Entergy

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Michael A. Balduzzi
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December 14, 2004

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555-0001

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

Technical Specifications Amendment Request to Relocate Various Specifications Not Meeting the Criteria of 10 CFR 50.36(c)(2)(ii)

REFERENCE: NUREG-1433, Standard Technical Specifications for General Electric Plants, BWR/4, Revision 3

LETTER NUMBER: 2.04.104

Dear Sir or Madam:

Pursuant to 10 CFR 50.90, Entergy Nuclear Operations Inc. (Entergy) hereby proposes to amend its Facility Operating License, DPR-35. This proposed license amendment would relocate various requirements from the TS to the Final Safety Analysis Report (FSAR) or Technical Specification (TS) Bases. These requirements do not meet the criteria for inclusion in the TS as presented in 10 CFR 50.36(c)(2)(ii) and relocation is consistent with the content of the Standard Technical Specifications (NUREG-1433, Revision 3). Entergy has reviewed the proposed amendment in accordance with 10 CFR 50.92 and concludes it does not involve a significant hazards consideration.

Entergy requests approval of the proposed amendment by December 30, 2005. Once approved, the amendment shall be implemented within 60 days. Commitments made by the licensee in this letter are listed in Attachment 2.

A001

If you have any questions or require additional information, please contact Bryan Ford at (508) 830-8403.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 14th day of December, 2004.

Sincerely,

Michael A. Balduzzi

Michael A. Balduzzi

ES/dm

Enclosure: Evaluation of the proposed change – 9 pages

Attachments:
1. Proposed Technical Specification and Bases Changes (mark-up) – 12 pages
2. List of Regulatory Commitments – 1 page

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ENCLOSURE

EVALUATION OF THE PROPOSED CHANGE

ENCLOSURE

Evaluation of the Proposed Change

Subject: Technical Specifications Amendment Request to Relocate Various Specifications Not Meeting the Criteria of 10 CFR 50.36(c)(2)(ii)

1. Description

Entergy Nuclear Operations, Inc. (Entergy) is requesting to amend Operating License DPR-35 for Pilgrim Nuclear Power Station (PNPS). The proposed changes would revise the Operating License, Technical Specifications (TS) to relocate various requirements from the TS to the Final Safety Analysis Report (FSAR) or TS Bases. These requirements do not meet the criteria for inclusion in the TS as presented in 10 CFR 50.36(c)(2)(ii).

2. Proposed Changes

2.1 Relocate Reactor Protection System (RPS) alarm instrumentation functional test requirements to the FSAR. Affected TS Sections and pages:

- Table 4.1.1, page 3/4.1-5

2.2 Relocate trip system bus power monitors requirements to the FSAR for residual heat removal (RHR)/low pressure coolant injection (LPCI), core spray, automatic depressurization system (ADS), high pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) systems. Affected TS Sections and pages:

- Table 3.2.B, page 3/4.2-15
- Table 4.2.B, Item 7, page 3/4.2-32

2.3 Relocate core spray sparger (header) d/p instrumentation requirements to the FSAR. Affected TS Sections and pages:

- Table 3.2.B, page 3/4.2-15
- Table 4.2.B, Item 9, page 3/4.2-32
- 4.5.A.1.d, page 3/4.5-2

2.4 Relocate structural integrity requirements to the FSAR. Affected TS Sections and pages:

- 3.6.G and 4.6.G, page 3/4.6-8
- Bases pages B3/4.6-11 and B3/4.6-12

2.5 Relocate drywell-suppression chamber vacuum breaker position indication alarm system and associated actions to the TS Bases. Remove explicit detail defining "operable" drywell-suppression chamber vacuum breakers and include new surveillance to verify vacuum breaker closure. Make editorial terminology correction. Affected TS Sections and pages:

- 3.7.A.3.a, page 3/4.7-7: add "vacuum" between "reactor building" and "breakers."
- 3.7.A.4.a, page 3/4.7-7: Delete "Drywell-pressure suppression chamber vacuum breakers shall be considered operable if:" Also, make administrative corrections to referenced Specifications 3.7.A.4.b, c, and d reflecting other changes such that the referenced Specification is 3.7.A.4.b only.
- 4.7.A.4.a.1, page 3/4.7-7 added as a new surveillance to require: "Verify each drywell-pressure suppression chamber vacuum breaker is closed, except for testing, at least every 14 days." Current TS 4.7.A.4.a.1 and a.2 renumbered to a.2 and a.3.
- 3.7.A.4.a.1, 2, and 3, 3.7.A.4.b, and 4.7.A.4.b.2, page 3/4.7-8 are deleted. Renumber 3.7.A.4.c as 3.7.A.4.b.
- 3.7.A.4.d, page 3/4.7-9 is deleted.
- Associated Bases, page B3/4.7-7 revised to reflect these changes.

2.6 Delete TS 3.6.H, page 3/4.6-8.

3. Background

3.1 The reactor protection system (RPS) automatically initiates a reactor scram to (1) preserve the integrity of the fuel cladding, (2) preserve the integrity of the reactor coolant system, and (3) minimize the energy which must be absorbed following a loss of coolant accident, and prevents criticality. PNPS TS 3/4.1, Reactor Protection System, provides the limiting conditions for operation necessary to preserve the ability of the system to tolerate single failures and still perform its intended function even during periods when instrument channels may be out of service because of maintenance.

The RPS is of the dual channel type (reference FSAR Section 7.2 for additional design detail). The system is made up of two independent trip systems, each having two subchannels of tripping devices. Each subchannel has an input from at least one instrument channel that monitors a critical parameter. The outputs of the subchannels are combined in a 1 out of 2 logic (i.e., an input signal on either one or both of the subchannels will cause a trip system trip). The outputs of the trip systems are arranged so that a trip on both systems is required to produce a reactor scram.

Whenever an 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. Alarms are not required for plant safety. 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.

3.2 The purpose of the Residual Heat Removal (RHR) and Core Spray (CS) trip system bus power monitors is to monitor availability of Start-up transformer, availability of the emergency 4160 kV busses A5 and A6, and availability of the 125V DC control power to their respective logic systems. If any of these monitored parameters (bus power) are not available, these devices will annunciate an alarm in the main control room alerting the operator to investigate and take corrective action. The purpose of the trip system bus power monitors for the Automatic Depressurization System (ADS), High Pressure Coolant Injection system (HPCI), and Reactor Core Isolation Cooling system (RCIC) is to monitor availability of 125V DC control power to the logic systems. If 125V DC power is unavailable, these devices will annunciate an alarm in the main control room alerting the operator to investigate and take corrective action. The only function of these devices is to provide alarm in the control room; they do not initiate any trips or automatic actions.

3.3 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. 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 two 100 percent capacity core spray lines separately enter the reactor vessel through the two core spray nozzles. The lines divide immediately inside the reactor vessel. The two halves are routed to opposite sides of the reactor vessel. 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 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.

A detection system is also provided to continuously confirm the integrity of the core spray piping between the inside of the reactor vessel and the core shroud. A differential pressure switch measures the pressure difference between the top of the core support plate and the inside of the core spray sparger pipe just outside the reactor vessel. If the core spray sparger piping is sound, this pressure difference will be the small drop across the core resulting from inter-channel leakage. If integrity is lost, this pressure drop will also include the steam separator pressure drop. An increase in the normal pressure drop initiates an alarm in the main control room.

3.4 The Pilgrim Nuclear Power Station Inservice Inspection Program conforms to the requirements of 10 CFR 50.55a(g). Where practical, the inspection of ASME Section XI Class 1, 2, and 3 components conforms to the edition and addenda of Section XI of the ASME Boiler and Pressure Vessel Code required by 10 CFR 50.55a(g). When implementation of an ASME Code required inspection is determined to be impractical for PNPS, a request for relief from the inspection requirement is submitted to the NRC in accordance with 10 CFR 50.55a(g)(5)(iii).

Requests for relief from the ASME Code inspection requirements are submitted to the NRC prior to the beginning of each 10-year inspection interval for which the inspection requirement is known to be impractical. Requests for relief from inspection requirements that are identified to be impractical during the course of the inspection interval are reported to the NRC on an annual basis throughout the inspection interval.

3.5 The purpose of the drywell-suppression chamber vacuum breakers is to limit the pressure differential between the suppression chamber and drywell during post-accident drywell coolant operations so that the structural integrity of the containment is maintained. Additionally, when the vacuum breakers are in the closed position, the drywell atmosphere is directed through the suppression chamber vent header downcomers during drywell pressurization conditions. The flow path area for drywell atmosphere to reach suppression chamber air space without quenching via submerged downcomers (i.e., bypass area) must not exceed an allowable area. The allowable bypass area is based upon analysis considering primary system break area, suppression chamber effectiveness, and containment design pressure. Analyses show that the maximum allowable bypass area is 0.2 ft^2, which is equivalent to all vacuum breakers open 3/32". The effective total bypass area can be measured with a differential pressure decay rate, which is limited to 25% of allowable, thus providing a margin of safety for the primary containment in the event of a small break in the primary system.

Each drywell suppression chamber vacuum breaker is equipped with three switches. One switch provides full open indication only. Another switch provides closed indication and an alarm should any vacuum breaker come off its closed seat by greater than 3/32". The third switch provides a separate signal to the alarm should any vacuum breaker come off its closed seat by greater than 3/32". The annunciator system is non-safety related and performs no direct safety function.

4. Technical Analysis

Section 182a of the Atomic Energy Act of 1954, as amended (the Act) requires applicants for nuclear power plant operating licenses to include the TS as part of the license. The Commission's regulatory requirements related to the content for the TS are set forth in 10 CFR 50.36. That regulation requires that the TS include items in eight specific categories. The categories are (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation; (3) surveillance requirements; (4) design features; (5) administrative controls; (6) decommissioning; (7) initial notification; and (8) written reports. However, the regulation does not specify the particular requirements to be included in a plant's TS.

The Commission amended 10 CFR 50.36 (60 FR 36593, July 19, 1995), and codified four criteria to be used in determining whether a particular matter is required to be included in a limiting condition for operation (LCO), as follows: (1) Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary; (2) a process variable, design feature, or operating restriction that is an initial condition of a design-basis accident or transient analysis that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier; (3) a structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design-basis accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier; or (4) a structure, system, or component which operating experience or probabilistic safety assessment has shown to be significant to public health and safety. LCOs and related requirements that fall within or satisfy any of the criteria in the regulation must be retained in the TS, while those requirements that do not fall within or satisfy these criteria may be relocated to licensee-controlled documents. The PNPS FSAR and TS Bases are such licensee-controlled documents.

Consistent with these criteria, Entergy proposes to relocate the following specifications from the PNPS TS to the FSAR or TS Bases. The four criteria of 10 CFR 50.36 are addressed for each change.

4.1 TS Table 4.1.1 Functional Test requirements to include "and Alarm" are proposed for relocation to the FSAR.

(1) The alarm portion of the RPS instrumentation channels can be used to assist the operator in diagnosing the cause of any reactor trip. However, this instrumentation is not used to detect and indicate in the control room a significant abnormal degradation of the reactor coolant pressure boundary.

(2) The alarm portion of the RPS instrumentation channels specified in TS Table 4.1.1 are not used as an initial condition of a design basis accident or transient analysis that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier. RPS trip functions are assumed to function; however, this alarm instrumentation is not required to maintain or preclude a challenge to that integrity.

(3) The alarm portion of the RPS instrumentation channels specified in TS Table 4.1.1 are not used as part of the primary success path which functions or actuates to mitigate a design basis accident or transient. RPS trip functions are assumed to function for

accident mitigation sequences; however, this alarm instrumentation is not required to maintain or preclude a challenge to that function.

(4) Operating experiences or probabilistic safety assessments have not shown the alarm portion of the RPS instrumentation channels specified in TS Table 4.1.1 to be significant to public health and safety.

The alarm portion of the RPS instrumentation channels functional test requirements specified in TS Table 4.1.1 will be relocated to the FSAR. Therefore, any changes to these requirements will be strictly controlled by the provisions of 10 CFR 50.59.

4.2 TS Tables 3.2.B and 4.2.B trip system bus power monitors requirements for residual heat removal (RHR)/low pressure coolant injection (LPCI), core spray, automatic depressurization system (ADS), high pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) systems are proposed for relocation to the FSAR.

(1) The trip system bus power monitors alarm instrumentation channels can be used to assist the operator in diagnosing the off-normal conditions. However, this instrumentation is not used to detect and indicate in the control room a significant abnormal degradation of the reactor coolant pressure boundary.

(2) The trip system bus power monitors alarm instrumentation channels specified in TS Tables 3.2.B and 4.2.B are not used as an initial condition of a design basis accident or transient analysis that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier. Trip system bus power is assumed to provide trip functions; however, this alarm-only instrumentation is not required to maintain or preclude a challenge to that function.

(3) The trip system bus power monitors alarm instrumentation channels specified in TS Tables 3.2.b and 4.2.B are not used as part of the primary success path which functions or actuates to mitigate a design basis accident or transient. Trip system bus power is assumed to function for accident mitigation sequences; however, this alarm-only instrumentation is not required to maintain or preclude a challenge to that function.

(4) Operating experiences or probabilistic safety assessments have not shown the trip system bus power monitors alarm instrumentation to be significant to public health and safety.

The trip system bus power monitors alarm instrumentation channel requirements specified in TS Tables 3.2.B and 4.2.B will be relocated to the FSAR. Therefore, any changes to these requirements will be strictly controlled by the provisions of 10 CFR 50.59.

4.3 TS Tables 3.2.B and 4.2.B, and Surveillance 4.5.A.1.d, core spray sparger (header) d/p instrumentation requirements are proposed for relocation to the FSAR.

(1) The core spray sparger (header) d/p instrumentation channels specified in TS 3.2.B and 4.2.B, and Surveillance 4.5.A.1.d, can be used to detect integrity of the core spray piping between the inside of the reactor vessel and the core shroud. However, this instrumentation is not used to detect and indicate in the control room a significant abnormal degradation of the reactor coolant pressure boundary.

(2) The core spray sparger (header) d/p instrumentation channels specified in TS 3.2.B and 4.2.B, and Surveillance 4.5.A.1.d, are not used as an initial condition of a design basis

accident or transient analysis that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier. Core spray header integrity is assumed, however, this instrumentation is not required to maintain or preclude a challenge to that integrity.

(3) The core spray sparger (header) d/p instrumentation channels specified in TS 3.2.B and 4.2.B, and Surveillance 4.5.A.1.d, are not used as part of the primary success path which functions or actuates to mitigate a design basis accident or transient. Core spray header integrity is assumed for accident mitigation sequences; however, this instrumentation is not required to maintain or preclude a challenge to that function.

(4) Operating experiences or probabilistic safety assessments have not shown the core spray sparger (header) d/p instrumentation channels specified in TS 3.2.B and 4.2.B, and Surveillance 4.5.A.1.d, to be significant to public health and safety.

The core spray sparger (header) d/p instrumentation channels specified in TS 3.2.B and 4.2.B, and Surveillance 4.5.A.1.d, requirements will be relocated to the FSAR. Therefore, any changes to these requirements will be strictly controlled by the provisions of 10 CFR 50.59.

4.4 The structural integrity requirements of TS 3.6.G and 4.6.G are proposed for relocation to the FSAR.

(1) TS 3.6.G and 4.6.G establishes the programmatic elements for conducting ASME Code Class 1, 2, and 3 component inspections by reference to Section XI of the ASME Code. The safety basis for establishing programmatic requirements on structural integrity in TS relate to prevention of component degradation and continued long-term maintenance of acceptable structural conditions. Therefore, structural integrity of safety systems are not operational limits that are an initial assumption of any DBA or transient analysis. Additionally, the inspections stipulated by this specification are not used to detect and indicate in the control room a significant abnormal degradation of the reactor coolant pressure boundary.

(2) The inspections stipulated by TS 3.6.G and 4.6.G do not monitor process variables that are initial assumptions in a DBA or transient analysis.

(3) The ASME Code Class 1, 2, and 3 components inspected per TS 3.6.G and 4.6.G are assumed to function to mitigate accidents. Their capability to perform this function is addressed by other TS. TS 3.6.G and 4.6.G, however, only specifies inspection requirements for these components. Therefore, Criterion 3 is not satisfied.

(4) The TS 3.6.G and 4.6.G requirement is currently covered by 10 CFR 50.55a and the PNPS Inservice Inspection Program. Duplicating regulatory requirements in TS is not a structure, system, or component which operating experience or probabilistic safety assessment has shown to be significant to public health and safety.

The structural integrity requirements of TS 3.6.G and 4.6.G requirements will be relocated to the FSAR. Therefore, any changes to these requirements will be strictly controlled by the provisions of 10 CFR 50.59, as well as 10 CFR 50.55a(g).

4.5 The drywell-suppression chamber vacuum breaker details of operability in 3.7.A.4.a are adequately specified in the associated surveillances and are deleted. The position indication alarm system requirements specified in TS 3/4.7.A.4 are proposed for relocation to the TS Bases.

(1) The drywell-suppression chamber vacuum breaker position indication alarm system is not used to detect and indicate in the control room a significant abnormal degradation of the reactor coolant pressure boundary.

(2) The drywell-suppression chamber vacuum breaker position indication alarm system is not used as an initial condition of a design basis accident or transient analysis that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier. Maintaining the drywell-suppression chamber vacuum breakers in the closed position is an assumed initial condition; however, this alarm system is not required to maintain, or minimize a challenge to, actual disk position.

(3) The drywell-suppression chamber vacuum breaker position indication alarm system is not used as part of the primary success path, which functions or actuates to mitigate a design basis accident or transient. Proper operation of the drywell-suppression chamber vacuum breakers to relieve negative pressure and otherwise return to the closed position are credited mitigative functions; however, this alarm system instrumentation is not required to assure that function.

(4) Operating experiences or probabilistic safety assessments have not shown the drywell-suppression chamber vacuum breaker position indication alarm system to be significant to public health and safety.

The drywell-suppression chamber vacuum breaker operability details remain unchanged and are adequately assured by the surveillance requirements and by the definition of operability. The criteria of 10 CFR 50.36(c)(2)(ii) apply to retain the requirement for operability; however, the convention consistent with NUREG-1433 to locate explicit details of operability to Surveillances, the Bases and the FSAR is applied.

Additionally, position indication alarm system requirements will be relocated to the TS Bases and replaced with a new surveillance requirement 4.7.A.4.a.1 to verify each drywell-suppression chamber vacuum breaker is in the closed position at least every 14 days. This is consistent with Standard Technical Specifications for General Electric Plants, BWR/4, NUREG-1433, Revision 3, Surveillance Requirement (SR) 3.6.1.8.1. Also consistent with NUREG-1433 Bases, the PNPS TS Bases for this surveillance will indicate that the periodic verification may utilize the position indications or by verification of a differential pressure decay rate test. For PNPS, the differential pressure decay rate test will be required when one of the two position indication alarm systems are inoperable as is currently required by action 3.7.A.4.d. This action currently requires verification every 15 days, however, based on the proposed surveillance 4.7.A.4.a.1, this re-verification will be required every 14 days.

The NUREG-1433 SR 3.6.1.8.1 also requires confirmation of drywell-suppression chamber vacuum breaker position (either position indicators or differential pressure decay test) "within 2 hours after any discharge of steam to the suppression chamber from the safety/relief valves (S/RVs) or any operation that causes the drywell-to-suppression chamber differential pressure to be reduced by ≥ [0.5] psid." Entergy is not proposing this portion of the NUREG-1433 surveillance frequency. This situational frequency is not required to be explicitly included. Normal operational monitoring of the status of plant systems, components, and valve positions has been shown adequate to assure proper valve positions are maintained. The addition of proposed surveillance 4.7.A.4.a.1, which adds a normal periodic verification not imposed in current requirements, provides adequate increased operational focus. This exception, based on historical TS requirements and normal operational monitoring, was similarly approved for the James A. FitzPatrick conversion to Standard TS, Amendment 274, dated July 3, 2002.

The corrected component terminology in TS 3.7.A.3.a is editorial and serves to facilitate proper use and application.

The proposed Bases changes are provided for information along with this amendment request. Any changes to these requirements will be strictly controlled by the provisions of 10 CFR 50.59 and TS 5.5.6, "Technical Specifications (TS) Bases Control Program."

4.6 TS 3.6.H is a previously "Deleted" Specification. This historical reference to a Specification no long in use is editorially deleted with no impact to any TS requirements.

In conclusion, the above relocated requirements are not required to be in the TS under 10 CFR 50.36 or 182a of the Atomic Energy Act, and are not required to obviate the possibility of an abnormal situation or event giving rise to an immediate threat to the public health and safety. In addition, sufficient regulatory controls over the relocated requirements exist (e.g., 10 CFR 50.59, 10 CFR 50.55a(g), and TS 5.5.6) to assure continued protection of public health and safety.

5. Regulatory Safety Analysis

5.1 No Significant Hazards Consideration

Entergy Nuclear Operations, Inc. (Entergy) is proposing to modify the Pilgrim Technical Specifications (TS) to relocate various requirements from the TS to the Final Safety Analysis Report (FSAR) or TS Bases. These requirements do not meet the criteria for inclusion in the TS as presented in 10 CFR 50.36(c)(2)(ii).

Entergy has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No. The proposed relocations are administrative in nature and do not involve the modification of any plant equipment or affect basic plant operation. The associated instrumentation and inspections are not assumed to be an initiator of any analyzed event, nor are these limits assumed in the mitigation of consequences of accidents.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No. The proposed change does not involve any physical alteration of plant equipment and does not change the method by which any safety-related system performs its function. As such, no new or different types of equipment will be installed, and the basic operation of installed equipment is unchanged. The methods governing plant operation and testing remain consistent with current safety analysis assumptions. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No. The proposed changes to relocate current TS requirements to the FSAR, consistent with regulatory guidance and previously approved changes for other stations, are administrative in nature. These changes do not negate any existing requirement, and do not adversely affect existing plant safety margins or the reliability of the equipment assumed to operate in the safety analysis. As such, there are no changes being made to safety analysis assumptions, safety limits or safety system settings that would adversely affect plant safety as a result of the proposed change. Margins of safety are unaffected by requirements that are retained, but relocated from the Technical Specifications to the FSAR. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Pilgrim concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Environmental Consideration

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need to be prepared in connection with the proposed amendment.

6. Precedents

The NRC has approved similar changes (e.g., relocation of specifications which do not meet the criteria of 10 CFR 50.36(c)(2)(ii)) in a number of amendments. Examples include Pilgrim Nuclear Power Station amendment No. 202 dated July 21, 2003. Similar regulatory criteria based relocations, as well as consistent presentation of new surveillance for drywell-suppression chamber vacuum breakers, are consistent with James A. FitzPatrick conversion to Standard TS, Amendment 274, dated July 3, 2002.

7. References

1. 10 CFR 50.36, "Technical Specifications"

2. NUREG-1433, Rev. 3, "Standard Technical Specifications, General Electric Plants, BWR/4"

3. Pilgrim Nuclear Power Station, amendment No. 202 dated July 21, 2003

4. James A. FitzPatrick conversion to Standard TS, Amendment 274, dated July 3, 2002

ATTACHMENT 1

PROPOSED TECHNICAL SPECIFICATION AND BASES

CHANGES (MARK-UP)

PNPS TABLE 4.1.1

REACTOR PROTECTION SYSTEM (SCRAM) INSTRUMENTATION FUNCTIONAL TESTS

MINIMUM FUNCTIONAL TEST FREQUENCIES FOR SAFETY INSTRUMENTATION AND CONTROL CIRCUITS

	Functional Test	Minimum Frequency (3)
Mode Switch in Shutdown	Place Mode Switch in Shutdown	Each Refueling Outage
Manual Scram	Trip Channel and Alarm	Every 3 Months
RPS Channel Test Switch (5)	Trip Channel and Alarm	Once per week
IRM		
High Flux	Trip Channel and Alarm (4)	Once Per Week During Refueling and Before Each Startup
Inoperative	Trip Channel and Alarm	Once Per Week During Refueling and Before Each Startup
APRM		
High Flux	Trip Output Relays (4)	Every 3 Months (7)
Inoperative	Trip Output Relays (4)	Every 3 Months
Flow Bias	Trip Output Relays (4)	Every 3 Months
High Flux (15%)	Trip Output Relays (4)	Once Per Week During Refueling and Before Each Startup
High Reactor Pressure	Trip Channel and Alarm (4)	Every 3 Months
High Drywell Pressure	Trip Channel and Alarm (4)	Every 3 Months
Reactor Low Water Level	Trip Channel and Alarm (4)	Every 3 Months
High Water Level in Scram Discharge Tanks	Trip Channel and Alarm (4)	Every 3 Months
Main Steam Line Isolation Valve Closure	Trip Channel and Alarm	Every 3 Months
Turbine Control Valve Fast Closure	Trip Channel and Alarm	Every 3 Months
Turbine First Stage Pressure Permissive	Trip Channel and Alarm (4)	Every 3 Months
Turbine Stop Valve Closure	Trip Channel and Alarm	Every 3 Months
Reactor Pressure Permissive	Trip Channel and Alarm (4)	Every 3 Months

PNPS
TABLE 3.2.B (Cont)

INSTRUMENTATION THAT INITIATES OR CONTROLS THE CORE AND CONTAINMENT COOLING SYSTEMS

Minimum # of Operable Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting	Remarks
1	RHR (LPCI) Trip System bus power monitor	NA	Monitors availability of power to logic systems.
1	Core Spray Trip System bus power monitor	NA	Monitors availability of power to logic systems.
1	ADS Trip System bus power monitor	NA	Monitors availability of power to logic systems and valves.
1	HPCI Trip System bus power monitor	NA	Monitors availability of power to logic systems.
1	RCIC Trip System bus power monitor	NA	Monitors availability of power to logic systems.
2	Recirculation Pump A d/p	≤2 psid	Operates RHR (LPCI) break detection logic which directs cooling water into unbroken recirculation loop.
2	Recirculation Pump B d/p	≤2 psid	
2	Recirculation Jet Pump Riser d/p A>B	0.5<p<1.5 psid	
1	Core Spray Sparger to Reactor Pressure Vessel d/p	-1(±1.5) psid	Alarm to detect Core Spray sparger pipe break.

PNPS
TABLE 4.2.B

MINIMUM TEST AND CALIBRATION FREQUENCY FOR CSCS

Instrument Channel	Instrument Functional Test	Calibration Frequency	Instrument Check
1) Reactor Water Level	(1) (7)	(7)	Once/day
2) Drywell Pressure	(1) (7)	(7)	Once/day
3) Reactor Pressure	(1) (7)	(7)	Once/day
4) Auto Sequencing Timers	NA	Once/Operating Cycle	None
5) ADS - LPCI or CS Pump Disch. Pressure Interlock	(1)	Once/3 months	None
6) Start-up Transf. (4160V)			
a) Loss of Voltage Relays	Monthly	Once/Operating Cycle	None
b) Degraded Voltage Relays	Monthly	Once/Operating Cycle	None
7) ~~Trip System Bus Power Monitors~~	~~Once/Operating Cycle~~	~~NA~~	~~Once/day~~
8) Recirculation System d/p	(1)	Once/3 months	Once/day
9) ~~Core Spray Sparger d/p~~ (Deleted)	~~NA~~	~~Once/18 months~~	~~Once/day~~
10) Steam Line High Flow (HPCI & RCIC)	(1)	Once/3 months	None
11) Steam Line High Temp. (HPCI & RCIC)	(1)	Once/24 months	None
12) Safeguards Area High Temp.	(1)	Once/24 months	None

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

A. Core Spray and LPCI Systems (Cont)

4. During Run, Startup, and Hot Shutdown Modes with the LPCI system inoperable, restore the LPCI system to Operable status within 7 days and maintain both core spray systems and the diesel generators Operable. Otherwise, be in at least Cold Shutdown within 24 hours.

5. Two low pressure injection/spray subsystems shall be Operable during Cold Shutdown and Refuel Modes unless the rector head is removed, the spent fuel pool gates are removed, and water level is at greater than or equal to elevation 114 foot, except as specified in 3.5.A.6.

6. During Cold Shutdown and Refuel Modes unless the reactor head is removed, the spent fuel pool gates are removed, and water level is at greater than or equal to elevation 114 foot:

   a. With one of the required low pressure injection/spray subsystems inoperable, restore the inoperable required low pressure injection/spray subsystem to Operable status within 4 hours. Otherwise, take immediate action to suspend activities with potential for draining the reactor vessel.

   b. With both of the required low pressure injection/spray subsystems inoperable, take immediate action to suspend activities with potential for draining the reactor vessel and restore 1 low pressure injection/spray subsystem to Operable status within 4 hours. Otherwise, take immediate action to restore secondary containment and one standby gas treatment system to Operable status and to restore isolation capability in each required secondary containment penetration flow path not isolated.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

A. Core Spray and LPCI Systems (Cont)

1. c. Motor Operated Valve Operability	As Specified in 3.13
~~d. Core Spray Header Δp Instrumentation~~	
~~Check~~	~~Once/day~~
~~Calibrate~~	~~Once/3 months~~
~~Test Step~~	~~Once/3 months~~

2. This section intentionally left blank

3. LPCI system testing shall be as follows:

a. Simulated Automatic Actuation Test	Once/ Operating Cycle
b. Pump Operability.	When tested as specified in 3.13, verify that each LPCI pump delivers 4800 GPM at a head across the pump of at least 380 ft.
c. Motor Operated Valve Operability	As Specified in 3.13

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

F. Jet Pump Flow Mismatch

1. Whenever both recirculation pumps are in operation, pump speeds shall be maintained within 10% of each other when power level is greater than 80% and within 15% of each other when power level is less than or equal to 80%.

2. If Specification 3.6.F.1 is exceeded immediate corrective action shall be taken. If recirculation pump speed mismatch is not corrected within 30 minutes, an orderly shutdown shall be initiated and the reactor shall be in the Cold Shutdown condition within 24 hours unless the recirculation pump speed mismatch is brought within limits sooner.

~~G. Structural Integrity~~

~~1. The structural integrity of the primary system boundary shall be maintained at the level required by the ASME Boiler and Pressure Vessel Code, Section XI "Rules for Inservice Inspection of Nuclear Power Plant Components," Articles IWA, IWB, IWC, IWD and IWF and mandatory appendices as required by 10CFR50.55a(g), except where specific relief has been granted by the NRC pursuant to 10CFR50.55a(g)(6)(i).~~

G ~~H. Deleted~~

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

F. Jet Pump Flow Mismatch

Recirculation pump speeds shall be checked and logged at least once per day.

~~G. Structural Integrity~~

~~Inservice inspection of components shall be performed in accordance with the PNPS Inservice Inspection Program. The results obtained from compliance with this program will be evaluated at the completion of each ten year interval. The conclusions of this evaluation will be reviewed with the NRC.~~

BASES:

3/4.6 **PRIMARY SYSTEM BOUNDARY (Cont)**

G. Structural Integrity

The Pilgrim Nuclear Power Station Inservice Inspection Program conforms to the requirements of 10CFR50.55a(g). Where practical, the inspection of ASME Section XI Class 1, 2, and 3 components conforms to the edition and addenda of Section XI of the ASME Boiler and Pressure Vessel Code required by 10CFR50.55a(g). When implementation of an ASME Code required inspection has been determined to be impractical for PNPS, a request for relief from the inspection requirement is submitted to the NRC in accordance with 10CFR50.55a(g)(5)(iii).

Requests for relief from the ASME Code inspection requirements will be submitted to the NRC prior to the beginning of each 10 year inspection interval for which the inspection requirement is known to be impractical. Requests for relief from inspection requirements which are identified to be impractical during the course of the inspection interval will be reported to the NRC on an annual basis throughout the inspection interval.

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LIMITING CONDITION FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

3. Pressure Suppression Chamber - Reactor Building Vacuum Breakers

a. Except as specified in 3.7.A.3.b below, two pressure suppression chamber - reactor building vacuum breakers shall be operable at all times when primary containment integrity is required. The setpoint of the differential pressure instrumentation which actuates the pressure suppression chamber - reactor building breakers shall be 0.5 psig.

b. From and after the date that one of the pressure suppression chamber - reactor building vacuum breakers is made or found to be inoperable for any reason, reactor operation is permissible only during the succeeding seven days unless such vacuum breaker is sooner made operable, provided that the repair procedure does not violate primary containment integrity.

4. Drywell-Pressure Suppression Chamber Vacuum Breakers

a. When primary containment is required, all drywell-pressure suppression chamber vacuum breakers shall be operable except during testing and as stated in Specification~~s~~ 3.7.A.4.b~~, c and d~~ below. ~~Drywell-pressure suppression chamber vacuum breakers shall be considered operable if:~~

SURVEILLANCE REQUIREMENT

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

3. Pressure Suppression Chamber - Reactor Building Vacuum Breakers

a. Verify operability of the pressure suppression chamber-reactor building vacuum breakers as specified in 3.13.

b. Check the associated instrumentation including set points for proper operation every three months.

4. Drywell-Pressure Suppression Chamber Vacuum Breakers

a. Periodic Operability Tests

1. Verify each drywell-pressure suppression chamber vacuum breaker is closed, except during testing, at least every 14 days

2. ~~(1)~~ Once each month each drywell-pressure suppression chamber vacuum breaker shall be exercised and the operability of the valve ~~and installed position indicators and alarms~~ verified.

3. ~~(2)~~ A drywell to suppression chamber differential pressure decay rate test shall be conducted at least every 3 months.

LIMITING CONDITION FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

~~1. The valve is demonstrated to open with the applied force of the installed test actuator as indicated by the position switches and remote position indicating lights.~~

~~2. The valve shall return by gravity when released after being opened by remote or manual means, to within 3/32" of the fully closed position.~~

~~3. Neither of the two position alarm systems, which annunciate in the Control Room when any vacuum breaker opening exceeds 3/32", are in alarm.~~

~~b. Any drywell-suppression chamber vacuum breaker may be non-fully closed as determined by the position switches provided that the drywell to suppression chamber differential decay rate is demonstrated to be not greater than 25% of the differential pressure decay rate for the maximum allowable bypass area of $0.2 ft^2$.~~

b. ~~c.~~ Reactor operation may continue provided that no more than 2 of the drywell-pressure suppression chamber vacuum breakers are determined to be inoperable provided that they are secured or known to be in the closed position.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

A. Primary Containment (Cont)

b. During each refueling interval:

1. Each vacuum breaker shall be tested to determine that the disc opens freely to the touch and returns to the closed position by gravity with no indication of binding.

(Deleted)

2. ~~Vacuum breaker position switches and installed alarm systems shall be calibrated and functionally tested.~~

3. At least 25% of the vacuum breakers shall be visually inspected such that all vacuum breakers shall have been inspected following every fourth refueling interval. If deficiencies are found, all vacuum breakers shall be visually inspected and deficiencies corrected.

4. A drywell to suppression chamber leak rate test shall demonstrate that the differential pressure decay rate does not exceed the rate which would occur through a 1 inch orifice without the addition of air or nitrogen.

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LIMITING CONDITION FOR OPERATION

3.7 CONTAINMENT SYSTEMS (Cont)

~~A. Primary Containment (Cont)~~

~~d. If a failure of one of the two installed position alarm systems occurs for one or more vacuum breakers, reactor operation may continue provided that a differential pressure decay rate test is initiated immediately and performed every 15 days thereafter until the failure is corrected. The test shall meet the requirements of Specification 3.7.A.4.b.~~

5. Oxygen Concentration

a. The primary containment atmosphere shall be reduced to less than 4% oxygen by volume with nitrogen gas during reactor power operation with reactor coolant pressure above 100 psig, except as specified in 3.7.A.5.b.

b. Within the 24-hour period subsequent to placing the reactor in the Run mode following a shutdown, the containment atmosphere oxygen concentration shall be reduced to less than 4% by volume and maintained in this condition. De-inerting may commence 24 hours prior to a shutdown.

6. If the specifications of 3.7.A.1 thru 3.7.A.5 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in Cold Shutdown condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS (Cont)

~~A. Primary Containment (Cont)~~

5. Oxygen Concentration

The primary containment oxygen concentration shall be measured and recorded at least twice weekly.

A: Primary Containment (Cont)

Reactor operation is not permitted if differential pressure decay rate is demonstrated to exceed 25% of allowable, thus providing a margin of safety for the primary containment in the event of a small break in the primary system.

Each drywell suppression chamber vacuum breaker is equipped with three switches. One switch provides full open indication only. Another switch provides closed indication and an alarm should any vacuum breaker come off its closed seat by greater than 3/32". The third switch provides a separate ~~and redundant~~ signal to the alarm should any vacuum breaker come off its closed seat by greater than 3/32". ~~The two alarms above are those referred to in Section 3.7.A.4.a.3 and 3.7.A.4.d.~~ INSERT

The water in the suppression chamber is used only for cooling in the event of an accident; i.e., it is not used for normal operation; therefore, a daily check of the temperature and volume is adequate to assure that adequate heat removal capability is present.

Inerting

The relatively small containment volume inherent in the GE-BWR pressure suppression containment and the large amount of zirconium in the core are such that the occurrence of a very limited (a percent or so) reaction of the zirconium and steam during a loss-of-coolant accident could lead to the liberation of hydrogen combined with an air atmosphere to result in a flammable concentration in the containment. If a sufficient amount of hydrogen is generated and oxygen is available in stoichiometric quantities, the subsequent ignition of the hydrogen in rapid recombination rate could lead to failure of the containment to maintain a low leakage integrity. The 4% oxygen concentration minimizes the possibility of hydrogen combustion following a loss-of-coolant.

The occurrence of primary system leakage following a major refueling outage or other scheduled shutdown is much more probable than the occurrence of the loss-of-coolant accident upon which the specified oxygen concentration limit is based. Permitting access to the drywell for leak inspections during a startup is judged prudent in terms of the added plant safety offered without significantly reducing the margin of safety. Thus, to preclude the possibility of starting the reactor and operating for extended periods of time with significant leaks in the primary system, leak inspections are scheduled during startup periods, when the primary system is at or near rated operating temperature and pressure. The 24-hour period to provide inerting is judged to be sufficient to perform the leak inspection and establish the required oxygen concentration.

The primary containment is normally slightly pressurized during periods of reactor operation. Nitrogen used for inerting could leak out of the containment but air could not leak in to increase oxygen concentration. Once the containment is filled with nitrogen to the required concentration, no monitoring of oxygen concentration is necessary. However, at least twice a week the oxygen concentration will be determined as added assurance. Mark I Containment Long Term Program testing showed that maintaining a drywell to

INSERT page B3/4.7-7

These position switches and installed alarm systems are calibrated and functionally tested each refueling interval.

Surveillance 4.7.A.4.a.1 is normally performed by observing the vacuum breaker position indications. If one of the two installed position alarm systems indicates any vacuum breaker may be non-fully closed, a differential pressure decay rate test is performed to verify that the vacuum breakers are closed. This method of verification can continue to meet 4.7.A.4.a.1 every 14 days thereafter until the indication failure is corrected. The test is satisfied if the drywell to suppression chamber differential decay rate is demonstrated to be not greater than 25% of the differential pressure decay rate for the maximum allowable bypass area of $0.2ft^2$. If this test fails, one or more drywell-pressure suppression chamber vacuum breakers is considered open. As such, with failure of the position alarm system(s), ... *<<add existing Bases as shown in markup>>*

ATTACHMENT 2

LIST OF REGULATORY COMMITMENTS

List of Regulatory Commitments

The following table identifies those actions committed to by Pilgrim in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments.

REGULATORY COMMITMENT	DUE DATE
Relocate specified requirements to the FSAR and TS Bases.	Within 60 days of license amendment approval.