operation necessary to satisfy nuclear safety operational criteria.

66. Automatic Primary Containment Isolation Valve - A primary containment isolation valve which receives an automatic primary containment isolation signal.

67. Operation with the Potential to Drain the Reactor Vessel (OPDRV) - Any repair, maintenance, or their associated system restoration activity that could result in draining or siphoning the reactor vessel water level below the top of fuel limit without crediting the use of mitigating measures (e.g., operator actions, reliance on automatic isolation valves) to terminate the uncovering of fuel. This excludes activities where a qualified passive engineered device which meets plant design basis (e.g., blind flange, closed manual valve, deactivated automatic valve, back-seated valve) is credited or installed to ensure there is not a credible failure that could lead to draining the reactor vessel. Normal operation of plant systems to perform their design functions with reactor cavity water level maintained as required in applicable technical specifications are not considered to pose an OPDRV.

68. The "Security Owner Controlled Area" (SOCA), is an area where access is restricted for security reasons. It is not considered as Radiological Restricted Area. The SOCA is a permanently owner controlled area clearly demarcated with physical security barriers, access to which is controlled in accordance with the Pilgrim Station Access Control Program to enter into the Protected Area for the purpose of plant operational activities. This definition complies with the objectives of the requirements of 10 CFR 73.55, Requirements for Physical protection of Licensed Activities in Nuclear Power Reactors against Radiological Sabotage".

69. The "Radiological Restricted Area" is any area to which access is limited by the Licensee for the purpose of protecting individuals against undue risk from exposure to radiation or radioactive materials. The Radiological Restricted Area boundaries exclude any area to be used for residential use purposes. The boundaries between radiological restricted area and unrestricted area are defined by the licensee. This definition complies with 10 CFR 20.1003, as discussed in FSAR Section 12.3.

1.10 QUALITY ASSURANCE PROGRAM

1.10.1 Introduction

Boston Edison Company, as original owner and operator of Pilgrim Nuclear Power Station, assumed full responsibility and authority for facility operation and has taken appropriate action to ensure the station is designed, modified, operated, and maintained in accordance with sound engineering principles and safe operating practices. The Boston Edison Company Quality Assurance Program for operation of PNPS was defined in the Boston Edison Quality Assurance Manual Volume II (BEQAM).

The ownership and operation of PNPS was transferred From Boston Edison Company to the Entergy Nuclear Generation Company (ENGC), effective July 13, 1999.

The ENGC Quality Assurance Program for operation of PNPS was defined in the Pilgrim Quality Assurance Manual (PQAM), which was the governing document for quality related activities relating to Pilgrim Station until May 5, 2002, when the NRC approved ENGC's transfer of plant operating responsibility to Entergy Nuclear Operations Inc. (ENOI). At this time the PQAM was replaced by adopting the Entergy QA Program Manual (QAPM), as the QA program description for PNPS.

The requirements in the QAPM, and its Predecessors (BEQAM and PQAM), were established to comply with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants."

1.10.2 QA Program Objectives

The quality assurance program's objectives are to ensure compliance with regulatory requirements, company commitments, and established practices for efficient design, modification, maintenance, testing, and operation of Pilgrim Station. The program requires every person involved in quality assurance program related activities to comply with the provisions of the program.

1.10.3 QA Program Organization

The function of the Pilgrim Quality Assurance Organization established by Entergy is to monitor the quality oriented activities of all organizations involved in the design, modification, operation, and maintenance of Pilgrim Station and report the results of such monitoring activities to the appropriate levels of management.

The site quality assurance organization reports off-site to the Director, Oversight. This reporting relationship ensures the appropriate organizational freedom required by 10 CFR 50 Appendix B, Criteria I as needed for the site QA organization to effectively perform their assigned functions.

1.10.4 Quality Control and Assurance Measures

The degree to which quality control and assurance measures are assigned is a direct function of the safety and operating requirements of the various structures, systems, and components.

Essential equipment and nuclear systems are emphasized; however, nonessential and non-safety related systems and components may be included in the Quality Assurance Program to the extent necessary to assure reliability of station operation.

The quality assurance organization has developed an integrated system of planned audits, reviews, surveillances, inspections, and assessments in order to fulfill its responsibility for monitoring of QA Program implementation. The system has been designed to meet or exceed applicable regulatory, license, and national code or standard requirements. The audits, reviews, and surveillances are scheduled to provide comprehensive oversight and verification of all aspects of the QA Program and to provide management of the affected areas with continuous assessments of facility operation.

In addition to the commitments to NRC Regulatory Guides and ANSI Standards described in the Entergy QAPM, the following Regulatory Guides and associated ANSI Standards will be applied to construction related activities associated with major modifications during the operational phase that are comparable in nature and extent to related activities occurring during initial plan design and construction:

- Regulatory Guide 1.54, Rev. 0, 1973. "QA Requirements for Protective Coating Applied to Water-Cooled Nuclear Power Plants."
- Regulatory Guide 1.55, Rev. 0, 1973. "Concrete Placement in Category I Structures."
- ANSI N45.2.16, "Requirements for the Calibration and Control of Measuring and Test Equipment Used in the construction and Maintenance of Nuclear Power Generating. Stations."

UFSAR, Appendix D describes the quality assurance program for the initial design and construction phase of Pilgrim Station.

1.10.5 Quality Records and Documentation

Documentation to support quality assurance is essential to the safe operation, integrity and proper maintenance of Pilgrim Station. It is compiled and maintained throughout the life of the plant. In general, the minimum requirements for documentation for PNPS are those requirements imposed by the QAPM.

Refer to Section 13.7.5 relative to records retention.

1.10.6 Quality Program Review

Periodic, independent reviews of the QA Program policies and implementation are conducted to evaluate the continued adequacy and effectiveness of the program.

1.10.7 QA Program Update

The QA Program applied to operation and modification of Pilgrim Station is set forth in the QAPM.

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STATION SITE AND ENVIRONS

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The inlet mixer section of each jet pump is held in place by a beam-bolt assembly located in the riser transition piece. The beam ends are positioned within packets in the transition piece, and the beam load is transferred to the elbow through a bolt located in the center of the beam. See view D-D of Figure 3.3-5 (BECo MIE44-1). A preload is applied to the beam when it is installed to ensure enclosure integrity of the joint between the riser and the inlet mixer assemblies. Ultrasonic testing in mid-1979 and early 1980 detected cracking in some beams in certain BWR/3s. To preclude failure by intergranular stress corrosion cracking which has been observed in jet pump beams in some BWR plants, the existing Pilgrim jet pump beams that were of BWR-3 design have been replaced by improved BWR-4 beam bolt assemblies. These replacement beam bolt assemblies are different in four aspects:

- The beam depth has been increased
- The Inconel material heat treatment has been changed
- The beam bolt material has been changed to 316L
- The retaining device design has been changed

Beams reflecting these design changes are not expected to crack.

These improvements are discussed further in the GE NEDE report of December 1981 (Reference 5), which also presents a recommended schedule for inservice inspection of the replacement beams.

3.3.4.5 Steam Dryers

The steam dryers remove moisture from the wet steam which exits from the steam separators. The wet steam leaving the steam separators flows across the dryer vanes and the moisture flows down through collecting troughs and tubes to the water above the downcomer annulus. See Figure 3.3-6. A skirt extends down into the water to form a seal between the wet steam plenum and the dry steam flowing out the top of the dryers to the steam outlet nozzles. Vertical guide rods facilitate positioning the dryer and shroud head in the vessel. The dryers rest on steam dryer support brackets attached to the reactor vessel wall, and are restricted from lifting by steam dryer hold-down brackets, which are attached to the reactor vessel closure head over the top of the steam dryer lifting lugs when the head is in place.

3.3.4.6 Feedwater Spargers

The feedwater spargers are stainless steel headers located in the mixing plenum above the downcomer annulus. A separate sparger is fitted to each of four feedwater nozzles and is shaped to conform to the curve of the vessel wall. Sparger end brackets are attached to vessel brackets to support the weight of the spargers, and wedge blocks position the spargers away from the vessel wall. Feedwater flow enters the center of the spargers and is discharged through top mounted elbows, each with a converging discharge nozzle. The cooler feedwater blows downward to mix with the downcomer flow from the steam separators before it contacts the vessel wall. The feedwater also serves to collapse any steam voids and to subcool the water flowing to the jet pumps and recirculation pumps.

3.3.4.7 Core Spray Lines

The two 100 percent capacity carbon steel core spray lines separately enter the reactor vessel through the two core spray nozzles as shown on Figure 4.2-2. See Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. The lines divide immediately inside the reactor vessel. The two halves are routed to opposite sides of the reactor vessel and are supported by clamps attached to the vessel wall. The header halves are then routed downward into the downcomer annulus and pass through the upper shroud immediately below the flange. The flow divides again as it enters the center of the semicircular sparger ring which is routed halfway around the inside of the upper shroud. The ends of the two sparger rings for each line are supported by slip-fit brackets designed to accommodate thermal expansion of the rings. The header routing and supports are designed to accommodate differential movement between the shroud and the vessel. The other core spray line is identical except that the header enters the opposite side of the vessel and the sparger rings are at a slightly different elevation in the shroud. The proper spray distribution pattern is provided by a combination of distribution nozzles pointed radially inward and downward from the sparger rings. See Section 6, Core Standby Cooling Systems.

3.3.4.8 Deleted

3.3.4.9 Differential Pressure and Liquid Control Line

The stainless steel differential pressure and liquid control line serves a dual function within the reactor vessel. It injects liquid control solution into the coolant stream as discussed in Section 3.8, Standby Liquid Control System, and senses the differential pressure across the core support assembly, as discussed in Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. The line enters the reactor vessel at a point below the core shroud as two concentric pipes. In the lower plenum, the two pipes separate. The inner pipe terminates near the lower shroud with a perforated length below the core support assembly. It is used to sense the pressure below the core support during normal operation and to inject liquid control solution when required. This location assures that good mixing and dispersion are facilitated. The use of the inner pipe also reduces the thermal shock to the vessel nozzle should the Standby Liquid Control System (SLCS) ever be used. The outer pipe terminates immediately above the core support assembly and senses the pressure in the region outside the fuel assembly channels.

3.3.4.10 Incore Flux Monitor Guide Tubes

The incore flux monitor guide tubes are welded to the top of the incore flux monitor housings in the lower plenum and extend up to the top of the core support. See Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. The power range detectors for the power range monitoring units and the dry tubes for the source range monitoring/intermediate range monitoring (SRM/IRM) detectors are inserted through the guide tubes, and are held in place below the top guide by spring tension. A latticework of clamps, tie bars, and spacers give lateral support and rigidity to the guide tubes. The bolts and clamps are welded after assembly to prevent loosening during reactor operation.

3.3.4.11 Startup Neutron Sources

The startup neutron sources are required during the first startup of the reactor. At the end of the first operating cycle, the neutron sources can be removed since the reactor has adequate neutron source in the form of fuel carried to the subsequent operating cycle. Neutron sources have been removed after four operating cycles since experience on other BWR plants has shown that startup neutron source holders left in the core longer than one operating cycle have a tendency to become brittle and are subject to cracking and separation. Cores with an average exposure of 5,000 MWd/t will emit enough neutrons to permit startup following a 120 day outage. Higher core average exposure will allow longer outage periods. For an extended outage, where neutron startup sources would be required, new antimony rods would have to be irradiated and installed in new holders.

To allow full core discharge and reloading without the startup neutron sources and without meeting the activity requirements of the fuel, a spiral reloading and unloading pattern is followed.

3.3.4.12 Surveillance Holders

The surveillance sample holders are welded baskets containing impact and tensile specimen capsules. See Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. The baskets hang from brackets on the inside wall of the reactor vessel at the midheight of the active core, and at radial positions chosen to expose the specimens to the same environment and maximum neutron fluxes experienced by the reactor vessel itself, while at the same time avoiding jet pump removal interference or damage.

3.3.5 Vibration

3.3.5.1 Vibration Analysis

A vibration analysis of reactor vessel internals was performed in the design to determine any potential hydraulically induced equipment vibrations and to check that the structures do not fail due to fatigue. The structures were analyzed for natural frequencies, mode shapes, and vibrational magnitudes that could lead to fatigue at these frequencies. The cyclic loadings were evaluated using the cyclic stress criteria of the ASME Code, Section III as a guide.

3.3.5.2 Vibration Testing

The criteria for selecting BWR plants to be vibration tested is to test each new plant which contains a significant design departure from a plant that has been previously vibration tested (e.g., the first plant of each standard plant design). Since all jet pump plants are geometrically quite similar, it is not expected that there will be a great deal of difference in the vibration response of the various plants of approximately the same size. However, where vessel diameters changed significantly, or where flow velocities increased significantly, vibration tests were scheduled.

Depending on the reactor vessel manufacturer, BWRs are equipped with two types of shroud support structures. Reactors such as Dresden 2 and 3, Peach Bottom 2 and 3, Brunswick, and Zimmer are equipped with a stilt-type shroud support. Reactors such as Fermi 2, Cooper, Millstone 1, and Pilgrim are equipped with a gusset-type shroud support. Pilgrim differs from Millstone 1 in the area of jet pump riser support, both at the inlet thermal sleeve attachment and at the riser brace elevation. Because of these design differences, confirmatory vibration tests were conducted on Pilgrim plant to ensure that the flow induced vibrations do not jeopardize the integrity of internal structure of the reactor vessel. This program supplemented the first of a kind data obtained from the Millstone 1 tests. The vessel internal components monitored were:

1. Shroud - to measure horizontal displacements
2. Jet Pump Assembly Riser Brace - to measure strain in the braces of the riser pipe for two jet pumps
3. Jet Pumps - to measure horizontal radial motion of two pumps with respect to the reactor pressure vessel

The vibration of the various reactor internal components were detected by sensors mounted directly on those components. The vibration amplitude signals from these sensors were amplified and displayed by an oscillograph type recorder and also recorded on magnetic tape. Data were obtained from operable sensors during the power test program and periodically during steady state operation throughout the first operating cycle.

The operating conditions established for the vibration measurements during the power test program are listed below. These operating conditions are indicative of the range of operating conditions applicable for variations in vibration excitations. Actual test points are designed to cover this range of variations in steam and coolant flow.

Operating Conditions

1. 75 percent Thermal Power Line
2. 100 percent Thermal Power Line

Measurements were monitored for each of the above power levels at the following conditions:

1. Four approximately equally spaced flow points from minimum flow to 100 percent flow
2. With 100 percent core flow trip Pump A
3. With Pump B only operating, open equalizer
4. With 100 percent core flow trip Pump B
5. With Pump A only operating, open equalizer
6. With 100 percent core flow trip both pumps simultaneously

3.3.5.3 Increased Core Flow Vibration Analysis

The increased core flow vibration analysis was performed by analyzing the startup test vibration data for Millstone 1 and Pilgrim. The vibration levels for 100% flow operation were conservatively extrapolated by the ratio of flow velocity squared for each of the instrumented reactor internal components. The jet pump riser braces showed the highest vibration response (32.4% of acceptance criteria) at 112.5% of rated core flow. In addition to analyzing the startup test data, an evaluation of the riser brace structural natural frequency was performed to determine if an excitation phenomena exists because of increased recirculation pump speed (blade passing frequency). The results show the riser brace natural frequency is high enough (169% of blade passing) to avoid such an excitation. This riser brace excitation would be most limiting as a result of an increase in pump speed and flow. Based on the results of these analyses and a review of test data it is apparent that operation with increased core flow does not result in flow-induced vibrations of reactor internals which exceed acceptable mechanical design limits (Reference 6).

3.3.6 Safety Evaluation

3.3.6.1 Evaluation Methods

To determine that the safety design basis is satisfied, the responses of the reactor vessel internals to loads imposed during normal operation, abnormal operational transients, and accidents are examined. Determination of these effects on the ability to insert control rods, cool the core, and flood the inner volume of the reactor vessel are made. The various structural loading combinations assumed to be imposed on the reactor vessel internals are as described in Appendix C for Class I equipment. These loading combinations include upset loads, emergency loads, and faulted loads.

The ASME Boiler and Pressure Code, Section III for Class A vessels, is used as a guide to determine limiting stress intensities and cyclic loadings for the reactor vessel internals. For those components for which buckling is not a possible failure mode and stresses are within those stated in the ASME Code, it is concluded that the safety design basis is satisfied. For those components, for which either buckling is a possible failure mode or stresses exceed those presented in the ASME Code, either the elastic stability of the structure or the resulting deformation is examined to determine if the safety design basis is satisfied.

3.3.6.2 Plant Conditions

All events that the plant might credibly experience are evaluated to establish a design basis for plant equipment. These events are divided into four plant conditions. The plant conditions described in the following paragraphs are based on event probability (i.e., frequency of occurrence) and correlated design conditions as defined in the ASME B&PV Code, Section III.

3.3.6.2.1 Normal Condition

Normal conditions are any conditions in the course of system startup, operation in the design power range, normal hot standby (with condenser available), and system shutdown other than upset, emergency, faulted, or testing. For this condition, structural loadings on the reactor vessel internals are evaluated at 100% power and 100% recirculation flow.

3.3.6.2.2 Upset Condition

Upset conditions are any deviations from normal conditions which are anticipated to occur often enough that the design should include a capability to withstand the conditions without operational impairment. The upset conditions include those transients which result from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power.. For this condition, the analysis is based on a reactor power corresponding to 105% of related steam flow and 100% recirculation flow.

3.3.6.2.3 Emergency Condition

Emergency conditions are those deviations from normal conditions which require shutdown to correct the conditions or to repair damage in the reactor pressure coolant boundary (RCPB). These conditions have a low probability of occurrence, but are included to provide assurance that no gross loss of structural integrity results as a concomitant effect of any damage developed in the system. Emergency condition events include, but are not limited to, transients caused by one or more of the following: a multiple valve blow down of the reactor vessel; loss of reactor coolant from a small break or crack which does not depressurize the reactor system, nor result in leakage beyond normal makeup system capacity, but which does require the safety functions of containment isolation and reactor shutdown. The reactor is analyzed at core power corresponding to 102% of rated power and 100% recirculation flow. For Pilgrim the limiting event for this plant condition is an unintentional actuation of the Automatic Depressurization System (ADS). This event results in a sudden depressurization of the reactor system, similar to but less severe than the design basis LOCA.

3.3.6.2.4 Faulted Condition

Faulted conditions are those combinations of conditions associated with extremely unlikely postulated events, with consequences such that the integrity and operability of the system may be so impaired that considerations of public health and safety are involved. Faulted conditions encompass events that are postulated because their consequences include the potential for releasing significant amounts of radioactive material. These postulated events are the most drastic that must be designed against, and thus represent limiting design bases. Faulted condition events include, but are not limited to, one or more the following: a control rod drop accident; a fuel-handling accident; a main steam line break; a recirculation loop break; the combination of small break/large break accident.

For Pilgrim, the reactor is analyzed at two states; 1) 100% recirculation flow and 102% of rated power and 2) 110% recirculation flow and 23% of rated power (the lowest power at which 110% recirculation flow is permissible). The limiting events are an instantaneous circumferential break of a main steam line upstream of the main steam line flow limiters and the instantaneous circumferential break of a recirculation line.

3.3.6.2.5 Correlation of Plant Conditions with Event Probability

The probabilities per reactor year, P, of normal, upset, emergency and faulted events are listed below. These probabilities can be used to identify the appropriate plant condition for any hypothesized event or sequence of events.

Plant Conditions	Events Encountered (probability per reactor year)
Normal (planned)	1.0
Upset (moderate probability)	$1.0>P>10^{-2}$
Emergency (low probability)	$10^{-2}>P>10^{-4}$
Faulted (extremely low probability)	$10^{-4}>P>10^{-6}$

3.3.6.3 Specific Events To Be Evaluated

Examination of the spectrum of conditions for which the safety design basis must be satisfied reveals four significant events:

1. Loss of coolant accident: This accident is a break in a recirculation line. The accident results in some pressure differentials across the reactor vessel internals which exceed normal loads

2. Steam line break accident: This accident is a break in one main steam line between the reactor vessel and the flow restrictor. The accident results in significant pressure differentials across the reactor vessel internals

3. Thermal shock: The most severe thermal shocks to the reactor vessel internals occur when low pressure coolant injection (LPCI) operations or high pressure coolant injection (HPCI) operations reflood the reactor vessel inner volume following either a recirculation line break or a main steam line break. See Section 6, Core Standby Cooling System

4. Earthquake: This event subjects the reactor vessel internals to significant forces as a result of ground motion. These seismic loads are combined with other transients loads such as ADS loads or LOCA loads to demonstrate the structural integrity of the reactor components under such combined events.

Analysis of other conditions existing during normal operation, abnormal operational transients, and accidents show that the loads affecting the reactor vessel internals are less severe than the four postulated events. Hence, the design bases for structural stress evaluations are based on the above limiting events.

3.3.6.4 Pressure Differentials During Rapid Depressurization

A digital computer code (Reference 7) is used to analyze the transient conditions within the reactor vessel following the recirculation line break accident and the steam line break accident. The analytical model of the vessel consists of nine spatial nodes with their boundaries located at interfaces defined by physical restrictions in the reactor system. Each node is connected to the necessary adjoining nodes by flow paths having the required resistance and inertial characteristics. The reactor system model is designed for short-term transients where there is rapid system depressurization. Its calculations typically include the first 30 to 45 seconds of the blowdown. The program solves the energy and mass conservation equations for each node, giving the depressurization rates and pressure in the various regions of the reactor. The flow resistances are evaluated from the irreversible pressure drops associated with known flow rates. Momentum effects are considered for all flow paths. Figure 3.3-7 shows the nine reactor nodes in the model. They are: 1) the subcooled lower plenum, 2) the core, 3) the upper plenum, 4) the mixing region, 5) the downcomer, 6) and 7) the two recirculation loops, 8) the core bypass region, and 9) the steam dome.

This computer code is approved for use in ECCS conformance evaluation under 10CFR 50, Appendix K. In order to adequately predict the blowdown pressure effect on individual reactor assembly components, three features are included in the model that are not applicable to the ECCS analysis and are, therefore, not described in Reference 5. These additional features are:

1. The liquid level in the steam separator region, and in the annulus between the dryer skirt and the pressure vessel, is tracked to determine more accurately the flow and mixture quality in the steam dryer and the steam line.

2. The flow path between the bypass region and the shroud head is more accurately modeled for a steam line break since the fuel assembly pressure differential is influenced by flashing in the guide tubes and the bypass region. In the ECCS analysis, the momentum equation is solved in this flow path but its irreversible loss coefficient is conservatively set at an arbitrary low value.

3. The enthalpies in the guide tubes and the bypass region are calculated separately since the fuel assembly differential pressure is influenced by flashing in these regions. In the ECCS analysis, these regions are lumped together.

3.3.6.5 Recirculation Line Break

3.3.6.5.1 Accident Definition

This accident is the same design basis LOCA as described in Section 6, Core Standby Cooling Systems, and Section 14, Station Safety Analysis. It is assumed that an instantaneous, circumferential break occurs in one recirculation loop (the largest liquid break).

As detailed in Section 3.3.6.5.1, the vessel depressurization rate is less for liquid breaks (recirculation line breaks) than for steam breaks (steam line breaks). Therefore the postulated recirculation line break accident is not the design basis for internal pressure loads. Maximum loads occur following the postulated steam line break and are discussed in Section 3.3.6.5.

3.3.6.5.2 Jet Pump Joints

An analysis has been performed to evaluate the potential leakage from within the floodable inner volume of the reactor vessel during the recirculation line break and subsequent reflooding. The two possible sources of leakage are:

1. Jet pump throat to diffuser joint

2. Jet pump nozzle to riser joint

The jet pump to shroud support joint is welded and therefore is not a possible source of leakage. The throat to diffuser joints for all jet pumps leak no more than a total of 225 gal/min. The jet pump nozzle to riser joint by analysis is shown to leak no more than a total of 225 gal/min. The jet pump nozzle to riser joint analysis is shown to leak no more than 582 gal/min for the pumps through which the vessel is being flooded.

The summary of maximum leakage is then:

Total leakage through all throat to diffuser joints	225 gpm
Total leakage through all operational nozzle to riser joints.	582 gpm
TOTAL MAXIMUM RATE ..	807 gpm

CSCS capacity is sized to accommodate 3,000 gal/min leakage at these locations. It is concluded that the reactor vessel internals retain sufficient integrity during the recirculation line break accident to allow reflooding the inner volume of the reactor vessel.

3.3.6.6 Steam Line Break Accident

3.3.6.6.1 Accident Definition

The analysis of this accident assumes an instantaneous circumferential break of one main steam line between the reactor vessel and the main steam line flow restrictor. This is not the same accident as described in Section 14, Station Safety Analysis, because greater differential pressures across the reactor vessel internals result from this accident. It is noteworthy that this accident results in greater loading of the reactor vessel internals and a higher depressurization rate than does the recirculation line break. The steam line break accident is more severe because the depressurization rate is proportional to the mass flow rate and the difference between the fluid escape enthalpy, he, and the saturated water enthalpy, hf. However, mass flow rate is inversely proportional to escape enthalpy he; therefore, depressurization rate is proportional to 1 - hf/he. Consequently, depressurization rate decreases as he decreases. That is, depressurization is less for mixture flow (recirculation line break) than for steam flow (steam line break).

A steam line break upstream of the flow restrictors produces a larger blowdown area, and thus a faster depressurization rate, than a break downstream of the restrictors. A faster depressurization rate results in greater pressure differentials across the reactor internal structures.

To add conservatism to the analysis it is assumed that only steam is discharged through the break; this maximizes the vessel depressurization rate and the resultant loadings on the vessel internals.

The steam line break accident produces significantly higher pressure differentials across the reactor internal structures than does the recirculation line break. This fact results from the greater reactor depressurization rate associated with the steam line break. Therefore, the steam line break is the design basis accident for internal pressure differentials.

3.3.6.6.2 Effects of Initial Reactor Power and Core Flow

The maximum internal pressure loads can be considered to be composed of two parts: a steady-state part and a transient part. For a given plant, the core flow and the core power are the two major factors which influence the reactor internal pressure differentials. The core flow essentially affects only the steady-state part. For a fixed power, the greater the core flow, the larger the steady-state pressure differentials. The core power affects both the steady-state and the transient parts. As the power is decreased, there is less steam generation rate and, consequently, the steady-state core pressure differential is less. However, less voiding in the core also means that less steam is generated to replace steam flow out of the broken steam line, thus increasing the depressurization rate and the transient part of the maximum pressure load. As a result, the total loads on some components are higher at low power.

To ensure that the calculated pressure differences are bounding, an analysis is conducted at a low power/high recirculation flow combination in addition to the standard safety analysis combination of high power/rated recirculation flow. The power chosen for the low power/high recirculation flow combination is the minimum value permitted by the recirculation system controls at rated recirculation drive flow (that is, the drive flow necessary to achieve rated core flow at rated power). This condition maximizes those loads which are inversely proportional to power. It must be noted that this condition, while possible, is unlikely; the reactor generally operates at or near full power and, at reduced power, high core flow is neither required nor desirable.

3.3.6.7 Reactor Internals Pressure Differences at Normal, Upset, Emergency and Faulted Condition

Table 3.3-2 summarizes the pressure differentials across the reactor internal components for the limiting plant configuration/transient for normal, upset, emergency and faulted conditions. As shown, the maximum pressure loads acting on the reactor internals result from a steam line break (a faulted condition). On most components the loads are maximum when operating at the minimum power associated with the maximum core flow. This observation is substantiated by the analytical comparison of liquid breaks versus steam breaks, and by the investigation of the effects of core power and core flow.

As discussed earlier, it is possible but not probable that the reactor is operating at this rather abnormal condition of minimum power and maximum core flow. More realistically, the reactor is at or near a full power condition. Thus, use of the pressure loads associated with this abnormal condition, where maximum, introduces additional conservatism in the analysis.

The maximum differential pressures in Table 3.3-2 are used, in combination with other assumed structural loads as described in Appendix C, to determine the total loading on the various reactor vessel internals. The various internals are then examined to assess the extent of deformation and collapse, if any. Of particular interest are the responses of the core support assembly, the guide tubes, and the channels around the fuel bundles.

Reference 12 reevaluated pressure differences across reactor internals for maximum extended load line limit (MELLL) region operation. The results were bound by the design limits and have adequate design margin for operation in the MELLL region.

3.3.6.7.1 Core Support

The core support assembly sustains the maximum net force, which is an upward force following the steam line break accident, so the effect on the core support holddown bolts must be established. Analysis shows that the applied stresses are about 1/2 of yield strength for the bolts, indicating that the core support can withstand the effects of the accident.

In RFO #10 a reactor shroud repair was implemented as described in Section 3.3.4.1.1. The design loads for the shroud stabilizers included seismic plus main steam line break accidents. The effect of the shroud repair on the reactor pressure vessel was analyzed and the results included in a stress report that is an addendum to the original design stress report for the reactor pressure vessel. The shroud stabilizers change the points of application of the forces applied to the vessel from the shroud. There are new forces applied to the pressure vessel from the shroud stabilizer springs and a change in the forces applied from the existing shroud support plate and gussets to the vessel wall. These new and revised forces were combined with the forces defined in the original vessel design stress report and analyzed per the original reactor pressure vessel Code of Construction. The analysis concluded that all stresses within the reactor pressure vessel remain within their allowable limits.

3.3.6.7.2 Guide Tubes

Because of the externally applied pressure, the guide tube is examined for collapse. As in the case of the lower shroud and core support assembly, a number of formulae are utilized to calculate the collapse pressure. Unfortunately, the Winderberg test is not applicable because the geometry of the guide tube is outside of the test range. Use of ASME curves indicates the extreme sensitivity to wall thickness. For the minimum wall thickness for a 10 in Schedule 10 pipe, the ASME curves give a collapse load of 45 psi. Using the average wall thickness, the collapse pressure is increased to over 70 psi. Using empirical relations for tubes over the critical length, the calculated collapse pressure is over 100 psi. The ASME curves calculate that the collapse pressure is reached at 54 psi for a wall thickness of 0.150 in, which is 6 mils over the minimum for a 10 in Schedule 10 pipe. The calculated total loading for the guide tubes is considerably below the collapse loading, and it can be concluded that no failure occurs. The analysis also indicates that the control rods are 70 percent to 80 percent inserted at the time the maximum external pressure is applied to the guide tubes.

3.3.6.7.3 Fuel Channels

The BWR Zircaloy fuel channel performs the following functions:

a. forms the fuel bundle flow path outer periphery for bundle coolant flow;

b. provides surfaces for control rod guidance in the reactor core;

c. provides structural stiffness to the fuel bundle during lateral loadings applied from fuel rods through the fuel spacers;

d. minimizes, in conjunction with the finger springs and bundle lower tie plate, coolant bypass flow at the channel/lower tie plate interface;

e. transmits fuel assembly seismic loadings to the top guide and fuel support of the core internal structures;

f. provides a heat sink during loss-of-coolant accident (LOCA); and

g. provides a stagnation envelope for in-core fuel slipping.

The channel is open at the bottom and makes a sliding seal fit on the lower tie plate surface. The upper end of the fuel assemblies in a four-bundle cell are positioned in the corners of the cell against the top guide beams by the channel fastener springs. At the top of the channel, two diagonally opposite corners have welded tabs, one of which supports the weight of the channel from a threaded raised post on the upper tie plate. One of these raised posts has a threaded hole. The channel is attached using the threaded channel fastener assembly, which also includes the fuel assembly positioning spring. Channel-to-channel spacing is provided for by means of spacer buttons located on the upper portion of the channel adjacent to the control rod passage area. Reference 4 provides a complete description and analytical results for channels supplied by the General Electric Company (GE). The channels supplied by other vendors have been evaluated and are predicted to behave in a similar fashion as GE supplied channels.

3.3.6.8 Thermal Shock

The most severe thermal shock effects for the reactor vessel internals result from the reflooding of the reactor vessel inner volume. For some vessel internals, the limiting thermal shock occurs from LPCI operation and for others HPCI operation is controlling, dependent upon the location of the component. These effects occur as a result of any large LOCA, such as the recirculation line break and the steam line break accidents previously described.

The locations are as follows:

1. Shroud support plate

The peak strain resulting in the shroud support plate is about 6.5 percent. This strain is higher than the 5.0 percent strain permitted by the ASME Code, Section III, for 10 cycles, but the 1 cycle, peak strain corresponds to about 6 allowable cycles of an extended ASME Code curve as applied to less than 10 cycles.

Figure 3.3-9 illustrates both the ASME Code curve and the basic material curves from which it was established (with the safety factor of 2 on strain or 20 on cycles, whichever is more conservative). The extension of the ASME Code curve represents a similar criteria to that used in the ASME Code, Section III, but applied to fewer than 10 cycles of loading. For this Type 304 stainless steel material, a 10 percent peak strain corresponds to one allowable cycle of loading. Even a 10 percent strain for a single cycle loading represents a very conservative suggested limit because this has a large safety margin below the point at which even minor cracking is expected to begin. Because the conditions which lead to the calculated peak strain of 6.5 percent are not expected to occur even once during the entire reactor lifetime, the peak strain is considered tolerable.

2. Shroud to shroud support plate discontinuity

The results of the analysis of the shroud to shroud support plate discontinuity region are as follows:

Amplitude of alternating stress.	180,000 psi
Peak strain.	1.34 percent

The ASME Code, Section III, allows 220 cycles of this loading, thus no significant deformations result.

3. Shroud inner surfaces at highest irradiation zone

By the end of station life, the peak thermal shock stress is 155,700 psi, corresponding to a peak strain of 0.57 percent. The shroud material is Type 304 stainless steel, which is not significantly affected by irradiation. The material does experience a loss in reduction of area. Because reduction of area is the property which determines tolerable local strain, irradiation effects can be neglected. The peak strain resulting from thermal shock at the inside of the shroud represents no loss of integrity of the reactor vessel inner volume.

3.3.6.9 Earthquake

The seismic loads on the RPV and internals, due to horizontal motion, are based on a dynamic analysis of the RPV and internals model. Seismic analysis is performed by coupling this lumped mass model of the RPV, and internals with the building soil structure model to determine the system natural frequencies and mode shapes. The relative displacement, acceleration, and load response of the RPV and internals are then determined by either the time history method or the response spectrum method. In the time history method, the dynamic response is determined for each mode of interest and added algebraically for each instant of time. Resulting response time histories are then examined and the maximum value of displacement, acceleration, shears, and moments are used for design calculations. In the response spectrum method, the relative displacements, accelerations, shears, and moments are determined for each mode of interest. The square root of the sum of squares (SRSS) of these individual responses is then used for design calculations. Since the RPV and its internal system are made up of many separate components, there are many natural frequencies spaced closer than the natural frequencies of single component structures. When the time history method of seismic analysis is used as it is on Pilgrim, the physical displacements, accelerations, shears, and moments due to each mode are added algebraically at each instant of time and, hence, no criteria concerning the method of combining loads due to closely spaced modal frequencies needs to be set. When the response spectrum method of seismic analysis is used, it can be argued that, for very closely spaced frequencies, the peak modal response may occur at practically the same time and hence, the absolute sum (instead of SRSS) of the contributions from each mode should be taken. However, this argument overlooks the fact that signs of the mode shapes and participation factors of two neighboring modes, may be such that the load contribution from these modes subtract from one another instead of reinforcing one another, in parts of the structure. If this occurs, the loads would be definitely lower than the loads from an absolute sum.

The best indication of the adequacy of the SRSS method of combining modal load contributions is a comparison of the results from time history methods, and from response spectrum methods with SRSS load combinations and smoothed spectra. Such comparisons for the RPV and internals in BWR plants generally show that the loads determined by both methods are comparable in magnitude with the loads determined by the response spectrum method, being generally on the high side. Therefore, it may be concluded that the SRSS method of combining loads is adequate even for closely spaced modes.

The natural frequencies of the reactor internals, reactor vessel, and pedestal system in the vertical direction have been found to be approximately 20 Hz. Examination of the response spectra shows no significant amplification at this frequency. Hence, omitting the vertical motion from seismic analysis to reduce the analytical complexities is acceptable. The effects of vertical excitations are accounted for by increasing or decreasing (whichever causes higher stress) the weight of the various components by a percentage equal to the vertical acceleration expressed in percent g.

The coupling of the vertical and lateral motions will cause an extremely small change in the bending moment experienced by some components. Since this change is a very small fraction of the moment caused by lateral moment, it can be neglected.

The stresses caused by the combined Safe Shutdown Earthquake and the LOCA conditions have been compared with and found to be within the Appendix C primary stress limits for faulted conditions.

To demonstrate that the reactor vessel internals can adequately resist the stresses resulting from an earthquake, a 1.0g lateral force was assumed. This does not mean that the Operating Basis Earthquake, which is used in combination with the accident loadings described (see Appendix C) is of this magnitude, but that the assumption of 1.0g lateral force is more than adequate to demonstrate the capabilities of the reactor vessel internals. For the reactor shroud, this analysis was superseded by the stress and seismic analyses performed subsequently as part of the shroud repair.

In RFO #10, a reactor shroud repair was implemented as described in Section 3.3.4.1.1. The design loads for the shroud stabilizers included seismic plus main steam line break accidents. The seismic analysis was done with a lumped mass and beam element two-dimensional finite element model of the entire reactor building and reactor vessel structure. To be consistent with the original design basis seismic analysis, the model has a single horizontal translational degree of freedom for each node. The model included in the reactor internals with elements to represent the fuel, guide tubes and shroud. The model was first benchmarked against the original GE seismic analysis. The shroud repair was then added to the model by inserting two linear spring elements representing the upper and lower shroud stabilizer springs and a single rotational spring element to represent the four tie rods by an equivalent restraint against the shroud horizontal (overturning) movement.

The seismic analysis was done via the time history with modal superposition method. The ground motion input was done using both a Housner Response Spectrum synthetic time history per FSAR requirements shown in FSAR Figures 2.5-5 (OBE) and 2.5-6 (SSE), and a Taft earthquake time history consistent with the original seismic analysis. The shroud stabilizer design loads conservatively bound the higher of either the Housner or Taft responses.

The shroud stabilizers limit the displacement of the top guide and core support plates in the horizontal and vertical directions. The displacement limits were specified by General Electric based on analytical and empirical data on the ability to insert control rods with both transient and permanent displacements of the top guide and core support plate. The safety factors from Table C.3-6 were applied to the maximum displacement limits for the upset, emergency, and faulted conditions.

It can be concluded that earthquake forces do not cause deformations of the reactor vessel internals sufficient to prevent the insertion of control rods, the proper operation of the CSCS, or the proper flooding of the inner volume of the reactor vessel.

3.3.6.10 Impact of Increased Core Flow (ICF) and Final Feedwater Temperature Reduction (FFWTR) on Reactor Internal Components

To support plant operation at 107.5% of rated recirculation flow, a safety analysis of the reactor internal components was performed to verify that the expected structural loading increases remain within the safety design bases limits. The analysis includes ICF with both normal feedwater temperature

Feedwater temperature affects the steady state and transient components of the pressure differentials differently. A reduction in feedwater temperature decreases the steady state component due to a reduced void fraction and a corresponding reduction in two-phase friction effects. However, a reduction in feedwater temperature increases the transient portion of the pressure differentials due to the reduced steam generation rate and the corresponding increase in the depressurization rate during a LOCA event (see Section 3.3.6.5.2). When effects on the steady state and transient components are combined, it turns out that the reduced feedwater temperature increases the overall pressure differential across the reactor components located in high steam environments, i.e. above the core region. These reactor internals are typically the top guide, upper shroud, shroud head and steam dryer. The loads for these components are limiting at the reduced feedwater temperature condition. At or below the core region, where the environment is mostly in a liquid or low steam quality state, the reduced feedwater temperature has negligible overall impact on the reactor components. These components include the shroud support, core plate, and fuel channels. For these components, the limiting loads are still experienced at normal feedwater temperatures.

A review was made of the effect of 75°F feedwater temperature reduction on reactor internals pressure differentials (RIPDs). The conclusion was that "normal" and "upset" RIPDs were not adversely affected, and the increase on LOCA RIPDs (<2%) over the 43°F case was very small relative to the margin existing, in the design. This review is documented in General Electrics design record file (J11-02368, Reference 11).

3.3.6.10.1 Reactor Internals

The reactor internals most affected by pressure differences under increased core flow conditions are the core plate, guide tube, shroud support, shroud and top guide. These components were evaluated under normal, upset, emergency, and faulted conditions. The pressure differentials for these components during increased core flow operation were found to produce stresses that are within the allowable limits of the safety design bases.

3.3.6.10.2 Fuel Channels

The fuel channels were also evaluated under normal, upset, emergency and faulted conditions for increased core flow and/or FFWTR. The channel wall pressure differentials were found to be within the allowable design values.

3.3.6.10.3 Fuel Bundles

The margin to fuel bundle lift was re-evaluated for increase core flow operation and/or FFWTR. The analysis considered the added bundle lift component due to increased core flow, with and without FFWTR, in addition to the effect of the design basis LOCA, the control rod friction force due to scram and the design-basis earthquake. The fuel bundle minimum lift margin was found to be 135 pounds (net downward force on fuel bundle) during the worst-case faulted event from rated operating conditions (a steamline break at 102% power, 107.5% flow). This analysis found the effect of increased core flow with or without FFWTR to yield acceptable results in terms of avoiding fuel bundle lift.

3.3.6.11 Conclusions

The analyses of the responses of the reactor vessel internals to situations imposing various loading combinations on the internals show that deformations are sufficiently limited to allow both adequate control rod insertion, and proper operation of the CSCS. Sufficient integrity of the internals is retained in such situations to allow successful reflooding of the reactor vessel inner volume. The analyses considered various loading combinations, including loads imposed by external forces. Thus, safety design bases 1, 2, and 3 are satisfied.

These conclusions extend to plant operation at rated core flow and increased core flow with and without final feedwater temperature reduction.

3.3.7 Inspection and Testing

Quality control methods are used during the fabrication and assembly of reactor vessel internals to assure that the design specifications are met.

The Reactor Coolant System (RCS), which includes the reactor vessel internals, is thoroughly cleaned and flushed before fuel is loaded initially.

During the preoperational test program, operational readiness tests are performed on various systems. In the course of these tests such reactor vessel internals as the feedwater spargers, the core spray lines, the vessel head cooling spray nozzle, and the SLCS line are functionally tested.

A vibration analysis of reactor vessel internals was performed in the design to reduce failures due to vibration. With this analysis as a guide, the reactor internals are instrumented and tested to ascertain that there are no gross instabilities. Field test data are correlated with the analysis to ensure validity of the analytical techniques on a continuing basis. For vibration testing of reactor vessel internals, refer to Section 3.3.5.2.

The reactor vessel and internals are designed to assure adequate working space and access for inservice inspection. The criteria for selecting the components and locations to be inspected are based on the probability of a defect occurring or enlarging at a given location, and includes areas of known stress concentrations and locations where cyclic strain or thermal stress might occur. When practical, 100 percent inspection is planned at these locations; however, in cases where access is difficult, hazardous, or limited, it is planned to inspect a statistically significant portion. The type of inspection planned at each location is dependent on the type and location of defects anticipated.

3.3.8 References

1. NEDC-20259, "Summary Report on the Pilgrim Channel Wear Investigation and Corrective Measures Taken", January 1974.

2. NEDE-24323-P, "Core Support Plate Plug Service Life", March 1981.

3. "Design and Performance of G.E. BWR Jet Pumps", General Electric Co., Atomic Power Equipment Department, APED-5460, July 1968.

4. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A, Revision Number Listed in Latest Supplemental Reload Submittal in Appendix Q.

5. NEDE-24362-1, "Improvements in Jet Pump Hold-Down Beam Service Life", December 1981.

6. NEDO-30242, "Safety Review of Pilgrim Nuclear Power Station, Unit No. 1 at Core Flow Conditions Above Rated Flow Throughout Cycle 6", August 1983.

7. NEDE-20566-P, "Analytical Model for Loss-of-Coolant Accident in Accordance with 10CFR50, Appendix K", General Electric Company.

8. NEDC-32120P, "Revision of Core Support Plate Plug Service Life", General Electric Nuclear Energy, July 1992.

9. NEDO-20855-01, "GE BWR Reload No. 2 Licensing Submittal for PNPS, Unit 1 with Bypass Flow Holes Plugged", GE Boiling Water Reactor Projects Department, September, 1975.

10. M-2-ER-Q-EO "Engineering Report for Core Support Plate Plug Life Extension", March 1994.

11. General Electric (D.C. Serell) to Boston Edison (B. Hagemeier), January 16, 1997, "Pilgrim Cycle 11 Reactor Internal Pressure Differences for Increased Core Flow with 75° F Feedwater Temperature Reduction".

12. NEDC-32306P, "Maximum Extended Load Line Limit Analyses for Pilgrim Nuclear Power Station Reload 9 Cycle 10", General Electric Company, March 1994 (SUDDS/RF94-042)

13. SE3084, "Various jet pumps have mixer swing gates that do not have the latch pins engaged in their associated holes and restrainer bracket set screws not in contact with the inlet mixer", April 4, 1997. [Includes SUDDS/RF 97-41, SIA Report No. SIR-97-028, "Evaluation of the Pilgrim Jet Pumps with and without Gaps at Set Screws and Wedges" dated April 1997]

14. SUDDS/RF 97-41 Rev. 1 of vendor report SIR 97-028 Rev. 2.

15. SUDDS/RF 03-036 SIA Calculation PNPS-10Q-313 "Jet Pump Gap Analysis" dated 3/7/03.

3.4 REACTIVITY CONTROL MECHANICAL DESIGN

3.4.1 Safety Objective

The safety objective of the reactivity control mechanical design is to provide a means to quickly terminate the nuclear fission process in the core so that damage to the fuel barrier is limited.

3.4.2 Safety Design Basis

1. The reactivity control mechanical design includes control rods. Each control rod:

   a. Has sufficient mechanical strength to prevent the displacement of their reactivity control material.

   b. Has sufficient strength and are of such design as to prevent deformation that could inhibit their motion.

   c. Includes a device to limit its free fall velocity to such a rate that the nuclear system process barrier is not damaged due to a pressure increase, caused by the rapid reactivity increase resulting from the free fall of one control rod from its fully inserted position.

2. The reactivity control mechanical design provides for a sufficiently rapid insertion of control rods so that no fuel damage results from any abnormal operating transient.

3. The reactivity control mechanical design includes positioning devices, each of which individually supports and positions a control rod. Each positioning device:

   a. Prevents its control rod from withdrawing as a result of a single malfunction

   b. Avoids conditions which could prevent its control rod from being inserted

   c. Is individually operated such that a failure in one positioning device does not affect the operation of any other positioning device

   d. Is individually energized when rapid control rod insertion (scram) is signaled so that failure of a power source external to the positioning device does not prevent other control rods from being inserted

   e. Is locked to its control rod to prevent undesirable separation

4. The reactivity control mechanical design includes reactivity control devices (control rods and initial core control curtains) which contain and hold the reactivity control material necessary to maintain the core at least 1 percent Δ k/k subcritical with the highest worth rod in the fully withdrawn position.

3.4.3 Power Generation Objective

The power generation objective of the reactivity control mechanical design provides a means to control power generation in the fuel.

3.4.4 Power Generation Design Basis

The reactivity control mechanical design includes provisions for adjustment of the control rods to permit control of power generation in the core.

3.4.5 Description

The reactivity control mechanical design consists of control rods which can be positioned in the core during power operation by individual control rod drive (CRD) mechanisms.

The CRD mechanisms are part of the CRD system. The CRD system hydraulically operates the CRD mechanisms using water from the Condensate and Demineralized Water Storage and Transfer System as a hydraulic fluid. The CRD mechanisms manually position the control rod during normal operation but act automatically to rapidly insert the control rods during abnormal (scram) conditions.

The control rods, CRD mechanisms, and that part of the CRD Hydraulic System necessary for scram operation are designed as seismic Class I equipment in accordance with Appendix C.

3.4.5.1 Reactivity Control Devices

3.4.5.1.1 Control Rods

The control rods perform the dual function of power shaping and reactivity control. See Figure 3.4-2. Power distribution in the core is controlled during operation of the reactor by manipulation of selected patterns of control rods. The control rods are positioned in a manner which counterbalances steam void effects at the top of the core and results in significant power flattening.

The control rods are 9.75 inches in total span and are located uniformly through the core on a 12 inch pitch. Each control rod is surrounded by four fuel assemblies.

Control rods in the following categories are used:

Standard control rods that maintain the same dimensions and characteristics as the original equipment control rods.

Hybrid control rods that maintain the same external dimensions as the original control rods and utilize hafnium in the blade tips and wing edges to improve nuclear and mechanical lifetimes. These control rods are the Duralife 160 series described in Reference 7.

Hybrid control rods that introduce a larger diameter absorber tube to obtain a greater load of neutron absorber material. These control rods are the Duralife 230 series described in Reference 8.

Hybrid control rods that replace the sheath-enclosed absorber tube with square tubes welded together to form each wing. The square tubes contain hafnium in the wing tips and encapsulated boron carbide elsewhere. These control rods are the Marathon D series described in Reference 11.

All of the above control rods have been designed to ensure interchangeability with the original equipment control rods from both the reactivity perspective, system performance, and mechanical fit. The reactivity worth is approximately identical (within $\pm$ 5%) to the original equipment control rods and can be used interchangeably without affecting lattice physics, core reload analyses or core monitoring software.

The nuclear lifetime of the standard control rod is determined by the burnup of Boron-10 from neutron absorption. The nuclear lifetime limit of the standard equipment control rod is reached when depletion results in a 10 percent reduction in the reactivity worth of any quarter axial segment of the control rod relative to its zero depletion cold worth. The nuclear lifetime of a replacement control rod is defined as the quarter-segment depletion at which the cold worth is the same as the end-of-nuclear life cold worth of the standard control rod it replaces. For example, if a replacement control rod has an initial cold worth 4% greater than the standard control rod, then it may be depleted to a reduction of 14% from its initial cold worth. Additional details are provided in Reference 9.

In order to maintain the nuclear lifetime discussed above, each control rod design must ensure the absorber material remains capable of performing its function. The design bases for control rod mechanical lifetime is based on maintaining absorber tube integrity. The mechanical lifetime limit is reached when the depletion-induced B_4C swelling or tube pressurization results in stresses in any absorber tube of the control rod in excess of the yield stress. For those designs that incorporate hafnium as a poison, there are no mechanically based lifetime limiting mechanisms associated with hafnium. Additional details are provided in Reference 9.

The plant computer is used to track total accumulated exposure for each quarter segment of each control rod in the reactor core. Percent Boron-10 depletion is calculated for each control rod based on conversion factors that correlate accumulated exposure to percent Boron-10 depletion (Reference 2 and 9). Recommended limits in terms of percent Boron-10 depletion from the manufacturer are adhered to as provided in the current revision of Reference 9.

Standard Control Rod

The main structural member of a control rod is made of Type 304 stainless steel and consists of a top casting which incorporates a handle, a bottom casting which incorporates a velocity limiter and control rod drive coupling, a vertical cruciform center post, and four U-shaped absorber rod sheaths. The two end castings and the center post are welded into a single skeletal structure. The U-shaped sheaths are resistance welded to the center post and castings to form a rigid housing to contain the absorber rods. Rollers at the top and the bottom of the control rod provide guidance for the control rod as it is inserted and withdrawn from the core. The control rods are cooled by the fuel assembly bypass flow.

The U-shaped sheaths are perforated to allow the coolant to freely circulate about the absorber rods. Operating experience has shown that control rods constructed as described above are not susceptible to dimensional distortions, as required by safety design basis 1.b.

The absorber rods in a standard control rod are comprised entirely of boron carbide (B_4C) powder in stainless steel tubes. The boron carbide (B_4C) powder in the absorber tubes is compacted to about 70 percent of its theoretical density; the boron carbide contains a minimum of 76.5 percent by weight natural boron. The Boron-10 (B^{10}) content of the boron is 18.0 percent by weight minimum. The absorber tubes are made of Type 304 stainless steel. An absorber tube has a 0.188 inch outside diameter and a 0.05 inch wall thickness. An absorber tube is sealed by a plug welded into each end. The boron carbide is separated longitudinally into individual compartments by stainless steel balls at approximately 16 inch intervals. The steel balls are held in place by a slight crimp of the tube. Should the boron carbide tend to compact further in service, the steel balls will distribute the resulting voids over the length of the absorber tube.

If the control rod blades are subjected to sufficient exposure to cause approximately 50 percent local depletion of the poison tube Boron-10 (B^{10}), the potential for tube cracking and boron leaching exists. (See References 1, 2, 3 and 4). Local depletion levels are measured in 6-inch axial segments.

The cracking is due to stress corrosion induced by solidification of boron carbide (B_4C) particles and swelling of the compacted B_4C as helium and lithium concentrations grow. Once primary coolant penetrates the cladding (i.e. the cracking has progressed through the cladding wall and the helium-lithium pressures are sufficient to open the crack), boron is leached out of the tube. The cracking and boron loss shorten the design life of the control rod. To extend the control rod mechanical lifetime, the absorber rod at the outer end of each control rod blade is constructed in two half-length sections.

Since the control rods enter from the bottom of the core, the neutron exposure of the control rods is skewed towards the top half

of the control rod. The absorber rod at the outer edge of each blade of the control rod receives more neutron irradiation than any other rod in the blade. Neutron irradiation is significantly less for each absorber rod located closer to the center of the control rod. The absorber rod tubing at the lower end of the control rods undergoes negligible fast flux irradiation and, as a result, retains its initial annealed material properties throughout the lifetime of the control rods. Thus, the allowable design stress for all absorber rod tubes which extend into the bottom end of the control rod is based upon the mechanical properties of fully annealed Type 304 stainless steel. The tubing of the top half length absorber rod undergoes full irradiation strengthening such that the allowable design stress for this tube is determined by the mechanical properties of fully irradiated material. Thus, by making the outer absorber rod in two sections, the absorber rod tube with the highest internal pressure benefits from a higher allowable design stress. As a result, the mechanical lifetime of the control rod is extended.

The standard control rods meet the requirements of safety design basis 1.a.

Hybrid Control Rod

The principle design change in the hybrid control rod is the use of hafnium absorber rods in place of B_4C absorber rods in selected high-flux locations. Hafnium is a proven long-life absorber that does not swell during reactor service. Each hybrid control rod contains a total of twelve hafnium absorber rods, three per control rod wing, located as shown in Figure 3.4-14. The number of hafnium rods was determined by establishing an acceptable local boron depletion limit for B_4C absorber rods and then placing hafnium in locations where local burnup exceeded this limit. The local depletion limit for the B_4C absorber rods was maximized since hafnium increases both the weight and cost of the control rod.

Besides the use of hafnium, hybrid control rods are improved over standard control rods by:

1) substitution of high-purity Type 304 stainless steel absorber tubes in place of commercial-quality Type 304 stainless steel and

2) substitution of new pin and roller materials in place of cobalt-bearing stellite.

High-purity Type 304 stainless steel is more resistant to stress corrosion cracking than commercial-quality Type 304 stainless steel. Stress corrosion cracking is a precursor to boron leaching. Elimination of cobalt-bearing stellite yields lower end-of-life gamma activity and attendant reductions in personnel exposures and radionuclide disposal requirements.

Except for the thickness of the sheath material, the dimensions of the hybrid control rod are identical to the dimensions of the standard control rod. The sheath material thickness is reduced by

22 mils to offset the greater weight of the hafnium absorber rods. Gross weights of the hybrid and standard control rods are identical. The dimensional similarity of the hybrid control rod makes this rod compatible with NSSS hardware designed for the standard control rod.

The reactivity worth is approximately identical (within ± 5%) to the original equipment control rods and can be used interchangeably without affecting lattice physics, core reload analyses or core monitoring software.

Operational lifetime of the hybrid control rods is determined by the same set of nuclear and mechanical design constraints as with the standard control rod.

The hybrid control rods meet the requirements of Safety Design Basis 1.a.

Model Duralife 230

The General Electric Model Duralife 230 (D230) Control Blade is an extension of the Hybrid Design described above with improvements. See Figure 3.4-15. Improvements to and differences from the Hybrid Blade can be used to describe the D230 blade. The three hafnium rods in each hybrid wing have been replaced by a solid strip of hafnium in the D230. The D230 also has a six inch plate of hafnium atop each wing. As in the hybrid blade, the D230 uses hafnium in areas where the thermal flux tends to be the highest for the same reasons. Mechanically and dimensionally, the D230 blade is very similar to the hybrid blade. B_4C tubing is a larger diameter and the sheath thickness is the same as the hybrid (0.045 inch) which does not quite compensate for the larger diameter B_4C tubing. Therefore, the wing thickness is 0.012 inch thicker than the original blade. The entire D230 is manufactured from low cobalt stainless steels.

The reactivity worth is approximately identical (within ± 5%) to the original equipment control rods and can be used interchangeably without affecting lattice physics, core reload analyses or core monitoring software.

Operational lifetime of the hybrid control rods is determined by the same set of nuclear and mechanical design constraints as with the standard control rod.

The Model D230 control blade meets the requirements of Safety Design Basis 1.a. (Reference 8)

Model Marathon D

The General Electric Marathon D control rod is an extension of the hybrid design described above with improvements. The Marathon design is directly interchangeable with previously installed control rod designs: Standard, Hybrid or D230. The essential difference between the Marathon control rod and the D230 design is replacement

of the absorber tube and sheath arrangement with an array of square absorber tubes, which results in reduced weight and increased absorber volume. The absorber tubes are welded together lengthwise to form the four wings of the control rod. Empty absorber tubes may be used near the tie rods to obtain the desired reactivity worth. The square tubes are circular inside and are or may be loaded with empty capsules, or capsules containing boron carbide or hafnium. Empty capsules are used to provide a plenum for helium released during boron carbide burnup. The boron carbide is contained in separate stainless capsules to prevent its migration. The capsules securely contain the boron carbide while allowing the helium to migrate through the absorber tube.

The reactivity worth is approximately identical (within ± 5%) to the original equipment control rods and can be used interchangeably without affecting lattice physics, core reload analyses or core monitoring software.

Operational lifetime of the Marathon control rod is determined by the same set of nuclear and mechanical design constraints as with the standard control rod. GE Hitachi Inc. has substituted Marathon D with M7 control rods, which are essentially identical to Marathon D, except that they have spacer pads instead of pins and rollers to avoid cracking/corrosion problems with pin-holes. GE Hitachi Inc. has substituted Marathon D with Marathon Ultra HD (High Duty) control rods. The Marathon Ultra HD control rods are functionally equivalent to the Marathon D blades. The Marathon Ultra designs eliminate swelling induced strains on the outer absorber tube by resizing the inner capsule diameter. Marathon Ultra are designed such that a diametric clearance exists between the inner capsule and the outer absorber tube at 100% local Boron-10 depletion, worst-case capsule and absorber tube dimensions, and upper bound $+3_6$ boron carbide swelling rates. Capsule cross-sectional geometry provides a larger gap between the inner capsule and the outer absorber tube. Therefore, Marathon Ultra HD control rods have more tolerance to the stress corrosion cracking phenomenon than Marathon D control rods leading to longer blades lifetime. The Marathon Ultra HD control rods have been approved by NRC. (Reference 12)

The Marathon D control blade meets the requirements of Safety Design Basis 1.a. (Reference 11).

3.4.5.1.2 Control Rod Velocity Limiter

The control rod velocity limiter is an integral part of the bottom assembly of each control rod. This Engineered Safeguard protects against a high reactivity insertion rate by limiting the control rod velocity in the event of a control rod drop accident. It is a one way device in that the control rod scram velocity is not significantly affected, but the control rod dropout velocity is reduced to a permissible limit. See Figures 3.4-3 and 3.4-4.

The velocity limiter is in the form of two nearly mated conical elements that act as a large clearance piston and baffle inside the control rod guide tube over the length of the control rod stroke.

The hydraulic drag forces on a control rod are approximately proportional to the square of the rod velocity and are negligible during normal rod withdrawal or rod insertion. However, during the scram stroke the rod reaches high velocity and the drag forces could become appreciable.

To limit control rod velocity during dropout but not during scram, the velocity limiter is provided with a streamlined profile in the scram (upward) direction. Thus, when the control rod is scrammed, the velocity limiter assembly offers little resistance to the flow of water over the smooth surface of the upper conical element into the annulus between the guide tube and the limiter. In the dropout direction, however, water is trapped by the lower conical element and discharged through the annulus between the two conical sections. Because this water is jetted in a partially reversed direction into water flowing upward in the annulus, a severe turbulence is created,thereby slowing the descent of the control rod assembly to less than 5 ft/sec at 70°F.

3.4.5.2 Control Rod Drive Mechanisms

The CRD mechanism (drive), used for positioning the control rod in the reactor core, is a double acting, mechanically latched, hydraulic cylinder using water from the Condensate and Demineralized Water Storage Transfer System as its operating fluid. The demineralizer system is the preferred source because of reduced conductivity and oxygen content. See Sections 11.7 and 11.9. The individual drives are mounted on the bottom head of the reactor pressure vessel. Each drive is an integral unit contained in a housing extending below the reactor vessel. The lower end of each drive housing terminates in a flange to which the drive is bolted. The drives do not interfere with refueling and are operative even when the head is removed from the reactor vessel. The drives are accessible for inspection and servicing. The bottom location makes maximum utilization of the water in the reactor as a neutron shield giving the least possible neutron exposure to the drive components. The use of condensate or demineralizer water as the operating fluid eliminates the need for special hydraulic fluid. Drives are able to utilize simple piston seals since the leakage does not contaminate the reactor vessel and helps cool the drive mechanisms. See Figures 3.4-3, 3.4-5, 3.4-6, and 3.4-7.

The drives are capable of inserting or withdrawing a control rod at a slow controlled rate for reactor power level adjustment, as well as providing rapid insertion when required. A locking mechanism on the drive allows the control rod to be locked at every 6 in of stroke over the 12 ft length of the core.

A coupling at the top end of the drive index tube (piston rod) engages and locks into a mating socket at the base of the control rod

The weight of the control rod is sufficient to engage and lock this coupling. Once locked, the drive and rod form an integral unit which must be manually unlocked by specific procedures before a drive and its rod can be separated; this prevents accidental separation of a control rod from its drive.

Each drive positions its control rod in 6 in increments of stroke, and holds it in these distinct latch positions until actuated by the hydraulic system for movement to a new position. Indication is provided for each rod that shows when the insert travel limit or withdraw travel limit is reached. An alarm annunciates when the withdraw overtravel limit on the drive is reached. Normally, the control rod seating at the lower end of its stroke prevents the drive withdraw overtravel limit from being reached. If the drive can reach the withdrawal overtravel limit, it indicates that the control rod is uncoupled from its drive. The over travel limit alarm allows the coupling to be checked.

The positions of the drive selected for movement, together with positions of three (or less) adjacent drives, and Local Power Range Monitor signals in the vicinity of the selected drive, are continuously displayed as described in Section 7.5, Neutron Monitoring System. The selected rod is indicated by a status light. The positions of all drives not selected for movement are continuously monitored for motion. A change in drive position (drive drifting) initiates an audible alarm and indicates the faulty drive. The rod position information received from the drive position indicator probes are processed by the Rod Position Indicator System (RPIS), and distributed to various displays, annunciators, and the computer.

The status of all drives, scram valves, and accumulators are continuously indicated by panel lights. The indicated status include the following:

- Drive fully inserted
- Drive fully withdrawn
- Drive selected for movement
- Drive drifting (position change when not selected)
- Scram valve not closed
- Accumulator trouble (low pressure and/or leak)

In addition to the above, an annunciator signal is also produced by a rod overtravel.

Status indicators are differentiated by location and color in order to minimize operator error. The indicator arrangement is such as to graphically depict the actual location of rods in the reactor core. The position signals of selected drives, together with a drive identification signal, are provided for recording by a computer in accordance with the requirements of Section 7.16, Process Computer. The acquisition of a position signal by the computer does not interrupt the position indication.

The previous CRD design (Model 7RDB144-A2) used on other reactors utilized an inner filter which is attached to the lower end of the coupling spud. In this location, the inner filter moved with the moving drive whenever the CRD was normally inserted and withdrawn or scrammed. During scram, the downward forces on the CRD index tube was minimized by passing water through the inner filter at low pressure drops. In this location, if the resistance to flow through this inner filter increased due to various degrees of plugging, the pressure drop across the inner filter increased, resulting in increased downward force on the CRD index tube and consequent increase in scram times.

The Pilgrim CRD design (Model 7RDB144-B1) has changed the location of the inner filter from the moving spud to stationary location on top of the stop piston assembly. In this location, the inner filter is no longer a part of the moving drain line, and consequently, if plugging of this filter should occur, it will not affect scram times. In the previous location, the inner filter passed seal leakage water plus the necessary water to fill the volume between the stop piston seals and the inner filter. In the Pilgrim location, the inner filter must only pass seal leakage water. The location of the new inner filter design in the CRD is shown on Figure 3.4-8.

The effectiveness and reliability of this design modification was demonstrated under field conditions by surveillance, and testing performed during the preoperational and startup programs. Those informal surveillance procedures which demonstrated their effectiveness in diagnosing degradation of drive scram performance, due to dirt accumulation, were modified to improve their effectiveness and formalized by incorporation in the preoperational and startup testing program. These surveillance test procedures supplement the tests which demonstrate conformance with operating techniques specification limits, and are designed to detect changes in scram performance. The principles on which the surveillance tests were based are as follows:

1. A sample of all operable installed drives will be periodically tested to measure a characteristic scram performance parameter which will be evaluated for significant changes. Indication of a change suggesting performance degradation will require additional testing to determine the extent and cause of the fault

2. The sample size and acceptance limits were chosen to provide at least a 95 percent confidence that a change in performance is detected with 5 percent chance of making a false assumption of change. The basis for the choice of sample size and acceptance limits is the observed statistical characteristics of the results of the performance demonstration tests of the drives. Experience indicates that a sample size of 15 to 25 is adequate

3. The sample contains drives uniformly distributed in the core and are reconstituted for each successive measurement to measure the entire core progressively. With this routine sample is measured those drives which exceed the normally anticipated performance limits and therefore require continued surveillance

   The characteristic parameter of drive scram performance that yields the greatest accuracy and is most indicative of drive condition, is the time required to reach 90 percent stroke insertion at rated vessel pressure (1,000 psig)

Following the low vessel pressure scram performance tests of the preoperational test program, and before power operation, the scram performance of all drives at rated vessel pressure was measured and compared with predicted performance and operating technical specifications. This demonstration test was used as a basis for setting surveillance limits.

Thereafter, surveillance tests of a drive sample were performed before zero power and before each power increase during the startup program. Furthermore, during the startup program, periodic surveillance tests were performed at 4, 8, and 16 week intervals, continuing at 16 week intervals until the startup program was finished. In the event of a shutdown requiring vessel head removal or extensive work on the major reactor systems during the startup program, a performance measurement was required on all drives before resuming power operation, and the surveillance test of drive samples reverted to the 1, 2, 4, 8, and 16 week intervals until the startup program was finished.

3.4.5.2.1 Components

Figure 3.4-5 illustrates the principle of operation of a drive. Figures 3.4-6 and 3.4-7 illustrate the drive in more detail. Following is a description of the main components of the drive and their functions.

Drive Piston and Index Tube

The drive piston is mounted at the lower end of the index tube which functions as a piston rod. The drive piston and index tube make up the main moving assembly in the drive. The drive piston operates between positive end stops, with a hydraulic cushion provided at the upper end only. The piston has both inside and outside seal rings and operates in an annular space between an inner cylinder (fixed piston tube), and an outer cylinder (drive cylinder).

The effective piston area for down travel or withdraw is about 1.2 in^2 versus 4.0 in^2 for up travel or insertion. This difference in driving area tends to balance out the control rod weight, and makes it possible to always have a higher insertion force than withdrawal force.

The index tube is a long hollow shaft made of nitrided Type 304 or ASTM A479 Grade XM-19 stainless steel. This tube has circumferential locking grooves spaced every 6 in along the outer surface. These grooves transmit the weight of the control rod to the collet assembly which positions the rod.

Collet Assembly

The collet assembly serves as the index tube locking mechanism. It is located in the upper part of the drive unit. The collet assembly prevents the index tube from accidentally moving downward. The collet assembly consists of the collet fingers, a return spring, a guide cap, a collet housing (part of the cylinder, tube, and flange), and the collet piston seals.

Locking is accomplished by six fingers mounted on the collet piston at the top of the drive cylinder. In the locked or latched position the fingers engage a locking groove in the index tube.

The collet piston is normally held in the latched position by a return spring force of approximately 150 lb.

Metal piston rings are used to seal the collet piston from reactor vessel pressure. The collet assembly will not unlatch until the collet fingers are unloaded by a short, automatically sequenced, drive in signal. A pressure of approximately 180 psi above reactor vessel pressure acting on the collet piston is required to overcome spring force, slide the collet up against the conical surface in the guide cap, and spread the fingers out so that they do not engage a locking groove. The collet piston is nitrided to minimize wear due to rubbing against the surrounding cylinder surfaces.

Fixed in the upper end of the drive assembly is a guide cap. This member provides the unlocking cam surface for the collet fingers. It also serves as the upper bushing for the index tube and is nitrided to provide a compatible bearing surface for the index tube.

If reactor water is used to supplement accumulator pressure during a scram, it is drawn through a filter on the guide cap.

Piston Tube and Stop Piston

Extending upward inside the drive piston and index tube is an inner cylinder or column called the piston tube. The piston tube is fixed to the bottom flange of the drive and remains stationary. Water is brought to the upper side of the drive piston through this tube. A series of orifices at the top of the tube provides progressive water shutoff to cushion the drive piston at the end of its scram stroke.

A stationary piston, called the stop piston, is mounted on the upper end of the piston tube. This piston provides the seal between reactor vessel pressure and the space above the drive piston. It also functions as a positive end stop at the upper limit of control rod travel. A stack of spring washers just below the stop piston helps absorb the final mechanical shock at the end of control rod travel. The piston rings are similar to the outer drive piston rings. A bleed off passage to the center of the piston tube is located between the two pairs of rings. This arrangement allows seal leakage from the reactor vessel during a scram, to be bled directly to the discharge line, rather than to the space above the drive piston. The lower pair of seals is used only during the cushioning of the drive piston at the upper end of the stroke.

Position Indicator

The center tube of the drive mechanism forms a well to contain the position indicator probe. The position indicator probe is an aluminum extrusion attached to a cast aluminum housing. Mounted on the extrusion are a series of hermetically sealed, magnetically operated, position indicator switches. Each switch is sheathed in a braided glass sleeve, and the entire probe assembly is protected by a thin walled stainless steel tube. The switches are actuated by a ring magnet carried at the bottom of the drive piston. The drive piston, piston tube, and indicator tube are all of nonmagnetic stainless steel, allowing the individual switches to be operated by the magnet as the piston passes. One switch is located at each

position corresponding to an index tube groove, thus allowing indication at each latching point. An additional switch is located at each midpoint between latching points, allowing indication of the intermediate positions during drive motion. Thus, indication is provided for each 3 in of travel. Duplicate switches are provided for the full-in and full-out positions. One additional switch (an overtravel switch) is located at a position below the normal full-out position. Because the limit of down travel is normally provided by the control rod itself as it reaches the backseat position, the index tube can pass this position and actuate the overtravel switch only if it is uncoupled from its control rod. A convenient means is thus provided to verify that the drive and control rod are coupled after installation of a drive or at any time during station operation.

Flange and Cylinder Assembly

A heavy flange is welded to the drive cylinder. A sealing surface on the upper face of this flange is used in making the seal to the drive housing flange. Teflon coated, stainless steel O-rings are used for these seals. In addition to the reactor vessel seal, the two hydraulic control lines to the drive are sealed at this face. A drive can thus be replaced without removing the control lines, which are permanently welded into the housing flange. The drive flange contains the integral ball or two way check (shuttle) valve. This valve is so situated as to direct reactor vessel pressure or driving pressure, whichever is higher, to the underside of the drive piston. Reactor vessel pressure is admitted to this valve from the annular space between the drive and drive housing through passages in the flange. A screen is provided to intercept foreign material at this point.

Water used to operate the collet piston passes between the outer tube and the cylinder tube. The inside of the cylinder tube is honed to provide the surface required for the drive piston seals.

Both the cylinder tube and outer tube are welded to the drive flange. The tops of these tubes have a sliding fit to allow for differential expansion.

Coupling Spud, Plug, Unlocking Tube

The upper end of the index tube is threaded to receive a coupling spud. The coupling (Figure 3.4-3) is designed to accommodate a small amount of angular misalignment between the drive and the control rod. Six spring fingers allow the coupling spud to enter the mating socket on the control rod. The control rod weight is sufficient to force the spud fingers to enter the socket (control rod weight is approximately 250 lb). The lock plug then enters the spud and prevents uncoupling.

With the lock plug in place, a force in excess of 50,000 lb is required to pull the coupling apart.

Two means of uncoupling are provided. With the reactor vessel head removed, the lock plug may be raised against the spring force of approximately 50 lb by a rod extending up through the center of the control rod to an unlocking handle, located above the control rod velocity limiter. The control rod, with the lock plug raised, can then be separated from the drive. The lock plug may also be pushed up from below, if it is desired to uncouple a drive without removing the reactor pressure vessel head for access. In this case, the central portion of the drive mechanism is pushed up against the uncoupling rod assembly which raises the lock plug, and allows the coupling spud to disengage the socket as the drive piston and index tube are driven down.

The coupling spud and locking tube thus meet the requirements of safety design basis 3.e.

3.4.5.2.2 Materials of Construction

Factors determining the choice of materials are listed below:

1. The index tube must withstand the locking and unlocking action of the collet fingers. A compatible bearing combination must be provided which is able to withstand moderate misalignment forces. The reactor environment limits the choice of materials suitable for corrosion resistance. The column and tensile loads can be satisfied by an annealed 300 series stainless steel. The wear and bearing requirements are provided by Malcomizing the completed tube, or by using ASTM A479 Grade XM-19 stainless steel. To obtain suitable corrosion resistance, a carefully controlled process of surface preparation is employed

2. The coupling spud is made of Inconel 750 which is aged to produce maximum physical strength and also provide the required corrosion resistance. As misalignment tends to produce a chafing in the semispherical contact area, the entire part is protected by a thin vapor deposited chromium plating (Electrolizing). This plating also serves to prevent galling of the threads attaching the coupling spud to the index tube

3. Inconel 750 is used for the collet fingers, which must function as leaf springs when cammed open to the unlocked position. Colmonoy 6 hard facing is applied to the area contacting the index tube, and unlocking cam surface of the guide cap to provide a long wearing surface adequate for design life

4. Graphitar 14 is selected for seals and bushings on the drive piston and stop piston. The material is inert and has a low friction coefficient when water lubricated. Since loss of strength is experienced at higher temperatures, the drive is supplied with cooling water to hold temperatures below 250°F. The Graphitar is

relatively soft, which is advantageous when an occasional particle of foreign matter reaches a seal. The resulting scratches in the seal reduce sealing efficiency until worn smooth, but the drive design can tolerate considerable water leakage past the seals into the reactor vessel

All drive components exposed to reactor vessel water are made of AISI 300 series stainless steel except the following:

1. Seals and bushings on the drive piston and stop piston are Graphitar 14

2. All springs and members requiring spring action (collet fingers, coupling spud, and spring washers) are made of Inconel 750

3. The ball check valve employs a Haynes Stellite cobalt base alloy

4. Elastomeric O-ring seals are ethylene propylene

5. Collet piston rings are Haynes 25 alloy

6. Certain wear surfaces are hard faced with Colmonoy 6

7. Nitriding by a proprietary new Malcomizing process, electrolizing (a vapor deposition of chromium), and chromium plating or ASTM A479 Grade XM-19 stainless steel are used in certain areas where resistance to abrasion is necessary

8. The drive piston head is made of Armco 17-4Ph

Pressure containing portions of the drives are designed and built in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code.

3.4.5.3 Control Rod Drive Hydraulic System

The CRD Hydraulic System supplies and controls the pressure and flow requirements to the drives. See Figure 3.4-9 (Drawing M250).

There is one supply subsystem which supplies water at the proper pressures and sufficient flow to the hydraulic control units (HCUs). Each HCU controls the flow to and from a drive. The water discharged from the drives during a scram flows through the HCUs to the scram discharge volume. The water discharged from a drive during a normal control rod positioning operation flows through its HCU and returns it to the reactor vessel by backflow through the 121 valves of other CRD HCUs.

3.4.5.3.1 CRD Hydraulic Supply and Discharge Subsystems

The CRD hydraulic supply and discharge subsystems control the

pressure and flows required for the operation of the control rod drive mechanisms. These hydraulic requirements identified by the function they perform are as follows. See Figures 3.4-9 (Drawing M250), 3.4-10 (Drawing M1D12-4), and 3.4-11 (Drawing M1D12-4).

1. Accumulator charging pressure normal range is 1,380 psig to 1,510 psig. Flow is required only during scram reset or during system startup. Charging water pressures outside of the normal range may occur as drive water pump performance change during its service life.

2. Drive pressure of about 250 psi above reactor vessel pressure is required at a flow rate of approximately 4 gal/min to insert a control rod and 2 gal/min to withdraw a control rod during normal operation.

3. Cooling water to the drives is required at approximately 10 psig above reactor vessel pressure, and at a flow rate of 0.20 to 0.34 gal/min per drive unit. Cooling water may be interrupted for short periods without drive damage.

4. The exhaust water header is maintained at a pressure approximately 15 psi above vessel pressure to receive the flow of the water displaced during normal control operation of the drives.

5. A scram discharge instrument volume of approximately 1.1 gallon per drive to receive the water displaced from the drives during a scram is required. The scram discharge instrument volume is required to contain air at atmospheric pressure, except during scram when it is filled with water until the scram signal is cleared and the system reset. The scram discharge instrument volume will reach reactor pressure following a scram.

6. General Electric (GE) supplied 1-in. pressure equalizing valves are installed between the CRD cooling water header and the exhaust water header. The pressure equalizing valves are self-actuated, and will perform the functions of (a) preventing continuous flow to the normal exhaust water header and coincident reverse flow through the directional control solenoid valve V-121, (b) preventing flow from the carbon steel piping in the normal exhaust water header to the drive cooling water header, and (c) repressurizing the exhaust header following a scram and preventing excessive high CRD operating differential pressure during subsequent operation of a selected CRD.

The CRD hydraulic supply and discharge systems provide the required functions with the pumps, filters, valves, instrumentation, and piping shown on Figure 3.4-9 and described in the following paragraphs.

Duplicate components are included, where necessary, to assure continuous system operation if an inservice component requires maintenance.

Pumps

One supply pump is provided to pressurize the system with water downstream of the condensate demineralizer or the condensate storage tank. One spare pump is on standby. Each pump is installed with a suction strainer and a discharge check valve to prevent bypassing flow backwards through the nonoperating pump.

A minimum flow bypass connection between the discharge of the pump and the condensate storage tank prevents overheating of the pump in the event that the pump discharge is inadvertently closed.

Filters

The filter removes foreign material larger than 50 microns absolute (25 microns nominal) from the hydraulic supply subsystem water. A differential pressure indicator and alarm monitor the filter element as it collects foreign material. A strainer in the filter discharge line guards the hydraulic system in the event of filter element failure.

Accumulator Charging Pressure

The accumulator charging pressure is maintained automatically by a flow sensing element, controller, and an air operated flow control valve. During normal operation, the accumulator charging pressure is established upstream from the flow control valve by the restriction of the flow control valve. During scram, the flow sensing system upstream of the accumulator charging header detects high flow in the charging header and partly closes the flow control valve. The flow control valve is closed enough so that the proper flow to recharge the accumulators is diverted from the hydraulic supply header to the accumulator charging header.

The pressure in the charging header is monitored in the control room with a pressure indicator and low pressure alarm.

During normal operation, the constant flow established through the flow control valves is the sum of the maximum water required to cool all the drives.

Drive Water Pressure

The drive water pressure control valve, which is manually adjusted from the control room, maintains the required pressure in the drive water header.

A flow rate of approximately 6 gpm (the sum of the flow rates required to insert and to withdraw a control rod) normally passes from the drive water pressure header through two solenoid operated stabilizing valves (arranged in parallel) and, then to the cooling water supply header down steam of the drive water pressure control

valve. One stabilizing valve passes flow equal to the drive insert flow. The other passes flow equal to the drive withdrawal flow. The appropriate stabilizing valve is closed when operating a drive to divert the required flow to the drive. Thus, the flow through the drive pressure control valve is always constant.

Flow indicators are provided in the drive water header and in the line down stream from the stabilizing valves, so that flow rate through the stabilizing valves can be adjusted. Differential pressure between the reactor vessel and the drive water pressure header is indicated in the control room.

Cooling Water Pressure

The water not required for drive movement passes through the drive water control valve through the cooling water header and then to the reactor vessel.

The flow through the drive water control valve is constant. Therefore, the drive water pressure control valve can maintain the required cooling water pressure with minimum adjustments independent of reactor pressure. Changes in the setting of the pressure control valve is required only to adjust for changes in the cooling requirements of the drives, as their seal characteristics change with time. The cooling water flow is monitored by a flow indicator in the control room. A differential pressure indicator in the control room indicates the difference between reactor vessel pressure and the drive cooling water pressure. Although the drives can function without cooling water, the life of their seals is shortened by exposure to reactor temperatures.

Exhaust Water Header

The exhaust water header takes water during a normal control rod positioning operation, and returns it to the reactor vessel by backflow through the 121 valve of other CRD's. Two equalizing valves are provided between the cooling water line and the exhaust header to repressurize the exhaust header following a scram. This prevents excessively high operation of a selected CRD.

Scram Discharge Volume

The scram discharge volume is used to limit the loss of and contain the reactor vessel water from all the drives during a scram. The volume consists of two separate scram discharge headers and their associated scram discharge instrument volumes (SDIV). During normal plant operation, the discharge volume is empty with two drain valves on each SDIV and two vent valves on each header open. Upon receipt of a scram signal, the drain and vent valves close. Position indicator switches on the drain and vent valves indicate valve position by lights in the main control room.

During a scram, the scram discharge volume partly fills with water which is discharged from above the drive pistons. While scrammed, the CRD seal leakage continues to flow to the discharge volume until the discharge volume pressure equals reactor vessel pressure. There is a check valve in each HCU which prevents reverse flow from the scram discharge header to the drive. When the initial scram signal is cleared from the Reactor Protection System (RPS) the scram discharge volume scram signal is overridden with the key lock override switch and the scram discharge volume is drained.

Two test pilot valves allow the discharge volume valves to be tested without disturbing the RPS. Closing the vent and drain valves allow the outlet scram valve seats to be leak tested by timing the accumulation of leakage inside the scram discharge volume. The test pilot valves also provide for the reset of the air dump system. See Figure 3.9-4.

Three level switches and two level transmitters with analog trip units on each scram discharge instrument volume (SDIV), set at three different water levels, guard against operation of the reactor without sufficient free volume present to receive the scram discharge water in the event of a scram. At the first (lowest) level, each of two analog trip units off of two level transmitters on each SDIV initiate an alarm for operator action. Also, they send signals to the plant computer. At the second level, one level switch on each SDIV initiates a rod withdrawal block to prevent further withdrawal of any control rod. At the third (highest) level, the two level switches and two analog trip units off of two level transmitters on each SDIV (one of each type of instrument for each RPS trip system for each SDIV) initiate a scram to shut down the reactor while sufficient free volume is still present to receive the scram discharge. After a scram, these same level switches must be cleared by draining the scram discharge volume and the air dump system must be reset before reactor operation can be resumed.

Weldolet couplings and socket welded caps are provided on both CRD scram discharge headers to facilitate flushing and decontamination of the headers. Four instrument standpipes are connected to each SDIV. Connections are also provided on instrument standpipes to facilitate flushing and test/calibration of level instruments during reactor power operations.

The piping and equipment pressure parts in the CRD hydraulic supply and discharge subsystems are in accordance with Appendix A.

3.4.5.3.2 Hydraulic Control Units

Each HCU controls a single drive unit. The basic components in each HCU are manual, pneumatic, and electrically operated valves, an accumulator, filters, related piping, and electrical connections. See Figures 3.4-9 and 3.4-13.

Each HCU furnishes pressurized water upon signal to a CRD. The drive then positions its control rod as required. Operation of the electrical system which supplies scram and normal control rod positioning signals to the HCU is described in Section 7.7, Reactor Manual Control System.

The basic components contained in each HCU and their functions are as follows:

Insert Drive Valve

The insert drive valve is a solenoid operated valve which opens on an insert signal to supply drive water to the bottom side of the main drive piston.

Insert Exhaust Valve

The insert exhaust valve is a solenoid operated valve which opens on an insert signal to discharge water from above the drive piston to the exhaust header.

Withdrawal Drive Valve

The withdrawal drive valve is a solenoid operated valve which opens on a withdrawal signal to supply drive water to the top side of the drive piston.

Withdrawal Exhaust Valve

The withdrawal exhaust valve is a solenoid operated valve which opens on a withdrawal signal to discharge water from below the main drive piston to the exhaust header.

Speed Control Valves

The speed control valves, which regulate the control rod insertion and withdrawal rates during normal operation, are manually adjustable flow control valves used to regulate the water flow to and from the volume beneath the main drive piston. Once a speed control valve is properly adjusted, it is not necessary to adjust the valve except to compensate for changes in piston seal leakage.

Scram Pilot Valves

The scram pilot valve are operated from the RPS trip system. Two scram pilot valves control both the scram inlet valve and the scram exhaust valve. The scram pilot valves are identical, three way, solenoid operated, normally energized valves. On loss of electrical signal to the pilot valves, the inlet ports are closed and the exhaust ports are opened on both pilot valves. The pilot valves are arranged as shown on Figures 3.4-9 and 3.4-10 so that the trip system signal must be removed from both valves before air pressure is discharged from the scram valve operators.

Scram Inlet Valve

The scram inlet valve is opened to supply scram water pressure to the bottom of the drive piston. The scram inlet valve is a globe valve which is opened by the force of an internal spring and system pressure, and closed by air pressure applied to the top of its diaphragm operator. The opening force of the spring is approximately 700 lb. The valve opening time is approximately 0.1 sec from start to full open.

The scram inlet valve has a position indicator switch which energizes a light in the control room as soon as the valve starts to open.

Scram Exhaust Valve

The scram exhaust valve opens slightly before the scram inlet valve, exhausting water from above the drive piston during a scram. Quicker opening times are achieved because of a larger spring in the valve operator. Otherwise this valve is similar to the scram inlet valve.

Scram Accumulator

The scram accumulator stores sufficient energy to insert a control rod to the fully inserted position during a scram independent of any other source of energy. The accumulator consists of a water volume pressurized by a volume of nitrogen. The accumulator has a piston separating the water on top from the nitrogen below. A check valve in the charging line to each accumulator retains the water in the accumulator in the event supply pressure is lost.

During normal plant operation, the accumulator piston operates with a pressure drop across it of approximately 280 psid to 410 psid nominal range (depending on drive water pump performance). The piston contacts the accumulator lower end cap. Loss of nitrogen causes a decrease in the nitrogen pressure which actuates the pressure switch, and sounds an alarm in the control room.

Also, to ensure that the accumulator is always capable of producing a scram, it is continuously monitored for water leakage. A float type level switch actuates an alarm if water leaks past the barrier, and collects in the accumulator instrumentation block. The accumulator instrumentation block is located below the accumulator (nitrogen side) in such a way that it will receive any water which leaks past the accumulator piston.

The scram accumulator thus meets the requirements of safety design basis 3.d.

3.4.5.4 Control Rod Drive System Operation

The CRD System performs three operational functions: rod insertion, rod withdrawal, and scram. The functions are described below.

Rod Insertion

Rod insertion is initiated by a signal from the operator to the insert valve solenoids which open both insert valves. The insert drive valve applies reactor pressure plus approximately 90 psig to the bottom of the drive piston. The insert exhaust valve allows water from above the drive piston to discharge to the exhaust header.

As illustrated on Figure 3.4-6, the locking mechanism is a ratchet type device and does not interfere with rod insertion. The speed at which the drive moves is determined by the pressure drop through the insert speed control valve, which is set for about 4 gal/min for a shim speed (nonscram operation) of 3 in/sec. During normal insertion, the pressure on the downstream side of the speed control valve is 90 to 100 psi above reactor vessel pressure. However, if the drive slows down for any reason, the flow through and pressure drop across the insert speed control valve will decrease, and the full 250 psi differential pressure will be available to cause continued insertion. With 250 psi differential pressure acting on the drive piston, the piston exerts an upward force of 1,000 lb.

Rod Withdrawal

Drive withdrawal is, by design, more involved. First, the collet fingers (latch) must be raised to reach the unlocked position as in Figure 3.4-5. The notches in the index tube and the collet fingers are shaped so that the downward force on the index tube holds the collet fingers in place. The index tube must be lifted before the collet fingers can be released. This is done by opening the drive insert valves (in the manner described in the preceding paragraph) for approximately 1 sec. The withdraw valves are then opened, applying driving pressure above the drive piston and opening the area below the piston to the exhaust header. Pressure is simultaneously applied to the collet piston. As the collet piston raises, the collet fingers are cammed outward, away from the index tube, by the guide cap.

The pressure required to release the latch is set and maintained high enough to overcome the force of the latch return spring, plus the force of reactor pressure opposing movement of the collet piston. When this occurs, the index tube is unlatched and free to move in the withdrawal direction. Water displaced by the drive piston flows out through the withdrawal speed control valve which is set to give the control rod a shim withdrawal of 3 in/sec. The entire valving sequence is automatically controlled, and is initiated by a single operation of the rod withdraw switch.

Rod Scram

During a scram the scram pilot valves and scram valves are operated as previously described. With the scram valves open, accumulator pressure is admitted under the drive piston and the area over the drive piston is vented to the scram discharge volume.

The large differential pressure (initially about 1,400 psi and always several hundred psi depending on reactor vessel pressure), produces a large upward force on the index tube and control rod, giving the rod a high initial acceleration and providing a large margin of force to overcome any possible friction. The characteristics of the hydraulic system are such that, after the initial acceleration is achieved, the drive continues at a fairly constant velocity. This characteristic provides a high initial rod insertion rate. As the drive piston nears the top of its stroke, the piston seals close off the large passage in the stop piston tube and the drive slows down.

Each drive requires about 2.5 gal of water during the scram stroke. There is adequate water capacity in each drive's accumulator to complete a scram in the required time at low reactor vessel pressure. At higher reactor vessel pressures, the accumulator is assisted on the upper end of the stroke by reactor vessel pressure acting on the drive via the ball check (shuttle) valve. As water is forced from the accumulator, the accumulator discharge pressure falls below reactor vessel pressure. This causes the check valve to shift its position to admit reactor pressure under the drive piston. Thus, reactor vessel pressure furnishes the force needed to complete the scram stroke at higher reactor vessel pressures. When the reactor vessel is up to full operating pressure, the accumulator is actually not needed to meet scram time requirements. With the reactor at 1,000 psig and the scram discharge volume at atmospheric pressure, the scram force without an accumulator is over 1,000 lb.

The average scram performance requirements of the CRD System are provided in the current station Technical Specifications referenced in Appendix B.

3.4.6 Safety Evaluation

3.4.6.1 Evaluation of Control Rods

It is apparent from the description that the control rods meet the design basis requirements. The description also indicates how the control rod to drive coupling unit meets design basis requirements.

3.4.6.2 Evaluation of Control Rod Velocity Limiter

The control rod velocity limiter limits the free fall velocity of the control rod to a value which cannot result in nuclear system process barrier damage,[5] as required by safety design basis 1.c. This velocity is evaluated by the rod drop accident analysis in Section 14, Station Safety Analysis.

The following sequence of events is necessary to postulate an accident in which the control rod velocity limiter is required:

1. The rod to drive coupling fails.

2. The control rod sticks near the top of the core.

3. The drive is withdrawn and the control rod does not follow.

4. The operator fails to notice the lack of response as the control rod drive is withdrawn.

5. The control rod later becomes loose and falls freely to the withdrawn position.

3.4.6.3 Evaluation of Scram Time

The rod scram function of the CRD System provides the negative reactivity insertion which is required by safety design basis 2. The scram time shown in Section 3.4.5 is adequate as shown by the transient analyses of Section 14, Station Safety Analysis.

3.4.6.4 Analysis of Malfunctions Relating to Rod Withdrawal

There is no known single malfunction which could cause even a single rod to withdraw. The following malfunctions have been postulated and the results analyzed:

1. Drive Housing Fails At Attachment Weld

   The bottom head of the reactor vessel has a penetration with an internal nozzle for each control rod drive location. A drive housing is raised into position inside each penetration and fastened to the top of the internal nozzle with a J-weld. The drive is raised into the drive housing and bolted to a flange at the bottom of the housing. The basic failure considered is a complete circumferential crack through the housing wall at an elevation just below the J-weld. The housing material is seamless Type 304 stainless steel pipe with a minimum tensile strength of 75,000 psi.

Static loads on the housing wall include the weight of the drive and the control rod, the weight of the housing below the attachment weld to the vessel nozzle, and reactor pressure acting on the 6 in diameter cross sectional area of the housing and the drive. Dynamic loading is due to the reaction force during drive operation.

If the housing were to fail, as described above, the following sequence of events is foreseen. The housing would separate from the vessel and the control rod, the drive and the housing would be blown downward against the support structure by reactor pressure acting on the cross sectional area of the housing, and the drive. The amount of downward motion of the drive and associated parts would be determined by the gap between the bottom of the drive and the support structure, and by the amount the support structure deflects under load. In the current design, maximum deflection is approximately 3 in. If the collet were to remain latched, no further control rod ejection would occur.[6] The housing would not drop far enough to clear the vessel penetration. Reactor water would leak through the 0.06 in diametral clearance between the housing od and the vessel penetration id at a rate of approximately 440 gal/min.

If the basic housing failure were to occur at the same time the control rod is being withdrawn (this is a small fraction of the total drive operating time), and if the collet were to stay unlatched, the housing would separate from the vessel, the drive and housing would be blown downward against the CRD housing support, and calculations indicate that the steady state rod withdrawal velocity would be 0.3 ft/sec. During withdraw, pressure under the collet piston would be approximately 250 psi greater than the pressure over it. Therefore, the collet would be held in the unlatched position until driving pressure is removed from the pressure over port.

2. Rupture of Either or Both Hydraulic Lines to A Drive Housing Flange

   (a) Pressure Under Line Breaks

   In this case, a partial or complete circumferential opening is postulated at or near the point where the line enters the housing flange. Failure is more likely to occur after another basic failure wherein the drive housing, or housing flange, separates from the reactor vessel. Failure of the housing, however, does not necessarily lead directly to failure of the hydraulic lines.

If the pressure under line were to fail, and if the collet were latched, no control rod withdrawal would occur. There would be no pressure differential across the collet piston in this case, and therefore no tendency to unlatch the collet. Consequently, it would not be possible to either insert or withdraw the control rod involved

If reactor pressure were to shift the drive ball check valve against its upper seat, the broken pressure under line would be sealed off. If the ball check valve were to be prevented from seating, reactor water would leak to the atmosphere. Cooling water could not be supplied to the drive involved because of the broken line. Loss of cooling water would cause no immediate damage to the drive. However, prolonged drive exposure to temperatures at or near reactor temperature could lead to deterioration of material in the seals. High temperature would be indicated to the operator by the thermocouple in the position indicator probe.

If the basic line failure were to occur at the same time the control rod is being withdrawn, and if the collet were to remain open, calculations indicate that the steady state control rod withdrawal velocity would be 2 ft/sec. In this case, however, there would not be sufficient hydraulic force to hold the collet open and spring force would normally cause the collet to latch, stopping rod withdrawal.

(b) Pressure Over Line Breaks

The failure considered is complete breakage of the pressure over line at or near the point where the line enters the housing flange. If the line were to break, pressure over the drive piston would drop from reactor pressure to atmospheric pressure. If there were any significant reactor pressure, approximately 500 psig or greater, it would act on the bottom of the drive piston, and the drive would insert to the fully inserted position. Drive insertion would occur regardless of the operational mode at the time of the failure. After full insertion, reactor water would leak past the stop piston seals, the contracting seals on the drive piston, and the collet piston seals. This leakage would exhaust to atmosphere through the broken pressure over line. In an experiment to simulate this failure, a leakage rate of 80 gal/min has been measured with reactor pressure at 1,000 psi. If the reactor were hot, drive temperature would increase. The reactor operator would be apprised of the situation by indication of the fully inserted drive, by high drive temperature alarmed and recorded in the control room, and by operation of the drywell sump pump

(c) Coincident Breakage of Both Pressure Over and Pressure Under Lines

This failure would require simultaneous occurrence of the failures described above. Pressures above and below the drive piston would drop to zero and the ball check valve would shift to close off the broken pressure under line. Reactor water would flow from the annulus outside of the drive through the vessel ports to the space below the drive piston. As in the pressure over line break case, the drive would then insert at a speed dependent on reactor pressure. Full insertion would occur regardless of the operational mode at the time of failure. Reactor water would leak past the drive seals and out of the broken pressure over line to the atmosphere as described above. Drive temperature would increase. The reactor operator would be apprised of the situation by indication of the fully inserted drive, high drive temperature printed out by a recorder and alarmed in the control room, and by operation of the drywell sump pump.

3. All Drive Flange Bolts Fail in Tension

Each CRD is bolted to a flange at the bottom of a drive housing which is welded to the reactor vessel using eight bolts and slotted washers.

In the event that progressive or simultaneous failure of all of the bolts were to occur, the drive would separate from the housing, and the control rod and the drive would be blown downward against the support structure due to reactor pressure acting on the cross sectional area of the drive. Impact velocity and support structure loading would be slightly less than in drive housing failure, since reactor pressure would act on the drive cross sectional area only and the housing would remain attached to the reactor vessel. The drive would be isolated from the cooling water supply. Reactor water would flow downward past the velocity limiter piston and through the large drive filter into the annular space between the thermal sleeve and the drive. For worst case leakage calculations, it is assumed that the large filter would be deformed or swept out of the way so that it would offer no significant flow restriction. At a point near the top of the annulus, where pressure has dropped to 350 psi, the water would flash to steam and choke flow conditions would exist. Steam would flow down the annulus and out the space between the housing and the drive flanges to the atmosphere. Steam formation would limit the leakage rate to approximately 840 gal/min.

If the collet were latched, control rod ejection would be limited to the distance the drive can drop before coming to rest on the support structure. Since pressure below the collet piston would drop to zero, there would be no tendency for the collet to unlatch.

Pressure forces, in fact, exert 1,435 lb to hold the collet in the latched position.

If the bolt failure were to occur while the control rod is being withdrawn, pressure below the collet piston would drop to zero and the collet, with 1,650 lb return force, would latch, stopping rod withdrawal.

4. Weld Joining Flange to Housing Fails in Tension

The failure considered is a crack in or near the weld joining the flange to the housing that extends through the wall, and completely around the circumference of the housing so that the flange can separate from the housing. The flange material is forged Type 304 stainless steel with a minimum tensile strength of 75,000 psi. The housing material is seamless Type 304 stainless steel pipe with a minimum tensile strength of 75,000 psi. A conventional full penetration weld of Type 308 stainless steel is used to join the flange to the housing. Minimum tensile strength is approximately the same as the parent metal. The design pressure is 1,250 psig and the design temperature is 575°F. A combination of reactor pressure acting downward on the cross sectional area of the drive; the weight of the control rod, drive, and flange; and the dynamic reaction force during drive operation result in a maximum tensile stress at the weld of approximately 6,000 psi.

In the event that the basic failure described above were to occur, the flange and the attached drive would be blown downward against the support structure. The support structure loading would be slightly less severe than in drive housing failure, since reactor pressure would act only on the drive cross sectional area. Since there would be no differential pressure across the collet piston, the collet would remain latched and control rod motion would be limited to approximately 3 in. Downward drive movement would be small; therefore, most of the drive would remain inside the housing. The pressure under and pressure over lines are flexible enough to withstand the small downward displacement, and remain attached to the flange. Reactor water would follow the same leakage path described in malfunction No. 3 above, except that the exit to the atmosphere would be through the gap between the lower end of the housing, and the top of the flange. Water would flash to steam in the annulus surrounding the drive. The leakage rate would be approximately 840 gal/min.

If the basic flange to housing joint failure were to occur at the same time the control rod is being withdrawn, a small fraction of the total operating time, and if the collet were held unlatched, the flange would separate from the housing, the drive and flange would be blown downward against the support structure, and the calculated steady state rod withdrawal velocity would be 0.13 ft/sec. Since the pressure under and pressure over lines remain intact, driving water pressure would continue to be supplied to the drive and the normal exhaust line restriction would exist. The pressure below the velocity limiter piston would decrease below normal due to leakage out of the gap between the housing and the flange to the atmosphere. This differential pressure across the velocity limiter piston would result in a net downward force of approximately 70 lb. However, leakage out of the housing would greatly reduce the pressure in the annulus surrounding the drive, so that the net downward force on the drive piston would be less than normal. The overall effect would be a reduction of rod withdrawal speed to a value approximately one half of normal speed. The collet would remain unlatched with a 560 psi differential across the collet piston, but should relatch as soon as the drive signal is removed.

5. Housing Wall Ruptures

The failure considered in this case is a vertical split in the drive housing wall just below the bottom head of the reactor vessel. The hole was considered to have a flow area equivalent to the annular area between the drive and the thermal sleeve so that flow through this annular area, rather than flow through the hole in the housing, would govern leakage flow. The housing is made from Type 304 stainless steel seamless pipe having a minimum tensile strength of 75,000 psi. The maximum hoop stress of 11,900 psi is due primarily to reactor design pressure of 1,250 psig acting on the inside of the housing.

If the housing wall rupture described above were to occur, reactor water would flash to steam and leak to the atmosphere at approximately 1,030 gal/min through the hole in the housing. Choke flow conditions described in malfunction No. 3 above would exist. In this case, however, the leakage flow would be greater because the flow resistance is less; that is, the leaking water and steam would not have to flow down the length of the housing to reach the atmosphere. Critical pressure at which the water would flash to steam is 350 psi.

There would be no pressure differential across the collet piston tending to cause collet unlatching, but the drive would insert due to loss of pressure in the drive housing, and therefore, in the space above the drive piston.

If the basic housing wall failure were to occur at the same time the control rod is being withdrawn (a small fraction of the total operating time), the drive would stop withdrawing, but the collet would remain unlatched. The drive stoppage would be caused by a reduction in the net downward force acting on the drive line. This would occur when the leakage flow of 1,030 gal/min reduces the pressure in the annulus outside the drive to approximately 540 psig, and therefore reduces the pressure acting on the top of the drive piston to this value. There would be a pressure differential of approximately 710 psi across the collet piston, holding the collet unlatched as long as the operator held the withdraw signal.

6. Flange Plug Blows Out

A 3/4 in diameter hole is drilled in the drive flange to connect the vessel ports with the bottom of the ball check valve. The outer end of this hole is sealed with an 0.812 in diameter plug, 0.250 in thick. The plug is held in place with a full penetration weld of Type 308 stainless steel. The failure considered is a full circumferential crack in this weld and subsequent blow out of the plug.

If the weld were to fail and the plug were to blow out, there would be no control rod motion provided the collet were latched. There would be no pressure differential across the collet piston tending to cause collet unlatching. Reactor water would leak past the velocity limiter piston, down the annulus between the drive and the thermal sleeve through the vessel ports and drilled passage, and out the open plug hole to the atmosphere at approximately 320 gal/min. This leakage calculation is based on liquid only exhausting from the flange as a worst case. Actually, hot reactor water would flash to steam, and choke flow conditions would exist, so that the expected leakage rate would be lower than the calculated value. Drive temperature would rise, and the alarm would signal the operator.

If the basic plug weld failure were to occur at the same time the control rod is being withdrawn (a small percentage of the total operating time), and if the collet were to stay unlatched, calculations indicate that control rod withdrawal speed would be approximately 0.24 ft/sec. Leakage out of the open plug hole in the flange would cause reactor water to flow downward past the velocity limiter piston. The small differential pressure across the piston would result in an insignificant driving force of approximately 10 lb tending to increase withdraw velocity.

The collet would be held unlatched by a 295 psi pressure differential across the collet piston as long as the driving signal was maintained.

The exhaust path from the drive would have normal flow resistance since the ball check valve would be seated at the lower end of its travel by pressure under the drive piston.

7. Pressure Regulator and Bypass Valves Fail Closed (Reactor Pressure 0 psig)

Pressure in the drive water header supplying all drives is controlled by regulating the amount of water from the supply pump that is bypassed back to the reactor. This is accomplished primarily with the drive water control valves, and secondarily with the pressure stabilizing valves. There are two drive water control valves arranged in parallel. One is a motor operated valve that can be adjusted from the control room. This valve is normally in service and is partially open to maintain a pressure of reactor pressure plus 250 psig in the header just upstream from the valve. The other is a hand operated valve that is normally closed but that can be valved in and operated locally whenever the motor operated valve is out of service.

The pressure stabilizing valves are solenoid operated and have built in needle valves for adjusting flow. The two valves are arranged in parallel between the drive water header and the return line to the reactor. One valve is set to bypass 2 gal/min, and closes when any drive is given a withdraw signal, so that flow is diverted to the drive being operated rather than back to the reactor. Relatively constant header pressure is thus maintained. Similarly, the other valve is set to bypass 4 gal/min, and closes when any drive is given an insert signal.

The failure considered is when all of these valves are closed so that maximum supply pump head of 1,700 psi builds up in the drive water header. The major portion of the bypass flow normally passes through the motor operated valve; therefore, closure of this valve is most critical.

Since lowest exhaust line pressure exists when reactor pressure is zero, this reactor condition is also assumed.

If the valve closure failure described above were to occur at the same time the control rod is being withdrawn, calculations indicate that steady state withdrawal speed would be approximately 0.5 ft/sec or twice normal velocity. The collet would be held unlatched by a 1,670 psi pressure differential across the collet piston. Flow would be upward past the velocity limiter piston, but retarding force would be negligible.

8. Ball Check Valve Fails to Close Off Passage to Vessel Ports

The failure considered in this case depends upon the following sequence of events. If the ball check valve were to seal off the passage to the vessel ports during the "up" signal portion of the jog withdraw cycle, the collet would be unlatched. This is the normal withdrawal sequence. Then if the ball were to move up and become jammed in the ball cage by foreign material, or prevented from reseating at the bottom by foreign material, that settles out on the seat surface, water from below the drive piston would return to the reactor through the vessel ports, and the annulus between the drive and the housing. Since this return path would have lower than normal flow resistance, the calculated withdrawal speed would be 2 ft/sec. During withdrawal, there would be a differential pressure across the collet piston of approximately 40 psi. Therefore, the collet would tend to latch and would have to stick open before continuous withdrawal at 2 ft/sec could occur. Water would flow upward past the velocity limiter piston and a small retarding force would be generated (approximately 120 lb).

9. Hydraulic Control Unit Valve Failures

Various failures of the valves in the HCU can be postulated, but none are capable of producing differential pressures which approach those described in the preceding paragraphs, and none are capable alone of producing a high velocity withdrawal. Leakage through either or both of the scram valves produces a pressure which tends to insert the control rod rather than withdraw it. If the pressure in the scram discharge volume should exceed reactor pressure following a scram, a check valve in the line to the scram discharge header prevents this pressure from operating the drive mechanisms.

10. Failure of the Collet Fingers to Latch

    The drive continues to withdraw, after removal of the signal, at a fraction of its normal withdrawal speed. There is no known means for the collet fingers to become unlocked without some initiating signal. Failure of the withdrawal drive valve to close, following a rod withdrawal has the same effect as failure of the collet fingers to latch in the index tube, and is immediately apparent to the operator. Accidental opening of the withdrawal drive valve normally does not unlock the collet fingers because of the characteristic of the collet fingers to remain locked until unloaded.

11. Withdrawal Speed Control Valve Failure

    Normal withdrawal speed is determined by differential pressures at the drive and set for a nominal value at 3 in/sec. The characteristics of the pressure regulating system are such that withdrawal speed is maintained independent of reactor vessel pressure. Tests have determined that accidental opening of the speed control valve to the full open position produces a velocity of approximately 6 in/sec.

    The CRD System prevents rod withdrawal as required by safety design basis 3.a. It is shown above that only multiple failures in a drive unit and its control unit could cause an unplanned rod withdrawal.

3.4.6.5 Scram Reliability

High scram reliability is the result of a number of features of the CRD system, such as the following:

1. There are two sources of scram energy to insert each control rod when the reactor is operating: Accumulator pressure and reactor vessel pressure
2. Each drive mechanism has its own scram and pilot valves so that only one drive can be affected by failure of a scram valve to open. Two pilot valves are provided for each drive. Both pilot valves must be vented to
3. The RPS and HCUs are designed so that the scram signal and mode of operation override all others
4. The collet assembly and index tube are designed so that they will not restrain or prevent control rod insertion during scram
5. The scram discharge volume is monitored for accumulated water and will scram the reactor before the volume is filled to a point that could interfere with a scram

The scram reliability meets the requirements of safety design basis 3.b and 3.c.

3.4.6.6 Control Rod Support and Operation

As shown in the description, each control rod is independently supported and controlled as required by safety design basis 3.

3.4.7 Inspection and Testing

3.4.7.1 Development Tests

The development drive (one prototype) testing included over 5,000 scrams and approximately 100,000 latching cycles during 5,000 hr of exposure to simulated operating conditions. These tests have demonstrated the following:

1. That the drive withstands the forces, pressures, and temperatures imposed without difficulty

2. That wear, abrasion, and corrosion of the nitrided Type 304 stainless parts are negligible. That mechanical performance of the nitrided surface is superior to materials used in earlier operating reactors

3. That the basic scram speed of the drive has a satisfactory margin above minimum plant requirements at any reactor vessel pressure
4. That usable seal lifetimes greater than 1,000 scrams cycles may be expected

3.4.7.2 Factory Quality Control Tests

Quality control of welding, heat treatment, dimensional tolerances, material verification, etc., is maintained throughout the manufacturing process to assure reliable performance of the mechanical reactivity control components. Some of the quality control tests on the control rods, CRD mechanisms, and HCUs are as follows:

<u>Control Rod Absorber Tube Tests</u>

1. The tubing and end plug material integrity is verified by ultrasonic inspection

2. Boron content of the Boron-10 fraction of each lot of boron carbide is verified
3. The weld integrity of the finished absorber tubes is verified by helium leak testing

CRD Mechanism Tests

1. Hydrostatic testing of the drives to check pressure holds is in accordance with ASME codes

2. Electrical components are checked for electrical continuity and resistance to ground

3. All drive parts which cannot be visually inspected for dirt are flushed with filtered water at high velocity. No significant foreign material is permissible in effluent water

4. Seal leakage tests are performed to demonstrate proper seal operation

5. Each drive is tested for shim motion, latching, and control rod position indicating

6. Each drive is subjected to cold scram tests at various reactor pressures to verify proper scram performance

Hydraulic Control Unit Tests

Each HCU receives the following tests:

1. All hydraulic systems are hydrostatically tested in accordance with USAS B-31.1.0

2. All electrical components and systems are tested for electrical continuity and resistance to ground

3. The correct operation of the accumulator pressure and level switches is verified

4. The unit's ability to perform its part of a scram is demonstrated

5. Proper operation and adjustment of the insert and withdrawal valves is demonstrated

3.4.7.3 Operational Tests

After installation, all rods, HCUs and drive mechanisms are tested through their full travel range for operability.

During normal operation, each time a control rod is withdrawn a notch, the operator can observe the incore monitor indications to verify that the control rod is following the drive mechanism. All control rods that are partially withdrawn from the core can be tested for rod following by inserting or withdrawing the rod one notch and returning it to its original position, while the operator observes the incore monitor indications.

To make a positive test of control rod to CRD coupling integrity, the operator can withdraw a control rod to the end of its travel and then attempt to withdraw the drive to the overtravel position. Failure of the drive to overtravel demonstrates rod to drive coupling integrity.

Hydraulic supply subsystem pressures can be observed from instrumentation in the control room. Scram accumulator pressures can be observed on the nitrogen pressure gages.

3.4.8 Deleted

3.4.9 Operational Nuclear Safety Requirements

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

3.4.10 References

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REACTOR COOLANT SYSTEM

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4.2 REACTOR VESSEL AND APPURTENANCES MECHANICAL DESIGN

4.2.1 Safety Objective

The safety objective of the reactor vessel and appurtenances, in conjunction with other safety systems, is to provide a barrier to the release of radioactive materials when operated within the range of conditions considered by the Station Safety Analysis.

4.2.2 Safety Design Basis

1. The reactor vessel and appurtenances shall be designed to withstand combinations of loadings and forces resulting from operation under abnormal and accident conditions.

2. To minimize the possibility of brittle fracture failure of the nuclear system process barrier, the following shall be required: (a) the initial ductile brittle transition temperature of materials used in the reactor vessel shall be known by reference or established empirically; (b) expected shifts in transition temperature during design service life due to environmental conditions, such as neutron flux, shall be determined and employed in the reactor vessel design; and (c) operation margins to be observed with regard to the transition temperature shall be designated for each mode of operation.

3. The reactor vessel and appurtenances shall be designed so that failure of piping integrity does not compromise the ability to provide a refloodable volume.

4.2.3 Power Generation Objective

The reactor vessel design objective is to provide a volume in which the core can be submerged in coolant, thereby allowing power operation of the fuel. The reactor vessel appurtenances design provides the means for the attachment of pipelines to the reactor vessel and the means for the proper installation of vessel internal components.

4.2.4 Power Generation Design Basis

1. The location and design of the external and internal supports provided as an integral part of the reactor vessel shall be such that stresses in the reactor vessel and supports due to reactions at these supports are within ASME Code limits.

2. The original reactor vessel design lifetime was 40 years. Subsequent evaluation of the vessel determined it acceptable for 60 years (54 EFPY) of operation

3. The design of the reactor vessel and appurtenances shall allow for the accomplishment of a suitable program of periodic inspection and surveillance.

4.2.5 Description

4.2.5.1 Reactor Vessel

The reactor vessel is a vertical cylindrical pressure vessel with hemispherical heads of welded construction. The reactor vessel was designed and fabricated for a useful life of 40 years based upon the specified design and operating conditions. Subsequent evaluation of the vessel determined it acceptable for 60 years (54 EFPY) of operation. The vessel is designed, fabricated, inspected, tested, and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section III (1965 Edition and January 1966 addenda), its interpretations, and applicable requirements for Class A Vessels as defined therein. The reactor vessel and its supports are designed in accordance with the loading criteria of Appendix C. The materials used in the design and fabrication of the reactor pressure vessel are shown on Table 4.2-1. Reactor vessel data is shown on Table 4.2-2.

The cylindrical shell and bottom hemispherical head of the reactor vessel are fabricated of low alloy steel plate which is clad on the interior with stainless steel weld overlay. The plates and forgings are ultrasonically tested and magnetic particle tested over 100 percent of their surfaces after forming and heat treatment. Preheat of vessel plate and forgings is maintained during welding until the weld joints are post weld heat treated. Full penetration welds are used at all joints including nozzles throughout the vessel except for nozzles of less than 3 in nominal size and control rod drive stub tubes.

Although little corrosion of plain carbon or low alloy steels occurs at temperatures of 500°F to 600F, higher corrosion rates occur at temperatures around 140°F. The stainless steel cladding provides the necessary corrosion resistance during reactor shutdown and also helps maintain water clarity during refueling operations. Exterior exposed ferritic surfaces of pressure containing parts have a minimum corrosion allowance of 1/16 in. All carbon and low alloy steel nozzles exposed to the reactor coolant have a corrosion allowance of 1/16 in. The vessel is designed to limit coolant retention pockets and crevices.

The nil-ductility transition temperature (NDTT) is defined as the temperature below which ferritic steel fractures in a brittle rather than a ductile manner. The NDTT increases as a function of neutron fluxes at integrated neutron fluxes greater than about 1 x 10^{17} nvt with neutrons of energies in excess of 1 MeV. The material NDTT dictates the minimum operating temperature at which the reactor vessel can be pressurized. One way to control the material NDTT is by selecting fine grained steels and by using advanced fabrication techniques to minimize radiation effects. The as fabricated initial NDTT for all carbon and low alloy steel used in the main closure flanges and the shell and head materials connecting to these flanges is limited to a maximum of 10°F as determined by ASTM E208. For all other carbon and low alloy steel pressure containing materials and the vessel support skirt material, the as fabricated initial NDTT is no higher than 40°F. A grain size of 5 or finer, as determined by the method in ASTM E112, is the objective of the fabrication technique.

Another way of minimizing any increases to the NDTT is by reducing the integrated neutron exposure at the inner surface of the reactor vessel.

The vessel top head is secured to the reactor vessel by studs and nuts which are designed to be tightened with a stud tensioner. The vessel flanges are sealed by two concentric Inconel seal rings designed for no detectable leakage through the inner or outer seal at any operating condition, including cold hydrostatic pressure test at the full design pressure, and heating to operating pressure and temperature at a maximum rate of 100°F/hr. To detect lack of seal integrity, a vent tap is provided in the area between the two seal rings and a monitor line is attached to the tap to provide an indication of leakage from the inner seal ring seal. A tap is also provided in the area outside the outer seal ring for use in monitoring leakage.

The head and vessel flanges are low alloy steel forgings. The reactor vessel head, flange sealing surfaces, and shell flange sealing surfaces are weld overlay clad with austenitic stainless steel similar to the vessel which consists of a minimum of two layers and a minimum of 0.25 in total thickness after all machining, including the area under the seal grooves.

The first layer is deposited with a composition equivalent to ASTM A371, Type ER309, and the second layer has a composition equivalent to ASTM A371, Type ER308, except that the carbon content does not exceed 0.08 percent.

Stress analysis and load combinations for the reactor vessel have been evaluated for the cycles expected throughout the original 40 year design life, with the conclusion that ASME Code limits are satisfied. The details of assumed loading combinations are described in Appendix C for Class I equipment.

The reactor vessel was originally designed for a 40-year life and an exposure of not more than 1 x 10^{19} nvt of neutrons with energies exceeding 1 MeV. Extensive tests have established the magnitude of changes in the NDTT as a function of the integrated neutron dosage. Figure 4.2-5 presents pertinent test data for SA302B steel and plots the change in ductile to brittle transition temperature as a function of integrated neutron flux (nvt). Because SA533 is the same as 302B, all test data on SA302B is applicable to SA533 used in the vessel. The 30 ft lb refers to the energy absorbed by the Charpy V-Notch sample at the test (transition) temperature. The upper two curves apply to thick walled pressure vessels and the lower curve is for the wall thickness range representative of this reactor vessel. The SA302B steel with the fabrication procedures specified for the reactor vessel is relatively insensitive to neutron irradiation.

TransWare Report, No ENT-FLU-001-R-001, Revision 0, provides Pilgrim reactor vessel fluence values using the NRC-approved RAMA methodology and a power level of 2028 MW_t. The Pilgrim fluence calculation results show the reactor vessel will experience peak ID (at the clad/base metal interface) fluence at 34 EFPY of $7.53x10^{17}$ n/cm^2 at the Lower Intermediate Weld 1-338A/C locations, and $8.42x10^{17}$ n/cm^2 at the lower intermediate Shell Plates, respectively. Even though the peak fluence occurs in the Lower Intermediate Shell Plates, Lower Shell Plate 337-01C has a higher ART due to material chemistry effects (peak fluence - $6.96x10^{17}$ n/cm^2 at 34 EFPY). In addition, the N2 nozzle peak fluence at 34 EFPY was calculated to be $1.90x10^{17} n/cm^2$, and the N16A/B instrument ("drill-hole" style) nozzle fluence at 34 EFPY was calculated to be $3.52x10^{15}$ n/cm^2. Both nozzles were evaluated for their impact on the Pilgrim P-T curves, and the limits presented the PTLR incorporate any effects of these nozzles accordingly. All fluence values at 34 EFPY are linearly interpolated from the data in TransWare Report, No. ENT -ENT - FLU-001-R-001.

34 EFPY P-T Limit Curves based on the extrapolated fluence from TransWare Report, No. ENT-FLU-001-R-001 and Calculations M1282, M1283 and M1284 were developed. For Core Not Critical (Curve B) and Core Critical (Curve C) conditions, the P-T curves specify a coolant heatup and cooldown temperature rate of $\leq 100^{\circ}F/hr$ for which the curves are applicable. For Hydrostatic Pressure and Leak Test (Curve A) conditions, a coolant heatup and cooldown temperature rate of $\leq 25^{\circ}F/hr$ must be maintained. The P-T limits and corresponding limits of either Curves A or B may be applied, if necessary, while achieving or recovering from test conditions. So, although Curve A applies during pressure test conditions, the limits of Curve B may be conservatively used during pressure testing if the pressure test heatup and cooldown rate limits cannot be maintained. Adjusted reference temperature (ART) and reference temperature shift (ΔRT_{NDT}) values for Pilgrim Nuclear Power Station (PNPS) reactor pressure vessel (RPV) plates and welds exposed to fluences greater than

1.0×10^{17} n/cm^2 were developed in accordance with Nuclear Regulatory Commission (NRC) Regulatory Guide 1.99, Revision 2 (RG1.99).

The reactor assembly is designed such that the average annular distance from the outermost fuel assemblies to the inner surface of the reactor vessel is approximately 80 cm. This annular volume, which contains the core shroud, the jet pump assemblies, and reactor coolant, serves to attenuate the fast flux incident upon the reactor vessel wall. For plant operation at 1,998 MWt, 80 percent station availability, and 40-year station life, the neutron fluence at the inner surface of the vessel was calculated to be 1.5 x 1018 nvt for neutrons having energies greater than 1 MeV. Initially the "worst case" curve from Figure 4.2-5 would produce a NDTT shift of less than 50°F. This figure is retained for historical purposes. With an initial NDTT in the vessel plate material of 40°F, the resulting maximum NDTT of the vessel wall at the end of 40-years would be less than 90°F. This end of life NDTT provides a substantial margin for brittle fracture prevention, since the vessel cannot be pressurized until coolant temperatures in excess of 212°F are reached. Vessel operation up to 60 years (54 EFPY) was projected using the methods of Regulatory Guide 1.99, Revision 2. This projection resulted in a maximum fluence to the vessel inner wall of 1.28×10^{18} n/cm^{2}. The limiting CvUSE for the lower shell welds and lower intermediate shell welds remain above the 50 ft-lb minimum required. The lower intermediate shell welds remain limiting for RT_{NDT}, with an adjusted RT_{NDT} of 92.7°F

A stress of between 5,000 and 8,000 psi is considered necessary to produce brittle fracture at or below the NDTT. Therefore, during operation when pressure is dependent upon temperature, brittle failure of the vessel is not considered possible until the integrated neutron flux of the reactor vessel reaches a value on the order of 10^{20} nvt. This value is a factor of more than 100 times greater than the maximum neutron flux conservatively calculated during the lifetime of this station.

In addition to the minimum requirements of the ASME Boiler and Pressure Vessel Code, the following precautions are taken and tests made either to assure that the initial NDTT of the reactor vessel material is low or to reduce the sensitivity of the material to irradiation effects:

1. The material is selected and fabrication procedures are controlled to produce as fine a grain size as practical. It is an objective in fabrication to maintain a grain size of five or finer.

2. Drop weight impact tests are performed on each heat and heat treatment charge of all low alloy steel plate material in its "as fabricated" condition.

3. Drop weight impact tests are made on the weld metal, the heat affected zone of the base metal, and the base metal of the weld test plates simulating seams. If different welding procedures are used for nozzle welds, drop weight tests of similarly prepared coupons are made. The NDTT test criteria for the weld and heat affected zone of the base material are the same as for the unaffected base metal.

4. The actual NDTT of the plates opposite the center of the reactor core is determined. In other areas it is sufficient to demonstrate that the two drop weight test specimens do not break 10°F above the design NDTT. The area of the vessel located opposite the core is fabricated entirely of plate welded material and is not penetrated by nozzles, nor are there any other structural discontinuities in this area which would act as stress risers.

Quality control methods are used during the fabrication and assembly of the reactor vessel and appurtenances to assure that the design specifications are met.

The fabrication test program is carried out by the reactor vessel vendor on material representative of the formed, heat treated, and fully fabricated vessel. Tests of base metal and welded joint are performed and the results are reported during the early stages of vessel construction. Tensile specimens (0.505 inch in dia) from the shell plate material are prepared for various thickness levels of the plate material. These specimens are tested at various temperatures per ASTM Specifications E8 and E21 to determine tensile strength, yield strength, elongation, and reduction of area. Tensile specimens whose gage diameter is at least 80 percent of the reactor vessel wall thickness are prepared from base metal and weld material. These specimens are tested at room temperature per ASTM Specification E8 to provide stress strain curves, tensile strength, yield strength, elongation, reduction of area, and macrophotographs of the breaks. Charpy V-Notch impact specimens are prepared from base metal and tested per ASTM Specification E23, Type A, to establish curves for determining the transition temperature at which 30 ft lb of absorbed energy result in ductile fracture for various thickness levels of the plate material. Table 4.2-4 summarizes the results of Charpy V-Notch and drop weight tests for the reactor vessel plates and forgings. The Charpy V-Notch test results have been subsequently adjusted to account for rolling direction in accordance with USNRC Branch Technical Position MTEB 5-2.

Data available from the heavy section steel technology (HSST) program show that there is no true size effect on the NDTT in the temperature regime where $K_{I_C} / \sigma_y.5 \geq 1$ regardless of whether it is defined by the drop weight test or the dynamic tear test, where:

K_{I_C} = Critical stress intensity required to initiate a brittle crack

$\sigma_y.5$ = Material yield stress

The matter of upper shelf energy for transverse specimens is specifically treated in USNRC Branch Technical Position MTEB 5-2 and the Charpy V-Notch impact test results have been adjusted accordingly. Provisions for brittle fracture control in ferritic materials which are part of the primary coolant pressure boundary meet the impact test requirements of Section III for Class A vessels, with Appendix 1 of B31.7 for piping, and with Appendix E of the Nuclear Pump and Valve Code for pumps and valves, although these codes do not apply to the piping, pumps, and valves in other respects. The use of the un-adjusted Charpy V Notch fixed energy values for each material, and an acceptance test temperature of 60°F below the lowest service metal temperature, had been the standard practice adopted by the codes.

Detailed stress analyses have been made on the reactor vessel for both steady state and transient conditions with respect to material fatigue. The results of these analyses are compared to allowable stress limits. The specific conditions analyzed included numerous cycles of normal startup and shutdown with a heating and cooling rate of 100°F/hr applied continuously over a temperature range of 100°F to 546°F. The expected number of normal heatup and cooldown cycles to which the vessel will be subjected is listed in the "Reactor Thermal Cycles" document (Figure C.3-1, MIA12-2) and as modified by analyses performed for License Renewal per EC12412.

4. The reactor vessel shall be vented and depressurized unless the reactor vessel temperature equals or exceeds that indicated by the upper curve on Figure 4.2-6.

The NDTT is defined as the temperature below which ferritic steel breaks in a brittle rather than a ductile manner. Radiation exposure from fast neutrons (>1 MeV) above about 10^{17} nvt may increase the NDTT of the vessel base metal. Extensive tests have established the magnitude of changes in the NDTT as a function of integrated neutron exposure. The initial maximum NDTT of the reactor vessel is not greater than 40°F. The original design life of the reactor vessel was 40 years and the maximum fast neutron fluence calculated for 40 years was calculated to be 2.5×10^{18} nvt. The fluence calculated for 60 years (54 EFPY) is still below this estimated bounding value. See Section 4.2.6 for details.

The NDTT limit upper curve on Figure 4.2-6 is based on the more conservative thick walled pressure vessel data. This curve also incorporates a 60°F factor of safety which is based on the requirements of the ASME Code and the considerations that resulted in these requirements. The estimated inservice transition temperature shift is not based on data related to control of residual elements.

The lowest pressurization temperature of 100°F (40°F + 60°F) is determined by the 40°F NDTT material in the vessel. As part of the surveillance program, removable neutron flux monitors are installed in the reactor vessel. Results of this program will confirm and, if necessary, adjust the calculation of integrated flux used to determine NDT shift. It is understood that the NRC pressurization temperature limit of 180°F applies only above 250 psig with fuel in the reactor vessel and not to head bolt down discussed in item 1. Also, investigations may support the conservatism of the100°F temperature limit. Should this be the case, a request will be made to revise the higher temperature.

4.2.8.4 Proposed Surveillance Requirements for Initial Plant Operation

The following surveillance requirements are given to determine the condition of the reactor vessel and that of the safety devices related to it.

1. Neutron flux wires and specimen samples of the vessel material shall be installed in the reactor vessel to experimentally verify the calculated values of integrated neutron flux that are used to determine the NDTT from Figure 4.2-6 and to monitor the affect of neutron exposure on these materials.

   The integrated neutron flux at the vessel wall is calculated from core physics data and is measured using flux wires. The measurements of the neutron flux at the vessel wall are used to check and, if necessary, correct the calculated data to determine an accurate flux. A conservative prediction of the NDTT shift can then be made well in advance of any potential changes in properties.

   The samples shall include both tensile and Charpy V-Notch impact specimens representing base metal, heat affected zone, and weld metal. The samples will be located as close as practicable to the vessel wall; correlation data is available to relate this to actual vessel wall conditions. These samples will provide further assurance that the shift in NDTT is conservative.

   It is not planned that any vessel material, other than that already in the surveillance program described above, will be retained for preparing Charpy V-Notch test specimens for the purpose of additional irradiation monitoring of vessel material, or the monitoring of thermal annealing treatments if required to recover fracture toughness in the later years of vessel service. Refer to the discussion of neutron fluence expected during the reactor vessel life in Sections 4.2.5.1 and 4.2.6.

2. Nondestructive examinations of the pressure vessel shall be made in accordance with the intent of the requirements of draft Code for Inservice Inspection of Nuclear Reactor Coolant Systems.

3. A visual examination for leaks shall be made with the Reactor Coolant System at pressure during each scheduled refueling outage or after major repairs have been made to the Reactor Coolant System.

   The visual examination for leaks is based on the observed rate of growth of defects from fatigue studies sponsored by the NRC. These studies show that it requires thousands of stress cycles, at stresses beyond any conceived in a reactor system, to propagate a crack; thus, it is concluded that the frequency is adequate.

4.3 RECIRCULATION SYSTEM

4.3.1 Power Generation Objective

The power generation objective of the Reactor Recirculation System is to provide a variable moderator (coolant) flow to the reactor core for adjusting reactor power level.

4.3.2 Power Generation Design Basis

1. The Reactor Recirculation System shall provide sufficient subcooled water to the core during normal power operation to maintain normal operating temperatures.

2. The Reactor Recirculation System shall operate over a flow control range of 20 percent to 100 percent flow to allow power variation.

3. The Reactor Recirculation System shall be designed to minimize maintenance situations that would require core assembly and fuel removal.

4.3.3 Safety Design Basis

1. The Reactor Recirculation System shall be designed so that adequate fuel barrier thermal margin is assured following Recirculation Pump System malfunctions.

2. The Reactor Recirculation System shall be designed so that failure of piping integrity does not compromise the ability of the reactor vessel internals to provide a refloodable volume.

4.3.4 Description

The Reactor Recirculation System consists of the two recirculation pump loops external to the reactor vessel which provide the driving flow of water to the reactor vessel jet pumps. See Figures 4.3-1, 4.3-2 (Drawing M251), and 4.3-3 (Drawing M252). Each external loop contains one high capacity motor-driven recirculation pump and two motor-operated gate valves for pump maintenance. Each pump discharge line contains a venturi type flowmeter nozzle. The recirculation loops are a part of the nuclear system process barrier and are located inside the drywell containment structure. The jet pumps are reactor vessel internals and their location and mechanical design are discussed in Section 3.3, Reactor Vessel Internals Mechanical Design; however, certain operational characteristics of the jet pumps are discussed in this section. A summary of the characteristics of the Reactor Recirculation System is presented on Table 4.3-1.

The recirculated coolant consists of saturated water from the steam separators and dryers which has been subcooled by incoming feed water. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant exits from the vessel and passes through the two external recirculation loops to become the driving flow for the jet pumps. The two external recirculation loops each discharge high pressure flow into external manifolds from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pumps at the suction inlet and is accelerated by the driving flow. The driving and driven flows are mixed in the jet pump throat section resulting in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing section. See Figure 4.3-4. The adequacy of the total flow to the core is discussed in Section 3.7, Thermal and Hydraulic Design. Tests have been conducted and documented(1) to show that the jet pump design is sound and that jet pump operation is stable and predictable.

Each discharge gate valve has the capability of being jogged in the open direction only. By jogging the valve so that it is just cracked open, the system can be used to preheat an idle loop by reverse flow prior to returning a pump to service. The pump is started to slow speed with the main discharge valve closed and the operator must start to open the valve within 10 seconds of a successful pump start with the nuclear system at full pressure. Pump speed is not increased until after the main valve has been fully opened. There is actually a very low probability that a recirculation loop that has been allowed to cool would need to be placed in service again with the nuclear system hot. The only potential reason for closing both the pump discharge valve and the suction valve is to prevent leakage out of that portion of the recirculation loop between the valves. A leak of this nature cannot be repaired without shutting the plant down to permit access to the drywell. As such, the suction and discharge valves were not explicitly designed to close to isolate a leak between them. The nuclear system would in all probability have been cooled prior to repairing the leak. To limit the amount of unheated water which could be added to the reactor vessel from a cold loop startup, interlocks are provided to allow pump start only if the suction valve is open and the discharge valve is closed. To assure that the recirculation pump suction valves remain open, aiding the vessel depressurization for a LOCA (when pipe break occurs between recirculation pump suction and discharge valves), the automatic closure feature of the suction valves has been removed.

Since the removal of Reactor Recirculation System valve internals requires unloading of the nuclear fuel, the valves are provided with high quality back seats and trim to facilitate stem packing renewal without draining the vessel and to provide adequate leak tightness during normal operation.

It is possible to operate at reduced power with one recirculation pump. PNPS is licensed for continuous Single Loop Operation (Ref 3). The acceptable operating domain is administratively limited during SLO. This mode of operation requires adjustment of thermal limits as discussed in Section 3.7. The APRM flow biased are also adjusted as discussed in Section 14.4 (Ref 4).

The idle pump loop is not completely valved off if it is desired to return the idle loop to service prior to the next reactor cooldown (such as pump shutdown for motor generator set repair). The recirculation pump casing allowable heatup rate is 100°F/hr, the same as the loop hot with the idle loop valves left open, permitting the pressure head created by reverse flow through the idle jet pumps to cause reverse flow through the idle loop. The feedwater flowing into the reactor vessel annulus during operation provides subcooling for the fluid passing to the recirculation pumps, thus determining the additional net positive suction head (NPSH) available beyond that provided by the pump location below the reactor vessel water level. If feedwater flow is below 20 percent, the recirculation pump speed is automatically limited.

The recirculation pumps can be operated during nuclear system heatup for hydrostatic tests, with pump speed being limited so that due consideration is given to NPSH and vibration concerns. At this time, they act in conjunction with any contribution from reactor core decay heat to raise nuclear system temperature above the limit imposed on the reactor vessel by nil-ductility transition temperature (NDTT) considerations so that the hydrostatic test can be conducted.

Decontamination connections are provided in the piping on the suction and discharge side of the pump as shown on Figure 4.3-2, to permit flushing and decontamination of the pump and adjacent piping. These connections are arranged for convenient and rapid connection of temporary piping. The "A" pump suction decontamination flange has the capability of accepting up to four chemistry probes for special monitoring. The piping low point drain is used during flushing or decontamination to conduct crud away from the piping low point and is also designed for connection of temporary piping.

Each recirculation pump is a single stage, variable speed, vertical, centrifugal pump equipped with mechanical shaft seal assemblies. The pump is capable of stable and satisfactory performance while operating continuously at any speed corresponding to a power supply frequency range of 11.5 to 57.5 Hz. For loop startup, each pump operates at a speed corresponding to a power supply frequency of 11.5 Hz with the main discharge gate valve closed.

The recirculation pump shaft seal assembly consists of two individual seals built into a cartridge which can be readily replaced without removing the motor from the pump. The seal assembly is designed to require minimum maintenance over a long period of time, regardless of whether the pump is stopped or operating. It must seal over a wide range of pressures and temperatures. Each seal is designed for a minimum service time of two 24 month fuel cycles. Seal rebuilds are scheduled based on actual seal performance.

Each individual seal in the cartridge is capable of sealing against pump design pressure so that any one seal can adequately limit leakage in the event that the other seal(s) should fail. A breakdown annulus is provided along the pump shaft to reduce leakage in the event of a gross failure of all shaft seals. Provision is made for monitoring the pressure drop across each individual seal as well as the cavity temperature of each seal. Provision is also made for piping the seal leakage to a flow measuring device.

In addition, a recirculation pump seal purge system is provided to cool the sealing faces of the recirculation pump mechanical seals, thus improving the seal life and also to minimize leakage from the recirculation pump seals. High pressure reactor coolant water is supplied from the CRD drive water header. Flow is through the recirculation pump seals into the reactor recirculation loop. The purge system is seismically supported but performs no safety function. In the event of a loss-of-seal purge flow, the recirculation pump may continue to operate using water from the closed cooling water system.

Each recirculation pump motor is a variable speed ac induction motor which can drive the pump over a controlled range of 20 percent to 102 percent of rated pump speed. The motor is designed to operate continuously at any speed within the power supply frequency range of 11.5 to 57.5 Hz. Electrical equipment is designed, constructed, and tested in accordance with the applicable sections of the NEMA standards.

A variable frequency ac motor generator set located outside the drywell supplies power to each recirculation pump motor.

Each motor generator set consists of a horizontal induction motor driving a synchronous generator through an adjustable speed fluid drive, all mounted on a common base to form an integrated unit.

The normal procedure for starting a pump is to close the discharge valve, start the motor generator set drive motor with the fluid drive control in the minimum torque or speed position, accelerate the fluid drive to drive the generator to minimum speed, and apply sufficient exciter field excitation by the control rectifier from

an external 120 V ac source. After the pump has been accelerated to a minimum speed, transfer the controlled silicon rectifier from an external source to the generator terminal potential source, open the discharge valve, and increase the fluid drive torque and generating speed to bring the pump to desired speed.

The inertia of the rotating elements in the motor generator sets supplements the inertia of the rotating elements in the pump and pump motor to extend the deceleration time upon loss of station electrical power. The full flywheel effect required to maintain circulation in order to protect the nuclear fuel against excessive temperature following a power failure, depends upon adequate generator excitation and dependable fluid drive scoop tube control during the coastdown following a power failure.

The generator speeds of both units are normally adjusted in unison by means of a manually operated master speed selector in the main control room. In addition to the master speed selector, an individual speed selector for each generator is provided to control the frequency while taking a pump out of service or returning it to normal operation.

The recirculation pumps are classified as machinery and as such are specifically exempt from the jurisdiction of any section of the ASME Boiler and Pressure Vessel Code or of the USA Standard Code for Pressure Piping. The Standards of the Hydraulic Institute are the only standards which are applicable. However, they are more pertinent to the testing and performance of the pump and consequently provide little or no guidance in the areas of casing quality and structural integrity.

To assure that the pump casing can withstand a pressure equivalent to that inside the reactor vessel, the pump casing is designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class C, as far as this code can be applied. This class is used because the pump casing does not experience temperature transients as severe as those that portions of the reactor vessel and certain piping connections experience. Therefore, it is not necessary to make the cyclic analysis required for Class A equipment.

The design objective for the recirculation pump casing was a useful life of 40 years, accounting for corrosion, erosion, and material fatigue. The pump drive motor, impeller, wear rings, and seals are designed for as long a life as is practical. The design provides a unit which should not require removal from the system for rework or overhaul at intervals of less than 5 years. The pump casing was reviewed for license renewal and loss of material due to corrosion, erosion, and cracking due to material fatigue are managed such that the casing will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

The Recirculation System piping is of all welded construction and is designed and constructed to meet the requirements of the ASME Boiler and Pressure Vessel Code Section III for Class 1 Piping. The system is classified as Class A as described in Appendix A, Pressure Integrity of Piping and Equipment Pressure Parts. The suction and discharge pipes are welded to the pump casing.

The requirements of Section III of the ASME Boiler and Pressure Vessel Code for Class C vessels are used as a guide in calculating the thickness of pressure retaining parts of the recirculation pumps. The casings and forgings are fabricated from austenitic stainless steel.

The coolant in the Nuclear Process System is at high pressure and contains a large amount of energy. Substantial failure of the Nuclear Process System could result in a rapid loss of coolant. Although loss of the moderator (coolant) would render the reactor core subcritical, lack of cooling could cause overheating of the reactor core from residual and decay heat, leading to fuel damage and fission product release. The CSCS (which adequately cool the reactor core following a design basis LOCA), and the primary containment and containment cooling systems (which control the release of fission products and absorb the energy released by the accident), are not intended to diminish the overall design objective of the entire nuclear system (to design and construct a nuclear system which will not fail). The intent of the Recirculation System design is to provide quality equivalent to the reactor pressure vessel to which it is attached.

The Reactor Recirculation System, except for the motor generator sets, is designed as Class I seismic equipment (see Appendix C) to resist sufficiently the response motion at the installed location within the supporting structure for the Operating Basis Earthquake with the pump assumed filled with water for the analysis. Vibration snubbers located at the top of the motor and at the bottom of the pump casing are designed to resist the horizontal reactions.

The recirculation piping, valves, and pumps are supported by constant and variable support hangers to avoid the use of piping expansion loops which would be required if the pumps were anchored. In addition, the recirculation loops are provided with a system of supports designed to limit pipe motion so that reaction forces associated with any split or circumferential break do not jeopardize containment integrity. This support system provides adequate clearance for normal

Thermal expansion movement of the loop. The spacing between limit stops is set on the basis that a split pipe retains its structural load resisting characteristics. Impact loading is not considered on limit stops since possible pipe movement is limited to slightly more than the clearance required for thermal expansion movement.

The Recirculation System piping, valves, and pump casings are covered with thermal insulation having an average maximum heat transfer rate of 65 Btu/hr-ft2 with the system at rated operating conditions. The insulation is flexible blanket insulation, composed of fiberglass, covered by a woven glass cloth, (some are protected in addition by a stainless steel metal jacket) and is prefabricated into components for field installation. Special features for easy removal is provided at various locations to allow for periodic inspection of the insulated equipment.

4.3.5 Safety Evaluation

Reactor Recirculation System malfunctions that pose threats of damage to the fuel barrier are described and evaluated in Section 14, Station Safety Analysis. There it is shown that none of the malfunctions results in fuel damage; thus, the Recirculation System has sufficient flow coast down characteristics to maintain fuel thermal margins during abnormal operational transients. This satisfies safety design basis 1.

Interlocks provide protection against a significant addition of unheated water from a cold recirculation loop. Pump start permissive is allowed only if the suction valve is open, and the discharge valve is closed.

The core flooding capability which is provided by a jet pump design plant is pictured on Figure 4.3-5. There is no recirculation line break which can prevent reflooding of the core to the level of the jet pump suction inlet. The core flooding capability of a jet pump design plant is discussed in detail in the CSCS document filed with the AEC as a GE Topical Report.(2) This satisfies safety design basis 2.

The Reactor Recirculation System piping and pump design pressures are based on peak steam pressure in the reactor dome plus the static head above the lowest point in the recirculation loop. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the listed code design criteria provides assurance that a system designed, built, and operated within design limits has an extremely low probability of failure due to any known failure mechanism.

No equipment to protect against overspeed is provided on the recirculation pump. An analysis (1), applicable to all GE BWRs, demonstrates that for the complete spectrum of breaks in piping on the discharge side of the recirculation pump, no overspeed conditions will exist. The study indicates by conservative analysis that in the unlikely event of a completely offset guillotine suction break, potential overspeed may be calculated. However, further considerations support the conclusion that this calculated overspeed condition would not realistically create an unsafe condition.

4.3.6 Inspection and Testing

Quality control methods were used during the fabrication and assembly of the Reactor Recirculation System to assure that the design specifications were met. Inspection and testing were carried out as described in Appendix A, Pressure Integrity of Piping and Equipment Pressure Parts. The Reactor Coolant System was thoroughly cleaned and flushed before fuel was loaded initially.

During the preoperational test program, the Reactor Recirculation System was given a hydrostatic test at 125 percent of reactor vessel design pressure. Subsequent to the Recirculation Pipe Replacement Program in 1984, the Reactor Recirculation System was given a pressure test at 110 percent of reactor vessel design pressure. A hydrostatic test in accordance with ASME Code Section I is made every 10 yr and a leak test is made following each removal and replacement of the reactor vessel head. Other preoperational tests on the Reactor Recirculation System include operating valves and verifying that seat leakage is small enough to permit pump maintenance work, operating pumps and motor generator sets, and checking flow control transient operation.

During the startup test program, the horizontal and vertical motions of the Reactor Recirculation System piping and equipment were observed and adjustments of supports are made, as necessary, to assure that components are free to move as designed. Nuclear system responses to recirculation pump trips at rated temperatures and pressure were evaluated during the startup tests, and the plant power response to recirculation flow control was determined. Following the Recirculation Piping Replacement Program in 1984, a thermal expansion, vibration and strain measurement test was made during pre-op and initial start-up conditions. The purpose of these tests is to verify that piping vibrations are within acceptable limits as required by NB-3622.3 of ASME III, and to demonstrate that obstructions to thermal expansion do not exist.

Inservice inspection is considered in the design of the Reactor Recirculation System to assure adequate working space and access for inspection of selected components. The criteria for selecting the components and locations to be inspected are based on the probability of a defect occurring or enlarging at a given location, including areas of known stress concentrations and locations where cyclic strain or thermal stress might occur.

4.3.7 Operational Nuclear Safety Requirements for Plant Operation

A stationwide BWR systems analysis (Appendix G) indicates that a restriction against starting a recirculation pump in a cold, idle loop must be observed to ensure that the change in coolant temperatures at the reactor vessel nozzles and bottom head remain within the conditions analyzed for planned operation. The restriction is as follows:

The pump in an idle recirculation loop shall not be started unless the temperature of the coolant within the idle recirculation loop is within 50°F of the reactor coolant temperature.
Normally, the temperature of the coolant in an idle recirculation loop is expected to remain at reactor coolant temperature unless the loop is valved out of service. This limiting condition for operation is derived from the following matrix blocks of Table G.5-3:

Matrix 3

Operating State	Row	Column
A	1	55
B	2	55
C	2	55
D	3	55
E	2	55
F	4	55

Matrix 3 of Table G.5-3 also indicates that the Recirculation System must be considered in setting limits on water quality and nuclear system leakage. Analysis reveals that it is the reactor vessel that is most limiting with regard to water quality and leakage; therefore, no separate limits are observed on these parameters for the Recirculation System.

4.3.8 Current Technical Specifications

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

4.3.9 References

1. Design and Performance of GE BWR Jet Pumps, General Electric Company, Atomic Power Equipment Department, APED-5460, September 1968.

2. Ianni, P.W., Core Standby Cooling Systems for Boiling Water Reactors, General Electric Company, Atomic Power Equipment Department, APED-5458, March 1968.

3. NRC letter to PNPS dated April 12, 2006 (PNPS Ltr 1.06.042), Issuance of Amendment 219, SER for Single Recirculation Loop Operation.

4. General Electric Report GE-NE-0000-0027-5301-R2-P, April 2006, Pilgrim Nuclear Power Station Single Loop Operation.

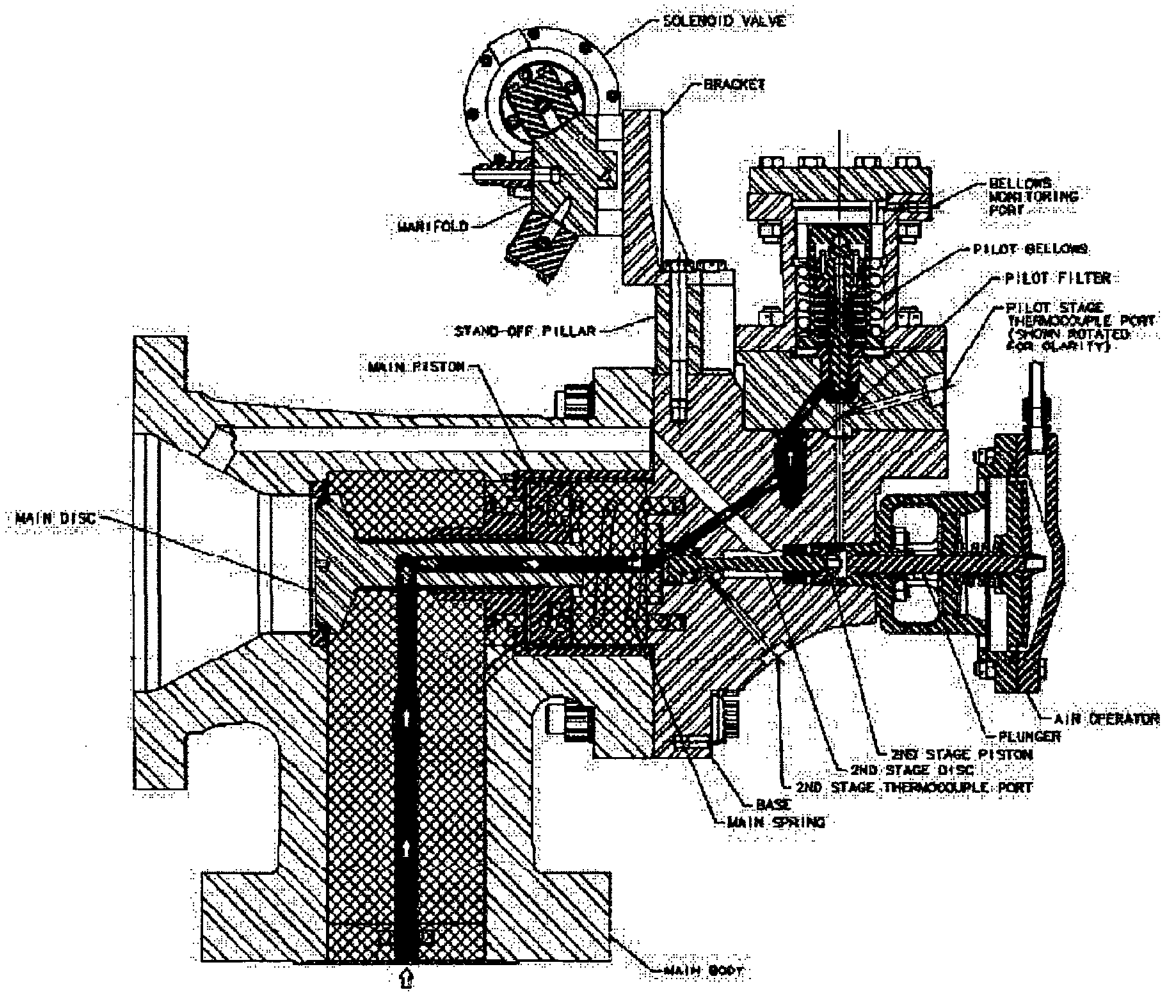

FIGURE 4.4-1
NUCLEAR SYSTEM RELIEF VALVE
THREE-STAGE – CLOSED POSITION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

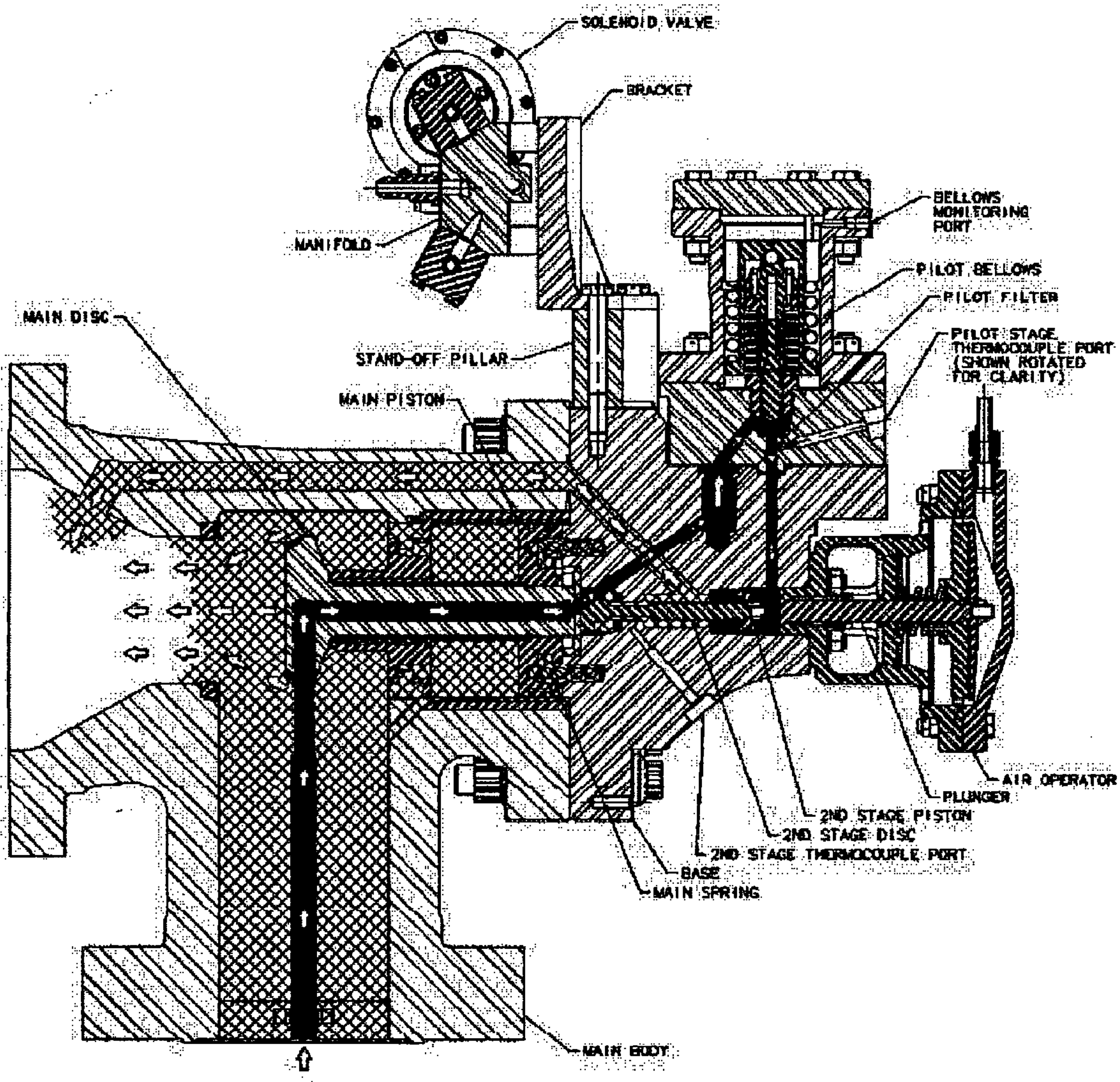

FIGURE 4.4-2
NUCLEAR SYSTEM RELIEF VALVE
THREE-STAGE – OPEN POSITION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

4.6 MAIN STEAM LINE ISOLATION VALVES

4.6.1 Safety Objectives

Two isolation valves, one as close as practical to each side of the primary containment barrier, in each main steam line close automatically upon receipt of certain isolation signals to:

1. Prevent damage to the fuel barrier by limiting the loss of reactor cooling water in case of a major leak from the steam piping outside the primary containment

2. Limit release of radioactive materials by closing the primary containment barrier in case of a major leak from the nuclear system inside the primary containment

4.6.2 Safety Design Basis

The main steam line isolation valves, individually or collectively, shall:

1. Close the pipelines within the time established by design basis accidents to limit the release of reactor coolant or radioactive materials

2. Close the pipelines at a speed slow enough so that simultaneous (inadvertent) closure of all steam lines will not induce a more severe transient on the nuclear system than closure of the turbine stop valves coincident with failure of the bypass valves to open

3. Close the pipeline when required despite single failure in either valve or the attached controls, to provide a high level of reliability for the safety function

4. Use separate energy sources for the motive force to independently close the redundant isolation valves in each steam line

5. Use local stored energy to close at least one isolation valve in each steam pipeline without relying on continuity of any variety of electrical power for the motive force to achieve closure

6. Be able to close the pipelines during or after seismic loadings to assure isolation if the nuclear system is breached by the earthquake

7. Be testable during normal operating conditions to demonstrate that the valves will function

4.6.3 Description

Two isolation valves are provided in series in a horizontal run of each main steam line, as close as practical to the primary containment, one inside (inboard) and the other outside (outboard). The valves, when closed, form part of the primary containment barrier for nuclear system breaks inside the containment, and part of the nuclear system process barrier for main steam line breaks outside the primary containment.

The description and testing of the controls for the main steam line isolation valves are included in Section 7.3, Primary Containment and Reactor Vessel Isolation Control Systems.

A drawing of a main steam isolation valve is shown on Figure 4.6-1. These valves each employ a pneumatic cylinder operator and closing springs as separate, locally stored energy sources for rapid closure.

Each valve is a 20 in globe valve having a Y-pattern body with a cylindrical main disc moving in a centerline 45 deg upward from the axis of the horizontal main steam inlet line. The valve is of full port design in that the main valve seat is very nearly the same diameter as the inside diameter of the pipe. This design provides essentially straight line flow through the valve with less than 6 psi pressure drop through the valve at rated flow with the valve fully open during normal station operation. It also enables the normal steam flow and pressure to aid in closing the valve and holding it closed.

The main disc, guided at the bottom by hard faced ribs cast integral with the valve body, has a hard faced seal surface at the bottom which mates with a hard faced seat welded into the valve body when the valve is closed. The main disc is attached to the lower end of the valve stem which penetrates the bonnet through a stuffing box. The upper end of the stem is connected to a spring seat member. The air cylinder and an oil dashpot are mounted in tandem on a common shaft which extends downward and which is also connected to the spring seat member. The cylinder and dashpot assembly is also supported by four tie rods which use the valve bonnet as their support surface. Four of these support rods also act as guides for four stacks of two helical valve closing springs, each of which is fitted between the spring seat member and the air cylinder mounting plate.

The bottom end of the valve stem is chamfered and seals against a mating hard faced seat in the middle of the main disc to act as a pilot valve. This provides a means of balancing the pressure across the main disc, just before the main disc is lifted and while it is off its seat. A helical spring between the stem and the disc keeps

this pilot valve open when the disc is off its seat, but failure of this spring will not prevent closure of the valve. The air cylinder is capable of lifting the disc with differential pressures across the isolation valve in either direction as great as 200 psi; opening of the pilot valve enables disc opening at higher differential pressures due to the pressure balancing which it affords. Approximately the last 0.5 in of disc travel as it seats closes the pilot valve.

The upper edge of a shoulder on the valve stem is chamfered and seals against a mating surface on the bottom bonnet to provide a backseat when the isolation valve is fully open. This prevents leakage through the stem packing. The bonnet, which is bolted to the body, has provisions for seal welding in case leaks develop after the valve has extensive service.

The main disc is guided at the top inside a cylinder liner fitted snugly into the valve body to provide support when it is off its seat. Running clearances are provided to permit the disc to align with the seat ring in the body. Other design features which eliminate the possibility of the disc binding in its guides are:

1. The cylindrical shape of the disc with length greater than diameter

2. Sufficient clearance between the disc and its guide surfaces such that some cocking of the disc or warpage of the seat can be tolerated and still allow tight seating

3. Force from the valve actuation is applied through the valve stem to the bottom of the disc such that the possibility of cocking the disc is minimized

The air cylinder is utilized to operate the isolation valve. Opening and closing of the valve is affected by the admission of valve operating air to the bottom and top, respectively, of the air cylinder piston. This is accomplished through the control unit which is attached to the air cylinder and contains the pneumatic, ac, and dc control valves. The valve operating air is supplied to the Control System from the plant Instrument Air/Nitrogen System through a check valve. An air tank accumulator is connected to the system between the check valve and the control valve to provide backup operating air. The Valve Pilot System and the accumulator are piped in such a way that when one or both pilots are energized the accumulator pressurizes the valve operator to overcome the closing force exerted by the spring to open the main valve. When both pilots are deenergized, as in a two channel trip or manual switch in the closed position, the accumulator pressure is switched to pressurize the opposite side of the valve operator and help the spring close the valve. The pressure from the accumulator and the spring force are each capable of independently closing the valve against full reactor pressure. This is in the event that if one fails the other will successfully close the valve.

The accumulator volume is adequate to provide full stroking of the valve through one half cycle (open to close) when supply air to the accumulator has failed. The supply line to the accumulator is large enough to make up pressure to the accumulator at a rate faster than the valve operation bleeds pressure from the accumulator during valve opening or closure.

The hydraulic dashpot functions as a hydraulic buffer and is utilized to control the speed with which the isolation valve is closed by the air actuator. Oil is displaced from one side of the dashpot piston to the other through the hydraulic return line along side the dashpot; the rate at which it is displaced and thus the rate at which the valve can be closed is controlled by the speed control valve in this return line. Increasing the flow through this line decreases the time it takes to close the isolation valve, and vice versa. In this way, the valve closing time is adjustable between 3 and 10 sec.

Each of the four spring guide shafts contains three stacks of springs which are compressed when the valve is open. These springs function to expand when air pressure is either vented or lost from under the air cylinder piston and thus exert a downward force against the spring seat member which pushes the valve stem and disc down to close the valve. There are spring guides installed on each guide shaft which prevent scoring during normal operation and binding should one of the springs break. The spring seat member is also closely guided on the support shafts and rigidly attached to the stem to offset any eccentric force being applied in case of a broken spring. The design is such that springs on three guide shafts will close the valve in the event that one set is broken or otherwise placed out of service.

Either manual or automatic signals can be sent to the Pneumatic Control System for each isolation valve. The Control System (see Figure 4.6.2) consists of:

1. Normal opening and closing components operated four way poppet valve (part 2), an ac solenoid valve (part 5), and a dc solenoid valve (part 4)

2. Exercising components - four way poppet valve (part 1) and solenoid valve (part 6)

All Control System components except the air storage tank (part 3) and the check valve (part 9) are bolted to a sub-plate that is fastened to the air cylinder mounting plate on each isolation valve.

The control power available is 120 V ac, 60 cycles, 0.5 amps control and 125 V dc, 0.5 amps control.

Remote manual switches in the control room enable the operator to open or close at normal speed (3 to 10 sec) or at the slow speed (45 to 60 sec) for exercising and testing. Position indicating lights actuated by limit switches on each isolation valve give the control room operator valve full open, full closed, and partially

closed display. Pairs of switches at 90 percent open and closed valve positions are actuated by motion of the spring seat member. The 90 percent open switches turn off the open lights for purposes of valve testing, and initiate reactor scram if three of the four main steam lines isolate (closure of one valve in each main steam line - see Section 7.2, Reactor Protection System).

The isolation valve is designed to pass saturated steam at 1,250 psig and 575°F with a moisture content of approximately 0.23 percent, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The design objective for the valve is a minimum of 40 years of service at the specified operating conditions. The estimated operating cycles were 100 cycles during the first year and 50 cycles/year thereafter. In addition to minimum wall thickness required by applicable codes, a corrosion allowance of 0.120 inches minimum was added. For license renewal, aging management programs were identified, as necessary, to address the effects of aging, including loss of material due to corrosion, for the MSIV through the term of the renewed license. Projected operating cycles through the term of the renewed license are less than the total operating cycles estimated during design.

Design specification ambient operating conditions are 135°F normal, 150°F maximum, at 100 percent relative humidity, in a radiation field of 15 Rad/hr gamma and 25 Rad/hr neutron plus gamma, continuous for design life. The inboard valves are not exposed to these maximum conditions continuously and the outboard valves are in much less severe ambient conditions.

In the event that the main steam line breaks downstream from the isolation valve, the steam flow quickly increases to 200 percent of rated flow. The flow is limited from further increase by the venturi flow restrictor installed upstream of the inboard isolation valve. During approximately the first 75 percent of closing, the isolation valve has little or no effect in reducing flow because the flow is restricted by the venturi. During the last 25 percent of valve closure travel, flow is reduced by the isolation valve as a function of the valve area vs travel characteristic.

The main steam line valve installations are designed as Class I equipment to resist sufficiently the response motion at the installed location within the supporting building from the Operating Basis Earthquake (see Appendix C). The valve assembly is manufactured to withstand the design basis seismic forces applied at the mass center assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are considered to act simultaneously and are added directly. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress for this combination of loads is based on the ordinary allowable stress as set forth in the applicable codes. The parts of the main steam isolation valves which constitute a process fluid pressure

boundary are designed, fabricated, inspected, and tested as described in Appendix A, Pressure Integrity of Piping and Equipment Pressure Parts. The control valves and other equipment provided in the valve assembly are designed, manufactured, and shop tested in accordance with the following codes and standards where applicable.

USA Standards Institute B31.1.0 and B16.5
American Society for Testing Materials (ASTM)
American Society of Mechanical Engineers (ASME)
Boiler and Pressure Vessel Code, Sections I, III and VIII
American Institute of Electrical and Electronic Engineers
Pipe Fabrication Institute
National Electrical Manufacturers Association

4.6.4 Safety Evaluation

The ability of the isolation valve to close within the times established by the design basis accidents, under conditions of high pressure differentials and fluid flows, with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of tests in dynamic test facilities. A full size, 20 in valve produced for actual use in a BWR was tested in a range of steam/water blowdown conditions simulating postulated accident conditions. The test valve was opened and closed more than 400 times (200 cycles) during the test program, during which it shut off 40 flow tests which simulated accident conditions up to those more severe than postulated for the design basis accident in the nuclear power plant. The extensive analytical program utilized resulted in finding no conditions more severe than the design basis accident. The variety of steady flow conditions on which the valve was closed covered the following ranges:

Steam Tests:	50-1,080 lb/sec
Water Tests:	240-3,490 lb/sec
Mixture Tests:	1,530-3,860 lb/sec (quality 17-45 percent)
Surge Tests:	520-2,970 lb/sec (quality 1-33 percent)

The analysis of valve closing performance on this wide variety of conditions demonstrated that closure is not critically sensitive to temperature, pressure, fluid in the valve, and fluid flow through the valve. In every case, the valve opened and closed when signaled and shut off the flow completely and reliably. It was further observed that steam and mixture flows assisted valve closure, with closing speeds up to 20 percent faster than those obtained under cold station conditions. A detailed description and analysis of this test program is contained in Design and Performance of General Electric Boiler Water Reactor Main Steam Isolation Valves, APED-5750, D.A. Rockwell and E.H. van Zylstra, March 1969.

The analysis of a complete sudden steam line break outside the primary containment is described in the Section 14, Station Safety Analysis. It shows that the fuel barrier is protected against loss of cooling if main steam isolation closure takes as long as 10.5 sec (including up to 0.5 sec for the instrumentation to initiate valve closure after the break). The calculated radiological effects of the radioactive material assumed released with the steam are shown to be well within the guideline values of 10CFR100 for such an accident.

Thus, Safety Design Basis 1 is shown to be satisfied with considerable margin.

The shortest closing time (approximately 3 seconds) of the main steam isolation valves is also shown to be satisfactory in Section 14, Station Safety Analysis. The switches on the valves initiate reactor scram when either the inboard or outboard valve on three or more steamlines are more than 10 percent closed. The pressure rise in the system from stored and decay heat may cause the nuclear system relief valves to open briefly, but the rise in fuel cladding temperature will be insignificant. The transient is less than that from sudden closure of the turbine stop valves (in approximately 0.1 seconds) coincident with postulated failure of the turbine bypass valves to open. No fuel damage results. Thus, Safety Design Basis 2 is shown to be satisfied with considerable margin.

The following design features of the valve and the system ensure reliable mechanical operation under the most adverse conditions:

1. Use of the venturi flow limiters upstream of the inboard isolation valve plus ensuring a tortuous flow through main steam piping runs significantly reduce (by approximately a factor of 4) impact pressure that could impinge on a partially closed isolation valve as a result of the design steam break accident

2. Utilization of steam dryer and separator materials and construction which ensure that all associated components can withstand higher than normal loading due to flooding, such that no parts are expected to break loose to be carried into steam lines and foul isolation valve closure

3. Significant margin between maximum yield strengths and maximum operating parameters for all pressure containing parts. The valve body, bonnet, bonnet bolting, valve stem, disc, disc guides, stuffing box, and packing can all withstand pressures and forces of from 4 to 6 times those expected under all expected operating conditions

4. Utilization of the pilot valve arrangement to balance differential pressure across the disc during the closing stroke, and to ensure that maximum loading cannot be applied to the disc until it is fully seated

5. Utilization of closure devices capable of applying a mechanical closing force of more than sufficient strength to close the valve, and to keep it seated against maximum back pressures expected. Further insurance is obtained by utilizing the orientation of the operator/stem/disc which takes advantage of normal steam flow, and higher inlet pressure to assist in closing the valve and maintaining a tight seal

6. Design of springs such that breakage cannot result in binding of the valve or the application of eccentric forces

It is therefore concluded that mechanical operation of the valve is extremely reliable, which has been borne out by all test programs which have been conducted. This contributes to the satisfaction of all safety design bases.

The valves are of fail-safe design in that they will be closed by the springs in the event of loss of instrument air. They will also be closed by the air operator in the event of loss of both ac and dc to the two solenoids associated with each valve. Both solenoids must be deenergized, however, to effect closure of the isolation valve to prevent spurious closure if one solenoid power supply is lost.

Two redundant isolation valves are provided in each steam line so that either can perform the isolation function, and either can be tested for leakage after closing the other. The inside valve and the outside valve and their control systems are separated physically. Considering the redundancy, the mechanical strength, the closing forces, and the leakage tests discussed above; the main steam isolation valves satisfy safety design bases 3 through 5.

The isolation valves and their installation are designed as Class I equipment for inclusion of seismic loadings, as delineated in Appendix C. Therefore, the seismic loading requirement of safety design basis 6 is met.

4.6.5 Inspection and Testing

The main steam isolation valves can be tested during station operation and tested and inspected during refueling outages. The requirements for testing are shown in the Technical Specifications referenced in Appendix B.

The valves can be tested and exercised individually to the 90 percent open position without reducing reactor power because the valves still pass rated steam flow.

The valves can be tested and exercised individually to the fully closed position at 75 percent power. During reactor shutdowns for refueling, the main steam isolation valves can be tested and visually inspected.

During pre-startup tests following an extensive shutdown, the valves receive the same hydrotests (=1,000 psi) which are imposed on the primary system.

This test and leakage measurement program will insure that the valves are operating properly, and that a leakage trend is detected.

4.6.6 Operational Nuclear Safety Requirements

Table 4.6-1 presents the operational nuclear safety requirements for the Main Steam Line Isolation Valves for each applicable BWR operating state. The entries in Table 4.6-1 represent an extension of the plant-wide BWR systems described in Appendix G to the Main Steam Line

Isolation Valves. The following referenced portions of the safety analysis report provide information substantiating entries in Table 4.6-1.

Reference	Information Provided
1. Preceding parts of subsection 4.6	Description of Main Steam Line Isolation Vavles and associated components.
2. Station Safety Analysis, Section 14	Analyses verifying response of Main Steam Line Isolation Valves to transients and accidents.
3. Station Nuclear Safety Analysis, Appendix G.	Identifies conditions and events for which Main Steam Line Isolation Valve action is required
4. Jacobs, I. M., "Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards", General Electric Company, Atomic Power Equipment Department, April 1969, (APED-5736).	Describes methods used to establish allowable repair times for engineered engineered safeguards.

Each requirement in Table 4.6-1 is referenced to the most significant plant condition originating the need for the requirement by identifying a matrix block on one of the six matrices of Appendix G. These references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns of Table 4.6-1 and are coded as follows:

Example of Matrix Reference:

```
F41-57
│ │  │
└─┼──┼---F =  BWR operating state F
  └──┼---41 =  Event (row #41)
     └----57 =  Main Steam Line Isolation Valves (column 57)
```

There are no requirements imposed on the Main Steam Line Isolation Valves in operating states A and B. Operability of the Main Steam Line Isolation Valves is necessary only when the associated main steam lines are unisolated; with the head off in these two states, all Main Steam Line Isolation Valves would be closed or steam line plugs installed. The requirements imposed on the Main Steam Line Isolation Valves in operating states C, D, E, and F result from considerations for the main steam line break design basis accident or lesser cases thereof.

These operational nuclear safety requirements pertain only to mechanical aspects of the Main Steam Line Isolation Valves. Those pertaining to associated sensors and control systems are contained and discussed in subsection 7.3 "Primary Containment and Reactor Vessel Isolation Control System".

TABLE 4.6-1

MAIN STEAM LINE ISOLATION VALVES REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Physical closure of valves on automatic signal	Main steam line isolation valves	2 valves per main steam line	A	None
			B	None
			C	With nuclear system pressurized, 1 valve operable per un-isolated line (C41-57)
			D	With nuclear system pressurized, 1 valve operable per un-isolated line (D41-57)
			E	With nuclear system pressurized, 1 valve operable per un-isolated line (E41-57)
			F	With nuclear system pressurized, 1 valve operable per un-isolated line (F41-57)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting conditions is for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Figure 4.6-1 has been removed.

Please refer to Drawing 2518-2-6 (Sh 1 + 2).

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TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
MO-1301-25	RCIC Pp. Suction From Torus	X-220;OPC	125.0	B-X	Gate	DC	DC	Closed	-- --	RM	28
MO-2301-36	HPCI Pp. Suction From Torus	X-221;OPC	37.0	B-X	Gate	DC	DC	Closed	4 Closed	L,RM	26,28
MO-1001-7A	RHR Pp. Suction	X-222A;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7B	RHR Pp. Suction	X-222D;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7C	RHR Pp. Suction	X-222B;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7D	RHR Pp. Suction	X-222C;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
2301-45	HPCI Turbine Exhaust	X-223; OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev. Flow	
2301-74	HPCI Turbine Exhaust	X-223;OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev. Flow	
2301-218	HPCI Low Point Drain	X-223;OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev. Flow	
CV-9068A	HPCI Gland Seal Condenser	X-223;OPC	--	B-X	Globe	DC	Spring	Closed	4 Closed	L,AA,RM	
CV-9068B	HPCI Gland Seal Condenser	X-223;OPC	--	B-X	Globe	DC	Spring	Closed	4 Closed	L,AA,RM	
MO-2301-33	HPCI Turbine Ex. Vac. Brkr.	X-223;OPC	30.0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36
MO-2301-34	HPCI Turbine Ex. Vac. Brkr.	X-223;OPC	30.0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36
2301-217	HPCI Exhaust Line Drain	X-224;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
1301-64	RCIC Turbine Exhaust	X-225; OPC	--	B-X	Stop Check	--	Process	Closed	-- --	Rev. Flow	28
1301-59	RCIC Vac. Pp. Discharge	X-226; OPC	--	B-X	Check	--	Process	Closed	-- --	Rev. Flow	28
SV-5084A	Post Acc. Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5084B	Post Acc. Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5083A	Post Acc. Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5083B	Post Acc. Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19

SECTION 6

CORE STANDBY COOLING SYSTEMS

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6.4 DESCRIPTION

6.4.1 High Pressure Coolant Injection System (HPCIS)

The HPCIS consists of a steam turbine assembly driving a constant flow pump assembly and system piping, valves, controls, and instrumentation. The HPCIS is shown schematically on Figure 6.4-1 (Drawing M1J6-4).

The principal HPCIS equipment is installed in the Reactor Building. The turbine-pump assembly is located in a shielded area to assure that personnel access to adjacent areas is not restricted during operation of the HPCIS. Suction piping comes from the condensate storage tank and the suppression pool. Injection water is piped to the reactor feedwater pipe at a T-connection. Steam supply for the turbine is piped from a main steam header in the primary containment. This piping is provided with an isolation valve on each side of the drywell barrier. Remote controls for valve and turbine operation are provided in the station main control room. The controls and instrumentation of the HPCIS are described, illustrated, and evaluated in detail in Section 7.4, Core Standby Cooling Controls and Instrumentation.

The HPCIS is provided to ensure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the nuclear system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCIS permits the reactor to be shut down while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized, the pressure at which Low Pressure Coolant Injection (LPCI) operation or Core Spray System operation maintain core cooling.

If a loss of coolant accident occurs, the reactor scrams upon receipt of a low water level signal or a high drywell pressure signal. The HPCIS starts when the water level reaches a preselected height above the core, or if high pressure exists in the primary containment. The HPCIS automatically stops when a high water level in the reactor vessel is signaled.

The HPCIS is designed to pump water into the reactor vessel over a wide range of pressures in the reactor vessel, from 150 psig to 1120 psig (Reference Table 6.3-1). Accident safety analysis requires the HPCIS deliver 4250 gpm to the reactor vessel over a range of reactor pressures from 150 psig to 1000 psig, which is well within the design capability of the HPCIS.

The HPCIS also serves as a backup for the RCIC system during loss of feedwater transients (i.e., no pipe break), and similar to RCIC the nominal HPCIS injection flowrate at the upper analytical SRV setpoint of 1190 psig is 400 gpm. Analysis performed to increase the SRV setpoint to 1115 ± 11 psig demonstrated that 320 gpm was sufficient to prevent core uncovery with margin of approximately 4 feet above top of active fuel (TAF)(Ref. 4.7.10.1).

The analysis described in reference 4.7.10.1 remains valid for the current SRV upper analytical setpoint of 1190 psig (1155 ± 3%), because the change in total inventory lost from the vessel at the higher SRV setpoint is negligible because the inventory loss is primarily dependent on decay heat which is unaffected by the setpoint increase (Reference 4.7.10.2).

Because, the HPCIS minimum flow valve automatically opens on low flow, the HPCIS flowrate with reactor pressure at the upper analytical SRV setpoint must remain above the low flow setpoint to avoid diversion of injection flow to the torus. Periodic testing is performed that verifies the HPCIS can provide a flow rate of 3000 gpm at a system head corresponding to the upper analytical SRV setpoint of 1190 psig. This test requirement demonstrates a HPCIS performance substantially greater than required for reactor isolation events.

Two sources of water are available. Initially, demineralized water from the condensate storage tank is used instead of injecting from the suppression pool into the reactor. This provides reactor grade water to the reactor vessel for the case where the need for the HPCI is rapidly satisfied. Water from either source is pumped into the reactor vessel via the feedwater line. Flow is distributed within the reactor vessel through the feedwater spargers to obtain mixing with the hot water or steam in the reactor pressure vessel.

The pump assembly is located below the level of the condensate storage tank and below the water level in the suppression pool to assure positive suction head to the pumps.

The HPCIS turbine-pump assembly and piping are located to be protected from the physical effects of design basis accidents, such as pipe whip, and high temperatures; the equipment is located outside the primary containment. This arrangement satisfies safety design basis 9.

The HPCIS turbine is driven by steam from the reactor which is generated by decay heat and residual heat. The steam is extracted from a main steam header upstream of the main steam line isolation valves. The two HPCIS isolation valves in the steam line to the HPCIS turbine are normally open to keep the piping to the turbine at elevated temperatures to permit rapid startup of the HPCIS. Signals from the HPCIS control system open or close the turbine stop valve.

A condensate drain pot is provided upstream of the turbine stop valve to prevent the HPCIS steam supply line from filling with water. The drain pot normally routes the condensate to the main condenser, but upon receipt of an HPCIS initiation signal or a loss of control air pressure, isolation valves on the condensate line automatically shut.

The turbine has two devices for controlling power; a speed governor which limits turbine speed to its maximum operating level and a control governor with automatic speed set point control which is positioned by a demand signal from a flow controller to maintain constant flow over the pressure range of HPCIS operation. Manual operation of the governor is possible when in the test mode, but it is automatically repositioned by the demand signal from the flow controller if system initiation is required.

As reactor steam pressure decreases, the HPCIS turbine throttle valves open further to pass the steam flow required to provide the necessary pump flow. The capacity of the system is selected to provide sufficient core cooling to limit clad temperature while the pressure in the reactor vessel is above the pressure at which core spray and LPCI become effective.

Exhaust steam from the HPCIS turbine is discharged to the suppression pool. A drain pot at the low point in the exhaust line collects moisture present in the steam. Collected moisture is discharged through a trap to the suppression pool or bypassed to the gland seal condenser if the trap fails.

The HPCIS turbine exhaust line has two separate vacuum relief mechanisms which prevent significant vacuum from developing. Vacuum relief prevents water from being drawn into the turbine exhaust line from the torus and aids draining of condensed steam. The relief mechanisms include a pipe (including vacuum relief check valves and containment isolation valves) from the torus atmosphere to the HPCIS turbine exhaust line downstream of the double check valve arrangement and a nitrogen purge system (not safety related) which can be used to pressurize the HPCIS turbine exhaust line after a turbine trip.

The HPCIS turbine gland seals are vented to the gland seal condenser and part of the water from the HPCIS pump is routed through the condenser for cooling purposes. Noncondensible gases from the gland seal condenser are pumped to the Standby Gas Treatment System when the Reactor Building is isolated.

The system piping is designed to USASI B31.1.0 and the additional requirements of Appendix A. The pump is designed to ASME Section III, Class C and is also designed and tested in accordance with the Standards of the Hydraulic Institute.

The HPCIS turbine exhaust vacuum breaker line from the torus to the HPCIS exhaust line is designed to ASME Section III Subsection NC.

The HPCIS equipment, piping, and support structures are designed as Class I equipment. See Section 12 and Appendix C. This satisfies design basis 10.

The system was designed for an original service life of 40 years, accounting for corrosion, erosion, and material fatigue. The HPCI system was reviewed for license renewal and loss of material due to corrosion, erosion, and cracking due to material fatigue are managed such that the system will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

Startup of the HPCIS is completely independent of ac power. Only dc power from the station batteries and steam extracted from the Nuclear System are necessary. This satisfies safety design basis 5.

The various operations of the HPCIS components are summarized as follows:

The HPCIS controls automatically start the system and bring it to design flow rate within 90 sec from receipt of a reactor vessel low water level signal, or a primary containment (drywell) high pressure signal.

The HPCIS turbine is shut down automatically by any of the following signals:

1. Turbine overspeed - This prevents damage to the turbine and turbine casing.

2. Reactor vessel high water level - This indicates that core cooling requirements are satisfied.

3. HPCIS pump low suction pressure - This prevents damage to the pump due to loss of flow.

4. HPCIS turbine exhaust high pressure - This indicates a turbine or turbine control malfunction.

5. Automatic HPCIS isolation signal - If an initiation signal is received after the turbine is shut down, the system is capable of automatic restart if no shutdown signals exist.

Because the steam supply line to the HPCIS turbine is part of the Nuclear System process barrier, certain signals automatically isolate this line, causing shutdown of the HPCIS turbine. Automatic shutoff of the steam supply is described in Section 7.3, Primary Containment and Reactor Vessel Isolation Control System. However, automatic depressurization and the low pressure systems of the CSCS act as backup, and automatic shutoff of the steam supply does not negate the ability of the CSCS to satisfy the safety objective.

In addition to the automatic operational features of the system, provisions are included for remote manual startup, operation, and shutdown (provided initiation or shutdown signals do not exist).

HPCIS initiation automatically actuates the following valves:

HPCIS pump discharge test bypass valves
HPCIS pump suction shutoff valve
HPCIS pump discharge shutoff valve
HPCIS steam supply shutoff valves
HPCIS turbine stop valves
HPCIS turbine control valves
HPCIS steam supply line drain isolation valves

Startup of the hydraulic oil pump and proper functioning of the Hydraulic Control System is required to open the turbine valves. Operation of the gland seal condenser components is required to prevent outleakage from the turbine shaft seals. Startup of the equipment is automatic. Prior to startup, the control governor may be anywhere between its high speed and low speed stop positions. Upon receipt of an initiating signal, the flow control signal automatically runs the control governor toward its high speed stop (maximum demand signal from flow controller). The same initiating signal automatically starts the hydraulic oil pump and when sufficient oil pressure is developed, both the turbine stop valve and the control valves open simultaneously and the turbine accelerates toward the rpm of either the control governor or the speed governor, whichever is lower. When rated flow is established, the flow controller signal adjusts the setting of the control governor so that rated flow is maintained as Nuclear System pressure decreases.

A minimum flow bypass is provided for pump protection. The bypass valve automatically opens on a low flow signal, and automatically closes on an increasing flow signal. When the bypass is open, flow is directed to the suppression pool. There are shutoff valves in the line used for system testing. These valves are sequenced to close by the signal which actuates system operation, and are interlocked closed when either suction valve from the suppression pool is open. All automatically operated valves are equipped with a remote manual functional test feature.

The HPCIS initially injects water from the condensate storage tank. When the water level in the tank falls below a predetermined level or on high level in the suppression pool, the pump suction is automatically transferred to the suppression pool. This transfer may also be made from the control room using remote controls. This establishes a closed loop for recirculation of water escaping from a break.

6.4.2 Automatic Depressurization System

In case the capability of the Feedwater System, the control rod drive water pumps, Reactor Core Isolation Cooling System (RCICS), and HPCIS is not sufficient to maintain the reactor water level, the Automatic Depressurization System functions to reduce the reactor pressure so that flow from LPCI and the core spray system enters the reactor vessel in time to cool the core and limit fuel clad temperature.

The automatic depressurization system utilizes the four nuclear system pressure relief valves to relieve the high pressure steam to the suppression pool. The design, description, and evaluation of the pressure relief valves are discussed in detail in Section 4.4, Nuclear System Pressure Relief System and it is shown that Safety Design Bases 5, 9, and 10 are satisfied.

The pressure relief valves automatically open upon coincident signals of reactor vessel low-low water level, primary containment (drywell) high pressure, and discharge pressure indication of any low pressure cooling system (LPCI or core spray), but only after a time delay. The time delay provides time for the high pressure systems to restore reactor water level and for the operator to cancel the automatic depressurization signal if main control room information indicates the signal is false or is not needed.

6.4.3 Core Spray System

Two independent loops are provided as a part of the core spray system. Each loop consists of a core spray pump, a sparger ring, a spray nozzle, and the necessary piping, valves, and instrumentation. Figure 6.4-2 (Drawing M1K 2-4) shows a schematic process diagram of the core spray system.

In case of low water level in the reactor vessel or high pressure in the drywell, the core spray system, when reactor vessel pressure is low enough, automatically sprays water onto the top of the fuel assemblies in time and at a sufficient flow rate to cool the core and limit fuel clad temperature (The LPCI System starts from the same signals and operates independently to achieve the same objective by flooding the reactor vessel).

The core spray system provides protection of the core for the large break in the nuclear system when the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are unable to maintain reactor vessel water level.

The protection provided by the core spray system also extends to a small break (see Figure 6.3-1) in which the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are all unable to maintain the reactor vessel water level and the automatic depressurization system has operated to lower the reactor vessel pressure so LPCI and the core spray system can provide core cooling.

The core spray pumps receive power from the station 4,160V auxiliary buses. Each core spray pump motor and the associated automatic motor valves receive AC power from different buses. Similarly, control power for each loop of the core spray system comes from different DC buses. This arrangement satisfies Design Basis 5.

The core spray pumps and all automatic valves can be operated individually by manual switches in the main control room. Operating information is provided in the main control room with pressure indicators, flow meters, and indicator lights.

The major equipment for one loop is described in the following paragraphs.

When the system is actuated, water is taken from the suppression pool. Flow then passes through a normally open butterfly valve and a motor operated valve which can be closed by a remote manual switch from the main control room. This motor operated valve is normally open. The butterfly valve is located in the core spray pump suction line as close to the suppression pool as practical. This valve is equipped with an extension operator to permit manual closure of the valve from the floor above the suppression chamber.

The core spray pumps are located in the reactor building below the water level in the suppression pool to assure positive pump suction. The pump, piping, controls, and instrumentation of each loop are separated and protected so that any single physical event, or missiles generated by rupture of any pipe in any system within the containment drywell, cannot make both core spray loops inoperable. The switchgear for each loop is in a separate cabinet for the same reason. This arrangement satisfies safety design basis 9.

The effects on available NPSH for the core spray pumps due to a postulated accumulation of LOCA generated debris on the suction strainers in the suppression pool were evaluated in accordance with Regulatory Guide 1.82 Rev. 2. The RHR and core spray suction strainers in each loop were replaced with a large capacity (670 ft^2) stacked disk strainer spanning the width of one torus bay and connected to the three pumps. The debris analysis determined the maximum volume of shredded fiberglass, sludge, dirt/dust, rust flakes, and paint chips generated from the bounding line break inside primary containment. Based on a bounding analysis for debris generation, transport, and accumulation, the increase in suction strainer head loss is within the margin for NPSH available to the core spray pumps following the design basis LOCA. Refer to Section 14.5.3 for the NPSH evaluation.

A shaft seal drain line is provided from the pump casings which drains to the radwaste system.

A low flow bypass line is provided from the pump discharge to below the surface of the suppression pool. The bypass flow is required to prevent the pump from overheating when pumping against a closed discharge valve. An orifice limits the bypass flow. A manual valve, normally locked open, is used to close the bypass line for maintenance.

A relief valve, set for 500 psig, protects the low pressure core spray system upstream of the outboard shutoff valve from reactor pressure. The relief valve discharges to the radwaste system.

A full flow test line permits circulating water to the suppression pool for testing the system during planned operations. A normally closed, motor operated valve in the line is controlled by a remote manual switch in the main control room. Partial opening of the valve combined with an orifice in the test line permits test operation at rated core spray flow at a pressure drop equivalent to discharging into the reactor vessel. A flow indicator is provided in the main control room to monitor core spray system flow rate.

Two motor operated valves are provided to isolate the core spray system from the nuclear system when the core spray pump is not running. These valves admit core spray water to the reactor when signaled to open. Both valves are installed outside the drywell to facilitate operation and maintenance, but as close as practical to the drywell to limit the length of line exposed to reactor pressure. The valve nearer the containment is normally closed to back up the inside check valve for containment purposes. The outboard valve is normally open, to limit the equipment needed to operate in an accident condition. A drain line is provided between the two shutoff valves to measure leakage through the inside check valve or the inboard shutoff valve. A drain line is normally closed with two valves and a pipe cap to assure containment.

A check valve is provided in each core spray pipeline just inside the primary containment, to prevent loss of reactor coolant outside containment in case the core spray line breaks. A normally locked open manual valve is provided downstream of the inside check valve to shut off the core spray system from the reactor during shutdown conditions for maintenance of the upstream valves. The two core spray system pipes enter the reactor vessel through nozzles 120 deg apart. Each internal pipe then divides into a semicircular header with a downcomer at each end which turns through the shroud near the top. A semicircular sparger is attached to each of the four outlets to make two practically complete circles, one above the other. Short elbow nozzles are spaced around the spargers to spray the water radially into the tops of the fuel assemblies.

Core spray piping upstream of the outboard shutoff valve is designed for the lower pressure and temperature of the core spray pump discharge. The outboard valve and piping downstream are designed for reactor vessel pressure and temperature. The system is designed in accordance with Appendix A. The core piping and support structures are designed in accordance with Class I seismic criteria. See Section 12 and Appendix C. The core spray system is assumed filled with water for seismic analysis. It is concluded that Safety Design Basis 10 is satisfied.

Upon signals of reactor low-low water level and low vessel pressure or drywell high pressure, the automatic controls turn on the core spray pumps and restore other valves to the spray mode. When reactor pressure decreases, the core spray shutoff valves are signaled to open. Flow to the sparger begins when the pressure differential opens the inside check valve. Section 7.4, Core Standby Cooling System Controls and Instrumentation, contains further details and evaluation.

6.4.4 Low Pressure Coolant Injection

In case of low-low water level in the reactor and low vessel pressure or high pressure in the containment drywell, LPCI mode of operation of the residual heat removal (RHR) system pumps water into the reactor vessel in time to flood the core to limit fuel clad temperature.

(The core spray system starts from the same signals and operates independently to achieve the same objective.)

LPCI operation provides protection to the core for the case of a large break in the nuclear system when the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are unable to maintain reactor vessel water level.

Protection provided by LPCI also extends to a small break (see Figure 6.3-1) in which the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are all unable to maintain the reactor vessel water level and the automatic depressurization system has operated to lower the reactor vessel pressure so LPCI and the core spray system start to provide core cooling.

Figure 6.4-3 shows a schematic process diagram of LPCI. LPCI operation consists of using at least three of the four ac motor driven centrifugal pumps taking water from the suppression pool and pumping it into one or the other recirculation loop. The water enters the reactor through the jet pumps to restore the water level in the reactor vessel. LPCI operation includes using associated valves, controls, instrumentation, and pump accessories. The LPCI pump motors receive power from the station 4,160V auxiliary busses. The LPCI pump motors and the associated automatic motor valves within each loop receive ac power from the same bus. This arrangement satisfies safety design basis 5.

LPCI pumps and piping equipment are described in detail in Section 4.8, Residual Heat Removal System, which also describes the other functions served by the same pumps if not needed for the LPCI function. The portions of the RHR System required for accident protection are designed in accordance with Class I seismic criteria. See Section 12 and Appendix C. It is concluded that safety design basis 10 is satisfied.

LPCI pump motors and the associated automatic motor valves within each loop receive ac power from the same bus. This arrangement satisfies safety design basis 5.

LPCI pumps and piping equipment are described in detail in Section 4.8, Residual Heat Removal System, which also describes the other functions served by the same pumps if not needed for the LPCI function. The portions of the RHR System required for accident protection are designed in accordance with Class I seismic criteria. See Section 12 and Appendix C. It is concluded that safety design basis 10 is satisfied.

FSAR Figure 6.3-1 shows that the HPCIS range can be divided into two categories: (1) the half width bars show break sizes for which HPCI requires assistance by low pressure systems within 1000 seconds to prevent core uncovery, and (2) the full width bars show break sizes for which HPCI can alone maintain reactor water level above top of active fuel (TAF) for at least 1000 seconds. The 1000 seconds is included in the definition because the HPCIS requires a minimum vessel pressure to sustain the operation of the turbine.

The upper limit of the HPCIS unassisted capability (0.1 ft2 for liquid breaks and point 0.7 ft2 for steam breaks on Figure 6.3-1) is defined as the largest break size for which the HPCIS can protect the core for a period of at least 1000 seconds without assistance from any other Core Standby Cooling System. Since the decay heat generation continually decreases with time a point will eventually be reached where the energy additions from decay heat will no longer be sufficient to maintain the required operating pressure for the HPCIS turbine. However, this point is well below the pressure at which either the Core Spray System or the LPCI System is sufficient to keep the core cool after the HPCIS shuts off. Analysis of this break size is illustrated on Figure 6.5-1 which shows that the HPCIS delivers enough water into the reactor vessel before shutdown because of low reactor pressure, that reactor level does not reach TAF until 1000 seconds. As indicated on Figure 6.5-1, reactor pressure remains below 1000 psia throughout the period of the HPCIS operation. This analysis for the upper limit of the HPCIS unassisted capability (0.1 ft2 liquid line break) defines HPCI pump performance requirements at a flowrate of 4250 gpm.

The HPCIS turbine is designed to accommodate dry and saturated steam. The design objective for the turbine casing was a useful life of 40 years accounting for corrosion, erosion, and material fatigue. The HPCI system was reviewed for license renewal and loss of material due to corrosion, erosion, and cracking due to material fatigue are managed for the period of extended operation. Condensate and moisture carryover are prevented from accumulating by a drain pot and steam traps located immediately upstream of the turbine inlet valve. When the turbine is shutdown, the inlet line is kept at an elevated temperature and the condensate is continuously drained.

An analysis has been made to determine if any carryover occurs in the steam supply to the HPCIS turbine which could have a detrimental effect on turbine operation. In the case of a break in a liquid line, when the HPCIS is energized, the level in the reactor vessel is low enough to prevent carryover in the steam which leaves the reactor vessel. In the case of a small break in the reactor steam region simultaneously with a loss of offsite power, reactor scram, recirculation pump coastdown, and loss of feedwater, analysis shows that the initial decrease of pressure in the reactor results in no significant level swell and no carryover of water into the

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SECTION 7

CONTROL AND INSTRUMENTATION

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SECTION 7

CONTROL AND INSTRUMENTATION

7.1 SUMMARY DESCRIPTION

This Section presents the details of the more complex control and instrumentation systems in the station. Some of these systems are safety systems; others are power generation systems.

7.1.1 Safety Systems

The safety systems are the following:

Nuclear safety systems and engineered safeguards (required for accidents and abnormal operational transients):

Reactor Protection System (RPS)

Primary Containment Isolation System (PCIS)

Core Standby Cooling Systems Control and Instrumentation

Neutron Monitoring System (specific portions)

Main Steam Line Radiation Monitoring System

Refueling Ventilation Exhaust Radiation Monitoring System

Reactor Building Isolation and Control System

Containment Atmospheric Dilution System (Refer to Section 5.4)

Panels and racks associated with the RPS, PCIS, and Engineered Safeguards Systems (ESS) are identified so that two facts are apparent: first, that the equipment is part of the RPS, PCIS, or the ESS; and second, the grouping (or division) of enforced segregation with which the equipment is associated.

These panels and racks are labeled with marker plates identifying the system which are a different color from the marker plates used on other similar panels.

Certain trip inputs to the RPS, PCIS and ESS are provided by an Analog Trip System. The system consists of analog transmitters as sensors and remote electronic trip units providing the trip input. The system provides continuous monitoring of the sensed process variable with built-in calibration capabilities for each trip unit. A single analog transmitter can operate up to 8 trip units, one master trip unit and seven slave trip units. The master trip unit is a circuit board assembly designed to accept a 4-20 ma signal from

the analog transmitter. The master trip unit produces a trip output signal when the process signal passes through a preset trip point. The master trip unit also produces a buffered analog output signal which isproportional to the input and is used to drive up to seven slave trip units. The slave trip units in the analog trip system are used to provide additional setpoints for a common analog transmitter. The slave trip unit produces a trip output signal when the input signal passes through a preset trip point. Both master and slave trip units operate output relays which are input signals to the RPS, PCIS and ESS logic circuits.

Process safety systems (required for planned operation):

Neutron Monitoring System (specific portions)

Refueling Interlocks

Reactor Vessel Instrumentation

Process Radiation Monitors (except Main Steam Line Radiation Monitoring System and Refueling Ventilation Exhaust Radiation Monitoring System)

7.1.2 Power Generation Systems

The power generation systems are the following:

Reactor Manual Control System

Recirculation Flow Control System

Feedwater System Control and Instrumentation

Pressure Regulator and Turbine Generator Control

Area Radiation Monitors

Site Environs Radiation Monitors

Health Physics and Laboratory Analysis Radiation Monitors

Process Computer System

7.1.3 Safety Functions

The major functions of the safety systems are summarized as follows:

Reactor Protection System

The RPS initiates an automatic reactor shutdown (scram) if monitored nuclear system variables exceed pre-established limits. This action prevents fuel damage and limits system pressure, thus restricting the release of radioactive material.

Primary Containment and Reactor Vessel Isolation Control System

The PCIS initiates closure of various automatic isolation valves in response to off limit nuclear system variables. The action provided limits the loss of coolant from the reactor vessel and contains radioactive materials either inside the reactor vessel or inside the primary containment. The system responds to various indications of pipe breaks or radioactive material release.

Core Standby Cooling Systems Control and Instrumentation

This Section describes the arrangement of control devices for High Pressure Coolant Injection, Automatic Depressurization, Core Spray (CS), and Low Pressure Coolant Injection Systems.

Neutron Monitoring System

The Neutron Monitoring System (NMS) uses incore neutron detectors to monitor core neutron flux. The safety function of the NMS is to provide a signal to shutdown the reactor when an overpower condition is detected. High average neutron flux is used as the overpower indicator. In addition, the NMS provides the required power level indication during planned operation.

Refueling Ventilation Exhaust Radiation Monitoring System

This Section describes the monitoring system used to indicate high radiation in the refueling floor area of the Reactor Building, initiate isolation of the normal Reactor Building ventilation systems, and start the Standby Gas Treatment System.

Reactor Building Isolation and Control System

The Reactor Building Isolation and Control System (RBICS) initiates trip of the Reactor Building supply and exhaust fans, isolates the normal ventilation system, and provides the starting signals for the Standby Gas Treatment System (SGTS) in the event of a loss of coolant accident (LOCA) inside the drywell or a fuel handling accident in the Reactor Building. These actions limit the release to the environs of radioactive material so that offsite doses from these accidents will be below the guideline values listed in 10CFR100.

Refueling Interlocks

The refueling interlocks serve as a backup to procedural core reactivity control during refueling operation.

Reactor Vessel Instrumentation

The reactor vessel instrumentation monitors and transmits information concerning key reactor vessel operating parameters during planned operations to ensure that sufficient control of these parameters is possible.

Process Radiation Monitors

(except Main Steam Line Radiation Monitoring Systems and Refueling Ventilation Exhaust Radiation Monitoring System)

A number of radiation monitoring systems are provided on process liquid and gas lines to provide sufficient control of radioactive material release from the site.

RHR Service Water System (SSW, RBCCW)

The SSW System and RBCCW System objectives and descriptions are contained in Sections 10.7 and 10.5, respectively.

Equipment Area Cooling System

The equipment area cooling system objectives and description is contained in Section 10.18.

7.1.4 Station Operational Control

The major systems used to control the station during planned operations are the following:

Reactor Manual Control System

This system allows the operator to manipulate control rods and determine their positions. Various interlocks are provided in the control circuitry to avoid unnecessary safety system action resulting from operator error.

Recirculation Flow Control System

This system controls the speed of the two reactor recirculation pumps by varying the electrical frequency of the power supply for the pump motors. Varying pump speed will vary the coolant flow rate through the core and cause a change to the power output level. The system is arranged to allow for manual control (operator action) or automatic control (through the turbine speed/load control instrumentation).

Feedwater System Control and Instrumentation

This system regulates the feedwater system flow rate so that proper reactor vessel water level is maintained. The feedwater system controller uses reactor vessel water level, main steam flow, and feedwater flow signals to regulate feedwater flow. The system is arranged to permit single element control (level only), three element control (level, steam flow, feedwater flow), or manual flow control operation.

Pressure Regulator and Turbine Generator Controls

Normally, the pressure regulator, EPR and MPR adjusts steam control valve position to maintain constant reactor pressure. The ability of the station to follow system load is not used.

A single pressure regulator, with a backup regulator, is used to control both the turbine admission valves and the turbine bypass system valves. The two valves are coupled together by a linkage system.

The backup pressure regulator is provided to take over control of pressure in the event the operating regulator should fail. The setpoint of the backup regulator is normally a few psig above the setpoint of the normal operating pressure regulator. The linkage system also contains a mechanical stop arrangement (lift limit) which limits the total steam flow to a value about 110 percent of the turbine design flow.

7.1.5 Seismic Design Criteria (Reactor Protection and Engineered Safeguards Systems)

The seismic design bases for the RPS and ESS require that they withstand the loading forces and perform their required functions during the Operating Basis Earthquake or the Safe Shutdown Earthquake of 0.08g and 0.15g horizontal, respectively.

The equipment and instruments in these systems are designed to withstand and perform their functions during an Operating Basis Earthquake or a Safe Shutdown Earthquake. This qualification will be ascertained by either analytical techniques or vibration testing techniques or by a combination of the two techniques.

Specific evaluation, testing, or investigation have not yet been performed regarding the ability of Class I electrical control components to initiate a protective action during peak acceleration. However, since the electrical contacts of Class I components are capable of maintaining their position during the seismic disturbance, it is expected that initiation of protective action will not be precluded by the seismic disturbance. The time duration of the peak acceleration is short, sufficiently so that any momentary delay of the initiation of the safety action induced by the peak seismic disturbance will not affect the ability of safety systems to meet their intended functions.

If a seismic disturbance occurs during post accident operation shocking the Reactor Protection and Safeguard Systems, emergency core cooling would not be interrupted. The design is such that, once the system is initiated, it will not shut down except by proper signal from the operator or, in the case of some systems, after sensing a high reactor water level condition.

Class I pressure boundary devices in these systems are considered qualified if the combined seismic and normal loads will not cause stresses to exceed allowable stresses as defined in Appendix C.

Acceptability of other Class I components in these systems will be based on the ability of the equipment to withstand mechanical stresses and to perform its principal safety functions when subjected to the specified seismic loadings. Procurement specifications identify components that are required to meet Class I seismic requirements. The horizontal and vertical g forces that the equipment is expected to endure while performing its function is specified. Procurement specifications also require the vendor to show by test and/or analysis that the equipment will meet the seismic criteria.

The vendor must submit the test data and/or the seismic analysis for the responsible design engineer's approval as a condition of acceptance of the equipment for the intended function. The vendor may use test data on the particular components or equipment, applicable data from previously tested comparable equipment, performance data from comparable equipment which, during normal operating conditions, has been subjected to equal or greater shock loadings and/or suitable analytical results.

Seismic test and analyses were performed on instrumentation, devices, panels, and racks supplied by General Electric Company to qualify them for use in critical safety applications. These tests confirm that "g" levels will remain within the range of operability of the instrumentation. Instrumentation, devices, panels, and racks supplied by General Electric Company and used in critical safety applications have been reviewed for their response to calculated accelerations and been found to be acceptable at Pilgrim Nuclear Power Station.

Bechtel Corporation has reviewed or is currently reviewing panels, racks, instrumentation and control components, and electrical components associated with the RBICS. The seismic evaluation of the panels and instrumentation associated with the RBICS is not yet complete. However, on the basis of seismic evaluations of comparable panels supplied by the same panel vendor, it is expected the forthcoming vendor seismic calculation will show the panel will be able to sustain the specified accelerations within the stress levels given in the purchase specification.

The electrical components are evaluated primarily from test results supplied from their respective manufacturer. These test reports are reviewed to ensure that the proper acceleration levels were applied and that their testing procedures adequately represent the installed condition.

7.1.6 Radiation Resistance Design Criteria

The design criteria as discussed in Section 12.3.1.2 for Pilgrim Nuclear Power Station safety system equipment are:

1. Safety system equipment shall be capable of withstanding, without loss of function, the potential effects of the total integrated radiation dose from normal operation during the expected lifetime of the station plus a one time dose from an accident exposure. See Sections 12.3 and 14.9

2. The radiological consequences accident analysis methods and models employed in the design of the Pilgrim facility are those cited in the GE Topical Report, Analytical Methods for Evaluating the Radiological Aspects of the GE-BWR. GE-APED-5756, March 1969

3. Comparison of the potential exposures which equipment within the primary containment could experience from the design basis LOCA source terms, (derived from GE-APED-5756) to the expected original 40-year lifetime exposures shows that the expected doses are usually greater than the potential APED accident doses. The safety system equipment specification for components inside the primary containment require that materials used in the component's fabrication are able to withstand a specified total integrated dose which is based upon the component's expected original 40-year lifetime dose plus a LOCA. The environmental qualification (EQ) of electrical components program ensures that EQ components are maintained in accordance with their qualification bases.

4. RPS and engineered safety feature electrical and mechanical equipment will withstand, without loss of capability for performance of their safety functions, the total exposure

   resulting from a design basis LOCA using source terms as stated in Section 14.9 at the end of station life.

5. Section 14.9 demonstrates the capability of Pilgrim Station engineered safety feature systems to withstand the radiation effects. This section contains the source term assumptions and specific evaluations of the SGTS, the CSCS components, electrical penetrations, the control room, and materials within the primary containment

6. The electrical power and control cabling for safety system equipment which must function in a radiation environment is not discussed in Section 14.9, but it has been tested under simulated post accident radiation environment. The cabling has been irradiated with a CO-60 source to a dose of at least 5 X 107 rads which is far in excess of that which safety system cabling inside the primary containment would experience during normal operations plus that which would be experienced over a 30 day period from the release into the primary containment according to the assumptions stated in Section 14. The results of the test indicate that the power and control cabling run to Pilgrim Station safety systems is capable of satisfactory performance in a boiling water reactor (BWR) primary containment environment

7. The individual components and greases of Limitorque operators have been reviewed by the manufacturer for their ability to withstand the design basis radiation environment; i.e., that experienced during normal operation plus that radiation which would be experienced resulting from a fission product release into the primary containment according to the assumptions stated in Section 14 during that portion of a LOCA in which valve operation would be required. The manufacturer's review indicates that the Limitorque operators are capable of proper operation after irradiation in excess of the design basis radiation environment. In fact, the manufacturer expects proper operation after irradiation up to approximately 1.5 X 108 rads

8. Windings of solenoids on the main steamline isolation valves and relief/safety valves utilize Class H insulation, which has been proven capable of withstanding the design basis radiation environment with considerable margin

7.1.7 Safety Related Components Inside Containment: Environmental Qualification

Safety related equipment inside the primary containment which must operate in an accident environment is limited to isolation valves, recirculation line valves, auto relief valves, acoustic monitors, limit switches, junction boxes, solenoid valves, splicers, terminators, and their associated electrical penetrations and cabling. These cables, operators, and penetrations are designed for in excess of the required period of usage under their design basis accident conditions. In addition, indication of drywell pressure and torus water temperature are required and provided for the full range of postulated accident environmental conditions. The containment isolation and recirculation line valves are required to operate for only short time durations. This is true for the full spectrum of break sizes.

Electrical cables use an insulation type that has been environmentally tested to demonstrate suitability for this service for periods of time greatly in excess of the required operating time.

Specifications for the above equipment included the requirement to remain operable as required during and/or subsequent to a design basis LOCA. Manufacturer's proposals, manuals, and drawings are carefully reviewed for selection of materials and conformance to the specified temperature, pressure, and humidity requirements.

Qualification tests have not been required for the temperature sensors because their design range of operation and calibration encompasses the environmental conditions expected within the primary containment as the result of LOCA or steam line break accident.

Qualification tests (prototype tests) have been performed on the Limitorque operators, and power and control cabling runs to engineered safety feature equipment inside the primary containment, and on electrical penetrations to ensure required operation and/or leakage integrity under LOCA conditions.

The Limitorque valve operators and the solenoids associated with the relief and main steam line isolation valves have been tested and the results of these tests were originally submitted in Amendment 18 of Millstone Unit 1 FSAR. These results show that suitable operation of these components can be expected during that portion of the transient in which operation would be required.

Power and control cabling samples were tested in a saturated steam environment above the peak design basis LOCA conditions. Satisfactory operation was verified throughout the test including the peak test conditions. Subsequent to these tests, electrical tests were performed to verify that insulation properties were maintained.

Drywell electrical penetration qualification tests have been accomplished. The design specifications of these components required that a prototype of each type be tested under design basis LOCA conditions. The tests satisfactorily demonstrated the penetrations will maintain its electrical and leak tightness characteristics at peak conditions.

For equipment inside the drywell that is not safety-related, purchase specifications include the requirement to remain operable under normal operating environmental conditions. A non-safety related components ability to function for restart following a lesser incident has not been evaluated. Following any LOCA, equipment and components would be checked for functional operability before station restart.

7.1.8 Effect of Loss of Heating, Ventilation, or Air Conditioning System on Safety-Related Equipment

Safety-related control and electrical equipment located in the control room or other equipment rooms is not dependent upon normal station air-conditioning and/or ventilation.

An analysis of the control room assumed that all normal ventilation and air conditioning systems were inoperative; the only ventilation being through one of two Main Control Room Environmental Control Systems (MCRECS) filter trains (1,000 ft3/min). See Section 10.17.

Under the conditions imposed, a loss of all normal ventilation and air-conditioning, the control room operator would initiate an emergency shutdown of nonessential equipment and lighting to reduce the heat generation to a minimum. Heat removal would be accomplished by conduction through the floors, ceilings, and walls to adjacent rooms and to the environment. Additionally, at least one of the 1,000 ft3/min MCRECS would remove heat.

The equilibrium condition for temperature and humidity in the control room and other equipment rooms following the loss of all air-conditioning and normal ventilation would be 114#F, 48 percent relative humidity. The equilibrium temperature of 114#F would be achieved during ambient conditions of 90#F, 90 percent relative humidity.

All control board instrumentation is specified to be operable up to 120#F and 90 percent relative humidity. Therefore, the temperature within the control room will never increase to a point that will require reactor shutdown. All instrumentation will be functionally tested after installation and prior to plant startup to confirm satisfactory operability of control and electrical equipment under normal environmental conditions. The extreme of environmental conditions is far less than the design requirement of the instrumentation. Operation below this design value is always expected so that additional testing is not warranted.

Areas of the station where heat generation occurs as a result of safety-related mechanical equipment operation, i.e., the High Pressure Coolant Injection (HPCI), Reactor Core Isolation Cooling (RCIC), and the Residual Heat Removal (RHR)/Core Spray compartments, have been provided with two redundant, full capacity, Class I equipment area coolers which will maintain the ambient temperatures below the specified design temperature limits for the equipment in these compartments. See Section 10.18.

7.1.9 Safety System Periodic Testing Criteria

Provisions have been made in the Pilgrim design for periodic testing of engineered safety feature instrumentation and control equipment as described below:

Core Spray Subsystem

All sensors are of the pressure sensing type and are installed with calibration taps and instrument valves to permit testing during normal plant operation or during shutdown. The reactor low pressure sensors can be easily checked for operability during plant operation by comparing the A & B train analog trip unit indicators associated with these sensors. The reactor vessel level sensors can be similarly checked for operability by comparing the A & B train analog trip unit indicators associated with these sensors. The drywell high pressure sensors can be checked by comparing the A & B train analog trip unit indicators associated with these sensors.

The CSCS is capable of being completely tested during normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function. Sensors can be checked by comparing the A & B train for agreement at the analog trip unit indicators. The trip unit can be tested/calibrated by applying a simulated signal to its input and observing the scale reading/trip indication. Logic relays can be exercised by means of plug-in test switches used alone or in conjunction with single sensor tests. Pumps can be started by the appropriate breakers to pump against system check valves (or return to suppression pool through test valves) while the reactor is at pressure. Motor-operated valves can be exercised by the appropriate control relays and starters, and all essential indications and annunciations can be observed as the system is tested. CS water will not actually be introduced into the vessel except initially before fuel loading and during refueling outages when the torus is drained to verify core spray pump operability.

Low Pressure Coolant Injection Subsystem

The capability for sensor checks applies equally to the Core Spray (CS) Subsystem and Low Pressure Coolant Injection (LPCI) Subsystem. The capability for test and calibration also applies equally to the CS Subsystem and LPCI Subsystem, except that the only portion of the LPCI logic which cannot be tested with the reactor at full power is the recirculation pump trip portion of the loop selection logic. However, a continuity check on this portion of the LPCI logic can be made during power operation.

High Pressure Coolant Injection Subsystem

The capability for test, calibration, and sensor checks applies equally to the CS Subsystem and HPCI Subsystem.

Automatic Depressurization Subsystem

All sensors are of the pressure sensing type and are installed with calibration taps and instrument valves which allow for the application of a test pressure for calibration and/or functional tests during normal plant operation or during shutdown.

The reactor vessel level sensors can be checked for operability during plant operation by comparing the A&B train analog trip unit indicators associated with these sensors. The trip units can be tested/calibrated by applying a simulated signal to its input and observing trip indication.

The drywell high pressure sensors can be checked for operability during plant operation by comparing the A&B train analog trip unit indicators associated with these sensors. The trip units can be tested/calibrated by applying a simulated signal to its input and observing trip indication.

The Automatic Depressurization Subsystem is not tested in its entirety during actual plant operation, but provisions are incorporated so that operability of all elements of the system can be verified at periodic intervals. Testing of control circuitry is accomplished at the control relay cabinet by means of test jacks, switches, and indicator lights while exercising trip units one at a time. The test method is generally as follows:

ACTION	OBSERVATION
1. Exercise a trip unit	a. Trip unit relay pickup b. Alarm is given
2. Start a CS or RHR (LPCI mode) pump	a. Off-normal alarm b. Low pressure cooling system available relay pickup
3. Exercise logic subchannel by test switch	a. Logic subchannel relay pickup b. Continuity lights on each valve circuit are energized
4. Reset logic subchannel	a. Annunciators clear
5. Repeat above steps for other trip units, other low pressure core cooling pumps, other logic subchannels.	Same as for associated steps above

Primary Containment and Reactor Vessel Isolation Control System

The reactor vessel instruments can be checked one at a time by

application of simulated signals. These include level, pressure, radiation, and flow. HPCI and RCIC temperature sensors can be checked periodically during full power operation. Temperature sensors in the ventilation exhausts from the main steamline tunnel and the condenser compartment area are fully testable during full power operation.

All active components of the PCIS, with the exception of the analog trip sensors, are tested and calibrated during plant operation. The analog trip sensors can be cross-checked against their companions for verification of operability. Since the radiation sensors are used with reference to background and the analog trip sensors are highly reliable, they do not require actual sensitivity verification on a frequent basis. There are certain segments of wiring in the logic that are difficult to check during plant operation. These are wires that make up the parallel contacts in the one-out-of-two taken twice logic for the main steam isolation valves. However, the intercabinet wiring is so arranged that disabling shorts could only be achieved by double grounds, which would cause fuse failure on the grounded system and thus fail safe. In addition, it is very easy to observe the contact action on an HFA type relay during a channel trip condition to verify actual dropout when deenergized. The auxiliary relay circuits can be tested individually by pulling the individual valve circuit fuses and observing relay dropout as manifested by the indicators provided on the contact blocks of each relay. Thus, testability of major elements of the system can be demonstrated without shutting down the station.

Reactor Building Isolation and Control System

The Refueling Ventilation Exhaust Radiation Monitoring System contains four instrument channels to detect radiation resulting from a postulated fuel handling accident. The sensors are separated into two areas: A,B in one area: C,D in another. The upscale trip outputs are arranged in a one-out-of-two taken twice logic configuration. All four instruments are "bugged" with a source to provide a "live" zero, and any one upscale or test switch operation causes a control room annunciation. Testing is accomplished by placing one instrument at a time in the TEST mode by operation of a front panel switch. A simulated signal is introduced into the instrument input to verify operation of the trip unit at the established setpoint. The normally energized channels produce a trip output for power loss, i.e., they are fail-safe.

The SBGT is fully testable during reactor operation as part of the online test capability of the RBICS.

7.1.10 Definitions

The complexity of the control and instrumentation systems requires the use of certain terminology for clarification in the description of the safety systems. See additional definitions in Section 1.2.

1. Channel - A channel is an arrangement of one or more sensors and associated components used to evaluate plant variables and produce discrete outputs used in logic. A channel terminates and loses its identity where individual channel outputs are combined in logic. See Figure 7.1-2.

2. Sensor - A sensor is that part of a channel used to detect variations in the measured station variable. See Figure 7.1-2.

3. Logic - Logic is that array of components which combines individual bistable output signals to produce decision outputs. See Figure 7.1-2.

4. Trip System - A trip system is that portion of a system encompassing one or more channels, logic, and bistable devices used to produce signals to the actuation logic. A trip system terminates and loses its identity where outputs are combined in logic. See Figure 7.1-2.

5. Actuation Device - An actuation device is an electrical or electromechanical module controlled by an electrical decision output used to produce mechanical operation of one or more activated devices to accomplish the necessary action. See Figure 7.1-2.

6. Activated Device - An activated device is a mechanical module in a system used to accomplish an action. An activated device is controlled by an actuation device. See Figure 7.1-2.

7. Trip - A trip is the change of state of a bistable device which represents the change from a normal condition. A trip signal, which results from a trip, is generated in the channels of a trip system and produces subsequent trips and trip signals throughout the system as directed by the logic.

8. Setpoint - A setpoint is that value of the monitored plant variable which causes a channel trip.

9. Component - Items from which the system is assembled (e.g., resistors, capacitors, wires, connectors, transistors, switches, springs, pumps, valves, piping, heat exchangers, vessels, etc.).

10. Module - Any assembly of interconnected components which constitutes an identifiable device, instrument, or piece of equipment.

11. Incident Detection Circuitry - Incident detection circuitry includes those trip systems which are used to sense the occurrence of an incident. Such circuitry is described and evaluated separately where the incident detection circuitry is common to several systems.

7.2 REACTOR PROTECTION SYSTEM

7.2.1 Safety Objective

The Reactor Protection System (RPS) provides timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier (uranium dioxide sealed in cladding) and the nuclear system process barrier. Excessive temperature threatens to perforate the cladding or melt the uranium dioxide. Excessive pressure threatens to rupture the nuclear system process barrier. The RPS limits the uncontrolled release of radioactive material from the fuel and nuclear system process barrier by terminating excessive temperature and pressure increases through the initiation of an automatic scram.

7.2.2 Safety Design Bases

1. The RPS shall initiate with precision and reliability a reactor scram in time to prevent fuel damage following abnormal operational transients.

2. The RPS shall initiate a scram with precision and reliability in time to prevent damage to the nuclear system process barrier as a result of internal pressure. Specifically, the RPS initiates a reactor scram in time to prevent nuclear system pressure from exceeding the pressure allowed by applicable industry codes.

3. To limit the uncontrolled release of radioactive materials from the fuel or nuclear system process barrier, the RPS shall initiate, with precision and reliability, a reactor scram upon gross failure of either of these barriers.

4. To provide assurance that conditions which threaten the fuel or nuclear system process barriers are detected with sufficient timeliness and precision to fulfill safety design bases 1, 2, and 3, RPS inputs shall be derived, to the extent feasible and practical, from variables that are true, direct measures of operational conditions.

5. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design bases 1, 2, and 3, the RPS shall respond correctly to the sensed variables over the expected range of magnitudes and rates of change.

6. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design bases 1, 2, and 3, an adequate number of sensors shall be provided for monitoring essential variables that have spatial dependence.

7. The following bases provide assurance that the RPS is designed with sufficient reliability to fulfill Safety Design Bases 1, 2, and 3:

   a. No single failure within the RPS shall prevent proper RPS action when required to satisfy Safety Design Bases 1, 2, or 3

   b. Any one intentional bypass, maintenance operation, calibration operation, or test to verify operational availability shall not impair the ability of the RPS to respond correctly. During such an operation, the requirements of Basis 7a shall continue to be met

   c. The system shall be designed for a high probability so that when any monitored variable exceeds the scram setpoint, the event shall result in an automatic scram and shall not impair the ability of the system to scram as other monitored variables exceed their scram trip points

   d. Where a plant condition that requires a reactor scram can be brought on by a failure or malfunction of a control or regulating system, and the same failure or malfunction prevents action by one or more RPS channels designed to provide protection against the unsafe condition, the remaining portions of the RPS shall meet the requirements of Safety Design Bases 1, 2, 3, and 7a

   e. The power supply for the RPS shall be arranged so that loss of one supply neither causes nor prevents a reactor scram

   f. The system shall be designed so that, once initiated, a RPS action goes to completion. Return to normal operation after protection system action shall require deliberate operator action

   g. There shall be sufficient electrical and physical separation between channels and between logics monitoring the same variable to prevent environmental factors, electrical transients, and physical events from impairing the ability of the system to respond correctly

   h. Earthquake ground motions shall not impair the ability of the RPS to initiate a reactor scram. See Section 7.1.6

8. The following bases are specified to reduce the probability that RPS operational reliability and precision will be degraded by operator error:

   a. Access to all trip settings, component calibration controls, test points, and other terminal points for equipment associated with essential monitored variables shall be under the physical control of station operations personnel

   b. The means for manually bypassing logics, channels, or system components shall be under the control of the control room operator. If the ability to trip some essential part of the system has been bypassed, this fact shall be continuously annunciated in the main control room

9. To provide the operator with means independent of the automatic scram functions to counteract conditions that threaten the fuel or nuclear system process barrier, it shall be possible for the control room operator to manually initiate a reactor scram

10. The following bases are specified to provide the operator with the means to assess the condition of the RPS and to identify conditions that threaten the integrity of the fuel or nuclear system process barrier:

    a. The RPS shall be designed to provide the operator with information pertinent to the operational status of the protection system

    b. Means shall be provided for prompt identification of channel and trip system responses

11. It shall be possible to check the operational availability of each channel and logic.

7.2.3 Description

7.2.3.1 Identification

The RPS includes the motor generator power supplies with associated control and indicating equipment, sensors, trip units, relays, bypass circuitry, and switches that cause rapid insertion of control rods (scram) to shutdown the reactor. It also includes outputs to the process computer system and annunciators. The RPS is designed to comply with the intent of IEEE-279 and the Commission's proposed General Design Criteria. Refer to Appendix F and Appendix J for additional details. The Process Computer System and annunciators are not part of the RPS. Although scram signals are received from the Neutron Monitoring System, this system is treated as a separate nuclear safety system and is discussed in Section 7.5.

7.2.3.2 Power Supply

Power to each of the two reactor protection trip systems is supplied, via a separate bus, by its own high inertia ac motor generator set.

See Figure 7.2-1 (Drawing M1P 5-5). Each generator has a voltage regulator which is designed to respond to a step load change of 50 percent of rated load with an output voltage change of not greater than 15 percent. High inertia is provided by a flywheel. The inertia is sufficient to maintain voltage within 5 percent of rated value and a frequency of not less than 55 Hz for at least 1.0 second following a total loss of power to the drive motor.

Alternate power is available to either RPS bus from emergency service bus B6 of the auxiliary power distribution system. The alternate power switch prevents simultaneously feeding both buses from the same source. The switch also prevents paralleling a motor generator set with the alternate supply. DC power is supplied to the backup scram valve solenoids from the plant batteries.

7.2.3.3 Physical Arrangement

Instrument piping that taps into the reactor vessel is routed through the drywell wall, and terminates inside the secondary containment (Reactor Building). Reactor vessel pressure and water level information is sensed from this piping by instruments mounted on instrument racks in the Reactor Building. The sensors for RPS signals from equipment in the Turbine Building are mounted locally in the Turbine Building. The two motor generator sets that supply power for the RPS are located in an area where they can be serviced during reactor operation. Cables from sensors and power cables are routed to the analog trip cabinets in the Cable Spreading Room and/or to the two RPS cabinets in the Control Room, where the logic circuitry of the system is formed. One Control Room cabinet is used for each of the two trip systems. The logics of each trip system are isolated in separate bays in each cabinet. The RPS is designed as Class I equipment to assure a safe reactor shutdown during and after seismic disturbances. The detailed requirements for Class I equipment are described in Appendix C.

7.2.3.4 Logic

The basic logic arrangement of the system is illustrated on Figure 7.2-2 (Drawing M1P 6-6). The RPS is arranged as two separately powered trip systems. Each trip system has three logics, as shown on Figure 7.2-3. Two of the logics are used to produce automatic trip signals. The remaining logic is used for a manual trip signal. Each of the two logics used for automatic trip signals receives input signals from at least one channel for each monitored variable. Thus, two channels are required for each monitored variable to provide independent inputs to the logics of one trip system. At least four channels for each monitored variable are required for the logics of both trip systems.

As shown on Figure 7.2-4, each actuator logic is a one-out-of-two arrangement. To produce a scram, the actuator logics of both trip systems must be tripped. The overall logic of the RPS could be termed one-out-of-two taken twice.

7.2.3.5 Operation

To facilitate the description of the RPS, the two trip systems are called trip system A and trip system B. The automatic logics of trip system A are logics A1 and A2; the manual logic of trip system A is logic A3. Similarly, the logics for trip system B are logics B1, B2, and B3. The actuators associated with any particular logic are identified by the logic identity (such as actuators B2) and a letter. See Figure 7.2-3. Channels are identified by the name of the monitored variable and the logic identity with which the channel is associated (such as reactor vessel high pressure channel B1).

During normal operation all sensor and trip contacts essential to safety are closed; channels, logics, and actuators are energized. In contrast, however, trip bypass channels consist of normally open contact networks.

There are two scram pilot valves for each control rod, arranged functionally as shown on Figure 7.2-1 (Drawing M1P 5-5). Each scram pilot valve is solenoid operated. With solenoids normally energized, the scram pilot valves control the air supply to both scram valves for each rod. With either scram pilot valve energized, air pressure holds the scram valves closed. The scram valves control the supply and discharge paths for control rod drive water. One of the scram pilot valves for each control rod is controlled by actuator logics A, the other valve by actuator logics B. There are two dc solenoid operated backup scram valves which provide a second means of controlling the air supply to the scram valves for all control rods. The DC solenoid for each backup scram valve is normally de-energized. The backup scram valves are energized (initiate scram) when both trip system A and trip system B are tripped.

A free standing instrument rack (C3002) is located on the reactor building 23ft elevation to control the SPVAH pressure and assure adequate CRD scram times. The rack consists of two parallel trains of an isolation valve, air pressure regulator, and a second isolation valve. A third pressure regulator with a slightly higher setpoint is located in the common discharge header to ensure that if the in-service parallel regulator fails, the air header to the CRD system does not exceed the pressure at which scram time testing was performed. The equipment on the instrument rack is connected to the existing SPVAH system between the SPVAH dump valve and the ARI solenoids.

The two parallel trains are designed to be redundant. If the on-line regulator fails open (PCV-302-89A or B), the regulator in the common discharge header (PCV-302-89C) will maintain pressure in the air line until the regulator in parallel with the failed regulator is brought on-line. If one of the parallel regulators fails open, the outlet pressure gauge will indicate higher than the normal pressure in addition to the alarm from the Kaye Temperature Computer, TISU-8125.

Single failure criterion is met. Separation criteria is not applied because the location is not subject to seismic or missile hazards that could initiate a common mode failure.

During PBOC, the scram function will be performed before environmental conditions exceed the qualification of the regulators.

The Air Dump System provides a third means for controlling the air supply to the scram valves of all control rods. The Air Dump System consists of a 3-way air operated valve which is actuated by a 3-way snap acting switching valve. The switching valve senses pressure in the scram pilot valve air header and upon sustained low pressure in the header, it actuates the 3-way air operated valve which vents the header and thereby initiates control rod insertion. A remote manual switch located in the control room provides for reset of the Air Dump System.

Means are also provided to scram the reactor through the Alternate Rod Insertion (ARI) function of the Recirculation Pump Trip (RPT) System in the unlikely event that the RPS fails to accomplish a reactor scram from power (Reference Section 3.9).

The functional arrangement of sensors and channels that constitute a single logic is shown on Figure 7.2-2 (Drawing M1P 6-6). A schematic is given on Figure 7.2-3.

Whenever a channel sensor contact opens, its sensor relay deenergizes, causing contacts in the logic to open. The opening of contacts in the logic deenergizes its actuators. When deenergized, the actuators open contacts in all the actuator logics for that trip system. This action results in deenergizing the scram pilot valve solenoids associated with that trip system, (one scram pilot valve solenoid for each control rod). Unless the other scram pilot valve solenoid for each rod is deenergized, the rods are not scrammed. If a trip then occurs in any of the logics of the other trip system, the remaining scram pilot valve solenoid for each rod is deenergized, venting the air pressure from the scram valves, and allowing control rod drive water to act on the control rod drive piston. Thus, all control rods are scrammed. The water displaced by the movement of each rod piston is vented into a scram discharge volume. Figure 7.2-1 (Drawing M1P 5-5) shows that when the solenoid for each backup valve is energized, the backup scram valves vent the air supply for the scram valves; this action initiates insertion of every control rod regardless of the action of the scram pilot valves.

A scram can be manually initiated. There are two scram buttons, one for logic A3 and one for logic B3. Depressing the scram button on the logic A3 deenergizes actuators A3 and opens corresponding contacts in actuator logics A. A single trip system is actuated as a result, but no scram occurs. To affect a manual scram, the buttons for both logic A3 and logic B3 must be depressed. By operating the manual scram button for one manual logic at a time, followed by reset of that logic, each trip system can be tested for manual scram capability. It is also possible for the control room operator to scram the reactor by interrupting power to the RPS. This can be done by operating power supply breakers. The manual scram capability provided in the control room meets Safety Design Basis 9.

To restore the RPS to normal operation following any single trip system trip or scram, the actuators must be manually reset. Reset is possible only if the conditions that caused the trip or scram have been cleared and is accomplished by operating switches in the control room. Figure 7.2-2 (Drawing M1P 6-6) shows the functional arrangement of reset contacts for trip system A. This meets Safety Basis 7f.

7.2.3.6 Single Failure and Channel Independence Criteria (IEEE-279)

Circuitry involving common devices in the RPS has been designed to assure that no single failure (short, open, or ground) can disable a safeguards function. Where single switches accomplish redundant functions (and have no independent backup interlocks), barriers are installed between switch sections to preclude the possibility of inadvertent shorting between adjacent sections. Barriers are installed between adjacent terminal points where potential for shorting exists. Barriers are also installed between switches that are required to accomplish redundant functions if the switches:

a. are located within 6 inches of each other

b. do not have independent backups

The RPS reset switch and associated logic comply with the single failure criterion requirements. Details of the RPS reset switch are shown on Figure 7.2-5. Each contact of the reset switch is wired to an individual auxiliary relay coil whose contacts are used in the RPS trip logic as shown on Figures 7.2-6 and 7.2-7.

Proper operation of the reset switch and its auxiliary relays can be ascertained during periodic test of the RPS, or whenever any particular channel is returned from a tripped state to the normal untripped condition. Failure would be noted as an automatic reset of specific trip actuators (depending upon the cause of failure) rather than remaining in a deenergized state until manually reset.

Since opening of the process sensor trip channels is the initiating event for reactor scram, failure of the reset switch will not prevent deenergization of the trip actuators during the time interval that the process actually exceeds the trip set point.

To comply with the channel independence criterion, the four RPS reset channels to the trip actuators are physically separated and electrically isolated as shown on Figure 7.2-6.

7.2.3.7 Identification of Protective Actions and Information Readouts (IEEE-279)

Whenever a RPS sensor trips, it lights a printed red window (common to all the channels for that variable) on the reactor control panel in the control room to indicate the out of limit variable. Each trip system lights a red window to indicate which trip system has tripped. An RPS channel trip also sounds a buzzer or horn, which can be silenced by the operator. The annunciator window lights latch in until manually reset. Reset is not possible until the condition causing the trip has been cleared. A computer printout identifies each tripped channel. However, the physical positions of RPS relays may be used to identify individual sensors that have tripped from a group of sensors monitoring the same variable. The location of alarm windows provides the operator with the means to quickly identify the cause of RPS trips, and to evaluate the threat to the fuel or nuclear system process barrier.

IEEE-279 design requirement 4.19 requires that the protective actions be indicated and identified down to the channel level. Design requirement 4.20 requires that these indications be accurate, complete, and timely, and that they provide a lucid presentation of information to the operator.

Paragraph 4.19 of IEEE-279 can be very easily misinterpreted. The objective is to make the operator aware of any single trip and allow the operator to determine which specific instrument channel has tripped. This should be satisfied by some common annunciation and visible manifestation of operation of each trip device. This visible manifestation need not be an indicating light, but is just as reasonably an indicating relay or a window type relay with readily visible contact actuation. Indication of protective channel trips occurs at the channel output.

The presentation of this information to the operator is accurate, timely, and adequate for his immediate consideration. When a trip occurs, his first concern should be with which variable has exceeded a setpoint. Consequently, the design uses the annunciator windows to provide this display. A secondary concern is identification of the particular channel of that variable annunciating the trip, and this information is obtained from observation of the relay position.

To provide the operator with the ability to analyze an abnormal transient during which events occur too rapidly for direct operator comprehension, all RPS trips are recorded by an alarm typewriter controlled by the Process Computer System. All trip events are recorded. The first 40 are recorded in chronological sequence except that events occurring within 4 milliseconds of each other are treated as having occurred simultaneously. Use of the alarm typewriter and computer is not required for plant safety, and information provided is in addition to that immediately available from other annunciators and data displays. The printout of trips is of particular use for routinely verifying the proper operation of pressure, temperature level, and valve position switches as trip points are passed during startups, shutdowns, and maintenance operations.

RPS inputs to annunciators, recorders, and the computer are arranged so that no malfunction of the annunciating, recording, or computing equipment can functionally disable the RPS. Signals directly from the RPS sensors are not used as inputs to annunciating or data logging equipment. Relay contact isolation is provided between the primary signal and the information output. The arrangement of indications pertinent to the status and response of the RPS satisfies safety design bases 10a and 10b.

7.2.3.8 Scram Functions and Bases for Trip Settings

The following discussion covers the functional considerations for the variables or conditions monitored by the RPS. Table 7.2-1 lists the specifications for the instruments providing signals for the system that are used in the current plant safety analysis. Figure 7.2-8 shows the scram functions in block form.

Neutron Monitoring System Trip

To provide protection for the fuel against high heat generation rates, neutron flux is monitored and used to initiate a reactor scram. The neutron monitoring system setpoints and their bases are discussed in Section 7.5, Neutron Monitoring System.

Nuclear System High Pressure

High pressure within the nuclear system poses a direct threat of rupture to the nuclear system process barrier. A nuclear system pressure increase, while the reactor is operating, compresses the steam voids and results in a positive reactivity insertion causing increased core heat generation that could lead to fuel failure and system over pressurization. A scram counteracts a pressure increase by quickly reducing the core fission heat generation. The nuclear system high pressure scram setting is chosen slightly above the reactor vessel maximum normal operating pressure, to permit normal operation without spurious scram, yet provide a wide margin to the maximum allowable nuclear system pressure. The location of the pressure measurement, as compared to the location of highest nuclear system pressure during transients, was also considered in the selection of high pressure scram setting. The nuclear system high

pressure scram works in conjunction with the pressure relief system in preventing nuclear system pressure from exceeding the maximum allowable pressure. This same nuclear system high pressure scram setting also protects the core from exceeding thermal hydraulic limits as a result of pressure increases for some events that occur when the reactor is operating at less than rated power and flow.

Reactor Vessel Low Water Level

A low water level in the reactor vessel indicates that the reactor is in danger of being inadequately cooled. The effect of a decreasing water level while the reactor is operating at power is to decrease the reactor coolant inlet subcooling. The effect is the same as raising feedwater temperature. Should water level decrease too far, fuel damage could result as steam forms around fuel rods. A reactor scram protects the fuel by reducing the fission heat generation within the core.

The reactor vessel low water level scram setting was selected to prevent fuel damage following those abnormal operational transients, caused by single equipment malfunctions or single operator errors that result in a decreasing reactor vessel water level. Specifically, the scram setting is chosen far enough below normal operational levels to avoid spurious scrams, but high enough above the top of the active fuel to assure that enough water is available to account for evaporation losses and displacements of coolant following the most severe abnormal operational transient involving a level decrease. The selected scram setting was used in the development of thermal hydraulic limits, which set operational limits on the thermal power level for various coolant flow rates.

Turbine Stop Valve Closure

Closure of the turbine stop valve with the reactor at power can result in a significant addition of positive reactivity to the core, as the nuclear system pressure rise collapses steam voids. The turbine stop valve closure scram, which initiates a scram earlier than either the neutron monitoring system or nuclear system high pressure, is required to provide a satisfactory margin below core thermal hydraulic limits for this category of abnormal operational transients. The scram counteracts the addition of positive reactivity due to pressure by inserting negative reactivity with the control rods. Although the nuclear system high pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine stop valve closure scram provides additional margin to the nuclear system pressure limit.

The turbine stop valve closure scram setting is selected to provide the earliest positive indication of valve closure. The trip logic was chosen both to identify those situations in which a reactor scram is required for fuel protection and to allow functional testing of this scram function.

Turbine Control Valve Fast Closure

With the reactor and turbine generator at power, fast closure of the turbine control valves can result in a significant addition of positive reactivity to the core as nuclear system pressure rises. The turbine control valve fast closure scram, which initiates a scram earlier than either the neutron monitoring system or nuclear system high pressure, is required to provide a satisfactory margin to core thermal hydraulic limits for this category of abnormal operational transients. The scram counteracts the addition of positive reactivity due to pressure by inserting negative reactivity with the control rods. Although the nuclear system high pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine control valve fast closure scram provides additional margin to the nuclear system pressure limit.

The turbine control valve fast closure scram setting is selected to provide timely indication of control valve fast closure. The trip logic was chosen to identify those situations in which a reactor scram is required for fuel protection.

Main Steam Line Isolation

The main steam line isolation valve closure scram is provided to limit the release of fission products from the nuclear system. Automatic closure of the main steam line isolation valves is initiated upon conditions indicative of a steam line break. Immediate shutdown of the reactor is appropriate in such a situation. The scram initiated by main steam line isolation valve closure anticipates a reactor vessel low water level scram. The main steam line isolation scram setting is selected to give the earliest positive indication of isolation valve closure. The trip logic allows functional testing of main steam line isolation trip channels with one steam line isolated.

In conjunction with the low turbine pressure MSIV closure setpoint, the MSIV closure scram also provides automatic protection of the safety limit on core thermal power at low reactor pressures. At reactor pressures <800 psia, the GEXL correlation is no longer valid. Consequently, a safety limit is imposed which protects fuel cladding integrity without the need for CPR calculations. This low pressure safety limit is 25% of rated core thermal power. The RPS protects this core thermal power safety limit when the reactor mode switch is in the REFUEL or STARTUP position by an APRM scram at 15% of rated power. In the RUN mode, the safety limit is protected by a low turbine pressure MSIV closure setpoint which corresponds to a reactor pressure > 800 psia. Tripping this setpoint closes the MSIVs which, in turn, scrams the reactor.

Scram Discharge Volume High Water Level

The scram discharge volume is designed with sufficient volume to accept the water displaced by the motion of the control rod drive pistons during a scram. The volume consists of two separate scram discharge headers and their associated scram discharge instrument volumes (SDIV). Should the scram discharge volume fill up with water to the point where not enough space remains for the water displaced during a scram, control rod movement would be hindered in the event a scram were required. To ensure the operability of the control rod drive system, the reactor is scrammed when the water level in either of the scram discharge instrument volumes attains a value high enough to verify that the volume is filling up, yet low enough to ensure that the remaining capacity in the volume can accommodate a scram.

Primary Containment High Pressure

A high pressure inside the primary containment could indicate a break in the nuclear system process barrier. It is prudent to scram the reactor in such a situation to minimize the possibility of fuel damage and to reduce the addition of energy from the core to the coolant. The reactor vessel low water level scram also acts to scram the reactor for loss of coolant accidents. The primary containment high pressure scram setting is selected to be as low as possible without inducing spurious scrams.

Manual Scram

To provide the operator with means to shutdown, RPS push buttons are located in the control room that initiate a scram when actuated by the operator.

The movement of the mode switch to the SHUTDOWN position is the preferred method to initiate a manual scram.

Mode Switch in SHUTDOWN

The mode switch provides appropriate protective functions for the condition in which the reactor is to be operated. The reactor is to be shutdown with all control rods inserted when the mode switch is in SHUTDOWN. To enforce the condition defined for the SHUTDOWN position, placing the mode switch in the SHUTDOWN position initiates a reactor scram. This scram is not considered a protective function because it is not required to protect the fuel or nuclear system process barrier, and it bears no relationship to minimizing the release of radioactive material from any barrier. The scram signal is removed after a short time delay, permitting a scram reset which restores the normal valve lineup in the control rod drive hydraulic system.

7.2.3.9 Mode Switch

A conveniently located, multiposition keylock mode switch is provided to select the necessary scram functions for various station conditions. In addition to selecting scram functions from the proper sensors, the mode switch provides appropriate bypasses. The mode switch also interlocks such functions as control rod blocks and refueling equipment restrictions, which are not considered here as part of the RPS. The switch itself is designed to provide separation between the two trip systems . The mode switch positions and their related scram functions are as follows:

1. SHUTDOWN; Initiates a reactor scram and bypasses main steam line isolation scram if nuclear system pressure is below 600 psig

2. REFUEL; Selects Neutron Monitoring System scram for low neutron flux level operation, as described in Section 7.5, and bypasses main steam line isolation scram if nuclear system pressure is below 600 psig

3. STARTUP; Selects Neutron Monitoring System scram for low neutron flux level operation, as described in Section 7.5, and bypasses main steam line isolation scram if nuclear system pressure is below 600 psig

4. RUN; Selects Neutron Monitoring System scram for power range operation, as described in Section 7.5

7.2.3.10 Scram Bypasses

A number of scram bypasses are provided to account for the varying protection requirements depending on reactor conditions, and to allow for instrument service during reactor operations. Some bypasses are automatic and others are manual. All manual bypass switches are in the control room under the direct control of the control room operator. If the ability to trip some part of the system has been bypassed, this condition is continuously indicated in the control room.

Automatic bypass of the scram trip from main steam line isolation is provided when both of the following conditions exist concurrently:

a. Mode switch not in RUN
b. Nuclear system pressure less than 600 psig

The bypass allows reactor operations at low power with the main steam lines isolated. These conditions exist during startup and during certain reactivity tests while refueling. The scram initiated by placing the mode switch in SHUTDOWN is automatically bypassed after a time delay of 2 sec. The bypass allows the scram to reset, restoring the Control Rod Drive Hydraulic System valve line up to normal. Note that following a reactor scram, a minimum delay period of 10 seconds must be observed before resetting. An annunciator in the control room indicates the bypassed condition.

Automatic bypass of the turbine control valve fast closure scram and turbine stop valve closure scram is effected by a trip of the high pressure turbine first stage shell low pressure switches. The design basis analytical limit for the switch setpoint in terms of percent rated core thermal power is $\leq$ 32.5%. An automatic bypass at or below 32.5% of rated core thermal power does not constitute a threat to the integrity of any barrier to the release of radioactive material. A high pressure turbine first stage shell pressure of 140.3 psig corresponds to 32.5% of rated core thermal power based on a limiting balance of plant feedwater heater configuration. This scram bypass trip setpoint is set below the Technical Specification allowable value of 112 psig to accommodate instrument drift and is based on the combined uncertainty of the associated instrument loop components. To maintain an automatic bypass that is compatible with the turbine bypass system and serves to avoid opening of any safety-relief valve during most moderate frequency pressurization transients, the automatic bypass will only be effected whenever core thermal power is $\leq$ 30% of rated. Bypasses for the Neutron Monitoring System channels are described in Section 7.5. A manual keylock switch located in the control room permits the operator to bypass the scram discharge volume high level scram trip if the mode switch is in SHUTDOWN or REFUEL. This bypass allows the operator to reset the RPS, so that the system is restored to operation while the operator drains the scram discharge volume. In addition to allowing the scram relays to be reset, actuating the bypass initiates a control rod withdrawal block. Resetting the trip actuators opens the scram discharge volume vent and drain valves. An annunciator in the control room indicates the bypass condition. The arrangement of bypasses meets safety design basis 8b.

See Section 7.2.3.6 for Single Failure and Channel Independence Criteria.

<u>Scram Discharge Volume High Water Level Trip Bypass</u>

The single failure criterion is satisfied as follows:

Since the scram discharge instrument volume high water level trip bypass requires manual operation of a bypass switch and the mode switch to establish four bypass channels, the design of the bypass function complies with this design requirement. For the bypass switch, a single operator connects to two separate blocks of switch contacts within the switch body, and wiring from contacts is routed to separate terminal strips.

One set of switch contacts, in conjunction with mode switch contacts, is used to energize two trip channel bypass relays when the bypass condition is desired; in a similar fashion, the other set of bypass switch and mode switch contacts energize two other trip channel bypass relays. Contacts from one relay are connected in series

with contacts from a relay in the other group to produce the RPS A1 trip channel bypass function. The trip channel bypass function for the redundant A2 trip channel is produced from series connected contacts of the other two relays.

Consequently, it is necessary that four out of four relays be energized in order to bypass the automatic RPS trip channels for this protective function. There is no single failure of this bypass function that will satisfy the four out of four condition necessary to establish the bypass condition. Hence, this function complies with the single failure criterion.

The channel independent criterion is satisfied as follows:

The scram discharge instrument volume high water level trip bypass circuitry complies with this design requirement. For operator convenience, a single switch has been selected for the bypass function. Utilization factors considered in this selection were the number of bypass operations required in any given operating period, and the expected duration of each bypass. Since the bypass switch is used only to permit manual reset of the RPS and permit the operator to drain the discharge volume following reactor scram, it was determined that the switch would be used infrequently (i.e., each reactor scram) and for short time periods (i.e., several minutes to accomplish the necessary draining of the volume). A single switch is used to minimize the possibility of operator error in terms of removal of the bypass. However, in order to fully satisfy the design requirement that all four bypass channels be independent of one another, the following techniques are employed:

1. Two manual switch operations are required: one involves the bypass switch, and the other involves the mode switch
2. Both switches are keylock types under administrative control
3. Two contact blocks are used with the single bypass switch operator and two banks of the mode switch are used with its single operator
4. One series connected contact string energizes two relays in RPS panel 915; the other contact string energizes two relays in panel 917
5. For each trip channel, the bypass relay contact arrangement is:

   A1: Relay A upstream and Relay B downstream
   See Figure 7.2-9
   A2: Relay C upstream and Relay D downstream
   B1: Relay B upstream and Relay A downstream
   B2: Relay D upstream and Relay C downstream

6. For each trip channel, both bypass relays must be energized to produce the trip channel bypass function This makes removal of the protective action dependent upon all four relays being energized.

7. Any single trip channel bypass initiates the control room annunciator.

Care has been taken to assure that sufficient physical separation, and electrical isolation exists to assure that the bypass channels are satisfactorily independent. Moreover, the conditions for bypass have been made quite stringent in order to provide additional margin.

Neutron Monitoring System Trip Bypass

The single failure criterion is satisfied as follows:

For any given bypass switch, the following design provisions have been made to assure that one, and only one, channel is bypassed at one time with a given bypass switch.

1. The switch operator is a joy stick type, with four positions located on the quadrant extremes (i.e., 90, 180, 270, and 360 deg) with a vertical center off position. This operator type makes selection of bypass for one channel mutually exclusive from selection of any other channel associated with that same switch.

   Cabling associated with the bypass switch is individually shielded, separated, and grounded such that failures in a common wireway would only result in loss of bypass capability.

2. The switch itself is provided with a physical barrier to reduce probability of shorts that could cause energizing of several APRM or IRM channels associated with a single switch.

The channel independent criterion is satisfied as follows:

The neutron monitoring bypass channels comply with this design requirement. The bypass channel output to the individual APRM or IRM trip channel is obtained from an isolated relay contact, and is introduced into the trip logic as shown on Figure 7.2-10. This contact output is physically separated and electrically isolated from the other Neutron Monitoring System bypass channels.

Main Steam Line Isolation Valve Closure Trip Bypass

The main steam line isolation valve closure trip bypass function complies with the single failure criterion as follows:

One contact from each bank of the mode switch is connected in series with a contact from the trip unit relay of one of four pressure transmitters sensing reactor pressure as shown on Figure 7.2-11. The two contacts in series energize one of four bypass relays whose contacts are connected into the RPS trip logic as demonstrated by Figure 7.2-12.

The relationship of these bypass relays to the RPS trip channels is on a one to one basis. Consequently, two particular bypass relays must be energized in order to bypass the protective function. Hence, no single failure in the bypass circuitry will interfere with the protective action of the trip channels.

The four bypass channels comply with the channel independence design requirement as follows:

One contact from each bank of the mode switch and one contact from the trip unit relay of each of four pressure transmitters monitoring reactor pressure are physically separated, and electrically isolated from the others to satisfy this requirement. The four bypass relays are independent of one another and physically separated and electrically isolated from one another.

Turbine Stop Valve and Control Valve Trip Bypass

This bypass function complies with the single failure criterion as follows:

Two pressure transmitters are mounted on each of two turbine first stage pressure taps as shown on Figure 7.2-13. Contacts from the associated trip unit relays are routed in conduit to the RPS cabinets in the control room. The logic configuration for the bypass is the standard one-out-of-two taken twice arrangement such that a single bypass channel is associated with a single trip channel for stop valve closure, and single trip channel for control valve fast closure.

Each pressure transmitter trip unit relay contact is connected to a single bypass channel output relay as shown on Figure 7.2-14, and the connection of the output relay contacts into the RPS trip logic is shown on Figure 7.2-15.

No single failure of this bypass circuitry will interfere with the normal protective action of the RPS trip channels.

The four bypass channels comply with the channel independence design requirement as follows:

One contact from each pressure transmitter trip unit relay is connected to one bypass relay in the RPS cabinets. The pressure transmitters and taps are physically separated, and their wiring is electrically isolated to provide channel independence. The four bypass relays are independent of one another, and are physically separated to meet this design requirement.

7.2.3.11 Instrumentation

Channels providing inputs to the RPS are not used for automatic control of process systems, thus the operations of protection and process systems are separated. The RPS instrumentation, shown on Figure 7.2-16, is discussed as follows:

Neutron Monitoring System instrumentation is described in Section 7.5. The relationship between Neutron Monitoring System channels, Neutron Monitoring System logics, and the RPS logics is clarified on Figure 7.2-17. The Neutron Monitoring System channels are considered part of the Neutron Monitoring System. The Neutron Monitoring System logics are considered part of the RPS. There are four Neutron Monitoring System logics associated with each trip system of the RPS as shown on Figure 7.2-18. Each RPS logic receives inputs from two Neutron Monitoring System logics. Each Neutron Monitoring System logic receives signals from one IRM channel and one APRM channel. The position of the mode switch determines which input signals will affect the output signal from the logic. The arrangement of Neutron Monitoring System logics is such that the failure of any one logic cannot prevent the initiation of a high neutron flux scram.

Nuclear system pressure is tapped from the reactor vessel at two separate locations. A pipe from each tap is routed outside the primary containment, and terminates in the Reactor Building. Two locally mounted, nonindicating pressure transmitters monitor the pressure in each pipe. Cables from these transmitters are routed to the Analog Trip Units in the Cable Spreading Room and then to the Control Room. The two pairs of transmitters are physically separated. Each transmitter provides a high pressure signal to one channel. The transmitters are arranged so that each pair provides an input to trip system A and trip system B, as shown on Figure 7.2-19. The physical separation, and the signal arrangement assure that no single physical event can prevent a scram due to nuclear system high pressure.

Reactor vessel low water level signals are initiated from differential pressure transmitters which sense the difference between the pressure due to a reference column of water, and the pressure due to the actual water level in the vessel. The transmitters are arranged in pairs in the same way as the nuclear system high pressure transmitters. See Figure 7.2-19. Two instrument pipelines attached to taps, one above and one below the water level, on the reactor vessel are required for the differential pressure measurement for each pair of transmitters.

The two pairs of pipelines terminate outside the primary containment and inside the Reactor Building. They are physically separated from each other and tap off the reactor vessel at widely separated points. The RPS pressure sensors, as well as instruments for other systems sense pressure and level from these same pipes. The physical separation and signal arrangement assure that no single physical event can prevent a scram due to reactor vessel low water level.

Turbine stop valve closure inputs to the RPS are from valve steam position switches mounted on the four turbine stop valves. Each of the double pole, single throw switches is arranged to open before the valve is more than 10 percent closed, to provide the earliest positive indication of closure. Either of the two channels associated with one stop valve can signal valve closure, as shown on Figure 7.2-20. The logic is arranged so that closure of three or more valves initiates a scram.

Turbine control valve fast closure inputs to the RPS are from four pressure switches sensing discharge oil pressure from the acceleration relay. The acceleration relay is that part of the turbine control system used to effect fast closure of the turbine control valves. These pressure switches provide signals to both RPS trip systems, as shown on Figure 7.2-19. The logic is one-out-of-two taken twice. The switches are normally closed but open after the control valve starts to close.

There are eight main steam line isolation channels, two for each main steam line. Each channel senses isolation of the associated main steam line via a valve stem position switch on each isolation valve in the main steam line. The double pole, single throw switch on each main steam line isolation valve is arranged to open before the valve is more than 10 percent closed, to provide the earliest indication of isolation. The closure of either valve in a main steam line causes both channels associated with that steam line to signal isolation. The arrangement of main steam line isolation channels is shown on Figure 7.2-21. The main steam line isolation valve closure scram function is effective only under either of the following conditions:

a. Reactor mode switch in RUN

b. Reactor vessel pressure greater than 600 psig

The outputs from the channels are combined in RPS logic in such a way that the isolation of three or four main steam lines (closure of one valve in each main steam line) causes a scram. The logic arrangement is shown on Figure 7.2-21. Wiring of the isolation channels from any one main steam line is physically separated in the same way that wiring to a duplicate sensor on a common process tap is separated. The effects of the logic arrangement and separation provided for the main steam line isolation valve closure scram are as follows:

1. Closure of one valve for test purposes with one steam line already isolated without causing a scram due to valve closure

2. Automatic scram upon isolation of all steam lines

3. No single failure can prevent an automatic scram required for fuel protection due to main steam line isolation

Each SDIV (East and West) is provided with two level transmitters and three, RTD type, heat actuated level sensors. The Analog Trip System associated with the level transmitters is located in the cable spreading room of the reactor building. For SDIV-East, a contact associated with each analog transmitter trip unit inputs to RPS Trip Channels A1 and B1. Trip Channels A2 and B2 receive inputs from contacts associated with the RTD type sensors. For DIV-West, the reverse is true. The analog transmitter trip units input to Trip Channels A2 and B2, and the RTD's input to Trip Channels A1 and B1, as shown in Figure 7.2-19. The contacts are arranged in pairs so that no single event will prevent a reactor scram due to scram discharge volume high water level. The trip point for the RTD type of switch cannot be adjusted without physically cutting out the scram discharge instrument volume. However, the trip points associated with the analog trip units can be adjusted at the cable spreading room. A scram is initiated when sufficient capacity remains in the scram discharge volume to accommodate a scram. Both the amount of water discharged and the volume of air trapped above the free surface during a scram, were considered in selecting the trip setting.

Primary containment pressure is monitored by four no indicating pressure transmitters which are mounted on instrument racks outside the drywell in the Reactor Building. Cables are routed from the transmitters to analog trip units in the Cable Spreading Room. Each trip unit provides an input to one channel. See Figure 7.2-19. Pipes that terminate in the secondary containment (Reactor Building) connect the transmitters with the drywell interior. The transmitters and respective trip units are grouped in pairs, physically separated, and electrically connected to the RPS so that no single event will prevent a scram due to primary containment high pressure.

Post accident monitoring of the primary containment pressure is accomplished by four transmitters and two recorders which are redundant and powered from the plant vital instrumentation busses. Each pressure instrumentation loop consists of a high and a low range transmitter wired to a recorder. The two loops are maintained physically separated.

Four nuclear system pressure transmitters and respective trip units are provided to initiate the automatic bypass of the main steam line isolation trip. As noted in Section 7.2.3.10, the automatic bypass is only effective when the mode switch is not in the RUN position and the system pressure is less than 600 psig. The transmitters are mounted outside the drywell on instrument racks that are physically separated. These transmitters are the same transmitters that are used to initiate the nuclear system high pressure scram. The arrangement of the transmitters and trip units is such that no single failure can prevent a scram due to main steam line isolation valve closure or main condenser low vacuum.

Four turbine first stage pressure transmitters and trip units are provided to initiate the automatic bypass of the turbine control valve fast closure, and the turbine stop valve closure scrams when the first stage pressure is below some preset fraction of rated pressure. The transmitters and trip units are arranged so that no single failure can prevent a turbine stop valve closure scram or turbine control valve fast closure scram.

Channel and logic relays are fast response, high reliability relays. Power relays for interrupting the scram pilot valve solenoids are type CR105 magnetic contactors, made by the General Electric Company. All RPS relays are selected so that the continuous load will not exceed 50 percent of the continuous duty rating. Component electrical characteristics are selected so that the system response time, from the opening of a sensor contact up to and including the opening of the trip actuator contacts, is less than 50 milliseconds. The time requirements for control rod movement are discussed in Section 3.4, Reactivity Control Mechanical Design.

To gain access to those calibration and trip setting controls that are located outside the control room, a cover plate, access plug, or sealing device must be removed by operations personnel before any adjustment in trip settings can be effected.

7.2.3.12 Channel Test and Calibration

Scram Discharge Volume High Water Level Scram Trip

Four instrument standpipes are provided on each SDIV to allow individual channel test/calibration procedures during reactor power operation. After closing the upper and lower manual isolating valves of the standpipe in test, demineralized water is added to the standpipe through the appropriate test connection. (The upper test connection is used to flush the standpipe, the lower connection is used for filling during test/calibration procedures.) Verification of level setpoints and adjustments are made at the analog trip units located in the cable spreading room. A sight glass is provided on each SDIV to observe the water level during the test/calibration procedures and means are provided to drain the standpipe to the SDIV drain following test/calibration. Before proceeding to calibrate instruments in another standpipe, the manual isolating valves must be opened and the trip channel must be reset.

At plant shutdown, level switches may be calibrated by introducing a fixed volume of water into the discharge volume and observing that all level switches operate at their specified level settings.

Main Steam Line Isolation Valve and Turbine Stop Valve Closure Trips

During reactor shutdown, verification of the main steam line isolation valve and turbine stop valve limit switch set points at a valve position of 10 percent closure is possible by physical observation of the valve stem. The setpoint is mechanically locked in place.

During plant operation, the operator can confirm that the limit switches operate during valve movement, from the full open to full closed positions and vice versa, by observing the valve position indicator lights in the control room following an RPS trip. This will provide the operator with an indication that the limit switches operate between the limiting positions of the valve.

Turbine Control Valve Fast Closure Scram

In order to test the operation of the RPS interface the individual acceleration relay pressure switches are valved out of service when the plant is operating above the preset fraction of rated pressure (monitored by first stage pressure transmitters). As any one pressure switch is placed in the tripped condition, the control room operator will obtain an annunciation of the channel trip. The pressure switch setpoint may be verified by using a variable source of pressure.

Reactor Vessel Low Water Level Trip

During the calibration procedure, operation of the level trip unit relay contacts can be confirmed to operate at the proper setpoint. When the trip setpoint has been exceeded, the Control Room Operator will obtain an annunciation of the trip, in addition to local indication at the Analog Trip Cabinet.

Neutron Monitoring Scram Trip

The APRMs and IRMs are calibrated to reactor power by using the traversing incore probe (TIP) system to establish the relative local flux profile. LPRM gain settings are determined from these profiles once the total reactor heat balance has been determined.

The gain adjustment factors for the LPRMs are produced as a result of the process computer nuclear calculations involving the reactor heat balance for the TIP flux distributions. These adjustments, when incorporated into the LPRMs, permit the nuclear calculations to be completed for the next operating interval, and establish the APRM calibration and IRM calibration relative to reactor power.

Primary Containment and Reactor Vessel High Pressure Scram Trips

Under administrative control, testing of the pressure trip unit and its setpoint is performed using a test signal. When the trip setpoint has been exceeded, the control room operator will obtain an annunciation of the trip, in addition to local indication at the Analog Trip Cabinet.

Scram Discharge Volume High Water Level Trip Bypass

During plant operation in the startup and run modes, imposition of this bypass function is inhibited by the reactor system mode switch. Under these circumstances, operation of the bypass switch will not produce a bypass condition for any single trip channel. This fact can be determined from the control room annunciator, a visual inspection of the bypass relays, and from the process computer printout of any discharge volume high water level trip channel placed in a tripped condition prior to the bypass switch test.

In the startup and run modes of plant operation, the preceding procedures may be used to confirm that trip channels are not bypassed as a result of operation of the bypass switch. In the shutdown and refuel modes of plant operation, a similar procedure may be utilized to produce bypassing of all four trip channels. Due to the discrete ON-OFF nature of the bypass function, calibration is not meaningful.

Main Steam Line Isolation Valve Closure Trip Bypass

Since each pressure trip unit may be individually removed from service for test and calibration, it is possible during plant operation to confirm the setpoint value for the automatic portion of this bypass. The test procedure is similar to that stated in 7.2.3.12 under the heading Primary Containment and Reactor Vessel High Pressure Scram Trips. Full testing of the bypass circuit can only be accomplished when the mode switch is not in the RUN position. Since it can be confirmed that the bypass is not in effect when operating in the RUN mode, the tests are adequate to confirm proper bypass status during plant operation.

7.2.3.13 Wiring

Criteria for wiring and cables in the RPS instrumentation are outlined in Section 8.4.

7.2.4 Safety Evaluation

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. It is the objective of Section 14, Station Safety Analysis, to identify and evaluate events that challenge the fuel barrier and nuclear system process barrier. The methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are sought and identified, are presented in that section.

Design procedure has been to select tentative scram trip settings that are far enough above or below normal operating levels that spurious scrams and operating inconvenience are avoided. It is then verified by analysis that the reactor fuel and nuclear system process barriers are protected as required by the basic objective. In all cases, the specific scram trip point selected is not the only value of the trip point which results in acceptable results relative to the fuel or nuclear system process barrier. Trip setting selection is based on operating experience and constrained by the safety design basis. The scrams initiated by Neutron Monitoring System variables, nuclear system high pressure, turbine stop valve closure, turbine control valve fast closure, and reactor vessel low water level are sufficient to prevent excessive fuel damage following abnormal operational transients.

Section 14, Station Safety Analysis, identifies and evaluates the threats to fuel integrity posed by abnormal operational events. In no case does excessive fuel damage result from abnormal operational transients. The RPS meets the timeliness and precision requirements of safety design basis 1.

The evaluation of the scram function provided by the Neutron Monitoring System is presented in Section 7.5 as well as in Section 14.

The scram initiated by nuclear system high pressure, in conjunction with the Pressure Relief System, is sufficient to prevent damage to the nuclear system process barrier as a result of internal pressure. For turbine generator trips, the turbine stop valve closure scram and turbine control valve fast closure scram provide a greater margin to the maximum allowed nuclear system pressure than would the high pressure scram alone. Section 14, Station Safety Analysis, identifies and evaluates accidents and abnormal operational events that result in nuclear system pressure increases. In no case does pressure exceed the maximum allowed nuclear system pressure. The RPS meets the timeliness and precision requirements of safety design basis 2.

The scrams initiated by the Neutron Monitoring System, main steam isolation valve closure, and reactor vessel low water level, satisfactorily limit the radiological consequences of gross failure of the fuel or nuclear system process barriers. Section 14, Station Safety Analysis evaluates gross failures of the fuel and nuclear system process barriers. In no case does the release of radioactive material to the environs exceed the guideline values of published regulations. The RPS meets the precision requirements of safety design basis 3.

Because the RPS meets the timeliness and precision requirements of safety design bases 1, 2, and 3 and the monitored variables are true direct measures of operational conditions, it is concluded that safety design basis 4 is met.

Because the RPS meets the precision requirements of safety design bases 1, 2, and 3, by using instruments with the characteristics described on Table 7.2-1, it is concluded that safety design basis 5 is met.

Neutron flux is the only essential variable of significant spatial dependence that provides inputs to the RPS. The basis for the number and locations of neutron flux detectors is discussed in Section 7.5, Neutron Monitoring System. Because the precision requirements of safety design bases 1, 2, and 3 are met using the Neutron Monitoring System as described, it is concluded that the number of sensors for spatially dependent variables satisfies safety design basis 6.

The items of safety design basis 7 specify the requirements that must be fulfilled for the RPS to meet the reliability requirements of safety design bases 1, 2, and 3. It has already been shown in the description of the RPS that safety design basis 7f has been met. The other requirements are fulfilled through the combination of logic arrangement, channel redundancy, wiring scheme, physical isolation, power supply redundancy, and component environmental capabilities. The following discussion evaluates these subjects.

In terms of protection system nomenclature, the RPS is a one-out-of-two taken twice system (1 of 2 x 2). Theoretically, its reliability is slightly higher than a two out of three system and slightly lower than a one-out-of-two system. However, since the differences are slight, they can, in a practical sense, be neglected. The advantage of the dual trip system arrangement is that it can be tested thoroughly during reactor operation without causing a scram. This capability for a thorough testing program, which contributes significantly to increased reliability, is not possible for a one-out-of-two system.

The use of independent channels allows the system to sustain any channel failure without preventing other sensors monitoring the same variable from initiating a scram. A single sensor or channel failure will cause a single trip system to trip and actuate alarms that identify the trip. The failure of two or more sensors or channels would cause either a single trip system to trip, if the

failures were confined to one trip system, or a reactor scram, if the failures occurred in different trip systems. Any intentional bypass, maintenance operation, calibration operation, or test, will cause a single trip system to trip. This leaves at least two channels, per monitored variable, capable of initiating a scram by causing a trip of the remaining trip system. The resistance to spurious scrams contributes to station safety, because unnecessary cycling of the reactor through its operating modes would increase the probability of error or actual failure. It is concluded from the preceding paragraphs evaluating the logic, redundancy, and failure characteristics of the RPS, that the system satisfies the reliability requirement stated in safety design bases 7a and 7b.

A condition in which an essential monitored variable exceeds its scram trip point is sensed by at least two independent channels in each trip system. Because only one channel must trip in each trip system to initiate a scram, the arrangement of two channels per monitored variable in each trip system provides assurance that scram will occur.

Each control rod is controlled as an individual unit. A failure of the controls for one rod will not affect the operation of other rods. The backup scram valves provide a second method of venting the air pressure from the scram valves, even if either scram pilot valve solenoid for any control rod fails to deenergize when a scram is required. It is concluded from the evaluations in the above paragraphs that the RPS meets safety design basis 7c.

Sensors, channels, and logics of the RPS are not used directly for automatic control of process systems. Therefore, failure in the controls and instrumentation of process systems cannot induce failure of any portion of the protection system. This meets safety design basis 7d.

Failure of either RPS motor generator set would result, at worst, in a single trip system trip. Alternate power is available to the RPS buses. A complete, sustained loss of electrical power to both motor generator sets would result in a scram, delayed by the motor generator set flywheel inertia, in about 3 sec. In addition, Electrical Protection Assemblies (EPA's) are installed on the power sources for the RPS to disconnect the power source on over voltage, under voltage or under frequency conditions. This protects the RPS components and auxiliaries from damage due to sustained abnormal voltage/frequency conditions. This meets safety design basis 7e.

The environmental conditions in which the instruments and equipment of the RPS must operate were enveloped by the Environmental Qualification Program. The RPS components which are located inside the primary containment, and which must function in the environment resulting from a break of the nuclear system process barrier inside the primary containment, are the condensing chambers and associated variable and reference leg piping. Special precautions are taken to ensure satisfactory operability after the accident.

The environmental capabilities of the RPS components, combined with the previously described physical and electrical isolation of sensors, and channels, satisfy safety design basis 7g.

Safe shutdown of the reactor during earthquake ground motion is assured by the design of the system as a Class I system (see Appendix C) and the failsafe characteristics of the system. The system only fails in a direction that causes the reactor to scram when subjected to the extremes of vibration and shock. This meets safety design basis 7h.

Calibration and test controls for the Neutron Monitoring System are located in the control room, and are because of their physical location, under the direct physical control of the control room operator. Calibration and test controls for pressure and level switches, transmitters, analog trip units, and valve position switches are located on the devices themselves. These devices are located in the Turbine Building, Reactor Building, and primary containment. To gain access to the setting controls on each switch, transmitter or trip unit, a cover plate or sealing device must be removed. The control room operator is responsible for granting access to the setting controls to properly qualified station personnel for the purpose of testing or calibration adjustment. This meets safety design basis 8a.

It has been shown in the description of the RPS that safety design bases 8b, 9, 10a, and 10b are satisfied.

7.2.5 System Inspection and Testing

The RPS can be tested during reactor operation by six separate tests. The first of these is the manual trip actuator test. By depressing the manual scram button for one trip system; the manual logic actuators are deenergized, opening contacts in the actuator logics. After resetting the first trip system, the second trip system is tripped with the other manual scram button. The total test verifies the ability to deenergize all 8 groups of scram pilot valve solenoids by using the manual scram push button switches. Scram group indicator lights verify that the actuator contacts have opened.

The second test is the automatic actuator test which is accomplished by operating, one at a time, the keylocked test switches for each automatic logic. The switch deenergizes the actuators for that logic, causing the associated actuator contacts to open. The test verifies the ability of each logic to deenergize the actuator logics associated with the parent trip system. The actuator and contact action can be verified by observing the physical position of these devices.

The third test includes calibration of Neutron Monitoring System by means of simulated inputs from calibration signal units. These calibrations are discussed in Section 7.2.3.12 above and in Section 7.5, Neutron Monitoring System.

The fourth test is the single rod scram test which verifies capability of each rod to scram. It is accomplished by operation of toggle switches on the protection system operations panel. Timing traces can be made for each rod scrammed. Prior to the test, a physics review must be conducted to assure that the rod pattern during scram testing does not create a rod of excessive reactivity worth.

The fifth test involves the application of a test signal to each RPS channel in turn and observing that a logic trip results. This test also verifies the electrical independence of the channel circuitry. The test signals can be applied to the process type sensing instruments (pressure and differential pressure) through calibration taps or via the analog trip unit. Generic test procedures are discussed below; additional procedures unique to specific scram channels are discussed in Section 7.2.3.12.

The sixth test involves the application of a test signal to a RPS channel under test similar to the fifth test except a scram inhibit test device will bypass the scram logic relay contact while the relay is under test. The scram inhibit test device will monitor logic relay contact status while maintaining the circuit path preventing the scram relay from initiating half a scram.

1. An instrument technician, following instruction of authorized personnel, either shuts off the instrument line, or removes the channel from service at the Analog Trip Cabinet.

2. The instrument is isolated using the instrument valve (or instrument manifold valve) and a calibration set is attached to the instrument calibration taps which are arranged to avoid spilling of water (if the instruments are normally filled). If isolation is performed via an electrical switch at the Analog Trip System, all that is required to calibrate is injection of an electrical test signal.

3. A calibration signal sufficient to actuate the sensor contacts is applied while reading the value of the applied signal.

4. The trip points and reset point are compared to the required setpoint and the value is logged.

5. Adjustments are made to the trip setting if necessary; adjustments are logged.

6. Communication with the control room is maintained during the test to verify the trip point as registered on control room instruments. The trip value is logged.

7. Proper protective relay operation is also verified by observation.

8. Upon completion of calibration, all test equipment is then removed, and the channel is restored to service.

9. The final state of the system valving (if required) and indication is verified by reactor operations or instrument personnel, and the test is logged as complete.

RPS response times are first verified during preoperational testing and may be verified thereafter by similar tests. The elapsed times from sensor trip to each of the following events is measured:

1. Channel relay deenergized
2. Actuators deenergized

The alarm typewriter provided with the process computer verifies the proper operation of many sensors during plant startups and shutdowns. The verification provided by the alarm typewriter is not considered in the selection of test and calibration frequencies and is not required for plant safety.

The provisions for functionally testing and calibrating the RPS meet the requirements of safety design basis 11.

7.2.6 Nuclear Safety Requirements for Plant Operation

Table 7.2-4 presents the nuclear safety requirements for the RPS for each BWR operating state. The entries on Table 7.2-4 represent an extension of the stationwide BWR systems analysis of Appendix G to the components of the RPS.

The following referenced portions of the safety analysis report provide important information justifying the entries on Table 7.2-4:

Reference	Information Provided
1. Preceding parts of Section 7.2	Description of RPS hardware; RPS sensor setpoints
2. Station Safety Analysis, Section 14	Analyses verifying response of RPS to transients and accidents
3. Station Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which reactor protection system action is required
4. Jacobs, I.M., Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards, General Electric Company, Atomic Power Equipment Department, APED-5736 April 1969	Describes methods used to establish allowable repair times and surveillance requirements for protection systems

Each detailed requirement on Table 7.2-4 is referenced, where possible, to the most significant plant condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns of Table 7.2-4 and are coded as follows:

Example of Matrix Reference:

```
F21-71
|||
|||--- F = BWR operating state F
 ||--   21 = Event (row No. 21)
  |----     71 = RPS (column No. 71)
```

Most of the operational requirements on Table 7.2-4 are obvious in consideration of the information of Appendix G and the information of Section 7.2 describing the RPS in detail. An explanation of several of the less obvious requirements from Table 7.2-4 follows:

System Action 7.2.2 - Neutron Monitoring System Scram Initiation

The requirements for the Neutron Monitoring System logics refer only to that circuitry considered part of the Reactor Protection System, as shown on Figure 7.2-18. The requirements for the individual channels of the Neutron Monitoring System are developed in Section 7.5. Three IRM logics per operable trip system are required to assure that the IRM capability is sufficient to monitor the total core volume. Because the APRMs are themselves arranged to monitor average power throughout the entire core, only one APRM logic is needed in each operable RPS logic.

System Action 7.2.12 - Refueling Restrictions

The reactor mode switch is required to be in the REFUEL position whenever core alterations are being carried out. This requirement assures that the refueling interlocks are in service during such alterations. Although this requirement is not associated at all with any scram action, it is listed here because the reactor mode switch itself is considered a part of the RPS.

Because the point at which the reactor becomes less than one rod subcritical (not shutdown) is not easily recognized during station startup, requirements for RPS channels are shown for operating States A, C, and E. These requirements are selected to anticipate the need for protection should the one rod subcritical point be passed.

7.2.6.1 Surveillance Requirements for Plant Operation

The minimum functional testing frequencies for the components of the RPS are based on an analysis using two GE topical reports NEDC-30844 (Reference 3), which analyzed a representative BWR plant and provided a technical basis for ensuring that the current RPS on-line test intervals meet the recommendations of Generic Letter 83-28, Item 4.5.3, and NEDC-30851P (Reference 4), which used the base case results from NEDC-30844 to establish a basis for extending the current RPS on-line test intervals and allowable out-of-service times (AOTs). These reports used reliability analyses with fault tree modeling to estimate RPS failure frequency. Sensitivity analyses were used to vary the factors that represented the five areas of concern delineated in Item 4.5.3 so that their impact was considered appropriately.

To apply generic plant analyses to specific plants, GE collected necessary information on the RPS for each BWR, determined the differences for each plant, and analyzed the effect of each identified difference on the RPS failure frequency. The analysis evaluated the RPS using the RPS failure frequency as the risk measure.

The calculations of RPS failure frequency depend on two sets of parameters. The first set consists of initiating events that eventually lead to actuation of the RPS. The second set consists of "RPS unavailabilities," which are the probabilities that the RPS is unavailable given the demands for RPS actuation. Depending on each initiating event, the number of sensors that could actuate the RPS would vary. Therefore, the RPS unavailability for one initiating event may differ from that for another.

For each initiating event, a fault tree was developed to quantify RPS unavailability per demand. The fault tree models the logical relationship of the faults that may contribute to RPS unavailability. The logical representation of the fault tree was used with the computer code WAMCUT (Reference 5) to obtain the dominant cutsets which are the combinations of faults that cause the RPS to be unavailable. The dominant cutsets, together with information on testing and repairing the RPS, was then used with the computer code FRANTIC III, (Reference 6) which calculated the unavailability of RPS per demand.

A sensitivity analyses was performed to determine the sensitivity of RPS unavailability to uncertainties in component failure rates. The component failure rates were multiplied with an error factor, which is the ratio of the upper uncertainty bound and the median value. The results indicated that uncertainties in the component failure rates have a negligible impact on RPS unavailability. Therefore, it is concluded that the RPS unavailability is not sensitive to the uncertainties in component failure rates.

It was determined that the common cause failure rates of the scram contactors do contribute significantly to the RPS unavailability for each of the initiating events, however even when these common cause failure rates are considered, the results are still lower than other published results.

The analysis indicated that among the components in the RPS, the scram contactors are de-energized whenever an individual sensor and its associated relay are tested. Because 11 different types of sensors are tested while the reactor is at full power, the scram contactors would be challenged more often than other components in the RPS. For this reason, the effect of scram contactor wear out caused by testing was examined. The analysis indicated that the scram contactor wear created by the number of tests required does not cause any significant increase in RPS failure frequency.

The impact of reduced system redundancy during testing on the RPS unavailabilities by comparing two cases was examined. In the first case, a sensor channel is "jumpered" during a test and is unable to provide an RPS signal upon actual demand. In the second case, a sensor channel is placed in trip during a test and thus does provide an RPS signal.

The RPS unavailability for the first case is higher than that for the second case. However, the difference between these two RPS unavailabilities was found to be small and indicates that reduced redundancy during testing has no significant impact on RPS unavailability.

The analysis considered two types of human errors during a test: an operator disabling components randomly during a test and an operator causing a common cause failure of all similar components during a test. The analysis determined that the first type of operator error does not have significant impact on RPS failure frequency, but the second type of operator error does.

The analysis determined that operator error disabling all scram contactors was the biggest contributor to the RPS failure frequency. The operators perform channel functional testing of the manual scram on a weekly basis by actuating the channel manual scram/test switches in the control room.

RPS failure frequency was calculated by varying the surveillance testing intervals of the average power range monitor (APRM) and other sensors from monthly to quarterly. The results showed a small change in RPS failure frequency.

The original Technical Specifications (TSs) for the relay RPS allowed AOTs of 1 hour for repairing and 2 hours for testing a single sensor channel without placing the channel in a tripped state. The short times allowed by the original TS could cause an operator error as a result of stress during repair and testing. Placing an individual channel in a tripped condition when repairs

and tests cannot be completed within the allowable outage time could increase the likelihood of an inadvertent scram. Therefore, it was proposed to extend the AOTs for repair and for testing. The present AOTs, which are based on the average times needed to complete tests and repairs, include sufficient time margins so that the operators would not be placed under undue stress. To support these above changes, sensitivity analyses were performed and concluded the changing of the AOTs had a negligible impact on RPS failure frequency.

7.2.7 Current Technical Specifications

The current limiting conditions, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

7.2.8 References

1. US Nuclear Regulatory Commission, "Generic Implications of the ATWS Events at the Salem Nuclear Power Plants", Vols. 1 and 2, NUREG-1000, April, 1983.

2. Eisenhut, D.G., NRC letter to All Licensees of Operating Reactors, Applicants for Operating License, and Holders of Construction Permits, "Required Actions Based on Generic Implications of Salem ATWS Events" (Generic Letter 83-28), July 8, 1983.

3. S. Visweswaren, et al., "BWR Owners' Group Response to NRC Generic Letter 83-28, Item 4.5.3," General Electric Company, NEDC-30844, January 1985.

4. W.P. Sullivan et al., "Technical Specification Improvement Analyses for BWR Reactor Protection Systems," General Electric Company, NEDC-30851P, May 1985.

5. R.C. Erdmann, F.L. Leverenz, and H. Kirch, "WAMCUT; A Computer Code for Fault Tree Evaluations," EPRI NP-803, Science Applications, Inc., June 1978.

6. T. Ginzburg et al., "FRANTIC III; A Computer Code for Time-Dependent Reliability Analysis," Broken National Laboratory and Science Applications, Inc., April 1984.

7. B. Collins et al., "A Review of the BWR Owners Group Technical Specification Improvement Analyses for the BWR Reactor Protection System", EGG-EA-7105, corporate publisher, January 1986.

8. D.M. Rasmusen et al., "COMCAN III; Use of COMCAN III in System Design and Reliability Analysis," EGG-2187, corporate publisher, October 1982.

9. A.S. McClymont et al., "ATWS: A Reappraisal, Part 3: Frequency of Anticipated, Transients," EPRI NP-2230, Science Applications, Inc., January 1982.

10. M. McCann et al., "Probabilistic Safety Analysis Procedures Guide," NUREG/CR-2815, Vol. 1, Rev. 1, August 1985.

11. D.P. Mackowiak et al., "Development of Transient Initiating Event Frequencies For Use in Probabilistic Risk Assessment" NUREG/CR-3862 (Draft), June 1984.

12. NRC - Letter dated March 25, 1993 (BECo Letter 1.93.057).

7.16 PROCESS COMPUTER SYSTEM

The Replacement Process Computer System (PCS) has contractually been designated the "Emergency and Plant Information Computer" (EPIC).

7.16.1 Power Generation Objective

The objectives of the Process Computer System are to provide a quick and accurate determination of core thermal performance, to improve data reduction, accounting, and logging functions; and to supplement procedural requirements for control rod manipulation during reactor startup and shutdown.

7.16.2 Safety Design Basis

The Process Computer System shall provide inputs to the rod block circuitry to supplement and aid in the enforcement of procedural restrictions on control rod manipulation, so that rod worth is limited to the values assumed in plant safety analyses.

7.16.3 Power Generation Design Basis

1. The Process Computer System shall be designed to periodically determine the three dimensional power density distribution for the reactor core, and provide printed logs which permit accurate assessment of core thermal performance.

2. The Process Computer System shall provide continuous monitoring of the core operating level, and appropriate alarms based on established core operating limits to aid the operator in assuring that the core is operating within acceptable limits at all times, including periods of maneuvering.

7.16.4 EPIC SYSTEM DESCRIPTION

7.16.4.1 GENERAL

The Pilgrim Nuclear Power Station (PNPS) Emergency and Plant Information Computer (EPIC) is a centralized, integrated system which performs the process monitoring and calculations defined as being necessary for the effective evaluation of normal and emergency power plant operation. The EPIC acquires and records process data including temperatures, pressure, flows, and status indicators. This data is then processed by the EPIC to produce meaningful displays, logs, and plots of current or historical plant performance and presented to plant personnel in the plant main control room or other user definable locations.

The EPIC can be functionally divided into major functional groupings which perform definable functions. These functional groupings are:

a. Main Processing Functions - performs functions entailing basic data manipulations and preprocessing.

b. Man-Machine Interface - performs the function of interfacing the human with the EPIC system.

c. Data Acquisition Functions - performs data acquisition and plant process instrumentation interface.

d. Performance Monitoring Functions - performs all functions necessary to evaluate the performance of the Nuclear Steam Supply System and Balance of Plant.

e. Transient, and Recording and Analysis Functions - performs analysis logging, plotting and recording functions.

f. Real-Time Analysis and Display Functions - performs all functions required to produce displays including display building and dynamic display processing functions.

A brief description of each major function is provided below.

7.16.4.1.1 MAIN PROCESSING FUNCTIONS

Main processing functions are those functions which are generic in nature and perform basic data preparation functions. Included in these functions are conversions, evaluation, alarming and data definition functions. This function of the EPIC performs any generic calculations and processing of data for display or further analysis. These functions include point compositions (generation of a point from 2 or more other points), limit checking, complex algorithm processing, and engineering unit conversions. In addition; many system level functions such as database building and security control (password, key lock, etc.) are a part of this EPIC function.

7.16.4.1.2 MAN-MACHINE INTERFACE

The Man-Machine Interface (MMI) performs the function of interfacing the EPIC with plant personnel. Using the interface, the user can place demands on the system or acknowledge information received by the system. The interface also presents the results of monitoring, calculations, and control actions taken to the user. MMI hardware consists of keyboards, function keys, CRT's, printers and types.

7.16.4.1.3 DATA ACQUISITION (DA)

The Data Acquisition functions perform the function of interfacing the EPIC with process variable instrumentation. This interface function is able to acquire real-time analog, digital, and pulse data simultaneously from the process instrumentation and make that data available to the EPIC. The Data Acquisition function has the ability to gather data at specified rates and is capable of accommodating user specific requirements for the gathering and transmitting of that process data.

The Data Acquisition function is provided by a modular set of solid state components. The data acquisition function samples the plant signals at rates of up to 250 samples/second for analog signals and 500 samples/second for digital signals. The data acquisition portion of the EPIC has provisions for checking, signal loop calibration, signal conditioning and self-testing. In addition, incoming data is provided with "time tags" in order to provide Sequence of Events determination. The data is interfaced with plant sensors via Input/Output modules (IOMs) and transmitted by fiber optic cable in order to provide a means to isolate the EPIC from existing plant equipment. Transmission via wire cable is also provided where isolation is not required.

7.16.4.1.4 PERFORMANCE MONITORING (PM)

The Performance Monitoring (PM) functions provide monitoring of total plant performance. The PM, in addition to being an evaluation tool, also aids in providing efficiency of plant operation. Evaluations are performed including, but not limited to, thermal power distribution, thermal limit margins, core and hot channel decay ratio, energy summaries, exposure accumulations, enthalpies, data summaries, calibration and diagnostics for analysis of the nuclear steam supply. In addition, provisions are available to include Balance of Plant performance calculation capabilities for turbine cycle, condenser, electrical, and feedwater heater performance analysis.

7.16.4.1.5 TRANSIENT RECORDING AND ANALYSIS (TRA)

The Transient Recording and Analysis (TRA) functions provide a real-time and historical perspective for the operation of the power plant. The purpose of the TRA functions is to provide high resolution recording capabilities for various plant parameters and means for event monitoring, data archival, plotting, trending, analyses, automatic and on-demand logging.

The TRA portion of the EPIC provides a means of data recording, archiving and analysis in order to support the determination and analysis of plant transients. Data recording and archiving capabilities can record changing plant parameters for up to 2-hours of pre-event data and 12-hours of post-event data. Data is then available for various outputs such as alarm logs, sequence of events report, trending, post trip logs, significant change reporting and plotting. In addition, analysis routines are available to provide statistical evaluation (such as means minimums, maximums, standard deviations) and time series analysis.

7.16.4.1.6 REAL-TIME ANALYSIS AND DISPLAY (RTAD)

The Real-Time Analysis and Display (RTAD) functions provide automatic reporting and display updating of plant parameters for current user requests. The RTAD shows critical plant parameters such as water levels, temperatures, pressures, flows, and status of pumps, valves, and other equipment. The RTAD is also capable of showing plant operational parameters.

The Real-Time Analysis and Display (RTAD) function of the EPIC provides real-time color graphic displays to provide a medium for the SPDS requirements of NUREG 0737, Supplement 1. The Real-Time Analysis and Display function provides the capability to display sampled data, status indications, synthesized data and trends. Displays on the RTAD hardware are updated at least every 2 seconds. Trend information can also be provided for up to 60 minutes of data. In addition to display capability, the RTAD function provides display creation functions.

Table 7.16-1 provides an instrumentation input summary of some of the nuclear system variables monitored by the process computer system (PCS).

Table 7.16-2 provides an instrumentation output summary of some of the signal requirements from the PCS to plant instrumentation.

7.16.4.2 Reactor Core Performance Function

7.16.4.2.1 Power Distribution Evaluation

The local power density for a specified axial segment of every fuel assembly is calculated, using plant inputs of pressure, temperature, flow, Local Power Range Monitor (LPRM) levels, control rod positions, and the calculated fuel exposure. Total core thermal power is calculated from a reactor heat balance. Iterative computational methods are used to establish a compatible relationship between the core coolant flow and core power distribution. The results are subsequently interpreted as local power at specified axial segments for each fuel bundle in the core.

After calculating the power distribution within the core, the computer uses appropriate reactor operating limit criteria to establish alarm trip settings (ATS) for each LPRM channel. The ATSs are expressed as maximum acceptable LPRM values to which the actual scanned LPRM readings are compared. These then assist the operator in maintaining core operation within permissible thermal limits established by prescribed maximum fuel rod power density and minimum critical power flux ratio criteria.

The core evaluation analytical sequence is completed periodically and on demand. Subsequent to executing the program, the computer prints a periodic log for record purposes.

7.16.4.2.2 LPRM Calibration

Flux level and position data from the traversing incore probe (TIP) equipment are read into the computer. The computer evaluates the data and determines gain adjustment factors by which the LPRM amplifier, gains can be altered to compensate for exposure-induced sensitivity loss. The LPRM amplifier gains are not to be physically altered except immediately prior to a whole core calibration using the TIP system. The gain adjustment factor computations help to indicate to the operator when such a calibration procedures is necessary.

7.16.4.2.3 Fuel Exposure

Using the power distribution data, a distribution of fuel exposure increments from the time of a previous power distribution calculation is determined and is used to update the distribution of cumulative fuel exposure. Each fuel bundle is identified by batch and location, and its exposure is stored for each of the axial segments used in the power distribution calculation. These data are printed out on demand by the operator.

7.16.4.2.4 Control Rod Exposure

Exposure increments are determined periodically for each one-quarter length section of each control rod. The corresponding cumulative exposure totals are periodically updated and printed out on demand by the operator.

7.16.4.2.5 LPRM Exposure

The exposure increment of each LPRM is determined periodically, and is used to update both the cumulative ion chamber exposures, and the correction factors for exposure dependent LPRM sensitivity loss, and can be printed out on demand by the operator.

7.16.4.2.6 Isotopic Composition of Exposed Fuel

The computer provides on-line capability to determine monthly and on demand the isotopic composition of each fuel bundle in the core. This evaluation consists of computing the weight of three uranium and five plutonium isotopes as well as the total uranium and total plutonium content. The isotopic composition is calculated for each one-quarter length of the fuel bundle and summed accordingly by bundles and batches. The method of analysis consists of relating the computed fuel exposure, and the exposure weighted void fraction for the given fuel segments to computer stored isotopic characteristic applicable to the specific fuel type. The output is to data files which can be obtained for future use and for additional data processing.

7.16.4.2.7 PNPS's Core Thermal Power Evaluation

CTP = Qfw + Qcr + Qcu + Qrad + Qp
where:

CTP = 100% License Core Thermal Power = 2028 MWt
Qfw = Power transferred to Feedwater Flow
Qcr = Power transferred to Control Rod Drive Flow
Qcu = Power loss in Cleanup Demineralizer System
Qrad = Radiative Power Loss
Qp = Power added by Recirculation Pumps

Station design documents and control calculations identify instrument loops and account for uncertainties to ensure licensed power level is not exceeded with a confidence of 95%.

7.16.4.2.8 Feedwater Correction Factor

Feedwater flow is the major component of the core thermal power evaluation. A correction factor within the computer provides a bias to account for feedwater flow element fouling and erosion.

7.16.4.2.9 SOLOMON

Core and Hot Channel Decay Ratio are required to be monitored during operation in the Buffer Zone. These parameters are calculated in the SOLOMON program from other process computer inputs, and printed out automatically or at operator request. These outputs provide the primary means of performing on-line stability monitoring. These actions are required during SLO, as well as dual recirculation loop operation. Section 3.7 provides discussion on the applicable operating conditions when SOLOMON is being used as the on-line stability monitor. Operator actions are required based on SOLOMON outputs and operating conditions as given in the table below:

Applicability	Condition	Require Action
Prior to planned entry into the Buffer Zone	SOLOMON results for predicted entry shall indicate Core decay ratio < 0.6 AND Hot channel decay ratio < 0.55	If not met, Entry prohibited
Prior to increasing power when operating in the Buffer Zone	SOLOMON results for predicted entry shall indicate Core decay ratio < 0.7 AND Hot channel decay ratio < 0.55	If not met, Power increase is prohibited.
During continued operation with thermal Power and Core Flow in the Buffer Zone	Every hour SOLOMON case shall indicate the following: Core decay ratio < 0.7 AND Hot channel decay ratio < 0.55	If not met, Immediately exit the Buffer Zone
Upon entry into the Buffer Zone due to a transient	SOLOMON results shall indicate: Core decay ratio < 0.7 AND Hot channel decay ratio < 0.55	If not met, Immediately exit the Buffer Zone

7.16.4.3 Rod Worth Minimizer Function

The rod worth minimizer (RWM) function assists and supplements the operator with an effective backup control rod monitoring routine that enforces adherence to established startup, shutdown, and low power level control rod procedures. The computer prevents the operator from establishing control rod patterns that are not consistent with prestored RWM sequences by initiating appropriate rod select block, rod withdrawal block, and rod insert block interlock signals to the reactor manual control systems rod block circuitry. The RWM sequences stored in the computer memory are based on control rod withdrawal procedures designed to limit and, thereby, minimize individual control rod worths to acceptable levels as determined by the design basis rod drop accident.

The RWM function does not interfere with normal reactor operation, and in the event of a failure does not itself cause rod patterns to be established which would violate the above objective. The RWM function may be bypassed and its rod block function disabled only by specific procedural control initiated by the operator.

The enforcement of the pre-stored RWM sequences is on a Rod-by-Rod basis. Multiple rod movements are grouped in to a "step", and the sequence of rod movements within each step must be followed. The enforcement software will issue interlock signals to ensure compliance with the pre-stored RWM sequences. The following operator and sensor inputs are utilized by the RWM:

7.16.4.3.1 RWM Inputs

1. Sequence

The operator can select either one of two permissible sequences to be enforced by the computer.

The operator is permitted to switch from sequence A to sequence B or vice versa at shutdown, and whenever the reactor is operating above the low power level set point.

2. Shutdown Margin Test Sequence

By selecting this input option, the operator is permitted to withdraw and re-insert any two control rods in the core while all other control rods are maintained in the fully inserted position.

3. Normal/Bypass Mode

A key lock switch is provided to permit the operator to apply permissives to RWM rod block functions at any time during plant operation.

4. System Start/Reset

This input is initiated by the operator to start or restart the RWM programs and system at any time during plant operation.

5. Control Rod Selected

The RWM recognizes the binary coded identification of the control rod selected by the operator.

6. Control Rod Position

The RWM recognizes the binary coded identification of the control rod position.

7. Control Rod Drive Selected and Driving

The RWM utilizes this input as a logic diagnostic verification of the integrity of the rod select input data.

8. Control Rod Drift

The RWM recognizes a position change of any control rod using the control rod drift indication. This information is used to evaluate permissible withdrawal or insertion of subsequently selected rods.

9. Reactor Power Level

Feedwater flow and steam flow signals are used to implement two digital inputs to permit program control of the RWM function. These two inputs, the low power setpoint and the low power alarm setpoint, are used to disable the RWM blocking function at power levels above the intended service range of the RWM function. The low power setpoint is initially set at 20 percent rated power. The low power alarm setpoint is initially set at 25 percent rated power.

10. Permissive Echoes

Rod select, rod withdraw, and rod insert permissive echo inputs are utilized by the RWM as a verification "echo" feedback to the system hardware to assure proper response of a RWM output.

11. Diagnostic Inputs

The RWM utilizes selected diagnostic inputs, such as parity error and stall alarm, to verify the integrity and performance of the processor.

7.16.4.3.2 RWM Outputs

The RWM provides isolated contact outputs to plant instrumentation as follows:

1. Blocks

The RWM is interlocked with the reactor manual control system to permit or inhibit selection, withdrawal, or insertion of a control rod. These actions do not affect any normal instrumentation displays associated with the selection of a control rod.

2. Scan Mode

This RWM output is used to synchronize acquisition of control rod position data during the scan mode.

7.16.4.3.3 RWM Indications

The RWM control panel provides the following indications:

1. Insert Error

Control rod coordinate identification for up to two insert errors.

2. Withdrawal Error

Control rod coordinate identification for one withdrawal error.

3. Latched Group

Identification of the RWM sequence group number currently enforced by the computer.

4. Sequence Select

Indication of the RWM sequence last selected by the operator.

5. Latched Sequence

Indication of the RWM sequence currently being enforced by the computer.

6. RWM Bypass

Indication that the RWM is manually bypassed.

7. Select Error

Indication of a control rod selection error.

8. Blocks

Indication that a selection block, withdrawal block, or insertion block is in effect for all control rods.

9. Low Power-Out of Sequence

Indication that the actual control rod pattern is out of sequence with the RWM sequence currently being monitored while the reactor is operating above the low power setpoint but below the low power alarm setpoint.

10. RWM Off Line

Indication that the RWM is unable to operate properly.

7.16.4.4 Monitor Alarm and Logging Functions

1. General

The processor is capable of checking each analog input variable against two types of limits for alarming purposes: (a) process alarm limits as determined by the computer during computation or as pre-programmed at some fixed value by the operator, and (b) a reasonableness limit of the analog input signal level as determined and programmed by the operator.

The alarming sequence consists of an audible high pitch tone, a console indication, and a typewriter message for the variables exceeding process alarm limits. An acknowledge pushbutton is provided to reset the high pitch tone and console indication to normal. A variable that is returning to normal is signified by an audible low pitch tone and typewritten message.

The processor provides the capability to alarm the system in the event of abnormal PCS operation. Abnormal conditions for alarm include but are not limited to over temperature, and selected program driven PCS contacts.

2. Event Recall Logging

The processor measures and stores the values of analog and/or digital variables at preset intervals to provide a history of nuclear system data. Select balance of station variables are measured at preset intervals to provide a history of balance of station data. An on demand request permits the operator to initiate typing of this data and to subsequently terminate the log printout.

The processor automatically prints the values of these analog and/or digital variables for the period immediately preceding and the period following a reactor scram. A scram is indicated by a digital signal internal to the processor.

3. Trend Logging

A trend capability is provided for logging the values of operator-selected analog and/or digital inputs and calculated variables. The periodicity of the log is limited to a nominal selection of intervals, which can be adjusted as desired by program control.

7.16.4.4.2 Digital Monitor and Alarm

1. Sequence Annunciator Recording

Selected digital inputs are implemented to provide for logging the sequence of contact closure or opening on the alarm output device. Input alarms received are sequentially differentiated and chronologically printed. The printout includes point description and time of occurrence to the nearest 1/60th of a sec.

2. Status Alarm

The status alarm function scans digital inputs at least once each second and provides a printed record of system alarms. The record includes point description and time of occurrence.

7.16.4.4.3 Alarm Logging

The alarm logs required by the associated process programs are typed by the alarm typewriter located in the control room. Alarm printouts are used to inform the operator of computer system malfunctions, system operation exceeding acceptable limits, and potentially unreasonable, off-normal, or failed input sensors.

7.16.5 Safety Evaluation

As described in the Station Safety Analysis (Section 14) for the initial core treatment of the control rod drop accident, the maximum rod worth below 20 percent power assumed was 0.025 k. The rod worth minimizer operates to maintain the maximum rod worth below 0.01 k. At levels above 20 percent of rated power, the maximum rod worth possible was assumed in the control rod drop accident cases; thus, no rod worth control is required above 20 percent of rated power. Should the rod worth minimizer program be inoperative for any reason, the reactor operator can maintain acceptable rod worth by simply adhering to prescribed control rod patterns and sequences when below 20 percent of rated power.

For the reload core, the rod worth assumed in the analysis of the control rod drop accident in the station safety analysis is referenced in Section 14.

7.16.6 Inspection and Testing

The process computer system is self checking. It performs diagnostic checks to determine the operability of certain portions of the system hardware, and it performs internal programming checks to verify that input signals and selected program computations are either within specific limits or within reasonable bounds.

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ELECTRICAL POWER SYSTEM

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8.4 AUXILIARY POWER DISTRIBUTION SYSTEM

8.4.1 Safety Objective

The emergency service portion of the Auxiliary Power Distribution System (APDS), under all transient and accident conditions, distributes ac power required to safely shut down the reactor, maintain the shutdown condition, and operate all auxiliaries necessary for station safety.

8.4.2 Power Generation Objective

The entire APDS, normal and emergency service portions, distributes ac power to all station ac auxiliaries required for startup, operation, and shutdown of the station.

8.4.3 Safety Design Basis

1. The emergency service portion of the APDS distributes power to the station auxiliaries and all loads which are essential to plant safety.

2. The APDS, normal and emergency service portions, is arranged so that a single failure will not prevent or impair the operation of essential station safety functions.

3. The emergency service portions of the APDS are supplied from both offsite and onsite ac power sources.

4. The emergency service portion of the APDS shall be in accordance with the IEEE-308, Standard Criteria for Class IE Electrical Systems for Nuclear Power Generating Stations.

8.4.4 Power Generation Design Basis

The APDS distributes power to all the station auxiliaries necessary for normal station operation.

8.4.5 Description

8.4.5.1 Arrangement of Auxiliary Buses

There are six 4,160 V buses (A1,A2,A3,A4,A5, and A6) in the station APDS. The six buses are divided into emergency service and normal service buses. See Figures 8.2-1, 8.2-2, and 8.4-1. The two emergency service buses, A5 and A6, supply power to essential loads required during abnormal operational transients and accidents. The four normal service buses, A1,A2,A3, and A4, supply power to other station auxiliaries requiring ac power during planned operations. For description of major loads on 4,160 V buses, see Table 8.4-1.

Power is distributed to the six 4,160 V station auxiliary buses during normal operation from either the unit ac power or the preferred ac power source. The preferred power source is used to supply 4,160 V buses during normal startup and shutdown. After the main generator has been

synchronized to the 345 kV system and a minimum stable load established (approximately 20 percent of full output), the 4,160 V buses are individually transferred from the preferred power source to the unit power source. This is done by manually closing the unit power source supply breaker (after synchronization checks) to an individual 4,160 V bus while it is still energized from the preferred power source. The preferred power source supply breaker to this bus is then manually opened and the transfer is complete.

This results in the temporary interconnection of the preferred power source (startup transformer) through a single 4,160 V auxiliary bus.

These procedures are repeated until all six 4,160 V buses have been individually transferred from the preferred power source to the unit power source. Procedural restrictions and synchronization switch interlocks assure that the 4,160 V buses are individually transferred. The preferred and unit power sources are parallel through one 4,160 V bus only for the short period required to verify that the unit power source supply breaker has closed before the preferred power source supply breaker is manually opened.

Each safety-related 4,160 V bus is provided with automatic second- level undervoltage (Degraded Voltage) protection as outlined below:

(a) Two fast-acting undervoltage relays are connected to the bus's potential transformers which will alarm at an undervoltage condition below normal but above a voltage level which is considered degraded (set at approximately 95 percent of nominal.)

(b) Four similar relays are connected to the potential transformers of the preferred ac source (startup transformer) which protect safety-related equipment from damage or misoperation due to sustained degraded voltage by removing this source from the bus. Power to the affected bus is restored automatically from the standby source. These relays are connected in one-out-two taken twice coincidence logic and set at approximately 93 percent of nominal.

An appropriate time delay is provided for all the above relays to override transients such as motor starting.

Automatic fast transfer is provided to restore each 4,160 V bus to the preferred power source in the event that the unit power source is lost. The preferred source supply breaker to an individual 4,160 V bus closes automatically whenever the unit power source supply breaker to the bus opens, and fast transfer logic is operational, thus maintaining power to all station auxiliaries connected to that bus. To ensure automatic transfer of the 4,160 V emergency bus supplies during a design basis event, backup trips of the normal supply breakers to emergency buses A5 and A6 are provided through the operation of seismically qualified undervoltage relays and RPS logic relays. The fast transfers of individual

4,160 V buses from the unit power source to the preferred power source will not interfere with normal station operation. Automatic transferring is in one direction only, from the unit power source to the preferred power source. The diesel generator load shedding logic will also be actuated (See section 8.5.4), immediately upon the fast transfer of the safety related buses A5 and A6 to the Startup Transformer, in the presence of a LOCA signal, when the startup transformer secondary voltage is below the degraded voltage alarm reset setpoint.

The 4,160 V emergency service buses, A5 and A6, can also be supplied from the standby ac power source or the secondary ac power source. In the event that both the unit power source and the preferred power source are lost, the standby ac power source will reenergize buses A5 and A6 within approximately 10 sec. The failure of a diesel generator to restore voltage on one of these emergency service buses would result in automatically connecting the affected bus to the secondary (offsite) ac power source after an additional approximate 2 sec time delay. The secondary (offsite) ac power source may also be manually connected to the emergency service 4,160 V buses to reduce the duration of diesel generator operation whenever both the unit power source and the preferred power source are unavailable. The secondary (offsite) ac power source is from the Commonwealth Electric Company 23 kV distribution line No. 72 discussed in Section 8.3. However, the secondary and standby source supply breakers are interlocked to prevent parallel operation. If <u>either one</u> or both standby AC power sources are unavailable and the secondary offsite AC power source is also unavailable, the Station Blackout Diesel Generator will be able to power either A5 or A6 bus with limited loading requirements. (Refer to Section 8.10).

The eight 480 V buses, B1, B2, B3, B4, B5, B6, B7, and B8 are also divided into normal service buses and emergency service buses. The essential 480 V auxiliaries required during abnormal operational transients and accidents are all supplied from the three emergency service buses, B1, B2, and B6. The five normal services buses, B3, B4, B5, B7, and B8 supply power to other 480 V auxiliaries required during planned operations. The 480 V emergency service buses B1 and B2 receive power from the 4,160 V emergency service buses A5 and A6 respectively. The common 480 V emergency service bus, B6, receives power from either B1 or B2 and is automatically transferred to the alternate source upon loss of voltage on the normal supply.

The 480 V buses B3 and B7 receive power from the 4,160 V bus A3, and the 480 V buses B4, B5, and B8 receive power from the 4,160 V bus A4. Provisions are included to permit normal service buses B3 and B4 to be manually transferred to emergency service buses B1 and B2 respectively in the event that bus A3 or A4 is out of service. The tie breakers are interlocked to prevent bus B3 (or B4) from being connected to both bus A3 (or A4) and B1 (or B2) simultaneously. Procedural restrictions prevent closure of the tie breakers during power operation. See Figure 8.4-2.

Power from the 4,160 V switchgear buses is fed directly to 250 hp motors and larger, and through load center transformers to the 480 V load center buses. Power from the 480 V load centers is fed directly to motors and to motor control centers (MCC). Power from the MCC is fed directly to motors, motor operators, and power panels.

Ammeters are provided for monitoring four safety-related MCC, B10, B14, B15, and B20; and two nonsafety-related MCCs, B19A and B19B. These ammeters will aid the operator to prevent overload condition during unique operating conditions and prevent tripping of the MCCs. MCCs 19A and 19B, although not safety-related, are essential inmaintaining ambient temperatures within limits to assure continuous smooth operation of the plant.

8.4.5.2 System Components

All of the 4,160V switchgear, described on Table 8.4-2, are of the metal clad indoor type with dripproof covers. The circuit breakers are electrically operated three-pole vertical lift breakers with stored energy closing mechanism operated from the 125V DC station batteries described in Section 8.6.

Seven of the 480V load centers, described on Table 8.4-2, consist of low voltage switchgear and a transformer. One load center, B6, consists of switchgear only. All of the switchgears are of the metal enclosed indoor type with dripproof covers. Two of the transformers are rated at 1000/1333 KVA AA/FA, 115°C/150°C temperature rise, three-phase, 60 Hz. Five are dry-type AA, 150°C temperature rise, three phase, 60 Hz/1000 kVA. The circuit breakers are electrically operated three-pole breakers with stored energy closing mechanisms operated from the 125V DC station batteries, described in Section 8.6.

Three of the 480V load centers (B17, B18, B20) have been provided with walk-in enclosures which assure environmental qualification of the MCCs. The exterior walls of the enclosure consist of 1/4" thick steel plate and are designed to withstand the effects of postulated seismic events (OBE and SSE), external pressure due to PBOCs (1 psid), and tornado loads. The walls of the enclosures are covered with insulating material in order to minimize heat transfer from the Reactor Building Atmosphere to the enclosure following a PBOC. Major penetrations such as conduit and pipe are installed with foam sealant.

Each enclosure also includes a non-safety related and safety related cooling system. The non-safety related cooling system consists of two, 100% capacity, split design type air conditioning units. These units are utilized during normal operation to maintain local air temperatures within the enclosures to less than or equal to 80°F. This meets the normal operating environmental qualification temperature criteria for the MCCs electrical equipment to perform their safety functions during normal and postulated accident conditions. The safety related cooling system consists of a vane axial fan and normally closed inlet and outlet dampers

(motor operated butterfly valves) which operate to force reactor building air through the enclosure when the internal enclosure air temperature increases to more than that 120°F. In the event both non-safety related cooling units fail, or are not available, following a PBOC, Reactor Building temperature will decrease below 120°F before the internal enclosure local air temperature reaches the 120°F actuation setpoint for the safety related ventilation system. This results in motor control center (MCC) enclosures' 30-day air temperature profiles following a postulated PBOC which is less severe than the profiles the MCCs' electrical equipment were qualified to perform their safety functions.

The principal design criteria are provided in Table 8.4-4.

All of the 480V motor control centers are NEMA Type I gasketed construction with dripproof covers. The circuit breakers are manually operated. Circuit breakers are provided with either magnetic or thermal magnetic short circuit protection on all poles. All motor starters are provided with thermal overload protection on all poles which will either trip the motor starter or alarm in the main control room. See Figures 8.4-2 through 8.4-5 (Drawings E9, E10, E11, and E12).

Cables have adequate flame resistant properties, and are designed to resist radiation, high temperature, and high humidity levels of the area in which they are installed. Power and control cables to safeguard equipment within the primary containment are designed to withstand the environmental conditions caused by any accident during which the equipment they are supplying is assumed to operate. The current carrying capacity of all power cables is conservatively calculated to preclude damage due to thermal overloads except where deviations are approved by design engineering as stated in Section 8.9.5. Cables used within the containment penetration sealed canisters meet additional insulation material and current carrying capacity restrictions.

Cables and components of redundant circuits are physically separated by space, fire barriers, or concrete walls and floors to assure maximum independence of redundant channels. Cables are installed in conduits or metal trays.

8.4.6 Safety Evaluation

Provisions to ensure continued availability of AC power to the emergency service portions of the auxiliary power distribution system have been made in the design. The multiplicity of offsite and onsite sources feeding these buses, the redundancy of transformers and buses within the plant, and the division of critical loads between buses yields a system that has a high degree of reliability. Also, the physical separation of buses and service components provides independence to limit or localize the consequences of electrical faults or mechanical accidents occurring at any point in the system.

480 Volt Bus B6

Independence is not compromised by the source transfer scheme which transfers ac power from one independent emergency power source to the other in the event that the first source is lost.

Since the diesel generators could be supplying emergency power, the source transfer is slowly performed to ensure their complete independence. The transfer is a slow transfer which allows the load voltage to decay before reapplying power from the second source. This eliminates the possibility of immediately transferring a motor from one diesel generator operating at one frequency to the other diesel generator operating out of phase or at another frequency. Due to the loss of voltage during transfer, loads which are not essential to station safety will be shed.

To ensure the desired degree of independence between redundant engineered safeguard systems, protective device coordination curves were developed which demonstrate adequate margin between primary and secondary protection. These protective devices both sense and isolate faulted equipment. The protective device settings are set as low as the largest engineered safeguard load would permit, while maintaining adequate margin between devices.

Considering a single breaker or bus failure criterion, overload protection was provided on both of the series connected tie breakers. Hence, a fault on emergency service bus B1 will not cause the loss of buses B2 or B6 or vice versa. A fault on bus B6 will not cause the loss of bus B1 or B2.

The 480 V buses B1, B2, and B6 are shown on Figure 8.4-2. Bus B6 normally receives power from either bus B1 or B2 through series connected circuit breakers 102 and 601 or through 202 and 602. One set of series breakers is closed and the other set is open. An automatic transfer signal (loss of normal supply voltage or a reduction of voltage to degraded levels with a time delay to override transients such as motor starting.) causes both "closed" circuit breakers to trip after a time delay The open circuit breakers are then closed by two independent closing signals provided there is adequate voltage on the alternate source. This completes the automatic transfer. Buses B1 and B2 cannot be connected together through B6 by a single failure since (a) the two circuit breakers in series are normally open and (b) their closing circuits cannot both be actuated by the single failure. Interlocks are provided to preserve independence as described below:

1. Failure of either breaker 601 or 602 to trip would prevent closure of the other

2. Failure of either breaker 102 or 202 to trip would prevent closure of the other

3. A fault on 480 V bus B6 would be isolated by either breakers 601 or 102 (or 602 or 202), one breaker located at B6 and one at the power source (B1 or B2). This isolation maintains the source voltage and prevents transfer of the faulted bus B6 to the other source. Two series connected circuit breakers at different locations must both fail for a transfer malfunction. Since the breakers are series connected, the only postulated single failure source is excessive overcurrent.

The breakers are designed to interrupt the short circuit currents available when supplied from the preferred ac power source. Since the diesel generators are incapable of supplying short circuit current of this magnitude, the simultaneous failure of both breakers 601 and 102 (or 602 and 202) to trip is not considered a single failure

4. Each 480 V load center (B1, B2, and B6) is sectionalized, providing barriers for added reliability and physical independence. The load centers are separated by a concrete wall or floor

The source transfer feature is an essential part of the overall station design for safeguard loads and provides additional, desirable operating reliability for nonsafeguard loads of importance. The existence of bus B6 is justified by the objective for each load to have access to redundant ac power supplies. To facilitate the ensuing analysis of the requirements of each load, the loads are divided into groups as follows:

1. RHR System Injection Valves and Recirculation Loop Valves
2. Containment Motor-Operated Isolation Valves
3. Station Economic Investment Loads
4. Fire System Loads
5. Loads Requiring a Backup Power Source

As shown by the above grouping, the selection of bus B6 as power source for each load is not based only on engineered safeguard load performance during postulated accidents or transients. Bus B6 was selected as the best available ac power source to loads which are critical during planned operations. AC loads, which have dc backup, are supplied from bus B6 to provide access to either ac source.

1. RHR System (LPCI) Injection Valves and Recirculation Loop Valves

   Power to the RHR injection valves and recirculation loop valves which must operate for the LPCI mode during loss of coolant accident (LOCA) conditions is supplied from bus B6. The automatic source transfer allows the operation of two RHR pumps in LPCI mode in the event that one diesel generator is not available.

   The LPCI mode of the RHR System is designed to inject water into the intact recirculation loop in the event that a recirculation line break initiates a LOCA. Power to the RHR injection valves and recirculation valves required to operate during the LOCA is supplied from bus B6.

The station as designed assumes the operability of one Core Spray System and two RHR pumps in LPCI mode in the event of the single failure of one diesel generator. Water from the two RHR pumps may not be available under this condition unless automatic source transfer is accomplished thus making power available to the selected recirculation loop valves from the operating diesel generator.

In the event of a single failure resulting in the loss of Bus B6, the station as designed assumes that both diesel generators and two Core Spray Systems remain operable.

2. Containment Motor-Operated Isolation Valves

The inboard ac valves are backed up by outboard dc valves. DC valves are powered from 125 V dc side A, 125 V dc side B, or 250 V dc side B, with all three batteries used. For additional reliability the inboard ac valves are connected to bus B6 and therefore can be supplied from either diesel generator. The inboard ac valve cables are routed as SX while the outboard dc cables are routed as both SA and SB; therefore separation is maintained.

3. Station Economic Investment Loads

These loads, such as the turbine turning gear, are vital to protect the station economic investment. Assuming only one diesel generator is running, it is desirable to operate these loads although they may be automatically blocked from operation if safeguard loads dictate the diesel generator or startup transformer loading requirements.

4. Fire System Loads

Assuming only one diesel generator is running, it is desirable to operate fire system auxiliary loads although they are automatically blocked from operation if safeguards loads dictate the diesel generator loading requirements. These loads are not required for initiation of any fire system equipment, but are required to maintain the system's readiness to function and rejuvenate after system operation.

5. Loads Requiring a Backup Power Source

Systems with <u>third</u> backup components in addition to two redundant A and B components should be capable of operating the third component upon failure of either A or B power source. For example, the 125 V dc backup battery charger would be manually energized if either A or B side battery charger is out of service.

The plant air compressor is a third component which differs from the above. The compressor will be rotationally selected as one of the two running compressors, the third on standby status. It is desirable that two compressors are available, hence the third is supplied from bus B6.

8.4.7 Inspection and Testing

Inspection and testing at vendor factories and initial system tests were conducted to ensure that all components were operational within their design capability.

Periodic tests of the equipment and system are conducted as shown on Table 8.4-3 to:

1. Detect the deterioration of equipment in the system toward an unacceptable condition

2. Demonstrate the capability of equipment which is normally deenergized to perform properly when energized

8.4.8 Proposed Nuclear Safety Requirements for Initial Plant Operation

The emergency service portions of the Auxiliary Power Distribution System are required for station startup and for operability of the standby ac power system. Operating limitations are related to the operability status of the auxiliary ac power sources and are described in Section 8.5.6.

The safeguard control power subsystem receives power from the APDS described in section 8.4. Power is supplied from 480V emergency service buses B17, B17a, B18, B18a, and B20 through stepdown transformers. The 208/120V ac safeguard subsystem supplies control power to the PCIS, PASS and PAM control panels. It also supplies control power to various other valves and control panels. The panels are NEMA class I, Type B wiring panels. The step down transformers supplying power to the panels are 10KVA, 480-120V, single phase, two wire, 60 Hz for panels Y3 and Y31,and Y4 and Y41, 25KVA, 480 122/244V, single phase, two wire, 60 Hz for panels Y13 and Y14; and 15KVA, 480-208/120V, 3 phase, 4 wire, 60 Hz for panels Y6, Y7 and Y8.

The 10KVA step-down transformers for distribution panels Y3 and Y31 and Y4 and Y41 are voltage regulating type maintaining output voltage at 120VAC ± 4% for voltage inputs of 480VAC + 10% / -25% for panels Y3 and Y31 . The 25KVA step down transformers which supply power to distribution panels Y13 and Y14 are voltage regulating type maintaining output voltage at 122VAC ± 4% for voltage inputs of 480VAC ± 20%. During undervoltage transients below 480VAC -25% for panels Y3 and Y31 and below 480V -20% for panels Y13 and Y14, the regulating transformers will select the highest transformer tap to maximize the output voltage as close to 120V AC as possible. During overvoltage transients above 480VAC +10% for panels Y3 and Y31 and above +20% for panels Y13 and Y14, the regulating transformer will select the lowest tap to limit the output voltage as close to 120VAC as possible.

The RPS components which are located inside the primary containment, and which must function in the environment resulting from a break of the nuclear system process barrier inside the primary containment, are the condensing chambers and associated variable and reference leg piping. Special precautions are taken to ensure satisfactory operability after the accident.

8.8.6 Inspection and Testing

Inspection and testing at vendor factories and initial system tests were conducted to insure that all components are operational within their design ratings.

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10.6 TURBINE BUILDING CLOSED COOLING WATER SYSTEM

10.6.1 Power Generation Objective

The power generation objective of the Turbine Building Closed Cooling Water (TBCCW) System is to provide cooling to the equipment located in the Turbine Building and to the Station Air Conditioning Systems.

10.6.2 Power Generation Design Basis

The TBCCW System is designed to provide an adequate supply of coolant to the essential power generation equipment located in the Turbine Building and to the Station Air Conditioning Systems.

10.6.3 Description

The TBCCW System, as shown on Figure 10.6-1, consists of a single closed loop with two centrifugal pumps in parallel, taking suction from TBCCW heat exchangers arranged in parallel, and delivering cooling water to the equipment listed on Table 10.6-1. The TBCCW pump, TBCCW heat exchanger, and Retention Building Booster Pump specifications are given on Table 10.6-2. The TBCCW loop is designed for a system pressure of 150 psig. The TBCCW pump shutoff head of 110 ft plus the Retention Building Booster Pump shutoff head of 125 ft plus the static head of 75 ft combined will not exceed the design pressure downstream piping and components.

The 500 gal capacity head tank, located at the highest point of the loop, accommodates system volume changes, maintains static suction pressure on the pumps, detects gross leaks in the TBCCW System and provides a means for adding makeup water. Makeup water to the TBCCW System from the demineralized water storage tank is supplied by a connection from the demineralized water transfer pump to the head tank. Tank level is maintained automatically by means of level transmitters and controllers mounted locally. A signal from these transmitters opens the valve on the makeup line to fill the surge tank to the desired level. The surge tank is readily accessible during reactor operation for level adjustment if desired. Venting of the tank is directed to the Reactor Building. An inhibitor is added as necessary to the demineralized water by means of a chemical addition tank to limit corrosion.

The discharge side of each TBCCW System pump has a pressure indicator. The common discharge header for the pumps is monitored for low pressure and alarmed in the control room. A pressure indicator, located on the outlet header of the heat exchangers, and a pressure test point on the inlet header may be used for pressure testing. A temperature element is located on the cooling water pump discharge to indicate the temperature of the cooling water on the indicator controller in the main control room. A constant water temperature is maintained automatically by the controller, which governs the quantity of water flowing through the bypass around the cooling water heat exchangers. Cooling water sampling points are located at the outlet of each TBCCW heat exchanger. Samples will be taken periodically to determine activity levels and quality of the cooling water.

The following conditions will alarm in the main control room:

1. Head tank low level

2. Head tank high level

3. Pump discharge header low pressure

The original design ratings for the TBCCW system are based on the operation of both system heat exchangers. The TBCCW system is designed to transfer a maximum heat load of 38 MBtu/Hr in order to limit equipment inlet temperature to 95°F, assuming a seawater inlet temperature of 75°F. The actual TBCCW System heat load has been estimated to be less than 30 MBtu/Hr during normal full power operation and is typically shared equally by the two TBCCW heat exchangers operating at an average heat load of less than 15 MBtu/Hr each. During normal station full power operation, only one TBCCW pump is typically operated with both heat exchangers, which provides adequate flow and cooling for all normal heat loads during most conditions. At times of peak SSW heat sink temperatures, typically occurring from June into October, there may be periods when it is preferred to operate both TBCCW Pumps with both heat exchangers to raise the component cooling water flow rates in the system to their rated values and to maintain the cold loop temperature at 85 to 95°F.

At times of low SSW heat sink temperatures, typically from October to June, there are periods when it is possible to operate adequately with one TBCCW Pump and only one heat exchanger providing cooling. This configuration allows for online maintenance to be performed on one heat exchanger under these conditions.

Following the loss of the preferred AC power source without a LOCA initiation signal, a TBCCW pump will be started automatically and loaded on its respective diesel generator. A time delay relay will start the P-110A pump within approximately 35 seconds from the loss of power. If header pressure remains low due to the failure of the first pump or other abnormality, the P-110B pump is started within approximately 55 seconds from the loss of power.

Following the loss of the preferred AC power source with a LOCA initiation signal, the TBCCW pumps will not be enabled to start until one of the ECCS pumps is no longer in service. The time delay relays will remain in place but since the logic will have energized them as soon as power is restored there will be no additional delay after one of the ECCS pumps is removed from service.

The system is provided with two remote manual motor operated valves that serve to isolate the nonessential loads from the system. Cooling water continues only to the main control room, computer room, and cable spreading room air conditioning units, and air

compressors following this isolation. A single TBCCW pump operates at a low flow condition and higher brake horsepower when only the essential loads are provided with cooling water. Since adequate cooling is provided to essential and nonessential loads one TBCCW Pump, the isolation of the nonessential heat loads is not required.

The TBCCW System contains a coolant sidestream particulate filter. When in service, the filter sidestream bypasses less than 1% of the coolant flow around the TBCCW heat exchangers. The filter removes particulates 5 microns and larger from the coolant without removing corrosion inhibitor chemicals.

The Class I seismic designation to certain portions of the TBCCW System was initiated at an early design stage and prior to the finalization of design for the major plant, air, and control room ventilation systems.

As a result of incorporating the Main Control Room Environmental Control System and Class I air accumulators on critical air-operated valves, etc., into the plant design, the need for Class I piping and components in the TBCCW System was eliminated. Currently, the TBCCW System is Class II. The portions of piping in the RBCCW/TBCCW Heat Exchanger Room are designed MQCI (II/I) to protect Class I equipment belonging to other systems in this room. Since the loss of the TBCCW System will not affect the safe shutdown of the plant, special controls or emergency procedures are not required.

10.6.4 Inspection and Testing

Pumps in the TBCCW have been proven operable by their use during normal station operations. Motor-operated isolation valves in the system can be tested to assure that they are capable of opening and closing by operating manual switches in the control room, and observing the position lights. System subsections normally closed to flow can be tested periodically to ensure their operability and the integrity of the system.

10.7 SALT SERVICE WATER SYSTEM

10.7.1 Safety Objective

The safety objective of the Salt Service Water (SSW) System is to provide a heat sink for the Reactor Building Closed Cooling Water (RBCCW) System under transient and accident conditions.

10.7.2 Safety Design Basis

1. The system is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective.

2. The system is designed to continuously provide a supply of cooling water to the secondary side of the RBCCW heat exchangers adequate for the requirements of the RBCCW under transient and accident conditions.

10.7.3 Power Generation Objective

The power generation objective of the SSW System is to provide a heat sink for the RBCCW System and the Turbine Building Closed Cooling Water (TBCCW) System during planned operations in all operating states.

10.7.4 Power Generation Design Basis

The system is designed to function as the ultimate heat sink for all the systems cooled by the RBCCW and TBCCW during all planned operations in all operating states by continuously providing adequate cooling water flow to the secondary sides of the RBCCW and TBCCW heat exchangers.

10.7.5 Description

The entire SSW System shown on Figure 10.7-1 is designed in accordance with Class I criteria, and there is no Class II Seismic piping in the system. See Appendix C and Section 12.

The Service Water System consists of five vertical service water pumps located in the intake structure, and associated piping, valving, and instrumentation. The pumps discharge to a common header from which independent piping supplies each of the two cooling water loops, each loop consisting of one Reactor Building and one Turbine Building cooling water heat exchangers. Two division valves are included in the common discharge header to permit the SSW System to be operated as two independent loops. The water then returns to the bay from the outlet of the heat exchangers. The heat exchangers are valved such that they can be individually backwashed without interrupting system operation. Any marine growth occurring in the heat exchangers will be controlled by hypochlorination based upon residual chlorine content measured in the discharge headers.

Sample valves have been installed in each of the independent cooling water loops, between the pumps and the heat exchangers. These valves are to be used for the following purposes:

1. To obtain a grab sample of service water.

2. To provide access to the header for venting

Each service water pump has an automatic air vent to prevent water hammer. Pump bearings are marine cutlass type, suitable for sea water application and are lubricated by water as it rises through the pump column.

The following number of pumps will be used during each of the indicated modes:

	Number of Pumps
Normal Operations	1 to 4
Accident Conditions (LOCA)	2
Shutdown Conditions	4

The number of pumps required for normal operation is selected based on plant cooling needs and SSW inlet temperature. Pressure transmitters mounted at the discharge header provide indication in the control room to allow operators to monitor SSW pump performance.

Plant Technical Specifications originally described the minimum required SSW pump performance as 2700 gpm at 55 ft TDH. Actual SSW pump rated performance is 2700 gpm at 95 ft TDH and minimum required performance for in-service testing is defined as 2700 gpm at 87.5 ft TDH. These TDH values are for the pump bowl not including the 40 ft vertical pump column. The 55 ft value represents the minimum required pressure, in feet, measured at the centerline of the pump discharge piping (EL 23.9 ft) for a pump bowl operating at 2700 GPM at 87.5 ft TDH.

The sea water tide level used in accident analysis calculations is 7.1 ft below msl, the yearly astronomical minimum low tide. This is the value used for the design basis analysis of the minimum SSW system performance required to perform the emergency containment cooling function. This low tide occurs for short periods of time during the semidiurnal tidal variations once every year. For the SSW system performance analysis, this lowest tide level is assumed to be constant, thereby yielding a conservatively low SSW system flow rate during accident analyses that span a several day period. The SSW pumps are also assumed to be operating at their minimum performance thereby providing only the required 4500 gpm to the RBCCW heat exchanger.

The minimum sea water level for maintaining SSW pump rated performance is approximately 13 feet 9 inches below msl. This represents the lowest sea water at which a SSW pump bowl operating at its rated performance of 95 feet TDH at 2700 gpm will produce a discharge head of 55 feet at 2700 gpm as measured at EL 23.9 feet. The lowest postulated instantaneous sea water level is 10.1 feet below msl(Section 2.4.4.2) caused by a hurricane producing 110 mph winds blowing directly offshore during the same critical hour at which the yearly astronomical low tide occurs. At this lowest water level, the pumps are capable of maintaining rated performance which implies that they have adequate NPSH and submergence (to prevent vortexing). It is not appropriate to assume that this condition will exist long enough to require that it be the design basis for the long term emergency cooling function of the SSW system for which these pumps are assumed to be at their minimum required performance level.

The buried portions of the 22" nominal diameter discharge piping from the last flange connections in the Auxiliary Building piping vault to the end of the discharge pipes at the Seal Well opening have been provided with a Cured-In-Place-Pipe (CIPP) lining. The 240 ft total length Loop "A" lining was installed in RFO-14 and the 225 ft total length "B" lining was installed in RFO-13. The CIPP liner material consists of a tube composed of nonwoven polyester felt material that is saturated with either an isophthalic polyester resin and catalyst system (Loop "A") or epoxy resin and hardener system (Loop "B") with a polyurethane or polyethylene inner membrane surface. The liner has a nominal 1/2" installed thickness. The resulting configuration is a rigid resin composite pipe within the original pipe with no requirements for bonding between the pipes.

The Salt Service Water System is designed to provide a heat sink for the Reactor Building Closed Cooling Water System under accident and transient conditions. Section 14.5 describes the Containment Cooling System analysis for a design basis loss of coolant accident (LOCA) at both a salt water inlet temperature of 65°F and 75°F.

Modifications have been made to help improve salt service water pump reliability and to allow greater maintenance and operational flexibility within the salt service water east and west bays. Flow conditions have been improved by the addition of a rear sluice gate at the opening in the common wall separating the east and west salt service water bays, and by the addition of baffle plates in the west salt service water bay. Restraints have also been installed to stabilize each service water pump column. Salt service water pump design functions can be accomplished with the rear sluice gate either in the open or closed position, and with or without baffle plates or pump column restraints.

To ensure that sufficient seawater flow is maintained through the RBCCW heat exchangers (minimum of 4500 gpm for each heat exchanger), motor-operated butterfly valves on the TBCCW heat exchanger outlets will automatically adjust to preset throttling positions and the RBCCW outlet valves will simultaneously open. Automatic adjustment of the outlet valves occur following a loss of coolant accident (LOCA) with a coincident Loss of Offsite Power (LOOP), or a LOCA with degraded voltage on the safety buses while being supplied from the startup transformer. If a LOCA occurs without a LOOP or degraded voltage condition, the heat exchanger outlet valves remain as-is. Manual adjustments of the outlet valves will be made by operators to achieve adequate cooling water flow.

The loss of AC power will trip all service water pumps and will close one of the two division valves in the common pump discharge header, effectively dividing the service water system into two independent loops. Two pumps would be connected to each loop. The two division valves are arranged to permit the fifth (middle) pump to be operated on either loop. The operator preselects the division valve to be closed and thereby determines which loop will be connected to the middle pump. Either valve can also be closed by a hand switch.

For the limiting design basis emergency condition, the Circulating Water System pumps (Section 11.6) are not operating. This assumption is based on the need for the containment heat removal function of the SSW System versus the Circulating Water System when the Main Condenser is not being used as the heat sink. For either emergency containment heat removal or normal shutdown cooling, the SSW System is the main heat sink for the reactor core decay heat only after the discharge of steam to the Main Condenser has stopped. For the bounding design basis LOCA (Section 14.5), it is only the RHR, RBCCW, and SSW Systems that provide containment heat removal. To maximize the containment heat removal from a single loop of these systems, when required, the circulating water pumps are secured so that the level in the SSW pumps bay(s) will be equal to the ocean tide level and unaffected by operation of the Circulating Water System.

There are a number of single failures that can result in a SSW System configuration where one SSW pump will be supplying flow to both trains of SSW during the first ten minutes of an accident. Should this occur, operators are then expected to align the SSW System for optimal performance by starting additional pumps and/or closing division valves as required. This mode of operation has been analyzed and determined to be acceptable.

The pumps are separated into two loops electrically. In the event of the loss of the preferred AC power source, the two SSW pumps on loop A are powered by diesel generator A. They provide cooling to RBCCW loop A (also powered by diesel generator A) which provides cooling to all Core Standby

Cooling System components loaded on diesel generator A. The two salt service water pumps on loop B have the same relationship, both to their standby AC power source, diesel generator B, and to RBCCW Loop B. The fifth pump is loaded on a common emergency service bus which can be powered from either standby AC power source.

Initiation of standby AC power following loss of the preferred AC power source will automatically start at least one pump in each loop during normal conditions. Following a LOCA and loss-of-offsite power one and only one pump will start in each loop because of diesel load limitations. Additional pumps are started manually by the operator as additional cooling loads are established and diesel capacity is made available.

10.7.6 Safety Evaluation

The SSW System is designed with sufficient redundancy so that no single active system component failure nor any single active component failure in any other system can prevent it from achieving its safety objective. Two independent closed loops with full heat transfer capacity on each loop are provided.

The existence of single failures which place the SSW system in the mode of one pump supplying both trains of heat exchangers for the first ten minutes of an accident has been analyzed and found to be acceptable. Operator action is credited after ten minutes to realign the system for optimal performance.

The 22 inch discharge headers leave the Reactor Building at an elevation of 15 ft 7 in msl. The two parallel lines run approximately parallel to the shoreline with a 2.8 percent slope. At a point approximately in line with the edge of the intake structure the lines turn and then parallel the centerline of the discharge structure with a 1.98 percent slope. At an elevation of -6 1/2 ft msl the two discharge lines turn and enter the side of the discharge structure sealwell.

Detection of leakage in the Reactor Building auxiliary bay is provided by two water level detectors mounted in each area. The detectors provide control room personnel with early indication of flooding such that personnel can be dispatched to the area to identify the source and effect isolation.

Dewatering of a major pipe rupture is accomplished by two 14 inch drain lines in each area which direct the water to the torus compartment. The discharge of the drain lines is submerged in a water trough to ensure that a sufficient water seal exists between the torus compartment and the Reactor Building auxiliary bay. The drain line dewatering capacity is sized on the maximum possible flooding rate which results from a single failure in any one line.

Numerous small diameter floor drains in the RBCCW compartments are plugged to prevent chloride and nitrate intrusions in radwaste. Therefore, normal leakage can accumulate to a level of four inches before overflowing the lip around the fourteen inch dewatering lines located in each of the RBCCW compartments. All safety related equipment in the RBCCW compartments will be unaffected by flooding four inches above the floor level. Normal leakage will not prevent safety related systems or components from performing their intended safety functions.

A major pipe break in this area will not result in a loss of both RBCCW and TBCCW Systems because the redundant portions of each system are separated by a watertight barrier. The watertight barrier consists of a watertight door and a spray barrier. The spray barrier is located in the pipeway immediately above the watertight door. Position switches provide station personnel with status information for the watertight door at all times.

In order to evaluate Pilgrim Station's susceptibility to damage due to a major oil spill in Cape Cod Bay near the Pilgrim Nuclear Power Station, previous oil spills have been examined relative to power plant and industrial proximity to the spill and the effects observed. Additionally, the various mechanisms by which spilled oil can be transported in water have been analyzed relative to the station design. The basis for these comparisons was Systems Study of Oil Cleanup Procedures (Dillingham Corporation, 1969) and the American Petroleum Institute (API) Conference on Prevention and Control of Oil Spills (December 1969).

Floating oil would be prevented from entering the intake structure by various devices. The primary oil containment device of the intake structure is its entrance skimmer wall, which functions as a submerged baffle. Minimum submergence of the baffle is 5 ft at design low water level. A secondary oil containment device is a concrete baffle wall inside the intake structure, downstream from the trash racks and upstream of the traveling screens and pumps. This baffle provides 2.2 ft submergence at mlw level. The final and most effective oil containment devices in the intake structure are the sluice gates through which the service water pump suction water must flow. The sluice gates are designed to allow isolation and dewatering of either circulating water bay. Positioning of the gates halfway closed would allow effective baffling to a submergence of 5 ft at design low water level.

In the unlikely event of some oil penetrating the aforementioned barriers, the minimum submergence at design low water level of the service water pumps of 11 ft would prevent the oil from being drawn into the pump suction.

Should slight amounts of emulsified oil reach the salt service water pump suction the observable effects would be limited to a small decrease in pumping efficiency and higher system head losses due to slightly increased fluid viscosity.

10.7.7 Inspection and Testing

Testing is performed on the SSW pumps, safety related check valves, and all safety related motor and air operated valves in the SSW system in accordance with the In-Service Testing (IST) program. The testing is performed per the ASME code as required by 10 CFR 50.55a(f), to demonstrate compliance with plant technical specifications for the SSW pumps. Operational performance testing is also conducted on the SSW system to verify that the system meets design criteria. Examinations are conducted on SSW system components in accordance with the In-Service Inspection (ISI) program.

10.7.8 Nuclear Safety Requirements for Plant Operation

General

This section represents the nuclear safety requirements for the SSW System for each BWR operating state which result from the station wide BWR systems analysis of Appendix G. The following referenced portions of the safety analysis report provide important information justifying the entries in this section:

	Reference	Information Provided
1.	Section 10.7.5	Description of the SSW System hardware
2.	Station Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which SSW System action is required

Each detailed requirement in the following analysis is referenced, if possible, to the most significant station condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" section. The matrix block references identify the BWR operating state, the event number and the system number. For example, F39-99, identifies BWR operation state F, event (row) No. 39, and system (column) No. 99, on Table G.5-3.

<u>System Action</u>

The SSW System provides a heat sink for the RBCCW System.

<u>Number Provided by Design</u>

This system consists of two open loops. Each loop has two pumps (plus a common spare), piping, valving, instrumentation, and controls as necessary to provide coolant to one RBCCW heat exchanger and one TBCCW heat exchanger on each loop.

<u>Minimum Required for Action</u>

BWR Operating States A, B, C, D, E, & F:
Two pumps with associated controls and instrumentation on one loop must be operable and the following valves on that loop operable:

1. One TBCCW heat exchanger outlet valve unless valve is throttled
2. One RBCCW heat exchanger outlet valve unless valve is open
3. One discharge header valve (for loop separation unless valve is fully closed

(A35-99)	(B35-99)
(C39-99)	(D39-99)
(E39-99)	(F39-99)

10.7.9 Current Technical Specifications

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

10.8 FIRE PROTECTION SYSTEM

10.8.1 Power Generation Objective

The power generation objective of the fire protection system is to provide adequate fire protection capability in all areas of the station and to ensure safe shutdown in the event of a fire in any area of the plant.

10.8.2 Power Generation Design Basis

The fire protection system is designed to furnish water, halon, carbon dioxide, and/or dry chemicals as necessary for fire extinguishment in the station. The fire protection system is designed to provide the following:

1. A reliable supply of fresh water for fire fighting

2. A reliable system for delivery of water to potential fire locations

3. Automatic fire detection in selected areas

4. Fire extinguishment or control by fixed equipment activated either automatically or manually for areas with a high fire risk

5. Manually operated fire extinguishing equipment for use by operating personnel at selected points throughout the station

In addition, an alternate shutdown system has been installed to ensure that the station's safe shutdown capability is not adversely affected by a fire (Reference 6).

The requirements contained in the Entergy Quality Assurance Program Manual (QAPM) are applied to those activities affecting fire protection systems and equipment required to limit fire damage to safety-related structures, systems, and components so that the capability to safely shut down the plant is ensured.

10.8.3 Description

The fire protection system, piping and instrumentation diagram is shown on Figure 10.8-1 (BECo M218).

10.8.3.1 Fire Water System

The site fire water supply is taken from two 250,000 gal, lined carbon steel water tanks which are devoted exclusively to fire protection. The fire water system may also use water from a city water main.

The water supply is delivered by either an electric motor-driven pump (rated at 2,000 gal/min) or a diesel engine driven pump (rated at 2,500 gal/min). The diesel engine driven pump is used for standby and emergency use on loss of ac power. A hydro turbine driven by diesel fire pump P-140 drives the backup diesel fuel transfer pump (P-181). This pump takes suction from the emergency diesel generator fuel oil storage tanks, bypasses diesel transfer pump P141-A and discharges to day tank T-123. The purpose of this hydro turbine driven pump is to provide a redundant (non-electric power dependent) diesel fuel oil transfer pump for the diesel fire pump P-140. This redundant pump will allow extended operation of the diesel fire pump as a water source for the RHR system during extended station blackout and severe accident scenarios beyond design basis. A small jockey pump (rated at 50 gal/min) is provided to maintain a constant pressure for the water system. If the system pressure drops substantially, the motor-driven fire pump will start automatically, and if pressure continues to drop, the diesel-driven pump will also start automatically.

The pumps feed outdoor fire hydrants, interior hose stations, sprinkler systems, and deluge systems for the station.

As part of the Safety Enhancement Program (SEP), a piping connection is provided from the Fire Protection System to the RHR System. This connection will allow water from the Fire Protection System fire pumps to flow to the upper containment spray header, torus spray header, and/or LPCI injection lines during a severe accident or station blackout.

The interconnection of the Fire Protection System and the RHR is manually initiated. Inadvertent admission of fire water to the RHR and or RHR contamination of the FPS is prevented by requiring the operator to install a removable pipe section with couplings and to open two locked closed valves. The removable pipe section is not installed during normal operation.

There are four types of sprinkler or water spray systems used at PNPS: (1) deluge, (2) pre-action, (3) wet pipe, and (4) dry pipe systems.

Deluge and pre-action systems have empty pipes. In these systems, the water is controlled (i.e., held out) by a separate heat detection system. Deluge systems have "open" sprinkler heads or water spray nozzles and pre-action have "closed" automatic heads or nozzles.

Wet pipe systems have pressurized water in their pipes and "closed" sprinkler heads. Dry pipe systems have pressurized air in their pipes and automatic "closed" sprinkler heads.

Deluge systems protect the exterior surface of the following equipment:

1. Main Transformer
2. Auxiliary Transformer
3. Shutdown Transformer
4. Startup Transformer

Wet pipe sprinkler systems protect the following areas:

1. Turbine basement area (west of shield wall)
2. Turbine lube oil reservoir room
3. Turbine lube oil conditioning room
4. Contaminated tool storage area
5. Recirculation motor generator sets room
6. Station heating boiler room
7. Old Machine shop
8. Offices at 37′ elevation radwaste bldg.
9. Diesel fire pump and day tank rooms
10. Offgas Retention Building - charcoal filter room
11. Radwaste hydraulic press (baler) area
12. Access control area and radiological offices
13. Condenser Retubing Building
14. Reactor Building (20 ft wide sprinkler systems only on El. 23'0" and 51'-0")
15. Reactor Auxiliary Building - Water Treatment Room
16. Safety enhancement program (SEP) Pump Building.
17. Redline building (RCA ingress/egress area and trash and laundry area).
18. Trash Compaction Facility

There are pre-action systems provided for the following areas:

1. Hydrogen seal supply oil area (sprinklers)
2. Diesel generator and day tank rooms (sprinklers)
3. Deleted
4. Turbine lube oil reservoir (water spray)
5. Turbine generator bearings (water spray) and oil hazards below the turbine lagging (sprinklers)

There is a dry pipe sprinkler system in the radwaste trucklock and condenser retubing building trucklock areas.

10.8.3.2 Other Extinguishing Systems

Total flooding, automatically actuated Halon 1301 fire suppression systems protect the following areas:

1. Cable spreading room
2. Plant computer room
3. O&M building record storage vault
4. Station blackout (SBO) diesel generator building

Dry chemical wheeled cart fire extinguishers will be provided in the following areas:

1. Diesel generator building
2. HPCI pump and turbine areas
3. Recirculation pump motor generator set room
4. Reactor feedpump area

Portable CO_2 hand extinguishers are provided in the control room and computer room. Portable dry chemical and pressurized water hand extinguishes are provided throughout the plant, as indicated in the Fire Protection System Evaluation and as modified by the Safety Evaluation Reports (References 1, 2, and 3).

10.8.3.3 Other Fire Protection Features

Fire detection systems which alarm in the control room are located in the following areas:

1. Diesel generator building
2. Reactor feed pump area
3. Computer room
4. Recirculation pump motor generator set room
5. Control room air recirculation fan inlet duct
6. Control room cabinets and consoles required for safe shutdown
7. Vital motor generator set room
8. Safety pump rooms (HPCI, RCIC, RHR)
9. CRD modules and MCC areas - east and west elevation 23 ft
10. Switchgear rooms and battery rooms
11. Radwaste trucklock area
12. Reactor Building areas at elevations 51 ft, 74 ft 3 in, 91 ft 3 in, and 117 ft and other areas housing safe shutdown equipment, panels, cable trays, and instrumentation
13. Reactor Building closed cooling water pump rooms A and B
14. Offgas Retention Building
15. The cable spreading room

Fire Detection Systems which do not alarm in the Control Room are located in the following areas:

1. Operation & Maintenance Building
2. EPIC Computer Room

10.8.3.4 Fire Barriers

Three hour rated fire walls, and some that are less than three hour rated in accordance with PNPS Safety Evaluation Report (Reference 4), are identified in the Fire Protection Evaluation Report (Reference 1). Doors, dampers, pipe penetrations, and cable penetrations through these fire walls are also rated 3 hour fire resistant, unless an evaluation demonstrates a fire rating of less than 3 hours is acceptable.

These fire walls separate fire areas containing safety related equipment for safe shutdown of the station in accordance with PNPS Safety Evaluation Reports (References 2, 3, and 4).

There are fire wraps for some safe shutdown raceways routed in certain areas as follows:

- "B" Switchgear Room - Enclosures #1 and #2, three hour rated.
- Cable Spreading Room - Enclosure #3, one hour rated.
- Torus Room (Bay 15) - Fire Wrap, one hour rated for instrumentation raceway M994.
- Control Room, Shift Managers Office - Fire Wrap, Three hour rated for raceway A-260.

Fire exits in the turbine auxiliary building (i.e., access area and time tunnel) are separated by smoke control doors.

Noncombustible shields are installed between the feedwater pumps (i.e., turbine building) to prevent oil from one pump from spraying on the other(s).

The diesel generator day tank room(s) are designed to prevent diesel fuel oil from entering the diesel generator room(s).

Curbs have been installed in the Generator Auxiliaries Area of the Turbine Building to contain potential oil spills and prevent them from spreading into the Lower Switchgear Room. These curbs, in conjunction with the sprinkler system in the area, provide a reasonable means of fire control should an oil fire occur.

10.8.3.5 Alternate Shutdown System

The alternate shutdown system, independent of cabling and equipment in the cable spreading room (CSR) and Control Room, is provided to effect safe shutdown of Pilgrim in the event of a fire in the CSR or the Control Room. This is accomplished by installing isolation switches for safety-related equipment that will provide the capability for the plant operators to reach a safe shutdown condition. These switches will isolate their associated equipment from the CSR cables, thus transferring control from the Control Room to the local emergency shutdown stations outside of the CSR and Control Room. These isolation switches are located in alternate shutdown panels and are located as close as practical to the equipment or switchgear they serve.

Alternate shutdown panels are provided for the following systems:

a. Core Spray
b. RHR
c. RBCCW
d. Salt Service Water
e. HPCI
f. RCIC
g. Automatic Depressurization System
h. Diesel Generators

An Emergency Lighting System has been installed to provide sufficient illumination for the access routes to each alternate shutdown panel and for operation of the safety related equipment from these panels (References 2, 3, & 4).

10.8.4 Inspection, Testing and Technical Requirements for Fire Protection Equipment

The following provides surveillance frequencies, acceptance criteria and degraded equipment requirements for equipment associated with fire protection. This section reflects the guidance provided in Generic Letters 86-10 and 88-12.

10.8.4.1 Fire Detection Instrumentation

10.8.4.1.1 Fire Detection Instrumentation Technical Requirements

The minimum fire detection instrumentation for each fire detection zone shown in Table 10.8-1 shall be operable at all times when equipment in that fire detection zone is required to be operable.

<u>ACTION</u>: With the number of minimum operable fire detection instruments less than required by Table 10.8-1:

a. Within 1 hour, establish a fire watch patrol to inspect the zone with the inoperable instrument(s) at least once per hour; and

b. Restore the inoperable instrument(s) to operable status within 14 days to assure the minimum operable detectors for each detection zone, or determine the cause of the malfunction and develop plans for restoring the instrument(s) to operable status.

c. For inoperable fire detectors controlling fire suppression systems, see the respective fire suppression system section (i.e., Section 10.8.4.3 for water suppression systems or 10.8.4.4 for gaseous suppression systems).

10.8.4.1.2 Fire Detection Instrumentation Surveillance Requirements

As a minimum, the number of fire detectors noted in Table 10.8-1 shall be demonstrated operable in accordance with NFPA 72 Fire Code by a functional test at least once per year.

EXCEPTION; The detectors in the charcoal vault in the augmented offgas building need to be functionally tested once per refueling outage.

10.8.4.2 Fire Water Supply System

10.8.4.2.1 Fire Water Supply System Technical Requirements

At all times when any safety related equipment is required to be operable, the fire water supply system shall be operable with:

1. Two 2000 gpm, 119 psig (95% of the 125 psi rated output), fire pumps which are arranged to start automatically.

2. Two water supplies with a minimum storage quantity of 240,000 gallons of water in each.

3. Two independent water flow paths from 1 and 2 above to each fire water suppression system. (10.8.4.3 and 10.8.4.5)

ACTION: With less than the above required equipment:

a. Restore the inoperable equipment to operable status within 7 days or implement the plans and procedures to be used to provide for the loss of redundancy in this system.

b. With no Fire Water Supply System flow path operable, establish the Backup Fire Water Supply System within 24 hours (in accordance with station procedures) or an orderly shutdown of the reactor shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

10.8.4.2.2 Fire Water Supply System Surveillance Requirements

The fire water supply system shall be tested and verified to be operable:

a. by checking the volume of water in each fire water tank at least once every 7 days.

b. by automatically starting each fire pump at least once every month and running the diesel engine driven pump for thirty minutes and the motor driven pump for at least 10 minutes at that time.

c. by visually checking every shutoff valve on the fire water supply system at least once every month for proper position. (Exception - once per cycle for those in Locked High Radiation Areas)

d. by cycling each fire water supply system shutoff valve through its full operation at least once per cycle.

e. by verifying at least once per cycle that each pump starts and delivers at least 2000 gpm while maintaining a system pressure of at least 119 psig (95% of the 125 psi rated output).

f. by performing a water flow test on the fire water yard loop at least once every year.

g. by verifying at least once every month that the diesel fire pump fuel storage tank contains a minimum of 175 gallons of fuel oil.

h. at least once per operating cycle by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with the manufacturer's recommendations for the class of service.

i. by verifying at least once per 3 months that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM D4057-81 or D4177-82, is within the acceptable limits specified in Table 1 of ASTM D975-81 with respect to viscosity, water content, and sediment.

j. by demonstrating that the diesel starting 24-volt battery bank and charger are operable as follows:

    1. at least once per week by verifying that the electrolyte level of each battery is above the plates and battery voltage is at least 24 volts.

    2. at least once per 3 months by verifying that the specific gravity is appropriate for continued service of the battery.

    3. at least once per operating cycle by verifying that the batteries and battery racks show no visual indication of physical damage or abnormal deterioration and the battery-to-battery and terminal connections are clean, tight, free of corrosion, and coated with anti-corrosion material.

10.8.4.3 Spray and/or Sprinkler Systems

10.8.4.3.1 Spray and/or Sprinkler Systems Technical Requirements

The spray and/or sprinkler systems located in the following areas shall be operable at all times when equipment in the spray/sprinkler protected area is required to be operable:

1. Diesel generator room preaction sprinkler systems (including detectors).

2. Diesel fire pump fuel oil storage room wet pipe sprinkler system.

3. Auxiliary boiler room wet pipe sprinkler system.

4. Recirculation pump MG set room wet pipe sprinkler system.

5. Hydrogen seal oil supply unit preaction sprinkler system (including detectors).

6. Turbine basement addition wet pipe sprinkler system.

7. Reactor building elevation 23'-0", north side wet pipe sprinkler system.

8. Reactor building Elevation 51'-0", north and south side wet pipe sprinkler systems.

9. Reactor auxiliary building, water treatment area, wet pipe sprinkler system.

10. Health physics access area wet pipe sprinkler system.

ACTION: From and after the date that a spray and/or sprinkler system is made or found to be inoperable:

a. Within one hour establish a continuous fire watch with backup suppression, except as specified in 10.8.4.3.1, actions c, d, e, f, and g.

b. Restore the system to operable status within 14 days or determine the cause of inoperability and develop plans for restoring the system to operable status.

c. If the Spray or Sprinkler System is not operable because no Fire Water Supply System flow path is operable, complete actions identified in Section 10.8.4.2.1.

d. If the suppression system of the diesel generator room preaction sprinkler systems (including detectors but excluding the Pilotex portion of the

system), is inoperable, establish an hourly fire watch patrol with backup suppression provided that the detection system in that fire area and the detection and suppression system for the redundant fire area is operable.

e. If two or more detectors of the diesel generator room preaction sprinkler system are found or made to be inoperable, within one hour charge that sprinkler system piping with water.

f. If the wet pipe sprinkler system for the reactor recirculation pump MG set room, reactor building auxiliary building water treatment room, auxiliary boiler room, reactor building elevations 23' & 51' north side, or reactor building elevation 51' south side is inoperable, establish an hourly fire watch patrol with backup suppression provided that the detection system in the area is operable. Additional administrative controls will be implemented to further reduce any potential fire hazards while the automatic suppression systems are inoperable.

g. When the entire fire area protected by a spray and /or sprinkler system is designated, "HIGH RADIATION AREA/AIRBORNE RADIOACTIVITY AREA", an hourly fire watch patrol may be established (e.g., for ALARA considerations in lieu of a continuous fire watch). If a zone of the fire area is so designated, one of the following shall apply: (1) If the zone is adequately inspectable from a non-High Radiation Area, the continuous fire watch shall be located in the non-High Radiation Area, or (2) If (1) cannot be accomplished, a fire watch patrol shall enter the High Radiation Area once every eight hours.

It is not necessary to enter areas designate designated as "Locked High Radiation Area".

10.8.4.3.2 Spray and/or Sprinkler Systems Surveillance Requirements

The spray and/or sprinkler systems shall be demonstrated to be operable according to the following:

1. Each sprinkler system and water spray system alarm shall be tested at least once every year by opening the alarm bypass or inspector test valve. Alarms in high radiation areas are to be tested once per cycle.

2. Deleted.

3. Each preaction sprinkler system shall be trip tested at least once per cycle.

4. Each water spray system shall be trip tested automatically by simulated actuation of the heat detectors at least once per cycle.

10.8.4.4 Halon System

10.8.4.4.1 Halon System Technical Requirements

The halon system for the cable spreading room shall be operable with each of the five storage tanks charged to at least 95% of the minimum quantity of halon (217 lbs. per tank) necessary to extinguish a fire, and minus or plus 10% of the pressure stamped on the data plate on the tank corresponding to an ambient temperature of 70°F. Detectors associated with the automatic initiation of the halon system shall be operable, except that an individual detector may be inoperable if the other detector in the same bay is operable and both detectors in all adjacent bays are operable.

The halon system shall be operable at all times when the safety related equipment in the cable spreading room is required to be operable.

ACTION:

a. Within one hour from and after the time that the system is found to be inoperable, establish a continuous fire watch with backup suppression equipment.

10.8.4.4.2 Halon System Surveillance Requirements

The halon system shall be demonstrated operable:

1. At least once per month by verifying the halon storage tank pressure and that the control panel is in the automatic mode.

2. At least once per 6 months by verifying the quantity of halon in the storage tank(s).

3. a. At least once per operating cycle by verifying that the system and associated devices actuate upon receipt of a simulated actuation signal, and

   b. Performance of an inspection to assure the nozzles are unobstructed.

10.8.4.5 Fire Hose Stations

10.8.4.5.1 Fire Hose Stations Technical Requirements

The interior fire hose stations shown in Table 10.8-2 shall be operable at all times when the equipment in the area protected by the fire hose station is required to be operable.

ACTION:

a. With a hose station inoperable, provide an additional equivalent capacity hose for the unprotected area at/from an operable hose station within 1 hour, except as specified in 10.8.4.5.1. Action b.

b. If a fire hose station is not operable because no fire water supply system flow path is operable, complete actions specified in section 10.8.4.2.1.

10.8.4.5.2 Fire Hose Stations Surveillance Requirements

Each interior fire hose station shall be verified to be operable:

1. At least once per month by visual inspection of the station to assure that the hose and nozzle are properly installed. (Exception - Once per cycle for those in Locked High Radiation Areas).

2. At least once per cycle by removing the hose for inspection, replacing any degraded coupling gaskets, and reracking.

3. At least once per two fuel cycles (approximately 4 years) by partially opening each hose station valve to verify valve operability and no obstruction. (Partial flow test).

4. By conducting a hydrostatic test of each hose every three years.

    a. at a pressure 50 psig greater than the maximum available pressure at that hose station, or

    b. at the applicable service test pressure as listed in Table 8-3 of the "Standard for Care, Maintenance of Fire Hose Including Connection and Nozzles." NFPA No. 1962-1979, or

    c. by replacing each nontested hose with a new or used hose which has been hydrostatically tested in accordance with the pressures specified in a or b above.

10.8.4.6 Fire Barrier System

10.8.4.6.1 Fire Barrier System Technical Requirements

All fire barrier systems providing separation of redundant safe shutdown systems shall be functional at all times when the safe shutdown systems are required to be operable.

ACTION: With one or more of the required fire barrier systems nonfunctional:

a. Within one hour either establish a continuous fire watch on one side of the affected barrier or verify the OPERABILITY of an automatic fire detection or suppression system on at least one side of the nonfunctional fire barrier and establish an hourly fire watch patrol, except as identified in 10.8.4.6.1 actions b and c.

b: When the fire areas on both sides of the affected fire barrier are designated "HIGH RADIATION AREAS/AIRBORNE RADIOACTIVITY AREA", an hourly fire watch patrol may be established (e.g. for ALARA considerations) in lieu of a continuous fire watch.

c Certain fire barrier components may be degraded without adversely affecting the fire barrier function of preventing fire damage to redundant trains of safe shutdown equipment. Fire Protection may perform an evaluation to document that no fire watch is necessary or to allow hourly fire watches for circumstances where degraded barriers are still capable of performing their fire protection function.

10.8.4.6.2 Fire Barrier System Surveillance Requirements

Surveillance requirements for penetrations in fire barriers are as follows:

1. Fire Barrier Penetration Seals: Approximately 20% of the fire barrier penetration seals shall be visually inspected once per cycle. The sampling shall ensure that 100% of the seals are inspected within a 10 year period or 5 fuel cycles. If any seal is found to be inoperable, then an additional 10% of the seals shall be inspected. Sampling and inspection shall continue until all of the seals in a sample are found to be operable or until 100% of the seals are inspected.

2. Fire Doors: Each fire door shall be tested once per cycle for operability of closure and latching mechanisms and for integrity.

3. Fire Dampers: Each fire damper shall be tested once per every 2 cycles for operability and integrity. In certain circumstances Fire Protection may determine that it is not necessary to test a damper and may recommend an inspection only. An evaluation will be prepared to document the basis for such determinations.

4. Fire barrier enclosures and fire wrap systems: Each fire barrier enclosure and fire wrap system will be visually inspected for integrity once each operating cycle.

10.8.4.7 Fire Brigade

A fire brigade of 5 members including a fire brigade leader shall be maintained on site at all times. This minimum excludes 3 members of the minimum shift crew necessary for safe shutdown and any personnel required for other essential functions during a fire emergency.

The fire brigade training shall be in accordance with Pilgrim Station's Fire Protection Training Program. The fire protection training of fire brigade members shall be held quarterly.

10.8.4.8 Alternate Shutdown Panels

The operability and surveillance requirements for the alternate shutdown system are in Section 3/4.12 of Pilgrim Station's Technical Specifications. The emergency lighting system for the alternate shutdown system is within the scope of the Maintenance Rule at PNPS. Performance requirements are established and monitored accordingly.

10.8.5 References

1. Pilgrim Station 600, Unit 1, Boston Edison Company, Fire Protection System Evaluation, March 1, 1977.

2. Safety Evaluation Report by the Office of Nuclear Reactor Regulation (Amendment 35 to License No. DPR-35) for Pilgrim Nuclear Power Station-1, December 21, 1978.

3. Safety Evaluation Report (additional Fire Protection Information Review) for Pilgrim Nuclear Power Station-1, October 7, 1980.

4. Safety Evaluation Report by the Office of Nuclear Reactor Regulation Related to Amendment No. 123 to Facility Operating License No. DPR-35, dated October 13, 1988.

5. Report 89XM-1-ER-Q Updated Fire Hazards Analysis.

6. Power System Calculation No. 32, "Appendix R, Safe Shutdown Analysis for PNPS".

7. License Amendment 143 resulting from Generic Letters 86-10 and 88-12.

TABLE 10.9-2
DESIGN TEMPERATURES (SUMMER)

Outdoor***: 88° F Dry Bulb

74° F Wet Bulb

Indoor:	Maximum
Turbine Building	105°F - 120°F
Reactor Building	See Note (1 Below)
Control Room Area	78°FDB 50% ** relative humidity
Access Control Area	78°FDB 50% relative humidity
Administration Building	78°FDB 50% relative humidity
Radwaste Area	100°F
Diesel Generator Building	105°F (Max)* - 95°F (5ft above Floor)*
Intake Structure	105°F*****
Machine Shop and Warehouse Area	105°F
Cable Spreading Room	-102°F to +76°F

NOTE 1: The following data represent the Reactor Building maximum summer design temperatures by specific location:

Location	Max. Room Temp. (°F)	Av. Room Temp (°F) 5 Feet Above Floor Level
Refueling Floor	105	95
General Floor Area	105	95
Main Steam Pipe Tunnel	135****	110
RHR/Core Spray Pump Area	115*	100*
CRD Pump Area	115	100
RCIC Pump Area	115*	100*
HPCI Pump Area	115*	100*
Cleanup Regn. & Nonregn. Heat Exchanger	115	100

* These temperatures apply only to conditions when the equipment in the area is operating. Under normal plant operation, temperature in these areas will be lower than indicated above.

TABLE 10.9-2 (Cont.)
DESIGN TEMPERATURES (SUMMER)

Outdoor***: 88°F Dry Bulb
74°F Wet Bulb

** See Section 7.1.8 for loss of HVAC conditions.

*** The outdoor design temperature used for rating HVAC equipment is selected in accordance with guidance from the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE). The design high temperature for outdoor ambient is a value with an associated exceedance criteria, i.e., the percent of time that the value is expected to be exceeded. The design summer outdoor conditions are 88° F dry bulb, 74° F wet bulb. The corresponding design indoor temperatures are listed for various locations. These temperatures correspond to the 1% exceedance values for the site locations. The 1% value would be expected to be exceeded for a total of 30 hours during the summer months (June to September) based on the ASHRAE design standards. This design method conforms to conventional engineering practice. FSAR Table 2.3-15 lists 102° F as the maximum expected outside air temperature that may occur during the months June, July, and August while 88° F may be exceeded during any of the months April through September.

**** With intermittent peaks to 140°F. Intermittent is defined as "one week per year".

***** Individual safety-related components have been evaluated and determined to be operable up to 127°F.

10.11 INSTRUMENT AND SERVICE AIR SYSTEMS

10.11.1 Power Generation Objective

The power generation objective of the Instrument and Service Air Systems is to provide the station with a continuous supply of oil-free compressed air. This air is directed to station instrumentation and general station services.

10.11.2 Power Generation Design Basis

1. The Instrument Air System is designed to supply clean, dry air to station instrumentation and controls at 70 to 100 psig with a design dewpoint of -40°F at 100 psig.

2. The Service Air System is designed to provide clean air to station services at 70 to 100 psig. The Low Pressure Service Air System is designed to provide clean air at a nominal pressure of 20 psig to station services.

10.11.3 Description

10.11.3.1 General

The air systems are, in general, designed to Class II requirements, although Class I equipment requiring air under accident conditions has Class I air accumulators and piping associated with that equipment. See Figure 10.11-1.

The high pressure air supply (nominal 100 psig with allowance for drops to 90 psig) is developed by three reciprocating and two rotary screw type air compressors operating in parallel. Each compressor has an after cooler and delivers the compressed air to a bank of receivers. There are five air receivers which are connected to a common discharge header that delivers the air to the high pressure service air system and to two instrument air dryers to provide high quality dry air to the various instrument air headers. There is one coalescing air filter located upstream of each instrument air dryer. There is one particulate air filter downstream of the instrument air dryer X-105 and dryer X-160 A&B. The downstream air filters are to ensure that no desiccant or other foreign material enters the instrument air system. There is also a bypass around the dryers and filters which can be opened by remote manual or automatic means for dryers X-105 and X-160A&B to assure a continued supply of instrument air to the essential instrument air header in the event of an air dryer failure. Normally, use of one of the two rotary compressors will maintain the air receivers at the desired pressure for system supply. The remaining compressors serve as standby units. Actuation of the standby units is automatic and is indicated in the control room.

The High Pressure Service Air System delivers air to various plant services which do not require drying, such as air powered tools.

The low pressure air supply (nominal 20 psig) is developed by two centrifugal air blowers. The blowers discharge for distribution through a moisture separator and a mist eliminator. Blower usage is intermittent. No dewpoint control is provided. The Low Pressure Service Air System interfaces with several plant systems which contain radioactivity. As a result of aging of system isolation components, unintentional cross-contamination of the Low Pressure Service Air System has occurred. While it is impractical to decontaminate the system and maintain it free of detectable radioactivity, this system should be operated and maintained so as to keep the levels of radioactivity contained within at a minimum commensurate with the goals of the station ALARA program.

A normally closed pressure reducing cross-over line is provided between the high pressure distribution header upstream of the air dryers and the low pressure distribution header. This cross-over may be used to continue low pressure service in the event of blower failure.

Pressure loss in the high pressure system, sensed by several pressure switches, will cause valves in the service air header, the low pressure service air cross-around line, and the non-essential instrument air header to close in a cascading sequence thus leaving the essential instrument air header as the only header drawing air from the receivers in the event that supply pressure decreases.

Instrumentation is provided to monitor the dew point downstream of each air dryer. Flow meters are provided for each air dryer train.

A 3" back-up air supply system was added to the Instrument Air system, tying into the permanent plant hardpipe connection from the outside of the turbine building where it is connected to a diesel driven oil-free air compressor. This back-up source of instrument air is used for station black-out conditions and/or to provide additional air for times when the system is not available due to maintenance.

The backup nitrogen system consists of two banks of ten cylinders each, a cylinder rack and manifold (X-169), associated piping and valves. The cylinders are arranged to automatically maintain the nitrogen supply to drywell instrumentation once the existing nitrogen supply is not available. The cylinders deliver nitrogen gas through 2 inch piping which ties into the existing drywell instrument supply header. A differential pressure indication switch with annunciator is connected between the cylinder supply and the existing supply which provides control room indication of switchover to the cylinders.

10.11.3.2 Equipment Description

Compressors

The three reciprocating air compressors are vertical, single stage, double acting reciprocating compressors. They are each rated to deliver 159.5 standard ft^3/min at 105 psig. The two rotary compressors are each rated to deliver 655 standard ft^3/min at 102 psig.

The diesel air compressor is sized to accommodate station air loads in a black-out or maintenance condition.

Each reciprocating compressor has a pressurized lubrication system for the power-end parts. The cylinders are non-lubricated having Teflon piston rings. They also have water cooled cylinders and have a displacement of 261 in^3. All intake valves have pneumatic operators which depress the valves allowing the cylinder to unload by venting to the atmosphere each time the motor starts and each time the receiver pressure reaches the top of its operating range.

Each of the three reciprocating compressors is belt-driven (4 belts) by a 40 hp drip proof induction motor. The compressor speed is 514 rpm.

The two rotary screw type compressors are direct driven by an electric motor which provides a shaft output of 156 hp at a compressor discharge pressure of 102 psig. The compressor speed is 3,550 rpm.

The accumulator charging compressor (K-203) and dryer (X-285) are powered by a 5 hp, 460 V/3 phase/60 Hz motor and supplies dry air, with a dew point of (-) 50°F, at 130 psig. This compressor serves as the alternate means of charging the Standby Gas Treatment and Torus Vacuum Breaker accumulators.

Aftercoolers

The reciprocating compressor aftercoolers are shell and tube counter current coolers with air passing through the tubes and water flowing around the tubes. They have an integral moisture separator equipped with an automatic drain trap to remove condensed moisture from the cooled air. Cooling water is supplied by the Turbine Building Closed Cooling Water System.

The rotary screw compressors are provided with intercoolers and aftercoolers, integral with each unit. Cooling water is supplied by the Turbine Building Closed Cooling Water System.

Air Receivers

The air receivers are vertical vessels built to the ASME code for a design pressure of 125 psig. Each receiver is equipped with two relief valves and an automatic drain trap. The volume of each receiver is 151 ft^3.

Air Dryers

The two air dryers are each rated to pass 100% of normal station air demand at 100 psig dried to a dewpoint of -40 F. Each drier has twin towers built to the ASME code for a design pressure of 150 psig. The air is dried by passing it through a desiccant. Moisture is removed from the desiccant by a heated purge air flow.

Class I Accumulators

Class I accumulators, associated piping, and check valves of appropriate size are provided for the following equipment:

1. Torus to Secondary Containment Vacuum Breaker Butterfly Valves

   The torus to secondary containment vacuum breaker butterfly valves are powered by Class I air accumulators. These accumulators are sized for a 30 day mission time without operator action and a design leakage rate of 0.1 SLM. A Class I manual make-up system allows the accumulators to be recharged from outside secondary containment and thus maintain the vacuum breakers valve function for an indefinite period of time. The vacuum breaker and make-up air supply are shown on Figure 10.11-1 (Drawing M220).

2. Main Steam Isolation Valves

3. Main Steam Relief Valves

   A Class I, seismic piping system allows two accumulators to be recharged from outside the Drywell, and thus maintain the RPV pressure control capability for an indefinite period of time.

4. Emergency Diesel Generator Ventilation System Dampers.

10.11.4 Inspection and Testing

The Instrument and Service Air System operates continuously and is observed and maintained during normal operation. No special inspection and testing will be required following preoperational testing.

10.15 COMMUNICATIONS SYSTEMS

10.15.1 Power Generation Objective

Internal and external communications are established by separate systems of loudspeakers and telephones designed to provide convenient, effective operational communications between various station buildings and locations.

10.15.2 Power Generation Design Basis

1. Voice communications between selected office areas and to points outside the station are provided by a dial telephone system.

2. The Industrial Communication System provides voice communication between various station buildings and locations using transistorized, industrial quality equipment with the following characteristics:

   a. Satisfactory voice communications are possible even in areas of extreme noise.

   b. Six separate and independent communication channels are provided; i.e. one page and five party lines. The page channel may be used to call personnel over the speakers, to issue station wide instructions, or for intercommunication between two or more handset stations.

   c. All system speakers carry the conversation during the page mode of operation.

   d. The party line channels are used for intercommunication after the page call is completed, thereby making the page channel available to others.

   e. Simultaneous conversations may take place on both the page and party channels without interference.

3. The maintenance and special operation system provide voice communication using one independent party line. This system is provided for use in areas requiring maintenance or special communication.

   a. Portable equipment is provided using permanent plug-in receptacles.

   b. Paging from the system is possible using the components of the Industrial Communication System.

   c. A group of receptacles are interconnected for special operations communication between the main control room, control rod drive areas, and the refueling floor.

4. A portable radio system is provided as a backup to the industrial communication system, should it be disabled during a fire, in accordance with Branch Technical Position 9.5-1, Guidelines for Fire Protection for Nuclear Power Plants.

5. A private line P.A. is installed between the control room and the refueling floor.

6. A wireless communication system is available with various Repeater Base Stations located throughout the site. It is accessed by means of a hand held telephone.

10.15.3 Description

The station communication systems are:

1. Public telephone system furnished and installed by the local telephone company consisting of components described below:

   a. Telephones are located in selected office areas and are connected to the Applicant's present CENTREX system providing dial type communication between the office areas within the station and the Applicant's offices at other locations.

   b. Telephones are located in selected areas which are connected to the local community (Plymouth) exchange providing dial type communication between the areas within the station and local community.

2. Industrial Communication System installed throughout the station site. All components of the system receive power from the 120 V AC instrument power bus. The components are described below:

   a. Speakers of various types are provided throughout the station for paging, public address, and carrying the evacuation warning signal. Each speaker was selected to insure adequate sound coverage throughout the area that the speaker covers.

   b. Handsets are provided throughout the station, each with access to five party lines and the page channel. To call an individual, an available party line channel is selected by pushbutton, the individual is paged throughout the station site, and the party line selected is used for conversation. The page channel may be used for conversation and emergency instructions as a sixth line of communication. While paging, handsets mute nearby speakers to eliminate system feedback. The system is operable in high noise areas without soundproof booths.

c. An operator recall alarm is generated by a tone generator. This tone, which lasts 10 to 15 seconds, is different than the evacuation warning signal (d). The operator recall alarm is initiated manually by the control room supervisor to alert the plant operators that a scram, fire, or other emergency has occurred, and they should report to either the control room or their assigned station. This tone eliminates the need for the control room supervisor to page all the operators during an emergency, or a scram.

d. An evacuation warning signal is generated by a tone generator located in the Control Room Communication Console. The signal can only be initiated from the main control room, and is carried over the paging channel, even if in use, through all of the speakers.

3. Maintenance and special operation system installed throughout the station site. All components of the system receive power through the Industrial Communication System from the 120 V ac instrument power bus. The components are described below:

a. Portable handset/speakers are provided with access to one party line and the same paging channel as the Industrial Communication System. The set must be plugged in to one of the many receptacles to be operable.

b. Receptacles are provided throughout the station with ac power and the paging channel provided from a nearby component of the Industrial Communication System. The party line from each receptacle is a separate and independent channel connected to the central switching panel. One group of receptacles for special operation has a common uninterruptable party line by interconnecting the group at the rear of the central switching panel. This special group permits uninterrupted conversation between the main control room, control rod drive equipment areas, and the refueling floor. Each receptacle has a low intensity blue light to locate the receptacle in the dark.

c. A central switching panel is provided in the cable spreading room. It is possible to select 1 of 23 circuits for each portable handset using selector switches in the panel. The special group of receptacles may be connected to additional area using the selector switches. The central switching panel can interconnect 100 receptacles or groups of receptacles.

4. The portable system provides communications within a building between each portable radio unit. The coverage and radio signals are governed by building loss, free space loss, and extra coupling loss. The radio units operate at 153.56 MHz with 5 watt power. A separate coaxial antenna cable (RADIAX) that has been installed in the fire fighting areas of the entire plant. These antennas are connected to a transmitter/receiver base station at the main guardhouse. The RADIAX cable permits any portable radio to operate within 80 feet of it with sufficient signal level at the base station receiver, as well as the base station to the portable radio. Portable communication within the building would be heard at the guardhouse. Communications to the portable would be via the guardhouse base station to the RADIAX cable. No portable-to-portable communication is possible through the RADIAX Cable. However, portable-to-portable communication is possible within the building subject to the signal loss due to the building, free space, and extra coupling.

5. Communication with the Dispatch Center will be done using station telephone lines.

6. The private line P.A. between the control room and the refueling floor has a microphone on panel 905 in the control room. This allows the operator in the control room to communicate without using his hands which then are used to simultaneously operate control rod positioning.

7. A UHF (Ultra High Frequency) radio repeater system provides communications, via handheld radios, for the operators during implementation of the alternate shutdown procedure. Satellite receivers have been installed at the exterior side of the North Wall of the Reactor Building. The two receivers are connected to a radio transmitter located in the Guardhouse. A UHF directional antenna has been installed on the roof of the Guardhouse to direct a radio signal back towards the Reactor Building.

   The two satellite receivers and the transmitter are powered from the UPS (Uninterruptable Power Supply) system in the Guardhouse. The UPS system in the Guardhouse is not affected by the loss of offsite power.

   Two wall mounted handheld radio racks have been installed in the Switchgear Rooms to store the handheld radios required to be used during implementation of the alternate shutdown procedure.

   Each rack contains five handheld radios with an internal battery charger to keep the five radios at a full charge.

8. A wireless telephone system provides communication by way of a handheld telephone. This system consists of a central processing unit, a number of Repeater Base Stations located throughout the site, and hand held telephones which are programmed into the system. This system is operated on high frequency and low output, therefore, no safety related equipment is effected by the wireless communication system.

9. A network based wireless communication system using access point antennas and electronic network switches connected via fiber and Category 5E cables, provides communication capabilities to process buildings throughout the plant. In addition to numerous other areas, this system provides direct communication between the refuel bridge and the control room.

10.15.4 Inspection and Testing

The design of the system permits routine surveillance and testing without disrupting normal communication facilities.

SECTION 11

POWER CONVERSION SYSTEMS

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Sodium hypochlorite solution is applied to each circulating pump bay alternately at an applied maximum dosage of 0.10 ppm for approximately 1 hr/day for control of slime growth and fouling organisms in the intake bays and circulating water piping systems. Approximately 10% sodium hypochlorite solution from a 14,000 gal storage tank will be metered through two 0-5 gpm Hypochlorination pumps, one operating and one standby. Water from the screen wash pump discharge header is used as dilution water to increase the volume of solution and therefore, the velocity of the solution leading and better mixing in the intake bay diffusers. The diluted hypochlorite solution enters the intake bay diffusers located downstream of the trash racks.

Two separate pumped hypochlorite systems of 0-5 gal/hr capacity provide a direct, metered, hypochlorite solution feed to either service water pump bay inlet at an applied chlorine dosage up to a maximum of 0.25 ppm as an alternative service water continuous chlorination system. This system has three 0-5 gpm pumps, two normally running and one on standby. Hypochlorination systems for the service water system operate continuously.

The maximum allowable discharge limit is 0.1 ppm for total residual clorine (TRC) to Cape Cod Bay as allowed by the NPDES Federal Permit No. MA 0003557 (State Permit No. 359) Section A.2.a.

The purpose of the Dechlorination System is to dechlorinate the Screen Wash Water so that chlorine does not impact the marine life when washing the screens.

The Dechlorination System consists of Sodium Thiosulphate reservoirs (dechlorination liquid), two dechlorination pumps and an event recorder. This equipment interfaces with the 4 traveling screens and the 2 screen wash pumps. The Sodium Thiosulphate is pumped from the dechlorination pumps to the suction side of the screenwash pumps. The dechlorination pumps are electronically interlocked with the screenwash pumps so that they run anytime the corresponding screen wash pump is running if the control switch is left in the automatic position.

The event recorder records the start/stop history of the 4 traveling screens, the 2 dechlorination pumps and the 2 screen wash pumps. This record provides proof that the screen wash water was properly dechlorinated for each screen wash in keeping with the requirements of NPDES Permit No. MA 0003557.

11.8 CONDENSATE AND FEEDWATER SYSTEM

11.8.1 Power Generation Objective

The objective of the Condensate and Feedwater System is to provide a dependable supply of feedwater to the reactor, to provide feedwater heating, and to maintain high quality feedwater.

11.8.2 Power Generation Design Basis

1. Provide the required flow to the reactor with sufficient margin to continue to provide flow under anticipated transient conditions.

2. Provide the required feedwater temperature to the reactor.

3. Provide a startup recirculation line from the reactor feed pump discharge lines to the condenser hotwell for the purpose of minimizing corrosion product input to the reactor during startup conditions.

11.8.3 Description

Three one-third capacity, motor-driven, condensate pumps take the condensate from the condenser hotwells and pump it through the air ejector condensers, gland seal condenser, and condensate demineralizers. Demineralizer effluent is then split into two parallel streams, each with three low-pressure and two high-pressure stages of feedwater heaters. Common bypass lines around the low-pressure and high-pressure feedwater heaters are provided. The bypass line around the high-pressure feedwater heaters is currently unavailable due to a modification to eliminate unintended bypass flow resulting from leakage of the bypass control valve.

Three one-third capacity, motor-driven, reactor feed pumps are installed in the heat cycle between the low-pressure and high-pressure heaters. See Figure 11.8-1 (Drawing M207).

A bypass loop of approximately 50 to 120 gal/min is installed from the feed pump discharge header to the feed pump suction header. A zinc dissolution column in the loop is used to maintain approximately 5-10 parts per billion zinc in the reactor coolant in order to control drywell dose rate build-up. This loop is periodically taken out of service for maintenance.

11.8.3.1 Condensate Pumps

Each condensate pump is a nine stage vertical, canned suction type, centrifugal pump. The pumps are installed at an elevation that permits full capacity operation at any level in the condenserhotwell, including extreme low level. The pumps provide the maximum design flow, plus design margins at the required pressure including static head, friction loss, and suction head of the reactor feed pumps. The pumps are rated at 6,550 gal/min and 1,030 ft. total head at 1,180 rpm when pumping 91.7F condensate. The motors are rated each 2,000 Hp, 1.15 S.F., 1,180 rpm,

4,000 V, 3-phase, 60 Hz, and are induction, open drip proof units with solid vertical shaft.

11.8.3.2 Feedwater Heaters

The lowest pressure (fifth point) heaters for both trains are straight tube; two pass units with external drain coolers. Both fourth point heaters and both third point heaters are U tube type with integral drain coolers.

The high pressure heaters are U tube type units with integral condensing and drain cooling sections.

The fourth point heaters of both trains and the third point heater of train B have stainless steel tubes roller expanded into the tube sheet. All other heaters, low and high pressure have stainless steel tubes welded to the tube sheet.

11.8.3.3 Reactor Feed Pumps

Each reactor feed pump is a three stage, horizontal, centrifugal pumps. The pumps operate in series with the condensate pumps and provide the maximum design flow plus design margins at the required pressure at the reactor inlet nozzles. The pumps are rated at 6,550 gal/min and 2,620 ft total head at 3,570 rpm when pumping 291.1°F water. The motors are rated each 5,000 Hp and are induction, open drip proof units. The Feedwater Control System is described in Section 7.

11.8.4 Power Generation Evaluation

An abnormal operational transient analysis is made for a loss of feedwater heater and is included in Section 14, Station Safety Analysis.

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12.4.4 Required Materials

The Licensee is authorized to receive, possess, use, and transfer materials as required for operation of the facility by License No. DPR-35.

12.4.5 Offsite Materials Safety Program

All radioactive materials fixed or contained within reactor system components and shipped to temporary field locations such as vendor facilities will remain in the custody of PNPS, and will be under direct supervision of a qualified PNPS representative normally on the Radiation Protection staff.

Radiation protection activities shall be conducted at the temporary field locations in order to assure that all Pilgrim radioactive reactor components are appropriately packaged, surveyed, and labeled in accordance with applicable NRC/Massachusetts DOT regulations and PNPS radiation protection procedures.

PNPS shall assume responsibility for all radiation protection activities incident to inspection, repair, and testing of Pilgrim equipment containing radioactive material while such equipment is at temporary field locations. These activities shall be conducted in accordance with the requirements of 105 CMR 120, Massachusetts Regulations for the Control of Radiation, at temporary field locations within the borders of Massachusetts, or the requirements of 10 CFR 20, Standards for Protection Against Radiation for temporary field locations outside the borders of Massachusetts but within the borders of the continental United States, as applicable. Radiation monitoring instrumentation and personnel monitoring devices such as those used at Pilgrim Station will be utilized at the offsite location.

The maximum total activity of mixed corrosion products contained within and/or fixed upon the surface of the reactor system components shipped to temporary field locations within the borders of Massachusetts or temporary field locations outside the borders of Massachusetts but within the borders of the continental United States, provided that the state has a reciprocity agreement with Massachusetts shall be limited to the values indicated in Massachusetts Materials License No. 07-6262.

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TABLE A.1-1

TANKS AND HEAT EXCHANGERS - CODES AND SPECIFICATIONS

System	Component	Code	Material Specification
Liquid Radwaste Systems Figures 9.2-3, 9.2-4	T-301 A & B Clean Waste Receiver Tank	API-650	ASTM A-283 Gr. C
	T-304 A & B Treated Water Holdup Tank	API-650	ASTM A-283 Gr. C
	T-312 A & B Chemical Waste Receiver Tank	API-650	ASTM A-283 Gr. C
	T-311 A, B, C Monitor Tank	API-650	ASTM A-283 Gr. C
Solids Recovery System Figure 9.3-1	T-308 Spent Resin Storage Tank	ASME Code Section III Class C	SA-240 Type 304 SS
	T-306 Misc. Waste Tank	API-650	ASTM A-283 Gr. C
	T-307 A & B Sludge Storage Tanks	API-650	SA-240 Type 304 SS
	T-318 Floc Recycle Tank	API-650	SA-240 Type 304 SS
Reactor Building Cooling Water System Figure 10.5-1	HX-E-209 A & B RBCCW Heat Exchanger	ASME Code Section VIII TEMA Class C	Shell: SA-515-70 Tube/Tubesheet: SB-111/SB-171 Channels: SB-402 Nozzles: SA-181-11, SB-402 SA-10
	HX-E-206 A & B Fuel Pool Heat Exchanger	ASME Code Section VIII TEMA Class C	Shell: SA-106B Tube/Tubesheet: SA-249-T304/SA-249-T304L
	T-211 A & B Head Tank	API-650	ASTM A-283 Gr. B
	T-201 A & B Head Tank	API-650	ASTM A-283 Gr. B

TABLE A.1-1

TANKS AND HEAT EXCHANGERS - CODES AND SPECIFICATIONS

System	Component	Code	Material Specification
Turbine Building Cooling Water System Figure 10.6-1	HX-E 122 A & B TBCCW Heat Exchanger	ASME Code Section VII TEMA Class C	Shell: SA-285C Tube/Tubesheet: SB-111/SB-171 Channel: SB-402 Heads: SA-515-70 Nozzles: SA-181-11
	T-104 Head Tank	API-650	A-283 Gr. B
Condensate and Demineralized Water Storage and Transfer System Figure 11.9-1	T-105 A & B Condensate Storage Tank	API-650	A-131C: A-36
	T-108 Demineralized Water Storage	API-650	A-36
Diesel Fuel Oil Storage and Transfer System figure 8.5-1	T-126 A & B Oil Storage Tank	API-650	A-131-C
	T-124 A & B Day Tank	Commercial Standards	A-285-C
SEP Diesel Fuel Oil Storage	T160 A & B Primary and Secondary Oil Storage Tanks	ASTM D4021-81; UL MH 9061 & MH 9061 9; MFPA Sections 30 & 31; Factory Mutual Systems Approval IM7A0AF	FRP

APPENDIX B

TECHNICAL SPECIFICATIONS

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FUNCTIONAL REQUIREMENTS FOR SRV/SSV TEMPERATURE MONITORING

3.6 PRIMARY SYSTEM BOUNDARY

D. Safety/ Relief Valves Temperature Monitoring

1. If the discharge pipe temperature of any safety relief valve (SRV) measured at 4.5 to 6 feet exceeds ambient temperature by 30°F during normal reactor power operation for a period of greater than 24 hours, an engineering evaluation shall be performed justifying continued operation for the corresponding SRV temperature increases.

2. Any SRV whose discharge pipe temperature measured under Section 3.6.D.1 exceeds ambient temperature by 30°F for 24 hours or more shall be removed at the next cold shutdown of 72 hours or more, tested in the as-found condition, and recalibrated as necessary prior to reinstallation.

3. Whenever SRVs are required to be operable, at least one of the dual thermocouples at each of the following locations shall be functional.

   a. Bellows monitoring temperature

   b. The discharge pipe temperature monitoring (Thermocouple 4.5 to 6 feet down stream from discharge point)

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY

D. Safety/ Relief Valves Temperature Monitoring

1. Whenever the safety relief valves are required to be operable, the safety relief valve discharge pipe temperature of each safety relief valve shall be logged daily.

2. Whenever the safety relief valves are required to be operable, the bellows thermocouple temperature of each safety relief valve shall be logged daily.

3. Instrumentation shall be calibrated and checked once per cycle during refueling outage.

4. First Stage Thermocouple, Second Stage Thermocouple, and safety relief valve discharge thermocouple located 16 to 22 feet down stream from discharge may be used to collect information for an engineering evaluation justifying continued plant operation for the corresponding temperature increases.

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STRUCTURAL LOADING CRITERIA

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C.3 COMPONENTS

C.3.1 INTENT AND SCOPE

C.3.1.1 Components Designed by Rational Stress Analysis

These general design criteria are intended to apply to those ductile metallic structures or components which are normally designed using rational stress analysis techniques such as pressure vessels, reactor internal components, etc. The criteria may also be applied to those components or structures whose ultimate loading capability is determined by tests. These criteria are intended to supplement applicable industry design codes where necessary. Compliance with these criteria is intended to provide design safety margins which are appropriate to extremely reliable structural components when account is taken of rare event potentialities which might be associated with a Safe Shutdown Earthquake or primary pressure boundary coolant pipe rupture, or a combination of events.

C.3.1.2 Components Designed Primarily by Empirical Methods

There are many important Class I components or equipment which are not normally designed or sized directly by stress analysis techniques. Simple stress analyses are sometimes used to augment the design of these components, but the primary design work does not depend upon detailed stress analysis. These components are usually designed by tests and empirical experience. Complete detailed stress analysis is currently not meaningful nor practical for these components. Examples of such components are valves, pumps, electrical equipment and mechanisms. Field experience and testing are used to support the design. Where the structural or mechanical integrity of components is essential to safety, the components referred to in these criteria must be designed to accommodate the events of the Safe Shutdown or Operating Basis Earthquake, or a design basis pipe rupture, or a combination where appropriate. The reliability requirements of such components cannot be quantitatively described in a general criterion because of the varied nature of each component and its specific function in the system.

Class I seismic criteria were applied in the design of Class I piping inside the Diesel Generator Fuel Oil Storage tanks. However, seismic calculations were not performed for tanks because they are essentially as qualified as the ground they are buried in.

C.3.2 Loading Conditions and Allowable Limits

The loading conditions established herein are expressed in generic terms and are related in a probabilistic manner to the loads which are to be investigated for safety considerations. Related probabilistic definitions are used to determine an appropriate minimum safety factor which is used to establish structural design allowable limits and functional design allowable limits. Certain of the limits described in these criteria, i.e., deformation limit, and fatigue limit, are included for completeness, but do not necessarily require application to all components. Where it is clear to the designer that fatigue or excess deformation are not of concern for a particular structure or component, a formal analysis with respect to that limit is not required.

C.3.2.1 Loading Conditions

The loading conditions may be divided into four categories; normal, upset, emergency, and faulted conditions. These categories are generically described.

Normal Conditions

Any condition in the course of operation of the station under planned and anticipated conditions, in the absence of upset, emergency, or faulted conditions.

Upset Conditions

Any deviations from normal conditions anticipated to occur often enough that design should include a capability to withstand these conditions. The upset conditions include abnormal operational transients caused by a fault in a system component requiring its isolation from the system, transients due to loss of load or power, and any system upset not resulting in a forced outage. The upset conditions may include the effect of the Operating Basis Earthquake.

Emergency Conditions

Any deviations from normal conditions which require shutdown for correction of the conditions or repair of damage in the system. The conditions have a low probability of occurrence but are included to provide assurance that no gross loss of structural integrity will result as a concomitant effect of specific damage developed in the system.

Faulted Conditions

Those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the nuclear system may be impaired to the extent where considerations of public health and safety are involved. Such considerations require compliance with safety criteria.

C.3.2.2 Allowable Limits

In addition to the generic definition of loading conditions in the preceding paragraphs, the meaning of those terms is expanded in quantitative probabilistic language. The purpose of this expansion is to clarify the classification of any hypothesized accident or sequence of loading events so that the appropriate limits or safety margins are applied. Knowledge of the event probability is necessary to establish meaningful and adequate safety factors for design. Table C.3-1 illustrates the quantitative event classifications.

These probabilities have been assigned to establish the appropriate structural design limits for the loading conditions in Section C.3.2.1. A summary of these limits is shown in the tables listed below:

Deformation Limit	Table C.3-2
Primary Stress Limit	Table C.3-3
Buckling Stability Limit	Table C.3-4
Fatigue Limit	Table C.3-5

There are many places where, through the exercise of designer judgment, it is unnecessary to actually carry out a formal analysis for each of these limits. A simple example consists of the case where two pieces of pipe of differing wall thickness are joined at a butt weld. If they are both subjected to the same loading, only the thinner piece would require a formal analysis to demonstrate that the primary stress limit has been satisfied.

The term SF min is defined as the minimum safety factor on load or deflection and is related to the event probability by the following equation:

$$SF\ min = \frac{9}{3 - \log 10\ P_{60}}$$

where:

$$10^{-1} > P_{60} \geq 10^{-5}$$

For event probabilities smaller than 10-5 or greater than 10-1 the following apply:

$$10^{-5} > P_{60} \geq 10^{-6}\ (SFmin = 1.125)$$
$$1.0 > P_{60} \geq 10^{-1}\ (SFmin = 2.25)$$

These expressions show the probabilistic significance of the classical safety factor concept as applied to reactor safety. The SF min values corresponding to the event probabilities are summarized on Table C.3-6.

The loadings which occur as a result of the conditions listed are factored into the design of the components in accordance with the requirements of the applicable design code, or to the requirements of these criteria. Where permitted by the applicable code and by these criteria, the SF min may be progressively lowered to a minimum acceptable level on the basis that there is a lesser need for design margin for loading conditions which have a diminishing probability of occurrence.

C.3.3 Method of Analysis

C.3.3.1 Piping Systems

Where appropriate, the piping systems were dynamically analyzed using the "response spectrum method" of analysis. For each of the piping systems, a mathematical model consisting of lumped masses at discrete joints connected together by weightless elastic elements was constructed. Valves were also considered as lumped masses in the pipe, and valve operators as lumped masses acting

through the operator center of gravity. Where practical, a support is located on the pipe at or near each valve. Stiffness matrix and mass matrix were generated and natural periods of vibration and corresponding mode shapes were determined. The acceleration response spectra was used as input to the dynamic analysis for the piping anchors. The increased flexibility of the curved segments of the piping systems was also considered. The results for earthquakes acting in the x and y (vertical) directions simultaneously, and z and y directions simultaneously were computed separately. Maximum joint displacements, member forces and support reactions were determined by a square root of the sum of the square combination of each of these parameters for each mode and for each set of earthquake directions. For the replacement recirculation, RHR, and RWCU piping the inputs to the dynamic analyses were the 2.0 percent damped Operating Basis Earthquake acceleration response spectra and the 3.0 percent damped Safe Shutdown Earthquake acceleration response spectra for the piping supports. Colinear responses due to the orthogonal components for the simultaneous application of the three spatial directions of the seismic excitation were combined by the square root sum of the squares (SRSS) method. Modal responses were combined using the double sum or grouping method which includes the effects due to closely spaced modes. The member forces thus obtained were combined with the member forces produced by other loading conditions to compute the stresses. Analysis and allowable stress limits are in accordance with USAS B 31.1.0, Appendix A, or Appendix C, replacements are in accordance with the appropriate provisions of ASME, Section XI.

C.3.3.2 Equipment

The equipment was analyzed to determine equipment adequacy for earthquake loading. The equivalent static coefficients for the equipment were obtained from the amplified floor response spectra corresponding to the support elevations of the equipment. In lieu of determining the natural frequency of the equipment, the peak value of the applicable floor response spectrum was used in calculating the earthquake induced loads. Alternately, the natural frequency of the equipment was determined and corresponding input acceleration was obtained from the appropriate amplified floor response spectra. For the replacement piping valves and pumps the static coefficient method was not used. Instead, the equipment was analyzed as part of the piping system.

The extent of stress analyses performed on equipment due to seismic forces is dependent upon the type of equipment and the type of fabrication. Fabricated shapes are generally made from plate or rolled shapes with uniform thickness and shapes with regular geometric configurations. These can be more readily analyzed by rational means. Included in this category are tanks, certain parts of heat exchangers, etc. Cast shapes are generally made with non-uniform material thickness in complicated shapes that are not regular geometric configurations. Manufacturers have traditionally designed cast shapes conservatively since these do

not lend themselves to rational analysis. This conservatism has been demonstrated by extensive test and experience. Included in this category are pumps, valves, etc.

C.3.4 Implementation of Criteria

C.3.4.1 Reactor Vessel

Criteria

The reactor vessel has been designed, fabricated, inspected, and tested in accordance with the ASME Boiler and Pressure Vessel Code, Section III, its interpretations, and applicable requirements for Class A vessels as defined therein, as of the date that the reactor vessel order was placed.

Stress analysis requirements and load combinations for the reactor vessel have been evaluated for the primary loading and cyclic conditions expected throughout the vessel life, with the conclusion that ASME code limits are satisfied.

Primary Stress

Selected components, considered to possibly have high primary stresses as a result of rare events or a combination of rare events, have been analyzed in accordance with the requirements of the loading criteria in this appendix. Results of the most critical of those analyses are included on Table C.3-7. The conclusion is that the limits in the criteria have been met.

Vessel Fatigue Analysis

An analysis of the reactor vessel shows that all components are adequate for cyclic operation by the rules of Section III of the ASME Code. Operating cycles are specified on reactor thermal cycle Figure C.3-1 and nozzle thermal cycle Figures C.3-2 through C.3-8. Additional transient events based on operating experience and not on thermal cycle figures were also considered. The results given on Table C.3-8 indicate that the primary plus secondary stress intensity range is less than 3S for the more critical pressure boundary components on the vessel. A plastic analysis is, however, applied to two components. Also, the usage factors including Environmental Fatigue for the specified operating cycles is substantially less than the code allowed 1.0 for 60 years of operation.

C.3.4.2 Reactor Vessel Internals

Criteria

Although not mandatory, the design of the reactor vessel internals is in accordance with the intent of Section III of the ASME Boiler and Pressure Vessel Code. The material used for fabrication of most of the materials is solution heat treated, unstabilized type 304 austenitic stainless steel conforming to ASTM specifications. Allowable stresses for the internals materials under normal operating conditions are taken directly from Section III.

For rare events or a combination of rare events, the internals have been analyzed in accordance with the requirements of the loading criteria in this appendix, and results of the most critical of those analyses are included on Table C.3-8. The conclusion is that the limits in the criteria have been met.

In RFO #10 a reactor shroud repair was implemented as described in Section 3.3.4.1.1. The shroud stabilizer design meets the structural criteria as described in Section 3.3 and with primary stress limits as specified in Table C.3-3 as a minimum. Seismic analysis was performed in accordance with the methods described in Sections 3.3.6.9 and 12.2. IN addition, as a design guide, the 1989 ASME Code Section III, Subsections NB "Class 1 Components" and NG "Core Support Structures" were used.

Together, the shroud stabilizer tie rod, upper support bracket, and lower spring form the load path from the shroud top edge down to the shroud support plate gusset. Stress limits for these components are based on the ASME Code Subsection NG limits for threaded structural fasteners. These limits ensure that material yielding (permanent deformation) will not occur for all normal and upset conditions so that fastener preload is maintained and no uplift of the shroud head or separation of existing cracks will occur.

The threaded structural fastener limits were also applied to shroud stresses that are within the load path affecting the tie rod preload. This effectively prevents yielding within the shroud that would cause the tie roads to lose their preload as a result of normal or upset conditions. The limiting upset event is the loss of feedwater pumps with HPCI/RCIC injection. This event creates the greatest differential expansion between the shroud and the tie rod assembly.

Internals Deformation Analysis

Control Rod System

If there were excessive deformation of the control rod system, made up of the control rod drive, control rod drive housing, control rod, control rod guide tube and fuel channels, and the core structural elements which support them (top guide, core support, and shroud and shroud support) it could possibly impede control rod insertion. The maximum loading condition that would tend to deform these long, slender components is the Safe Shutdown Earthquake. Analyses of the internal components which have the highest calculated stresses are included in a following section. The highest calculated stresses occur where the Safe Shutdown Earthquake and loads resulting from the Design Basis Accident (DBA) line break are considered to occur simultaneously. Even in these cases, the general stress levels are relatively low. No significant deformation is associated with these calculated stresses; therefore, rod insertion would not be impeded even after an assumed simultaneous Safe Shutdown Earthquake and line break accident.

Core Support

The core support sustains the pressure drop across the core support plate and the fuel. This pressure drop is the only load which causes significant deflection of the core plate. Excessive core support deflection could lift the control rod guide tubes off their seats on the control rod drive housings and thereby increase core bypass leakage. This upward deflection would have to be 1/2 in to begin to lift guide tubes. The maximum deflection under normal operation conditions for the Pilgrim core support is calculated to be 0.053 in. Under pipe rupture differential pressures the deflection is calculated to be 0.080 in. The guide tubes will not be lifted off, although even if they were, this would not be of concern because bypass leakage at this time is not important.

Fatigue Analysis

A fatigue analysis was performed using as a guide the ASME Boiler and Pressure Vessel Code, Section III. The method of analysis used to determine the cumulative fatigue usage is described in APED-5460, Design and Performance of GE-BWR Jet Pumps, September 1968. The most significant fatigue loading occurs in the jet pump-shroud-shroud support area of the internals. The analysis was performed for a plant where the configuration (gusset type shroud support) was almost identical to the Pilgrim station. Therefore, the calculated fatigue usage is expected to be a reasonable approximation for this station.

Loading Combinations and Transients Considered

1. Normal start up and shutdown

2. Operating Basis and Safe Shutdown Earthquakes

3. Ten minute blowdown from a stuck relief valve

4. HPCI operation

5. LPCI operation (DBA)

6. Improper start of a recirculation loop

Cumulative Fatigue Usage

$U_{allowable} = 1.0$

$U_{calculated} = 0.65$

The location of maximum fatigue usage is at the inside diameter of the jet pump diffuser adapter, at the thin end of the tapered transition section.

C.3.5 Miscellaneous Components

Test results and analyses of miscellaneous components are shown on Table C.3-9.

TABLE C.3-1

LOADING CONDITION PROBABILITIES

	P_{60} = 60 yr event encounter probability			
Upset (likely)	$1.0 >$	P_{60}	$\geq$	10^{-1}
Emergency (low probability)	$10^{-1} >$	P_{60}	$\geq$	10^{-1}
Faulted (extremely low probability)	$10^{-3} >$	P_{60}	$\geq$	10^{-6}

TABLE C.3-2

DEFORMATION LIMIT

Either One of (Not Both)	General Limit
a. $\dfrac{\text{Permissible Deformation, DP}}{\text{Analyzed Deformation Causing Loss of Function, DL}}$	$\leq \dfrac{0.9}{\text{SF min}}$
b. $\dfrac{\text{Permissible Deformation, DP}}{\text{Experimental Deformation Causing Loss of Function, DE}}$	$\leq \dfrac{1.0}{\text{SF min}}$

where

DP = Permissible deformation under stated conditions of normal, upset, emergency or fault

DL = Analyzed deformation which would cause a system loss of function[(1)]

DE = Experimentally determined deformation which would cause a system loss of function[(1)]

(1) Loss of Function can only be defined quite generally until attention is focused on the component of interest. In cases of interest, where deformation limits can affect the function of equipment and components, they will be specifically delineated. From a practical viewpoint, it is convenient to interchange, with the loss of function condition, some deformation condition at which function is assured if the required safety margins from the functioning condition can be achieved. Therefore, it is often unnecessary to determine the actual loss of function condition because this interchange procedure produces conservative and safe designs. Examples where deformation limits apply are: control rod drive alignment and clearances for proper insertion, core support deformation causing fuel disarrangement or excess leakage of any component.

TABLE C.3-3

PRIMARY STRESS LIMIT

Any One of (No More than One Required)		General Limit
a.	$\frac{\text{Elastic Evaluated Primary Stresses, PE}}{\text{Permissible Primary Stresses, PN}}$	$\leq \frac{2.25}{SF_{min}}$
b.	$\frac{\text{Permissible Load, LP}}{\text{Largest Lower Bound Limit Load, CL}}$	$\leq \frac{1.5}{SF_{min}}$
c.	$\frac{\text{Elastic Evaluated Primary Stress, PE}}{\text{Conventional Ultimate Strength at Temperature, US}}$	$\leq \frac{0.75}{SF_{min}}$
d.	$\frac{\text{Elastic Plastic Evaluated Nominal Primary Stress, EP}}{\text{Conventional Ultimate Strength at Temperature, US}}$	$\leq \frac{0.9}{SF_{min}}$
e.	$\frac{\text{Permissible Load, LP}}{\text{Plastic Instability Load, PL}}$	$\leq \frac{0.9}{SF_{min}}$
f.	$\frac{\text{Permissible Load, LP}}{\text{Ultimate Load from Fracture Analysis, UF}}$	$\leq \frac{0.9}{SF_{min}}$
g.	$\frac{\text{Permissible Load, LP}}{\text{Ultimate Load or Loss of Function Load from Test, LE}}$	$\leq \frac{1.0}{SF_{min}}$

TABLE C.3-3 (Cont)

Where:

PE= Primary stresses evaluated on the elastic basis. The effective membrane stresses are to be averaged through the load carrying section of interest. The simplest average bending, shear or torsion stress distribution which will support the external loading will be added to the membrane stresses at the section of interest.

PN= Permissible primary stress levels under normal or upset conditions under applicable industry code.

LP= Permissible load under stated conditions of emergency or fault.

CL= Lower bound limit load with yield point equal to $1.5S_M$' where S_M is the tabulated value of allowable stress at temperature as contained in the ASME III code or its equivalent. The lower bound limit load is here defined as that produced from the analysis of an ideally plastic (non-strain hardening) material where deformations increase with no further increase in applied load. The lower bound load is one in which the material everywhere satisfied equilibrium and nowhere exceeds the defined material yield strength using either a shear theory or a strain energy of distortion theory to relate multiaxial yielding to the uniaxial case.

US= Conventional ultimate strength at temperature or loading which would cause a system malfunction, whichever is more limiting.

EP= Elastic plastic evaluated nominal primary stress. Strain hardening of the material may be used for the actual monotonic stress strain curve at the temperature of loading or any approximation to the actual stress strain curve which everywhere has a lower stress for the same strain as the actual monotonic curve may be used. Either the shear or strain energy of distortion flow rule may be used.

PL= Plastic instability load. The plastic instability load is defined here as the load at which any load bearing section begins to diminish its cross sectional area at a faster rate than the strain hardening can accommodate the loss in area. This type analysis requires a true stress true strain curve or a close approximation based on monotonic loading at the temperature of loading.

TABLE C.3-3 (Cont)

UF= Ultimate load from fracture analyses. For components which involve sharp discontinuities (local theoretical stress concentration > 3) the use of a fracture mechanics analysis where applicable, utilizing measurements of plane strain fracture toughness may be applied to compute fracture loads. Correction for finite plastic zones and thickness effects as well as gross yielding may be necessary. The methods of linear elastic stress analysis may be used in the fracture analysis where its use is clearly conservative or supported by experimental evidence. Examples where fracture mechanics may be applied are for fillet welds or end of fatigue life crack propagation.

LE= Ultimate load or loss of function load as determined from experiment. In using this method, account shall be taken of the dimensional tolerances which may exist between the actual part and the tested part or parts as well as differences which may exist in the ultimate tensile strength of the actual part and the tested parts. The guide to be used in each of these areas is that the experimentally determined load shall use adjusted values to account for material properties and dimension variations, each of which has no greater probability than 0.1 of being exceeded in the actual part.

TABLE C.3-4

BUCKLING STABILITY LIMIT

	Any One of (No More than One Required)	General Limit
a.	$\frac{\text{Permissible Load, LP}}{\text{Code Normal Event Permissible Load, PN}}$	$\leq \frac{2.25}{\text{SF min}}$
b.	$\frac{\text{Permissible Load, LP}}{\text{Stability Analysis Load, SL}}$	$\leq \frac{0.674}{\text{SF min}}$
c.	$\frac{\text{Permissible load, LP}}{\text{Ultimate Buckling Collapse Load from Test, SE}}$	$\leq \frac{1.0}{\text{SF min}}$

where:

LP= Permissible load under stated conditions of normal, upset, emergency, or fault.

PN= Applicable code normal event permissible load.

SL= Stability analysis load. The ideal buckling analysis is often sensitive to otherwise minor deviations from ideal geometry and boundary conditions. These affects shall be accounted for in the analysis of the buckling stability loads. Examples of this are ovality in externally pressurized shells or eccentricity of column members.

SE= Ultimate buckling collapse load as determined from experiment. In using this method, account shall be taken of the dimensional tolerances which may exist between the actual part and the tested part. The guide to be used in each of these areas is that the experimentally determined load shall be adjusted to account for material property and dimension variations, each of which has no greater probability than 0.1 of being exceeded in the actual part.

TABLE C.3-5

FATIGUE LIMIT

		General Limit
Summation of mean fatigue (1) damage usage including emergency or fault events with design and operation loads following Miner's hypotheses. either one (not both)	a. Fatigue cycle usage from analysis	≤.056[2]
	b. Fatigue cycle usage from test	≤0.33

NOTES:

1. Fatigue failure is defined here as a 25% area reduction for a load carrying member which is required to function or excess leakage causing loss of function, whichever is more limiting. In the fatigue evaluation, the methods of linear elastic stress analysis may be used when the 3S range limit of ASME III has been met. If 3S is not met, account will be taken of (a) increases in local strain concentration, (b) strain ratcheting, (c) re-distribution of strain due to elastic plastic effects. The January, 1969 draft of the USAS B31.7 Piping Code may be used where applicable or detailed elastic plastic methods may be used. With elastic plastic methods, strain hardening may be used not to exceed in stress for the same strain, the steady state cyclic strain hardening measured in a smooth low cycle fatigue specimen at the average temperature of interest.

2. It is acceptable to use the ASME Section III Design Fatigue curves in conjunction with a cumulative usage factor of 1.0 (using Miner's Hypothesis) in lieu of using the mean fatigue data curves with a limit on fatigue usage of 0.05, since the two methods are approximately equivalent.

TABLE C.3-6

MINIMUM SAFETY FACTOR

Loading Conditions	Loads	P_{60}	SF_{min}
Upset 10^{-1}	N and A_D	10^{-1}	2.25
	or N and U	10^{-1}	2.25
Emergency	N and R	10^{-3}	1.5
	N and A_M	10^{-3}	1.5
	Other combinations in this probability range	$<10^{-3}$ to 10^{-3}	<2.25 to 1.5
Fault	N and A and R	$1.5 X 10^{-6}$	1.125
	Other combinations in this probability range	$<10^{-3}$ to 10^{-6}	<1.5 to 1.125

where

N = Normal loads
U = Upset loads (result in maximum system pressure)
A_D = Operating basis Earthquake
A_M = Safe Shutdown Earthquake

R = Loads resulting from jet forces and pressure and temperature transients associated with rupture of a single pipe within the primary containment. This load is considered as indicated in the tables.

The minimum safety factor decreases as the event probability diminishes and if the event is too improbable (incredible: $P_{60}<10^{-6}$) then no safety factor is appropriate or required.

TABLE C.3-7

REACTOR VESSEL INTERNALS AND ASSOCIATED EQUIPMENT

Criteria	Loading	Primary Stress Type	Results: Allowable Stress	Results: Calculated Stress
		STABILIZER BRACKET AND ADJACENT SHELL		
Primary Stress Limit ASME Boiler and Pressure Vessel Code Sect. III defines shear stress limit for SA 302-Gr. B bracket and A-533 Gr. B, Cl.1 shell S_M =26.7 Ksi	Normal and upset condition loads	Pure shear	16.00 Ksi	15.68 Ksi
For normal and upset condition shear stress limit=0.6S_M =16.00 Ksi	1. Operating Basis Earthquake emergency condition load	Pure shear	24.00 Ksi	20.07 Ksi
For emergency condition shear stress limit=1.5x16.00=24.00 Ksi	1. Safe Shutdown Earthquake faulted condition loads	Pure shear	32.00 Ksi	22.04 Ksi
For faulted condition shear stress limit=2.0x16.00=32.00 Ksi	1. Safe Shutdown Earthquake 2. Jet reaction forces			
		VESSEL SUPPORT SKIRT		
Primary Stress Limit ASME Boiler and Pressure Vessel Code, Sect.III, defines stress limit for SA 516 Gr. 70 material	Normal and upset condition loads 1. Dead weight 2. Operating Basis Earthquake	General membrane	19.10 Ksi	6.23 Ksi
For normal and upset condition S_M =19.10 Ksi	Emergency condition loads 1. Dead Weight 2. Safe Shutdown Earthquake	General membrane	28.65 Ksi	9.47 Ksi
For emergency condition S_{limit} =1.5S_M =1.5x19.10=28.65 Ksi	Faulted condition loads 1. Dead Weight 2. Safe shutdown Earthquake 3. Jet reaction forces	General membrane	38.20 Ksi	11.0 Ksi
For faulted condition S_{limit} =2.0S_M 2.0x19.10=38.2 Ksi				

TABLE C.3-7 (Cont)
REACTOR VESSEL INTERNALS AND ASSOCIATED

Criteria	Loading	Location	Results: Allowable Stress	Results: Calculated Stress
		RPV STABILIZER		
Primary Stress Limit AISC specification for the construction, fabrication, and erection of structural steel for buildings	Upset condition 1. Spring preload 2. Operating Basis Earthquake	Rod	81,600 psi	f_t =49,000 psi*
		Bracket	22,000 psi	f_b =14,300 psi
			14,000 psi	f_v =5,000 psi
For normal and upset conditions AISC allowable stresses, but without the usual increase for earthquake loads	Emergency condition 1. Spring preload 2. Safe Shutdown Earthquake	Bracket	33,000 psi	f_b =18,200 psi
			21,000 psi	f_v =6,300 psi
For emergency conditions 1.5xAISC allowable stresses	Faulted condition 1. Spring preload 2. Safe Shutdown Earthquake 3. Jet reaction load	Bracket	36,000 psi 21,500 psi	f_b =20,400 psi f_v =7,000 ps
For faulted conditions material yield strength		*The ratio calculated stress/allowable stresses limit is highest for upset loading conditions.		
		RPV SUPPORT (RING GIRDER)		
Primary Stress Limit AISC specification for the design, fabrication, and erection of structural steel for buildings	Normal and upset condition 1. Dead loads 2. Operating Basis Earthquake 3. Loads due to scram	Top flange Bottom flange vessel to girder bolts	27,000 psi 27,000 psi 60,000 ps	f_b =10,700 psi f_b =8,600 psi f_b =21,500 psi
For normal and upset conditions AISC allowable stresses, but without the usual increase for earthquake loads.			22,000 psi	f_b =4,500 psi
For faulted conditions 1.67xAISC allowable stresses for structural steel members yield strength for high strength bolts (vessel to ring girder)	Faulted condition 1. Dead loads 2. Safe Shutdown Earthquake 3. Jet reaction load	Top flange	45,000 psi	f_b =40,500 psi
		Bottom flange	45,000 psi	f_b =32,500 psi
		Vessel to girder bolts	125,000 psi 75,000 psi	f_t =79,500 psi f_v =10,000 psi

TABLE C.3-7 (Cont)
REACTOR VESSEL INTERNALS AND ASSOCIATED

Criteria	Loading	Location	Results: Allowable Stress	Results: Calculated Stress
		SHROUDS SUPPORT GUSSETS		
		Primary Stress Type	Allowable Stress Ksi	Calculated Stress Ksi
Primary Stress Limit ASME Boiler and Pressure Vessel Code, Sect. III defines allowable primary membrane stress plus bending for SB-168 material stress	Normal and Upset 1. Operating Basis Earthquake 2. Pressure drop across shroud (normal 3. Subtract dead weight	Local membrane plus bending	34.95 Ksi	22.7 Ksi
For normal and upset condition $S_A = 1.5 S_M = 1.5 \times 23.30 = 34.95$ Ksi	Emergency Condition Loads 1. Safe Shutdown Earthquake 2. Pressure drop across 3. Subtract dead weight	Local membrane plus bending	52.43 Ks	44.9 Ksi
For emergency condition $S_{limit} = 1.5 S_A = 1.5 \times 34.95 = 52.43$ Ksi	Faulted Condition Loads 1. Safe Shutdown Earthquake 2. Pressure drop across shroud during faulted condition 3. Subtract dead weight	Local membrane plus bending	69.90 Ksi	48.6 Ksi
For faulted condition $S_{limit} = 2.0 S_A = 34.95 = 34.95 = 69.90$ Ksi				
		TOP GUIDE-LONGEST BEAM		
Primary Stress Limit The allowable primary membrane stress plus bending stress is based on ASME Boiler and Pressure Vessel Code, Sect. III for type304 stainless steel plate.	Normal and Upset 1. Operating Basis Earthquake 2. Weight of structure 3. Weight of temporary control curtains	General membrane plus bending	24,000 psi	23,790 psi
For normal and upset condition Stress Intensity $S_A = 1.5 S_M = 1.5 \times 16{,}000$ psi - 24,000 psi	Emergency condition loads 1. Safe Shutdown Earthquake 2. Weight of structure 3. Weight of temporary control curtains	General membrane plus bending	36,000 psi	33,100 psi
For emergency condition(N+A) $S_{limit} = 1.5\ S_A 1.5 \times 24{,}000 = 36{,}000$ psi				
For faulted condition $S_{limit} = 2S_A = 2 \times 24{,}000 = 48{,}000$ psi	Faulted Condition Loads (same as emergency condition)	General membrane plus bending	48,000 psi	33,100 psi

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TABLE C.3-7 (Cont)
REACTOR VESSEL INTERNALS AND ASSOCIATED

Criteria	Loading	Location	Results	
			Allowable Stress	Calculated Stress
		TOP GUIDE-BEAM END CONNECTIONS		
Primary Stress Limit ASME Boiler and Pressure Vessel Code, Sect. III, defines material stress limit for type 304 stainless steel	Normal and Upset Condition Load 1. Operating Basis Earthquake 2. Weight of structure 3. Weight of temporary control curtains	Pure shear	9,600 psi	5,580 psi
	Emergency Condition Loads 1. Safe Shutdown Earthquake 2. Weight of structure 3. Weight of temporary control curtains	Pure shear	14,400 psi	8,800 psi
	Faulted Condition Loads (same as emergency condition)	Pure shear	19,200 psi	8,800 psi
		CORE PLATE STRUCTURE		
Primary Stress Limit The allowable primary membrane stress plus bending stress is based on ASME Boiler and Pressure Vessel Code, Sect. III for type 304 stainless steel plate.	Normal and Upset Condition Loads 1. Normal operation pressure drop 2. Operating Basis Earthquake	General membrane bending	24,000 psi	12,170 psi
For allowable stresses see top guide longest beam, above	Emergency Condition Loads 1. Normal operation pressure drop 2. Safe Shutdown Earthquake	General membrane plus bending	3,600psi	17,740 psi
	Faulted Condition Loads 1. Pressure drop after recirculation line rupture 2. Safe Shutdown Earthquake	General membrane plus bending	48,000 psi	23,140 psi
		CORE PLATE ALIGNERS		
Primary Stress Limit ASME Boiler and Pressure Vessel Code, Sect III, defines material stress limit for type 304stainless steel aligner pin	Normal and upset condition load 1. Operating Basis Earthquake	Pure shear	9,600 psi	0
For allowable shear stresses see top guide beam end connections, above	Emergency condition load1 1. Safe Shutdown Earthquake	Pure shear	14,400 psi	9,330 psi
	Faulted condition load 1. Safe Shutdown Earthquake	Pure shear	19,200 psi	9,330 psi

TABLE C.3-7 (Cont)
REACTOR VESSEL INTERNALS AND ASSOCIATED

Criteria	Loading	Location	Results: Allowable Moment (in.-lb)	Results: Calculated Moment (in.,-lb)
		FUEL CHANNELS		
Primary Stress Limit Allowable stress S_M for Zircaloy determined according to methods recommended by ASME Boiler and Pressure Vessel Code, Sect. III. Allowable moment determined by calculating limit moment using Table C-2, equation (b), then applying SF for emergency loads ($N+A_M$) S_M =9,270 psi $1.5S_M$ =13,900 psi Emergency Limit load= 1.5xNormal limit load calculated using 1.5 S_M = r yield	Emergency condition load Bending moment resulting from the Safe Shutdown Earthquake	Highest primary bending stress results from maximum moment at mid-span of the channel	42,350	18,900

TABLE C.3-7 (Cont)
REACTOR VESSEL INTERNALS AND ASSOCIATED

Criteria	Loading	Location	Results: Allowable Stress	Results: Calculated Stress
		CONTROL ROD DRIVE HOUSING		
Primary Stress Limit The allowable primary membrane stress is based on the ASME Boiler and Pressure Vessel Code, Sect III, for Class A vessels, for type 304 stainless steel For normal and upset conditions S =15,800 psi @575# °F	Normal and upset condition loads 1. Design Pressure 2. Stuck rod scram loads 3. Operating Basis Earthquake	Maximum membrane stress intensity occurs at the tube to tube weld near the center of the housing for normal, upset, and emergency conditions	15,800 psi	14,480 psi
For emergency conditions $(N+A_M)$ S_{limit}= 1.5S =1.5x15,800 = 23,700 psi	Emergency Condition Loads 1. Design pressure 2. Stuck rod scram loads 3. Safe Shutdown Earthquake		23,700 psi	22,030 psi
		CONTROL ROD DRIVE		
Primary Stress Limit The allowable primary membrane stress plus bending stress is based on ASME Boiler and Pressure Vessel Code, Sect. III for SA-212 TP316 tubing Stress intensity S_A=1.5S_M S_M@575BF=17,375 psi S_A=26,060 psi	Normal and upset condition loads. Maximum hydraulic pressure from the control rod drive supply pump **NOTE**: Accident conditions do not increase this loading. Earthquake loads are negligible.	Maximum stress intensity occurs at a point of the Y-Y axis of the indicator tube.	26,060 psi	20,790 psi
		CONTROL ROD GUIDE TUBE		
Primary Stress Limit The allowable primary membrane stress plus bending stress is based on the ASME Boiler and Pressure Vessel Code, Sect. III for type 304 stainless steel tubing. For normal and upset conditions S_M =15,800 psi @575#F S_A =1.5S_M For faulted condition S_{limit}=2.0S_A= 3.0x15,800=47,400 psi	Faulted Condition Loads 1. Dead weight 2. Pressure drop across guide tube due to failure of recirculation line 3. Safe Shutdown Earthquake	The maximum bending stress under faulted loading conditions occurs at the center of the guide tube	47,400 psi	7,535 psi

TABLE C.3-7 (Cont)
REACTOR VESSEL INTERNALS AND ASSOCIATED

Criteria	Loading	Location	Results: Allowable Stress	Results: Calculated Stress
		INCORE HOUSING		
Primary Stress Limit The allowable primary membrane stress is based on the ASME Boiler and Pressure Vessel Code, Sect. III, for Class A vessels for type 304 stainless steel Primary Stress Limit The allowable primary membrane stress plus bending stress is based on ASME boiler and Pressure Vessel Code, Sect. III for SA-212 TP316 tubing For normal and upset conditions S_M=15,800 psi @575°F For emergency condition $(N+A_M)$ S_{limit}=1.5 S_M=1.5 x15,800=23,700	Emergency condition load 1. Design Pressure 2. Safe Shutdown Earthquake	Maximum membrane stress intensity occurs at the outer surface the vessel penetration	23,700 psi	15,290 psi

TABLE C.3-8

RESULTS OF VESSEL FATIGUE AND STRESS ANALYSIS-
SUMMARY OF CRITICAL COMPONENTS

Component	Calculated	$3S_M$ Allowable	Usage Factor (1)(3)
Vessel Shell in Core Region	48.1	80.0	0.038
Closure Studs	77.9	129.9	0.01(4)
Closure Flanges	37.9	80.0	0.197
Bottom Head-Support Skirt Junction	71.9	80.0	0.391
Shroud Support	120.7(2)	69.3	0.242(2)
Feedwater Nozzle	77.0	80.0	0.506
Recirc. Inlet Nozzle Thermal Sleeve	63.0(2)	47.4	0.477(2)
CRD Housing to Stub Tube Junction	36.2	47.4	0.795

1. Based on ASME design fatigue curves.
2. These components were justified by a simplified elastic plastic analysis per N-417.6 because the primary plus secondary stress exceeded $3S_M$
3. Environmentally Assisted Fatigue Cumulative Usage Factor (CUF_{EN}) for 60 years, EC12412
4. The Studs do not come in contact with reactor coolant and there is no environmental fatigue component.

TABLE C.3-9

MISCELLANEOUS COMPONENTS

Criteria	Loading	Location	Results: Allowable Stress	Results: Calculated Stress
CRD HOUSING SUPPORT Primary Stress Limit AISC specification for the design, fabrication and erections of structural steel for buildings For normal and upset condition $F_a = 0.60\ F_y$ (Tension) $F_b = 0.60\ F_y$ (Bending) $F_y = 0.40\ S_y$ (Shear) For faulted conditions F_a limit = 1.5 F_a (Tension) F_b limit = 1.5 F_b (Bending) F_v limit = 1.5 F_v (Shear) F_y = Material yield strength	Faulted Condition 1. Dead weights 2. Impact force from failure of CRD housing (Earthquake load is negligible)	Beams (top cord) Beams (Bottom cord) Grid Structure	33,000 psi 33,000 psi 33,000 psi 33,000 psi 41,500 psi 27,500psi	F_a = 10,000 F_b = 19,000 F_a = 22,200 F_b = 10,600 F_a = 40,700 F_v = 11,100

TABLE C.3-9

MISCELLANEOUS COMPONENTS

Criteria	Loading	Location	Results	
			Allowable Stress	Calculated Stress
RECIRCULATING PIPE AND PUMP RESTRAINTS				
Primary Stress Limit Structural Steel: AISC specification for the design, fabrication and erection of structural steel for buildings For normal or upset conditions $F_a = 0.60\ F_y$ (Tension) For faulted conditions F_a limit = 1.5 F_a (Tension) F_y = yield strength Cable (wire rope) For faulted conditions $F_a = 0.80\ F_u$ (Tension) F_u = Ultimate Strength	Faulted Condition 1. Jet reaction force from a complete circumferential failure (break) of recirculation line.	Brackets on 28 in. pipe Cable on pump restraints	33,000psi 99,000 psi	29,000 psi 79,200 psi

TABLE C.3-9

MISCELLANEOUS COMPONENTS

Criteria	Loading	Location	Results: Allowable Stress	Results: Calculated Stress
FUEL STORAGE RACKS				
Primary Stress Limits ASME Code, Section III Normal or Upset (1) Subsection NF, 1980 Edition	Normal or Upset[1]			
For Normal or Upset Condition $F_t = 0.6S_y$ (Tension) $F_v = 0.4S_y$ (Shear) $F_b = 0.6S_y$ (Bending) $F_a = F(x)S_y$ (Compression)[2]	1. Dead Loads 2. Live Loads developed during lifting 3. Differential temperature induced loads. 4. Operating Basis Earthquake Loads. 5. Loads caused by the upward and sideways forces of a postulated stuck fuel assemble	Entire Structure	F_t = 15,000psi F_v = 1000psi F_b = 15,000psi F_a = 15,000psi	(See Ref. 1 and 2)
For the faulted condition the stress limits are1.2 (Sy/Ft) times the limits for the normal or upset condition	Faulted Condition[1] 1. Dead Loads 2. Live Loads developed during lifting 3. Differential temperature induced loads. 4. Safe shutdown Earthquake Loads	Entire Structure	F_t=30,000psi F_v=20,000psi F_b=30,000psi F_a=30,000psi	(See Ref. 1 and 2)
For the accidental drop condition[3]	1. Loads caused by the accidental drop of the heaviest load from the maximum possible height	Baseplate Top of Rack	The functional capability of racks should be demonstrated	(See Ref. 1 and 2)

TABLE C.3-9

MISCELLANEOUS COMPONENTS

Results of Fuel Rack Analysis

The results of the stress analysis in References 1 and 2 indicate that for both the normal/upset condition and the faulted condition the calculated stresses were well below the allowable ASME stress limits. The results of the fuel drop accident indicates that there would be some local yielding and possibly some permanent deformation. However, the racks will still maintain their functionality to prevent criticality of the adjacent racks and maintain their cross sectional geometry at that level of active fuel. The results of the drop accident calculation also indicates that the fuel pool liner stresses caused by the drop accident would be below the stress levels caused by the safe shutdown earthquake condition.

Notes

1. All loads are not considered to act simultaneously but in various combinations. See Reference 1 for loading combinations.
2. f(x) is a function of various parameters. Refer to Reference 1.
3. The accidental drop condition is not required by ASME.

References

1. Joseph Oat Co., Seismic Analysis of High Density Fuel Racks for Pilgrim Nuclear Power Station Unit 1, Report TM-729.

2. Holtec International, "PNPS Spent Fuel Capacity Expansion", Licensing Report #HI92925, January 5, 1993 (SUDDS/RF#93-01).

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APPENDIX M

REACTOR PRESSURE VESSEL DESIGN REPORT

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REACTOR PRESSURE VESSEL DESIGN REPORT

M.1 INTRODUCTION TO THE REPORT

The reactor pressure vessel for the Pilgrim Nuclear Power Station was fabricated, inspected, and tested in accordance with the American Society of Mechanical Engineers' Boiler and Pressure Vessel Code, Section III, "Nuclear Vessels" 1965 edition and addenda, plus the Nuclear Code Cases applicable. There were no deviations to the formal codes throughout the design, fabrication, inspection, and testing of the reactor pressure vessel.

The ASME Code and Cases were used as bases:

1. To establish minimum thickness of shell, head, flange, and nozzle materials,

2. To establish inspections and tests required by the Commonwealth of Massachusetts and any local governing bodies

Additional design rules, inspections, and tests not covered by the ASME Code and Cases are defined in the vessel specification.

A series of exhibits constitute the main body of this report. These exhibits present the purchase specifications, inspection report, fabrication test program, summary of tensile tests of special steels, and earthquake analysis of the reactor pressure vessel. These exhibits support the statement made in the opening paragraph. Reactor vessel stresses and analyses are summarized in Section C.3.4.1 of Appendix C. Stress analysis requirements and load combinations for the reactor vessel have been evaluated for the primary loading and cyclic conditions expected throughout the vessel life, with the conclusion that ASME code limits are satisfied.

A comparison of tentative thicknesses for the shell and heads with the formulas contained in Article I-1 follows:

Per Article I-1 of Section III of the ASME Boiler and Pressure Vessel Code, the minimum tentative thicknesses for the cylindrical shell and hemispherical heads are as follows:

A. Shell - $t = \frac{pR}{S_m - 0.5p}$ + Corrosion allowance

$$t = \frac{1250(113.812)}{26{,}700-0.5(1250)} + 0.062 = 5.5185 \text{ in}$$

Drawing minimum thickness = 5.53125 in

B. Heads - $t = \frac{pR}{zs_m - p}$ + Corrosion allowance

$$t = \frac{1250(112.344)}{2(26,700)-1250} + 0.062 = 2.755 \text{ in}$$

Drawing minimum thickness = 3.750 in

Figures M.1-1 and M.1-2 are provided as a part of this introduction to show the vessel physical dimensions and characteristics.

A description of the nozzle safe ends and weld pads on the Pilgrim reactor vessel is included in Section 4.2.5.1.

APPENDIX Q

SUPPLEMENTAL RELOAD LICENSING REPORTS

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SUPPLEMENTAL RELOAD LICENSING REPORTS

Q.1 INTRODUCTION

The latest plant supplemental reload licensing report is "Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 19/Cycle 20", 0000-0147-0084-SRLR, Revision 1, Class I, April 2013 (ECH-NE- 13-00002, Revision 0). This report provides the cycle core loading pattern and the results of the cycle specific nuclear transient and vessel overpressurization analyses. This report also addresses the applicability of generic stability and accident analyses. Refer to this report for reload information. All other sections of Appendix Q have been removed from the FSAR. References for previous cycle specific reports are as follows:

RELOAD SUBMITTAL REFERENCES

Reload No.	Reference
1	"Reload 1 Licensing Submittal of Pilgrim Nuclear Power Station", NEDO-20286, Revision 1, February 1974.
2	"General Electric Boiling Water Reactor Reload No. 2 Licensing Submittal for Pilgrim Nuclear Power Station Unit 1", NEDO-20855, June 1975.
	"Reload No. 2 Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 with Bypass Flow Holes Plugged", NEDO-20855-01, September 1975.
3	"General Electric Boiling Water Reactor Reload No. 3 Licensing Submittal for Pilgrim Nuclear Power Station Unit 1", NEDO-21460-01, May 1977.
4	"Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 4", NEDO-24224, November 1979.
	"Supplement 1 to Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 4", NEDO-24224-1, Supplement 1, March 1980.
	"Supplement 2 to Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 4 (Load Line Limit Analysis Reverification)", NEDO-24224-2, April 1981.
5	Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 5", Y1003J01A28, Revision 2, February 1983.

Reload No.	Reference
6	"Supplement Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 6", 23A1694, March 1984.
7	"Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Reload 7", 23A4800, December 1986.
8	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 8, Cycle 9," 23A7101, March 1991. (Note: the generator load reduction without bypass analyzed in the above licensing report is updated in another analysis (BECo SUDDS 91-44). All results presented here reflect this updated analysis).
9	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 9, Cycle 10" 23A7195, February 1993.
10	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 10, Cycle 11", 24A5172, Revision 0, February 1995.
11	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 11/Cycle 12", J11-03014SRL, Revision 0), February 1997.
12	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 12/Cycle 13", J11-03474-10 SRLR, Revision 0, Class I, April 1999 (SUDDS RF99-142).
13	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 13/Cycle 14", J11-03878-10 SRLR, Revision 0, Class I, February 2001 (SUDDS/RF 00-112).
14	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 14/Cycle 15", 0000-0008-6613-SRLR, Revision 1, Class I, March 2003 (SUDDS RFO258).
15	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 15/Cycle 16", 0000-0030-7302-SRLR, Revision 0, Class I, February 2005.
16	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 16/Cycle 17", 0000-0056-6173-SRLR, Revision 0, Class I, February 2007.
17	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 17/Cycle 18", 0000-0083-7478-SRLR, Revision 0, Class I, February 2009.

18 "Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 19/Cycle 20", 0000-0147-0084-SRLR, Revision 1, Class I, April 2013.

Sections Q.2, Q.A, Q.B, Q.C, and Q.D have been removed.

Please refer to "Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 19/Cycle 20", 0000-0147-0084-SRLR, Revision 1, Class I, April 2013 (ECH-NE-13-00002, Revision 0), and "Updated Loading Pattern GESTAR II Licensing Assessment for Pilgrim Cycle 20", GNF S-0000-0160-1647, Revision 1, April 2013 (ECH-NE-13-00002, Revision 0).

APPENDIX S

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LICENSE RENEWAL COMMITMENTS

S.1 Supplement for Renewed Operating License

The Pilgrim Nuclear Power Station license renewal application (Reference S.4-1) and information in subsequent related correspondence provided sufficient basis for the NRC to make the findings required by 10 CFR 54.29 (Final Safety Evaluation Report) (Reference S.4-2). As required by 10 CFR 54.21(d), this UFSAR supplement contains a summary description of the programs and activities for managing the effects of aging (Section S.2) and a description of the evaluation of time-limited aging analyses for the period of extended operation (Section S.3). The period of extended operation is the 20 years after the expiration date of the original operating license.

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S.2 Aging Management Programs and Activities

The integrated plant assessment for license renewal identified aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This section describes the aging management programs and activities required during the period of extended operation. All aging management programs have been initiated prior to entering the period of extended operation.

PNPS quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The Entergy Quality Assurance Program applies to safety-related structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished per the existing PNPS corrective action program and document control program and are applicable to all aging management programs and activities that will be required during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure that proposed actions are adequate, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program.

The corrective action controls of the Entergy (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities that will be required during the period of extended operation.

Operating experience is used at PNPS to enhance plant aging management programs. External nuclear industry operating experience, including operating experience related to the effects of aging, is screened, evaluated, and acted on to prevent or mitigate the consequences of similar events or conditions. External operating experience includes NRC generic communications (e.g., generic letters, bulletins, information notices, and regulatory information summaries) and other documents (e.g., 10

CFR 21 reports, licensee event reports, vendor bulletins, information for INPO and other industry groups). Internal operating experience includes information from event investigation reports, trending reports, lessons learned from in-house events, self-assessments, and the 10 CFR 50 Appendix B corrective action process. Operating experience is operating information pertinent to plant safety and reliability originating both within and outside the Entergy organization. Operating experience information describes events, issues, equipment failures, etc., including those resulting from the effects of aging, that represent opportunities to apply lessons learned to avoid negative consequences or to recreate positive experiences.

Entergy procedures provide direction for the evaluation of operating experience continuing through the period of extended operation. These procedures implement two programs that monitor, on an ongoing basis, industry and plant-specific operating experience that includes, but is not limited to, operating experience related to the effects of aging on in-scope structures and components. These programs are the Operating Experience Program and the Corrective Action Program. Procedures for these programs provide a method for evaluating and initiating action for operating experience information at all Entergy nuclear stations. The primary objective of assessing operating experience is to identify and transfer lessons learned into actions that enhance the safety and reliability of Entergy's nuclear plants. Operating experience involving age-related degradation mechanisms or aspects of programs that manage the effects of aging is provided to the respective program point of contact. Operating experience involving age-related degradation mechanisms for which no program can be readily identified is reviewed as documented in a written evaluation by the aging management operating experience point of contact for the station. The evaluations completed under these two programs ensure that aging management programs remain effective in managing the effects of aging for which they are credited.

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S.2.1 Boraflex Monitoring Program

The Boraflex Monitoring Program assures that degradation of the Boraflex panels in the spent fuel racks does not compromise the criticality analysis in support of the design of the spent fuel storage racks. The program relies on (1) neutron attenuation testing, (2) determination of boron loss through correlation of silica levels in spent fuel pool water samples and periodic areal density measurements, and (3) analysis of criticality to assure that the required 5% subcriticality margin is maintained.

License renewal commitment 49 governs implementation of this program. This program is being tracked by administrative controls.

S.2.2 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program included in its scope the Firewater, CST inlet to HPCI/RCIC, SSW, SBO fuel and coolant, EDG fuel, and the SBGTS piping.

The Firewater piping is addressed through the adoption of NFPA25 flow testing. The CST SS piping has been addressed through the GW testing, and is subject to future surveillance. The SSW inlet piping was determined to be non-susceptible. The SSW outlet has been modified with a non-susceptible CIPP, and is subject to the NRC credited Service Water Integrity Program, GL 89-13, which include regular internal visual surveillance and ongoing flow rate testing. The two EDG fuel oil tanks have been NDE tested and both tanks are subject to future NDE testing. The SBO, EDG, and the SBGTS piping have been excavated and inspected and are subject to future inspections. The Cathodic Protection Systems are operable and subject to ongoing surveillance. Pilgrim has committed to the Corporate Buried Pipe and Tank Program for all underground piping.

These inspections will be conducted at least once every ten years during the PEO. If measured soil resistivity is <20,000 ohms or scores higher than 10 points using the American Water Works Association C10S, or if backfill is found to have damaged the coating, the length of SBGTS pipe inspected will be doubled during subsequent ten (10) year inspections.

The two buried carbon steel EDG fuel oil tanks were inspected prior to the PEO and will be reinspected on a ten (10) year interval following the PEO.

If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

License renewal commitment 1 governs implementation of this program.

This program is being tracked by administrative controls.

S.2.3 BWR CRD Return Line Nozzle Program

Under the BWR CRD Return Line Nozzle Program, PNPS has cut and capped the CRD return line nozzle to mitigate cracking and continues in-service inspection (ISI) examinations to monitor the effects of crack initiation and growth on the intended function of the control rod drive return line nozzle and cap. ISI examinations include ultrasonic inspection of the nozzle-to-vessel weld and ultrasonic inspection of the dissimilar metal weld overlay at the nozzle.

License renewal commitment 30 specifies enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.4 BWR Feedwater Nozzle Program

Under the BWR Feedwater Nozzle Program, PNPS has removed feed water blend radii flaws, removed feed water nozzle cladding, and installed a triple-sleeve-double-piston sparger to mitigate cracking. This program continues with enhanced in-service inspection (ISI) of the feed water nozzles in accordance with the requirements of ASME Section XI, Subsection IWB and the recommendation of General Electric (GE) NE-523-A71-0594 to monitor the effects of cracking on the intended function of the feed water nozzles.

This program is being tracked by administrative controls.

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S.2.5 BWR Penetrations Program

The BWR Penetrations Program includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP) documents BWRVIP-27 and BWRVIP-49 and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-130 to ensure the long-term integrity of vessel penetrations and nozzles.

This program is being tracked by administrative controls.

S.2.6 BWR Stress Corrosion Cracking Program

The BWR Stress Corrosion Cracking Program includes (1) preventive measures to mitigate intergranular stress corrosion cracking (IGSCC), and (2) inspection and flaw evaluation to monitor IGSCC and its effects on reactor coolant pressure boundary components made of stainless steel or CASS.

PNPS has taken actions to prevent IGSCC and will continue to use materials resistant to IGSCC for component replacements and repairs following the recommendations delineated in NUREG-0313, Generic Letter 88-01, and the staff-approved BWRVIP-75 report. Inspection of piping identified in NRC Generic Letter 88-01 to detect and size cracks is performed in accordance with the staff positions on schedule, method, personnel qualification and sample expansion included in the generic letter and the staff-approved BWRVIP-75 report.

License renewal commitment 2 specifies enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.7 BWR Vessel ID Attachment Welds Program

The BWR Vessel ID Attachment Welds Program includes (1) inspection and flaw evaluation in accordance with the guidelines of staff-approved BWR Vessel and Internals Project (BWRVIP) BWRVIP-48, and (2) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-130 to ensure the long-term integrity and safe operation of reactor vessel inside diameter (ID) attachment welds and support pads.

This program is being tracked by administrative controls.

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S.2.8 BWR Vessel Internals Program

The BWR Vessel Internals Program includes (a) inspection, flaw evaluation, and repair in conformance with the applicable, staff-approved BWR Vessel and Internals Project (BWRVIP) documents, and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-130 to ensure the long-term integrity of vessel internals components.

License renewal commitments 3, 33, 34, and 37 specify enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.9 Containment Leak Rate Program

As described in 10 CFR 50, Appendix J, containment leak rate tests are required to assure that (a) leakage through primary reactor containment and systems and components penetrating primary containment shall not exceed allowable values specified in technical specifications or associated bases and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of containment, and systems and components penetrating primary containment. Corrective actions are taken if leakage rates exceed acceptance criteria.

This program is being tracked by administrative controls.

S.2.10 Diesel Fuel Monitoring Program

The Diesel Fuel Monitoring Program entails sampling to ensure that adequate diesel fuel quality is maintained to prevent plugging of filters, fouling of injectors, and corrosion of fuel systems. Exposure to fuel oil contaminants such as water and microbiological organisms is minimized by periodic draining and cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks.

License renewal commitments 4, 5, 6, and 38 specify enhancement(s) to this program.

This program is being tracked by administrative controls.

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S.2.11 Environmental Qualification (EQ) of Electric Components Program

The PNPS EQ of Electric Components program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are refurbished, replaced, or their qualification extended prior to reaching the aging limits established in the evaluations. Aging evaluations for EQ components are considered time-limited aging analyses (TLAAs) for license renewal.

This program is being tracked by administrative controls.

S.2.12 Fatigue Monitoring Program

In order not to exceed design limits on fatigue usage, the Fatigue Monitoring Program tracks the number of critical thermal and pressure transients for selected reactor coolant system components. The program ensures the validity of analyses that explicitly assumed a fixed number of thermal and pressure fatigue transients by assuring that the actual effective number of transients does not exceed the assumed limit.

The transient cycles tracked by this program are referenced in Section 4.2.6.

License renewal commitments 31 and 35 specify enhancement(s) to this program.

This program is being tracked by administrative controls.

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S.2.13 Fire Protection Program

The Fire Protection Program includes a fire barrier inspection and a diesel-driven fire pump inspection. The fire barrier inspection requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection requires that the pump be periodically tested and system components internally inspected to ensure that the fuel supply line can perform its intended function. The program also includes periodic inspection and testing of the Halon fire suppression system.

Corrective actions, confirmation process, and administrative controls in accordance with the requirements of 10 CFR 50 Appendix B are applied to the Fire Protection Program.

License renewal commitments 7 and 8 specify enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.14 Fire Water System Program

The Fire Water System Program applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, and aboveground and underground piping and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures functionality of systems. To determine if significant corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections are conducted. Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

In addition, wall thickness evaluations of fire protection piping are periodically performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion.

A sample of sprinkler heads will be inspected using the guidance of NFPA 25 (2002 Edition) Section 5.3.1.1.1, which states, "Where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing."

This sampling will be repeated every 10 years after initial field service testing.

License renewal commitments 9, 10, and 11 specify enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.15 Flow-Accelerated Corrosion Program

The Flow-Accelerated Corrosion Program applies to safety-related and nonsafety-related carbon steel components in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid > 2% of plant operating time.

The program, based on EPRI recommendations for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions. The program specifies repair or replacement of components as necessary.

This program is being tracked by administrative controls.

S.2.16 Heat Exchanger Monitoring Program

The Heat Exchanger Monitoring Program inspects heat exchangers for degradation. If degradation is found, then an evaluation is performed to evaluate its effects on the heat exchanger's design functions including its ability to withstand a seismic event.

Representative tubes within the population of heat exchangers are eddy current tested at a frequency determined by internal and external operating experience and trended to ensure that effects of aging are identified prior to loss of intended function. Along with each eddy current test, visual inspections are performed on accessible heat exchanger heads, covers and tube sheets to monitor surface condition for indications of loss of material. The population of heat exchangers includes the RHR heat exchangers, RHR pump seal heat exchangers, core spray pump motor thrust bearing lube oil coolers, HPCI gland seal condenser, HPCI turbine lube oil cooler, RCIC lube oil cooler, recirculation pump motor generator set fluid coupling oil and bearing coolers, CRD pump oil coolers, recirculation pump motor lube oil coolers, clean up recirculation pump lube oil coolers and stuffing box cooler, fuel pool heat exchangers, CRD pump thrust bearing coolers, recirculation pump seal water coolers, clean up demineralizer

non-regeneration heat exchangers, and EDG lube oil coolers.

License renewal commitment 12 governs implementation of this program.

This program is being tracked by administrative controls.

S.2.17 In-service Inspection - Containment In-service Inspection (CII) Program

The Containment In-service Inspection Program outlines the requirements for the inspection of Class MC pressure-retaining components (primary containment) and their integral attachments in accordance with the requirements of 10 CFR 50.55a(b)(2) and the 1998 Edition of ASME Section XI with 2000 Addenda, Inspection Program B.

The primary inspection method for the primary containment and its integral attachments is visual examination. Visual examinations are performed either directly or remotely with illumination and resolution suitable for the local environment to assess general conditions that may affect either the containment structural integrity or leak tightness of the pressure retaining component. The program includes augmented ultrasonic exams to measure wall thickness of the containment drywell structure.

License renewal commitment 41 specifies enhancement(s) to this program.

License renewal commitment 44 specified the performance of another set of UT measurements just above and adjacent to the sand cushion region prior to the period of extended operation and an additional set of measurements will be taken once within the first 10 years of the period of extended operation.

These programs are being tracked by administrative controls.

S.2.18 In-service Inspection - In-service Inspection (ISI) Program

The ISI Program is based on ASME Inspection Program B (Section XI, IWA-2432), which has 10-year inspection intervals. Every 10 years the program is updated to the latest ASME Section XI code edition and addendum approved in 10 CFR 50.55a. On July 1, 2005 PNPS entered the fourth ISI interval. The code edition and addenda used for the fourth interval is the 1998 Edition with 2000 Addenda.

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The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment, signs of degradation, flaw evaluation, and corrective actions.

This program is being tracked by administrative controls.

S.2.19 Instrument Air Quality Program

The Instrument Air Quality Program ensures that instrument air supplied to components is maintained free of water and significant contaminants, thereby preserving an environment that is not conducive to loss of material. Dewpoint, particulate contamination, and hydrocarbon concentration are periodically checked to verify the instrument air quality is maintained.

License renewal commitment 13 specifies enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.20 Metal-Enclosed Bus Inspection Program

Under the Metal-Enclosed Bus Inspection Program, internal portions of the non-segregated phase bus which connects the 4.16kV switchgear (A3 through A6) are inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. Bus insulation is inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. Internal bus supports have been and will be inspected for structural integrity and signs of cracks. Since bolted connections are covered with heat shrink tape or insulating boots per manufacturer's recommendations, a sample of accessible bolted connections is visually inspected for insulation material surface anomalies. Enclosure assemblies have been and will be visually inspected for evidence of loss of material and, where applicable, enclosure assembly elastomers are visually inspected and manually flexed to manage cracking and change in material properties.

These inspections are performed at least once every five years. License renewal commitment 14 governs implementation of this program.

This program is being tracked by administrative controls.

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S.2.21 Non-EQ Inaccessible Medium-Voltage Cable Program

The Non-EQ Inaccessible Medium Voltage Cable Program is based on, and consistent with NUREG-1801, Rev 2, section XI.E3. In scope, inaccessible medium-voltage and low-voltage (400V to 35KV) cables exposed to significant moisture are tested at least once every six years to provide an indication of the condition of the insulation. Significant moisture is defined as periodic exposures that last more than a few days. The specific test performed is a proven test for detecting deterioration of the insulation, such as power factor, partial discharge, polarization index, or other testing that is state-of-the-art at the time the test is performed. Evaluation of the test results are used to determine the need for increased test frequencies.

Inspections for water collection in cable manholes and conduit containing in scope medium and low voltage cables with a license renewal intended function (400V to 35KV) occur at least once every year. Additional condition-based inspections of these manholes are performed based on natural events for a coastal site. The results of the inspections are reviewed to determine if the inspection frequency, and/or testing frequency should be modified.

License renewal commitment 15 governs implementation of this program.

This program is being tracked by administrative controls.

S.2.22 Non-EQ Instrumentation Circuits Test Review Program

Under the Non-EQ Instrumentation Circuits Test Review Program, calibration or surveillance results for non-EQ electrical cables in circuits with sensitive, high voltage, low-level signals; (i.e., neutron flux monitoring instrumentation); are reviewed. Most neutron flux monitoring system cables and connections are calibrated as part of the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results is performed once every 10 years.

For neutron flux monitoring system cables that are disconnected during instrument calibrations, testing is performed at least once every 10 years using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry).

A review of the neutron monitoring system calibration and cable testing was completed before the period of extended operation and future tests will occur at least once every 10 years.

License renewal commitment 16 governs implementation of this program.

This program is being tracked by administrative controls.

S.2.23 Non-EQ Insulated Cables and Connections Program

The Non-EQ Insulated Cables and Connections Program provides reasonable assurance that intended functions of insulated cables and connections exposed to adverse localized environments caused by heat, radiation and moisture can be maintained consistent with the current licensing basis through the period of extended operation. An adverse localized environment is significantly more severe than the specified service condition for the insulated cable or connection.

A site walkdown of accessible insulated cables and connections is visually inspected at least once every 10 years for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, or surface contamination.

License renewal commitment 17 governs implementation of this program.

This program is being tracked by administrative controls.

S.2.24 Oil Analysis Program

The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil for detrimental contaminants, water, and particulates.

Sampling frequencies are based on vendor recommendations, accessibility during plant operation, equipment importance to plant operation, and previous test results.

License renewal commitments 18, 19, and 40 specify enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.25 One-Time Inspection Program

A one-time inspection activity is used to verify the effectiveness of the water chemistry control programs by confirming that unacceptable cracking, loss of material, and fouling is not occurring on components within systems covered by water chemistry control programs [Sections S.2.36, S.2.37, and S.2.38].

The elements of the One-Time Inspection Program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (b) identification of the inspection locations in the system or component based on the aging effect, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging degradation.

One-time inspection activities included:

- bottom surface of the condensate storage tanks
- main stack foundation
- verify absence of fatigue cracking for miscellaneous items not covered by a fatigue TLAA
- internal surfaces of buried carbon steel pipe on the standby gas treatment system discharge to the stack,
- internal surfaces of compressed air and EDG system components containing untreated air,
- internal surfaces of stainless steel radioactive waste and sanitary soiled waste and vent system components containing untreated water,
- small bore piping in the reactor coolant system and associated systems that form the reactor coolant pressure boundary,
- reactor vessel flange leak-off line, and
- main steam flow restrictors

The results were used to confirm that loss of material, and cracking as applicable, are not occurring or are so insignificant that an aging management program is not warranted.

When evidence of an aging effect was revealed by a one-time inspection, the corrective action process was used.

License renewal commitments 20, 36, and 39 govern implementation of this program.

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S.2.26 Periodic Surveillance and Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance Program include periodic inspections and tests that manage aging effects not managed by other aging management programs. The preventive maintenance and surveillance testing activities are generally implemented through repetitive tasks or routine monitoring of plant operations.

Temperatures are monitored during periodic emergency diesel generator (EDG), station blackout diesel, and security diesel surveillance tests to verify that associated heat exchangers are capable of removing the required amount of heat, thereby managing fouling of the heat exchanger tubes.

Periodic inspections using visual or other non-destructive examination techniques verify that the following components are capable of performing their intended function.

- reactor building crane, rails, and girders
- refueling platform carbon steel components
- main stack components
- standby liquid control system discharge accumulators
- carbon steel piping in the waterline region of the torus
- HPCI gland seal condenser blower and suction piping
- RCIC steam supply and exhaust piping downstream of the strainers and steam traps
- standby gas treatment system expansion joints, demister drain valves, and demister drain piping
- drain lines from each reactor building auxiliary bay passing into the water trough in the torus
- clean-up recirculation pump P-204B stuffing box cooler
- RBCCW copper alloy cooling coils
- EDG, station blackout diesel, and security diesel intake air, air start, and exhaust components

- EDG, station blackout diesel, and security diesel jacket water radiators
- security diesel oil cooler and aftercooler
- area coolers VAC-210A/B, VAC-202A/B, and VAC-204A/B/C/D
- VSF-103A/B, VAC-202A/B, VAC-204A/B/C/D, and EDG engine driven fan duct flexible connections
- condensate storage tanks
- circulating water, potable and sanitary water, radioactive waste, sanitary soiled waste and vent, plumbing and drains, and screen wash system components
- flex/expansion joints in the circulating water, HVAC/chilled water, and radioactive waste systems
- diesel fuel oil emergency transfer skid hoses, piping, pump casing, strainer, and valve bodies

License renewal commitment 21 specifies enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.27 Reactor Head Closure Studs Program

The Reactor Head Closure Studs Program includes in-service inspection (ISI) in conformance with the requirements of the ASME Code, Section XI, Subsection IWB, and preventive measures (e.g. rust inhibitors, stable lubricants, appropriate materials) to mitigate cracking and loss of material of reactor head closure studs, nuts, washers, and bushings.

This program is being tracked by administrative controls.

S.2.28 Reactor Vessel Surveillance Program

PNPS is a participant in the BWR vessel and internals project (BWRVIP) Integrated Surveillance Program (ISP) as incorporated into the plant Technical Specifications by License Amendment 209. The Reactor Vessel Surveillance Program monitors changes in the fracture toughness properties of ferritic materials in the reactor pressure vessel (RPV) beltline region. As BWRVIP-ISP capsule test reports become available for RPV materials representative of PNPS, the actual shift in the reference temperature for nil-ductility

transition of the vessel material may be updated. In accordance with 10 CFR 50 Appendices G and H, PNPS reviews relevant test reports to assure compliance with fracture toughness requirements and P-T limits.

BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal," describes the design and implementation of the ISP during the period of extended operation. BWRVIP-116 identifies additional capsules, their withdrawal schedule, and contingencies to ensure that the requirements of 10 CFR 50 Appendix H are met for the period of extended operation. The BWRVIP-116 report which was approved by the Staff will be implemented at PNPS with the conditions documented in Sections 3 and 4 of the Staff's final SE dated March 1, 2006, for the BWRVIP-116 report.

The Reactor Vessel Surveillance Program has been enhanced to proceduralize the data analysis, acceptance criteria, and corrective actions described in this program description.

If the PNPS standby capsule is removed from the reactor vessel without the intent to test it, the capsule will be stored in a manner which would permit its future use if necessary.

License renewal commitment 22 specifies enhancement(s) to this program.

S.2.29 Selective Leaching Program

The Selective Leaching Program ensures the integrity of components made of cast iron, aluminum, bronze, brass, and other alloys exposed to raw water, treated water, or groundwater that may lead to selective leaching. The program includes a one-time visual inspection and/or hardness measurement of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function for the period of extended operation.

License renewal commitment 23 governs implementation of this program.

This program is being tracked by administrative controls.

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S.2.30 Service Water Integrity Program

The Service Water Integrity Program relies on implementation of the recommendations of NRC GL 89-13 to ensure that the effects of aging on the salt service water (SSW) system are managed for the period of extended operation. The program includes component inspections for erosion, corrosion, and blockage and performance monitoring to verify the heat transfer capability of the safety-related heat exchangers cooled by SSW. Chemical treatment using biocides and chlorine and periodic cleaning and flushing of redundant or infrequently used loops are the methods used to control or prevent fouling within the heat exchangers and loss of material in SSW components.

License renewal commitment 24 specifies enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.31 Structures Monitoring - Masonry Wall Program

The objective of the Masonry Wall Program is to manage cracking so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation.

The program includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. Included components are the 10 CFR 50.48 required masonry walls, radiation shielding masonry walls, masonry walls with the potential to affect safety-related components, and the torus compartment water trough.

Masonry walls are visually examined at a frequency selected to ensure there is no loss of intended function between inspections.

This program is being tracked by administrative controls.

S.2.32 Structures Monitoring - Structures Monitoring Program

Structures monitoring is in accordance with 10 CFR 50.65 (Maintenance Rule) as addressed in Regulatory Guide 1.160 and NUMARC 93-01. Periodic inspections are used to monitor the condition of structures and structural components to ensure there is no loss of structure or structural component intended function.

License renewal commitments 25, 26, and 43 specify enhancement(s) to this program.

License renewal commitment 45 specifies that if groundwater continues to collect on the Torus Room floor, obtain samples and test such water to determine its pH and verify the water is non-aggressive as defined in NUREG-1801 Section III.A1 item III.A.1-4 once prior to the period of extended operation and once every five years during the period of extended operation.

License renewal commitment 46 specifies inspection of the condition of a sample of torus hold-down bolts and associated grout and determine appropriate actions based on the findings prior to the period of extended operations.

This program is being tracked by administrative controls.

S.2.33 Structures Monitoring - Water Control Structures Monitoring Program

The Water Control Structures Monitoring Program includes visual inspections to manage loss of material and loss of form for water-control structures (breakwaters, jetties, and revetments). The water-control structures are of rubble mound construction with the outer layer protected by heavy capstone. Parameters monitored include settlement (vertical displacement) and rock displacement. These parameters are consistent with those described in RG 1.127.

License renewal commitment 27 specifies enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.34 System Walkdown Program

The System Walkdown Program entails inspections of external surfaces of components subject to aging management review. The program is also credited with managing loss of material from internal surfaces, for situations in which internal and external material and environment combinations are the same such that external surface condition is representative of internal surface condition.

Surfaces that are inaccessible during plant operations are inspected during refueling outages. Surfaces are inspected at frequencies to provide reasonable assurance that effect of aging will be managed such that applicable components will perform their intended function during the period of extended operation.

System walkdown guidance includes visual inspection of high voltage insulators required for station blackout recovery.

License renewal commitment 28 specifies enhancement(s) to this program.

This program is being tracked by administrative controls.

S.2.35 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program

The purpose of the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is to assure that reduction of fracture toughness due to thermal aging and reduction of fracture toughness due to radiation embrittlement will not result in loss of intended function during the period of extended operation. This program evaluates CASS components in the reactor vessel internals and requires non-destructive examinations as appropriate.

License renewal commitment 29 governs implementation of this program.

This program is being tracked by administrative controls.

S.2.36 Water Chemistry Control - Auxiliary Systems Program

The purpose of the Water Chemistry Control - Auxiliary Systems Program is to manage loss of material for components exposed to treated water.

Program activities include sampling and analysis of the stator cooling water system to minimize component exposure to aggressive environments.

The One-Time Inspection Program confirmed the effectiveness of the program.

S.2.37 Water Chemistry Control - BWR Program

The objective of the Water Chemistry Control - BWR Program is to manage aging effects caused by corrosion and cracking mechanisms. The program relies on monitoring and control of water chemistry based on EPRI Report 1008192 (BWRVIP-130). BWRVIP-130 has three sets of guidelines: one for primary water, one for condensate and feed water, and one for control rod drive (CRD) mechanism cooling water. EPRI guidelines in BWRVIP-130 also include recommendations for controlling water chemistry in the torus, condensate storage tank, demineralized water storage tanks, and spent fuel pool.

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The Water Chemistry Control - BWR Program optimizes the primary water chemistry to minimize the potential for loss of material and cracking. This is accomplished by limiting the levels of contaminants in the RCS that could cause loss of material and cracking. Additionally, PNPS has instituted hydrogen water chemistry (HWC) to limit the potential for intergranular SCC (IGSCC) through the reduction of dissolved oxygen in the treated water.

The One-Time Inspection Program confirmed the effectiveness of the program.

S.2.38 Water Chemistry Control - Closed Cooling Water Program

The Water Chemistry Control - Closed Cooling Water Program includes preventive measures that manage loss of material, cracking, and fouling for components in closed cooling water systems (reactor building closed cooling water, turbine building closed cooling water, emergency diesel generator cooling water, station blackout diesel cooling water, security diesel generator cooling water, and plant heating). These chemistry activities provide for monitoring and controlling closed cooling water chemistry using PNPS procedures and processes based on EPRI guidance for closed cooling water chemistry.

The One-Time Inspection Program confirmed the effectiveness of the program.

S.2.39 Bolting Integrity Program

The Bolting Integrity Program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in the Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. The program relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting and structural bolting.

License renewal commitment 32 specifies enhancement(s) to this program.

This program is being tracked by administrative controls.

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S.2.40 Bolted Cable Connections Program

The Bolted Cable Connections Program focused on the metallic parts of the cable connections. This sampling program provides a one-time inspection to verify that the loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation was not an aging issue that requires a periodic aging management program. A representative sample of the electrical cable connection population subject to aging management review were inspected or tested. Connections covered under the EQ program, or connections inspected or tested as part of a preventive maintenance program were excluded from aging management review. The factors considered for sample selection were application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.) The technical basis for the sample selection was documented.

This program was completed prior to the period of extended operation.

License renewal commitment 42 governed implementation of the program.

S.2.41 Neutron Absorber Monitoring Program

The Neutron Absorber Monitoring Program is a new program that manages loss of material and reduction of neutron absorption capacity of Boral and Metamic neutron absorption panels in the spent fuel racks. The program will rely on periodic inspection, testing, monitoring of coupons, and analysis of the criticality design to assure that the required five percent subcriticality margin is maintained during the period of extended operation.

The program was initiated prior to the period of extended operation. One test on each material was performed within the five years preceding the period of extended operation, with additional testing performed on each material at least once every ten years during the period of extended operation.

This program is being tracked by administrative controls.

S.2.42 Protective Containment Coatings

The Protective Coating Monitoring and Maintenance Program manage the effects of aging on Service Level 1 coatings inside containment by means of periodic visual inspections. The program also includes direction to select and review the suitability of

the coatings applied to surfaces inside containment (e.g., steel containment shell, structural steel, supports, penetrations, and concrete walls and floors). Inspection of coatings inside containment is performed of accessible areas in accordance with the IWE requirements of ASME Section XI during every other refueling outage (once per ASME Section XI IWE period) which is a maximum of four years.

This program is being tracked by administrative controls.

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S.3 Evaluation of Time-Limited Aging Analyses

In accordance with 10 CFR 54.21(c), an application for a renewed license requires an evaluation of time-limited aging analyses (TLAA) for the period of extended operation. The following TLAA have been identified and evaluated to meet this requirement.

S.3.1 Reactor Vessel Neutron Embrittlement

The reactor vessel neutron embrittlement TLAA will either remain valid for the period of extended operation (P-T limits) in accordance with 10 CFR 54.21(c)(1)(i) or have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). Fifty-four EFPY would be the effective full power years at the end of the period of extended operation assuming an average capacity factor of 90% for 60 years.

S.3.1.1 Reactor Vessel Fluence

Calculated fluence is based on a time-limited assumption defined by the operating term. As such, fluence is the time-limited assumption for the time-limited aging analyses that evaluate reactor vessel embrittlement.

Fluence values were calculated using the RAMA fluence calculation method. The RAMA fluence method was developed for the Electric Power Research Institute, Inc. and the Boiling Water Reactor Vessel and Internals Project (BWRVIP) for the purpose of calculating neutron fluence in boiling water reactor components. This method has been approved by the NRC (Reference S.4-9) for application in accordance with Regulatory Guide 1.190 provided the fluence calculations for the reactor are appropriately benchmarked.

The benchmarking validation of the RAMA fluence calculation is ongoing for the PNPS reactor vessel. The RAMA calculated fluence is approximately 56% of the benchmark fluence calculated from the available surveillance capsule dosimetry. Uncertainties between the calculated and measured results from the dosimetry are still being examined to determine a possible cause for the discrepancy. An action plan to improve benchmarking data to support approval of new P-T curves will be developed and submitted for NRC review.

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An alternative analysis to determine the limiting fluence value has been performed (Reference S.4-12). This analysis assumes increasing fluence levels until an ASME Code or regulatory limit is reached based on the projected changes in material properties. Changes in the vessel (Ferritic) steel material properties are measured by an increase in adjusted reference temperature or a decrease in Charpy upper shelf energy. The effects of increasing fluence on the austenitic stainless steel core shroud and internals was also considered. By assuming increasing fluence levels, the analysis identifies the maximum fluence that can be experienced while meeting the Code and regulatory criteria.

The analysis determined that the limiting fluence value is set by the maximum mean RT_{NDT} value for the vessel axial welds of 114°F to remain below a calculated reactor vessel failure frequency of $5x10^{-6}$ per reactor-year. The corresponding maximum allowable ID fluence for the axial welds was determined to be 3.37E+18 n/cm^2. This fluence level is the limiting fluence value identified.

Entergy submitted to the NRC calculations consistent with Regulatory Guide 1.190 that demonstrated limiting fluence values will not be reached during the period of extended operation.

License renewal commitment 48 directed PNPS to submit fluence calculations consistent with RG 1.190 by June 8, 2010.

S.3.1.2 Pressure-Temperature Limits

Appendix G of 10 CFR 50 requires that reactor vessel bolt up, hydro test, pressure tests, normal operation, and anticipated operational occurrences are accomplished within established pressure-temperature (P-T) limits. These limits are established by calculations that utilize the materials and fluence data obtained through the Reactor Vessel Surveillance Program.

Pilgrim received License Amendment 227 dated March 29, 2007 that extended the existing P-T limit curves for Pilgrim through Cycle 18.

The P-T limit curves will continue to be updated, as required by Appendix G of 10 CFR Part 50 or as operational needs dictate. This updating will assure that the operational limits remain valid through the period of extended operation. Maintaining the P-T limit curves in accordance with Appendix G of 10 CFR 50 assures that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation consistent with 10 CFR 54.21(c)(1)(iii).

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S.3.1.3 Charpy Upper-Shelf Energy

Appendix G of 10 CFR 50 requires that reactor vessel beltline materials "have Charpy upper-shelf energy … of no less than 75 ft-lb initially and must maintain Charpy upper-shelf energy throughout the life of the vessel of no less than 50 ft-lb…." The initial (unirradiated) values of upper-shelf energy (CvUSE) for PNPS beltline welds were provided to the NRC in correspondence responding to Generic Letter 92-01.

Regulatory Guide 1.99, Radiation Embrittlement of Reactor Vessel Materials, Revision 2, provides two methods for determining Charpy upper-shelf energy (CvUSE). Position 1 applies for material that does not have surveillance data and Position 2 applies for material with surveillance data. Position 2 requires a minimum of two sets of credible material surveillance data. Since PNPS has data from only one material surveillance capsule, Position 2 does not apply. For Position 1, the percent drop in CvUSE for a stated copper content and neutron fluence is determined by reference to Figure 2 of Regulatory Guide 1.99, Revision 2. This percentage drop is applied to the initial CvUSE to obtain the adjusted CvUSE.

The predictions for percent drop in CVUSE at 54 EFPY must be based on chemistry data, the maximum 1/4T fluence values, and unirradiated CvUSE data submitted to the NRC in the PNPS response to GL 92-01. The predicted CvUSE values for 54 EFPY will utilize Regulatory Guide 1.99 Position 1. The predictions will use Regulatory Guide 1.99, Position 1, Figure 2; specifically, the formula for the lines will be used to calculate the percent drop in CvUSE.

PNPS will use chemistry data from previous licensing submittals, the PNPS response to GL 92-01, and the 1/4T fluence values to be determined to perform linear interpolation on the CvUSE percent drop values in RG 1.99, Revision 2, Figure 2.

The license renewal SER for BWRVIP-74, Action Item #10, states that each license renewal applicant shall demonstrate that the percent reduction in Charpy USE for their beltline materials is less than that specified for the limiting BWR/3-6 plates and the non-Linde 80 submerged arc welds given in BWRVIP-74. This action item is not applicable to PNPS if the PNPS projected CvUSE remains above the 50 ft-lb limit, even for the period of extended operation.

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An analysis determined that the limiting fluence value is set by the maximum mean RT_{NDT} value for the vessel axial welds of 114°F to remain below a calculated reactor vessel failure frequency of $5x10^{-6}$ per reactor-year. The corresponding maximum allowable ID fluence for the axial welds was determined to be 3.37E+18 n/cm^2. This fluence is the limiting fluence value identified.

If fluence remains below this limiting value during the period of extended operation, the fluence will result in acceptable results for the reactor vessel Charpy upper shelf energy TLAS. To confirm that this TLAA will be valid to the end of the period of extended operation, Entergy submitted to the NRC calculations consistent with Regulatory Guide 1.190 that demonstrated limiting fluence values will not be reached during the period of extended operation.

S.3.1.4 Adjusted Reference Temperature

Irradiation by high-energy neutrons raises the value of RT_{NDT} for the reactor vessel. RT_{NDT} is the reference temperature for nil-ductility transition as defined in Section NB-2320 of the ASME Code. The initial RT_{NDT} is determined through testing of unirradiated material specimens. The shift in reference temperature, ΔRT_{NDT}, is the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. The adjusted reference temperature (ART) is defined as initial RT_{NDT} + ΔRT_{NDT} + margin. The margin is defined in RG 1.99, Revision 2. The P-T curves are developed from the ART value for the vessel materials. RG 1.99 Revision 2 defines the calculation methods for RT_{NDT} and ART.

The PNPS reactor vessel was evaluated for an assumed exposure of less than 10^{19} nvt of neutrons with energies exceeding 1 MeV. After approximately 4.17 EFPY, the first surveillance capsule was withdrawn from the vessel and tested. The capsule test report concludes that the shift in RT_{NDT} and upper-shelf energy over 32 EFPY will be within 10 CFR 50 guidelines.

PNPS will project values for ΔRT_{NDT} and ART at 54 EFPY using the methodology of RG 1.99. These values will be calculated using the chemistry data, margin values, initial RT_{NDT} values, and chemistry factors (CFs) contained in the PNPS response to GL 92-01. Initial RT_{NDT} values are from report SIR-00-082, which was submitted in 2001 as part of the PNPS P-T limit change request. The 1/4T fluence values discussed in Section 4.2.1 will be used.

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New fluence factors (FFs) will be calculated using the expression in RG 1.99, Revision 2, Equation 2, where the fluence factor is given by

$$FF = f^{(0.28-0.10*\log f)}.$$

In this equation, f is the 1/4T fluence value. The new ΔRT_{NDT} values will be calculated by multiplying the CF and the FF for each plate and weld. Calculated margins and the initial RT_{NDT} will then be added to the calculated ΔRT_{NDT} in order to arrive at the new value of ART.

An analysis determined that the limiting fluence value is set by the maximum mean RT_{NDT} value for the vessel axial welds of 114°F to remain below a calculated reactor vessel failure frequency of $5x10^{-6}$ per reactor-year. The corresponding maximum allowable ID fluence for the axial welds was determined to be 3.37E+18 n/cm^2. This fluence is the limiting fluence value identified.

If fluence remains below this limiting value during the period of extended operation, the fluence will result in acceptable results for the reactor vessel adjusted reference temperature TLAS. To confirm that this TLAA will be valid to the end of the period of extended operation, Entergy submitted to the NRC consistent with Regulatory Guide 1.190 that demonstrated limiting fluence values will not be reached during the period of extended operation.

S.3.1.5 Reactor Vessel Circumferential Weld Inspection Relief

Relief from reactor vessel circumferential weld examination requirements under Generic Letter 98-05 is based on an analysis indicating acceptable probability of failure per reactor operating year. The analysis is based on reactor vessel metallurgical conditions as well as flaw indication sizes and frequencies of occurrence that are expected at the end of a licensed operating period.

PNPS received NRC approval for this relief for the remainder of the original 40-year license term. The basis for this relief request is an analysis that satisfied the limiting conditional failure probability for the circumferential welds at the expiration of the current license, based on BWRVIP-05 and the extent of neutron embrittlement. The anticipated changes in metallurgical conditions expected over the extended operating period require additional analysis to extend this relief request.

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The NRC evaluation of BWRVIP-05 utilized the FAVOR code to perform a probabilistic fracture mechanics (PFM) analysis to estimate the reactor pressure vessel (RPV) shell weld failure probabilities. Three key inputs to the PFM analysis are (1) the estimated end-of-life mean neutron fluence, (2) mean chemistry values based on vessel types, and (3) the assumption of potential for beyond-design-basis events.

PNPS will compare the reactor vessel limiting circumferential weld parameters to those used in the NRC analysis for the first two key assumptions. The data will be from the NRC SER for PNPS Relief Request 28, and from the data in Table 2.6.4 of the NRC SER for BWRVIP-05. (For comparison, the EOL mean RT_{NDT} will be calculated without margin and hence will be lower than the Section 4.2.2 RT_{NDT} value.)

The procedures and training used to limit cold over-pressure events will be the same as those approved by the NRC when PNPS requested approval of the BWRVIP-05 technical alternative for the current license term.

An analysis determined that the limiting fluence value is set by the maximum mean RT_{NDT} value for the vessel axial welds of 114°F to remain below a calculated reactor vessel failure frequency of $5x10^{-6}$ per reactor-year. The corresponding maximum allowable ID fluence for the axial welds was determined to be 3.37E+18 n/cm^2. This fluence is the limiting fluence value identified.

If fluence remains below this limiting value during the period of extended operation, the fluence will result in acceptable results for the reactor vessel circumferential weld failure probability TLAS. To confirm that this TLAA will be valid to the end of the period of extended operation, Entergy submitted to the NRC calculations consistent with Regulatory Guide 1.190 that demonstrated limiting fluence values will not be reached during the period of extended operation.

S.3.1.6 Reactor Vessel Axial Weld Failure Probability

The BWRVIP recommendations for inspection of reactor vessel shell welds (BWRVIP-05) are based on generic analyses supporting an NRC SER conclusion that the generic-plant axial weld failure rate is no more than $5x10^{-6}$ per reactor year. BWRVIP-05 showed that this axial weld failure rate is orders of magnitude greater than the 40-year end-of-life circumferential weld failure probability, and used this analysis to justify relief from inspection of the circumferential welds as described above.

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PNPS received relief from the circumferential weld inspections for the remainder of the original 40-year operating term. The basis for this relief request was a plant-specific analysis that showed the limiting conditional failure probability for the PNPS circumferential welds at the end of the original operating term was less than the values calculated in the BWRVIP-05 SER. The BWRVIP-05 SER concluded that the reactor vessel failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is less than $5x10^{-6}$ per reactor year. This failure frequency is dependent upon given assumptions of flaw density, distribution, and location. The failure frequency also assumes that "essentially 100%" of the reactor vessel axial welds will be inspected. The PNPS relief request requires additional relief request if less than 90% coverage is achieved.

Applicant Action Item 12 from the NRC SER for BWRVIP-74 specified that applicants should monitor axial beltline weld embrittlement. One acceptable method was to determine that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of the FSER for BWRVIP-74. The limiting mean RT_{NDT} value of 114°F for the axial welds was determined to be equivalent to a failure frequency of less than $5x10^{-6}$ per reactor-year.

An analysis determined that the ID fluence value that yields a mean RT_{NDT} value for the vessel axial welds of 114°F is 3.37E+18 n/cm^2. This fluence is the limiting fluence value identified.

If fluence remains below this limiting value during the period of extended operation, the fluence will result in acceptable results for the reactor vessel axial weld failure probability TLAS. To confirm that this TLAA will be valid to the end of the period of extended operation, Entergy submitted to the NRC calculations consistent with Regulatory Guide 1.190 that demonstrated limiting fluence values will not be reached during the period of extended operation.

S.3.2 Metal Fatigue

S.3.2.1 Class 1 Metal Fatigue

Class 1 components evaluated for fatigue and flaw growth include the reactor pressure vessel (RPV) and appurtenances, certain reactor vessel internals, the reactor recirculation system (RRS), and the reactor coolant system (RCS) pressure boundary. The PNPS Class 1 systems include components within the ASME Section XI, IWB inspection boundary.

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The design of the reactor vessel internals is in accordance with the intent of ASME Section III. A review of design basis documents reveals that the only reactor vessel internals components for which there is a fatigue evaluation are the core shroud tie rods (stabilizer), the result of a repair to structurally replace circumferential shroud welds.

The PNPS fatigue monitoring program will assure that the allowed number of transient cycles is not exceeded. The program requires corrective action if transient cycle limits are approached. Consequently, the TLAA (fatigue analyses) based on those transients will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i) or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

License renewal commitment 35 addresses metal fatigue for reactor vessel components, including the feedwater nozzles.

S.3.2.2 Non-Class 1 Metal Fatigue

For non-Class 1 components identified as subject to cracking due to fatigue, a review of system operating characteristics was conducted to determine the approximate frequency of any significant thermal cycling. If the number of equivalent full temperature cycles is below the limit used for the original design (usually 7000 cycles), the component is suitable for extended operation. If the number of equivalent full temperature cycles exceeds the limit, evaluation of the individual stress calculations require evaluation. No components were identified with projected cycles exceeding 7000. Therefore, the TLAA for non-Class 1 piping and components remain valid for the period of extended operation in accordance with 10 CFR 54.21(c) (i).

S.3.2.3 Environmental Effects on Fatigue

The effects of reactor water environment on fatigue were evaluated for license renewal. Projected cumulative usage factors (CUFs) were calculated for the limiting locations identified in NUREG/CR-6260. Several locations may exceed a CUF of 1.0 with consideration of environmental effects during the period of extended operation. For these locations, at least 2 years prior to entering the period of extended operation, for the locations identified in NUREG/CR-6260 for BWRs of the PNPS vintage, PNPS will refine the current fatigue analyses to include the effects of reactor water

environment and verify that the cumulative usage factors (CUFs) are less than 1. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following:

1. For locations, including NUREG/CR-6260 locations, with existing fatigue analysis valid for the period of extended operation, use the existing CUF to determine the environmentally adjusted CUF.

2. More limiting PNPS-specific locations with a valid CUF may be added in addition to the NUREG/CR-6260 locations.

3. Representative CUF values from other plants, adjusted to or enveloping the PNPS plant specific external loads may be used if demonstrated applicable to PNPS.

4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.

During the period of extended operation, PNPS may also use one of the following options for fatigue management if ongoing monitoring indicates a potential for a condition outside the analysis bounds noted above.

1. Update and/or refine the affected analyses described above.

2. Implement an inspection program that has been reviewed and approved by the NRC (e.g., periodic nondestructive examination of the affected locations at inspection intervals to be determined by a method acceptable to the NRC).

3. Repair or replace the affected locations before exceeding a CUF of 1.0.

License renewal commitment 31 addresses environmental assisted fatigue for the locations identified in NUREG/CR-6260 for BWRs of the PNPS vintage.

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S.3.3 Environmental Qualification of Electrical Components

The PNPS EQ Program implements the requirements of 10 CFR 50.49 (as further defined by the Division of Operating Reactors Guidelines, NUREG-0588, and Reg. Guide 1.89). The program requires action before individual components exceed their qualified life. In accordance with 10 CFR 54.21(c)(1)(iii), implementation of the EQ Program provides reasonable assurance that the effects of aging on components associated with EQ TLAAs will be adequately managed such that the intended functions can be maintained for the period of extended operation.

S.3.4 Fatigue of Primary Containment, Attached Piping, and Components

In conjunction with the Mark I Containment Long-Term Program, the torus and attached piping systems were analyzed for fatigue due to mechanical loadings as well as thermal and anchor motion. This analysis was based on assumptions of the number of SRV actuations, operating basis earthquakes, and accident conditions during the life of the plant.

The fatigue usage calculated for PNPS is zero. However, the analysis considered all BWR plants which utilize the Mark I containment design. The analysis concluded that for all plants and piping systems considered the fatigue usage factor for an assumed 40-year plant life was less than 0.5. Extending plant life by an additional 20 years would produce a usage factor below 0.75. Since this is less than 1.0, the fatigue criteria are satisfied. This TLAA has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

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ATTACHMENT 3

Description of 10 CFR 50.59(d) Evaluation

(3 pages)

1.0 Proposed Change

Pilgrim condition report CR-PNP-2011-00242/ 00245 identified a small leak in the RBCCW B Heat Exchanger. Depending on the Salt Service Water (SSW) System pressure, the leakage can be into or out of the RBCCW System. Since continued leakage out of the RBCCW System would eventually cause it to become inoperable, compensatory measures are required to ensure that sufficient volume is maintained in the RBCCW Surge Tank for system operation following design basis transients and accidents. The compensatory measures consist of the following:

1. During normal operation, the RBCCW surge tank T-201B will be maintained at the highest possible level so that the maximum fluid volume is available for leakage. Periodically, the surge tank will be replenished to the tank overflow.

2. During normal operation, the RBCCW loop B leakage rate will be checked by monitoring surge tank level changes.

3. A temporary system consisting of a supply tank, pump, power supply, and valves will be staged to provide make-up water to RBCCW loop B.

4. Procedures and operator actions will be relied on post accident to align the temporary make-up system in a timely manner to ensure RBCCW loop B maintains adequate inventory.

2.0 Background

The Reactor Building Closed Cooling Water (RBCCW) System, PNPS System 30A, supplies cooling during all operating modes to the equipment located in the Reactor Building. The safety objectives of the RBCCW System are to provide cooling to the Core Standby Cooling Systems (CSCS) components and provide a heat sink for the Residual Heat Removal (RHR) heat exchangers. The system serves as a barrier between the primary system and the Salt Service Water (SSW) System, preventing seawater leakage into the NSSS and minimizing radioactive releases to the sea water. The RBCCW System normally operates at a higher pressure than the SSW System and is continuously monitored for its level of radioactivity. The RBCCW system also provides an intermediate loop and contamination barrier, which yields advantages since the corrosiveness of the seawater is localized to the SSW system piping components only.

The two (2) RBCCW loops are independent systems, each having three (3) centrifugal pumps taking suction from the system heat exchanger (HX) and delivering cooling water to the equipment in the system. The cooling water is heated as it performs the cooling function for the system components and returns through the shell side of the cooling water heat exchangers, where it is cooled by the seawater (SSW) circulated through the tube side.

The RBCCW cooling water then returns to the pump suction header, thus forming a continuous closed loop. Each closed cooling water loop has a head tank located at the system high point that serves as 1) a static head tank ensuring sufficient suction pressure to the pumps, 2) a means of adding makeup water to the system and 3) an expansion tank and surge tank for the system. Each loop also has a chemical addition tank functioning as a bypass feeder taking flow from the pump discharge, through the tank, and back to the pump suction. This tank is used to add chemical solutions for pH control and corrosion inhibition.

The main function of the RBCCW system following analyzed transients or LOCA (defined as any rupture in the primary coolant system for which normal reactor coolant supply makeup is inadequate) is to provide coolant to the RHR Heat Exchangers and associated equipment as they are placed into operation to limit the temperature of the Suppression Pool, which serves as a condensing medium for fluid discharged from the primary system and as a heat sink for the CSCS. The RBCCW system is an integral part of the containment cooling system which is depended on to ensure and maintain safe shutdown following analyzed transients that include station blackout (SBO) and loss-of-offsite power (LOOP) which results in a loss of the main heat sink (main condenser).

A surge tank, also called a head tank, is provided in each closed loop. The tank is nominally 4'0" diameter by 6'0" high with a capacity of 500 gallons, which is sized to accommodate the largest system volume change due to thermal expansion. The tank is located at the highest point in the system and is connected, via a 3" pipe, to the 16-inch RBCCW pump suction header. Makeup water to the tank is supplied through a 1-1/2-inch connection from the Demineralized Water Transfer System. Head tank level is maintained automatically by modulating a 1-inch air-operated valve on signal from a level transmitter and controller mounted locally. A signal from the transmitter opens the valve sufficiently to maintain the head tank at the desired level. The head tank is readily accessible during reactor operation for level adjustment if desired. Venting of the tank is directed to the secondary containment. Make-up water for the RBCCW system is normally provided to T- 201A & B from the Demineralized Water Transfer System.

CR-PNP-2011-00242/ 00245 documents that leakage in the RBCCW heat exchanger B (E-209B) is evident. If RBCCW pressure is lower than SSW pressure then there is a condition of chloride infiltration into the cooling water. This is exhibited by a rise in system surge tank level and an increase in chloride concentration in RBCCW water. This was the discovered condition. This condition is unacceptable for long term viability of the system.

3.0 Compensatory Measures Review

Per NEI 96-07 the compensatory measures require an evaluation and not the degraded condition.

Based on this guidance this evaluation addresses the following compensatory measures:

1. Loop-B RBCCW Head Tank T-201B shall be maintained at a high tank level to maximize the water volume available for leakage and maintain an available reserve capacity of 400 gallons. Periodically the head tank will be replenished to the tank overflow.
2. The head Tank T-201B will be monitored for system leakage at a frequency within the RBCCW LCO action statement of 72 hours to verify the leakage rate remains within the maximum leakage rate of 400 gal/day under post-accident conditions.
3. A temporary system consisting of a supply tank, power supply, and valves will be installed to provide make-up water to RBCCW loop B.
4. Procedures and operator actions will be relied on required to align the temporary make-up system post-accident in a timely manner to ensure adequate RBCCW cooling water inventory is maintained.

4.0 Conclusion

Based on the results of the 50.59 Evaluation, it was concluded that the proposed activity did not require prior NRC approval.