Entergy

Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
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Kevin H. Bronson
Site Vice President

September 21, 2010

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

Entergy Response to NRC Request for Additional Information dated July 21, 2010, in support of Proposed License Amendment for Pilgrim Setpoint and Setpoint Tolerance Increases for Safety Relief Valves (SRV) and Spring Safety valves (SSV), and Related Changes (TAC NO. ME3543)

REFERENCE: 1. Entergy Letter No. 2.10.016, Proposed License Amendment to Technical Specifications: Revised Technical Specification for Setpoint and Setpoint Tolerances Increases for Safety Valves (SRV) and Spring Safety Valves (SSV), and Related Changes, dated March 15, 2010.

LETTER NUMBER: 2.10.040

Dear Sir or Madam,

This letter dockets Entergy's response to the NRC Request for Additional Information (RAI) forwarded to Pilgrim Licensing Staff by letter dated July 21, 2010.

Enclosure 1 provides the Entergy response to the NRC RAI. This information is not proprietary.

Enclosure 2 provides the proposed Updated FSAR, Appendix B pages for the relocated SRV leak detection temperature monitoring requirements.

Enclosure 3 provides re-typed Technical Specification and Bases pages.

Enclosure 4 is Revision 1 of GEH Report, NEDC-33532P, which was provided in Reference 1 as Attachment 1, and contains proprietary information as defined in 10 CFR 2.390, "Public inspections, exceptions, request for withholding." General Electric Hitachi (GEH), as the owner of the proprietary information, has executed an Affidavit provided within Enclosure 4, which identifies the information has been handled and classified as proprietary, is customarily held in confidence, and has been withheld from public disclosure. Accordingly, it is requested the proprietary information (Enclosure 4) be withheld from public disclosure in accordance with the provisions of 10 CFR 2.390 and 10 CFR 9.17, "Agency records exempt from public disclosure." A non-proprietary version of the information is provided as Enclosure 5.

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GEH Report NEDC-33532P, Rev. 1 does not materially change the information provided in Reference 1.

The enclosed Entergy response supports the proposed License Amendment for Setpoint and Setpoint Tolerances Increases for Safety Relief Valves (SRV) and Spring Safety Valves (SSV), and Related Changes and the No Significant Hazards Consideration determination submitted by Reference 1.

There are no commitments made in this submittal.

If you have any questions, please call Mr. Joseph Lynch, Pilgrim Licensing Manager at 508-830-8403.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 21 day of September, 2010

Sincerely,

Kevin Bronson

Kevin Bronson
Site Vice President

Enclosure 1: Entergy Response to NRC Request for Additional Information, dated July 21, 2010 (8 pages)
Enclosure 2: Proposed Pilgrim Updated FSAR, Appendix B (3 Pages)
Enclosure 3: Re-Typed Technical Specification and Bases Pages (13 Pages)
Enclosure 4: (Proprietary Version) GE Hitachi Nuclear Energy Report, NEDC-33532P, "Pilgrim Nuclear Power Station Safety Valve Setpoint Increase", Rev. 1, August 2010 (74 Pages)
Enclosure 5: (Non-Proprietary Version) GE Hitachi Nuclear Energy Report, NEDC-33532, "Pilgrim Nuclear Power Station Safety Valve Setpoint Increase", Rev. 1, August 2010 (71 Pages)

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ENCLOSURE 1

To Entergy Letter Number 2.10.040

ENTERGY RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION

DATED JULY 21, 2010

RELATED TO PROPOSED LICENSE AMENDMENT FOR SRV AND SSV SETPOINT AND SETPOINT TOLERANCES INCREASES

(Total 8 pages)

ENCLOSURE 1

to Entergy Letter No. 2.10.040

ENTERGY RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) RELATED TO REVISION TO TECHNICAL SPECIFICATION FOR SETPOINT AND SETPOINT TOLERANCE INCREASES FOR SAFETY RELIEF VALVES (SRV) AND SPRING SAFETY VALVES (SSV), AND RELATED CHANGES

PILGRIM NUCLEAR POWER STATION (TAC # ME3543)

Reference:

1. Letter from K. Bronson (Entergy) to USNRC, "Revised Technical Specification for Setpoint and Setpoint Tolerance Increases for Safety Relief Valves (SRV) and Spring Safety Valves (SSV), and Related Changes," March 15, 2010.

2. GE Hitachi Nuclear Energy Report, NEDC-33532P, "Pilgrim Nuclear Power Station Safety Valve Setpoint Increase," Rev. 1, August 2010.

NRC REQUEST FOR ADDITIONAL INFORMATION (RAI):

1. In Item No. 3 in Table 1: "Proposed TS Changes," of Attachment 1 to the submittal [Ref. 1], it was stated that Tailpipe Temperature Indication from Technical Specification (TS) Table 3.2.F and asterisk in Note (5) will be removed, and Note (6) will be revised and relocated to updated final safety analysis report (UFSAR). The staff understands that the limiting conditions of operation (LCO) for the instrumentation that monitors tail pipe temperature are given in Table 3.2-F. It provides the requirements for number of operable thermocouples (T/C) for SRV tail pipe temperature indication. In addition, Note (6) requires that if a T/C becomes inoperable, it shall be returned to an operable condition within 31 days, or the reactor shall be placed in a shutdown mode within 24 hours. Please provide the following additional information:

   a) Provide the language that will be added to the UFSAR.

   b) Will all of the requirements that currently exist in the TS be maintained after the proposed relocation to the UFSAR? If not, then justify why the requirement is no longer necessary.

   c) After removal of Tailpipe Temperature Indication from TS Table 3.2.F and asterisk in Note (5), and relocation of Note (6) to UFSAR, explain how the requirements for tailpipe temperature indication, as currently exist in the TS, will be implemented.

   d) As a follow up to part (c), the staff believes that limiting conditions for operation (LCO) for instrumentation must be located in the TS for appropriate regulatory control. Provide justification if you disagree.

   e) Are the proposed changes consistent with the Standard Technical Specification (STS)? If so, provide the relevant section numbers of the STS so that the staff can verify.

RESPONSE TO RAI 1.a) Provide the language that will be added to the UFSAR.

The proposed revision to the Updated FSAR, Appendix B is provided in Enclosure 2.

RESPONSE TO RAI 1.b) Will all of the requirements that currently exist in the TS be maintained after the proposed relocation to the UFSAR? If not, then justify why the requirement is no longer necessary.

No, all of the requirements that currently exist in the TS will not be maintained after the proposed relocation to the FSAR, Appendix B, because some of the requirements are not applicable for the 3-stage SRVs. The instrumentation provided to detect and evaluate valve leakage is significantly enhanced by additional thermocouples for the 3-stage SRVs. All of the requirements related to valve leak detection and evaluation will be included in the Updated FSAR. All of the requirements for valve position indication (open/close) will remain in the TS.

RESPONSE TO RAI 1.c) After removal of Tailpipe Temperature Indication from TS Table 3.2.F and asterisk in Note (5), and relocation of Note (6) to UFSAR, explain how the requirements for tailpipe temperature indication, as currently exist in the TS, will be implemented.

Enclosure 2 provides the requirements for Safety Relief Valve temperature monitoring that will be used to detect and evaluate valve leakage. The following description outlines the changes to valve leakage temperature monitoring that will be implemented with the 3-Stage Safety Relief Valves (SRVs).

Each of the currently installed 7567F 2-Stage Safety Relief Valves (SRVs) has one dual thermocouple located 16 to 22 feet from the valve discharge point. This thermocouple will be retained, and four additional thermocouples will be installed to monitor the 3-Stage SRV for leakage.

Each 3-Stage SRV will have a total of five dual thermocouples (T/Cs) as presented in the below Table that will be used in a systematic manner to detect and evaluate indications of SRV leakage.

Procedures will be developed that implement the requirements contained in Enclosure 2 which provides the functionality requirements for Safety Relief Valve temperature monitoring that will be used to detect and evaluate valve leakage. The information provided by the thermocouples will be used to detect valve leakage, determine the leak location, determine the need for increased monitoring, and if necessary, to declare the affected valve inoperable.

Data collection will be conducted during power ascension to establish baseline temperatures for the new thermocouples, which will be used to validate the alarm set points and response procedures.

The bellows and new discharge pipe ("tail pipe" is referred as "discharge pipe" hereafter) thermocouples will detect leakage and alarm in the control room at the predetermined increase above the baseline temperature. The tail pipe thermocouple located near the SRV discharge provides overall monitoring capability to detect leakage from any of the three stages. The first and second stage pilot valve thermocouples provide the capability to determine if either of the pilot valves is leaking. If neither of the pilot valves is leaking, and the discharge pipe alarm is valid, the main stage is the source of the leak by process of elimination. If a temperature alarm occurs on the bellows thermocouple, an increase in unidentified drywell leakage will be used to validate the alarm.

This condition would require the operators to write a Condition Report, which would require assessment of the adverse condition and appropriate corrective action in accordance with the requirements of 10 CR 50, Appendix B, including repair and/or replacement of the leaking SRV.

To comply with the corrective action process, an LCO is not required. Discharge pipe temperature indication and an alarm in the control room provide adequate information to commence corrective action, in the same manner an LCO would have required. Since Pilgrim is following the BWR STS which does not include an LCO for discharge pipe temperature monitoring, the requirements included in the Updated FSAR, Appendix B, which would be translated into applicable plant procedures provides for operator action upon observing increase in discharge pipe temperature and/or SRV leakage.

Table: 3-Stage SRV Thermocouples (Typical at 4 SRVs)

Point Description	RV-203-3X		Instrument Function/Purpose
	Element	**Alarms**	
First Stage Pilot Valve	TE-XXXX	NONE	Provide continuous temperature reading at the first stage pilot valve.
Second Stage Pilot Valve	TE-XXXX	NONE	Provide continuous temperature reading at the second stage pilot valve.
Bellows Integrity Monitoring	TE-XXXX	YES	Monitor ambient drywell temperature at a sensing line connected to the bonnet that surrounds the bellows. A control room alarm will occur at a predetermined temperature increase above ambient temperature that is indicative of bellows leakage.
New Discharge Pipe 4.5 to 6 ft down stream of discharge point (near)	TE-XXXX	YES	Monitor the SRV discharge pipe for indication of leakage from any of the three stages and provide initial control room alarm at predetermined temperature increase above ambient temperature. Provide backup SRV position monitoring for the Acoustic Monitor (primary)
Existing Discharge Pipe 16-22 ft down stream of discharge point (far)	TE-XXXX	NONE	Monitor the SRV discharge pipe for indication of leakage from any of the three stages. This location is too far from the first stage pilot valve to provide the required sensitivity to the small allowable leakage rate.

First Stage Thermocouple: This new thermocouple is installed in the valve body to detect first stage leakage which is a precursor to inadvertent main stage lift.

Second Stage Thermocouple: This new thermocouple is installed in the valve body to detect second stage leakage which is a precursor to inadvertent main stage lift.

Bellows Thermocouple: ASME B&PV Code, 1968 Edition. Section III, Article 9 Requirement N-911.2(5) states that where operation of the pilot control device is dependent upon integrity of a pressure sensing element, such as a bellows, means are to be provided to detect failure of the sensing element. The 3-Stage SRVs have a machined bellows that is used as a pressure sensor and operates the first stage pilot valve. A thermocouple is provided to detect leakage originating from the bellows. This thermocouple provides a control room alarm indicative of bellows leakage.

New Discharge Pipe Thermocouple: A new thermocouple will be installed approximately 4-1/2 to 6 feet downstream of the SRV discharge flange, positioned to detect small quantities of leakage from any of the three stages. This thermocouple is placed relatively close to the valve discharge to provide the required sensitivity for first stage leakage. This thermocouple also indicates valve actuation and will provide a control room alarm.

Existing Discharge Pipe Thermocouple: The existing SRV thermocouples (TE-6271, TE-6272, TE-6273, and TE-6276) contained in the current Technical Specifications 3/4.2 and Table 3.2.F and TS "NOTES FOR TABLE 3.2.F" are replaced with the functionally equivalent new thermocouples (TE-6285, TE-6286, TE-6287, and TE-6288). The new thermocouples will be listed in the NOTES FOR TABLE 3.2.F as a backup instrument for the acoustic monitors. Each SRV also has an acoustic monitor (ZE-203-3A, 3B, 3C, and 3D) with the sensor located on each valve discharge pipe, which provides valve open/close indication. Thus, the TS requirements for valve position indication are maintained. Note (6) from TS page 3/4.2-28, which addresses discharge pipe temperature monitoring for SRV leakage, is relocated to the Updated FSAR, Appendix B (Enclosure 2).

RESPONSE TO RAI 1.d) As a follow up to part (c), the staff believes that limiting conditions for operation (LCO) for instrumentation must be located in the TS for appropriate regulatory control. Provide justification if you disagree.

Entergy concurs with the NRC that the limiting conditions for operation (LCO) for instrumentation must be located in the TS for appropriate regulatory control, provided they fall within the scope of 10 CFR 50.36. The STS includes safety/relief valve position indication (open/close). NRC approved BWR STS Sections 3.3.3 and 3.4.3 do not provide for LCOs related to the discharge pipe temperature monitoring instrumentation for valve leakage.

Current instrumentation that provides SRV position indication are the acoustic monitor (primary) and a discharge pipe temperature thermocouple (backup), one per valve. This instrumentation is included in TS Table 3.2.F on page 3/4.2-26, with Note 5. The primary acoustic monitor and backup discharge pipe temperature thermocouple are listed under Note 5 on TS page 3/4.2-28, which provides the LCO with Action Statement. The current discharge pipe temperatures thermocouples located at 16 to 22 feet down stream on SRV discharge pipe are replaced with the new thermocouples located 4.5 to 6 feet from discharge point, as explained above. Either the acoustic (primary) or discharge pipe temperature (backup) parameter indicators shall be operable. Thus the regulatory controls associated with the SRVs and SSVs position indication are not relocated to the Updated FSAR.

The information associated with the discharge pipe temperature monitoring for SRV leakage is relocated to the Updated FSAR.

RESPONSE TO RAI 1.e) Are the proposed changes consistent with the Standard Technical Specification (STS)? If so, provide the relevant section numbers of the STS so that the staff can verify.

The proposed TS changes are consistent with the BWR STS 3.3.3 and 3.4.3. The relocation of SRV leakage temperature monitoring requirements in the Updated FSAR are consistent with the industry practice of maintaining TRM (Technical Requirements Manual), which is currently fulfilled by Updated FSAR, Appendix B.

NRC RAI 2

2. In 2nd paragraph in page 5 of Attachment 1 to the submittal [Ref. 1], it was stated that the existing TS surveillance for the two-stage Target Rock safety relief valve (SRVs) for tailpipe temperature monitoring, as specified in TS 3.6.D.3, 4, and 5, is not required and will be revised and relocated into the UFSAR. The staff understands that the objective of these surveillance requirements was to detect the leaking SRVs and to make corrective actions, if necessary, according to the LCO. Please provide the following additional information:

   a) Provide the language that will be added to the UFSAR.

   b) Describe how a potential leak during normal operation in a three-stage Target Rock SRV is detected, the corrective actions taken for leaking SRVs, and the LCO. As stated earlier, the staff believes that a LCO should be in the TS, and not in the UFSAR. Justify.

   c) Are the proposed changes consistent with the STS? If so, provide the relevant STS section numbers for the staff to verify.

RESPONSE TO RAI 2

As discussed in Response to RAI 1, Entergy is replacing the current two-stage SRVs with three-stage SRVs, and each SRV has five temperature monitoring instruments to detect and evaluate valve leakage. Temperature monitoring instruments for the purpose of detecting and evaluating valve leakage are not included in the BWR STS. Thus, the current TS 3.6.D.3, 4, and 5, as written are not applicable. Accordingly, the current TS 3.6.D.3, 4, and 5 requirements for valve leakage temperature monitoring instruments are modified to reflect the enhanced instrumentation (discharge pipe thermocouples) and relocated to the Updated FSAR, Appendix B (Enclosure 2).

RESPONSE TO RAI 2.a Provide the language that will be added to the UFSAR.

Proposed revision to the Updated FSAR, Appendix B is provided in Enclosure 2.

RESPONSE TO RAI 2.b Describe how a potential leak during normal operation in a three-stage Target Rock SRV is detected, the corrective actions taken for leaking SRVs, and the LCO. As stated earlier, the staff believes that a LCO should be in the TS, and not in the UFSAR. Justify.

Please refer to the response to RAI 1.c.

RESPONSE TO RAI 2.c Are the proposed changes consistent with the STS? If so, provide the relevant STS section numbers for the staff to verify.

The relocation of current TS 3.6.D.3, 4, and 5 requirements for SRV leakage monitoring to the UFSAR is consistent with the provisions of STS 3.3.3 and 3.4.3, which does not include discharge pipe temperature monitoring provisions to detect valve leakage.

NRC RAI 3

3. Results of plant-specific overpressure event for Pilgrim shown in Table 2-2 of the GEH report [Ref. 2] defines several types of pressure. The staff understands that the "Peak Dome Pressure" is the computer code (ODYN) calculated peak pressure at the vessel dome during the event; and the "Peak Vessel Pressure" is the peak pressure at the bottom of the vessel which is higher than the dome pressure by approximately an amount equal to the weight of fluid inside the vessel. The "Vessel Pressure Limit" is the ASME overpressure limit of 1375 psig [110% X 1250 psig (vessel design pressure)]. Please provide the following additional information:

   a) Confirm if the staff's understanding, as described above, is accurate. If not, clarify.

   b) Define the "Dome Pressure Safety Limit." Explain how the parameter is used in the safety analyses, methodology to calculate it, name of the computer code used. Also, justify the technical basis to arbitrarily increase its value from 1325 psig [106% of design pressure] to 1340 psig [107.2% of design pressure] in order to cover future cycle-to-cycle variation in cycle-specific calculations, and why it should be acceptable.

RESPONSE TO RAI 3.a

The staff's understanding as described in item 3 (above) is accurate.

RESPONSE TO RAI 3.b

The "Dome Pressure Safety Limit" refers to a conservative pressure limit established in the Technical Specification as the reactor pressure safety limit. If the Technical Specification "Dome Pressure Safety Limit" is not exceeded during operation, the ASME overpressure limit is not exceeded. The reactor steam dome pressure limit is measured directly by installed instrumentation, whereas the vessel bottom pressure cannot be directly measured by installed instrumentation. The "Dome Pressure Safety Limit" is currently set 50 psig below the ASME Code overpressure limit.

The "Dome Pressure Safety Limit" is used as a limit in the safety analyses. The proposed SRV and SSV setpoint and tolerance changes cause the calculated dome pressure to approach the currently established Technical Specification limit while substantially more margin remains to the ASME overpressure limit. Whereas, both the Technical Specification "Dome Pressure Safety Limit" and the ASME overpressure limit have the same purpose, the Technical Specification dome pressure safety limit is more limiting because it is currently set 50 psi below the ASME overpressure limit and the calculated pressure difference between the reactor steam dome and the vessel bottom is below 20 psi.

The ODYN computer code is used to perform overpressure protection analysis. This analysis is performed at 102% core thermal power with analytical control rod insertion times that bound the Technical Specification limits. The limiting event is a Main Steamline Isolation Valve (MSIV) closure with indirect scram from high neutron flux. The anticipatory scram signal that is initiated when the MSIVs are $\leq$ 10% closed is neglected for this analysis. This analysis calculates both the dome pressure and vessel bottom pressure.

The technical basis that justifies increasing the "Dome Pressure Safety Limit" from 1325 psig to 1340 psig is the ASME overpressure protection analysis performed for and submitted in support of this license amendment request [Ref. 2].

The results from Table 2-2 in Reference 2 (outlined below in Table 1), show the margin to the ASME overpressure limit is substantially greater than exists between the calculated dome pressure and the current "Dome Pressure Safety Limit" (i.e., 2 psid versus 34 psid). By utilizing the proposed "Dome Pressure Safety Limit" of 1340 psig as a limit in the safety analyses, the vessel bottom pressure is conservatively limited to a value of 1357 psig (e.g., 1340 psig + 17 psid) which is well below the ASME overpressure limit of 1375 psig.

Table 1: Reactor Dome Pressure Limit

TS Dome Pressure Safety Limit (psig)	Maximum Calculated Dome Pressure (psig)	Margin to TS Dome Pressure Safety Limit (psid)	Maximum Calculated RPV Bottom Pressure (psig)	Margin to ASME Overpressure Limit (psid)
Current 1325	1323	2	1341	34
Proposed 1340	1323	17	1341	34

The peak pressures for the piping systems connected to the reactor vessel have been recalculated based on the reactor peak dome pressure of 1340 psig and the hydrostatic head based on the piping elevations. The USAS Piping Code and ASME Section III permit pressure transients and other occasional loads whose combined effect do not exceed stress levels based on the duration of the loads and the applicable service limit. The peak pressures are below the lowest of the transient pressures permitted by the applicable design code. These analyses form the bases and justification for the proposed Technical Specification "Dome Pressure Safety Limit" of 1340 psig.

NRC RAI 4

4. In page 8 of the submittal [Ref. 1], it was stated, "All valves reviewed to date were successfully screened with the exception of the reactor core isolation coolant (RCIC) Pump Injection Valve (MO1301-49). This motor operated valve (MOV) does not demonstrate sufficient margin based on a review of the weak link and torque/thrust analyses. PNPS will modify valve components or replace MOVs as a part of the SRV/SSV modification package to assure that sufficient margin exists prior to implementing the full modification package." Please provide a more specific plan to implement your modification of MOVs.

RESPONSE TO RAI 4

A design change package has been prepared to modify MO-1301-49 in RFO18 to achieve increased thrust margin at torque switch trip. The existing weak link analysis for MO-1301-49 was reviewed in more detail, and it was determined that some excessively conservative assumptions could be revised in the calculation of the maximum allowed thrust for the limiting valve components. The result is an increase in the maximum allowed thrust. The overall gear ratio for the Limitorque actuator will be changed to increase the torque output, and therefore the operator output thrust margin. The valve will continue to function within its prescribed operating times. Diagnostic testing will be performed to confirm the adequacy of the torque switch setting and the resultant margin at torque switch trip. The performance of MO-1301-49 will continue to be evaluated as part of Pilgrim Station's MOV periodic verification program.

No other MOVs require modification in order to meet the new requirements imposed by the change in SRV and SSV setpoints and setpoint tolerances.

NRC RAI 5

5. Although the NRC staff has previously reviewed and approved NEDC-31753P, the staff notes that the topical report is based on General Electric (GE) fuel core designs. If Pilgrim core is designed with mixed fuel types and/or includes non-GE fuel design, then demonstrate that the NEDC-31753P evaluation is applicable to the Pilgrim core design.

RESPONSE TO RAI 5

Section 3.3 of NEDC-31753 states that it is applicable to BWR-2 to 6. Pilgrim is a BWR-3 with all GE fuel. Pilgrim is currently operating Cycle 18 and the core is composed of GE 10X10 fuel types GE14 and GNF2, which are similar. The next cycle will replace GE14 fuel with GNF2 fuel. Therefore mixed core type concerns are not relevant to the application of NEDC-31753 to Pilgrim.

NRC RAI 6

6. Is debris generated as a result of the safety valve discharge into the drywell? If so, please describe how this is taken into account in the analysis of the Anticipated Transient Without Scram event, especially the effect of the debris on available net positive suction head of the Residual Heat Removal System

RESPONSE TO RAI 6

Some Nukon insulation debris would be generated by an SSV discharge. There is a tee on the SSV discharge that splits the flow and directs the discharge to minimize impact on nearby components and structures. The insulation debris would have minimal impact on ECCS pump suction since there is no significant transport mechanism to move insulation debris to the torus. The SSVs are located above the grating at the 41' elevation. The openings to the vent pipes leading to the torus are at elevation 13' and there is additional grating at elevation 21'. Multiple levels or grating between the SSVs and the torus vent pipes serve as debris interceptors. PNPS drywell spray flow rates are only 1000 gpm so this would not be a significant debris transport mechanism. Pilgrim has two large full bay stacked disc ECCS strainers in the torus that provide suction to the RHR and Core Spray pumps.

The controlling debris generation event to the ECCS strainers is a double ended 28" recirculation line break during a postulated LOCA and this would result in a sustained steam and water flow to move the debris through the drywell and to the torus through the vent pipes and downcomers. The controlling recirculation line break is at a lower elevation than the SSVs so that the transport fraction would also be greater than the transport from upper elevations. ECCS flow rates post LOCA are in the 16,000 gpm range.

The acceptance criteria utilized for suppression pool temperature by PNPS for ATWS events requires the peak suppression pool temperature remain below the limiting event from design basis events. For PNPS, the limiting event in terms of suppression pool temperature and pump suction strainer debris loading is the design basis recirculation pump suction line break. The combination of the suction strainer debris loading and water temperature make the DBA-LOCA the limiting event for ECCS pump NPSH. PNPS specific analysis provided in NEDC-33532P, Table 3-10 demonstrates that the ATWS peak suppression pool temperature of 175.9°F is below the DBA-LOCA peak temperature of 185°F. Therefore, positive ECCS pump NPSH margin will be available during ATWS events because of a more favorable suppression pool temperature response and reduced ECCS strainer debris loading as compared to the DBA-LOCA.

ENCLOSURE 2

Entergy letter No. 2.10.040

RELOCATED PILGRIM TECHNCIAL SPECIFICATIONS

INTO THE PILGRIM UPDATED FSAR, APPENDIX B

(3 pages)

B. 2. 8 License Amendment No.____________ Relocation of Technical Specification Related to Safety Relief Valve Discharge Pipe Monitoring, 3/4.6.D.

This License Amendment relocates certain instrumentation related to Safety Relief Valve (SRV) discharge pipe temperature monitoring requirements to the FSAR. The relocated portions include requirements related to SRV discharge pipe temperature monitoring, daily temperature logging, and calibration and functioning of discharge pipe temperature monitoring instrumentation.

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 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 following dual thermocouples shall be functional.

   a. Bellows monitoring temperature

   b. The discharge pipe temperature monitoring (Thermocouple 4.5 to 6 feet down stream from discharge point)

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.

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.

3/4.6 D TECHNCIAL BASES FOR LEAKAGE MONITOTING

The purpose of monitoring Safety Relief Valve (SRV) discharge pipe temperature is to determine if the SRV is leaking so that appropriate corrective action can be taken to achieve acceptable SRV performance and compatibility with other requirements such as maintaining suppression pool temperature.

Enhanced temperature monitoring thermocouples have been installed to detect degraded SRV performance and to determine if leaking is occurring, and the source of the leakage. In addition to the thermocouples located on the discharge pipe 4.5 to 6 feet down stream of SRV discharge and the bellows monitoring thermocouples, there are thermocouples on the SRV first stage, second stage, and 16 to 22 feet down stream of SRV discharge. The bellows monitoring thermocouple will detect a degraded condition with the bellows and any leakage. The thermocouple 4.5 to 6 feet down stream of SRV discharge will detect any valve leakage due to the first stage, second stage or main stage. The first and second stage thermocouples can determine if valve leakage is due to first stage or second stage pilot leakage or main stage leakage. The thermocouple located 4.5 to 6 feet down stream of valve discharge is a backup to the acoustic monitor. The thermocouple located 16 to 22 feet down stream of the valve discharge is used to monitor larger leakage rates. A dual thermocouple will be installed at each temperature monitoring locations (first stage, second stage, 4.5 to 6 feet down stream on SRV discharge pipe, 16 to 20 feet down stream on SRV discharge pipe, and bellows monitoring). Under Section 3.6.D.3, only one of the dual thermocouples is necessary to perform the leakage monitoring function for 4.5 to 6 feet down stream on SRV discharge pipe and bellows monitoring.

General Electric (GE) Service Information Letter (SIL) No. 196, Supplement 11, dated October 31, 1977, provides a recommendation to install thermocouples 4.5 to 6 feet down stream of the discharge flange to achieve good sensitivity to determine SRV leakage with an alarm point setting for all SRVs. Thermocouples installed 4.5 to 6 feet down stream of the discharge point meet this recommendation for Pilgrim. This instrumentation provides indication and an alarm in the Control Room. This instrumentation replaces the temperature indication from the 16 to 22 feet down stream of the SRV discharge.

GE SIL 196. Supplement 5, dated October 31, 1977, recommends SRV bellows integrity monitoring with a pressure switch connected to the bonnet that surrounds the bellows assembly. Pilgrim has elected to monitor bellows integrity with a dual thermocouple connected to a sensing line attached to the bonnet surrounding the bellows assembly. Bellows assembly leakage will be considered to be present if there are indications of higher than normal temperature at the bellows thermocouple in combination with an unidentified drywell leakage rate increase. The thermocouples are more sensitive than pressure switches, as recommended by SIL 196, Supplement 11. The SRV bellows monitoring thermocouple will provide temperature indication and an alarm in the Control Room. The alarm setpoint will be determined during power ascension for operating Cycle 19 (restart from Refueling Outage 18) based upon the ambient temperature profile at the thermocouple location.

The SRV discharge pipe thermocouple located 4.5 to 6 feet down stream of the SRV discharge provides an alarm in the Control Room, which would indicate SRV leakage, but would not confirm SRV inoperability. Based on this indication an engineering evaluation would be required for continued operation. The SRV first stage, second stage and the discharge pipe thermocouple located 16 to 22 feet down stream of the discharge will provide additional information to determine the condition of SRV performance and leakage, which would be used in an engineering evaluation to determine the corrective actions.

ENCLOSURE 3

To Entergy Letter No. 2.10.040

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2.0 SAFETY LIMITS

2.1 Safety Limits

2.1.1 With the reactor steam dome pressure < 785 psig or core flow < 10% of rated core flow:

THERMAL POWER shall be ≤ 25% of RATED THERMAL POWER.

2.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow ≥ 10% of rated core flow:

MINIMUM CRITICAL POWER RATIO shall be ≥ 1.08 for two recirculation loop operation or ≥ 1.11 for single recirculation loop operation.

2.1.3 Whenever the reactor is in the cold shutdown condition with irradiated fuel in the reactor vessel, the water level shall not be less than 12 inches above the top of the normal active fuel zone.

2.1.4 Reactor steam dome pressure shall be ≤ 1340 psig at any time when irradiated fuel is present in the reactor vessel.

2.2 Safety Limit Violation

With any Safety Limit not met within two hours the following actions shall be met:

2.2.1 Restore compliance with all Safety Limits, and

2.2.2 Insert all insertable control rods.

REACTOR STEAM DOME PRESSURE (2.1.4)

The Safety Limit for the reactor steam dome pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the reactor coolant system is not endangered. The reactor pressure limit of 1340 psig as measured in the vessel steam dome was derived from the design pressure of the reactor vessel. The peak pressures for the piping systems connected to the reactor vessel have been recalculated based on a reactor steam dome peak pressure of 1340 psig. These peak pressures are below the lowest of the transient pressures permitted by the applicable design code: ASME Boiler and Pressure Vessel (B&PV) Code (1965 Edition, including the January 1966 Addendum) for the pressure vessel, USAS Piping Code B31.1 for the steam space piping and ASME Section III for the reactor coolant system recirculation piping. The ASME B&PV Code permits pressure transients up to 10% over the design pressure (110% x1250=1375 psig). The USAS Piping Code and ASME Section III permit pressure transients and other occasional loads whose combined effect do not exceed stress levels based on the duration of the loads and the applicable service limit.

REFERENCES

1) "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (through the latest approved amendment at the time the reload analyses are performed as specified in the CORE OPERATING LIMITS REPORT).

2) General Electric Thermal Analysis Basis (GETAB): Data, Correlation and Design Application, General Electric Co. BWR Systems Department, January 1977, NEDE-10958-PA and NEDO-10958-A.

3) "Methodology & Uncertainties for SLMCPR Evaluations," NEDC-32601-P-A (August 1999).

4) "Power Distribution Uncertainties for Safety Limit MCPR Evaluations," NEDC-32694-P-A (August 1999).

5) "GE 11 Compliance with Amendment 22 of GESTAR II," NEDE-31917P (April 1991).

6) "GE 14 Compliance with Amendment 22 of GESTAR II," NEDC-32868P (December 1998).

7) "Pilgrim Nuclear Power Station Safety Valve Setpoint Increase," GE Hitachi Nuclear Energy Report, NEDC-33532P, Rev. 1 (August 2010)

PNPS
TABLE 3.2.F (Cont)

SURVEILLANCE INSTRUMENTATION

Minimum # of Channels	Operable Instrument Instrument #	Parameter	Type Indication and Range	Notes
2	TI-5021-2A TRU-5021-1A TI-5022-2B TRU-5022-1B	Suppression Chamber Water Temperature Suppression Chamber Water Temperature	Indicator/ Multipoint Recorder 30-230°F (Bulk) Indicator/ Multipoint Recorder 30-230°F (Bulk)	(1) (2) (3) (4)) (1) (2) (3) (4)
1	PID-5021	Drywell/Torus Diff. Pressure	Indicator - .25 - +3.0 psig	(1) (2) (3) (4)
1	PID-5067A PID-5067B	Drywell Pressure Torus Pressure	Indicator -.25 - +3.0 psig Indicator -1.0 - +2.0 psig	(1) (2) (3) (4)
1/Valve	(a) Primary or (b) Backup	Safety/Relief Valve Position	a) Acoustic monitor b) Thermocouple	(5)
1/Valve	(a) Primary or (b) Backup	Safety Valve Position Indicator	a) Acoustic monitor b) Thermocouple	(5)
2	LI-1001-604A LR- 1001-604A LI-1001- 604B LR-1001- 604B	Torus Water Level (Wide Range) Torus Water Level (Wide Range)	Indicator /Multipoint Recorder 0 - 300"H_2O Indicator /Multipoint Recorder 0 - 300"H_2O	(1) (2) (3) (4) (1) (2) (3) (4)

NOTES FOR TABLE 3.2.F

(1) With less than the minimum number of instrument channels, restore the inoperable channel(s) within 30 days.

(2) With the instrument channel(s) providing no indication to the control room, restore the indication to the control room within seven days.

(3) If the requirements of notes (1) or (2) cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

(4) These surveillance instruments are considered to be redundant to each other.

(5) At a minimum, the primary or backup parameter indicators shall be operable for each valve when the valves are required to be operable. With both primary and backup instrument channels inoperable either return one (1) channel to operable status within 31 days or be in a shutdown mode within 24 hours.

The following instruments are associated with the safety/relief and safety valves:

Valve	Primary Acoustic Monitor	Backup Tail Pipe Temperature Thermocouple
203-3A	ZT-203-3A	TE6285
203-3B	ZT-203-3B	TE6286
203-3C	ZT-203-3C	TE6287
203-3D	ZT-203-3D	TE6288
203-4A	ZT-203-4A	TE6274-B
203-4B	ZT-203-4B	TE6275-B

(6) Deleted.

(7) With less than the minimum number of operable instrument channels, restore the inoperable channels to operable status within 7 days or prepare and submit a special report to the Commission within 14 days of the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the channels to operable status.

TABLE 3.2-G

INSTRUMENTATION THAT INITIATES RECIRCULATION PUMP TRIP AND ALTERNATE ROD INSERTION

Minimum Number of Operable or Tripped Instrument Channels Per Trip System (1)	Trip Function	Trip Level Setting
2	High Reactor Dome Pressure	1215 ± 5 psig
2	Low-Low Reactor Water Level	≥-46.3" indicated level

Actions (1) There shall be two (2) operable trip systems for each function.

(a) If the minimum number of operable or tripped instrument channels for one (1) trip system cannot be met, restore the trip system to operable status within 14 days or be in at least hot shutdown within 24 hours.

(b) If the minimum operability conditions (1.a) cannot be met for both (2) trip systems, be in at least hot shutdown within 24 hours.

3.2 PROTECTIVE INSTRUMENTATION (Cont)

The recirculation pump trip/alternate rod insertion systems are consistent with the "Monticello RPT/ARI" design described in NEDO-25016 (Reference 1) as referenced by the NRC as an acceptable design (Reference 2) for RPT. Reference 1 provides both system descriptions and performance analyses. The pump trip is provided to minimize reactor pressure in the highly unlikely event of a plant transient coincident with the failure of all control rods to scram. The rapid flow reduction increases core voiding providing a negative reactivity feedback. High pressure sensors and low water level sensors initiate the trip. The recirculation pump trip is only required at high reactor power levels, where the safety/relief valves have insufficient capacity to relieve the steam which continues to be generated in this unlikely postulated event. Requiring the trip to be operable only when in the RUN mode is therefore conservative. The low water level trip function includes a time delay of nine (9) seconds ± one (1) second to avoid increasing the consequences of a postulated LOCA. This delay has an insignificant effect on ATWS consequences. Additional Analysis of the ARI/RPT Setpoint for High Reactor Dome Pressure is identified in Reference 3.

Alternate rod insertion utlizes the same initiation logic and functions as RPT and provides a diverse means of initiating a reactor scram. ARI uses sensors diverse from the reactor protection system to depressurize the scram pilot air header, which in turn causes all control rods to be inserted.

References

1. NEDO-25016, "Evaluation of Anticipated Transients Without Scram for the Monticello Nuclear Generating Plant," September 1976.

2. NUREG-0460, Volume 3, December 1978.

3. "Pilgrim Nuclear Power Station Safety Valve Setpoint Increase," GR Hitachi Nuclear Energy Report, NEDC-33532P, Rev. 1, August 2010

Drywell Temperature

The drywell temperature limitations of Specification 3.2.H.1 ensure that safety related equipment will not be subjected to excess temperature. Exposure to excessive temperatures may degrade equipment and can cause loss of its operability.

The temperature elements for monitoring drywell temperature specified in Table 3.2.H were chosen on the basis of their reliability, location, and their redundancy (dual - element RTD's). These temperature elements are the primary elements used for the PCILRT.

The "nominal instrument elevations" provided in Tables 3.2.H and 4.2.H assist personnel in locating the instruments for surveillance and maintenance purposes and define the approximate containment region to be monitored. The "nominal instrument elevations" are not intended to provide a precise instrument location.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

C. HPCI System

1. The HPCI system shall be operable whenever there is irradiated fuel in the reactor vessel, reactor pressure is greater than 150 psig., and reactor coolant temperature is greater than 365°F, except as specified in 3.5.C.2 below.

2. From and after the date that the HPCI system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 14 days unless such system is sooner made operable, providing that during such 14 days all active components of the ADS system, the RCIC system, the LPCI system and both core spray systems are operable.

3. If the requirements of 3.5.C cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

C. HPCI System

1. HPCI system testing shall be as follows:

a. Simulated Automatic Actuation Test	Once/ Operating Cycle

---------------------- Note -----------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

----

b. Pump Operability	When tested as specified in 3.13, verify with reactor pressure ≤1035 and ≥ 940 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.
c. Motor Operated Valve Operability	As Specified in 3.13

---------------------- Note -----------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

----

d. Flow Rate at 150 psig.	Once/ Operating Cycle, verify with reactor pressure ≤ 150 psig. the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.

LIMITING CONDITIONS FOR OPERATION

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

D. Reactor Core Isolation Cooling (RCIC) System

1. The RCIC system shall be operable whenever there is irradiated fuel in the reactor vessel, reactor pressure is greater than 150 psig, and reactor coolant temperature is greater than 365°F, except as specified in 3.5.D.2 below.

2. From and after the date that the RCIC system is made or found to be inoperable for any reason, continued reactor operation is permissible only during the succeeding 14 days unless such system is sooner made operable, providing that during such 14 days the HPCIS is operable.

3. If the requirements of 3.5.D cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

D. Reactor Core Isolation Cooling (RCIC) System

1. RCIC system testing shall be as follows:

a. Simulated Automatic Actuation Test	Once/ Operating Cycle

---------------------- Note -----------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

----

b. Pump Operability	When tested as specified in 3.13, verify with reactor pressure ≤ 1035 and ≥ 940 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.
c. Motor Operability Valve Operability	As Specified in 3.13

---------------------- Note -----------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

----

d. Flow Rate at 150 psig.	Once/Operability Cycle verify with reactor pressure ≤ 150 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.

B 3/4.5 CORE AND CONTAINMENT COOLING SYSTEMS

3/4.5.E Automatic Depressurization (ADS) System

BASES

BACKGROUND

This specification ensures the operability of the ADS under all conditions for which the automatic or manual depressurization of the nuclear system is an essential response to station abnormalities.

The nuclear system pressure relief system provides automatic nuclear system depressurization for small breaks in the nuclear system so that the low pressure coolant injection (LPCI) and the core spray systems can operate to protect the fuel barrier.

Because the Automatic Depressurization System does not provide makeup to the reactor primary vessel, no credit is taken for the steam cooling of the core caused by the system actuation to provide further conservatism to the CSCS. Performance analysis of the Automatic Depressurization System is considered only with respect to its depressurizing effect in conjunction with LPCI or Core Spray. There are four valves provided and each has a capacity of 921,235 lb/hr at a reactor pressure of 1155 psig.

APPLICABLE SAFETY ANALYSIS

The limiting conditions for operating the ADS are derived from the Station Nuclear Safety Operational Analysis (FSAR Appendix G) and a detailed functional analysis of the ADS (FSAR Section 6).

ACTIONS

The allowable out of service time for one ADS valve is determined as 14 days because of the redundancy and because of HPCI operability; therefore, redundant protection for the core with a small break in the nuclear system is still available.

SURVEILLANCES

The testing interval for the core and containment cooling systems is based on industry practice, quantitative reliability analysis, judgment and practicality. The core cooling systems have not been designed to be fully testable during operation. For example, complete ADS testing during power operation causes an undesirable loss-of-coolant inventory. When components are tested and found inoperable the impact on system operability is determined, and corrective action or Limiting Conditions of Operation are initiated. A simulated automatic actuation test once each cycle combined with code inservice testing of the pumps and valves is deemed to be adequate testing of these systems. The ADS test circuit permits continued surveillance on the operable relief valves to assure that they will be available if required.

The surveillance requirements provide adequate assurance that the core and containment cooling systems will be operable when required.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

c. With no required leakage detection systems Operable, be in Hot Shutdown within the next 12 hours and in Cold Shutdown within the following 24 hours.

D. Safety and Relief Valves

1. During reactor power operating conditions and prior to reactor startup from a Cold Condition, or whenever reactor coolant pressure is greater than 104 psig and temperature greater than 340°F, both safety valves and the safety modes of all relief valves shall be operable.

2. If Specification 3.6.D.1 is not met, an orderly shutdown shall be initiated and the reactor coolant pressure shall be below 104 psig within 24 hours.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

D. Safety and Relief Valves

1. As specified in accordance with 3.13, verify the safety function lift setpoints of the safety and relief valves as follows:

No. of S/R Valves	Setpoint (psig)
2 Safety	1280 ± 38.4
4 Relief	1155 ± 34.6

Following testing, lift setting shall be within ± 1%.

---------------- Note ------------------

Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform test.

----

2. Once/ Operating Cycle, verify each relief valve opens when manually actuated.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

E. Jet Pumps

1. Whenever the reactor is in the Startup or Run Modes, all jet pumps shall be Operable. If it is determined that a jet pump is inoperable, the reactor shall be in Hot Shutdown within 12 hours.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

E. Jet Pumps

NOTES

1. Not required to be performed until 4 hours after the associated recirculation loop is in operation.
2. Not required to be performed until 24 hours after >25% Rated Thermal Power.

Whenever there is recirculation flow with the reactor in the Startup or Run Modes, jet pump operability shall be checked daily by verifying at least one of the following criteria (1, 2, or 3) is satisfied for each operating recirculation loop:

1. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns.
2. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns.
3. Each jet pump flow differs by ≤ 10% from established patterns.

C. Coolant Leakage (Cont)

The 2 gpm limit for unidentified coolant leakage rate increase within any 24 hour period is a limit specified by the NRC in Generic Letter 88-01: "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping". This limit applies only during the RUN mode to accommodate the expected coolant leakage increase during pressurization.

The total leakage rate consists of all leakage, which flows to the drywell equipment drain sump (Identified leakage) and floor drain sump (Unidentified leakage).

In addition to the sump monitoring of coolant leakage, airborne radioactivity levels of the drywell atmosphere is monitored by the Reactor Pressure Boundary Leak Detection System. This system consists of two panels capable of monitoring the primary containment atmosphere for particulate and gaseous radioactivity as a result of coolant leaks

D. Safety and Relief Valves

The valve sizing analysis considered four relief/safety valves and two safety valves. The set pressures are established in accordance with the following three requirements of Section III of the ASME Code:

1. The lowest safety valve must be set to open at or below vessel design pressure and the highest safety valve be set at or below 105% of design pressure.

2. The valves must limit the reactor vessel pressure to no more than 110% of design pressure.

3. Protection systems directly related to the valve sizing transient must not be credited with action (i.e., an indirect scram must be assumed).

BASES:

3/4.6 PRIMARY SYSTEM BOUNDARY (Cont)

D. Safety and Relief Valves (Cont)

A main steam line isolation with flux scram has been selected to be used as the safety valve sizing transient since this transient results in the highest peak vessel pressure of any transient when analyzed with an indirect scram. The original FSAR analysis concluded that the peak pressure transient with indirect scram would be caused by a loss of condenser vacuum (turbine trip with failure of the bypass valves to open). However, later observations have shown that the long lengths of steam lines to the turbine buffer the faster stop valve closure isolation and thereby reduce the peak pressure caused by this transient to a value below that produced by a main steam line isolation with flux scram.

Item 3 above indicates that no credit be taken for the primary scram signal generated by closure of the main steam isolation valves. Two other scram initiation signals would be generated, one due to high neutron flux and one due to high reactor pressure. Thus item 3 will be satisfied by assuming a scram due to high neutron flux.

Relieving capacity of 4 relief/safety valves in combination with 2 safety valves results in a peak pressure during the transient conditions used in the safety valve sizing analysis which is well below the pressure safety limit.

The relief/safety valve settings satisfy the Code requirements that the lowest safety valve set point be at or below the vessel design pressure range to prevent unnecessary cycling caused by minor transients. The results of postulated transients where inherent relief/safety valve actuation is required are identified or referenced in the Updated Final Safety Analysis Report.

Experience in safety valve operation shows that a testing of at least 50% of the safety valves per refueling outage is adequate to detect failures or deterioration. The tolerance value of ± 3% is in accordance with Section III of the ASME Boiler and Pressure Vessel Code. An analysis has been performed which shows that with all safety valves set 3% higher, the reactor coolant system pressure safety limit of 1375 psig is not exceeded.

The relief/safety valves have two functions; i.e., power relief or self-actuated by high pressure. Power relief is a solenoid actuated function (Automatic Pressure Relief) in which external instrumentation signals of coincident high drywell pressure and low-low water level initiate the valves to open. This function is discussed in Specification 3.5.E. In addition, the valves can be operated manually.

ENCLOSURE 5

To Entergy Letter No. 2.10.040

(Non-Proprietary Version)

GE Hitachi Nuclear Energy Report, NEDC-33532P,

"Pilgrim Nuclear Power Station Safety Valve Setpoint Increase", Rev. 1, August 2010

(71 Pages)