NPA-PD-LR

From: Ram Subbaratnam
To: Amar Pal; Angela Lavretta; Greg Galletti; Naeem IQBAL
Date: 8/23/2006 3:18:52 PM
Subject: Fwd: FW: Pilgrim License Renewal Application Amendment 6 (RAI Responses from Entergy on Pilgrim LRA)

Folks :

I am forwarding the responses received from Entergy on the RAI's that your branch/staff earlier provided to DLR for processing. I also provided you with a hard copy of these responses today. I earlier forwarded copies of your RAIs, as edited by the audit staff, who dropped duplicate questions previously covered during the audits.

Please study the responses and let me know ASAP, if the responses are satisfactory, or if you need further elaboration/phone call. I am also forwarding a copy of the audit questions and answers responses that the applicant provided on docket to the audit staff, if that helps with your review.

Please let me know ASAP as to what you need further in facilitating your SER input to me.

Thanking you in advance.

Ram Subbaratnam
PM Pilgrim LRA
415-1478

>>> "Ellis, Douglas" <dellis1@entergy.com> 08/23/2006 2:29 PM >>>
Ram - here is the pdf version. Hard copy in the U.S. Mail. Doug.

From: Marrier, Denise
Sent: Wednesday, August 23, 2006 2:21 PM
To: Ellis, Douglas
Subject: pdf file

Denise Marrier

Licensing Department

(508) 830-8568

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CC: Billy Rogers; Hossein Hamzehee; Sunil Weerakkody

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Creation Date 8/23/2006 3:18:52 PM
From: Ram Subbaratnam

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August 22, 2006

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

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

License Renewal Application Amendment 6

REFERENCE: Entergy letter, License Renewal Application, dated January 25, 2006 (2.06.003)

LETTER NUMBER: 2.06.074

Dear Sir or Madam:

In the referenced letter, Entergy Nuclear Operations, Inc. applied for renewal of the Pilgrim Station operating license. NRC TAC NO. MC9669 was assigned to the application.

This amendment to the License Renewal Application (LRA) consists of four attachments. Attachment A contains the response to the request for additional information (RAI) on LRA Section 2.1 (Scoping and Screening Methodology) conveyed in NRC letter dated July 25, 2006. Attachment B contains the response to the RAIs on LRA Sections 2.3.3.9 (Fire Protection System – Water) and 2.3.3.10 (Fire Protection System – Halon) conveyed in NRC letter dated July 26, 2006. Attachment C contains the response to the RAIs on LRA Section 2.5 (Scoping and Screening Results: Electrical and Instrumentation and Control Systems) conveyed in NRC letter dated July 31, 2006. Attachment D contains a replacement of LRA Appendix E (Environmental Report) Section 2.6.2 (Minority and Low-Income Populations) and new Tables 2-3a, 2-3b, and 2-3c and Figures 2-13 through 2-21.

This letter contains no new or revised commitments.

Please contact Mr. Bryan Ford, at (508) 830-8403, if you have any questions regarding this subject.

I declare under penalty of perjury that the foregoing is true and correct. Executed on August 22, 2006.

Sincerely,

(original signed by S. Bethay)

Stephen J. Bethay
Director, Nuclear Safety Assessment

DWE/dm
Attachments: (as stated)
cc: see next page

cc: with Attachments

Mr. Ram Subbaratnam
Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Ms. Alicia Williamson
Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Susan L. Uttal, Esq.
Office of the General Counsel
U.S. Nuclear Regulatory Commission
Mail Stop O-15 D21
Washington, DC 20555-0001

Sheila Slocum Hollis, Esq.
Duane Morris LLP
1667 K Street N.W., Suite 700
Washington, DC 20006

Mr. Joseph Rogers
Commonwealth of Massachusetts
Assistant Attorney General
Division Chief, Utilities Division
1 Ashburton Place
Boston, MA 02108

Mr. Matthew Brock, Esq.
Commonwealth of Massachusetts
Assistant Attorney General
Environmental Protection Division
One Ashburton Place
Boston, MA 02108

Diane Curran, Esq.
Harmon, Curran, and Eisenberg, L.L.P.
1726 M Street N.W., Suite 600
Washington, DC 20036

Molly H. Bartlett, Esq.
52 Crooked Lane
Duxbury, MA 02332

cc: without Attachments

Mr. James Shea
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Mr. Jack Strosnider, Director
Office of Nuclear Material and Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-00001

Mr. Samuel J. Collins, Administrator
Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

NRC Resident Inspector
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

Mr. Robert Walker, Director
Massachusetts Department of Public Health
Radiation Control Program
Schrafft Center, Suite 1M2A
529 Main Street
Charlestown, MA 02129

Ms. Cristine McCombs, Director
Massachusetts Emergency Management Agency
400 Worchester Road
Framingham, MA 01702

Mr. James E. Dyer, Director
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-00001

ATTACHMENT A to Letter 2.06.074
(5 pages)

Response to Request for Additional Information (RAI) on
LRA Section 2.1 (Scoping and Screening Methodology)

RAI 2.1-1: Review Methodology for Non-Accident Design Basis Events

10 CFR 54.4(a)(1) states, in part, that systems, structures, and components (SSCs) within the scope of license renewal include safety-related SSCs which are those relied upon to remain functional during and following design basis events (as defined in 10 CFR 50.49(b)(1). 10 CFR 50.49, states that design basis events are defined as conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena for which the plant must be designed. In regard to identification of design basis events, Section 2.1.3, "Review Procedures," of NUREG-1800 states:

The set of design basis events as defined in the rule is not limited to Chapter 15 (or equivalent) of the [updated final safety analysis report] (UFSAR). Examples of design basis events that may not be described in this chapter include external events, such as floods, storms, earthquakes, tornadoes, or hurricanes, and internal events, such as a high-energy-line break. Information regarding design basis events as defined in 10 CFR 50.49(b)(1) may be found in any chapter of the facility UFSAR, the Commission's regulations, NRC orders, exemptions, or license conditions within the [current licensing basis] (CLB). These sources should also be reviewed to identify systems, structures and components that are relied upon to remain functional during and following design basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the functions described in 10 CFR 54.4(a)(1).

During the scoping and screening methodology audit, the NRC staff questioned how non-accident design basis events, particularly design basis events that may not be described in the UFSAR, were considered during scoping. The NRC audit team noted that limiting the review of design bases events to those described in the UFSAR accident analysis could result in omission of safety-related functions described in the CLB.

The staff, therefore, requests the applicant to provide:

a. A list of the design basis events evaluated as part of the license renewal scoping process.

b. A description of the methodology used to ensure that all design basis events (including conditions of normal operation, anticipated operational transients, design basis accidents, external events, and natural phenomena) were addressed during license renewal scoping evaluation.

c. A list of the documentation sources reviewed to ensure that all design basis events were identified.

If, in addressing the above issues, the applicant's review indicates that additional scoping evaluations are required, describe these additional scoping evaluations to address the 10 CFR 54.4(a)(1) criteria. As applicable, list any additional SSCs included within the scope as a result of these efforts, and list those structures and components for which aging management reviews (AMRs) were conducted. For each structure or component describe the aging management programs (AMPs), as applicable, to be credited for managing the identified aging effects.

RAI 2.1-1 Response

a. The design basis events encompassed in the license renewal scoping process include the following.
   - Abnormal operational transients (UFSAR Table 14.4-1, "List of Transient Events")
   - Design basis accidents (UFSAR Section 14.5)
   - External events and natural phenomena (high winds, storm flooding, and seismic events evaluated in UFSAR Chapter 2)

b. Scoping evaluations relied on the safety classification process to ensure that all design bases events (including conditions of normal operation, anticipated operational transients, design basis accidents, external events, and natural phenomena) were addressed during license renewal scoping. Scoping included those systems, structures and components that are classified as safety-related for PNPS.

   The safety classification process is based on the Q-list procedure. During design basis events, unacceptable consequences are avoided by the successful performance of safety actions, which are defined in the Q-list procedure as a collection of activities performed by plant systems or personnel to ensure achievement of one or more of the primary safety goals during and following a design basis event. The primary safety goals, as defined in the procedure, correspond to 10 CFR 54.4(a)(1)(i) - (iii). Safety-related equipment is credited to perform safety actions. The safety actions listed in the Q-list procedure encompass the actions necessary to maintain the reactor coolant pressure boundary (RCPB), shutdown the reactor and maintain safe shutdown condition, and prevent or mitigate off-site releases for design basis events. The safety actions include protection from external events analyzed for the PNPS design basis. Systems and equipment necessary to perform safety functions defined in 10 CFR 54.4(a)(1)(i) - (iii) are classified as safety-related without exclusion of any design basis events.

c. As indicated in the response to (a) and (b) above, documentation sources reviewed to ensure that all design basis events were identified are the UFSAR and the site Q list.

No additional scoping evaluations were required as a result of addressing these issues.

RAI 2.1-2: 10 CFR 54.4(a)(2) Scoping Criteria for Nonsafety-related SSCs

NRC Regulatory Guide 1.188 (Reg. Guide 1.188), "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses," Revision 1, dated September 2005, (Reg. Guide 1.188) provided NRC endorsement on the use of NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 6, dated June 2005, (NEI 95-10). Reg. Guide 1.188 indicated that NEI 95 -10, Revision 6, provides methods that the NRC staff considers acceptable for complying with the requirements of 10 CFR Part 54 for preparing a license renewal application (LRA).

NEI 95-10, Appendix F, "Industry Guidance on Revised 54.4(a)(2) Scoping Criterion (Non-Safety Affecting Safety)," (NEI 95-10, Appendix F) discusses non-safety SSCs directly connected to safety-related SSCs. NEI 95-10, Appendix F states, in part, that an equivalent anchor may be defined in the CLB, or may consist of a large piece of plant equipment or series of supports that have been evaluated as a part of a plant-specific piping design analysis. Additionally, the guidance states that an applicant may use a combination of restraints or supports, such that the non-safety piping and associated structures and components attached to safety-related piping, is included in the scope up to a boundary point that encompasses at least two supports in each of three orthogonal directions. The guidance in NEI 95-10, Appendix F also describes as an alternative to identifying a seismic anchor or series of equivalent anchors, the use of bounding criteria which includes using a base-mounted component, a flexible connection, or the free end of the piping run as the end point for the portion of the non-safety piping attached to the safety-related piping to be included in the scope of license renewal.

Section 2.1.1.2.2, "Physical Failure of Nonsafety-related SSCs," of the LRA states the following: For Pilgrim Nuclear Power Station (PNPS), the "structural boundary" is defined as the portion of a piping system outside the safety class pressure boundary, yet relied upon to provide structural support for the pressure boundary.

Section 2.1.2.1.2, "Identifying Components Subject to Aging Management Review Based on Support of an Intended Function for 10 CFR 54.4(a)2," of the LRA states the following:

Nonsafety-related piping systems connected to safety-related systems were included up to the structural boundary or to a point that includes an adequate portion of the nonsafety-related piping run to conservatively include the first seismic or equivalent anchor. An equivalent anchor is a combination of hardware or structures that together are equivalent to a seismic anchor. A seismic anchor is defined as hardware or structures that, as required by analysis, physically restrain forces and moments in three orthogonal directions. The physical arrangement as analyzed insures that the stresses that are developed in the safety related piping and supports are within the applicable piping and structural code acceptance limits. This approach included piping beyond the safety/non-safety interface up to a base mounted component, flexible connection, or the end of a piping run (such as a drain line). This is consistent with the guidance in NEI 95-10, Appendix F.

Based on a review of the LRA, the applicant's scoping and screening implementation procedures, and discussions with the applicant, the NRC staff determined that additional information is required with respect to certain aspects of the applicant's evaluation of the 10 CFR 54.4(a)(2) criteria. The staff requests the applicant to provide the following information:

a. Indicate how the structural boundary, which includes the portion of the non-safety piping system outside the safety-related pressure boundary and relied upon to provide structural support for the pressure boundary, was developed. Include a description of the analysis performed to identify the portion of non-safety piping and components required to support the integrity of the safety-related piping and components.

b. Indicate whether equivalent anchors, outside of the analyzed structural boundary and not including the bounding condition terminations (base-component, flexible connection, and end of the piping run), were used. If equivalent anchors, outside of the analyzed structural boundary and not including the bounding condition terminations, were not used, items (c) and (d) below do not need to be addressed.

c. If equivalent anchors, as described in item (b) above, were used, indicate the definition of equivalent anchor which was used for the purpose of the 10 CFR 54.4(a)(2) evaluation and how the definition corresponds to the CLB and to the definition of equivalent anchor listed in NEI 95-10 Appendix F.

d. If equivalent anchors, as described in item (b) above, were used, indicate the number and location of equivalent anchors (i.e., extent of condition).

In addressing each of the above issues, if the review indicates that use of the scoping methodology precluded the identification of any non-safety SSCs that could interact with safety-related SSCs, describe any additional scoping evaluations to be performed to address the 10 CFR 54.4(a)(2) criteria.

As part of your response, list any additional SSCs included within the scope as a result of your efforts, and list those structures and components for which AMRs were conducted. For each structure and component, describe the AMPs, as applicable, to be credited for managing the identified aging effects.

RAI 2.1-2 Response

a. The structural boundary was developed through a review of the drawings prepared to indicate portions of systems that support system intended functions. The drawings were reviewed to identify safety/nonsafety interfaces. Nonsafety-related piping systems connected to safety-related systems were included to a point that includes enough of the nonsafety-related piping run to conservatively include the first seismic or equivalent anchor. This approach included piping beyond the safety/nonsafety interface up to a base-mounted component, flexible connection, or the end of a piping run (such as a drain line). No new piping stress analysis was performed to identify the portion of non-safety piping and components required to support the integrity of the safety-related piping and components and no isometric drawings were developed to identify the structural boundary. Existing drawings and the results of existing analyses as reflected on those drawings were used to develop the structural boundary. The use of this scoping method did not preclude the identification of any nonsafety-related SSCs that could interact with safety-related SSCs.

b. Equivalent anchors other than the analyzed structural boundaries and the bounding condition terminations as defined in NEI 95-10 Appendix F were not used to develop the structural boundaries.

c. Not applicable.

d. Not applicable.

RAI 3.0-X: Quality Assurance Program Attributes in Appendix A, "Updated Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs and Activities"

The NRC staff reviewed the applicant's AMPs described in Appendix A, "Updated Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs and Activities," of the LRA, and LRPD-02, "Aging Management Program Evaluation Report," Revision 1. The purpose of this review was to ensure that the quality assurance attributes (corrective action, confirmation process, and administrative controls) were consistent with the staff's guidance described in NUREG-1800, Section A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)."

Based on the NRC staff's evaluation, the descriptions of the AMPs and their associated quality attributes provided in Appendix A, Section A.2.1, and Appendix B, Section B.0.3, of the LRA are consistent with the staff's position regarding quality assurance for aging management. However, the description of the corrective action attribute in Section 2.0 of LRPD-02 did not credit the 10 CFR Part 50, Appendix B, quality assurance program.

Therefore, the NRC staff requests that the applicant clarify that the same corrective action program will be applied to all AMPs and that this program meets the requirements of 10 CFR Part 50, Appendix B.

RAI 3.0-X Response

LRA Appendix A Section A.2.1 is revised to include the following.

The corrective action controls of the Entergy (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities that will be required during the period of extended operation.

ATTACHMENT B to Letter 2.06.074

(8 pages)

Response to RAIs on LRA Sections 2.3.3.9 and 2.3.3.10

(Fire Protection Systems)

Section 2.3.3.9 Fire Protection System–Water

RAI 2.3.3.9-1

LRA drawings LRA-M-218-SH-01-0, LRA-M-218-SH-06-0, and LRA-M-218-SH-08-0 show the sprinkler and water spray systems for the turbine lube oil storage and conditioning as out of scope (i.e., not colored in orange). Please verify whether the turbine lube oil storage sprinkler system, conditioning room ceiling sprinkler system, and conditioning pre-action water spray system, are in scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a)(1). If they are excluded from the scope of license renewal and not subject to an AMR, provide justification for the exclusion.

RAI 2.3.3.9-1 Response

As described in Section 2.3.3.9 of the LRA, the fire protection system has no intended functions for 10 CFR 54.4(a)(1).

The fire protection–water system has the following intended function for 10 CFR 54.4(a)(2).

- Maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

The fire protection–water system and the fire protection–Halon system have the following intended function for 10 CFR 54.4(a)(3).

- The system is credited in the Appendix R safe shutdown analysis (10 CFR 50.48).

Therefore, the fire protection system is in scope for license renewal.

The turbine lube oil reservoir pre-action sprinkler subsystem, turbine lube oil storage room and ceiling sprinkler subsystems, and turbine lube oil conditioning pre-action water spray subsystem do not mitigate fires in areas containing equipment important to safe shutdown of the plant, nor are they credited with achieving safe shutdown in the event of a fire. These subsystems are designated nonFP-Q on the LRA drawings, indicating that they are only required to meet state, municipal, or insurance requirements. Therefore, these subsystems are not included in the aging management review summarized in LRA Table 3.3.2-9.

However, water-filled components in the fire protection system not covered in LRA Section 2.3.3.9 that could affect safety-related equipment require aging management review per 10 CFR 54.4(a)(2) due to potential spatial interaction. Therefore, these subsystems are subject to aging management review and are addressed in LRA Table 3.3.2-14-12. As stated in LRA Section 2.1.2.1.3, components subject to aging management review solely due to physical interaction under 10 CFR 54.4(a)(2) are not highlighted on the LRA drawings.

RAI 2.3.3.9-2

LRA drawing LRA-M-218-SH-02-0 shows the piping downstream of the city water supply as out of scope. With the city water supply serving as an alternate supply for the fire water system, please confirm and explain whether this line should be in scope for license renewal and subject to an AMR. If not, please explain the basis.

RAI 2.3.3.9-2 Response

The site fire water system takes suction from two 250,000-gallon water tanks devoted exclusively to fire protection. Although the city water supply may serve as an alternate supply for the fire water system, this source of water is not necessary to meet the requirements of 10 CFR 50.48. This source of water is designated nonFP-Q on LRA drawing LRA-M-218-SH-02-0, indicating that it is only required to meet state, municipal, or insurance requirements. Also, since it is outdoors away from safety-related equipment, the city water supply to the fire protection system cannot affect safety-related equipment per 10 CFR 54.4(a)(2) due to potential spatial interaction. Therefore, the city water supply to the fire water system is not in scope nor highlighted on LRA-M-218-SH-02-0 as subject to aging management review.

RAI 2.3.3.9-3

LRA Table 2.3.3-9 excludes several components shown in color (i.e., in scope) in the LRA drawing LRA-M-218-SH-01-0. For example, a reducer flange is shown in zone C-4 of the drawing and appears to restrict flow to the associated fire hose station. A blind flange is shown in zone F-6 in the reactor auxiliary bay. "Street box" housing is indicated in zone E-2. An unknown function or component is indicated by small trapezoid symbols shown mainly in headers upstream of hose stations in several buildings. An unknown function or component is indicated by a semi-circle symbol in zone F-4 located along a 2.5-inch line upstream of two hose stations in the reactor building. Please confirm and explain whether these components should be included in Table 2.3.3-9, as passive components within scope for license renewal and subject to an AMR. If not, please justify the exclusion.

RAI 2.3.3.9-3 Response

LRA section 2.0 states that the term "piping" in component lists may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. If such components have unique tag numbers or the specific component has a function other than pressure boundary, then flow elements, orifices and thermowells are identified as a separate component type.

The small trapezoidal symbols are reducers and the semi-circle in zone F-4 is a weld cap. The reducers and weld cap are passive components subject to aging management review. They are included in the "piping" line item in Table 2.3.3-9.

The "street box" housing in zone E-2 of LRA-M-218-SH-01-0 is a housing around the extension rod used to operate the buried valve. The street box does not perform a component intended function (defined in Table 2.0-1 of the LRA) and therefore is not subject to aging management review.

RAI 2.3.3.9-4

LRA Table 2.3.3-9 excludes several types of FP Water System components that appear in the SE and its supplements and/or UFSAR, and which also appear in the LRA drawings colored in orange. These components are listed below.

- hose station
- hose connections
- pipe fittings
- couplings
- threaded connections
- restricting orifices
- interface flanges
- chamber housing
- actuator housing (e.g., weight releasing cabinet housing)

For each, please determine whether the component should be included in Table 2.3.3.9, and if not, please provide the basis for the exclusion.

RAI 2.3.3.9-4 Response

- hose station – Since they support criterion (a)(3) equipment, hose stations are included in the structural aging management review. They are included in the "Fire hose reels" line item in LRA Table 2.4-6.
- hose connections – Hose connections are included in the "Piping" line item in LRA Table 2.3.3-9.
- pipe fittings – As stated in LRA section 2.0, the term "piping" in component lists may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Pipe fittings are included in the "Piping" line item in LRA Table 2.3.3-9.
- couplings – As stated in LRA section 2.0, the term "piping" in component lists may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Couplings are pipe fittings included in the "Piping" line item in LRA Table 2.3.3-9.
- threaded connections – As stated in LRA section 2.0, the term "piping" in component lists may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Threaded connections are pipe fittings included in the "Piping" line item in LRA Table 2.3.3-9.
- restricting orifices – As stated in LRA section 2.0, the term "piping" in component lists may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Restricting orifices are included in the "Piping" line item in LRA Table 2.3.3-9.
- interface flanges – As stated in LRA section 2.0, the term "piping" in component lists may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Interface flanges are pipe fittings included in the "Piping" line item in LRA Table 2.3.3-9.
- chamber housing – Retard chamber housings in sprinkler subsystems are included in "tank" line item in LRA Table 2.3.3-9.
- actuator housing (e.g., weight releasing cabinet housing) – Actuator housing is part of the active component "actuator" that is not subject to aging management review.

RAI 2.3.3.9-5

LRA Table 2.3.3-9 excludes other component types such as gear boxes, gauge snubbers, etc. Please determine whether these and/or additional component types are in scope and subject to an AMR, and should be included in Table 2.3.3-9. If not, please justify the exclusion.

RAI 2.3.3.9-5 Response

Gear boxes are active components not subject to aging management review. Gauge snubbers in the tubing to instruments are included in the "Tubing" line item in LRA Table 2.3.3-9.

RAI 2.3.3.9-6

LRA Tables 2.4-2, 2.4-3, 2.4-4, and 2.4-6 exclude noncombustible shields and curbs (and scuppers) from the list of structural FP components in scope for license renewal and subject to an AMR. Section 3.1.11 of the SE discusses the use of noncombustible shields between feedwater pumps to prevent oil release from one pump impinging on the other pumps. Sections 3.1.11 and 4.8 of the SE discuss the use of curbs (and scuppers) in the diesel oil day tank rooms to contain potential oil spills and prevent them from spreading to other fire areas in the event of an oil fire. Please determine whether noncombustible shields and curbs (and scuppers) should be included as components in scope for license renewal and subject to an AMR.

RAI 2.3.3.9-6 Response

The noncombustible shields between the feedwater pumps are subject to aging management review. The shields are composed of galvanized unistrut frames and marinate boards. The marinite is included in the "fire wrap" line item under elastomers and other materials in LRA Table 2.4-6. The frames are included in the "instrument racks, frames, and tubing trays" line item under steel and other metals in LRA Table 2.4-6.

LRA Table 2.4-6 also lists steel and concrete flood curbs as components subject to aging management review which includes the curbs in the diesel oil day tank rooms. Scuppers are openings in the curbs rather than separate components.

RAI 2.3.3.9-7

LRA Table 2.4-6 excludes smoke seals and fire retardant coatings from the list of structural bulk commodities components in scope for license renewal and subject to an AMR. The SE supplement dated March 24, 1988, discusses the installation of smoke seals in electrical conduits that pass through fire barriers and between fire areas. Sections 3.2.4 and 4.11 of the SE discuss the use of fire retardant coatings to protect polyvinyl chloride jacketed cables where the cables are not installed in enclosed cable trays. Please determine whether these two components should be in scope and subject to an AMR, and justify exclusion if they are out of scope.

RAI 2.3.3.9-7 Response

Smoke seals and fire retardant coatings are included in line items "fire stops" and "fire wraps" in LRA Table 2.4-6.

RAI 2.3.3.9-8

Section 4.3.5 of the SE discusses automatic water spray for the main power transformer, auxiliary transformer, and shutdown transformer. However, LRA drawing LRA-M-218-SH-01-0 and LRA-M-218-SH-05-0 show the Main Transformer Sprinkler System, Auxiliary Transformer Sprinkler System, Startup Transformer Sprinkler System, and Shutdown Transformer Sprinkler System, as out of scope of license renewal and AMR. Please confirm and explain whether these transformer sprinkler systems should be within scope for license renewal and subject to an AMR.

RAI 2.3.3.9-8 Response

As described in LRA Section 2.3.3.9, the fire protection system is in the scope of license renewal for 10 CFR 54.4(a)(3) because it is credited in the Appendix R safe shutdown analysis (10 CFR 50.48).

The main transformer sprinkler subsystem, auxiliary transformer sprinkler subsystem, startup transformer sprinkler subsystem, and shutdown transformer sprinkler subsystem do not mitigate fires in areas containing equipment important to safe operation of the plant, nor are they credited with achieving safe shutdown in the event of a fire. These subsystems are designated nonFP-Q on the LRA drawings, indicating that they are only required to meet state, municipal, or insurance requirements. Therefore, these subsystems are not included in the aging management review summarized in LRA Table 3.3.2-9.

The main transformer sprinkler subsystem, auxiliary transformer sprinkler subsystem, startup transformer sprinkler subsystem, and shutdown transformer sprinkler subsystem are deluge systems that do not normally contain water. Therefore, these subsystems do not require aging management review per 10 CFR 54.4(a)(2) due to potential spatial interaction.

RAI 2.3.3.9-9

Section 4.3.5 of the SE states that new sprinkler systems were proposed for the radwaste truck loading area and the access control area of the radwaste and control building. PNPS UFSAR Section 10.8.3.1 identifies sprinkler system FP for the access control area (i.e., wet pipe) and the radwaste truck lock area (i.e., dry pipe). However, the LRA drawing LRA-M-218-SH-01-0 shows these areas as out of scope. Please clarify whether these systems are in scope for license renewal and subject to an AMR.

RAI 2.3.3.9-9 Response

As described in LRA Section 2.3.3.9, the fire protection system is in the scope of license renewal for 10 CFR 54.4(a)(3) because it is credited in the Appendix R safe shutdown analysis (10 CFR 50.48).

The sprinkler subsystem for the radwaste truck loading area does not mitigate fires in areas containing equipment important to safe operation of the plant, nor is it credited with achieving safe shutdown in the event of a fire. This subsystem is designated nonFP-Q on the LRA drawings, indicating that it is only required to meet state, municipal, or insurance requirements. Therefore, this subsystem is not included in the aging management review summarized in LRA Table 3.3.2-9.

However, water-filled components in the fire protection system not covered in LRA Section 2.3.3.9 that could affect safety-related equipment require aging management review per 10 CFR 54.4(a)(2) due to potential spatial interaction. Therefore, this subsystem is subject to aging management review and is addressed in LRA Table 3.3.2-14-12. As indicated in LRA Section 2.1.2.1.3, components subject to aging management review solely due to physical interaction under 10 CFR 54.4(a)(2) are not highlighted on the LRA drawings.

The sprinkler subsystem for the access control area of the radwaste and control building is necessary to meet the Commissions regulations under 10 CFR 50.48, should be designated FP-Q on the LRA drawing, and is subject to aging management review. (A condition report has been issued under the corrective action program to correct the subsystem designation on the drawing.) LRA drawing LRA-M-218-SH-01-0 should have shown that this subsystem is subject to aging management review. Since the components, materials, and environments for this subsystem are the same as those for other subsystems, no changes are required to LRA Tables 2.3.3-9 or 3.3.2-9.

RAI 2.3.3.9-10

Section 4.8 of the SE discusses floor drains provided in all plant areas protected with fixed water fire suppression. LRA Section 2.3.3.9 states that structural FP components are reviewed in the structural evaluation for the building in which they are contained or in the structural bulk commodities review. However, LRA Tables 2.4-2, 2.4-3, 2.4-4, and 2.4-6 do not list floor drains as a FP component in scope for license renewal or an AMR. Should floor drains be included in scope for license renewal and subject to an AMR? If not, please provide justification for the exclusion.

RAI 2.3.3.9-10 Response

Water-filled components in the radioactive waste system (which includes the floor drain system) that could affect safety-related equipment require aging management review per 10 CFR 54.4(a)(2) due to potential spatial interaction. These components are subject to aging management review and are addressed in LRA Table 3.3.2-14-23.

Section 2.3.3.10 Fire Protection System–Halon

RAI 2.3.3.10-1

LRA drawing LRA-M-218-SH-04-0 shows a manual pneumatic actuator colored in purple (i.e., in scope). However, the actuator housing is not listed in LRA Table 2.3.3-10. Please clarify whether actuator housings are in scope and subject to an AMR. If not, please justify the exclusion.

RAI 2.3.3.10-1 Response

As stated in LRA section 2.0, the term "piping" in component lists may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. If such components have unique tag numbers or the specific component has a function other than pressure boundary, then flow elements, orifices and thermowells are identified as a separate component type.

The housings for the pneumatic actuators on drawing LRA-M-218-SH-04-0 are part of the system pressure boundary and are therefore subject to an aging management review. Since they are small components, without a unique tag number and no function other than pressure boundary, the housings for the pneumatic actuators are included in the "piping" line item in Table 2.3.3-10.

RAI 2.3.3.10-2

Section 4.4 of the SE discusses carbon dioxide as a fixed fire suppression system for the cable spreading room, turbine building tank, and hose reels in the switchgear area, reactor feed pump area, and generator area. SE supplements discuss conversion of the carbon dioxide fixed suppression capability to a Halon fixed suppression capability for the cable spreading room and switchgear area. The status of the other areas (i.e., the turbine building tank and the hose reels in the reactor feed plump and generator areas) is unclear. Please clarify whether fixed suppression exists for these other areas. If there is suppression, please describe the type of suppression provided and explain whether it is in scope and why.

RAI 2.3.3.10-2 Response

Section 4.4 of the SE does not state that the "turbine building tank" has a fixed fire suppression system. It states that the carbon dioxide for fire suppression is stored in a low pressure bulk storage tank located in the turbine building.

There are three fire hoses utilizing liquid CO_2 located in both the 23' and 37' switchgear rooms and turbine deck adjacent to the reactor feedwater pumps. However, these fixed carbon dioxide subsystems are required for insurance purposes but are not required for protection of safety-related systems.

The main turbine generator areas have fire water subsystems for suppression.

The turbine lube oil reservoir pre-action sprinkler subsystem, turbine lube oil storage and ceiling sprinkler subsystems, and turbine lube oil conditioning pre-action water spray subsystem do not mitigate fires in areas containing equipment important to safe operation of the plant, nor are they credited with achieving safe shutdown in the event of a fire. These subsystems are designated nonFP-Q on the LRA drawings, indicating that they are only required to meet state, municipal, or insurance requirements. Therefore, these subsystems are not included in the aging management review summarized in LRA Table 3.3.2-9.

However, water-filled components in the fire protection system not covered in LRA Section 2.3.3.9 that could affect safety-related equipment require aging management review per 10 CFR 54.4(a)(2) due to potential spatial interaction. Therefore, these subsystems are subject to aging management review and are addressed in LRA Table 3.3.2-14-12. As indicated in LRA Section 2.1.2.1.3, components subject to aging management review solely due to physical interaction under 10 CFR 54.4(a)(2) are not highlighted on the LRA drawings.

RAI 2.3.3.10-3

Section 4.4 of the SE states that a total flooding Halon extinguishing system will be installed for the computer and storage room, and PNPS FSAR Section 10.8.3.2 discusses automatic Halon suppression for the plant computer room and O&M building record storage vault. However, the LRA drawing LRA-M-218-SH-04-0, does not show the computer and storage room as in scope for license renewal and subject to an AMR. Furthermore, LRA Section 2.3.3-10 states that only passive mechanical components in the cable spreading room Halon system are required for compliance with 10 CFR 50.48 (fire protection regulations). However, please clarify whether these other areas are protected with automatic Halon suppression.

RAI 2.3.3.10-3 Response

Total flooding, automatically actuated Halon fire suppression systems protect the plant computer room and the O&M building record storage vault. These subsystems do not mitigate fires in areas containing equipment important to safe operation of the plant, nor are they credited with achieving safe shutdown in the event of a fire. These subsystems are only required to meet state, municipal, or insurance requirements. Therefore, these subsystems are not included in the aging management review summarized in LRA Table 3.3.2-10.

ATTACHMENT C to Letter 2.06.074

(3 pages)

Response to RAIs on LRA Section 2.5 (Scoping and Screening Results: Electrical and Instrumentation and Control Systems)

RAI 1

1. License renewal application (LRA) Section 2.5 states that the basic philosophy used in the electrical and instrumentation and control (I&C) components in the integrated plant assessment (IPA) was that components are included in the review unless they are specifically screened out. When used with the plant spaces approach, this method eliminates the need for unique identification of every component and its specific location. Also, it states that during the IPA, commodity groups and specific plant systems were eliminated from further review as the intended functions of commodity groups were examined. (1) Identify all the components that were screened out and provide a basis used for doing so. (2) Were all plant spaces evaluated under this methodology? If any spaces were excluded from evaluation, identify those spaces that were excluded and provide the reason why each space was excluded. (3) Identify commodity groups and specific plant systems that were eliminated from further review and provide a basis used for doing so.

Response to RAI 1

(1) The following passive, long-lived components within the cable and connection commodity group were determined to fulfill no license renewal intended functions.

Source range monitor cables

Source range monitors are nonsafety-related components that provide neutron flux information during reactor startup and low flux level operations. Failure of the source range monitors cannot prevent satisfactory accomplishment of a safety function and the monitors are not relied on to perform a function that demonstrates compliance with regulations for any of the regulated events.

Area radiation monitor cables (excluding high-range radiation monitors)

High-range area monitors are EQ and are replaced based on a qualified life. Other area radiation monitors are nonsafety-related components that provide information to warn of abnormal gamma radiation levels in areas where radioactive material may be handled. Failure of these area radiation monitors cannot prevent satisfactory accomplishment of a safety function and these monitors are not relied on to perform a function that demonstrates compliance with regulations for any of the regulated events.

(2) Electrical scoping and screening was based on a bounding approach that included all plant systems, irrespective of the spaces in which they are located. All plant commodity groups were evaluated under this method. The spaces approach is associated with the aging management review, not with screening. Spaces were not considered in screening.

(3) Two commodity groups were eliminated from further review. They are transmission conductors and uninsulated ground conductors.

Transmission conductors are uninsulated, stranded electrical cables used in outside buildings in high voltage applications.

A review of the PNPS UFSAR did not identify a license renewal intended function for transmission conductors. Transmission conductors do not meet the scoping criteria in 10 CFR 54.4. These components are not safety-related per 10 CFR 54.4(a)(1) and their failure cannot prevent satisfactory accomplishment of a safety function identified in 10 CFR 54.4(a)(1). Transmission conductors are not credited for mitigation of regulated events listed in 10 CFR 54.4(a)(3). Transmission conductors are subject to aging management review if they part of the plant systems portion of the offsite power system necessary for recovery of offsite power following an SBO as specified in ISG-2. However, PNPS does not utilize transmission conductors in the plant systems portion of the circuits for recovery of offsite power following SBO.

Uninsulated ground conductors (e.g., copper and aluminum cable, copper bar, and steel bar) make ground connections for electrical equipment. These uninsulated ground conductors connect to electrical equipment housings and electrical enclosures as well as metal structural features such as the cable tray system and building structural steel.

A review of the PNPS UFSAR did not identify a safety function or intended function for license renewal for uninsulated ground conductors. Uninsulated ground conductors enhance the capability of the electrical system to withstand disturbances (e.g., electrical faults, lightning surges) for equipment and personnel protection. Uninsulated ground conductors do not meet the scoping criteria in 10 CFR 54.4. These components are not safety-related per 10 CFR 54.4(a)(1) and are not credited for mitigation of regulated events listed in 10 CFR 54.4(a)(3). Industry and plant-specific OE for uninsulated ground conductors does not indicate credible failure modes that could prevent satisfactory accomplishment of a safety function identified in 10 CFR 54.4(a)(1).

RAI 2

2. LRA Section 2.5 states that fuse holders with metallic clamps are either part of a complex active assembly or part of circuits that perform no license renewal intended function. Where as in Table 2.5-1, fuse holder insulation material is identified as electrical and I&C components subject to aging management review (AMR). Confirm that Pilgrim Nuclear Power Station does not use fuse holders (with metallic clamps or bolted connection type) that are not part of a larger assembly, but support safety-related and non safety-related functions in which the failure of a fuse precludes a safety function from being accomplished [10 CFR 54.4(a)(1) and (a)(2)] and revise Table 2.5-1 accordingly.

Response to RAI 2

PNPS cables and connections commodity group includes fuse holders. Fuse holders are electrical connections (similar to terminal blocks) requiring aging management review.

The Interim Staff Guidance (ISG-5) on the Identification and Treatment of Electrical Fuse Holders for License Renewal (March 10, 2003) was issued due to NRC Staff concerns regarding fuse holders that use metallic clamps to secure the fuses. Consistent with this guidance, fuse holders inside enclosures of active components, such as switchgear, power supplies, power inverters, battery chargers, and circuit boards, are piece parts of the larger active assembly, and are not subject to aging management review.

Evaluations of fuse holders at PNPS indicated that the fuse holders utilizing metallic clamps or bolted connections are either part of an active component or located in circuits that perform no license renewal intended function. Therefore, fuse holders with metallic clamps at PNPS are not subject to aging management review.

RAI 3

3. LRA Section 2.5 states that electrical cables and connections subject to 10 CFR 50.49 environmental qualification (EQ) requirements are not subject to AMR since the components are replaced based on qualified life. Confirm that all electrical cables and connections subject to 10 CFR 50.49 EQ requirements are replaced based on qualified life (current licensing basis is 40 years).

Response to RAI 3

All electrical cables and connections subject to 10 CFR 50.49 EQ requirements are replaced based on qualified life.

ATTACHMENT D to Letter 2.06.074
(15 pages)

Changes to LRA Appendix E (Environmental Report)
Section 2.6.2 (Minority and Low-Income Populations)

Minority and Low-Income Populations

2.6.2.1 Background

The NRC performs environmental justice analyses utilizing a 50-mile radius around the plant as the environmental impact site and the state as the geographic area for comparative analysis. Entergy has adopted this approach for identifying the minority and low-income populations that could be affected by PNPS operations.

Entergy used ArcView® geographic information system software to combine U.S. Census Bureau (USCB) TIGER line data with USCB 2000 census data to determine minority and low-income characteristics (at the block-group level) within the 50-mile radius environmental impact site. Entergy included all block groups if any of their area lay within 50 miles of PNPS. The 50-mile radius includes 3,863 block groups. Entergy defines the geographic area for PNPS as a two-state area, with the largest portion of that area (89%) located in Massachusetts and a smaller portion (11%) in Rhode Island.

2.6.2.2 Minority Populations

The NRC procedural guidance for performing environmental assessments and considering environmental issues defines a "minority" population as the racial categories: American Indian or Alaskan Native, Asian, Native Hawaiian or Pacific Islander, Black races, other races, more than 2 races, and the aggregate of all minority races.

Hispanic ethnicity is also defined as a minority population category [Reference 2-33]. Hispanic ethnicity is not defined by the USCB as a racial category and, therefore, it is possible to have both white Hispanics and non-white Hispanics (e.g. Black Hispanic, Asian Hispanic). For the purposes of aggregation, a minority population that combines both minority races and Hispanic ethnicity can be defined as all non-white or multiple races plus white Hispanics. As a note, all non-white Hispanics are already counted in the non-white racial minority categories.

NRC guidance indicates that a minority population exists if either of the two following conditions exists:

Exceeds 50 Percent - the minority population of the environmental impact site exceeds 50 percent, or

More than 20 Percentage Points Greater - the minority population percentage of the environmental impact site is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

NRC guidance calls for use of the most recent USCB decennial census data. Entergy used 2000 census data [References 2-43 and 2-44] to determine the percentage of the total population in the two states that belong to each minority category (Table 2-3a). This information was then used to calculate minimum thresholds for each minority category. Because no block groups in the 50-mile radius environmental impact site exceeded the 50% minority population criterion above, the "more than 20% greater" criterion was used to establish minority population thresholds (Table 2-3a). Any block group with a minority category percentage that exceeded any of the minimum threshold listed in Table 2-3a was defined as a "minority population."

For each minority category, Entergy divided USCB minority population numbers for each block group by the total population within that block group to obtain the percent of the block group's population that belonged to each minority category. For each of the 3,863 block groups within 50 miles of PNPS, Entergy calculated the percent of the population in each minority category and compared the result to the corresponding geographic area's minority threshold percentages to determine if a minority population exists. The number of block groups that exceeded minority thresholds is summarized in Tables 2-3b and 2-3c. The location of each minority population within 50 miles of PNPS is shown in Figures 2-13 through 2-19 and Figure 2-22.

Based on the "more than 20 percent" criterion, a Native Hawaiian or other Pacific Islander minority population exists in one block group in Suffolk County, Massachusetts. Black minority populations exist in 261 block groups, with 233 of the block groups in Massachusetts and 28 in Rhode Island. Other minority race populations exist in 135 block groups, with 77 occurring in Massachusetts and 58 are in Rhode Island. No block groups exceeded the minimum threshold for more than 2 races. Aggregate of minority racial populations exist in 595 block groups, with 477 of the block groups occurring in Massachusetts and 120 in Rhode Island.

Minority populations based on Hispanic ethnicity occur in 240 block groups, with 145 of them in Massachusetts and 95 in Rhode Island. Minority populations composed of the aggregate of minority races <u>and</u> Hispanic ethnicity populations exist in 651 block groups, with 514 of the block groups occurring in Massachusetts and 137 in Rhode Island. The location of these minority populations is shown in Figure 2-22.

Overall, no minority populations were identified within a 6-mile radius of PNPS. The nearest minority population within a 50-mile radius was in west-central Plymouth County near the community of Brockton where several minority thresholds were exceeded. These populations are approximately 25 miles west of the PNPS site. Other minority populations within 50 miles of PNPS were typically clustered in or near the Boston, Massachusetts and Providence, Rhode Island areas.

2.6.2.3 Low-Income Populations

NRC guidance defines "low-income" by using USCB statistical poverty thresholds for the year 1999 [Reference 2-33, Appendix D]. Low-income populations within the 50-mile radius of PNPS were identified using information on both the number of individuals and number of households below the poverty level in Massachusetts and Rhode Island and block groups within the environmental impact site (50-mile radius). The USCB values for the number of individuals and households below the poverty level in Massachusetts was 9.3% and 9.8%, respectively (Table 2-3a). The number of individuals and households below the poverty level in Rhode Island was 11.9% and 12.4%, respectively.

A low-income population is considered to be present if:

(1) the low-income population of the block group or environmental impact site exceeds 50%, or

(2) the percentage of households below the poverty level in a block group is significantly greater (typically at least 20 points) than the low-income population percentage in the geographic area chosen for comparative analysis.

Because no block groups had more than 50% of its individuals or households below the poverty level, the "greater than 20%" criterion was used to identify low-income populations within the 50-mile radius environmental impact site (Table 2-3a). The number and percentage of block groups that exceeded these thresholds are included in Tables 2-3b and 2-3c. The locations of the low-income populations with the 50-mile radius area are shown in Figures 2-20 and 2-21.

Based on the "more than 20 percent" criterion, low-income "individual" populations exist in 190 block groups in Massachusetts and 79 in Rhode Island. Low-income populations based on the number of "households" exist in 179 block groups in Massachusetts and 74 block groups in Rhode Island.

Overall, no low-income populations were identified within a 6-mile radius of PNPS. The nearest low-income population occurring within a 50-mile radius was in northwest Plymouth County near the community of Brockton where thresholds for both low-income individuals and households were exceeded. These populations are approximately 25 miles northwest of the PNPS site. Other low-income populations within 50 miles of PNPS were clustered near Boston and in Bristol County near the communities of Fall River and New Bedford, Massachusetts and in Providence County Rhode Island.

Table 2-3a Average percentage of minority and low-income individuals in the MA and RI geographic areas and threshold criteria for identifying minority and low-income populations at the block group level

State	American Indian Alaska Native	Asian	Native Hawaiian Or Other Pacific Islander	Black Races	Other races	More than 2 races	Aggregate of minority races	*Hispanic* Ethnicity	Aggregate of minority races & Hispanic ethnicity	*Low-Income Population* (individuals)	Low-Income Population (Households)
MA	0.2	3.8	0.0	5.4	3.7	2.3	15.5	6.8	18.1	9.3	9.8
RI	0.5	2.3	0.1	4.5	5.0	2.7	15.0	8.7	18.1	11.9	12.4
Minority and low-income population threshold criteria											
MA	20.2	23.8	20.0	25.4	23.7	22.3	35.5	26.8	38.1	29.3	29.8
RI	20.5	22.3	20.1	24.5	25.0	22.7	35.0	28.7	38.1	31.9	32.4

Table 2-3b Number of block groups that exceed thresholds for minority and low-income populations for the 15 counties located within a 50-mile radius of PNPS

State	County	Number of Block Groups within 50 mile radius	American Indian Alaska Native	Asian	Native Hawaiian Or Other Pacific Islander	Black Races	Other races	More than 2 races	Aggregate of minority races	Hispanic Ethnicity	Aggregate of minority races & Hispanic ethnicity	Low-income Population (Individuals)	Low-income Population (Households)
MA	Barnstable	198	0	0	0	0	0	0	0	0	0	1	0
MA	Bristol	417	0	1	0	0	11	0	22	6	26	34	34
MA	Dukes	20	1	0	0	0	0	0	1	0	1	0	0
MA	Essex	317	0	0	0	1	5	0	33	25	36	12	10
MA	Middlesex	761	0	11	0	14	2	0	52	8	67	9	7
MA	Nantucket	4	0	0	0	0	0	0	0	0	0	0	0
MA	Norfolk	473	0	14	0	5	0	0	20	0	18	3	2
MA	Plymouth	366	0	0	0	17	8	0	43	0	45	11	11
MA	Suffolk	630	0	28	1	196	51	0	304	106	321	120	115
MA	Worcester	18	0	0	0	0	0	0	0	0	0	0	0
RI	Bristol	41	0	0	0	0	0	0	0	0	0	0	0
RI	Kent	83	0	0	0	0	0	0	0	0	0	1	0
RI	Newport	60	0	0	0	1	0	0	2	0	2	1	1
RI	Providence	471	0	3	0	27	58	0	118	95	135	77	73
RI	Washington	4	0	0	0	0	0	0	0	0	0	0	0
	Total	3863	1	57	1	261	135	0	595	595	651	269	253
Minority and low-income thresholds													
MA		3204	20.2	23.8	20.0	25.4	23.7	22.3	35.5	35.5	38.1	29.3	29.8
RI		659	20.5	22.3	20.1	24.5	25.0	22.7	35.0	35.0	38.1	31.9	32.4

Table 2-3c Number and percentage of census block groups within a 50-mile radius of PNPS that exceed thresholds for minority and low-income populations

Minority and Low-income Categories	MA Threshold (%)	Number Block Groups that Exceed State Threshold	Percentage of Block Groups that Exceed State Threshold
American Indian & Alaskan Native	20.2	1	0.0
Asian	23.8	54	1.7
Native Hawaiian or other Pacific Islander	20.0	1	0.0
Black Races	25.4	223	6.9
Other Races	23.7	77	2.4
More than two races	22.3	0	0.0
Aggregate of minority races	35.4	477	14.8
Hispanic Ethnicity	26.8	145	4.5
Aggregate of minority races and Hispanic Ethnicity	38.1	514	16.0
Low Income – Population	29.3	190	5.9
Low Income – Households	29.8	179	5.6
	RI Threshold (%)	Number Block Groups that Exceed State Threshold	Percentage of Block Groups that Exceed State Threshold
American Indian & Alaskan Native	20.5	0	0.0
Asian	22.3	3	0.5
Native Hawaiian or other Pacific Islander	20.1	0	0.0
Black Races	24.5	28	4.2
Other Races	25.0	58	8.8
More than two races	22.7	0	0.0
Aggregate of minority races	35.1	120	18.2
Hispanic Ethnicity	28.7	95	14.4
Aggregate of minority races and Hispanic Ethnicity	38.1	137	20.8
Low Income – Population	31.9	79	12.0
Low Income – Households	32.4	74	11.2

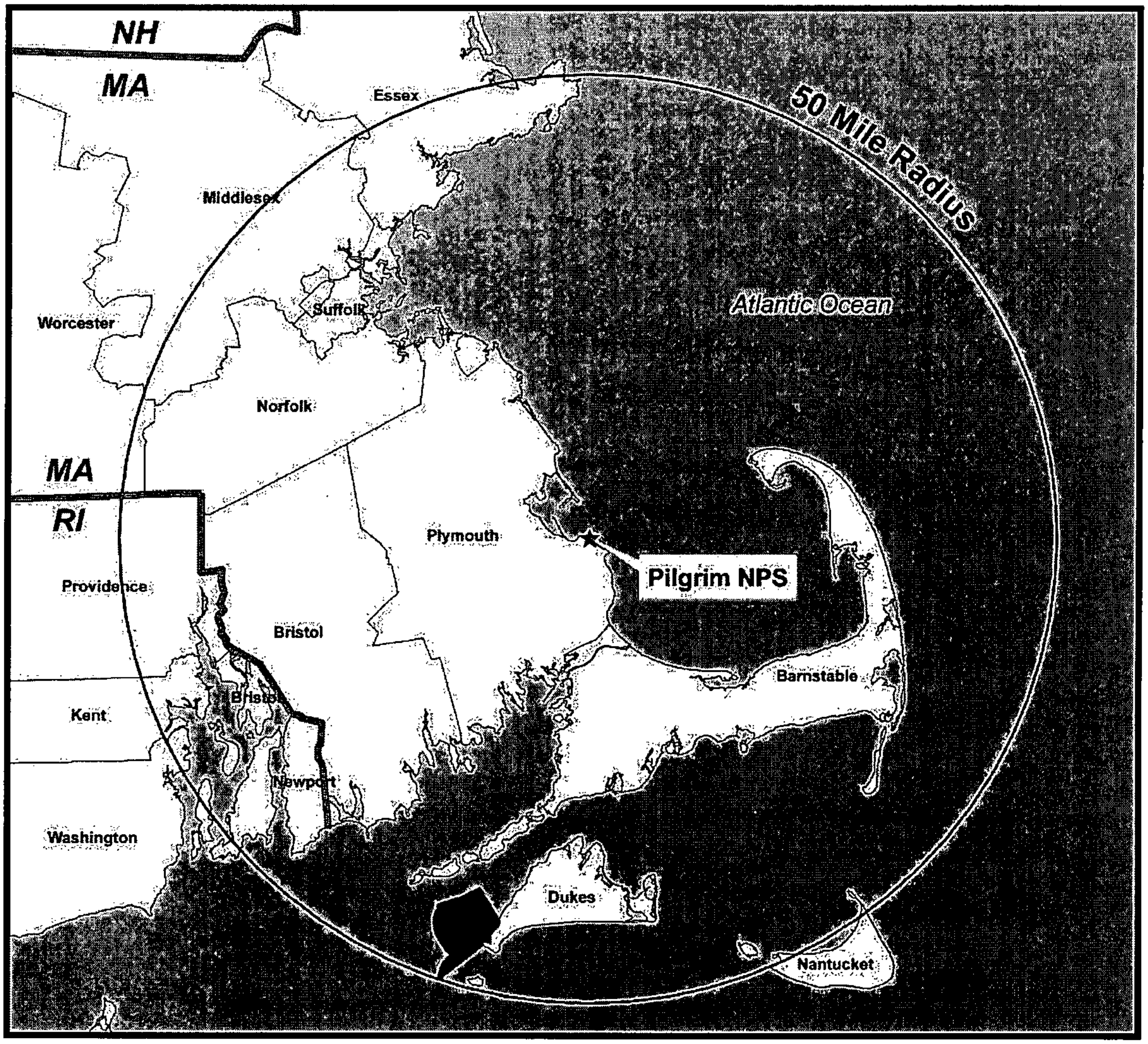

Figure 2-13
American Indian or Alaskan Native Minority Population Map

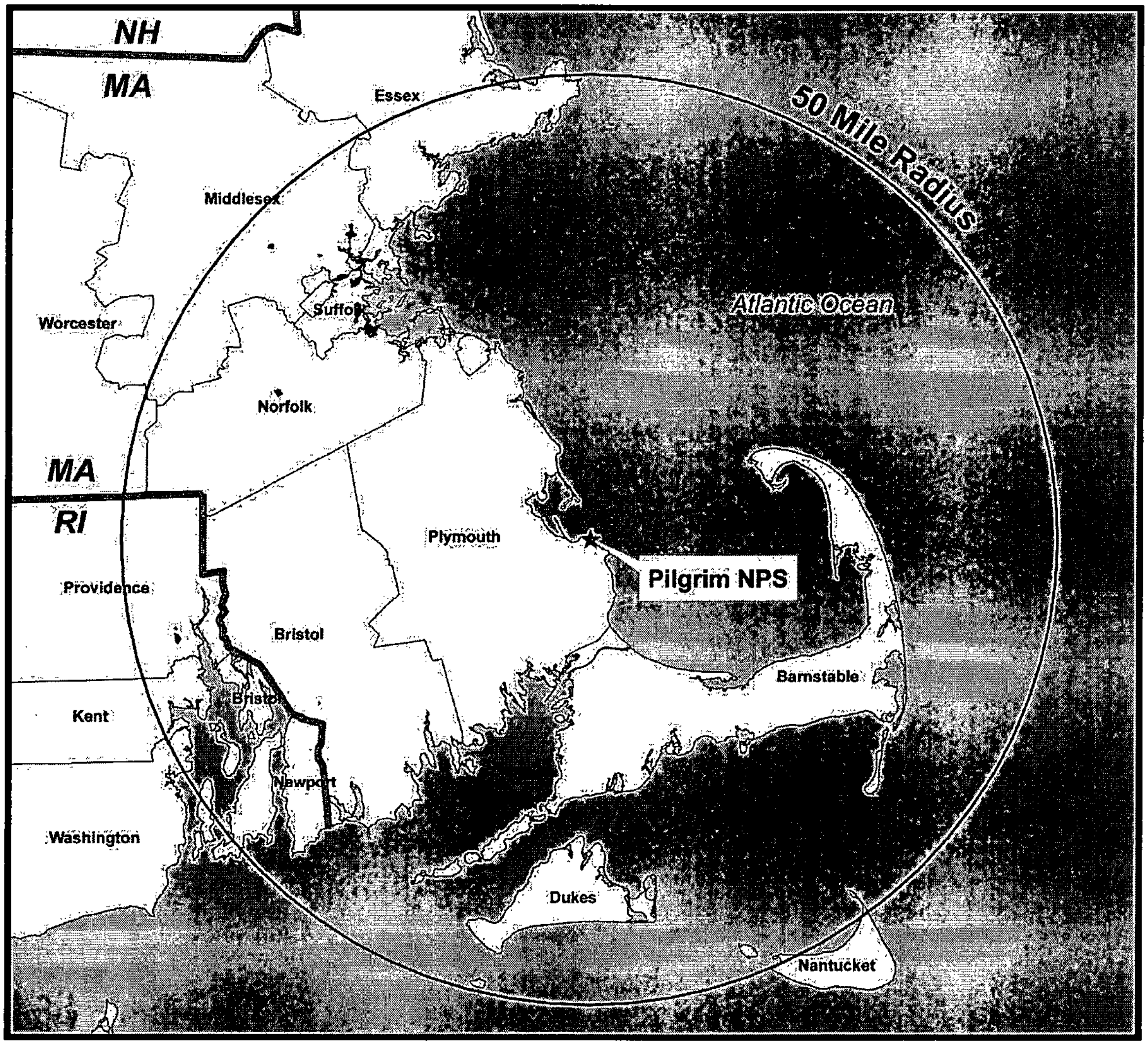

Figure 2-14
Asian or Pacific Islander Minority Population Map

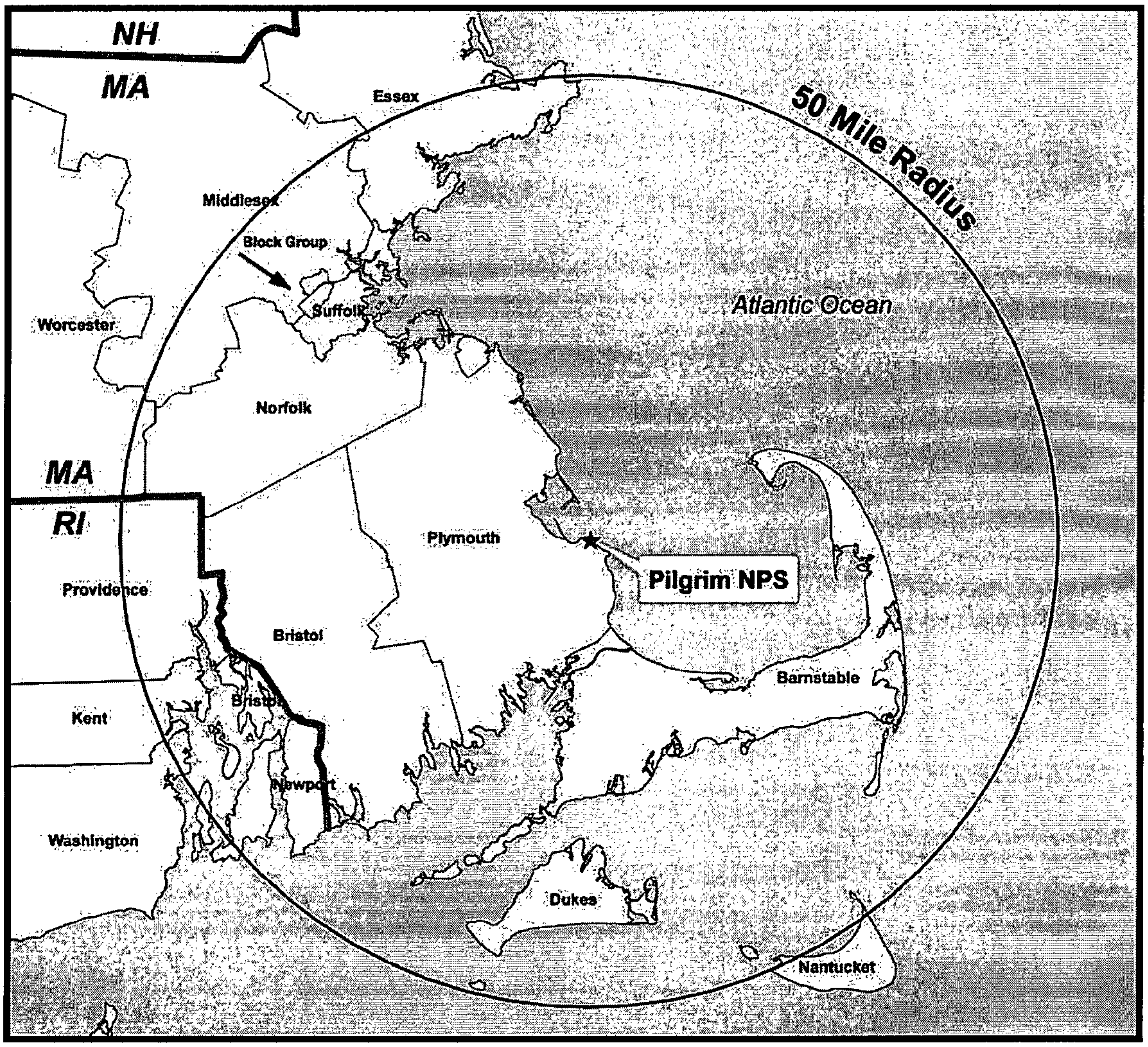

Figure 2-15
Native Hawaiian or Other Pacific Islander Minority Population Map

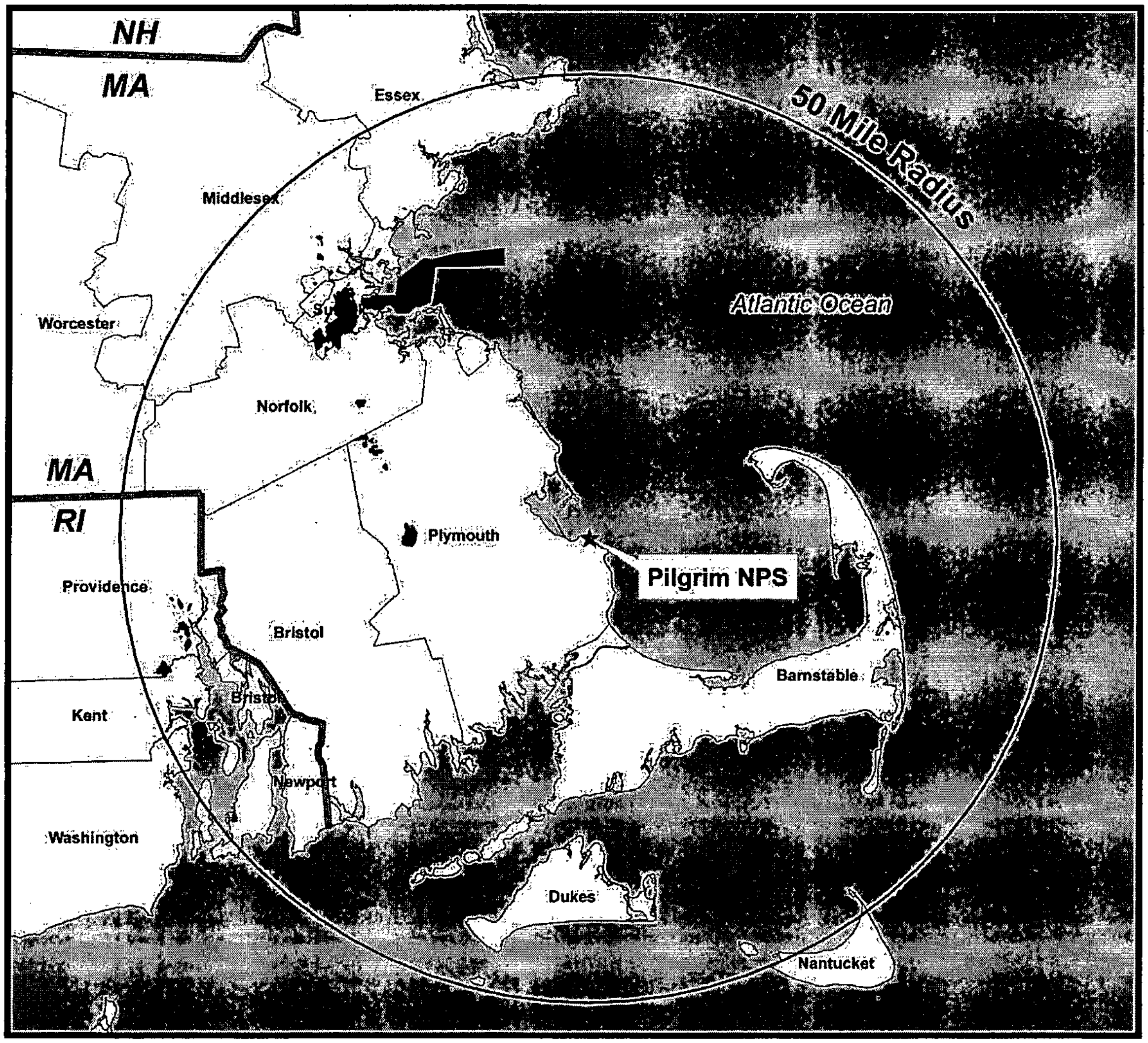

Figure 2-16
Black Races Minority Population Map

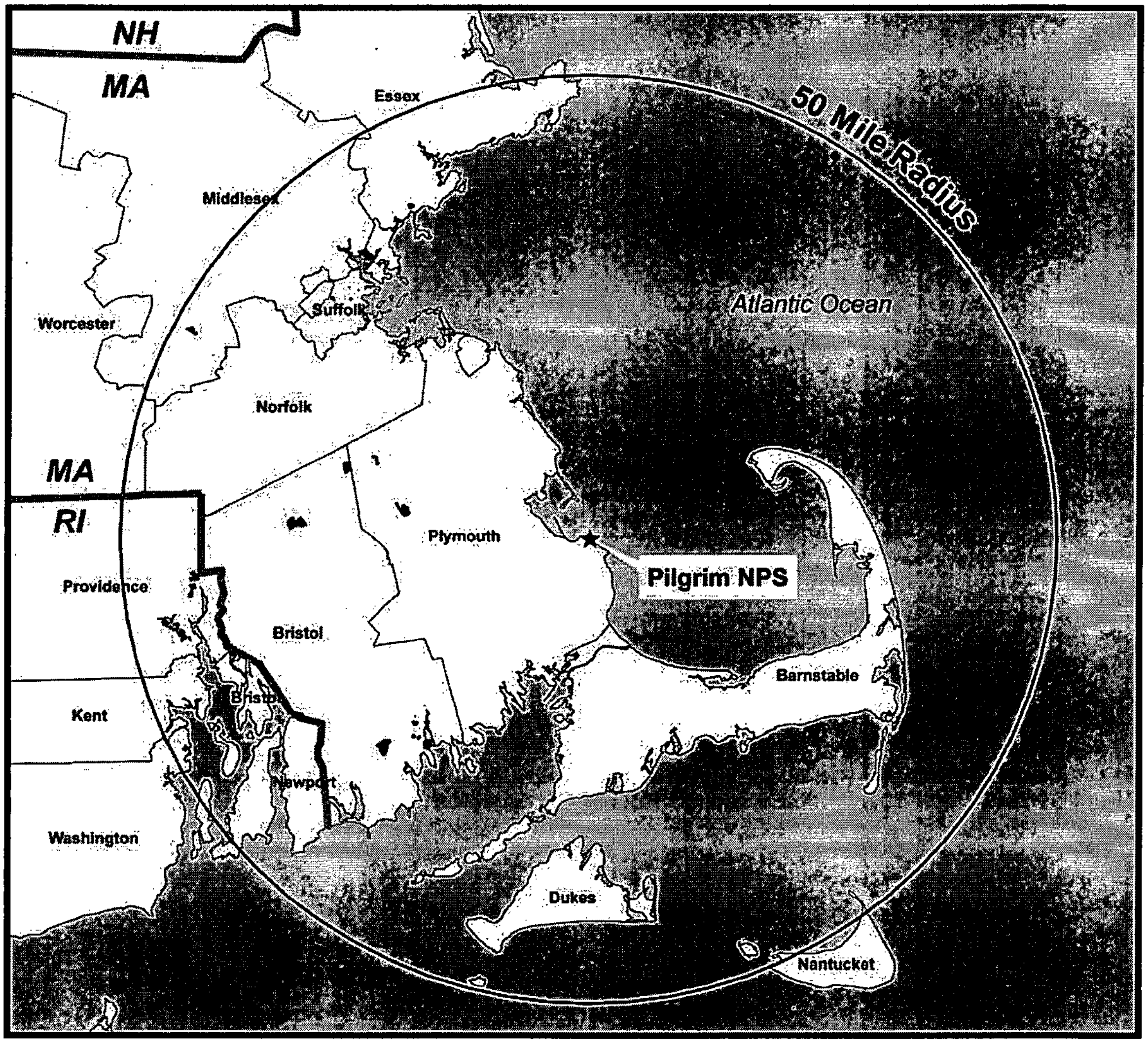

Figure 2-17
All Other Single Minorities Map

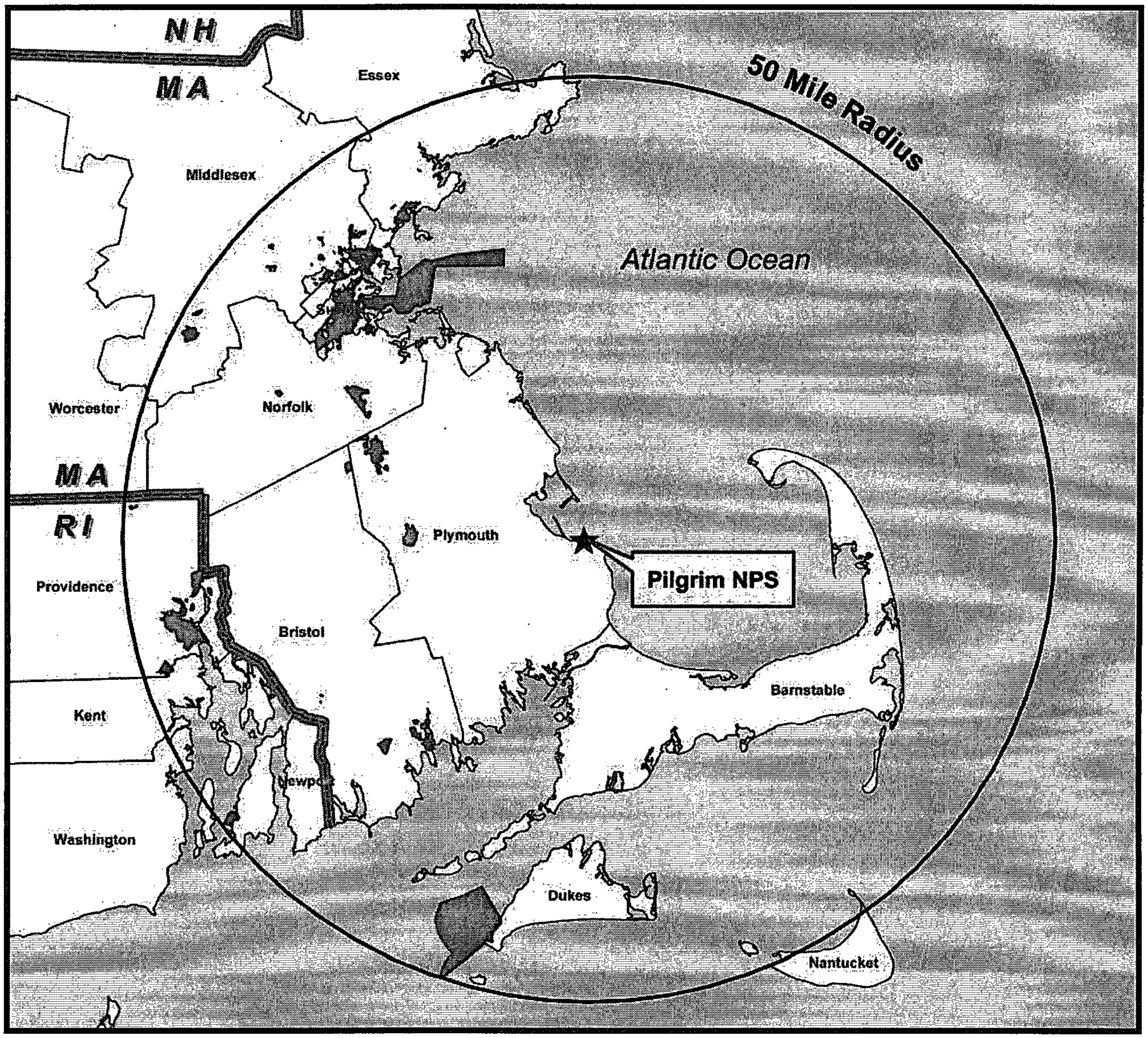

Figure 2-18
Aggregate of Minority Race Population Map

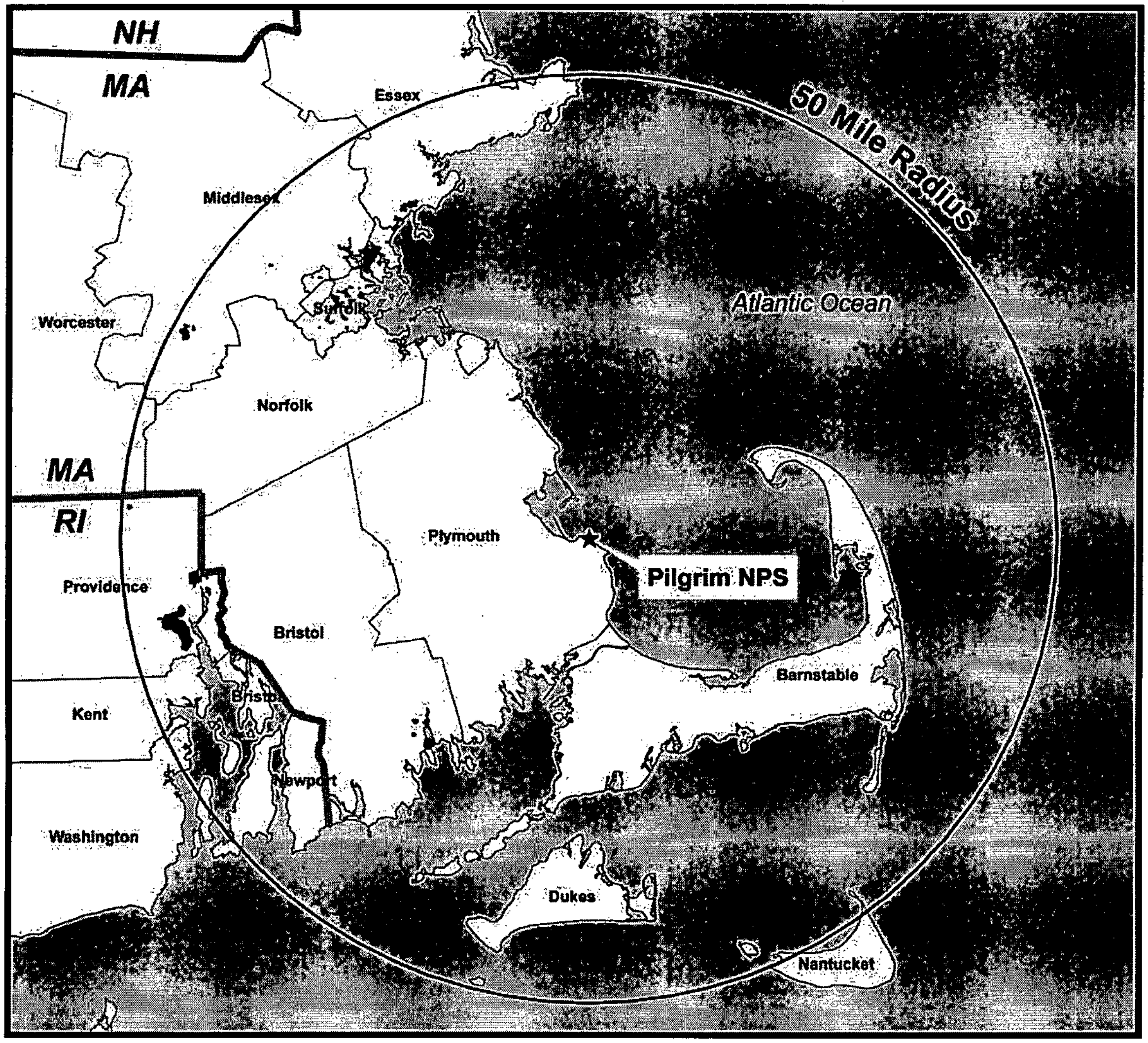

Figure 2-19
Hispanic Minority Population Map

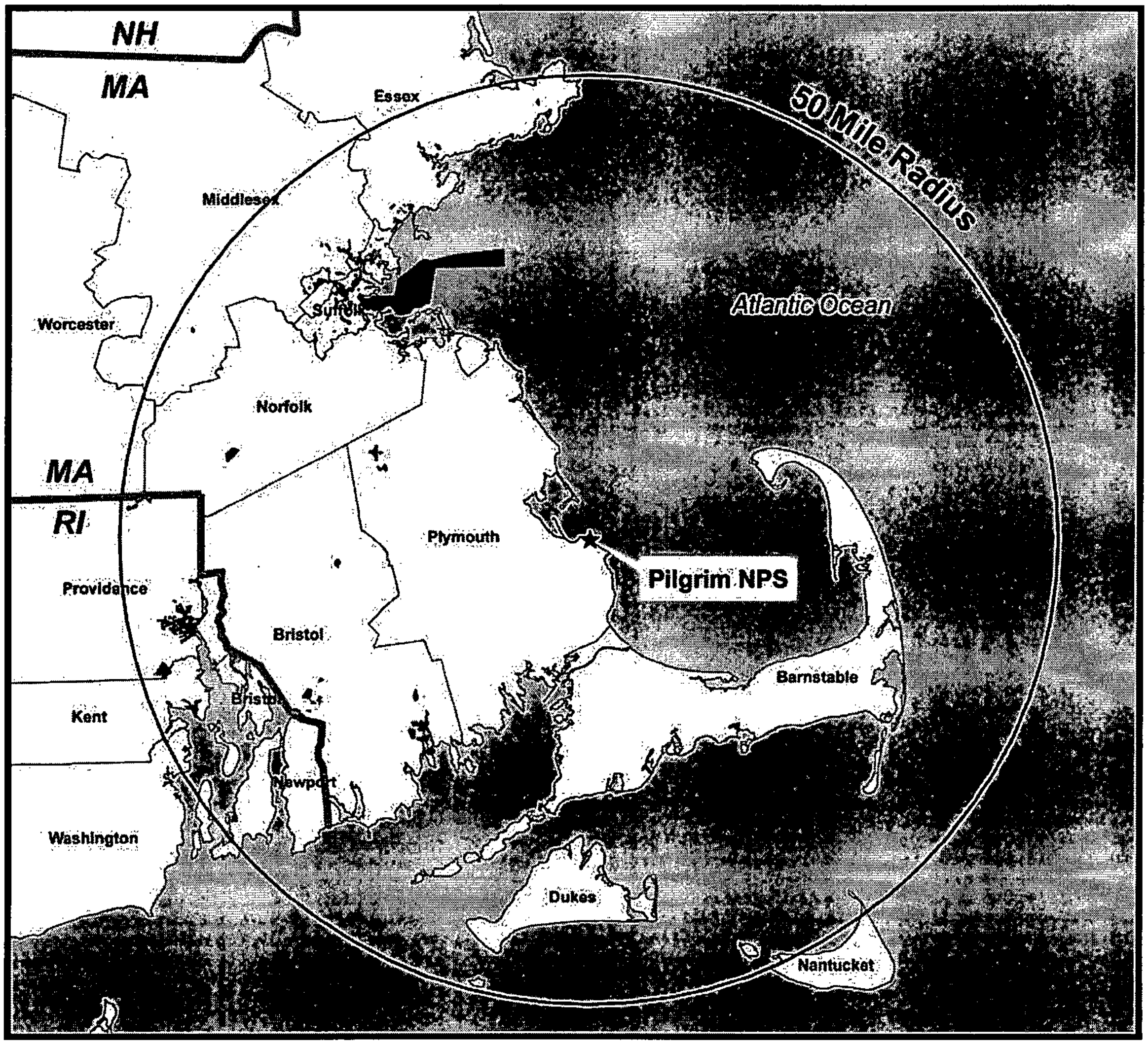

Figure 2-20
Low-Income by Individual Population Map

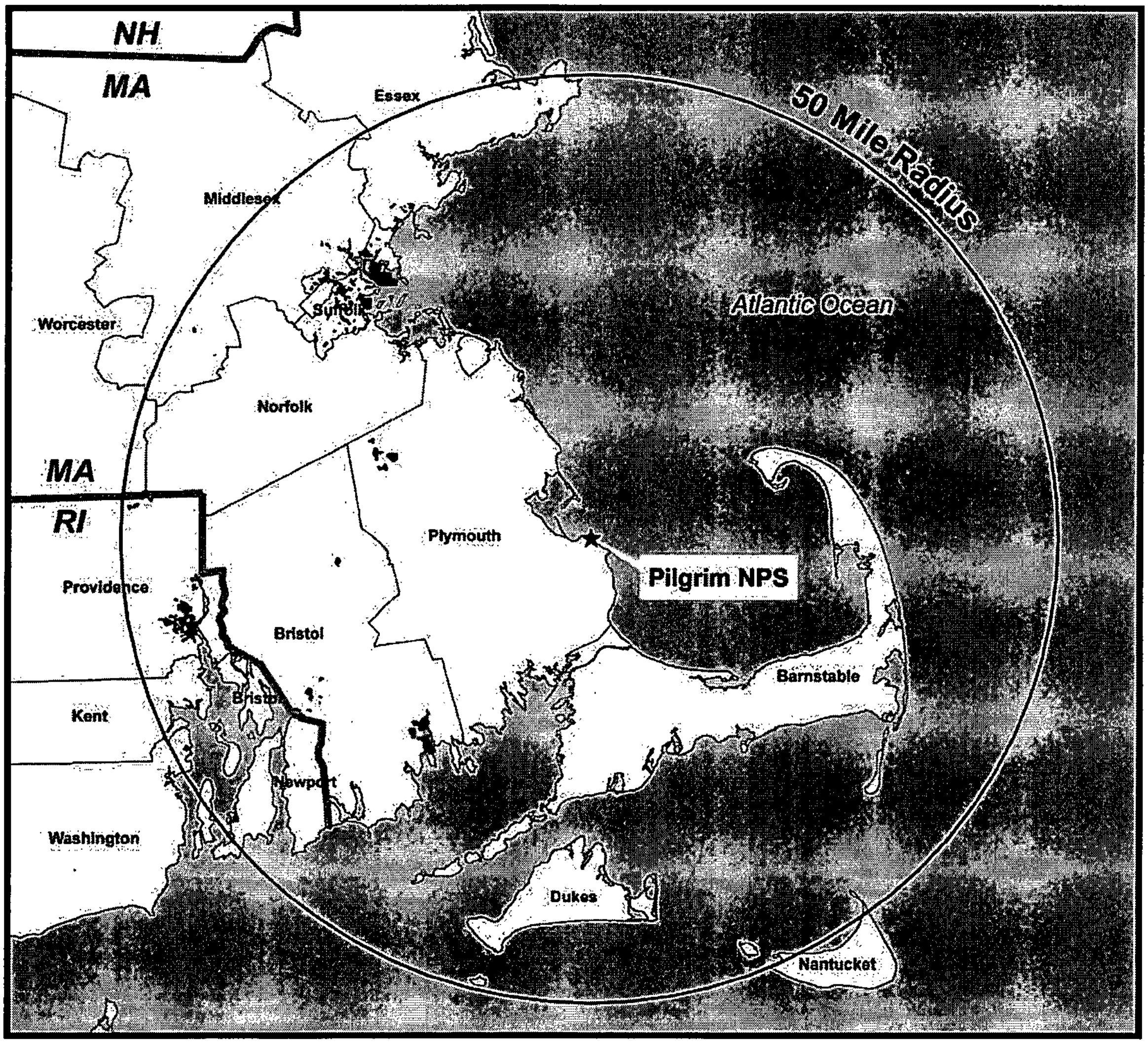

Figure 2-21
Low-Income by Household Population Map

Entergy

Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

Michael A. Balduzzi
Site Vice President

July 5, 2006

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

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

License Renewal Application Amendment 3

REFERENCE: Entergy letter, License Renewal Application, dated January 25, 2006 (2.06.003)

LETTER NUMBER: 2.06.057

Dear Sir or Madam:

In the referenced letter, Entergy Nuclear Operations, Inc. applied for renewal of the Pilgrim Station operating license.

This letter contains Amendment 3 of the License Renewal Application (LRA), which consists of three attachments. Attachment A consists of the list of regulatory commitments associated with the LRA. Attachment B consists of questions and answers from the NRC team audit of the Aging Management Programs portion of the LRA. Attachment C consists of the questions and answers from the NRC team audit of the Aging Management Reviews portion of the LRA.

Please contact Mr. Bryan Ford, at 508-830-8403, if you have any questions regarding this subject.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 5th day of July 2006.

Sincerely,

Stephen J. Bethay

Stephen J. Bethay

DWE/dm
Attachments: (as stated)

A119

cc: with Attachments

Mr. Ram Subbaratnam
Project Manager
U.S. Nuclear Regulatory Commission
Office 0-11F1
11555 Rockville Pike
Rockville, MD 20852

Mr. Joseph Rogers
Commonwealth of Massachusetts
Assistant Attorney General
Division Chief, Utilities Division
1 Ashburton Place
Boston, MA 02108

cc: without Attachments

Mr. James Shea
U.S. Nuclear Regulatory Commission
Office O-8B-1
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

Mr. Robert Walker, Director
Massachusetts Department of Public Health
Radiation Control Program
Schrafft Center, Suite 1M2A
529 Main Street
Charlestown, MA 02129

Mr. Jack Strosnider, Director
Office of Nuclear Material and Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-00001

Ms. Cristine McCombs, Director
Massachusetts Emergency Management
Agency
400 Worchester Road
Framingham, MA 01702

Mr. Samuel J. Collins, Administrator
Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Mr. James E. Dyer, Director
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-00001

NRC Resident Inspector
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

ATTACHMENT A to Letter 2.06.057
(5 pages)

List of Regulatory Commitments

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

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	Related LRA Section No. / Comments
1	Implement the Buried Piping and Tanks Inspection Program as described in LRA Section B.1.2.	June 8, 2012	Letter 2.06.003	B.1.2
2	Enhance the implementing procedure for ASME Section XI in-service inspection and testing to specify that the guidelines in Generic Letter 88-01 or approved BWRVIP-75 shall be considered in determining sample expansion if indications are found in Generic Letter 88-01 welds.	June 8, 2012	Letter 2.06.003	B.1.6
3	Inspect ten (10) percent of the top guide locations using enhanced visual inspection technique, EVT-1, within the first 12 years of the period of extended operation, with one-half of the inspections (50 percent of locations) to be completed within the first 6 years of the period of extended operation. Locations selected for examination will be areas that have exceeded the neutron fluence threshold.	Fifty (50) percent inspections within the first six years of the period of extended operation and the remainder within the first 12 years of the period of extended operation	Letter 2.06.003	B.1.8
4	Enhance the Diesel Fuel Monitoring Program to include periodic sampling of the security diesel generator fuel storage tank, near the bottom, to determine water content.	June 8, 2012	Letter 2.06.003	B.1.10
5	Enhance the Diesel Fuel Monitoring Program to install instrumentation to monitor for leakage between the two walls of the security diesel generator fuel storage tank to ensure that significant degradation is not occurring.	June 8, 2012	Letter 2.06.003	B.1.10
6	Enhance the Diesel Fuel Monitoring Program to specify acceptance criterion for UT measurements of emergency diesel generator fuel storage tanks (T-126A&B).	June 8, 2012	Letter 2.06.003	B.1.10

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	Related LRA Section No. / Comments
7	Enhance Fire Protection Program procedures to state that the diesel engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be enhanced to verify that the diesel engine did not exhibit signs of degradation while it was running such as fuel oil, lube oil, coolant, or exhaust gas leakage.	June 8, 2012	Letter 2.06.003	B.1.13.1
8	Enhance the Fire Protection Program procedure for Halon system functional testing to state that the Halon 1301 flex hoses shall be replaced if leakage occurs during the system functional test.	June 8, 2012	Letter 2.06.003	B.1.13.1
9	Enhance Fire Water System Program procedures to include inspection of hose reels for corrosion. Acceptance criteria will be enhanced to verify no significant corrosion.	June 8, 2012	Letter 2.06.003	B.1.13.2
10	Enhance the Fire Water System Program to state that a sample of sprinkler heads will be inspected using guidance of NFPA 25 (2002 Edition) Section 5.3.1.1.1. NFPA 25 also contains guidance to repeat this sampling every 10 years after initial field service testing.	June 8, 2012	Letter 2.06.003	B.1.13.2
11	Enhance the Fire Water System Program to state that wall thickness evaluations of fire protection piping will be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function.	June 8, 2012	Letter 2.06.003	B.1.13.2
12	Implement the Heat Exchanger Monitoring Program as described in LRA Section B.1.15.	June 8, 2012	Letter 2.06.003	B.1.15
13	Enhance the Instrument Air Quality Program to include a sample point in the standby gas treatment and torus vacuum breaker instrument air subsystem in addition to the instrument air header sample points.	June 8, 2012	Letter 2.06.003	B.1.17
14	Implement the Metal-Enclosed Bus Inspection Program as described in LRA Section B.1.18.	June 8, 2012	Letter 2.06.003	B.1.18
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program as described in LRA Section B.1.19. Include developing a formal procedure to inspect manholes for in-scope medium voltage cable.	June 8, 2012	Letter 2.06.003	B.1.19/Audit item 311
16	Implement the Non-EQ Instrumentation Circuits Test Review Program as described in LRA Section B.1.20.	June 8, 2012	Letter 2.06.003	B.1.20

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	Related LRA Section No. / Comments
17	Implement the Non-EQ Insulated Cables and Connections Program as described in LRA Section B.1.21.	June 8, 2012	Letter 2.06.003	B.1.21
18	Enhance the Oil Analysis Program to periodically change CRD pump lubricating oil. A particle count and check for water will be performed on the drained oil to detect evidence of abnormal wear rates, contamination by moisture, or excessive corrosion.	June 8, 2012	Letter 2.06.003	B.1.22
19	Enhance Oil Analysis Program procedures for security diesel and reactor water cleanup pump oil changes to obtain oil samples from the drained oil. Procedures for lubricating oil analysis will be enhanced to specify that a particle count and check for water are performed on oil samples from the fire water pump diesel, security diesel, and reactor water cleanup pumps.	June 8, 2012	Letter 2.06.003	B.1.22
20	Implement the One-Time Inspection Program as described in LRA Section B.1.23. This includes destructive or non-destructive examination of one (1) socket welded connection using techniques proven by past industry experience to be effective for the identification of cracking in small bore socket welds. Should an inspection opportunity not occur (e.g., socket weld failure or socket weld replacement), a susceptible small-bore socket weld will be examined either destructively or non-destructively prior to entering the period of extended operation.	June 8, 2012	Letter 2.06.003	B.1.23/Audit Item 219
21	Enhance the Periodic Surveillance and Preventive Maintenance Program as necessary to assure that the effects of aging will be managed as described in LRA Section B.1.24.	June 8, 2012	Letter 2.06.003	B.1.24
22	Enhance the Reactor Vessel Surveillance Program to proceduralize the data analysis, acceptance criteria, and corrective actions described in LRA Section B.1.26.	June 8, 2012	Letter 2.06.003	B.1.26
23	Implement the Selective Leaching Program in accordance with the program as described in LRA Section B.1.27.	June 8, 2012	Letter 2.06.003	B.1.27
24	Enhance the Service Water Integrity Program procedure to clarify that heat transfer test results are trended.	June 8, 2012	Letter 2.06.057	B.1.28

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	Related LRA Section No. / Comments
25	Enhance the Structures Monitoring Program procedure to clarify that the discharge structure, security diesel generator building, trenches, valve pits, manholes, duct banks, underground fuel oil tank foundations, manway seals and gaskets, hatch seals and gaskets, underwater concrete in the intake structure, and crane rails and girders are included in the program. In addition, the Structures Monitoring Program will be revised to require opportunistic inspections of inaccessible concrete areas when they become accessible.	June 8, 2012	Letter 2.06.003	B.1.29.2
26	Enhance Structures Monitoring Program guidance for performing structural examinations of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties.	June 8, 2012	Letter 2.06.003	B.1.29.2
27	Enhance the Water Control Structures Monitoring Program scope to include the east breakwater, jetties, and onshore revetments in addition to the main breakwater.	June 8, 2012	Letter 2.06.003	B.1.29.3
28	Enhance System Walkdown Program guidance documents to perform periodic system engineer inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	June 8, 2012	Letter 2.06.057	B.1.30/Audit Item 327
29	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program as described in LRA Section B.1.31.	June 8, 2012	Letter 2.06.003	B.1.31/Audit Item 257
30	Perform a code repair of the CRD return line nozzle to cap weld if the installed weld repair is not approved via accepted code cases, revised codes, or an approved relief request for subsequent inspection intervals.	June 30, 2015	Letter 2.06.057	B.1.3/Audit Item 141

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	Related LRA Section No. / Comments
31	Prior to entering the period of extended operation, for each location that may exceed a CUF of 1.0 when considering environmental effects, PNPS will implement one or more of the following: (1) further refinement of the fatigue analyses to lower the predicted CUFs to less than 1.0; (2) management of fatigue at the affected locations by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method acceptable to the NRC); (3) repair or replacement of the affected locations. Should PNPS select the option to manage the aging effects due to environmental-assisted fatigue during the period of extended operation, details of the aging management program such as scope, qualification, method, and frequency will be submitted to the NRC at least 2 years prior to the period of extended operation.	June 8, 2012 June 8, 2010 for submitting the aging management program if PNPS selects the option of managing the affects of aging due to environmentally assisted fatigue.	Letter 2.06.057	Audit item 302
32	Implement the Bolting Integrity Program in accordance with a license renewal application amendment.	June 8, 2012	Letter 2.06.057	Audit items 364, 373, 389, 390, 432, 443, & 470
33	PNPS will inspect the inaccessible jet pump thermal sleeve and core spray thermal sleeve welds if and when the necessary technique and equipment become available and the technique is demonstrated by the vendor, including delivery system.	As stated in the commitment.	Letter 2.06.057	Audit Item 488
34	Within the first 6 years of the period of extended operation and every 12 years thereafter, PNPS will inspect the access hole covers with UT methods. Alternatively, PNPS will inspect the access hole covers in accordance with BWRVIP guidelines should such guidance become available.	June 8, 2018	Letter 2.06.057	Audit item 461
35	Perform a new feedwater nozzle fatigue analysis prior to the period of extended operation.	June 8, 2012	Letter 2.06.057	Audit item 345
36	To ensure that significant degradation on the bottom of the condensate storage tank is not occurring, a one-time ultrasonic thickness examination in accessible areas on the bottom of the condensate storage tank will be performed. Standard examination and sampling techniques will be utilized.	June 8, 2012	Letter 2.06.057	Audit Item 363

ATTACHMENT B to Letter 2.06.057

Questions and Answers on the Aging Management Programs
Portion of the License Renewal Application

NRC Programs Audit PNPS - All Items (Open and Closed)

Item	Request	Response	Lead	Support	Category	Update
137	[B.1.1-W-01, Boraflex Monitoring] 1. "The program relies on periodic inspection of the Boraflex, monitoring of silica levels in the spent fuel pool water, and analysis of criticality to assure that the required 5% subcriticality margin is maintained." For Boraflex Monitoring Program, the GALL Report identifies parameters to be monitored including: physical conditions of the Boraflex panels, such as gap formation and decreased boron area density, and the concentration of the silica in the spent fuel pool. Does applicant's Boraflex Monitoring Program monitor all of these parameters, especially, the areal density measurement?	As stated in LRA Section B.1.1, the Boraflex Monitoring Program is consistent with NUREG-1801, Section XI.M22 with no exceptions. Thus, the Boraflex Monitoring Program monitors all of these parameters.	Potts, Lori	James, Gary	Closed	No

Item	Request	Response	Lead	Support	Category	Update
138	[B.1.1-W-02, Boraflex Monitoring] 2. In the Operating Experience Section, PNPS implies that the required 5% subcritically margin was demonstrated through the gap measurement. Please provide details how the results of gap measurement demonstrated that the 5% subcritically margin is maintained.	LRA Section B.1.1, Operating Experience, will be revised to the paragraphs below to clarify that reactivity calculations performed after direct material surveillance (blackness testing) using bounding assumptions with regard to neutron attenuation capability of the boraflex demonstrated that the 5% subcriticality margin is maintained. This requires an amendment to the LRA. Blackness testing was performed on Boraflex panels in the spent fuel storage racks during 1996 and 1998 to provide a baseline for development of the monitoring program. Results of the 1996 testing showed shrinkage and gapping in the Boraflex. Analysis of the criticality design of the fuel pool based on the 1996 blackness test used bounding assumptions with regard to neutron attenuation capability of the boraflex based on the observed gap sizes and locations and assumed levels of Boraflex erosion (thinning and edge loss). The analysis showed that the pool subcriticality margin was greater than 5%. Results of the 1998 testing showed about a 20% increase in average gap size, but overall shrinkage (gaps and end shortening) of the material was much less on a percentage change basis and was bounded by the criticality analysis assumptions. The report concluded that the Boraflex poison material in the spent fuel storage racks continues to perform its intended function. The Boraflex Monitoring Program (with areal density measurement) at PNPS has been instituted recently. Therefore, there is no additional plant-specific operating experience.	James, Gary	Potts, Lori	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
139	[B.1.1-W-03, Boraflex Monitoring] 3. The applicant states in the LRA that its Boraflex Monitoring Program is consistent with the program described in GALL Report Section XI.M22, Boreflex Monitoring. In the Detection of Aging Effects program element, the GALL Report states that: "The amount of boron carbides released from the Boraflex panel is determined through direct measurement of boron areal density and correlated with the levels of silica present with a predictive code. This is supplemented with detection of gaps through blackness testing and periodic verification of boron loss through areal density measurement techniques such as the BADGER device." What predictive code is being used at PNPS? Based on the predictive code and trending of the SFP silica level what is the projected useful life of the Boraflex racks?	The RACKLIFE predictive model is used at PNPS. However, as the model is under development, the projected useful life of the Boraflex racks has not yet been determined. Corrective actions would be initiated if test results find that the 5% subcriticality margin cannot be maintained because of current or projected degradation. Corrective actions consist of providing additional neutron-absorbing capacity by Boral or boron steel inserts, or other options which are available to maintain a subcriticality margin of 5%.	Potts, Lori	James, Gary	Closed	No
140	[B.1.1-W-04, Boraflex Monitoring] 4. As indicated in Table 3.3.2-13 of the LRA, PNPS identified that this AMP will be used in three line items (page 3.3-131). These three line items include managing neutron absorber aging effects of "loss of material," "change in material properties," and "cracking." All these three line items reference GALL Report item VII.A2-2. However, the aging effect identified by the GALL Report (VII.A2-2) is only "reduction of neutron-absorbing capacity/ Boraflex degradation." Please explain the discrepancies.	LRA Table 3.3.2-13 line items for neutron absorber aging effects "loss of material" and "cracking" will be changed to indicate that these aging effects are managed by the Water Chemistry Control – BWR Program. The line items will use note H, "Aging effect not in NUREG-1801 for this component, material and environment combination." LRPD-02 Revision 2 issued addressing this item. *This requires an amendment to the LRA.*	Potts, Lori	James, Gary	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
141	[B.1.3-D-01, BWR CRD Return Line Nozzle Program] 1. A structural weld overlay was applied over a through wall Crack in a 182/82 weld using alloy 52 material without removing the flaw. What regulatory basis was used to install this overlay? How will this be handled during the PEO? What is the regulatory basis for reducing the examination volume?	The CRD Return Line weld overlay was designed and installed in accordance with ASME Section XI Code Case N-504-2, "Alternate Rules for Repair of Class 1, 2 and 3 Austenitic Stainless Steel Piping" and Code Case N-638, "Similar and Dissimilar Metal Welding Using Ambient Temperature Machine GTAW Temper Bead Technique" and associated Relief Request PRR-36 and PRR-38. Both code cases were approved for use in NRC Regulatory Guide 1.147, Revision 13. ASME Section XI Code Case N-504-2 allows a repair to be performed by either removing the flaw or reducing it to an acceptable size. The weld overlay approach, by design, reduces the flaw to an acceptable size. The weld overlay assumes a flaw size through wall for 360 degrees around the component. The weld overlay is designed to structurally replace the cross-section of the underlying component such that no structural credit is taken for the remaining ligaments of the component. Code Case N-504-2 is the basis for the design and implementation of the structural weld overlay repair method. Code Case N-638 is used for the application of the temper bead technique for repair welding of dissimilar metals using the GTAW process. Code Case N-638 provides the applicable procedure qualification requirements for welding with nickel-based alloys on a ferritic base metal, which in this case includes welding to both a P-No. 3 low alloy carbon steel nozzle and a P-No. 43 nickel-chrome alloy pipe cap. It was necessary to take exceptions to the specific alloys described in the Code Case N-504-2 overlay repair method, which is based on the use of austenitic stainless steel alloys only. These specific exceptions are described in the Pilgrim Relief Request PRR-36. Additionally, relief was requested, via Pilgrim Relief Request PRR-38, to use an alternative program for implementation of ASME XI Appendix VIII, Supplement 11 for ultrasonic	Harizi, Phil	Finnin, Ron	Accepted	Yes

examinations. The alternative program was implemented through the Performance Demonstration Initiative (PDI) program.

The CRD Return Line Nozzle N-10 weld overlay repair will continue to be inspected under the PNPS Inservice Inspection Program as a Category E weld in accordance with BWRVIP-75-A "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules" during PEO.

PNPS commits (Commitment #30) to perform a code repair of the CRD return nozzle to cap weld as needed if the installed overlay weld repair is not approved via accepted code cases, revised codes, or subsequent approval of relief requests.

The N-10 nozzle weld overlay was inspected to the maximum extent physically possible based on the geometric limitations of the nozzle and examination equipment used. The examination volume is based on the component wall thickness; weld overlay thickness and structural length required. The N-10 Nozzle wall thickness is 0.578" and the required thickness for the N-10 weld overlay was 0.20" with a required structural axial length of 1" either side of the flaw. Based on these dimensions, the required length of the examination volume would be approximately 1-1/2". The length of the applied weld overlay on either side of the flaw was 1-3/4" and therefore provided sufficient length to allow full volumetric examination of the overlay.

The reduced examination volume for the CRD Return Line Nozzle to Vessel Weld is described in the LRA Appendix B.1.3. This reduction of the inspection volume for the adjacent base metal is now in accordance with ASME Code Case N-613-1, which has been approved for use by the NRC in Regulatory Guide 1.147 Rev. 14, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1". This LRA information will be updated to reflect the current status of this Code Case approval.

Item	Request	Response	Lead	Support	Category	Update
		LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.				
142	[B.1.3-D-02, BWR CRD Return Line Nozzle Program] 2. Was relief requested to use Code Case N-504-2 to do the weld overlay? What exceptions have you taken to Code Case -504-2? Do you meet the requirements for ASME Section XI non-mandatory Appendix Q? How will this be handled during the period of extended operation (PEO) ?	A Relief Request to use Code Case N-504-2 for the CRD Return Line weld overlay was applied for and approved prior to startup of the N-10 Nozzle repair outage. The Pilgrim Relief Request, PRR-36, Entergy letter number 2.03.120 requested that Alloys 152/52 be allowed for weld overlay repair material and an alternate inspection plan be allowed in lieu of a hydrostatic pressure test. The CRD Return Line Nozzle weld overlay repair was designed and installed in October of 2003 in accordance with the 1989 edition of ASME Section XI. ASME Section XI Non-Mandatory Appendix Q, "Weld Overlay Repair of Class 1, 2 and 3 Austenitic Stainless Steel Piping Weldments", was first published as part of the 2004 edition of ASME Section XI and therefore was not considered for the CRD Return Line Nozzle weld overlay modification. The CRD Return Line Nozzle N-10 weld overlay repair will continue to be inspected under the PNPS Inservice Inspection Program as a Category E weld in accordance with BWRVIP-75-A "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules" during PEO.	Harizi, Phil	Finnin, Ron	Closed	No
143	[B.1.4-D-1, BWR Feedwater Nozzle Program] 1. For this program what is the regulatory basis for reducing the examination volume?	The reduced volume inspection is in accordance with ASME Code Case N-613-1, which has been endorsed by the NRC in Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1." LRPD-02 Revision 2 issued addressing this item.	Finnin, Ron	Penny, Bob	Closed	No

Item	Request	Response	Lead	Support	Category	Update
144	[B.1.5-J-01, BWR Penetrations] 1. LRA Appendix B.1.5 (BWR Penetrations) in the Operating Experience states that in January 2005 three 2.5" piping butt welds in SLC system piping [shop welds RPV-N14-T1 and RPV-N14-T2 and field weld RPV-14-2] were found to be unidentified on inspection drawings and not included in the ISI weld population totals. It also states that weld RPV-14-2 was included in surface examinations of the N14 nozzle safe end weld and safe end extension piece performed in RFO11. It also states that corrective actions included adding the welds to the ISI weld population totals and performing a nozzle surface examination of weld RPV-N14-2 during RFO15. QUESTION: When was RFO11? Explain the apparent inconsistency that weld RPV-N14-2 was not included in the ISI weld population until RFO15, yet it was included in the N14 surface examinations of N14 nozzle safe end weld and safe end extension piece during RFO11.	RFO-11 was conducted in the February - April 1997 timeframe (2/15 - 4/14/97). GE SIL 571 recommends that surface examinations be performed on small bore nozzle safe end extensions fabricated from 304 stainless steel. The SIL recommends that the entire safe end extension piece including the nozzle to safe end weld receive a surface examination. The fabrication of the nozzle and safe end extension assembly includes line boring of the nozzle/safe end extension assembly inner surfaces and machining of the outside surface to a flush condition. The extensive cold working during fabrication can sensitize the austenitic stainless steel extension piece such that IGSCC could occur in the base metal of the safe end extension as well as the weld heat affected zones. This machining also prevents the nozzle to safe end weld transition from being easily detected by an inspector. To ensure that the entire nozzle to safe end extension piece and the nozzle to safe end weld were examined in RFO11, ISI NDE inspectors were instructed by PNPS to perform a surface examination of the entire nozzle and safe end extension piece from the RPV outside wall out to the adjacent tee. As a result of this conservative approach, the RPV-N14-2 weld was included by default in the surface examination boundary.	Finnin, Ron	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
145	[B.1.5-J-02, BWR Penetrations] 2. LRA Appendix B.1.5 (BWR Penetrations) under Exceptions states that "surface examinations are not performed on instrument penetration nozzle welds." It further states that inspections to monitor the effects of cracking on the intended function of instrument penetration nozzles (N15A/B and N16A/B) include enhanced visual (VT-2 with insulation removed) examinations during system pressure testing. It also states that a UT exam of the N16B safe end-to-reducer weld is performed every 10 years. However, ASME Section XI, Table IWB-2500-1 and BWRVIP-49 also recommend surface examinations. QUESTION: A surface examination is capable of finding indications with potential for failure before a through-wall leak can occur. However, a VT-2 examination looks for signs of leakage. Provide a more detailed discussion and justification of why PNPS's AMP B.1.5, with this exception, is adequate to manage the aging of these instrument nozzles during the extended period of operation. What is meant by the phrase "enhanced visual ... examinations"? Exactly what is the enhancement?	Regarding the N15A/B nozzles, the makeup capacity size exclusion provision in ASME XI IWB-1220(a) exempts these nozzles from code inservice surface examinations. The N15A/B and N16A/B nozzles are also excluded from the recommendations of GE SIL 571 due to the replacement of the 304SS safe end extensions with Inconel extensions in RFO#7. BWRVIP-49 recommends that surface examinations be performed per ASME XI IWB-2500 Category B-F requirements; however, Class 1 Category B-F and B-J welds at PNPS are inspected in accordance with the PNPS ISI Program. This program selects welds for examination based on a combined risk ranking that considers the risk of failure and the consequences of such a failure. This program selected one weld out of the four welds at the N16A and B nozzles, specifically weld RPV-N16B-R-2, for inspection. This weld was ultrasonically examined during RFO15 in 2005 with no indications detected. Additionally, when the predominant damage mechanism is an I.D. initiated one such as IGSCC in this case, there is no benefit to performing a surface examination since the component would already be leaking if the flaw propagates to the surface. A liquid penetrant examination will not detect a subsurface flaw. In this case, a VT-2 examination is the preferred examination as it is equivalent to a surface exam in this case, but is less time-consuming and results in reduced radiation exposure to inspection personnel. An "enhanced" VT-2 examination is performed with insulation removed as discussed in BWRVIP-27A, "BWR SBLC/Core Plate delta-P Inspection and Flaw Evaluation Guidelines". Periodic code system leakage tests do not require the removal of pipe insulation to perform VT-2 examinations for leakage. For partial penetration small bore nozzles such as the	Finnin, Ron	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
		N15A/B, N16A/B and N14 nozzles, an enhanced VT-2 examination is more effective as it is more likely to detect leakage from a degraded partial penetration weld on the reactor vessel inner wall. PNPS will continue to follow BWRVIP-27 guidelines during the period of extended operation including examinations in excess of code requirements for the N15A/B, N16A/B, and N14 nozzles.				

Item	Request	Response	Lead	Support	Category	Update
146	[B.1.5-J-03, BWR Penetrations] 3. LRA Appendix B.1.5 (BWR Penetrations) includes an "Exception Note" stating that PNPS has implemented risk-informed ISI (RI-ISI) in accordance with ASME Section XI, Code Case N-578. QUESTIONS: 1. Compare the number, type, frequency and extent of inspections required for instrument penetration nozzles N15A/B and N16A/B before implementation of RI-ISI and after implementation of RI-ISI. 2. Are N15A/B and N16A/B the only Pilgrim RPV instrument penetrations? 3. Please make available at the audit a copy of ASME Section XI, Code Case N-587.	1. The N15A/B nozzles are exempted from code inservice examination by the makeup capacity size exclusion provision as allowed by ASME XI paragraph IWB-1220(a). The N15A/B nozzles are subjected to steam conditions while the N16A/B and N14 nozzles are exposed to water service conditions. The makeup size exclusion calculation for PNPS excludes steam piping with an inside diameter less than 2.2 inches and water piping with an inside diameter of less than 1.1 inches. The PNPS makeup size exclusion calculation does not use ECCS systems as a basis for the calculation. As stated in Table 3.1.2-1 of the LRA, cracking of the instrumentation nozzles is managed by a combination of the BWR Water Chemistry Program and the BWR Penetrations Program. (Loss of material is managed by a combination of the BWR Water Chemistry and the Inservice Inspection Program). PNPS believes the existing combination of mitigation and inspections, with the ASME Code exclusions taken, provide acceptable aging management for the period of extended operation for the following reasons. a. ASME Section XI IWB-2500, without exclusion, requires a surface examination of these components. As the aging effects of interest originate on the ID wall (exposed to treated water >140 F), these surface examinations would only detect a flaw once the flaw propagated through-wall. The surface examinations would not detect any flaws that were not through-wall. b. The ISI program includes inspection of welds of the same material/environment combinations as the welds within the BWR Penetrations Program. These inspections will provide information on the aging of the subject components. If any indications are found on the similar component inspections, sample expansion will lead to inspection of more similar locations and if appropriate to the actual components in question. Inspection of representative sample	Finnin, Ron	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
		locations is acceptable to confirm the aging of the component/environment combination. c. As discussed in Question 145, PNPS performs an enhanced VT-2 of these penetrations. The enhancement is that the insulation is removed from the penetrations so that the penetration and welds are viewed directly and specifically during the leak test, insuring the detection of even very small amounts of leakage from this penetration. PNPS believes this is the most effective way to monitor the condition of these specific components. Given the code surface exams will only detect through-wall failures from the ID, these inspections will find the same through-wall flaws that the surface exams would find. Separate table was provided to the inspector which shows N15 and N16 nozzle inspection History. 2. The only instrument partial-penetration weld nozzles at Pilgrim are the N15A/B, N16A/B and N14 (SBLC/Core dP) nozzles. 3. A copy of code case N-578 was provided.				
147	[B.1.5-J-04, BWR Penetrations] 4. GALL Program Description XI.M8 (BWR Penetrations) states that an applicant may use the guidelines of BWRVIP-62 for inspection relief for vessel internal components with hydrogen water chemistry, provided that such relief is submitted under the provisions of 10 CFR 50.55a and approved by the staff. QUESTIONS Has Pilgrim implemented hydrogen water chemistry? Has Pilgrim requested and/or obtained inspection relief for vessel internal components using the guidelines of BWRVIP-62? If so, describe the details of the inspection relief requested and/or granted.	Pilgrim is on Hydrogen Water Chemistry. Pilgrim has not used or requested relief for vessel internal components. The industry is currently waiting for the NRC SER on this BWRVIP report which is being finalized by the NRC.	Finnin, Ron	Okas, Pete	Closed	No

Item	Request	Response	Lead	Support	Category	Update
148	[B.1.5-J-05, BWR Penetrations] 5. For PNPS AMP B.1.5 (BWR Penetrations), the description of the exception states that a UT exam of N16B safe end-to-reducer weld is performed every 10 years. For this same AMP, the Operating Experience provides relatively recent (RFO15) examination results for weld RPV-N14-2 (SLC nozzle) and for instrument penetration nozzles. The Operating Experience also states that liquid penetrant examination of instrument penetration nozzle N15A in 1990 resulted in no recordable indications. The Operating Experience does not discuss results of the 10-year UT examinations of N16B safe end-to-reducer weld. QUESTIONS: 1. Discuss results of the 10-year UT examination of N16B safe end-to-reducer weld. 2. For RPV-N14-2 and for instrument penetration nozzles, discuss the history of examination results that is earlier than RFO15.	1. The N16B nozzle safe end to reducer weld RPV-N16B-R-2 was ultrasonically examined in RFO15 per the 3rd Interval ISI Program Plan and the PNPS Risk-Informed ISI Program. Access was provided by the removal of the N16B concrete shielding blocks which were replaced after the examination was completed. The Inconel to 316 stainless steel weld was examined using Appendix VIII methods for dissimilar metal welds with full code coverage achieved during the exam. No recordable indications were identified. 2. A summary table of inspections performed on the N15 and N16 nozzles is included in the response to Question B.1.5.3 above. Leakage was discovered during power operations in 1986 at the socket weld on the 2 inch side of the N16A nozzle safe end extension to reducer (2x1) weld. A temporary sleeve repair was installed and all N15 and N16 safe end extensions were subsequently replaced with Inconel extensions during the next outage in 1987. The SBLC N14 nozzle to safe end weld RPV-N14-1 was included in the Class 1 weld inspection sample and received a PT examination during the 3rd 10-year ISI interval until the Risk-Informed ISI Program was implemented in 2001. This weld was not included in the risk-informed weld sample population for examination. The weld received a surface examination in both RFO11 and RFO15 with no indications detected. Since an adequate ultrasonic procedure that allows depth sizing of indications is not currently available, weld RPV-N14-1 is scheduled for a surface examination every two outages starting with RFO15 in accordance with BWRVIP-27A recommendations. Enhanced VT-2 examinations for leakage were performed on this weld in both RFO14 and RFO15. This schedule of an enhanced VT-2 every outage and surface examination every other outage will continue going forward at least until an adequate UT procedure is available.	Finnin, Ron	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
		SBLC nozzle safe end extension to tee weld RPV-N14-2 is examined for leakage with VT-2 methods during the Class 1 system pressure test during every outage as required by code at the close of each refueling outage.				
149	[B.1.6-J.-01, BWR Stress Corrosion Cracking] 1. The PNPS LRA states that the implementing procedure for ASME Section XI inservice inspection and testing will be enhanced to specify that the guidelines of Generic Letter 88-01 or approved BWRVIP-75 "shall be considered" in determining sample expansions if indications are found in Generic Letter 88-01 welds: QUESTIONS: What is PNPS's current basis for determining sample expansion if indications are found in GL 88-01 welds? In addition the guidelines in Generic Letter 88-01 or approved BWRVIP-75, what other considerations, if any, will PNPS use in determining sample expansion if indications are found in Generic Letter 88-01 welds?	1. If cracking is detected in GL 88-01 Category A welds, the scope expansion rules of the PNPS Risk-Informed ISI Program in accordance with EPRI Topical Report TR-112657 will be used to determine scope expansion size and content. Scope expansion caused by cracking detected in any other GL 88-01 category (B through G) will be determined by the scope expansion criteria of BWRVIP-75A used in conjunction with GL 88-01. 2. PNPS plans to use the scope expansion rules outlined in BWRVIP-75A and GL 88-01 for Category B through G welds. If cracking is detected in GL 88-01 Category A welds, the scope expansion rules of the PNPS Risk-Informed ISI Program in accordance with EPRI Topical Report TR-112657 will be used to determine scope expansion size and content. Sample expansion addressed in section 2.5 of IGSCC report PNPS-RPT—05-008.	Finnin, Ron	Pardee, R.	Closed	No
150	[B.1.6-J-02, BWR Stress Corrosion Cracking] 2. Make available at the audit, in both hard copy and electronic format, the documents that compare the ten elements of PNPS AMP B1.6 (BWR Stress Corrosion Cracking) to the ten elements of GALL AMP XI.M7 (BWR Stress Corrosion Cracking).	This information is available in LRPD-02 which was provided to the NRC at the beginning of the audit.	Finnin, Ron	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
151	[B.1.6-J-03, BWR Stress Corrosion Cracking] 3. LRA Appendix B.1.6 (BWR Stress Corrosion Cracking) identifies an Exception to NUREG-1801. The exception is described as PNPS' use of the 1998 edition with 2000 addenda of ASME Section XI, Subsection IWB-3600 for flaw evaluation, while NUREG-1801 specifies the 1986 edition of ASME Section XI, Subsection IWB-3600 for flaw evaluation. QUESTIONS: Make available at the audit a copies of ASME Section XI, Subsection IWB-3600, the 1986 edition, and the 1998 edition with 2000 addenda. Identify which specific subsections of IWB-3600 are different between the 1986 edition and 1998 edition with 2000 addenda of ASME Section XI.	Copies were made available during the audit. Differences between paragraph IWB-3600 in the 1986 edition and the 1998 through 2000 addenda are listed below: IWB-3610 – The '98-2000 code has expanded this paragraph to include requirements for evaluating flaws in clad components. Otherwise, no changes. IWB-3641.2 – The '98-2000 code differs slightly from the '86 edition. IWB3641.3 - The '98-2000 code differs slightly from the '86 edition. IWB-3650 – This is a new paragraph in the later code for evaluation procedures and acceptance criteria for flaws in ferritic piping. Table IWB-3641-1 - Notes under the table have been expanded in the '98-2000 code. Table data is the same. Table IWB-3641-2 - Notes under the table have been expanded in the '98-2000 code. Table data is the same. Table IWB-3641-5 - Table is deleted from '98-2000 code. Table IWB-3641-6 - Table is deleted from '98-2000 code.	Woods, Steve	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
152	[B.1.6-J-04, BWR Stress Corrosion Cracking] 4. The Standard Review Plan for License Renewal (NUREG-1800, Rev. 1), Section 3.1.2.4, FSAR Supplement, states that "The [summary] description [of the program in the FSAR supplement] should ... contain any future aging management activities, including enhancements and commitments, to be completed before the period of extended operation." PNPS LRA Appendix B.1.6 (BWR Stress Corrosion Cracking) identifies an enhancement to be initiated prior to the period of extended operation. The LRA states that "The implementing procedure for ASME Section XI inservice inspection and testing will be enhanced to specify that the guidelines in Generic Letter 88-01 or Approved BWRVIP-75 shall be considered in determining sample expansion if indications are found in Generic Letter 88-01 welds. PNPS LRA UFSAR Supplement A.2.1.6 (BWR Stress Corrosion Cracking Program) does not include a description of the enhancement to PNPS' implementing procedure for ASME Section XI inservice inspection. QUESTION: Include a description of the enhancement to PNPS' implementing procedure for ASME Section XI inservice inspection in the UFSAR Supplement's description, A.2.1.6 (BWR Stress Corrosion Cracking Program).	The enhancement, as stated in LRA Appendix B is "The implementing procedure for ASME Section XI inservice inspection and testing will be enhanced to specify that the guidelines in Generic Letter 88-01 or approved BWRVIP-75 shall be considered in determining sample expansion if indications are found in Generic Letter 88-01 welds." See Item # 320 for resolution.	Finnin, Ron	Pardee, R.	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
153	[B.1.7-J-01, BWR Vessel ID Attachment Welds] 1. For examination category B-N-2 , ASME Section XI, Table IWB 2500-1, specifies VT-1 examinations for interior attachment welds within the beltline region. It specifies VT-3 examinations for interior attachment welds beyond the beltline region and for core support structure welds. The guidelines of BWRVIP-48 recommend more stringent inspections for certain attachments. Specifically, the guidelines recommend enhanced visual VT-1 examination of all safety-related attachments and those non-safety-related attachments identified as being susceptible to IGSCC. QUESTION: Confirm that PNPS performs the more stringent inspections of applicable vessel ID attachment welds as recommended in BWRVIP-48. Provide a descriptive list of the category B-N-2 vessel ID attachment welds that are inspected using the more stringent enhanced VT-1 examination techniques.	PNPS follows the requirement of BWRVIP-48 (now BWRVIP-48-A) as approved by the NRC for inspections. These are: • Jet pump riser brace - primary brace attachments • Core Spray piping - primary bracket attachments • Steam dryer support brackets • Feedwater bracket attachments	Finnin, Ron	Okas, Pete	Closed	No
154	[B.1.7-J-02, BWR Vessel ID Attachment Welds] 2. Confirm PNPS AMP B.1.7 (BWR Vessel ID Attachment Welds) implements the evaluation guidelines of BWRVIP-14, BWRVIP-59 and BWRVIP-60 for evaluation of crack growth in stainless steel, nickel alloys and low alloy steels, respectively.	PNPS plant procedures require that flaws be evaluated in accordance with BWRVIP Inspection and Flaw Evaluation Guidelines for components that perform a safety function. Subsequent BWRVIP correspondence that has been approved by the BWRVIP Executive Committee must also be considered when evaluating flaws. For components that do not perform a safety function, flaw evaluation shall be established by Design Engineering using the Condition Report process. Any flaw evaluation done by PNPS would consider all pertinent information available at that time, including the three BWRVIP documents identified in the question (and in NUREG-1801 Section XI.M4).	Finnin, Ron	Okas, Pete	Closed	No

Item	Request	Response	Lead	Support	Category	Update
155	[B.1.8-J-01, BWR Vessel Internals] 1. The PNPS LRA states that top guide fluence is projected to exceed the threshold for IASCC prior to the period of extended period of operation. The LRA states that PNPS AMP B.1.8 (BWR Vessel Internals) will be enhanced to inspect ten (10) percent of the top guide locations using enhanced visual inspection technique, EVT-1, within the first 12 years of the period of extended operation, with one-half of the inspections (50 percent of the locations) to be completed within the first 6 years of the period of extended operation. QUESTIONS: Describe PNPS's plans for inspection of top guide locations during the final 8 years of the twenty-year period of extended operation. If no inspections are planned for the final 8 years of operation, provide a technical basis for not continuing inspection of top guide locations during this part of the period of extended operation.	As indicated in LRA Section B.1.8 under Enhancements, ten (10) percent of the top guide locations will be inspected using enhanced visual inspection technique, EVT-1, within the first 12 years of the period of extended operation, with one-half of the inspections (50 percent of locations) to be completed within the first 6 years of the period of extended operation. This enhancement will be revised to require inspection of an additional 5% of the top guide locations during the third 6 years of the period of extended operation. This enhancement is Item 3 of the PNPS commitments for license renewal. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Finnin, Ron	Okas, Pete	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
156	[B.1.8-J-02, BWR Vessel Internals] 2. The Standard Review Plan for License Renewal (NUREG-1800, Rev. 1), Section 3.1.2.4, FSAR Supplement, states that "The [summary] description [of the program in the FSAR supplement] should ... contain any future aging management activities, including enhancements and commitments, to be completed before the period of extended operation." PNPS LRA Appendix B.1.8 (BWR Vessel Internals Program) identifies an enhancement to be initiated prior to the period of extended operation. PNPS LRA UFSAR supplement A.2.1.8 (BWR Vessel Internals Program) does not describe this enhancement. QUESTION: Include a description of the enhancement to PNPS' AMP B.1.8 in the UFSAR Supplement's description of this program.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Enhancements to programs that are described in Appendix B of the LRA are, therefore, commitments. To facilitate tracking of the enhancements through the NRC review process and facilitate implementation once the renewed license is received, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Item 3 on the list of commitments for license renewal is the commitment to implement the enhancement to PNPS AMP B.1.8. See Item #320 for resolution.	Finnin, Ron	Okas, Pete	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
157	[B.1.8-J-03, BWR Vessel Internals] 3. PNPS LRA Appendix B.1.8 (BWR Vessel Internals) identifies the following described exception to Scope of Program and Detection of Aging Effects: "Inspection of the four top guide hold-down assemblies and four top guide aligner assemblies is not performed at PNPS." An Exception Note states, "PNPS has a plant-specific analysis to account for plant-specific dynamic loading of the top guide hold-down and aligner assemblies, which concludes that less than 20% of the weld area on the top guide hold-down and aligner assemblies is needed to resist load. Therefore, in accordance with Table 3.2 of BWRVIP-26, inspection of the four top guide hold-down assemblies and four top guide aligner assemblies is not performed at PNPS. Questions: Provide a staff-approved copy of BWRVIP-26, including Table 3.2, stating that inspection of the four top guide hold-down assemblies and four top aligners is not required if 20% or less of the weld area is sufficient to resist vertical loads from the top guide during faulted events.	A copy of BWRVIP-26 including table 3.2 was made available during the audit.	Okas, Pete	Finnin, Ron	Closed	No
158	[B.1.8-J-04, BWR Vessel Internals] 4. Provide a status summary of current industry activities to develop a delivery system for ultrasonic testing of the hidden welds in PNPS' core spray system.	The BWRVIP/ EPRI NDE center recently acquired blade probes to demonstrate UT capability. Plans for 2007 are to develop a white paper to document the inspection capability to examine the thermal sleeve welds. This project excludes tooling development as it is left to inspection vendors.	Okas, Pete	Finnin, Ron	Closed	No
159	[B.1.8-J-05, BWR Vessel Internals] 5. Provide a status summary of current industry activities to develop a delivery system for ultrasonic testing of the hidden welds in PNPS' jet pump assemblies.	The BWRVIP/ EPRI NDE center recently acquired blade probes to demonstrate UT capability. Plans for 2007 are to develop a white paper to document the inspection capability to examine the thermal sleeve welds. This project excludes tooling development as it is left to inspection vendors.	Okas, Pete	Finnin, Ron	Closed	No

Item	Request	Response	Lead	Support	Category	Update
160	[B.1.8-J-06, BWR Vessel Internals] 6. LRA Appendix B.1.8 (BWR Vessel Internals, Operating Experience, states that "Previous visual and enhanced visual examinations of vessel internals revealed indications on core spray piping welds, and steam dryer leveling screw tack welds." QUESTIONS: When were the earlier indications on core spray piping welds and steam dryer level screw tack welds found? What corrective actions were taken?	Core spray piping welds 1P5 and 3P5 in RFO11, and Steam dryer level screw tack welds in RFO7. Corrective action for the Core Spray piping 1P5 and 3P5 UT weld UT indications that were found in 1997 (RFO11) and re-examined in 1999 consisted of the performance of flaw evaluations that accounted for both crack growth and leakage considerations. The flaw evaluations found the 1P5 weld acceptable for continued operation for five cycles (RFO17) and the 3P5 weld acceptable for another six cycles (RFO18). Corrective action taken in 1987 (RFO7) for the cracked steam dryer leveling screw tack welds consisted of a weld repair to the 35 and 215 degree azimuth screws. The two leveling screws were re-tacked in two places each per the disposition detailed in Nonconformance Report NCR 87-87.	Okas, Pete	Finnin, Ron	Closed	No
161	[B.1.8-J-07, BWR Vessel Internals] 7. GALL Section XI.M9 (BWR Vessel Internals), Element 4 (Detection of Aging Effects) states: "The applicable and approved BWRVIP guidelines recommend more stringent inspections, such as enhanced VT-1 examinations or ultrasonic methods of volumetric inspection for certain selected components and locations:" QUESTION: Confirm that PNPS AMP B.1.8 (BWR Vessel Internals) performs the more stringent inspections recommended in the applicable and approved BWRVIP guidelines, except as documented in PNPS LRA under the discussion of "Exceptions to NUREG-1801."	The PNPS BWR Vessel Internals program will perform the more stringent inspections in the BWRVIP Inspection and Evaluation Guidelines approved by the NRC for referencing for license renewal. Any exceptions to the approved BWRVIPs are discussed as exceptions to NUREG-1801. Note that some of the specific BWRVIPs are considered part of sub-programs such as BWR Penetrations, BWR Vessel ID attachment welds, etc; but all are implemented via the BWR Vessel Internals Program (NE 21.01) at the PNPS site.	Okas, Pete	Woods, Steve	Closed	No

Item	Request	Response	Lead	Support	Category	Update
162	[B.1.9-H-01, 10 CFR 50 Appendix J (XI.S4)] 1. The applicant is requested to address and discussion the test Option related to this program. What and when was the most significant experience related to this program do you have? What was your corrective and preventive actions did you take? When will be your next "periodic interval"?	The PNPS program utilizes Option B and the guidance in NRC Regulatory Guide 1.163 and NEI 94-01. (Ref. Aging Management Program Evaluation Report LRPD-02, Section 4.8.B.5.b). During the most recent integrated leakage testing of primary containment performed in 1995, as-found and as-left test data met all applicable test acceptance criteria. QA audits in 2000 and 2005 revealed no issues or findings that could impact effectiveness of the program. (Ref. LRA B.1.9) During as-found local leak rate testing in the late 1990s, the main steam isolation valves and feedwater check valves experienced test failures. The MSIVs were modified and refurbished to improve seat leakage performance. Preventive maintenance to replace the soft seats on the feedwater check valves each refueling outage has improved the seat leakage performance. The current ILRT periodic interval is fifteen years (no later than May 25, 2010) based on License Amendment 213 to the PNPS Facility Operating License which allowed a five year extension to the ten year interval.	Ahrabli, Reza	Williams, M.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
163	[B.1.10-P-01, Diesel Fuel Monitoring] 1. Provide justification for not cleaning and visually inspecting the security diesel generator fuel storage tank on a periodic basis.	As stated in LRA Section B.1.10, the security diesel generator fuel storage tank is not periodically cleaned and inspected because the internals are inaccessible. The tank does not have manways. This is acceptable because the program enhancements described below will ensure that significant degradation is not occurring. One enhancement listed in LRA Section B.1.20 is for periodic sampling of the security diesel generator fuel storage tank, near the bottom, to determine water content. The other enhancement listed in LRA Section B.1.10 is to include periodic UT measurement on the bottom surface of the security diesel generator fuel storage tank. However, engineering evaluation after submittal of the LRA determined that UT is not feasible for this tank due to geometry. Therefore, this enhancement will be revised to add instrumentation to monitor for leakage between the two walls of the tank. This modification will be installed prior to the period of extended operation. LRPD-02 Revision 2 issued addressing this item. Item # 5 on the list of commitments for license renewal is the commitment to install instrumentation to monitor for leakage between the two walls of the security diesel generator fuel storage tank.	Potts, Lori	Hudson, Steve	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
164	[B.1.10-P-02, Diesel Fuel Monitoring] 2. Provide justification for not using all ASTM specifications.	The Diesel Fuel Monitoring Program does not use the guidelines of ASTM Standard D 6217 along with those of D 2276 for determination of particulates. ASTM D 2276 provides guidance on determining particulate contamination using a field monitor. It provides for rapid assessment of changes in contamination level without the time delay required for rigorous laboratory procedures. It also provides a laboratory filtration method using a 0.8 micron filter. ASTM D 6217 provides guidance on determining particulate contamination by sample filtration at an off-site laboratory. Thus, while either method may be used to determine particulates, there is no reason to use both methods. Since ASTM D 2276 is an accepted method of determining particulates and is a method recommended by ASTM D 975, the D 2276 method is used at PNPS.	Potts, Lori	Hudson, Steve	Closed	No
165	[B.1.10-P-03, Diesel Fuel Monitoring] 3. Provide justification of the "<= 60% of nominal thickness" acceptance criterion.	The enhancement is being revised to, "Enhance the Diesel Fuel Monitoring Program to specify acceptance criterion for UT measurements of emergency diesel generator fuel storage tanks (T-126A&B)." This enhancement is item # 6 on the list of commitments for license renewal and will be completed prior to the period of extended operation. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Potts, Lori	Hudson, Steve	Accepted	Yes
166	[B.1.10-P-04, Diesel Fuel Monitoring] 4. Will all tank bottoms be subjected to 100% UT inspection?	No, as described in the Aging Management Program Evaluation Report, a periodic ultrasonic thickness (UT) measurement is performed on the bottom surface of the underground emergency diesel fuel oil storage tanks. During these inspections, UT measurements are made at several random locations on the bottom of these tanks.	Potts, Lori	Hudson, Steve	Closed	No

Item	Request	Response	Lead	Support	Category	Update
167	[B.1.10-P-05, Diesel Fuel Monitoring] 5. If reduction of thickness is discovered during UT, will microbiological activity be monitored and biocide added in the future? If not, provide a justification for not doing so.	In accordance with the corrective action program, an engineering evaluation into the cause will be performed if test acceptance criteria are not met and corrective actions will be implemented, to ensure that the intended function of the tanks can be maintained consistent with the current licensing basis for the period of extended operation. If appropriate to address the cause, biocide addition may be an element of the corrective action.	Potts, Lori	Hudson, Steve	Closed	No
168	[B.1.10-P-06, Diesel Fuel Monitoring] 6. NUREG-1800, SRP for license renewal, section 3.X.3.4, FSAR Supplement, states the following: As noted in Table 3.X-2, an applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should confirm that the applicant has identified and committed in the license renewal application to any future aging management activities, including enhancements and commitments to be completed before entering the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date. The enhancements identified in the B.1.10 write-up are not included in the FSAR Supplement Appendix A.2.1.10. They should be in the UFSAR Supplement in order to address these commitments.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Enhancements to programs that are described in Appendix B of the LRA are, therefore, commitments. To facilitate tracking of the enhancements through the NRC review process and facilitate implementation once the renewed license is received, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Items 4, 5, and 6 on the list of commitments for license renewal are the commitments to implement the enhancements described in LRA Section B.1.10 Close to item #320.	Potts, Lori	Hudson, Steve	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
169	[B.1.11-N-01, Environment Qualification (EQ) of Electrical Components Program] 1. The results of the environmental qualification of electrical equipment in LRA Section 4.4. indicate that the aging effects of the EQ of electrical equipment identified in the TLAA will be managed during the extended period of operation under 10 CFR 54.21(c)(1)(iii). However, no information is provided on the attribute of a reanalysis of an aging evaluation to extend the qualification life of electrical equipment identified in the TLAA. The important attributes of a reanalysis are the analytical methods, the data collection and reduction methods, the underlying assumptions, the acceptance criteria, and corrective actions. Provide detail description on the important attributes of reanalysis of an aging evaluation of electrical equipment identified in the TLAA in the LRA or plant's basis document (under program description) to extend the qualification under 10 CFR 50.49(e).	PNPS may perform reanalysis of an aging evaluation in order to extend the qualification of electrical components under 10 CFR 50.49(e) on a routine basis as part of the plant's EQ program. As described in NUREG-1801, rev. 1, important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. LRA Appendix B.1.11 will be revised to include the following: EQ Component Reanalysis Attributes The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of an EQ program. While a component life limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to the station's quality assurance program requirements, which requires the verification of assumptions and conclusions. As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below. Analytical Methods: The analytical models used in the reanalysis	Stroud, Mike	Das, Swapan	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
		of an aging evaluation are the same as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (that is, normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5 (that is, 60 years/40 years). The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis. Data Collection and Reduction Methods: Reducing excess conservatism in the component service conditions (for example, temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis. Temperature data used in an aging evaluation is to be conservative and based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as (a) directly applying the plant temperature data in the evaluation, or (b) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to material activation energy values as part of a reanalysis are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the				

component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions:
EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Actions:
The reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component is to be refurbished, replaced, or re-qualified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (that is, sufficient time is available to refurbish, replace, or re-qualify the component if the reanalysis is unsuccessful.

Pilgrim utilizes a reanalysis methodology in accordance with 10 CFR 50.49(e) that applies the important attributes in the GALL Report as appropriate. Reanalysis of aging evaluations in accordance with 10 CFR 50.49(e) is an acceptable AMP for license renewal under option 10 CFR 54.21(c)(1)(iii).

This requires an amendment to the LRA.

Item	Request	Response	Lead	Support	Category	Update
170	[B.1.11-N-02, Environment Qualification (EQ) of Electrical Components Program] 2. PNPS B.1.11 under operating experience, you have stated that the overall effectiveness of the EQ of electric components program is demonstrated by the excellent operating experience for systems, structures, and components in the program. Discuss operating experience of the existing EQ program. Show where an existing program has succeeded and where it has failed in identifying aging degradation in a timely manner.	Under the EQ program, surveillance and maintenance activities are used to assure that equipment is maintained within its qualification basis and qualified life. The program provides that equipment shall be replaced, refurbished or re-qualified prior to exceeding its qualified life. The overall effectiveness of the Environmental Qualification (EQ) of Electric Components Program is demonstrated by the excellent operating experience for systems, structures, and components in the program. The program has been subject to periodic internal and external assessments that have resulted in program improvement. The Environmental Qualification (EQ) of Electric Components Program has been effective at managing aging effects. The Environmental Qualification (EQ) of Electric Components Program provides reasonable assurance that the effects of aging will be managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. References: ENN Engineering Assessment Report dated 3/1/01, and EQ Program Self-Assessment January 28, 2002 – February 01, 2002.	Das, Swapan	Stroud, Mike	Closed	No
171	[B.1.12-P-01, Fatigue Monitoring] 1. FSAR Supplement section A.2.1.12 references section 4.2.6 for location of the transient cycles that are tracked by this program. However, section 4.2.6 addresses RPV Axial Weld Failure Probability. Should section 4.3.1, Table 4.3-2 be referenced instead?	The referenced 4.2.6 is FSAR Section 4.2.6 not LRA.	Potts, Lori	Mileris, George	Closed	No

Item	Request	Response	Lead	Support	Category	Update
172	[B.1.13.1-P-01, Fire Protection] 1. Provide justification why carbon dioxide fire suppression system is not subject to aging management review.	The carbon dioxide fire protection system is required for insurance purposes but is not required to protect safety-related systems. Therefore the carbon dioxide fire protection system has no intended functions for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). Also, since the system does not contain liquid that could leak and cause physical interaction with safety-related components that could prevent satisfactory accomplishment of a safety function, it also has no intended functions for 10 CFR 54.4(a)(2).	Potts, Lori	Burke, Steve	Closed	No
173	[B.1.13.1-P-02, Fire Protection] 2. The exception taken for element 4 about the inspection frequency for penetration seals should also apply to element 3 for the same reason that it applies to element 4. Justify why this exception does not apply to element 3.	NUREG-1800, SRP for license renewal, Section A.1.2.3.4 states that Detection of Aging Effects (element 4) describes "when," "where," and "how" program data are collected. Therefore, the exception to inspection frequency for penetration seals was applied to element 4. PNPS does not take exception to the parameters to be monitored or inspected for penetration seals. Therefore, the exception does not apply to element 3.	Potts, Lori	Burke, Steve	Closed	No

Item	Request	Response	Lead	Support	Category	Update
174	[B.1.13.1-P-03, Fire Protection] 3. The two enhancements identified in B.1.13.1 write-up are not included in the FSAR Supplement Appendix A.1.13. NUREG-1800, SRP for license renewal, section 3.X.3.4, FSAR Supplement, states the following: As noted in Table 3.X 2, an applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should confirm that the applicant has identified and committed in the license renewal application to any future aging management activities, including enhancements and commitments to be completed before entering the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date. The enhancements should be included in the Appendix A write-up.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Enhancements to programs that are described in Appendix B of the LRA are, therefore, commitments. To facilitate tracking of the enhancements through the NRC review process and facilitate implementation once the renewed license is received, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Items 7 and 8 on the list of commitments for license renewal are the commitments to implement the enhancements described in LRA Section B.1.13.1. See Item #320 for closure for this Item.	Potts, Lori	Burke, Steve	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
176	[B.1.13.2-P-1a, Fire Water System] 1. NUREG-1800, SRP for license renewal, section 3.X.3.4, FSAR Supplement, states the following: As noted in Table 3.X 2, an applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should confirm that the applicant has identified and committed in the license renewal application to any future aging management activities, including enhancements and commitments to be completed before entering the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date. a) The enhancement for wall thickness evaluation of fire protection piping is identified in the Appendix A write-up in the present tense, meaning the inspections are being performed. However, the enhancement is addressed in the Appendix B write-up is in the future tense, meaning the inspections will be performed in the future (before the end of the current operating term). The Appendix A write-up should be revised to address this future commitment.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Enhancements to programs that are described in Appendix B of the LRA are, therefore, commitments. To facilitate tracking of the enhancements through the NRC review process and facilitate implementation once the renewed license is received, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Item 11 on the list of commitments for license renewal is the commitment to implement the enhancement for fire water system wall thickness evaluations described in LRA Section B.1.13. See Item #320 for closure for this Item.	Potts, Lori	Burke, Steve	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
177	[B.1.13.2-P-1b, Fire Water System] NUREG-1800, SRP for license renewal, section 3.X.3.4, FSAR Supplement, states the following: As noted in Table 3.X 2, an applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should confirm that the applicant has identified and committed in the license renewal application to any future aging management activities, including enhancements and commitments to be completed before entering the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date. b) The enhancement for revising procedures to include inspections of hose reels for corrosion is not addressed in the Appendix A write-up. The Appendix A write-up should be revised to address this future commitment.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Enhancements to programs that are described in Appendix B of the LRA are, therefore, commitments. To facilitate tracking of the enhancements through the NRC review process and facilitate implementation once the renewed license is received, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Item 9 on the list of commitments for license renewal is the commitment to implement the enhancement to inspect hose reels for corrosion described in LRA Section B.1.13.2. See Item #320 for closure for this Item.	Potts, Lori	Burke, Steve	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
178	[B.1.14-W-01, FAC] 1. How is the minimum allowable wall thickness defined in PNPS FAC program?	For the initial evaluation of data at PNPS a screening of criteria of 0.875 of Nominal is used to determine whether locations require further evaluation. If below this screening criteria the wear, wear rate and remaining service life are calculated in accordance with ENN-DC-315 section 5.6. PNPS uses the term minimum acceptable wall thickness (Taccept) in the FAC program. The term minimum acceptable wall thickness is defined as the maximum value of Tmin or Tcrit where Tmin is the minimum required global wall thickness based on hoop stress and Tcrit is the minimum required wall thickness per code of construction required to meet all design loading conditions. Taccept is used in the calculation of the remaining service life which determines whether the component may be returned to service. These definitions can be found in ENN-DC-315 in section 3.0.	Ivy, Ted	Bechen, G	Closed	No
179	[B.1.14-W-02, FAC] 2. The FAC program includes the use of a predictive code. Does PNPS belong to EPRI's CHECWORKS Users Group (CHUG), and CHECWORKS is being used?	As described in LRPD-02 section B.5.b CHECWORKS version 1.0F is being used at PNPS and PNPS is a member of the CHECWORKS Users Group.	Ivy, Ted	Bechen, G	Closed	No

Item	Request	Response	Lead	Support	Category	Update
180	[B.1.14-W-03, FAC] 3. If degradation is detected such that the measured wall thickness is less than the predicted thickness, explain how the sample size is increased to bound the thinning for the same inspection period.	From ENN-DC-315 rev. 1: 5.9 DISPOSITION OF INSPECTION RESULTS [1] ... [2] ... [3] If Tpred is = 0.875 Tnom Evaluate for sample expansion (Reference section 5.12). 5.12 SAMPLE EXPANSION [1] If a component is discovered that has a current or projected wall thickness less than the minimum acceptable wall thickness (Taccpt), then additional inspections of identical or similar piping components in a parallel or alternate train shall be performed to bound the extent of thinning except as provided below. Reference section 5.12.2. [2] When inspections of components detects significant wall thinning and it is determined that sample expansion is required, the sample size for that line should be increased to include the following: (a) Components within two diameters downstream of the component displaying significant wear or within two diameters upstream if the component is an expander or expanding elbow. (b) A minimum of the next two most susceptible components from the relative wear ranking in the same train as the piping component displaying significant wall thinning. (c) Corresponding components in each other train of a multi-train line with a configuration similar to that of the piping component displaying significant wall thinning.	Ivy, Ted	Bechen, G	Closed	No

Item	Request	Response	Lead	Support	Category	Update
181	[B.1.14-W-04, FAC] 4. In the Program Description, the applicant states that "This program applies to safety-related and nonsafety-related carbon steel components in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid > 2% of plant operating time." Which piping systems are excluded from the FAC program scoping as a result of low operating time (i.e., < 2% of plant operating time)? Has any inspection ever been performed to make sure that there is no wear on these lines?	Portions of the Main Steam system (Plant Heating; Reactor Vessel Vent Lines; portions of the Feedwater System (Recirculation lines to the Condenser – Feedwater clean-up line to the condenser); Feedwater Heater Start-up vent lines; portions of RCIC; and Portions of HPCI have been excluded. Inspections have been performed on some of these lines typically in response to operational issues such as valve leakage or orifice degradation occurring such that there is flow in the line during normal operation. In RFO14 and RFO15 the Feedwater recycle line (FAC pt# 366) was inspected to verify that a leaking valve had not caused damage. The piping wall thickness was found to not have appreciably changed during the two inspections which provided evidence that significant wear of the piping had not and was not occurring. In RFO15 the RCIC minimum flow bypass line (FAC pt# 376) was inspected due to suspected valve leak by and the downstream piping was found to show no significant wear based on wall thickness.	Bechen, Gerry	Ivy, Ted	Closed	No

Item	Request	Response	Lead	Support	Category	Update
182	[B.1.14-W-05, FAC] Describe the experience of FAC program at PNPS and the ability of the inspection programs to detect wall thinning in a timely manner before the intended function of piping components has been lost: 1. Have components been identified that did not meet the minimum allowable wall thickness prior to replacement or loss of pressure retaining capacity? 2. What corrective actions have been taken, and to what extent have these measures been effective in eliminating or reducing the wall thinning? 3. What changes to the program have occurred to ensure that aging effects due to FAC have been successfully managed? 4. Provide evidence that the current aging management program has been effective to successfully mitigate and detect wall thinning during the time period addressed by the LRA.	1. For example, in RFO14, FAC pt #319 and pt# 371 (1st point "B" operating vent line) were inspected and found below Taccept. This piping was upgraded with chrome-moly. FAC pt# 128.2 was inspected in RFO14 (Tscreen was less than required) and again in RFO15 to verify Tmin was not met. The issue is apparently due a low point on a socket weld and not FAC wear. The affected piping is scheduled for replacement in RFO16. Additionally, one of the 30" extraction steam lines to the 5th point heater was inspected in RFO13 and found to have a hole in it and was repaired. This piping is inside the condenser. Additional inspections were performed and general FAC degradation was noted on most of the lines. The decision was made replace all of this piping with chrome-moly piping. The last of it is scheduled for replacement in RFO16. In RFO14 FAC pt# 307 was inspected and found to have a wall thickness less than Tscreen. Re-evaluation concluded the location was acceptable for operation through RFO16. The component is currently scheduled for re-inspection in RFO16. 2. Piping upgrade to FAC resistant material such as A335 Gr. P11 piping has been extremely effective in eliminating or reducing the loss of wall thickness. Additionally, in some cases, the degraded components have been replaced in-kind. Measures also include: changing out leaking valves, changing out degraded restriction orifices, etc. 3. As documented in LRPD-05 section 4.1.14, a fleetwide procedure for the Entergy northeast plants has been developed that includes improvements based on industry and other Entergy Nuclear Northeast plant OE. For example, skid mounted piping is now included in the enhanced system susceptibility evaluation. In addition, during RFO15, several FAC points were added to inspections, or re-inspected, in response to	Ivy, Ted	Bechen, G	Closed	No

Item	Request	Response	Lead	Support	Category	Update
		industry OE and the MIHAMA Japan failure. 4. As documented in LRPD-05 section 4.1.14, examinations between RFO13 and RFO14 and during RFO14 (April, 2003) and examinations between RFO14 and RFO15) and during RFO15 (April, 2005) detected 8 locations with decreased wall thickness. Of these 8 locations four were either replaced or repaired and the remainder were determined to be acceptable after reevaluation.				
183	[B.1.15-P-01, Heat Exchanger Monitoring] 1. What method(s) will be used to detect localized corrosion? Identify areas to be inspected and frequency of inspections for localized corrosion.	This is a new program and the details have not yet been developed. In accordance with LRPD-02 sections 3.2.B.3 and 3.2.B.4, where practical, eddy current inspections of shell-and-tube heat exchanger tubes will be performed to determine tube wall thickness. Visual inspections will be performed on heat exchanger heads, covers and tube sheets where accessible to monitor surface condition for indications of loss of material such as areas where localized corrosion could occur (i.e. stagnant/low flow areas). A potential approach for determining the inspection frequency would be that once the initial inspections are completed, the results would be used to determine the frequency to ensure that effects of aging are identified prior to loss of intended function. Inspection frequency will be dependent on the specific component operating parameters (process fluid, cooling medium, pressures, materials), maintenance history, licensing commitments, NEIL Loss Control Standards and OE.	Ivy, Ted	Lane, K	Closed	No

Item	Request	Response	Lead	Support	Category	Update
184	[B.1.15-P-02, Heat Exchanger Monitoring] 2. Provide additional details describing the methods that will be used establish sample size and frequency.	A review of the specific component's mechanical design, environments, operating conditions and flow paths combined with its maintenance history, and internal and external OE will be used to determine the sample size and frequency. The sample size will most likely include peripheral tubes and areas within a particular heat exchanger that are more susceptible to wear, corrosion or damage, i.e. adjacent to inlet/outlet nozzles and changes in flow direction and will consider industry best practices and EPRI recommendations. Once the initial inspections are completed, the results will be used to determine the frequency to ensure that effects of aging are identified prior to loss of intended function. Visual inspections of accessible heat exchangers will be performed on the same frequency as eddy current inspections.	Ivy, Ted	Lane, K	Closed	No
185	[B.1.15-P-03, Heat Exchanger Monitoring] 3. Provide details on data collection.	Since this is a new program the details of data collection are not available. However, inspections will be performed either online or during refueling outages (dependent on the particular component). The data will be collected, analyzed and required actions taken at that time. The data will also be utilized for longer term trending and developing future action plans and will be maintained in accordance with site QA program requirements.	Ivy, Ted	Lane, K	Closed	No
186	[B.1.15-P-04, Heat Exchanger Monitoring] 4. Provide details describing the methods to assess remaining component life for loss of material using inspection results such that timely mitigative action can be made.	Because this is a new program exact details are not yet available. Wall thickness will be trended and projected to the next inspection. Corrective actions will be taken if projections indicate that the acceptance criteria may not be met at the next inspection. Reference LRPD-02 section 3.2.B.6. Trend information along with OE will be utilized to determine the remaining component life	Ivy, Ted	Lane, K	Closed	No

Item	Request	Response	Lead	Support	Category	Update
187	[B.1.15-P-05, Heat Exchanger Monitoring] 5. Provide more details on how acceptance criteria will be established.	The minimum acceptable tube wall thickness for each heat exchanger to be eddy current inspected will be established based upon a component specific engineering evaluation based on code requirements, EPRI guidelines, and internal calculations. Wall thickness will be acceptable if greater than the minimum wall thickness for the component. The acceptance criterion for visual inspections of heat exchanger heads, covers and tubesheets will be no evidence of degradation that could lead to loss of function. If degradation is detected such that if not corrected it would lead to loss of intended function, a condition report will be written and the issue resolved in accordance with the site corrective action program. Reference LRPD-02 section 3.2.B.6.	Ivy, Ted	Lane, K	Closed	No
188	[B.1.15-P-06, Heat Exchanger Monitoring] 6. Although this is a new program, provide operating experience with respect to heat exchanger wall thinning and other degradation resulting from adherence to GL 89-13.	GL 89-13 requires inspection of one RBCCW heat exchanger each refuel outage. Service water side inspections have resulted in some minimal tube plugging and weld or belzona repair to washed out areas on the pass partition plate or tube sheet. Past inspections have also identified degraded gasket seating surfaces and tube inlet sleeve erosion that have required repairs. The copper nickel tube degradation is typically due to internal erosion caused by material wedged in the tube and is random in location. There has also been external tube damage in the area impacted by the shell side inlet flow due to vibration. This particular OE is included in the Service Water Integrity Program (SWIP) B.1.28 since it is a heat exchanger in the scope of the SWIP and the OE confirms the effectiveness of the SWIP. In accordance with NEI 95-10 the review of operating experience is used to either confirm the effectiveness of an existing program or identify new site specific aging effects. For new programs such as the Heat Exchanger Monitoring Program B.1.15, applying this as OE is not required.	Lane, Ken	Ivy, Ted	Closed	No

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189	[B.1.16.1-H-01, CII] 1. Pilgrim AMP B.1.16.1 identifies that the Containment Inservice Inspection (CII) program is a plant-specific program encompassing the requirements for the inspection of class MC. The applicant is requested to identify the document(s) that includes the evaluation of Pilgrim AMP B.1.16.1 to include additional MC supports. Please provide the following information related to: (a) Identify the MC supports that are currently included in the existing inspection program. (b) Identify the MC supports that will be added to the scope of this inspection program for the license renewal period. (c) Specify the current inspection program and describe the current inspection details □for the MC supports that are identified in (b) above. (d) Confirm that, all MC supports will be included in the scope of this inspection program for the extended period of operation.	a. Torus supports and RPV stabilizer supports. The program document is PNPS-RPT—05-001. All torus supports, earthquake ties and upper drywell stabilizer supports are scheduled for examination during the PNPS 4th ten-year inspection interval. b.Torus supports and RPV stabilizer supports. The program document is PNPS-RPT—05-001. All torus supports, earthquake ties and upper drywell stabilizer supports are currently scheduled for examination during the PNPS 4th ten-year inspection interval. There are no other supports to add. c. These are under the ASME Section XI program and require VT-3 inspection. The Class MC supports at PNPS consist of 16 torus saddle supports, 4 torus earthquake ties and 8 upper drywell stabilizers. The original IWE program at PNPS was developed in accordance with the requirements ASME XI 1992 edition with 1992 addenda after the IWE section of the code was mandated in 1996. This edition of the code did not require inspection of Class MC supports. However, as a conservative measure, PNPS included a sample of 25% of the torus saddle supports, 25% of the earthquake ties, and 25% of the upper drywell stabilizers. The current IWE Program at PNPS was developed in accordance with the 1998 edition with 2000 addenda of ASME XI. This code edition requires that 100% of the Class MC supports be examined during the ten year interval. Accordingly, all torus supports, earthquake ties and upper drywell stabilizer supports are currently scheduled for examination during the PNPS 4th ten-year inspection interval. The first examinations under the 4th interval IWE program will occur immediately prior to and during RFO16 in 2007.	Pardee, Rich	Ahrabli, Reza	Closed	No

The torus saddle supports and earthquake ties are accessible to inspection as they are located on the torus floor. Inspection of the upper drywell stabilizers requires the removal of bolted access hatches to perform the required visual inspections. These hatches constitute a portion of the primary containment pressure boundary and are tested in accordance with Appendix J requirements after each opening.

d. These are currently included in the 4Th interval ISI program which expires in June 2015. The next interval will be updated and maintained as required by 10 CFR 50.55(a) and ASME Section requirements.

All torus supports, earthquake ties and upper drywell stabilizer supports continue to be examined in accordance with the PNPS IWE Program during the period of extended operation.

Item	Request	Response	Lead	Support	Category	Update
190	[B.1.16.1-H-02, CII] 2. The applicant is requested to identify and provide the inspection frequency against the AMP B.1.16.1. What is the cause for "Loose" torus anchor bolt found in 1999? Are there any other "loose and/or degraded" situations identified? Are there any Preventive Action for the Torus shell wall (thin wall)? Please, provide an examination details, acceptance criteria, qualifications, and documentation.	The condition discovered in 1999 involved two torus saddle support tie-down nuts. The anchor bolts themselves were not loose. The loose condition of the two torus saddle support tie-down nuts was discovered during a scheduled PNPS IWE Program visual examination of containment supports in 1999. Nonconformance Report NCR 99-19 and Problem Report PR 99.9102 were generated to document and investigate the condition. Corrective actions included re-torquing the two loose tie-down nuts to 80 ft-lb and checking the tightness of a sample of the remaining tie down nuts. No other loose bolting conditions were identified. The tightness of the support tie-down nuts is unrelated to torus anchor bolt tension as the upper tie-down bolting connects the torus saddle support to the free upper end of the anchor bolt, and is not used to tension the anchor bolt to the concrete floor. The cause of the two loose tie-down nuts found in 1999 may be indeterminate given the information available at this point in time. Inadequate initial preload during installation of the torus saddle supports during the Torus Mark I containment modifications in 1980 is considered to be an unlikely cause due to the high level of QA oversight on the project which included direct QC inspection of anchor bolt installation and torquing process. The loose bolting condition is not significant because the safety function of the torus saddle support tie-down bolting is to prevent vertical movement of the torus from a hydrodynamic event occurring during accident conditions. The 80 ft-lb torque for these nuts is intended to ensure the nuts remain in a flush condition with the saddle support bearing surface. As long as no gap exists between the tie-down nuts and the torus saddle support bearing surface, the support will perform the intended safety function. No gaps existed between the two loose nuts found in 1999 and saddle support surfaces.	Pardee, Rich	Ahrabli, Reza	Closed	No

In addition, unrelated to the condition discussed above, a corrosion assessment of torus saddle tiedown concrete anchor bolt assemblies was performed in 1999 and documented in supplier design document review form SUDDS/RF99-134. The assessment determined that ground water intrusion through the torus floor had not significantly degraded the tensile strength of the rock anchor bolts based on chemical testing of the groundwater.

PNPS monitors torus wall thickness via the inclusion of augmented UT thickness examinations in the PNPS IWE Program. These thickness examinations are performed at 8 locations distributed around the torus. Half of the inspections are performed at the torus vapor/water interface of the torus shell while the other half are performed at a location approximately halfway between the waterline and the lowest point on the torus shell. Torus shell thickness examinations are performed during each 40 month period (i.e. every other outage) while the plant is on-line. Comparison of UT results from 1999 and 2003 reveal no measurable change in wall thickness. These examinations will continue to be performed during the period of extended operation. The examinations are performed by qualified NDE technicians who are code certified to at least Level II in ultrasonic thickness measurement.

Item	Request	Response	Lead	Support	Category	Update
191	[B.1.16.1-H-03, CII] 3. The applicant is requested to address the results of the CII general walkdown of primary containment during April 2003 (RFO 14) and found some surface corrosion in the CRD penetration areas. What were your corrective and preventive action? Did a Root Cause Analysis was performed? Please provide your acceptance criteria, qualification? And/or any other means to support your conclusion?	Results of the IWE General Visual Walkdown performed during RFO14 are evaluated and dispositioned in Condition Report CR-PNP-2003-01618. Newly reported corrosion around the CRD penetrations at the 270 degree azimuth at approximately 35 feet elevation in the drywell was re-checked visually by the IWE Responsible/Design Engineer and found acceptable. This was characterized as surface corrosion that was not considered significant by the Responsible/Design Engineer. Since the determination was that the corrosion was acceptable, no root cause analysis was performed and no corrective or preventive actions were required. Acceptance criteria for the General Visual Walkdown are detailed in procedure PNPS 2.1.8.7 and Entergy Engineering Standard ENN-EP-S-001, Section 5. Conditions listed as requiring evaluation include, in part, peeling, flaking, blistering, cracking, checking, absence of coating, and rusting of the containment coating.	Pardee, Rich	Ahrabli, Reza	Closed	No

Item	Request	Response	Lead	Support	Category	Update
192	[B.1.16.1-H-04, CII] 4. The applicant is requested to address and discussion the Operating Experience in detail found in 1999, the below-water regions of all 16 torus bays as well as the drywell to torus vent areas. Did your scope expansion was required due to unacceptable found? Do you have any Preventive Actions to prevent it from further damaged and/or recur? If yes, why it's not including into this program?	PNPS performs desludging, inspection and coating repairs every other outage as part of the torus desludge project on torus below-water surfaces in accordance with a Preventive Maintenance (PM) task scheduled using the plant Master Surveillance Tracking Program (MSTP). This task was performed most recently in the 1999 and 2003 outages. During the 1999 outage (RFO12), IWE visual examinations were also performed by certified divers in accordance with the PNPS IWE Program. The 1999 IWE underwater visual examinations revealed the approximately 80% of the surfaces to be in fair good condition with sporadic coating defects (localized corrosion with pitting) identified in the remaining areas. Corrosion of the torus underwater surfaces is attributed to local zinc depletion in the zinc-rich protective coating. Pit depth measurements were taken and documented in the SG Pinney report and Problem Report PR 99.1345. All areas with pit depths measured at 0.032" and greater were recoated with a qualified coating. One pit exceeded the maximum allowable depth of 0.066 inches. This was determined to be a preservice gouge in the torus shell plate and was subsequently accepted by evaluation. None of the 1999 inspection results of torus underwater surfaces were considered significant (Ref. PR 99.1345 response). The current general corrosion rates determined from insepction data collected since 1991 will not result in pitting corrosion that would cause violating the general minimum wall thickness values for the torus shell by the end of the period of extended operation. Preventive actions to prevent recurrence of pitting consists of coating repairs with qualified coatings and periodic inspections associated with the torus desludge project every other outage. The IWE VT-3 visual examination of submerged surfaces is also performed every 10 years in accordance with the PNPS IWE Program.	Pardee, Rich	Neiderberger, Amy	Closed	No

Item	Request	Response	Lead	Support	Category	Update
		Augmented IWE visual examinations of selected portions of the drywell to torus vent system in 1999 revealed localized pitting due to degradation of the coating aggravated by standing water in the downcomer vent bowls (vent bowl drains had been cut and capped in a previous modification for seismic considerations). The scope of the examinations was expanded to include all 8 vents. All pitting was evaluated and found to be acceptable. The surfaces were prepped and recoated with a qualified coating to prevent recurrence of the corrosion.				

Item	Request	Response	Lead	Support	Category	Update
193	[B.1.16.1-H-05, CII] 5. "The drywell coolers, including the fans, with their power and control system were tested during the pre-operational tests...". When was the last time this system underwent a functional test? A justification for an additional 20 years is needed for the staff to review.	The drywell coolers are a continuous operating online system. Functional tests are not required because the system is constantly running and the drywell temperature is maintained below the tech spec limits: LIMITING CONDITIONS FOR OPERATION 3.2 PROTECTIVE INSTRUMENTATION H. Drywell Temperature 1. The drywell temperature shall be maintained within the following limits when the reactor coolant temperature is above 212°F. Above elevation 40' <=194°F Equal to or Below elevation 40' <=150°F SURVEILLANCE REQUIREMENTS 4.2 PROTECTIVE INSTRUMENTATION H. Drywell Temperature 1. When reactor coolant temperature is above 212°F, the drywell air temperature limits will be determined by reading the instruments listed in Table 3.2.H. These instruments shall be logged once per shift, and each reading compared to the limits of Section 3.2.H.1. The drywell coolers are not required during an accident, and have no mission time or required temperature to meet and have no auto start functions. Preventative maintenance is preformed during each refueling outages and coil cleaning is performed as required.	Ahrabli, Reza	Neiderberger, Amy	Closed	No

Item	Request	Response	Lead	Support	Category	Update
194	[B.1.16.2-J-01, ISI] 1. The LRA states that PNPS' AMP B.1.16.2 (Inservice Inspection) ISI Program is a plant-specific program encompassing ASME Section XI, Subsections IWA, IWB, IWC, IWD and IWF requirements. The LRA states that the ASME code edition and addenda used for the fourth interval is the 1998 edition with 2000 addenda. The LRA states that PNPS entered its fourth [ten-year] ISI interval on July 1, 2005. QUESTIONS: Clarify whether PNPS' AMP B.1.16.2 includes any exceptions or alternatives to the requirements of ASME Section XI, 1998 edition with 2000 addenda, granted or imposed under the provisions of 10 CFR 50.55a.	The following table lists exceptions or alternatives related to inservice inspection at the Pilgrim Nuclear Power Station during the fourth ten-year interval, which expires on June 30, 2015. Technical justifications for these exceptions and alternatives is included in PNPS-RPT-05-001, which is available for on-site review. PRR-2 Alternate Criteria for Class 1 Pressure Tests of Piping, Pumps, and Valves (Category B-P, Item Nos. B15.10, B15.50, B15.60, B15.70). PRR-4 Relief from leakage testing of 1" and less vent and drain lines and valves. Category B-P, Items B15.50 and B15.70 require the system leakage test to include all ASME Code Class 1 components within the system boundary. PRR-5 (Approved – NRC SER issued) Relief from Supplement 10 for examination of Category B-F dissimilar metal (DSM) welds. The Final Rule, 64 FR 51370, dated 09/22/1999, required Pilgrim to implement a program to comply with Supplement 10 by 11/22/2002. Supplement 10 contains the qualification requirements for procedures, equipment, and personnel involved with examining DSM welds using ultrasonic techniques. PRR-9 (Approved – NRC SER issued) Relief from ASME Code Section XI, Mandatory Appendix VIII, Supplement 11 for pressure retaining piping weld overlay examination. PRR-10 Risk-Informed ISI (RI-ISI): Relief from Category B-F & B-J weld examinations. The following exceptions or alternatives relate to components covered by BWRVIP programs. PRR-11 (Approved - NRC SER issued) Relief from code RPV shell-to-flange weld UT exam requirements conducted in accordance with Article 4 of ASME Section V, supplemented by the requirements of Table I-2000-1.	Pardee, Rich	Potts, Lori	Closed	No

PRR-15 Alternative Contingency Repair Plan for RPV nozzle safe-end and dissimilar metal piping welds using ASME Code Cases N-638 and N-504-2 with exceptions.

Previously approved 3rd interval receptions or alternatives applicable to the 4th interval (expiration date 6/8/2012):

PRR-28 Alternative to exam requirements of RPV circumferential shell welds (Item B1.10 of Exam Category B-A).

PRR-39 Full structural weld overlay contingency repairs for the welds associated with austenitic RPV nozzle safe-end and dissimilar metal piping welds.

Item	Request	Response	Lead	Support	Category	Update
195	[B.1.16.2-J-02, ISI] 2. The PNPS LRA, Appendix B.1.16.2 (Inservice Inspection), under Scope of Program, states, "The ISI Program manages cracking, loss of material, and reduction of fracture toughness of reactor coolant system piping, components, and supports. LRA Table 3.2.1-3 identifies reactor recirculation pump casings and covers, main steamline flow restrictors and valve bodies (>= 4" NPS and < 4"NPS) made of CASS as subject to the aging effect of reduction of fracture toughness. The aging management program is either Inservice Inspection or One-Time Inspection. The SRP-LRA (NUREG-1800, Rev.1), Appendix A.1.2.3.4 (Detection of Aging Effects), states that the applicant should "Provide information that links the parameters to be monitored or inspected to the aging effect being managed." QUESTIONS: Discuss how the parameters to be monitored by the ISI Program or One-Time Inspection are linked to the aging effect of reduction in fracture toughness? Which valves are subject to the aging effect of reduction in fracture toughness? (Please provide either valve numbers and drawing references or a functional description of the valves.)	LRA Table 3.1.2-3 identifies reactor recirculation pump casings and covers and valve bodies >=4" NPS made of CASS as subject to the aging effect of reduction of fracture toughness. The aging management program is Inservice Inspection. As stated in NUREG-1801, the ASME Section XI inspection requirements are sufficient for managing the effects of loss of fracture toughness due to thermal aging embrittlement of CASS pump casings and valve bodies. The Inservice Inspection Program uses NDE techniques specified in ASME Section XI to monitor for the presence and extent of cracking which provides indication of reduction in fracture toughness for these CASS components. LRA Table 3.1.2-3 identifies main steamline flow restrictors and valve bodies < 4"NPS made of CASS as subject to the aging effect of reduction of fracture toughness. The aging management program is One-Time Inspection. The One-Time Inspection Program uses NDE techniques consistent with those specified in ASME Section XI to monitor for the presence and extent of cracking which provides indication of reduction in fracture toughness for these CASS components. Since the One-Time Inspection Program is a new program, the list of valves subject to the aging effect of reduction of fracture toughness has not yet been compiled. However, the One-Time Inspection program (described in LRA section B.1.23) will inspect a representative sample of CASS components exposed to treated water >482 degrees F with emphasis on the most susceptible components.	Potts, Lori	Mileris, George	Closed	No

Item	Request	Response	Lead	Support	Category	Update
196	[B.1.16.2-J-03, ISI] 3. The SRP-LRA (NUREG-1800, Rev.1), Appendix A.1.2.3.5 (Monitoring and Trending), Paragraph 2, states: ".... The parameter or indicator trended should be described. The methodology for analyzing the inspection or test results against the acceptance criteria should be described. PNPS LRA Appendix B.1.16.2 (Inservice Inspection), Section 5 (Monitoring and Trending), does not describe the parameter(s) or indicator(s) being trended nor the methodology for analyzing the inspection or test results, either explicitly or by reference to specific standards tables. QUESTONS: For PNPS plant-specific AMP B.1.16.2, please provide a description of the parameter(s) or indicator(s) being trended and of the methodology for analyzing the inspection or test results.	The parameter(s) or indicator(s) being trended and the methodology for analyzing the inspection or test results are in accordance with the requirements of ASME Section XI. As described in LRA Section B.1.16.2, the Inservice Inspection Program uses nondestructive examination (NDE) techniques to detect and characterize surface and subsurface flaws. Therefore, the parameter being trended is the presence of a flaw indication. Results are compared, as appropriate, to baseline data and other previous test results. Indications are evaluated in accordance with ASME Section XI. If the component is qualified as acceptable for continued service, the area containing the indication is reexamined during subsequent inspection periods. Examinations that reveal indications that exceed the acceptance standards are extended to include additional examinations in accordance with ASME Section XI. LRA Section B.1.16.2, attribute 5, Monitoring and Trending will be amended to include this clarification. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Potts, Lori	Pardee, R.	Accepted	Yes
197	[B.1.17-P-01, Instrument Air Quality] 1. Provide a list of components or systems that are subject to the Instrument Air Quality Program.	Tubing and valve bodies are managed in the standby gas treatment system. Piping, tanks, tubing, and valve bodies are managed in the instrument air system.	Ivy, Ted	Rydman, Dave	Closed	No
198	[B.1.17-P-02, Instrument Air Quality] 2. General questions. What commitments were made as a result of the PNPS response to NRC GL 88-14? What industry standards are used for preventative actions and detection of aging effects?	The responses to GL 88-14 are included in initial response letter BECo letter 89-010, Response to Generic Letter 88-14: Instrument Air Supply system Problems Affecting Safety Related Equipment, dated February 3, 1989, Docket 50-293 and supplementary response letter BECo letter 89-071, dated May 30, 1989 which outline commitments and applicable industry standards. A copy of this information is available for review.	Ivy, Ted	Rydman, Dave	Closed	No

Item	Request	Response	Lead	Support	Category	Update
199	[B.1.17-P-03, Instrument Air Quality] 3. Provide details describing the methods that determine deteriorating air quality.	Deteriorating air quality is detected by trending of air quality test results, by procedure PNPS 7.1.69, System Air Quality Sampling in Section 8. A copy of this procedure is available for review.	Ivy, Ted	Rydman, Dave	Closed	No
200	[B.1.17-P-04, Instrument Air Quality] 4. Provide the basis for the acceptance criteria for dew point, oil mist and particulate including any industry standards invoked.	The instrument air systems are sampled and tested to the requirements of ANSI/ISA 7.3 per procedure PNPS 7.1.69, System Air Quality Sampling. A copy of this procedure is available for review.	Ivy, Ted	Rydman, Dave	Closed	No
201	[B.1.17-P-05, Instrument Air Quality] 5. NUREG-1800, SRP for license renewal, section 3.X.3.4, FSAR Supplement, states the following: As noted in Table 3.X-2, an applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should confirm that the applicant has identified and committed in the license renewal application to any future aging management activities, including enhancements and commitments to be completed before entering the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date. The enhancements identified in the B.1.17 write-up are not included in the FSAR Supplement Appendix A.2.1.19. They should be in the UFSAR Supplement in order to address these commitments.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Enhancements to programs that are described in Appendix B of the LRA are, therefore, commitments. To facilitate tracking of the enhancements through the NRC review process and facilitate implementation once the renewed license is received, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Item 13 on the list of commitments for license renewal is the commitment to enhance the Instrument Air Quality Program to include a sample point in the standby gas treatment and torus vacuum breaker instrument air subsystem in addition to the instrument air header sample points described in LRA Section B.1.1. See Item #320 for closure for this item.	Ivy, Ted	Rydman, Dave	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
203	[B.1.18-N-01, Metal Enclosed Bus Inspection] 1. PNPS AMP B.1.18, under Detection of Aging Affects, you have states that PNPS takes an exception to GALL XI.E4 by visual inspection of metal enclosed bus (MEB) bolted connections every 10 years. GALL XI.E4 under the same element states that as an alternate to thermography or measuring connection resistance of bolted connections, for the accessible bolted connections that are covered with heat shrink tape, sleeving, insulated boots, etc. (emphasis added), the applicant may use visual inspection of insulation material to detect surface anomalies, such as discoloration, cracking, chipping or surface contamination. When this alternate visual inspection is used to check bolted connections, the first inspection will be completed before the period of extended operation and every five years thereafter. NUREG-1833, Table IV, Justification for Changes in Aging Management Programs, states that since the visual inspection is less effective than testing, this inspection (visual) is to be performed once every five years instead of once every 10 years. a. Are all bolted connections covered with heat shrink tape, sleeving, or insulated boots? If they are, justify the 10 years frequency vs. the five years as recommended by NUREG-1801. b. If they are not, justify the visual inspection vs GALL's recommended thermography and/or resistance connections.	Since MEB bolted connections are covered with heat shrink tape or insulating boots per manufacturer's recommendations, a sample of accessible bolted connections will be visually inspected for insulation material surface anomalies. Internal portions of the MEBs will be inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. Bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. Internal bus supports will be inspected for structural integrity and signs of cracks. An inspection will occur before the end of the initial 40-year license term and every 5 years thereafter. If degradation is found in the metal-enclosed bus materials, an engineering evaluation will be performed when the inspection acceptance criteria are not met in order to ensure that the intended functions of the metal-enclosed bus can be maintained consistent with the current licensing basis. This evaluation is performed in accordance with the Entergy corrective action process per procedure EN-LI-102. This procedure provides the stated elements to consider including the extent of the concern, the potential root causes for not meeting the test acceptance criteria, the corrective actions required, and likelihood of recurrence. This engineering evaluation will determine the frequency of the next inspection, which will not exceed 5 years. LRA Appendix A.2.1.20 will be revised to "5 years". LRA Appendix B.1.18 will be revised to remove the exception to 5 years. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Stroud, Mike	Das, Swapan	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
204	[B.1.18-N-02, Metal Enclosed Bus Inspection] 2. In LRA, Section B.1.18 you have states that the program attribute of the Metal-Enclosed Bus (MEB) Inspection program at PNPS will be consistent with the program attribute described in NUREG-1801, Section XI.E4, Metal Enclosed Bus Aging Management Program with an exception. The exception is to inspect MEB enclosure assemblies in addition to internal surfaces using the MEB Inspection Program. GALL XI.E4 referred structures monitoring program for inspecting the metal enclosure bus assemblies. In addition to inspecting the enclosure assemblies for loss of material due to general corrosion, GALL's structure monitoring program also requires inspecting the enclosure seals for hardening and loss of strength due elastomers degradation. Are these enclosure seals included in the scope of MEB inspection program? What is the acceptance criteria for inspecting the enclosure assemblies?	The PNPS metal-enclosed bus program will visually inspect the enclosure assemblies for evidence of loss of material and enclosure assembly elastomers will be visually inspected and manually flexed. Revise LRPD-02 to read as follows: (Section 3.3.B.6.b - Acceptance Criteria - add after first paragraph) The acceptance criteria for enclosure assemblies will be no loss of material due to general corrosion. The acceptance criteria for elastomers will be no hardening and loss of strength due to degradation. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Closed	Yes

Item	Request	Response	Lead	Support	Category	Update
205	[B.1.18-N-03, Metal Enclosed Bus Inspection] 3. In LRA, Section B.1.18, under Operating Experience, you have stated that the Metal Enclosed Bus Inspection Program at PNPS is a new program for which there is no operating experience. NUREG-1800, Rev. 1, Appendix A, Branch Technical Position RLSB-1 states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. Describe how operating experience will be captured to confirm the program effectiveness or to be used to adjust the program as needed.	Operating Experience at PNPS is controlled by procedure EN-OP-100, Operating Experience Program. The program includes the following components: Operating Experience – Information received from various industry sources that describe events, issues, equipment failures, that may represent opportunities to apply lessons learned to avoid negative consequences or to recreate positive experiences as applicable. Internal Operating Experience – Operating experience that originates as a condition report or request from plant personnel which warrants consideration for possible Entergy-wide distribution. Internal OE can originate from any Entergy plant or headquarters. Impact Evaluation – Analysis of an OE event or problem that requires additional information and research to determine impact or potential impact, as it relates to plant condition and/or configuration. Impact evaluations are typically documented with a condition report. Condition report action items and corrective actions are used to confirm program effectiveness and to modify the program as needed.	Stroud, Mike	Das, Swapan	Closed	No

Item	Request	Response	Lead	Support	Category	Update
206	[B.1.19-N-01, Non-EQ Inaccessible Medium Voltage Cable Program] 1. GALL XI.E3 under Detection of Aging Effects recommends that the inspection for water collection should be performed based on actual plant experience with water accumulation in the manhole. However, the inspection frequency should be at least once every two years. LRPD-02, Rev. 1, Section 3.4, under the same attribute, states that inspection for water in collection in manholes and conduit occur at least once very two years. Explain how operating experience is considered in manhole inspection frequency.	PNPS inspection for water accumulation in manholes is conducted by plant inspection. An engineering evaluation will be performed per EN-LI-102. To clarify that the PNPS AMP is consistent with the GALL recommendation, LRPD-02 will be revised as follows: [Section 3.4.B.4.b - Detection of Aging Effects - replace 2nd paragraph] The inspection will be based on actual plant experience with water accumulation in the manholes and the frequency of inspection will be adjusted based on the results of the evaluation, but the frequency will be at least once every two years. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Closed	Yes

Item	Request	Response	Lead	Support	Category	Update
207	[B.1.19-N-02, Non-EQ Inaccessible Medium Voltage Cable Program] 2. In AMP B1.19 under Operating Experience element, you have stated that the Non-EQ Inaccessible Medium-Voltage Cable Program at PNPS is a new program for which there is no operating experience. NUREG-1800, Rev. 1, Appendix A, Branch Technical Position RLSB-1 states that an applicant may have to commit to provide operating experience in the future for new program to confirm their effectiveness. Describe how operating experience is captured to confirm the program effectiveness or to be used to adjust the program as needed.	Operating Experience at PNPS is controlled by procedure EN-OP-100, Operating Experience Program. The program includes the following components: Operating Experience – Information received from various industry sources that describe events, issues, equipment failures, that may represent opportunities to apply lessons learned to avoid negative consequences or to recreate positive experiences as applicable. *Internal Operating Experience* – Operating experience that originates as a condition report or request from plant personnel which warrants consideration for possible Entergy-wide distribution. Internal OE can originate from any Entergy plant or headquarters. Impact Evaluation – Analysis of an OE event or problem that requires additional information and research to determine impact or potential impact, as it relates to plant condition and/or configuration. Impact evaluations are typically documented with a condition report. Condition report action items and corrective actions are used to confirm program effectiveness and to modify the program as needed.	Stroud, Mike	Das, Swapan	Closed	No

Item	Request	Response	Lead	Support	Category	Update
208	[B.1.20-N-01, Non-EQ Instrumentation Circuits Test Review Program] 1. In LRA, Section A.2.1.22, you have stated that for neutron flux monitoring system cables that are disconnected during instrument calibration, testing is performed at least once every 10 years. GALL XI.E2 recommends that the test frequency shall be determined by the applicant based on engineering evaluation, but the test frequency shall be at least once every ten years. Explain how engineering evaluation is considered in the test frequency.	To clarify that the PNPS AMP is consistent with the GALL recommendation, LRPD-02 will be revised as follows: [Section 3.5.A - Program Description - add after 2nd sentence] The first test of neutron monitoring system cables that are disconnected during instrument calibrations shall be completed before the period of extended operation and subsequent tests will occur at least every 10 years. In accordance with the corrective action program, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the current licensing basis for the period of extended operation. LRPD-02 Revision 2 issued addressing this item. LRA Appendix A2.1.22 will be revised as shown below. The first test of neutron monitoring system cables that are disconnected during instrument calibrations shall be completed before the period of extended operation and subsequent tests will occur at least every 10 years. This require an amendment to the LRA.	Stroud, Mike	Das, Swapan	Accepted	Yes
209	[B.1.20-N-02, Non-EQ Instrumentation Circuits Test Review Program] 2. Confirm that the test include both cables and connections.	Yes, the B.1.20 program includes both cables and connections for the instrument circuits that are in scope for license renewal.	Stroud, Mike	Das, Swapan	Closed	No

Item	Request	Response	Lead	Support	Category	Update
210	[B.1.20-N-03, Non-EQ Instrumentation Circuits Test Review Program] 3. PNPS AMP B1.20 under Operating Experience element states that the Non-EQ Instrumentation Circuit Tests Review Program at PNPS is a new program for which there is no operating experience. Explain how operating experience is captured to confirm the program effectiveness or to be used to adjust the program as needed.	Operating Experience at PNPS is controlled by procedure EN-OP-100, Operating Experience Program. The program includes the following components: Operating Experience – Information received from various industry sources that describe events, issues, equipment failures, that may represent opportunities to apply lessons learned to avoid negative consequences or to recreate positive experiences as applicable. Internal Operating Experience – Operating experience that originates as a condition report or request from plant personnel which warrants consideration for possible Entergy-wide distribution. Internal OE can originate from any Entergy plant or headquarters. Impact Evaluation – Analysis of an OE event or problem that requires additional information and research to determine impact or potential impact, as it relates to plant condition and/or configuration. Impact evaluations are typically documented with a condition report. Condition report action items and corrective actions are used to confirm program effectiveness and to modify the program as needed.	Stroud, Mike	Das, Swapan	Closed	No

Item	Request	Response	Lead	Support	Category	Update
211	[B.1.21-N-01, Non-EQ Insulated Cables and Connections Program] 1. GALL XI.E1 under program description states that the program described herein is written specifically to address cables and connections at plants whose configuration is such that most (if not all) cables and connections installed in adverse localized environments are accessible. This program, as described, can be thought of as a sampling program. Selected cables and connections from accessible areas (the inspection sample) are inspected and represent, with reasonable assurance, all cables and connections in the adverse localized environment. If an acceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. As such, this program does not apply to plants in which most cables are inaccessible . a. Provide a ball part percentage of in-scope cable and connections population installed in adverse localized environments that are accessible. b. In LRA, Section B.1.21 you have stated that the a representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Explain the technical basis for cable sampling.	a. A ball park percentage of accessible in-scope cables and connections would be 80 to 85%. b. LRA Appendix B.1.21 will be revised to read as follows. This program addresses cables and connections at plants whose configuration is such that most cables and connections installed in adverse localized environments are accessible. This program can be thought of as a sampling program. Selected cables and connections from accessible areas will be inspected and represent, with reasonable assurance, all cables and connections in the adverse localized environments. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination will be made as to whether the same condition or situation is applicable to other accessible cables or connections. The sample size will be increased based on an evaluation per EN-LI-102 – Corrective Action Process. This requires an amendment to the LRA.	Stroud, Mike	Das, Swapan	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
212	[B.1.21-N-02, Non-EQ Insulated Cables and Connections Program] 2. In LRA, Section B.1.21 under Operating Experience element, you have stated that the Non-EQ Insulated Cables and Connection Program at PNPS is a new program for which there is no operating experience. Describe how operating experience will be captured to confirm the program effectiveness or to be used to adjust the program as needed.	Operating Experience at PNPS is controlled by procedure EN-OP-100, Operating Experience Program. The program includes the following components: Operating Experience – Information received from various industry sources that describe events, issues, equipment failures, that may represent opportunities to apply lessons learned to avoid negative consequences or to recreate positive experiences as applicable. Internal Operating Experience – Operating experience that originates as a condition report or request from plant personnel which warrants consideration for possible Entergy-wide distribution. Internal OE can originate from any Entergy plant or headquarters. Impact Evaluation – Analysis of an OE event or problem that requires additional information and research to determine impact or potential impact, as it relates to plant condition and/or configuration. Impact evaluations are typically documented with a condition report. Condition report action items and corrective actions are used to confirm program effectiveness and to modify the program as needed.	Stroud, Mike	Das, Swapan	Closed	No

Item	Request	Response	Lead	Support	Category	Update
213	[B.1.22-P-01, Oil Analysis Program] 1. Provide justification for not monitoring the flashpoint of oil that is not regularly changed. 2. Provide the document that establishes the frequency of monitoring for and the acceptance criteria for the allowable % dilution.	1. As stated in LRA Section B.1.22, exception note 1, flash point is not determined for sampled oil because analysis of filter residue or particle count, viscosity, total acid/base (neutralization number), water content, and metals content provide sufficient information to verify the oil does not contain water or contaminants that would permit the onset of aging effects. PNPS monitors the % fuel dilution in diesel engine oils which is a more accurate method than flash point for identifying fuel leaks and oil dilution. 2. Provided a copy of procedure 3.M.3-61.3, Emergency Diesel Generator Quarterly Preventive Maintenance, showing that quarterly lube oil samples are sent to the laboratory. Provided laboratory test results showing that % dilution is measured in accordance with ASTM standards. Acceptance criterion is < 3 %Wt and is based on ALCO diesel engine owners' group chemistry guidelines. The following will be added to LRA Section B.1.22 exception note. PNPS measures the % fuel dilution in diesel engine oils which is a more accurate method than flash point for identifying fuel leaks and oil dilution. Acceptance criterion is < 3% Wt based on ALCO diesel engine owners' group chemistry guidelines. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Potts, Lori	Carrol, W	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
214	[B.1.22-P-02, Oil Analysis Program] 2. Provide acceptance criteria for water and particulate contamination and viscosity and the basis of the limits.	As stated in the Aging Management Program Evaluation Report (AMPER), acceptance criteria resulting in re-sampling and increased sampling frequency include: -- particulates – large ferrous or non-ferrous contamination or trend increasing levels -- viscosity - increase of 15% from viscosity grade -- viscosity - decrease of 15% from viscosity grade -- water content - > 2000 ppm (0.2% by volume) The acceptance criteria are based on manufacturer's recommendations and industry experience.	Potts, Lori	Carrol, W	Closed	No
215	[B.1.22-P-03, Oil Analysis Program] 3. NUREG-1800, SRP for license renewal, section 3.X.3.4, FSAR Supplement, states the following: As noted in Table 3.X-2, an applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should confirm that the applicant has identified and committed in the license renewal application to any future aging management activities, including enhancements and commitments to be completed before entering the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date. The enhancements identified in the B.1.22 write-up are not included in the FSAR Supplement Appendix A.2.1.24. They should be in the UFSAR Supplement in order to address these commitments.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Enhancements to programs that are described in Appendix B of the LRA are, therefore, commitments. To facilitate tracking of the enhancements through the NRC review process and facilitate implementation once the renewed license is received, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Items 18 and 19 on the list of commitments for license renewal are the commitments to implement the enhancements described in LRA Section B.1.22. See Item #320 for closure for this Item.	Potts, Lori	Carrol, W	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
217	[B.1.23-P-01, One Time Inspection] 1. Provide a list of systems in element of "Scope of Activity", where One-Time Inspection will be performed.	As described in LRA Section B.1.23, the One-Time Inspection Program includes several activities. The activities to confirm the absence of aging effects identify the systems to which they apply. For instance, the activity for inspection of "Internal surfaces of buried carbon steel pipe on the standby gas treatment system discharge to the stack" inspects components in the standby gas treatment system. The activity to verify effectiveness of the water chemistry control programs is applicable to many systems. The systems are not listed in LRA Section B.1.23. However, they may be found in the tables in LRA Section 3.0, Aging Management Review Results. In these tables, systems with line items containing one of the water chemistry control programs, (Water Chemistry Control – Auxiliary Systems, Water Chemistry Control – BWR, or Water Chemistry Control – Closed Cooling Water), have components included in the sample population for this one-time inspection activity.	Potts, Lori	Woods, Steve	Closed	No
218	[B.1.23-P-02, One Time Inspection] 2. Identify how the sample of small piping welds, 4" and smaller will be picked for performing NDE inspection.	As described in the Aging Management Program Evaluation Report (AMPER), the One-Time Inspection Program activity for inspection of small-bore piping in the reactor coolant system and associated systems that form the reactor coolant pressure boundary will inspect a statistically significant sample of welds of each material and environment combination in Class I piping less than or equal to 4" NPS. The initial population will include all Class I small-bore piping and actual inspection locations will be selected based on physical location, exposure levels, NDE techniques, and locations identified in Information Notice 97-46, Un-isolable Crack in High-Pressure Injection Piping.	Potts, Lori	Woods, Steve	Closed	No

Item	Request	Response	Lead	Support	Category	Update
219	[B.1.23-P-03, One Time Inspection] 3. How will PNPS handle the aging of socket welds?	As indicated in plant procedures, during the 4th ISI Interval, PNPS plans to perform both VT-2 and □PT examinations, at a minimum, of socket welds in accordance with the PNPS 4th Interval ISI Program Plan. The One-Time Inspection of small-bore piping does not exclude locations based upon geometry. Therefore, Class I small-bore piping socket welds will be selected for one-time inspection based on physical location and exposure levels. The One-Time Inspection Program will also include destructive or non-destructive examination of one (1) socket welded connection using techniques proven by past industry experience to be effective for the identification of cracking in small bore socket welds. Should an inspection opportunity not occur (e.g., socket weld failure or socket weld replacement), a susceptible small-bore socket weld will be examined either destructively or non-destructively prior to entering the period of extended operation. This is commitment #20.	Potts, Lori	Woods, Steve	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
220	[B.1.23-P-04, One Time Inspection] 4. NUREG-1800, SRP for license renewal, section 3.X.3.4, FSAR Supplement, states the following: As noted in Table 3.X 2, an applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should confirm that the applicant has identified and committed in the license renewal application to any future aging management activities, including enhancements and commitments to be completed before entering the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date. The One-Time Inspection program is a new program that will be implemented prior to period of extended operation. Justify why this commitment is not included in the FSAR Supplement write-up in Appendix A.1.25.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Therefore, programs that are described in Appendix B of the LRA are commitments. To facilitate tracking through the NRC review process and facilitate implementation once the renewed license is received, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Item 20 on the list of commitments for license renewal is the commitment to implement the One-Time Inspection Program as described in LRA Section B.1.2. See Item #320 for closure for this item.	Potts, Lori	Woods, Steve	Accepted	Yes
222	[B.1.24-P-01, Periodic Surveillance and Preventative Maintenance] 1. Provide any codes and standards used for detection of aging effects.	As indicated in LRA Section B.1.24, many of the Periodic Surveillance and Preventive Maintenance activities include visual or other non-destructive examinations of structures, systems and components. These examinations are performed in accordance with approved procedures that are consistent with ASME Section XI and 10 CFR 50 Appendix B.	Potts, Lori	Chugh, Sub	Closed	No

Item	Request	Response	Lead	Support	Category	Update
223	[B.1.24-P-02, Periodic Surveillance and Preventative Maintenance] 2. NUREG-1800, SRP for license renewal, section 3.X.3.4, FSAR Supplement, states the following: As noted in Table 3.X-2, an applicant need not incorporate the implementation schedule into its FSAR. However, the reviewer should confirm that the applicant has identified and committed in the license renewal application to any future aging management activities, including enhancements and commitments to be completed before entering the period of extended operation. The staff expects to impose a license condition on any renewed license to ensure that the applicant will complete these activities no later than the committed date. The enhancements identified in the B.1.24 write-up are not included in the FSAR Supplement Appendix A.2.1.26. They should be in the UFSAR Supplement in order to address these commitments.	As stated in the letter submitting the license renewal application (letter number 2.06.003, dated 1/25/06), PNPS is committed to the programs listed in Appendix B, Section B.1 of the license renewal application. Enhancements to programs that are described in Appendix B of the LRA are, therefore, PNPS commitments. A list of specific commitments for license renewal will be developed to facilitate tracking and implementation of the enhancements through the NRC review process upon receipt of the renewed license. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. Item 21 on the list of commitments for license renewal is the commitment to implement the enhancements described in LRA Section B.1.24. See Item #320 for closure for this Item	Potts, Lori	Chugh, Sub	Accepted	Yes
225	[B.1.24-P-04, Periodic Surveillance and Preventative Maintenance] 4. Provide trending methods.	Inspection and testing intervals are established such that they provide for timely detection of structures, systems and components degradation. Inspection and testing intervals are dependent on the material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations. Trending of degraded components occurs within the Corrective Action Program.	Potts, Lori	Chugh, Sub	Closed	No

Item	Request	Response	Lead	Support	Category	Update
226	[B.1.25-J-01, Reactor Head Closure Studs] 1. The PNPS AMP B.1.25 (Reactor Head Closure Studs) states gives as examples of preventive measures to mitigate cracking "rust inhibitors, stable lubricants, appropriate materials." QUESTIONS: At PNPS what rust inhibitors and lubricants are approved for used on the reactor head closure studs, nuts, washers, and bushings? What is encompassed by the words "appropriate materials"?:	Approved lubricants for RPV studs are Neo-Lube or equivalent. (Ref. Procedure 3.M.4-48) The use of appropriate materials means that any replacement studs would be specified to be made from material that met all the requirements at the time of specification, and encompassed all the available operating experience. For example, no metal sheathed studs would be ordered and tensile strength would be specified.	Finnin, Ron	Pardee, R.	Closed	No
227	[B.1.25-J-02, Reactor Head Closure Studs] 2. The PNPS LRA, AMP B.1.25 (Reactor Head Closure Studs), Operating Experience states that volumetric examination of 18 reactor head closure studs and visual examination of 18 nuts and 18 washers was performed during RF015 (April, 2005). QUESTIONS: What is the fraction of total reactor head closure studs represented by the 18 studs examined during RVO15? Are all studs, nuts and washers examined during each 10-year ISI interval? Are the studs, nuts and washers examined during RF015 original equipment that has been in use since initial startup of the plant? If not, what is the approximate average length of time that these items have been in used in operation.	There are 56 reactor head studs, so a sample of 18 is 1/3 of the studs (19, 19, 18). Yes, all studs/nuts/washers are examined every 10 year interval. The studs/nuts/washers currently installed at PNPS are original equipment.	Finnin, Ron	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
228	[B.1.25-J-03, Reactor Head Closure Studs] 3. The PNPS LRA, AMP B.1.25 (Reactor Head Closure Studs), Operating Experience states that no new recordable indications were found for the studs, nuts and washers examined during RFO15. QUESTIONS: What is the examination history related to earlier refueling outages? Have indications been found in previous examinations? If indications were found, what corrective actions were taken?	PNPS has not detected any recordable indications in any of the 56 RPV closure head studs.	Pardee, Rich	Finnin, Ron	Closed	No

Item	Request	Response	Lead	Support	Category	Update
229	[B.1.25-J-04, Reactor Head Closure Studs] 4. RG 1.65 (Materials and Inspections for Reactor Vessel Closure Studs), which is referenced in and is a basis for GALL Program XI.M3 (Reactor Head Closure Studs), states that "visual and surface examinations may fail to reveal unacceptable defects, especially if the studs are examined in an untensioned condition." It also states that "a [volumetric examination] technique has been developed in which a transducer is lowered into the stud bolt center hole and an ultrasonic radial scan is used for the ultrasonic examination." QUESTIONS: With regard to reactor head closure studs that are removed for examination, does PNPS perform the surface examination with the studs in a tensioned or untensioned condition? Has PNPS performed any radial ultrasonic scans of its reactor vessel closure studs?	Since RFO15 (2005), PNPS has adopted the 1998 edition with 2000 addenda of ASME XI which requires either a surface exam or volumetric exam of RPV studs that are removed. PNPS elected to perform a volumetric examination on these four studs in RFO15 in the tensioned condition prior to their removal. No indications were detected in the four removed studs in 2005. The four studs adjacent to the fuel transfer chute are removed each refueling outage; these are the only studs that have been removed from the PNPS vessel. PNPS currently performs ultrasonic examination of RPV studs from the top surface of the stud. In the past, PNPS had performed this examination using a specially fabricated stud radial UT probe inserted into the stud's heater hole located on the stud's central axis. The technique currently in use utilizing the flat surface at the top of the stud is considered superior in the detection of flaws in RPV studs when compared to UT exams performed from the heater hole. RPV studs at PNPS are examined utilizing a straight beam ultrasonic testing (UT) technique. This method has been demonstrated and qualified by the Performance Demonstration Initiative (PDI) at the Electric Power Research Institute (EPRI) Nondestructive examination (NDE) Center. Examiners utilizing this qualified technique are also qualified by the PDI to perform this examination. This straight beam examination has been demonstrated by PDI to be capable of detecting a flaw of critical size. All 56 RPV studs at PNPS are examined once per interval using this technique.	Pardee, Rich	Finnin, Ron	Closed	No
230	[B.1.27-W-01, Selective Leaching Program] 1. PNPS states in LRA B.1.27,Selective Leaching Program, that this AMP is a new program, and it will be initiated prior to the period of extended operation. Will the implementation of this AMP be included in the commitment list?	Yes it is included. Item 23 of the commitment list states "Implement the Selective Leaching Program in accordance with the program as described in LRA Section B.1.27".	Ivy, Ted	Kalb, J	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
231	[B.1.27-W-02, Selective Leaching] 2. Provide a status of the implementation of this AMP, including scope of work, (planned) implementing procedures, parameters to be inspected and measured, and acceptance criteria.	As described in section B.1.27, the selective leaching program will be consistent with NUREG-1801, Section XI.M33, Selection Leaching of Materials. Scope, parameters inspected/measured, and acceptance criteria along with other program attributes are available for your review in the Aging Management Program Evaluation Report LRPD-02, section 3.8. Because this is a new program, the implementing procedures have not yet been developed, but will be in place prior to the period of extend operation.	Ivy, Ted	Kalb, J	Closed	No

Item	Request	Response	Lead	Support	Category	Update
232	[B.1.28-H-01, Service Water Integrity] 1. Identify applications where components are not coated or lined and the materials of construction.	Piping • The Salt Service Water Supply buried piping and sections of the supply and return wall penetration piping spools are constructed of Titanium, ASTM B381 GR. F2. These spools are not lined internally. • Salt Service Water Small bore pipe (=2") Vents and Drain piping are constructed of ASTM B-466, 90-10 CUNI. These spools are not lined internally. These spools are bolted onto large bore Carbon Steel rubber lined pipe. Valves • Salt Service Water Pump Discharge 12" Check Valves are not lined internally. They are constructed of; (3) ASTM B-61 bodies, (2) are ASTM A-494 Gr. M35-1 bodies. • Salt service Water Small bore (=2") Vent and Drain Valves are not lined internally. They are constructed of ASTM B-61 or ASTM B-62. Pumps • Salt Service Water Pumps are not lined internally. Their Column are constructed of; ASTM B-148-88 C95800 or ASTM B271-89 Alloy C95800. Heat Exchangers • The Closed Cooling Water (RBCCW & TBCCW) Heat Exchangers, Salt Service Water side are not lined internally. They are constructed of ASTM SB-171-C70600, 90/10 CuNi.	Gaedtke, Joe	Ivy, Ted	Closed	No

Item	Request	Response	Lead	Support	Category	Update
233	[B.1.29.1-H-01, Masonry Wall] 1. The program description for AMP B.1.29.1 in the Pilgrim LRA indicates that the scope of this program includes all masonry walls that perform an intended function in accordance with 10 CFR 54.4. The applicant is requested to provide the following information related to the scope of this program: (1) Identify whether any additional masonry walls have been added to the scope of the current Pilgrim program as a result of the LR scoping and screening process, particularly in light of the requirement to consider regulated events in the LR assessment. (2) If additional masonry walls have been added to the scope, explain how the requirements of I. E. Bulletin 80-11 have been applied to these walls, and describe any physical modifications that have/will be implemented to establish the evaluation bases. (3) If additional masonry walls have been added to the scope, explain why this is not considered an enhancement to the current Pilgrim program.	1. No additional masonry walls have been identified to be added to the scope of Pilgrim current masonry wall program as result of the LR scoping and screening process [Ref. Aging management program evaluation report LRPD-02, section 4.21.2]. 2. Not applicable since no additional masonry walls have been added to the scope of Pilgrim current masonry wall program as result of the LR scoping and screening process [Ref. item (1) above]. 3. Not applicable since no additional masonry walls have been added to the scope of Pilgrim current masonry wall program as result of the LR scoping and screening process [Ref. item (1) above].	Ahrabli, Reza	Kalb, J	Closed	No

Item	Request	Response	Lead	Support	Category	Update
234	[B.1.29.1-H-02, Masonry Wall] 2. The program description for AMP B.1.29.1 in the Pilgrim LRA does not indicates that this program includes all of the guidances provided in I.E. Bulletin 80-11, "Masonry Wall Design", and Information Notice 87-67, "Lessons learned from Regional Inspections of Licensee Actions in Response to I.E. 80-11". Also, what is your Visual examined frequency? The applicant is requested to provide and confirm to the above information related to this program.	Pilgrim masonry wall program which is consistent with the program described in NUREG-1801, Section XI.S5, Masonry Wall Program, includes the guidance and lessons learned from NRC Bulletin 80-11and Information Notice 87-67. As indicated in Aging Management Program Evaluation Report LRPD-02, section 4.21.2, Operating experience shows that this program has been effective in managing aging effects with consideration for recommendations and lessons learned from Bulletin 80-11 and Information Notice 87-67. Masonry walls are visually examined at frequency selected (at least once every 10 years) to ensure there is no loss of intended function between inspections. (Ref. Pilgrim procedure NE8.02, section 5, and Aging Management Program Evaluation Report LRPD-02, section 4.21.2) PNPS Engineering Design Standards Manual MCSB03.104 defines the procedure to maintain the qualification of safety-related masonry block walls in accordance with the provisions of NRC Bulletin 80-11, Masonry Wall Design". PNPS procedure NE8.02, "Structure Inspection and Condition Monitoring", Section 5.0 (last sentence, pg. 8) states "The inspection intervals are once every three years for accessible areas, once every ten years for normally inaccessible areas.	Ahrabli, Reza	Kalb, J	Closed	No
235	[B.1.29.2-H-01, Structures Monitoring Program] 1. Since the program coatings are not relied upon to manage the effects of aging for structures included in the Structures Monitoring Program (AMP B.1.29.2). Please provide the following information related to this enhancement: (a) What is your criteria and How are you going to qualify and monitor it under AMP B.1.29.2.	PNPS AMP B1.29.2 Structures Monitoring, Program Description states "Since protective coatings are not relied upon to manage the effects of aging for structures included in the Structures Monitoring Program, the program does not address protective coating monitoring and maintenance."	Ahrabli, Reza	Kalb, J	Closed	No

Item	Request	Response	Lead	Support	Category	Update
236	[B.1.29.2-H-02, Structures Monitoring Program] 2. In the discussion of operating experience, four noteworthy incidences of degradation are noted: cracks, gaps, corrosion, and flaking coating. For each of the first three incidences of degradation, please provide the plant documentation that describes the degradation, the assessment performed, the acceptance criteria applied, future monitoring recommendations, and any corrective action taken. Also describe the monitoring activities that are or will be conducted under the Structures Monitoring Program for each of the three regions.	The following plant documents, were available for review: PDF Files: Item 236 (part 1), Item 236 (part 2), Item 236 (part 3), Item 236 (part 4), and CR-PNP-2000-09246 CR-PNP-2000-09435 CR-PNP-2000-09448 CR-PNP-2001-09145 CR-PNP-2001-09700 CR-PNP-2004-03373 CR-PNP-2004-03981 Cracks, gaps and corrosion will be monitored as stated in LRPD-02 and Attachment 4- Structures Monitoring Program General Criteria (pg. 279). For Concrete, structures monitoring manages loss of material, cracking, and change in material properties, as identified in LRA tables 3.5.2-1 through 3.5.2-6.The acceptance criteria is the absence of the following: cracks, excessive rust bleeding, staining or discoloration, abrasion, erosion, cavitation, spalling, scaling, leaching, excessive settlement, corrosion of reinforcing, degraded waterproof membranes. For Steel, structures monitoring program manages the loss of material, as identified in LRA tables 3.5.2-1 through 3.5.2-6. The acceptance criteria is the absence of the following: Pitting, beam/column deflection, cracks, flaking coatings, excessive rust, loose/missing bolts, peeling paint, wide spread corrosion. (also see commitment numbers 25 and 26 regarding this program) For Elastomers the aging effect managed is cracking, change in material properties. The acceptance criteria will include the absence of cracks and gaps.	Kalb, Jeff	Ahrabli, Reza	Closed	No

Item	Request	Response	Lead	Support	Category	Update
237	[B.1.29.2-H-03, Structures Monitoring Program] 3. The Dresden/Quad Cities BWR units have a history of problems with containment penetration bellows, and the licensee has a long-term replacement program that will continue into the LR period. The applicant is requested to address this industry operating experience and submit a specific technical basis why the Pilgrim containment penetration bellows are not subject to the aging effects and aging mechanisms observed at Dresden/Quad Cities.	The Dresden/Quad Cities License Renewal Application (LRA) and Safety Evaluation Report (SER) provide a description of the Dresden/Quad Cities operating experience with their stainless steel bellows. The Dresden/Quad Cities review determined a total of 120 bellows were within the scope of license renewal. Of these 120 bellows, 24 bellows were identified as being degraded. The root cause was identified as stress corrosion cracking (SCC). From 1990 to 2003 Dresden/Quad Cities replaced or removed the degraded bellows from service. The SER states that several of the replaced bellows received metallurgical analysis. Analysis results from a couple of examples determined the presence of corrosive products, such as "magnesium salts", chlorides, fluorides, and sulfides. Also, these corrosive species are not typical of containment operating conditions. As a result, the SER concludes the corrosive species, leading to the site specific degradation of the bellows, were most probably introduced and contaminated during plant construction. (Reference Dresden/Quad Cities SER pages 3-403 to 3-408) Cracking due to SCC for the PNPS containment bellows is not an aging affect requiring management. There are no PNPS site specific operating experiences similar to that of Dresden/Quad Cities. In summary, the presence of corrosive products is necessary for SCC to exist. The normal environment for the PNPS drywell is dry and there has been no indication of contamination of the bellows during construction at PNPS. In addition, containment bellows for PNPS are not exposed to a corrosive environment. As such, SCC is not applicable to PNPS stainless steel bellows. (Ref. LRA paragraph 3.5.2.2.1.7)	Ahrabli, Reza	Kalb, J	Closed	No

Item	Request	Response	Lead	Support	Category	Update
238	[B.1.29.2-H-04, Structures Monitoring Program] 4. More information is needed about aging management of inaccessible concrete areas. The applicant is requested to submit the dates and complete results (at specific locations/not averages or ranges) of all past groundwater monitoring tests. Discuss why the groundwater is non-aggressive, and/or aggressive, if applicable. Confirm that the Pilgrim SMP credited for LR will inspect all inaccessible areas that may be exposed by excavation for any reason, whether the environment is considered aggressive or not, and also will inspect any inaccessible area where observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring.	a. On October 27, 2005, groundwater samples were taken from a well located ~3 feet from the foundation of the Pilgrim Station turbine building near the truck lock at the south side of the building. This well was installed in the late 90s to monitor for total petroleum hydrocarbons as a result of a transformer oil spill. The bottom of the well is ~25 feet below ground surface and at the time the sample was taken, the depth to water was ~16 feet. The sample was analyzed for chlorides, total phosphate, sulfate and pH. The results were as follows: • Chlorides: 420 ppm • Total phosphate: 0.26 ppm • Sulfate: 16 ppm • pH: 6.2 The sampling was performed by SAIC Engineering, Inc. and the analysis was performed by R. I. Analytical Laboratories, Inc. The recent test data shows PNPS ground water has remained non-aggressive (chloride < 500ppm, Sulfate < 1500 ppm and pH > 5.5). b. Although it is expected that inaccessible areas are inspected when exposed by excavation for any reason, Pilgrim site procedure for "Structures Inspection and condition monitoring" will be revised to require opportunistic inspections of inaccessible concrete areas when they become accessible (commitment 25). Expanding inspection to other areas (accessible or non- accessible) where significant concrete degradation is observed in the accessible area will continue to be part of corrective action program B.0.3. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Kalb, Jeff	Ahrabli, Reza	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
239	[B.1.29.2-H-05, Structures Monitoring Program] 5. The applicant is requested to address and discussion of operating experience in detail of pipe supports and cable trays found degradation in November 2004. Did your scope expansion was required due to unacceptable found? Provide the following information related to this recent operating experience: (a) Identify the system(s), ASME Code Class, the initial sample size, and the percentage found to be unacceptable.□ (b) Identify whether loss of material due to corrosion, loss of mechanical function, or both aging effects were observed. Did the as-found unacceptable conditions compromise any intended functions?□ (c) Identify the final sample size, after scope expansion, and the percentage found to be unacceptable. (d) Identify the number of supports returned to service based solely on evaluation and the number of supports returned to service after repair. (e) Describe the root cause evaluation and the corrective actions taken to prevent recurrence. (f) Identify any additional inspections scheduled for the next inspection period.	The discussion in the operating experience section (LPDR-05, pg. 41) of Pilgrim's LRA came from the System 56, Structures Maintenance Rule fourth quarter 2004 System Health Report. These items were however identified during System 56 walkdowns as part of the periodic inspections performed in accordance with PNPS procedure NE8.03, Structure Inspection and Condition Monitoring. When degraded conditions were observed a WRT/MR was written to correct the condition. MR # 04117586 MR # 04117332 MR # 04117319 MR # 04117320 MR # 04117318 MR # 04117334 MR # 04117333 MR # 04117590 MR # 04117591 MR # 04117313 MR # 04117279 MR # 04117272 MR # 04116777 MR # 04116773 MR # 04116774 MR # 04116775 MR # 04116776 (a) The affected systems vary with each component identified. All of the degraded conditions found occurred on non safety related conduits or pipe supports. None of the piping supports were ASME supports. There was no sample size since the various portions of the process buildings were walked down and inspected room by room. (b) Some of the degraded conditions were due to corrosion and some were due to conditions other than aging effects, such as, bent rods. See attached MRs. No as found conditions compromised any intended design function. (c) There was no sample size and there was no scope expansion.	Kalb, Jeff	Ahrabli, Reza	Closed	No

Item	Request	Response	Lead	Support	Category	Update
		(d) The supports in question were evaluated and determined all needed repair or maintenance before returning back to service. Approximately 50% of the supports, on different systems, have been repaired and returned to service. The remaining will be returned to service when the repairs are complete. As noted in the response to part (a), the degraded supports were found on nonsafety-related conduits or piping. (e) There was no root cause analyses performed and no additional corrective actions taken to prevent recurrence. (f) No additional inspections have been identified for the next inspection period.				
240	[B.1.29.2-H-06, Structures Monitoring Program] 6. Considering the relatively short time period remaining before Pilgrim enters the license renewal period, the staff expects that considerable progress has already been made in developing and formally documenting the implementing procedures required for new AMPs, and for significant enhancements to existing AMPs. In light of this, please address each of the following questions regarding the current status of implementing procedures for this AMP: (a) Provide the status of the implementing procedures for each enhancement to the existing Structures Monitoring Program. (b) Provide the schedule for initiating each of the enhancements to the existing Structures Monitoring Program.□ (c) Provide a sample of an implementing procedure for one enhancement to the existing Structures Monitoring Program.□ (d) Provide the results of any enhanced inspections that have already been completed.	Since 6 years remain before PNPS enters the period of extended operation, implementing procedures required for new AMPs, and procedure revisions for enhancements to existing AMPs have not yet been developed. Items 25 and 26 on the list of commitments for license renewal are the commitment to implement the enhancements to the Structures Monitoring Program described in LRA Section B.1.29.2. To facilitate tracking of enhancements through the NRC review process and facilitate implementation, a list of specific commitments for license renewal has been developed. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. See item #320 for closure of this item.	Ahrabli, Reza	Kalb, J	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
241	[B.1.29.2-H-07, Structures Monitoring Program] 7. Discuss PNPS use of Level III coatings and identify whether any Service Level III coatings are credited for corrosion protection for license renewal.	PNPS AMP B1.29.2 Structures Monitoring, Program Description states "Since protective coatings are not relied upon to manage the effects of aging for structures included in the Structures Monitoring Program, the program does not address protective coating monitoring and maintenance."	Kalb, Jeff	Ahrabli, Reza	Closed	No
242	[B.1.29.2-H-08, Structures Monitoring Program] 8. The scope of the enhancements listed for AMP B.1.29.2 are quite significant, and encompass several elements that would be expected to be part of an existing Structures Monitoring Program. Notable examples are the inclusion of anchors and the addition of loss of material due to corrosion of steel components to the current inspection criteria. Consequently, the applicant is requested to: (a) describe the scope of AMP B.1.29.2, including the structures and components in the scope of AMP B.1.129.2; the aging effects that are monitored; the inspection methods employed; and the inspection frequency; and (b) for the structures and components that will be added to the Structures Monitoring Program scope for license renewal, describe the aging management activities that are currently being implemented.	(a) The Structures Monitoring Program at PNPS is comparable to the program described in NUREG-1801, Section XI.S6, Structures Monitoring Program (SMP). The Structures Monitoring Program will be enhanced to clarify that the discharge structure, security diesel generator building, trenches, valve pits, manholes, duct banks, underground fuel oil tank foundations, manway seals and gaskets, hatch seals and gaskets, underwater concrete in the intake structure, and crane rails and girders are included in the program (commitment numbers 25 and 26). The structures, structural components and their aging effects requiring management under scope of SMP are included in LRA Tables 3.5.2-1 through 3.5.2-6. Visual inspections of accessible plant structures are performed at three-year intervals and inspections of normally inaccessible (insulated or high radiation zone) areas are performed at ten-year intervals. Visual inspections of buried plant structures are performed when opportunistic excavation occurs. However, more frequent inspections may be performed based on past inspection results, industry experience, or exposure to a significant event (e.g. tornado, earthquake, fire, chemical spill). (Ref. Aging Management Program Evaluation Report LRPD-02, section 4.21.1) (b) Currently there are no aging management activities being implemented for structures and components that will be added to the Structures Monitoring Program for license renewal.	Ahrabli, Reza	Kalb, J	Closed	No

Item	Request	Response	Lead	Support	Category	Update
243	[B.1.29.2-H-09, Structures Monitoring Program] 9. The applicant has not addressed aging management of the portion of the drywell shell embedded in the drywell concrete floor. This area is inaccessible for inspection, but is potentially subject to wetting on both the inside and outside surfaces. Are they any inspections planned prior to the extended period of operation for this portion of the drywell shell?	Aging management of drywell shell is provided by aging management program (AMP) B.16.1, "Containment Inservice Inspection (CII)". The inspections of buried plant structures and structural components (e.g., portion of drywell embedded in drywell concrete floor) are performed when they become accessible, inspection results of similar component show significant degradation, or operating experience warrants such inspections. (Ref. Aging Management Program Evaluation Report LRPD-02, section 4.14.2)	Ahrabli, Reza	Kalb, J	Closed	No
244	[B.1.29.3-H-01, Water Control Structures Monitoring Program] 1. Describe the "aggressive environment" and "water-flowing" environments for Reinforced Concrete Foundation, Slabs, and Reinforced Concrete Walls. What is the plant-specific program to manage potential degradation?	Aggressive environment is environment with pH less than 5.5 or chloride solution greater than 500 ppm, or sulfate solution greater than 1500 ppm (Ref. LRA section 3.5.2.2.2.4). "Water-flowing" is considered flowing water at greater than 3 fps. (Ref. LRA section 3.5.2.2.2.4 and EPRI report 1002950 "Aging Effects for Structures and Structural Components (Structural Tools), section 3.3.1.4) For concrete, structures monitoring manages loss of material, cracking, and change in material properties, as identified in LRA Tables 3.5.2-1 through 3.5.2-6. The acceptance criteria is the absence of the following: cracks, excessive rust bleeding, staining or discoloration, abrasion, erosion, cavitation, spalling, scaling, leaching, excessive settlement, corrosion of reinforcing, degraded waterproof membranes.	Ahrabli, Reza	Kalb, J	Closed	No

Item	Request	Response	Lead	Support	Category	Update
245	[B.1.29.3-H-02, Water Control Structures Monitoring Program] 2. Considering the relatively short time period remaining before Pilgrim enters the license renewal period, the staff expects that considerable progress has already been made in developing and formally documenting the implementing procedures required for new AMPs, and for significant enhancements to existing AMPs. In light of this, please address each of the following questions regarding the current status of implementing procedures for this AMP: (a) Provide the status of the implementing procedures for each enhancement to the existing RG 1.127, Inspection of Water-Control Structures program. (b) Provide the schedule for initiating each of the enhancements to the existing RG 1.127, Inspection of Water-Control Structures program. (c) Provide a sample of an implementing procedure for one enhancement to the existing RG 1.127, Inspection of Water-Control Structures program. (d) Provide the results of any enhanced inspections that have already been completed.	Since 6 years remain before PNPS enters the period of extended operation, implementing procedures required for new AMPs, and procedure revisions for enhancements to existing AMPs have not yet been developed. To facilitate tracking of enhancements through the NRC review process and facilitate implementation, a list of specific commitments for license renewal has been developed. Items 25 and 26 on the list of commitments for license renewal are the commitment to implement the enhancements to the Structures Monitoring Program described in LRA Section B.1.29.2. This list will be sent to the Staff under oath and affirmation and will be supplemented as necessary during the NRC review process. Both Appendix B of the LRA and the list of commitments for license renewal include commitments to implement new programs and commitments to enhance existing programs before the period of extended operation. See item #320 for closure of this item.	Ahrabli, Reza	Kalb, J	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
246	[B.1.29.3-H-03, Water Control Structures Monitoring Program] 3. LRA Appendix B, Section B.0.5 identifies AMP B.1.29.3 as an existing program. The Program Description states that this AMP is part of the Structures Monitoring Program, and further states the program will be used to manage aging of water-control structures. The scope of the enhancements listed for AMP B.1.29.3 encompass many of the elements that normally would be part of an existing inspection program for water-control structures. Consequently, the applicant is requested to describe the scope of AMP B.1.29.3, including the structures and components in the scope of AMP B.1.29.3; the aging effects that are monitored; the inspection methods employed; and the inspection frequency.	The Water Control Structures Monitoring Program at PNPS is comparable to the program described in NUREG-1801, Section XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. The program includes visual inspections to manage loss of material and loss of form for water-control structures (breakwaters, jetties, and revetments). The water-control structures are of rubble mound construction with the outer layer protected by heavy capstone. Parameters monitored include settlement (vertical displacement) and rock displacement. These parameters are consistent with those described in RG 1.127. Inspections are performed on water-control structures every 5 years and following major storms. Program scope will be enhanced to include the east breakwater, jetties, and onshore revetments in addition to the main breakwater (commitment number 27). These added items as enhancements are not currently monitored under the existing program. This requires an amendment to the LRA.	Ahrabli, Reza	Kalb, J	Accepted	Yes
247	[B.1.29.3-H-04, Water Control Structures Monitoring Program] 4. The applicant is requested to identify the document(s) that includes the evaluation of the Pilgrim program against the monitoring of trash racks. Does the Structures Monitoring Program is credited for aging management of trash racks?	The trash racks are in scope of license renewal, but they are not subject to aging management review. The trash racks are intended to protect the traveling screens from large debris. The failure of the trash racks will not affect any license renewal function. (Ref. AMRC-03 "Aging Management Review of the Intake Structure" table 2.1-2). Accordingly, structures monitoring program is not credited for aging management of trash racks.	Ahrabli, Reza	Kalb, J	Closed	No
248	[B.1.29.3-H-05, Water Control Structures Monitoring Program] 5. The applicant is requested to identify and provide the inspection frequency against the GALL AMP XI.S7. If greater than 5 years. Please explain why the inspection frequency is NOT identified as an exception to the GALL AMP. Also provide the technical basis for concluding that Pilgrim frequency is sufficient for submerged portions of structures.	Inspections are performed on water-control structures at least every 5 years and following major storms. [Ref. Aging Management Program Evaluation Report LRPD-02, section 4.21.3.4 (b)].	Ahrabli, Reza	Kalb, J	Closed	No

Item	Request	Response	Lead	Support	Category	Update
249	[B.1.29.3-H-06, Water Control Structures Monitoring Program] 6. Per the Operating Experience discussion for B.1.29.3, Pilgrim has experienced degradation of the main breakwater Structure had Rock displacement in 2004. Has the corrective action been completed? If not, why? If yes, provide the plant documentation that describes the degradation, the assessment performed, the acceptance criteria applied, future monitoring recommendations, and any preventive and/or corrective action taken.	The corrective action has been completed. The Main Breakwater was repaired in October of 2005. The Main Breakwater was repaired, assessment performed, and condition resolved in accordance with the requirements of PNPS Specification C20-ER-Q-E0, Main Breakwater Repair. (Ref. MR # 04118760). The degradation of the Main Breakwater is documented in Condition Reports CR-PNP-2004-03933, CR-PNP-2005-00093, CR-PNP-2005-00450 and CR-PNP-2005-03018. The Main Breakwater is monitored at PNPS using procedure PNPS 3.M.5-3, Main Breakwater Monitoring and Repair Procedure. The procedure provides methods for initiating and assessing the results for main breakwater surveys and repair of the main breakwater. In addition to scheduled walkdown inspections and detailed surveys, the wind speeds are monitored for determining the need for additional inspections. The wind speeds at two separate met towers are monitored routinely. If any wind sensor indicates speed in excess of 50 MPH for two consecutive hours, a walkdown inspection of the breakwater is performed to assess any damage and repair as needed. Additional walkdown inspections are performed at the discretion of the design engineer for any suspicion of damage, regardless of wind speed.	Ahrabli, Reza	Kalb, J	Closed	No

Item	Request	Response	Lead	Support	Category	Update
250	[B.1.29.3-H-07, Water Control Structures Monitoring Program] The applicant is requested to confirm that Pilgrim AMP B.1.29.3 identifies an inspection of underwater supports for loss of material due to corrosion and loss of mechanical function. Provide the following information related to this request: (a) Identify the specific underwater supports that will be added to the scope of the inspection program for the license renewal period, including the system name and ASME Code Class.□ (b) Specify the current inspection program and describe the current inspection details for the underwater supports that are identified in (a) above. (c) Confirm that, all ASME Code Class underwater supports will be included in the scope of the inspection program for the license renewal period.	a. Program scope will be enhanced to include the east breakwater, jetties, and onshore revetments in addition to the main breakwater (commitment number 27). No underwater supports are identified to be added to scope of this program for license renewal period. (Ref. Aging Management Program Evaluation Report LRPD-02, section 4.21.3.B.1.b). b. The Water Control Structures Monitoring Program at PNPS is comparable to the program described in NUREG-1801, Section XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. The program includes visual inspections to manage loss of material and loss of form for water-control structures (breakwaters, jetties, and revetments). The water-control structures are of rubble mound construction with the outer layer protected by heavy capstone. Parameters monitored include settlement (vertical displacement) and rock displacement. These parameters are consistent with those described in RG 1.127. There are no underwater supports identified in scope of this program. (Ref. Aging Management Program Evaluation Report LRPD-02, section 4.21.3.A) c. No underwater supports are identified to be added to scope of this program for the license renewal period. (Ref. Aging Management Program Evaluation Report LRPD-02, section 4.21.3.B.1.b).	Ahrabli, Reza	Kalb, J	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
251	[B.1.30-W-01, System Walkdown] 1. PNPS states in LRA A.2.1.34 , System Walkdown Program, that "Surfaces are inspected at frequencies to provide reasonable assurance that effect of aging will be managed such that applicable components will perform their intended function during the period of extended operation." However, there is only limited information provided in the LRA B.1.30, "System Walkdown." What is the frequency of inspection, and what are the inspection criteria for the current program?	As stated in LRA Section B.1.30, the system Walkdown Program is consistent with the program described in NUREG-1801, Section XI.M36, External Surfaces Monitoring. The frequency of inspection and the acceptance criteria are consistent with those described in NUREG-1801, Section XI.M36. Further information is provided in Section 4.22 of the PNPS License Renewal Project Aging Management Program Evaluation Report, LRPD-02, "Aging Management Program Evaluation Report." A copy of this section of the report is available for on-site review. System Walkdowns are performed in accordance with Entergy Procedure EN-DC-178, "System Walkdowns." A copy of this procedure was available for on-site review. System inspections are conducted at least once per refueling cycle. This frequency is acceptable since aging effects are typically caused by long-term degradation mechanisms such as corrosion. Surfaces that are inaccessible or not readily visible during plant operations and refueling outages are inspected at such intervals that would ensure the components intended function is maintained. The intervals of inspections may be adjusted as necessary based on plant-specific inspection results and industry experience. In addition, all plant personnel are required to identify adverse conditions via the corrective action process. Since adverse conditions include those which the system walkdowns are intended to manage, aging effects may be identified through routine operations and maintenance activities. System walkdown attributes are based on EPRI Technical Reports 1011223, "Aging Identification and Assessment Checklist – Electrical Components," January 2005, and 1011224, "Aging Identification and Assessment Checklist – Civil and Structural Components," January 2005, and are consistent with NUREG-1801, Section XI.M36. Examples of Walkdown Attributes include:	Potts, Lori	Trask, Tim	Closed	No

Item	Request	Response	Lead	Support	Category	Update
		•□Liquid on floor/components leaking •□Concrete or grout cracks •□Paint and preservation adequate •□Fasteners in place, in good condition, proper thread engagement •□Evidence of moisture entry on/in panels, conduits, or other components •□Hangers (loose, broken, improper fasteners, indications of improper motion, displacement) In addition, System Engineers have received training on EPRI Technical Report 1007933, "Aging Assessment Field Guide," December 2003, and use the Guide during performance of their System Walkdowns.				
252	[B.1.30-W-02, System Walkdown] 2. PNPS states in LRA B.1.30, "System Walkdown," that this AMP is consistent with the program described in GALL Report Section XI.M36, "External Surfaces Monitoring." The GALL Report XI.M36 indicates that this AMP manages aging effects through visual inspection and monitoring of external surfaces for loss of material and leakage. The GALL Report further states in the Detection of Aging Effects program element, that "Surfaces that are inaccessible or not readily visible during plant operations and refueling outages are inspected at such intervals that would ensure the components intended function is maintained." Discuss how PNPS plans to inspect inaccessible surfaces of components that are within the scope of license renewal.	Surfaces that are inaccessible or not readily visible during plant operations are inspected during refueling outages. Surfaces that are inaccessible or not readily visible during both plant operations and refueling outages are inspected at such intervals that would provide reasonable assurance that the effects of aging will be managed such that applicable components will perform their intended function during the period of extended operation. Surfaces that are insulated are inspected when the external surface is exposed (i.e., maintenance) at such intervals that would provide reasonable assurance that the effects of aging will be managed such that applicable components will perform their intended function during the period of extended operation. Corrosion of piping under insulation will be associated with discoloration of the external insulation or with visible degradation of the insulation which provided the pathway for the fluid to reach the piping. Consistent with NUREG-1801, Section XI.M36, staining on thermal insulation is a monitored parameter.	Trask, Tim	Potts, Lori	Closed	No

Item	Request	Response	Lead	Support	Category	Update
253	[B.1.30-W-03, System Walkdown] 3. Provide some examples of actual plant-specific operating experience of how the problems were identified and appropriate actions taken to demonstrate and ensure the effectiveness of the existing System Walkdown Program.	As stated in LRA Section B.1.30, system walkdowns between 1998 and 2004 identified evidence of aging effects, including corrosion and leakage. Examples include fire water storage tank and diesel fire pump fuel oil day tank leakage, through-wall leakage on SSW piping, signs of corrosion in fan room and auxiliary bays, and through-wall leakage without loss of function on a drain line to the aux bay sump. Corrective actions were accomplished in accordance with the site Corrective Action Program. Related condition reports are available for on-site review.	Trask, Tim	Potts, Lori	Closed	No
254	[B.1.31-W-01, Thermal Aging and Neutron Irradiation Embrittlement of CASS] 1. What are the screening criteria used by PNPS to determine the susceptibility of CASS components to thermal aging and neutron irradiation embrittlement?	The PNPS CASS program has not yet been developed. However, to ensure consistency with NUREG-1801, the screening criteria (casting method, molybdenum content, and ferrite content) given in Section XI.M13, Scope of the Program, would be used by PNPS to determine susceptibility to thermal aging. Components exposed to more that 1017 n/cm2 (E>1MeV) over the life of the plant will be included in the program as susceptible to neutron irradiation embrittlement.	Finnin, Ron	Okas, Pete	Closed	No
255	[B.1.31-W-02, Thermal Aging and Neutron Irradiation Embrittlement of CASS] 2. As indicated in Table 3.1.2-2 of the LRA, PNPS identified three components: CRD Guide Tubes, Fuel Support Pieces and Jet Pump Assemblies are subject to the aging effect of loss of fracture toughness due to thermal aging and neutron irradiation embrittlement. Are any other CASS components in primary pressure boundary and reactor vessel internal subject to this aging effect? Discuss the recent ISI inspection findings for those components that PNPS has identified to be subject to this aging effect.	The CASS program comparable to NUREG-1801 Section XI.M13 is applicable only to the reactor vessel internals. The identified CASS components of the internals (guide tube, fuel support pieces, and pieces of the jet pump assemblies) are not subject to ISI, so there are no ISI results to date. Outside the reactor vessel, the only CASS components are valve bodies, pump casings, and the main steam flow restrictors. PNPS has no CASS piping. The main steam flow restrictors are not pressure boundary parts, and hence they are not examined by ISI either. Reduction of fracture toughness for CASS valves and pump casings are managed by ISI, not by a CASS program, as discussed in NUREG-1801 Section XI.M1.	Finnin, Ron	Okas, Pete	Closed	No

Item	Request	Response	Lead	Support	Category	Update
256	[B.1.31-W-03, Thermal Aging and Neutron Irradiation Embrittlement of CASS] 3. As indicated in the description of LRA AMP B.1.31, PNPS claims that its B.1.31 AMP will be consistent with the GALL Report Section XI.M13 AMP. The GALL Report states that for each "potentially susceptible" component, an applicant can implement either (a) a supplemental examination of the affected component as part of a 10-year ISI program during the license renewal term, or (b) a component-specific evaluation to determine the component's susceptibility to loss of fracture toughness. Describe what kind of supplemental inspection will be used in PNPS for detecting the critical flaw size with adequate margin.	For those components that require inspection, PNPS will inspect them using enhanced visual examinations (EVT-1) capable of detecting 0.0005 inch resolution. PNPS will perform either component specific evaluations or examinations of those components that are not eliminated by the screening criteria discussed in Question 254. Component-specific evaluations may include mechanical loading analyses. Component examinations will be enhanced visual examinations (EVT-1). Evaluations/inspections will be performed by the first refueling outage in the period of extended operation. Acceptance criteria for any flaws detected during these examinations will be evaluated in accordance with the applicable procedures of IWB-3500, and may include flaw evaluations performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1).	Finnin, Ron	Okas, Pete	Closed	No
257	[B.1.31-W-04, Thermal Aging and Neutron Irradiation Embrittlement of CASS] 4. PNPS states in LRA B.1.31, that this AMP is a new program, and it will be initiated prior to the period of extended operation. Will the implementation of this AMP be included in the commitment list?	Yes, all new programs are included in the commitment list. Implementation of the Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel Program is commitment #29.	Finnin, Ron	Okas, Pete	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
258	[B.1.32.1-P-01, Water Chemistry Control - Auxiliary Systems] 1. Per SRP Appendix A1, section A1.2.3.4, the frequency of sampling water chemistry should be identified. PNPS Appendix B.1.32-1, element 4 does not identify the frequency. Identify the frequency.	Stator cooling water conductivity is monitored continuously using three conductivity elements with remote readouts and alarms. Dissolved oxygen is measured using a portable oxygen meter with a continuous local display. The oxygen meter is read weekly and the value is recorded. If the oxygen meter is out-of-service, a weekly grab sample is obtained and a chemical analysis is performed. Monthly copper analyses are performed to monitor for corrosion. 1. There are three installed plant conductivity elements (P&ID M275). They read out remotely and are alarmed for Operations. In addition, there is one portable conductivity meter kept in Sample Panel C-3006. The portable conductivity meter only has a local readout. Normally, the portable meter satisfies procedure PNPS 7.8.1 grab sample requirement. However, we are considering removing the portable meter from the sample panel and just use the installed conductivity elements. With three conductivity elements, there is more than enough monitoring. 2. The only oxygen meter is portable and located in Sample Panel C-3006. It only has a local readout. The oxygen meter continuously displays locally, but has no readout or alarms. The oxygen meter is read weekly and the value is recorded. If the oxygen meter is out-of-service, a weekly grab sample is obtained and a chemical analysis is performed. 3. PNPS does not do corrosion products analyses. Only copper analyses are performed. Copper is the only significant corrosion concern.	Smalley, Paul	Potts, Lori	Closed	No

Item	Request	Response	Lead	Support	Category	Update
260	[B.1.32.3-P-01, Water Chemistry Control - Closed Cooling Water] 1. The exception taken for element 4 about the performance and functional testing should also apply to element 3 for the same reason that it applies to element 4. Justify why this exception does not apply to element 3.	The exception in LRA Section B.1.32.3, which was applied to the detection of aging effects attribute (element 4) is equally applicable to the parameters monitored/trended attribute (element 3). The exception was discussed under Element 4 since it is more directly related to detection of aging effects. LRA Section B.1.32.3 will be amended to indicate that the exception is applicable to both attribute 3, Parameters Monitored/Trended and attribute 4, Detection of Aging Effects. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Smalley, Paul	Potts, Lori	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
261	[Generic-J-01, Appendix B Aging Management Program] 1. In the PNPS LRA Operating Experience section for several AMPs (e.g. B.1.5; B.1.6; B.1.7; B.1.8; B.1.25) describes only the results of relatively recent inspection during RFO14 (April 2003) and RFO15 (April 2005). In most cases, inspection results for these refueling outage are negative (no recordable indications). Then the LRA makes a statement such as "Absence of recordable indications on the vessel attachment welds provides evidence that the program is effective for managing aging of the component during the period of extended operation." LR-SRP (NUREG-1800, Rev. 1) in Appendix A, Section A.1.2.3.10 (Branch Technical Position RLSB-1, Operating Experience) states that "the operating experience of aging management programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. .... This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner." QUESTION: For those AMPs where only the negative inspection results of RFO14 and RFO15 inspections are presented in the LRA, please provide additional discussion of inspection results from earlier refueling outages (approximately 10-15 years of history). If historical inspection results have found indications at some times in the past, provide additional discussion of what corrective actions have been taken.	SRP Section A.1.2.3.10 states, "Operating experience with existing programs should be discussed." To identify operating experience for license renewal, Entergy focused on operating experience with the existing programs rather than operating experience from the program that existed 10 to 15 years ago. Entergy did not own the plant 10 years ago. Entergy focused on operating experience from the existing programs rather than operating experience from the program that existed 10 to 15 years ago, because results of the earlier inspections do not provide information regarding existing program effectiveness. In addition, BWRVIP programs incorporate industry operating experience from the entire BWR fleet. The PNPS programs are based on NUREG-1801 programs which are also based on industry experience.	Cox, Alan	Chan, Laris	Closed	No

Item	Request	Response	Lead	Support	Category	Update
262	[Generic-J-02, Appendix B Aging Management Program] 2. The Standard Review Plan for License Renewal (NUREG-1800, Rev. 1), Section 3.0.1, states that "Enhancements are revisions or additions to existing aging management programs that the applicant commits to implement prior to the period of extended operation." In describing enhancements, the PNPS LRA typically says, "The following enhancement will be initiated prior to the period of extended operation." In describing an enhancement as something to be "initiated", rather than "implemented", prior to the period of extended operation, the LRA wording appears is ambiguous with regard to whether the enhancement will be fully implemented prior to the period of extended operation. QUESTION: Clarify or resolve this ambiguity in the LRA description of enhancements.	The intent of saying that enhancements will be initiated prior to the period of extended operation is that the enhancements will be fully implemented prior to the period of extended operation. This clarification will be provided in an amendment to the LRA.	Cox, Alan	Chan, Laris	Accepted	Yes
298	B.1.16.2-J-04 Please provide a comparison of the number of category B-F weld inspections and category B-J weld inspections before and after implementation of risk-informed ISI.	See below for the number of B-F and B-J weld inspections before and after risk informed ISI (RISI) implementation: Code Category B-F There are a total of 40 B-F welds in the ISI program. Before RISI implementation there were 40 weld exams and after RISI there are now 11 welds examined. Code Category B-J There are a total of 598 B-J welds in the ISI program. Before RISI implementation there were 156 weld exams and after RISI there are now 60 welds examined. In addition to ISI program welds, there are augmented IGSCC BWRVIP-75A program welds examined. For the IGSCC category B through G welds examined per BWRVIP-75A there are 16 category B-F welds and 18 category B-J welds.	Potts, Lori	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
299	Generic - N - 01 Provide brief description of all AC power sources and sequence of power transfer.	Power to the New England Grid is provided via the Main Transformer and the 345kV switchyard. The six 4.16kV busses are powered via the Unit Auxiliary Transformer (UAT). Upon a unit trip, the 4.16kV buses are automatically fast transferred to the Start up transformer, the preferred source (SUT). On loss of SUT, the 4.16kV safety busses A5 and A6 are transferred to Emergency Diesel Generators (EDG) automatically after approximately 10 seconds. Loss of an EDG will result in a transfer of its respective 4.16kV bus automatically in approximately 12 seconds to the Shutdown Transformer (SDT) source. Upon loss of all AC power at PNPS, the Station Blackout Diesel (SBODG) is started manually from the Control Room in 10 minutes and manually loaded to the safety 4.16kV busses A5 or A6 as needed by Operations	Das, Swapan	Stroud, Mike	Closed	No
300	Generic - N - 02 What is the capability of 23kV Shut down Transformer (SDT) Source?	The secondary AC power, the Shutdown Transformer (SDT) is capable of supplying all require loads of one emergency AC 4.16kV bus A5 or A6 for the safe shutdown of reactor for postulated accidents per PNPS analysis. The SDT is capable of supplying both safety busses A5 and A6 loadings per PNPS analysis for normal shutdown.	Das, Swapan	Stroud, Mike	Closed	No

Item	Request	Response	Lead	Support	Category	Update
302	B.1.12-P-01 Review of AMPER 4.11 - element 2, Preventive Actions (page 137) In the comparison statement, PNPS states that PNPS preventive actions are not consistent with GALL Report and that the program only involves tracking of cycles, and does not include assessment of environmental fatigue. However, environmental fatigue is addressed by TLAA section 4.3.3, and therefore, PNPS is consistent with GALL Report. Please clarify if PNPS is consistent with GALL for this element.	The effects of the reactor coolant environment are not considered in the current fatigue monitoring program at PNPS. The CUFs given in Table 4.3-1 of the LRA are the basis for the current fatigue monitoring program, and these were calculated without considering environmental effects. Section 4.3.3 of the LRA presents a conservative estimate of the effects of the reactor coolant environment on fatigue for PNPS. The results (the CUFs in Table 4.3-3 of the LRA) show that several locations exceed 1.0 when the resulting Fen are applied. As stated in LRA Section 4.3.3: "Prior to entering the period of extended operation, for each location that may exceed a CUF of 1.0 when considering environmental effects, PNPS will implement one or more of the following: (1) further refinement of the fatigue analyses to lower the predicted CUFs to less than 1.0; (2) management of fatigue at the affected location by an inspection program that has been reviewed and accepted by the NRC (e.g. periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method acceptable to the NRC); (3) repair or replacement of the affected locations." Once this commitment is implemented (commitment #31), the allowable number of transient cycles will be inputs to the fatigue analyses that include consideration of the effects of the reactor coolant environment. Therefore, during the period of extended operation, the Fatigue Monitoring Program will include assessment of the impact of the reactor coolant environment on fatigue.	Finnin, Ron	Woods, Steve	Closed	No

Item	Request	Response	Lead	Support	Category	Update
303	B.1.12-P-02 Review of AMPER 4.11 - element 6, Acceptance Criteria (page 137) In the comparison to GALL element 6, PNPS states it is consistent with GALL. However, the comparison statement does not address environmental fatigue. As written, this statement is inconsistent with GALL Report. Please clarify how environmental fatigue is addressed by PNPS or justify why as written, this element is consistent with GALL Report.	An exception was not identified for Attribute 6 in the original Aging Management Program since the exception addressed under Attribute 2 was considered adequate. For clarification, the Aging Management Program document, and the License Renewal Application will be revised as follows to also show an exception for attribute 6. AMPER 4.11 – element 6. The final sentence will be changed to read "PNPS acceptance criteria are not consistent with NUREG-1801 because the PNPS Fatigue Monitoring Program does not consider environmental fatigue effects." LRA Section B.1.12 will be revised to add "6. Acceptance Criteria" under the Attributes Affected column for the first exception listed. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Finnin, Ron	Woods, Steve	Accepted	Yes
304	B.1.12-P-03 Review of AMPER 4.11 - element 7, Corrective Actions (page 137) In the comparison statement, PNPS states, "if the lifetime projection of CUF exceeds 1.0, ...", please explain what lifetime means. Is it 40 years or 60 years? This references PNPS procedure 1.3.118, section 7.0, where the lifetime is defined as 40 years. Will the procedure be revised to reflect 60-year life?	Lifetime projections, as used in Section 7.0 of procedure PNPS 1.3.118, are projections based on 40 years of operation. The procedure extrapolates the actual transient cycles that have occurred to date to 40 years and shows that the projected number of cycles remains below the number of cycles used to calculate the CUFs for the vessel and appurtenances. Hence, the fatigue analyses that calculated the CUFs remain valid. The procedure will be revised to extrapolate transient cycles to 60 years, and we will adjust CUFs accordingly, when the renewed license is approved. Projections of cycles to 60 years are provided in Section 4.3.1 (Table 4.3-2) of the LRA.	Finnin, Ron	Woods, Steve	Closed	No

Item	Request	Response	Lead	Support	Category	Update
305	B.1.27-W-03 Selective Leaching 3. Industry operating experience has identified graphitization (removal of iron from cast iron) of submerged pump components from long-term immersion in saltwater environments. PNPS indicates in LRPD-02, Section 3.8, that this AMP is credited in both Salt Service Water System and the Circulation Water System. Has any pump, in these systems, been replaced as a result of selective leaching? If yes, please discuss how the problem was identified and the corrective action taken.	Yes, PNPS took an aggressive approach to replace P-105A ("A" Circulating Sea Water Pump) in RFO15 (April 2005) as a result of OE from the Vendor (Flowserve) informing PNPS that a failure of a cast iron Circulating Water Pump occurred at the New Boston Fossil Station in 2004 due to graphitization. That pump was a similar design to PNPS with 6 additional years of submergence/operation in salt water. Six core samples of the pump casing were sent out to a materials lab for analysis and the results confirmed graphitization. Currently, there are plans to replace P-105B in RFO17 based on the core sample analysis obtained from P-105A columns. PNPS has also purchased, and has on-site the columns for P-105B overhaul/replacement. The new pump columns are cast iron enhanced with the addition of 3-5% Nickel to improve strength and resistance to graphitization. The original columns were ASTM A48 CL 35 with 1.75-2.25% Nickel. The Salt Service Water pumps are not cast iron. The cast iron valve bodies (lined with rubber and Ni-Resist cast iron discs) originally installed on the SSW System have been replaced with cast steel lined with rubber and monel discs such that there are no cast iron components in the SSW system.	Ivy, Ted	Sullivan, Brian	Closed	No
306	B.1.18-N-04 Provide acceptance criteria for inspecting enclosure assemblies or justify why acceptance criteria for enclosure assemblies is not necessary. Revise AMP B1.18 as appropriate.	LRPD-02 will be revised as follows: (Section 3.3.B.6.b - Acceptance Criteria - add after first paragraph) The acceptance criteria for enclosure assemblies will be no loss of material due to general corrosion. The acceptance criteria for elastomers will be no hardening and loss of strength due to degradation. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Closed	Yes

Item	Request	Response	Lead	Support	Category	Update
307	B.1.19-N-03 GALL XI.E3, under scope of program, defines significant moisture as periodic exposures to moisture that last less than a few days (e.g., cable in standing water). Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. PNPS LRPD-02, Revision 1, under Scope of Program states that this program will include inaccessible (e.g., in conduit or direct buried) medium-voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with applied voltage. AMRE-01, Revision 2, Section 3.4.1.5, Non-EQ Inaccessible Medium-Voltage Cable Screening, states that the cable that are susceptible to water treeing are those exposed to significant moisture (submerged for years). Revise AMP B1.19, under the scope of program, to be consistent with GALL's definition or explain how inaccessible medium-voltage cables exposed moisture for more than few days and less than years is not susceptible to water tree.	LRPD-02 will be revised as follows: (Section 3.4.B.1.b - Scope of Program - replace first paragraph) This program applies to inaccessible (e.g. in conduit or direct buried) medium-voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with significant voltage. Significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable in standing water). Periodic exposures to moisture that lasts less than a few days (i.e., normal rain and drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Closed	Yes
308	B.1.19-N-04 GALL XI.E3 under program description states, in part, that periodic actions such as inspecting for water collection in cable man holes, and draining water, as needed to prevent cable from being exposed to significant moisture. The above actions are not sufficient to assure water is not trapped elsewhere in the raceways. In addition to the above periodic actions, in-scope medium-voltage cables are tested to provide an indication of the condition of the conductor insulation. PNPS AMP B.1.19 under the same attribute states that periodic actions will be taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cables manholes and conduit, and draining water, as needed. In scope medium-voltage cables exposed to significant moisture and voltage will be tested to provide an indication of the condition of the conductor insulation. It is clear to the team if periodic actions of manhole inspections are used to preclude cable testings. Confirm that the intend of AMP B.1.19 is to inspect for water in manholes and to test all the in-scope medium-voltage cables.	The intent of the PNPS AMP B.1.19 is to inspect for water in manholes and to test the in-scope medium-voltage cables.	Stroud, Mike	Das, Swapan	Closed	No

Item	Request	Response	Lead	Support	Category	Update
309	B.1.19-N–05 GALL XI.E3 under program description defines medium-voltage is from 2 kV to 35 kV. AMRE-01, Rev 2, Attachment 4 lists medium voltage cables from 2kV to 23 kV. Provide definition of medium voltage in the LRA to be consistent with GALL or provide a justification of why water tree phenomenon is not applicable for inaccessible medium-voltage cable greater than 23 kV.	LRA Appendix B.1.19 will define medium voltage cables as follows: For this program, medium voltage is from 2kV to 35kV. This requires an amendment to the LRA.	Stroud, Mike	Das, Swapan	Accepted	Yes
310	B.1.19-N–06 GALL XI.E3 under parameters monitored/inspected states that the specific type of test performed will be determined prior to the initial test and it to be a proven test for detecting deterioration of the insulation system due to wetting such as power factor, partial discharge test, or polarization index, as described in EPRI TR-103834-P1, or other testing that is state-of-the-art at the time the test is performed. PNPS B.1.19 under the same attribute only states that the specific type of test performed will be determined prior to the initial test. Revise your AMP to be consistent with GALL or explain how you ensure that the test to be performed will be in accordance with industrial guideline or that is the state-of-the-art at the time the test is performed.	LRPD-02 will be revised as follows: (Section 3.4.B.3.b - Parameters Monitored/Inspected - replace 2nd sentence) This program will state that the specific type of test to be performed will be determined prior to the initial test and is to be a proven test for detecting deterioration of the insulation system due to wetting as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Closed	Yes
311	B.1.19-N–07 Do you currently inspect water in the man holes. Are there any existing procedures for inspecting man holes. Provide a copy of these procedures.	Yes, though not a formal procedure, PNPS has an existing repetitive task and job plan for inspecting manholes. An example is provided. PNPS will develop a formal procedure to inspect manholes for in-scope medium voltage cable. Commitment 15 on the Commitment list identifies this item. Also, LRPD-02, section 3.4.B.10 - Operating Experience will be revised to discuss the process for considering plant operating experience that will be used during implementation of the Non-EQ Medium-Voltage Cable Program. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
312	B.1.19-N-08 AMRE-01, Rev. 2, Page 71 of 87 provides a list of in-scope inaccessible medium-voltage cables that are in scope of AMP B.1.19. However, it does not include service water cables. Explain why service water cables are not in-scope of AMP B.1.19.	Since medium voltage cables are defined as 2kV to 35kV, the service water cables are not in scope because they run on a system voltage of 480 volts.	Stroud, Mike	Das, Swapan	Closed	No
313	B.1.20-N-04 GALL XI.E2 under scope of program states that this program applies to electrical cables and connections (cable system) used in circuits with sensitive, high voltage, low-level signal such as radiation monitoring and nuclear instrumentation that are subject to an AMR. PNPS AMP B.1.20 under the same attribute states that this program will include non-EQ electrical used in circuits with sensitive, high voltage, low-level signals, i.e., neutron flux monitoring instrumentation. Explain why high range radiation monitor cables are not in scope of B.1.20.	The high-range radiation monitoring system monitors radiation levels inside containment (drywell and torus areas) during and following a design basis event. The monitors (RE1001-606A/B and RE1001-607A/B) are safety-related. The cables from the detectors to the cabinets in the control room are EQ (10 CFR 50.49) and therefore, are replaced based on qualified life, so are not subject to aging management review.	Stroud, Mike	Das, Swapan	Closed	No
314	B.1.20-N-05 GALL XI.E2 under parameter monitored/inspected states that the parameter monitored are determined from the specific calibration, surveillance or testing performed and are based on the specific instrumentation under surveillance or being calibrated, as documented in plant procedures. PNPS AMP B.1.20 under same attribute states that results from the calibrations or surveillance of components within the scope of license renewal will be reviewed. The parameters reviewed will be based on the specific instrumentation circuit under surveillance or being calibrated, as document in the plant calibration or surveillance procedures. a. Why does the review of calibration results belong to parameter monitored/inspected attribute? b. The parameter monitored/inspected for cable testing was not mentioned. What is the parameter for cable testing. Confirm that cable testing will be perform on cables in scope of XI.E2 that are disconnected during instrumentation calibration.	a. LRPD-02 will be revised as follows: (Section 3.5.B.3.b - Parameters Monitored/Inspected - replace 2nd sentence) The parameters monitored are determined from the specific calibration, surveillance's or testing performed and are based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant procedures. b. LRPD-02 will be revised to read as follows: (Section 3.5.B.3.b - Parameters Monitored/Inspected - add to 2nd sentence) The parameters monitored are determined from the specific calibration, surveillances or testing performed. The parameter for cable testing is determined from the plant procedures. Cable testing is performed by plant procedures on cables in-scope of license renewal that are disconnected during instrument calibration. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Closed	Yes

Item	Request	Response	Lead	Support	Category	Update
315	B.1.21-N-03 GALL XI.E1 under scope of program states that this inspection program applies to accessible electrical cables and connections within the scope of license renewal that installed in adverse localized environments caused by heat or radiation in the presence of oxygen. PNPS B.1.21 under the same element states that this program will include accessible insulated cables and connections installed in structures within the scope of license renewal and prone to adverse localized environments. What "in a structure" means? Why are structures included in the scope of non-EQ cables and connections AMP?	"In a structure" means inside the plant, not outside. LRPD-02 will be revised to read as follows: (Section 3.6.B.1.b - Scope of Program - add to scope) The program applies to accessible electrical cables and connections within the scope of license renewal that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Closed	Yes
316	B.1.13.1-P-04 4. New question from site visit: GALL report states that the periodic function test and inspection performed at least once every six months detects degradation of the halon/CO2 fire suppression system before the loss of the component intended function. However, per review of LRPD-02, Rev.1, section 4.12.1.B.4.b, PNPS performs this test once each operating cycle, which is different than GALL report frequency. Please justify why this is not an exception to element 4, and if it is, please revise the LRA to include this exception.	As indicated in the PNPS repetitive task database, functional testing of the cable spreading room Halon fire suppression system is performed annually and inspection of the system is performed at least once every six months. Therefore, LRA Section B.1.13.1 will be revised to include the following exception to the Detection of Aging Effects Attribute. The NUREG-1801 program recommends that functional testing and inspection of the Halon fire suppression system occur at least once every six months. However, while PNPS performs inspections at least once every six months, functional testing is performed annually. Exception note: The variation in functional test frequency is insignificant with relation to detection of aging effects because functional tests are designed to verify the operability of active system components. Since system inspections are performed at least once every six months, aging effects are identified prior to loss of passive component intended function. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Potts, Lori	Burke, Steve	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
317	B.1.13.1-P-05 5. New question from site visit: In element 3, GALL states that visual inspection of the fire barrier walls, ceilings, and floors examines any sign of degradation such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. Procedure 8.B.29 addresses cracking, spalling, etc., however LOM is not addressed. Where is LOM addressed?	Loss of material for fire barrier walls, ceilings, and floors is addressed in procedure PNPS 8.B.29, Section 8.2 [1]. This procedure section describes how each fire barrier is to be inspected. It directs inspectors to take note of any damaged portions of the barrier, and lists cracks/gaps/voids in walls as an example of damage to be noted. It further states that if a major defect exists in any barrier it will be evaluated and entered into the corrective action process.	Potts, Lori	Burke, Steve	Closed	No
318	B.1.13.1-P-06 6. New question from site visit: The GALL AMP XI.M26 specifies approximately 10% of each type of seal should be visually inspected at least once every refueling outage (2 years). The exception taken in the LRA states inspection of approximately 20% of seals each operating cycle, with all accessible penetration seals being inspected at least once every five operating cycles (10 years). Please identify if each type of seal is included in this 20% sample.	The exception in LRA Section B.1.13.1 will be revised to state: The NUREG-1801 program states that approximately 10% of each type of penetration seal should be visually inspected at least once every refueling outage. The PNPS program specifies inspection of approximately 20% of the seals, including at least one seal of each type, each operating cycle, with all accessible fire barrier penetration seals being inspected at least once every five operating cycles. LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Potts, Lori	Burke, Steve	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
319	Please revise LRPD-02 pg 268, detection of aging effects for small bore piping inspection activity, to indicate that volumetric examinations are used to detect cracking in butt welds. Also revise LRPD-02 pg 267, scope of program for water chemistry inspection activity, to "A representative sample of susceptible components..."	LRPD-02 pg 268, detection of aging effects for small bore piping inspection activity, will be revised to state: "Combinations of non-destructive examinations (including VT-1, enhanced VT-1, ultrasonic, and surface techniques) will be performed by qualified personnel following procedures that are consistent with Section XI of ASME B&PV Code and 10 CFR 50 Appendix B. Volumetric examinations are used to detect cracking in butt welds. Actual inspection locations will be based on physical accessibility, exposure levels, NDE techniques, and locations identified in NRC Information Notice 97-46". LRPD-02 pg 267, scope of program for water chemistry inspection activity, will be revised to state: "A representative sample of susceptible components of each material and environment crediting water chemistry control programs for aging management will be inspected." LRPD-02 Revision 2 issued addressing this item.	Potts, Lori	Pardee, R.	Closed	No
320	Generic P-01 Since Appendix A will be placed in the FSAR immediately if and when the license renewal application is approved, new programs should be presented in future tense, rather than present tense as currently presented. Also, SRP-LR states that all enhancements to programs should be listed in Appendix A, UFSAR Supplement.	Program descriptions in Appendix A of the LRA will be revised, as applicable, to identify the commitment number(s) associated with the program. The program descriptions in Appendix A for new or enhanced programs will be amended to include one of the following statements as applicable. "License renewal commitment # _______ governs implementation of this program." Or, "License renewal commitment # _______ specifies enhancement to this program." This requires an amendment to the LRA.	Cox, Alan	Chan, Laris	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
321	B.1.1-W-05 Please revise LRPD-02, Sections 4.1.B.2.b and 4.1.B.4.b to clarify that BADGER testing is an areal density measurement.	LRPD-02, Sections 4.1.B.2.b and 4.1.B.4.b will be revised to clarify that BADGER testing is an areal density measurement. Section 4.1.B.2.b will state: Silica levels in the spent fuel pool water are monitored monthly. (Ref. Attachment 9, 7.8.1) Gap formation is measured by blackness testing, areal density (BADGER) is periodically measured and the RACKLIFE predictive model is used. (Ref. CR-PNP-2004-00285) PNPS preventive actions are consistent with NUREG-1801. Section 4.1.B.4.b will state: The amount of boron carbide released from the Boraflex panels is determined through correlation of the silica levels in the spent fuel pool water using the RACKLIFE code. Detection of gaps through blackness testing and periodic verification of boron loss through areal density measurements (BADGER) identify loss of material and cracking of the Boraflex panels. (Ref. Attachment 9, 7.8.1 and CR-PNP-2004-00285) This program is credited with managing the following aging effects. •change in material properties (reduction in neutron-absorbing capacity) for Boraflex neutron absorber panels (AMRM 21) PNPS detection of aging effects is consistent with NUREG-1801. LRPD-02 Revision 2 issued addressing this item.	Potts, Lori	Wollman, Stan	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
322	B.1.1.11-N-03 Provide a description of preventive actions for the PNPS EQ Program.	10 CFR 50.49 does not require actions that prevent aging effects. LRPD-02 will be revised to read as follows: (Section 4.10.B.2.b - Preventive Actions - add to end of first sentence) The program actions that could be viewed as preventive actions are the identification of qualified life and specific maintenance/installation requirements. LRPD-02 Revision 2 issued addressing this item.	Stroud, Mike	Das, Swapan	Closed	Yes
323	[B.1.32.2-P-02] GALL AMP XI.M2, element 3, Parameters Monitored/Inspected, lists monitoring of chlorides, sulfates, dissolved oxygen, and hydrogen peroxide. However, LRPD-02, section 4.23.2.B.3.b, which performs a comparison of element 3 with the PNPS AMP, monitoring of hydrogen peroxide is not mentioned, and concludes that the PNPS AMP is consistent with this element. Please clarify if hydrogen peroxide is not monitored, how is PNPS consistent with this element?	Reactor water hydrogen peroxide measurements, while they would be beneficial in determining the total oxidizing species affecting Stress Corrosion Cracking (SCC), are not practical. The results obtained through liquid sampling are inaccurate because of decomposition of hydrogen peroxide in the sample lines. No practical method exists for a BWR to obtain direct hydrogen peroxide measurements. In accordance with BWRVIP-130, reactor water Electrochemical Corrosion Potential (ECP) and dissolved oxygen measurements are used at PNPS to determine whether oxidizing species including H_2O_2 have been reduced sufficiently to minimize IGSCC.	Loomis, Larry	Potts, Lori	Closed	No
324	[B.1.32.3-P-02] The last sentence of exception note 1 states that "Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the closed cooling water chemistry program through monitoring and control of water chemistry parameters." Isn't the one-time inspection program also used to verify effectiveness of the chemistry program? If so, should that be addressed as part of this exception note 1 justification?	For clarity, LRA Section B.1.23.3, exception note 1 will be revised to state: "Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the closed cooling water chemistry and one-time inspection programs through monitoring and control of water chemistry parameters and verification of the absence of aging effects." This requires an amendment to the LRA.	Potts, Lori	Loomis, Larry	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
325	[B.1.32.1-P-02] Element 6 – Acceptance Criteria states that conductivity should be maintained <0.3 S/cm. Is the unit correct? Should it be µS/cm? (per LRPD-02, Rev. 1, section 4.23.1.B.6)	Yes, this was a software conversion error. Element 6 of LRA Section B.1.32.1 will be amended to correct the units of conductivity to µS/cm and delete the acceptance criteria for corrosion products. Corrosion product (copper) sampling is used to determine the type of copper oxide layer formed. Thus it is a diagnostic parameter without an acceptance criterion. This requires an amendment to the LRA.	Potts, Lori	Loomis, Larry	Accepted	Yes
326	[B.1.32.2-P-01] GALL Chapter XI.M2 suggests that for "susceptible locations," a one-time inspection verification program may be appropriate. Do you intend to implement a one-time inspection program for this water chemistry control program? Furthermore, will a one-time inspection program be implemented for other water chemistry control programs? If so, please explain why this is not included in Appendix A for each of these water chemistry control programs	Yes, the one-time inspection program described in LRA Section B.1.23 includes inspections to verify the effectiveness of the water chemistry control aging management programs by confirming that unacceptable cracking, loss of material, and fouling is not occurring. LRA Section 3 Table 1's discussions provide the link between the One-Time Inspection and Water Chemistry Control Program for susceptible components. However, for clarity, LRA Appendix A descriptions for the Water Chemistry Control - BWR, Closed Cooling Water and Auxiliary Systems programs will be amended to provide a link to the One-Time Inspection Program activities to confirm the effectiveness of these programs. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control-BWR, Water Chemistry Control- Auxiliary Systems and the Water Chemistry Control- Closed Cooling Water programs. This item is closed to Item 372.	Potts, Lori	Loomis, Larry	Closed	No

Item	Request	Response	Lead	Support	Category	Update
327	B.1.30-W-04 LRPD-02 identifies an enhancement to the System Walkdown Program that is not listed in the LRA. Please explain.	The enhancement in LRPD-02 was identified after the LRA was submitted to NRC for review. This enhancement will be added to LRA Section B.1.30 as follows. Enhancements Attribute Affected 1. Scope of Program Enhancement Enhance system walkdown guidance documents to clarify license renewal commitment. The commitment for license renewal is for periodic system engineer inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2). LRPD-02 Revision 2 issued addressing this item. This requires an amendment to the LRA.	Potts, Lori	Trask, Tim	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
328	GALL XI.E1, XI.E2, XI.E3, and XI.E4 indicates that operating experience has shown that degradation of metal enclosed bus, cables, and connections within the scope of E1, E2, E3, and E4 may exist. Provide a discussion of industry and plant operating experience for these programs.	The programs will be updated to include the following: The XXX program is a new aging management program. Industry operating experience that forms the basis for the program is described in the operating experience element of the NUREG-1801 program description. PNPS plant-specific operating experience has been reviewed against the industry operating experience identified in GALL. Although PNPS has not experienced all of the aging effects listed in GALL, the PNPS program will manage all of the aging effects identified in the Operating Experience section of GALL. The program is based on the program description in NUREG-1801, which in turn is based on relevant industry operating experience. As such, this program will provide reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. As additional operating experience is obtained, lessons learned can be used to adjust the program, as needed. This requires an amendment to the LRA.	Stroud, Mike	Cox, Alan	Accepted	Yes
478	B.1.25-J-05, Reactor Head Closure Studs: In response to Request B.1.25-01 (Item # 226), PNPS stated that, "Approved lubricants for RPV studs are Neo-Lube or equivalent. (Procedure 3.M.4-48)." QUESTION: The referenced PNPS procedure does not identify which specific Neo-lube products are approved for lubrication of the reactor vessel studs. Please clarify which specific Neo-lube lubricants are approved for the RPV studs at PNPS and the temperature range wherein the manufacturer recommends application of the approved lubricants	Pilgrim uses Dag-156 (similar to Neo-lube) which is a GE recommended lubricant for the RPV studs. This is what GE typically uses at other BWRs. The Dag-156 is approved for use on stainless steel material at temperature ranges typical for BWRs (approval is in the BWR material services handbook).	Chan, Laris	Finnin, Ron	Closed	No

Item	Request	Response	Lead	Support	Category	Update
479	B.1.8-J-08, BWR Vessel Internals: In response to Request B.1.8-03 (Item # 157), PNPS provided a copy of BWRVIP-26 and verbally discussed how criteria contained therein are applied with regard to inspections of the top guide at PNPS. QUESTION: Using the inspection location numbers provided in BWRVIP-26, Table 3-2, Matrix of Inspection Options, please confirm that the inspection locations relevant for the exception related to the Top Guide hold-down assemblies and aligner assemblies are inspection locations (2, 3) and inspection location (8)	The locations that are not inspected at PNPS are locations 2 and 3 (aligner assemblies) and locations 8 and 9 (hold down assemblies) from BWRVIP-26.	Finnin, Ron	Mileris, George	Closed	No

Item	Request	Response	Lead	Support	Category	Update
480	B.1.8-J-9-09, BWR Vessel Internals: The LRA states that, "The top guide rim weld does not exist at PNPS and is therefore exempt from inspection." BWRVIP-26, Section 2.2.8, states that for most BWR/3 through BWR/5's the rim welds are those circumferential welds which connect the bottom plate and the rim [of the top guide] and that these welds are full penetration all around groove welds, creating an uncreviced configuration. BWRVIP-26, Table 3-2 provides an inspection strategy for BWR/3,4 rim welds as follows: "Enhanced VT-1 every other cycle of rim weld locations accessible during normal refueling activities. If cracking is found, expand inspection to 25% of one side of the rim weld for qualitative evaluation." With a plant-specific analysis, BWRVIP-26, Table 3-2, provides that "No inspection [of rim welds is] required if analyses of reinforcement block pins with plant-specific loads shows that lower pin(s) have acceptable stress with the rim weld fully cracked." Questions: Please clarify whether the top guide rim weld does not exist (and has never existed) at PNPS or whether the top guide rim weld is assumed to be fully cracked. If the rim weld has never existed, please explain how the bottom plate of the top guide is connected to the rim of the top guide. Please discuss the function of the reinforcement block pins and clarify whether a plant specific analysis has been performed to show that the lower pin(s) have acceptable stress with the rim weld non-existent or fully cracked.	At PNPS, the bottom plate and rim are an integral machined piece. Because they are one piece there is no weld to fail and therefore no analysis of the lower pins with a failed weld. A copy of fabrication drawing DR432175-7 (2426-3-3 Sheet 2) was provided, showing that the top guide rim and bottom plate are one machined piece.	Finnin, Ron	Mileris, George	Closed	No

Item	Request	Response	Lead	Support	Category	Update
481	B.1.8-J-10, BWR Vessel Internals: In the PNPS BWR Vessel Internals Inspection Implementing Procedure (NE21.02) there is a technical justification related to deferring the inspection of the jet-pump thermal sleeve hidden welds TS-3 and TS-4. Part of the discussion in the technical justification states that cracks were found in thermal sleeve in the heat affected zone (HAZ) of the jet pump thermal sleeve-to-pad fillet welds (not the TS-3 and 4 welds) during the recirculation pipe replacement in 1984. The technical justification, as understood, states that the thermal sleeve-to-pad welds were part of the assembly process, with the pads used to help alignment; however, the implication is that after installation the sleeve-to-pad fillet welds have no real function. The technical justification, as understood, says that the cracks in the thermal sleeve-to-pad fillet welds were not repaired and that the PNPS plan was to suppress further cracking through implementation of hydrogen water chemistry. The LRA states that PNPS instituted hydrogen water chemistry in 1991 to mitigate cracking in the reactor internals, and to address crack growth in the jet pump thermal sleeve welds in particular. It is not clear whether PNPS has completed, or intends to complete, any sort of repair related to the cracking in the thermal sleeve found in the HAZ of the sleeve-to-pad fillet welds prior to entering the period of extended operation. Question: Please clarify what, if any, periodic examination of the HAZ for the sleeve-to-pad fillet welds is currently performed at PNPS. Please clarify whether a repair of cracks in the HAZ of the thermal sleeve-to-pad welds has been performed or is planned. If no repair of these cracks has been performed, please provide a discussion of the aging management that will be provided for the jet pump thermal sleeves during the period of extended operation.	a) No periodic examination of the HAZ for the sleeve-to-pad fillet welds is currently performed at PNPS. VT-1 examinations will be conducted when appropriate technique/tooling is developed by the BWRVIP. b) No repair of the cracks in the HAZ of the thermal sleeve-to-pad welds has been performed, and none is planned. c) The aging management of the Jet Pumps will be in accordance with BWRVIP-41, October 1997, which recommends modified VT-1 inspections of the jet pump thermal sleeves once the technique/tooling is available. Note: BWRVIP-41 assigns these welds a M/L (medium-low) safety priority rating. d) Yes, PNPS submitted several letters in response to the Commission's 1983 IGSCC Inspection Order Confirming Shutdown. These letters are summarized in the NRC's SER for restart, NRC Letter, HR Denton (NRC) to WD Herrington (BECo), dated 12/4/84. The main technical report that was docketed by PNPS was General Electric Calculation NEDC-30730-P, Pilgrim Nuclear Power Station Recirculation Nozzle Repair Program and Hydrogen Water Chemistry Materials Qualification, September, 1984. Copies of the GE report and the NRC SER were provided to the inspector. Also provided, BECO letter 2.94.146, dated 9/11/84, which included a commitment to implementing a hydrogen water chemistry (HWC) program at PNPS, BECO letter 2.94.111, dated 10/13/94, which discussed the performance of HWC at PNPS and NRC SER dated 11/28/94 (1.94.246) that included evaluation of BECO letter 2.94.111. The request made by BECo 2.94.111 was withdrawn by BECo letter dated 7/30/98, and the withdrawal was acknowledged in NRC letter 1.98.101 dated 8/11/98. The request was re-submitted by BECo letter 2.98.126 on 9/4/98, included description of the Pilgrim HWC program and HWC performance, that	Finnin, Ron	Mileris, George	Closed	No

Item	Request	Response	Lead	Support	Category	Update
	Please identify what, if any, docketed information PNPS has provided to the NRC with regard to evaluation of jet pump thermal sleeve cracking in the HAZ of the sleeve-to-pad fillet welds, and make copies of it available during the next audit visit.	was evaluated in NRC SER dated 5/27/99.				
482	B.1.16.2-J-05, Inservice Inspection: ASME Section XI, 1998 with 2000 addenda is the basis for PNPS's Inservice Inspection Program, which PNPS states is a plant-specific program in LRA, Appendix B.1.16.2, Inservice Inspection. In response to Request B.1.16.2-J-01 (Item 194), PNPS provided a list and a brief description of exceptions and alternatives to the requirements of ASME Section XI, 1998 edition with 2000 that have been granted under provisions of 10 CFR 50.55a. QUESTION: For each of the exceptions or alternatives (i.e., relief requests) listed in PNPS's response to request B.1.16.2-01, PNPS is requested to make a determination of whether the relief request affects the aging management of components that are within the scope of ASME Section XI, regardless of which aging management program they may be assigned to at PNPS For each of the relief requests where PNPS determines that the aging management of components within the scope of ASME Section XI is NOT affected, PNPS is requested to provide a summary of the critical thinking that supports PNPS's determination.. For each of the relief requests where PNPS determines that the aging management of components within the scope of ASME Section is affected, PNPS is requested to identify which PNPS aging management program(s) and which specific element(s) within the program(s) are affected, and to provide a summary of the critical thinking that supports PNPS' determination.	Due to its size and format, the documentation associated with this response is not suited for entry into this database. The response will be provided to the auditor during the AMR audit at PNPS.	Nichols, Bill	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
483	B.1.16.2-J-06, Inservice Inspection: In the LRA, Appendix B.1.16.2, Inservice Inspection, the PNPS inservice inspection program is described as a plant specific program encompassing ASME Section XI, Subsections IWA, IWB, IWC, IWD and IWD requirements. The guidelines for elements of an acceptable plant specific aging management program are set forth in NUREG-1800 (LRA-SRP), Appendix A, Section A.1.2.3, Aging Management Program Elements. In PNPS ,LRPD-02, Revision 1, Aging Management Program Evaluation Report, Section 4.14.1, Inservice Inspection Program, there is no direct comparison of the elements of PNPS plant-specific inservice inspection program against the elements of an acceptable plant specific aging management as described in NUREG-1800. The PNPS evaluation of its plant-specific inservice inspection program provides essentially the same information that is presented in LRA, Appendix B.1.16.2. Question: Please provide a direct comparison of each element of PNPS's plant specific inservice inspection program against the guidelines for acceptable aging management program elements as specified in NUREG-1800, Appendix A. or, Please provide a detailed discussion of the critical thinking that supports PNPS' determination that its plant-specific inservice inspection program complies with the guidelines of NUREG-1800, Appendix A.	A comparison of the PNPS ISI Program to the program elements described in NUREG-1800, Appendix A, has been prepared. Due to the size of the comparison document, it will be provided for review during the AMR audit at PNPS.	Nichols, Bill	Pardee, R.	Closed	No

Item	Request	Response	Lead	Support	Category	Update
484	B.1.1-W-06, Boraflex Monitoring Program: In response to Question B.1.1-W-05 (Item # 321), PNPS clarified that the BADGER testing is an areal density measurement, not blackness testing as originally described in LRPD-02, Section 4.1.B.2b and 4.1.B.4b. Please clarify the nature of the test of "blackness testing" used in response to Question B.1.1-W-02 (Item # 138). In that response, PNPS stated that, "Blackness testing was performed on Boraflex panels in the spent fuel storage racks during 1996 and 1998 to provide a baseline for development of the monitoring program."	Blackness testing is a technique that measures the thermal neutrons from a neutron source that pass through a material and are detected by a neutron detector. In an area where Boraflex material may be lost, a higher neutron count is interpreted as loss of material.	Nichols, Bill	Wollman, Stan	Closed	No
485	B.1.1-W-07, Boraflex Monitoring Program: PNPS states in Section A.2.1.1 (Boraflex Monitoring Program) of LRA UFSAR Supplement, that this program relies on (1) neutron attenuation testing, (2) determination of boron loss through correlation of silica levels in spent fuel pool water samples and periodic areal density measurements, and (3) analysis of criticality to assure that the required 5-percent subcriticality margin is maintained. However, in response to Question B.1.1-W-02 (Item # 138), PNPS stated that, "The Boraflex Monitoring Program (with areal density measurement) at PNPS has been instituted recently." Please clarify whether the *areal density measurements* (BADGER tests) have ever been performed at PNPS? Discuss the test results if they are available.	The program document for Boraflex monitor was recently issued for use. The BADGER testing has not yet been performed. BADGER testing is scheduled for the fourth quarter of 2006.	Nichols, Bill	Wollman, Stan	Closed	No
486	B.1.1-W-08, Boraflex Monitoring Program: To demonstrate the spent fuel pool subcriticality margin of greater than 5 percent, the current PNPS LRA (in the operating experience section) only discussed the gap measurement. Since PNPS also will perform (or performed) *in-situ* areal density test using the BADGER device, which provides more accurate results, please clarify that PNPS will also rely on the BADGER test results to demonstrate the spent fuel pool subcriticality margin of greater than 5 percent.	The results of BADGER testing will be used in calculations after the 2006 tests are completed to demonstrate that the spent fuel pool subcriticality margin is greater than 5%.	Nichols, Bill	Wollman, Stan	Closed	No

Item	Request	Response	Lead	Support	Category	Update
487	B.1.30-W-05, System Walkdown Program: In response to Question B.1.30-W-04 (Item # 327), PNPS indicated that an enhancement will be added to the LRA Section B.1.30. Please confirm that the same enhancement will also be captured in the UFSAR Supplement with a commitment number.	As noted in response to item #327, the *enhancements to be added to LRA section* B.1-30, System Walkdown Program, require an amendment to the LRA. These enhancements are identified as commitment #28 on the PNPS list of commitments for license renewal.	Potts, Lori	Mogolesko, Fred	Accepted	Yes
488	B.1.8-J-11, BWR Vessel Internals: LRA Appendix B.1.8 in description of the exception related to Core Spray says, "PNPS defers inspection of three inaccessible welds inside each of the two core spray nozzles until a delivery system for ultrasonic testing of the hidden welds in developed"; and in description of the exception related to Jet Pump Assembly says, "PNPS defers inspection of jet pump inaccessible welds until a delivery system for ultrasonic testing of the hidden welds is developed." There are also appropriate statements procedure PNPS-EP-06-0001, Rev. 0, that confirm PNPS's intention to perform the inspections of hidden welds when equipment for doing so becomes available in the industry. However, inspection of the hidden welds is not documented as a commitment on the PNPS list of Commitments for License Renewal. QUESTION: Please revise the list of PNPS Commitments for License Renewal to include these inspections	A technique to be able to access and to obtain UT data for the inaccessible jet pump and core spray welds is being developed under the BWRVIP. If and when the necessary technique and equipment become available and the technique is demonstrated by the vendor, including delivery system, PNPS will inspect the inaccessible jet pump thermal sleeve and core spray thermal sleeve welds. This is commitment #33.	Finnin, Ron	Pardee, R.	Accepted	Yes

Item	Request	Response	Lead	Support	Category	Update
489	B.1.16.2-J-07, Inservice Inspection: In its response to request B.1.16.2-J-01, ISI (Item # 194) PNPS listed nine (9) relief requests. However, the 4th year ISI plan, PNPS-RPT-05-001, Rev. 0, Appendix B, list fifteen (15) relief, and discussion with James Shea, NRC's operating plant project manager for Pilgrim, indicates that there are sixteen (16) relief requests. QUESTION: Please clarify the exact number of relief requests for PNPS 4th ISI interval, which extends approximately 3 years into the period of extended operation. Please include all 4th interval relief requests in your response to Question B.1.16.2-J-05 that asks PNPS to identify and discuss which relief requests do and which do not affect aging management during the period of extended operation.	PNPS-RPT-05-001, Rev. 0 includes thirteen (13) new relief requests for the 4th ISI interval, and two (2) additional relief requests from the 3rd interval that were approved up to the end of the current license that are being used in the 4th interval [see Appendix B of PNPS-RPT-05-001]. That makes fifteen (15) total relief requests. Two numbers (PRR-1 and PRR-3) are listed as "not used" in Appendix B. In addition to the above, there are three (3) 10CFR50.55a(g)(4)(iv) requests to use the 2001 Code Edition with 2003 Addenda [see Appendix D of PNPS-RPT-05-001]. The details on each of the requests is provided in the response to question B.1.16.2-J-05	Pardee, Rich	Chan, Laris	Closed	No
491	B.1.10 Diesel Fuel Monitoring (1) It is not clear in the PNPS LRA how water content and sediment are monitored in the diesel fuel tanks. Does PNPS use ASTM D 1796 and/or D2709 as recommended in NUREG 1801 Rev. 1? If not what methods are used to monitor these contaminants?	As stated in Parameters Monitored/Inspected in the AMPER LRPD-02 section 4.9, ASTM D1796 is used to check for water and sediment, but water and sediment checks may also be performed according to ASTM D2709. Also see attachment 17 of Procedure 7.8.1. These documents are available on site for review.	Potts, Lori	Hudson, Steve	Closed	No
492	B.1.10 Diesel Fuel monitoring (2) This question is regarding Item 164 of the Programs questions report. The project team reviewed ASTM D 6217-98 and ASTM D 2276-00 and could not find the acceptance criteria in either of these standard test methods. Please provide additional explanation as to where these acceptance criteria came from.	The response to Item 164 was incorrect and has been revised to remove the reference to acceptance criteria in these standards. There are no acceptance criteria in ASTM D 6217-98 and ASTM D 2276-00. The actual source of the acceptance criteria for water and sediment is in ASTM D975 Table 1, and for particulates is in Table 1 of VV-F-800D, Federal Specification, Fuel Oil Diesel.	Hudson, Steve	Ivy, Ted	Closed	No

Item	Request	Response	Lead	Support	Category	Update
493	B.1.24 Periodic Surveillance and Preventive Maintenance The enhancement in the LRA does not provide enough detail. Please provide information in the LRA as to which implementing documents will be enhanced or created, which components will be affected by the enhancement and what aging effect will be inspected along with frequency and acceptance criteria.	The details on the implementing documents that will be enhanced or created, which components are affected, the aging effect along with frequency and acceptance criteria is provided in Attachment 3 of LRPD-02 "Aging Management Programs Evaluation Report" which was previously provided to the NRC Inspectors and remains available for their review.	Ivy, Ted	Potts, Lori	Closed	No

ATTACHMENT C to Letter 2.06.057

Questions and Answers on the Aging Management Reviews Portion of the License Renewal Application

NRC AMR Audit PNPS - All Items (Open and Closed)

Item	Request	Response	Lead	Support	Category
341	In Table 4.1-1 of the LRA, the applicant did not identify a crane load cycle limit as a TLAA for the cranes within the scope of license renewal. Normally, based on the design code of the crane, a load cycle limit is specified at rated capacity over the crane's projected life. Therefore, it is generally necessary to perform a TLAA relating to crane load cycles estimated to occur up to the end of the extended period of operation. Please explain why the crane load cycle limit was not included as a TLAA.	The license renewal rule, in 10 CFR 54.3, defines a TLAA as a licensee calculation or analysis that, among other things, involves time-limited assumptions defined by the current operating term. For cranes, there is no calculation or analysis related to crane load cycles. In addition, the number of cycles is NOT based on the current operating term. CMAA-70 specifies an allowable stress range based on joint category and service class. Service class is based on load class (mean effective load factor) and number of cycles. The projected cycles for the PNPS reactor building crane are well below any of the cycle ranges given in CMAA-70. The discussion column of Item 3.3.1-1 of Table 3.3.1 will be clarified to read as follows: "No PNPS calculation or analysis related to cumulative fatigue damage for steel cranes met the definition of TLAA in 10 CFR 54.3. The projected cycles for the PNPS reactor building crane are well below the cycle ranges given in CMAA-70. Steel cranes are evaluated as structural components in Section 3.5." This requires an amendment to the LRA.	Finnin, Ron	Pace, Ray	Accepted

Item	Request	Response	Lead	Support	Category
342	In Table 4.3-1, Maximum CUFs for Class I Components, note 2 addresses exclusion rules for ASME Code. Please explain what these rules are.	The transients on the RPV main steam, vent and instrument nozzles are mild and stresses remain below the endurance limit. The original CE (Combustion Engineering) vessel analysis demonstrates that the requirements of ASME Section III -1965 with summer 1966 Addenda (Original Construction Code), Paragraph N-415.1 Vessels Not Requiring Analysis for Cyclic Operation, were met. This was later confirmed to be the case in the Altran analysis. A mistake exists in Table 4.3-1 of the LRA. The recirculation outlet nozzle usage factor does not meet the criteria of paragraph N-415.1. LRA Table 4.3-1 will be revised to add the appropriate usage factor for the recirculation outlet nozzle. Note 2 will no longer be applied to the recirculation outlet nozzle. Note 2 will be revised to read as follows. Detailed fatigue analysis is not required since component meets the requirements of ASME Section III -1965 with summer 1966 Addenda (Original Construction Code), Paragraph N-415.1 Vessels Not Requiring Analysis for Cyclic Operation. This requires an amendment to the LRA.	Finnin, Ron	Pace, Ray	Accepted

Item	Request	Response	Lead	Support	Category
343	Section 4.3.1.3, Class 1 piping and components states all remaining RCS pressure boundary piping is designed and analyzed in accordance with ANSI B31.1. However, in section 4.3.3, on page 4.3-8, it implies that fatigue analysis exists for feedwater piping (which is part of the RCS pressure boundary piping designed and analyzed IAW B31.1.). Please clarify this discrepancy, since B31.1 does not require a fatigue analysis calculation.	Section 4.3.1.3 of the LRA is correct. PNPS has no site-specific fatigue analysis for the feedwater piping. Section 4.3.3 of the LRA is discussing the effects of the reactor coolant environment on fatigue. Entergy will remove the generic (NUREG-6260) values for the core spray safe end, the RR outlet nozzle and the feedwater piping from Table 4.3-3. There are no PNPS-specific analyses for these locations. See the response to Question 346A below for the PNPS commitment for performing EAF (environmentally adjusted fatigue) analyses. This requires an amendment to the LRA.	Finnin, Ron	Pace, Ray	Accepted

Item	Request	Response	Lead	Support	Category
344	Section 4.3.1.3, Class I piping and components second paragraph states that the design transients are tracked and evaluated to ensure that cycle limits are not exceeded, thereby assuring that CUFs do not exceed 1.0. It further states that continuation of this program, therefore, will ensure that the allowed number of transient cycles is not exceeded. Consequently, the TLAA (fatigue analyses) for Class 1 piping and components will remain valid for the period of extended operation in accordance with 10 CFR 54.2 1(c)(1)(i) or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). This by itself could be a true statement, however, cycle counting does not address the effects of environmental fatigue, which is not included here. Acknowledging that section 4.3.3 addresses environmental fatigue, please clarify how that section is tied into the conclusion made in section 4.3.1.3.	PNPS will add the following sentence at the end of Section 4.3.1.3: "The effects of the reactor coolant environment on fatigue are addressed in Section 4.3.3 of the LRA." The TLAA addressed by Section 4.3.1.3 is calculation of CUFs without accounting for the effects of reactor coolant environment. This TLAA remains valid for the period of extended operation as long as the analyzed number of transients is not exceeded. The calculation of CUFs accounting for the effects of the reactor coolant environment does not exist, as the current licensing basis does not require consideration of environmental fatigue factors. Since 10 CFR 54.3 defines TLAAs as licensee calculations and analyses, there is not a TLAA that considers environmental fatigue factors. To remove the perceived implication that exceeding the allowable number of transients would cause the CUFs to exceed 1.0, the following changes will be made to the LRA. LRA Section 4.3.1, page 4.3-4 will be modified as follows: "The PNPS Fatigue Monitoring Program ensures that the numbers of transient cycles experienced by the plant remain within the allowable numbers of cycles, and hence the component CUFs remain below their analyzed values." LRA Section 4.3.1.3, Second sentence of the second paragraph will be changed as follows: "The design transients are tracked and evaluated to ensure that cycle limits are not exceeded, thereby assuring that CUFs remain below their analyzed values."	Finnin, Ron	Pace, Ray	Accepted

Item	Request	Response	Lead	Support	Category
		This response requires an amendment to the LRA.			
345	Section 4.3.1.4, Feedwater Nozzle Fatigue states that this extrapolated usage factor for the feedwater nozzles, considering both the currently analyzed system design transients and rapid cycling through the period of extended operation, is thus <0.899. This number is not correct. Please explain how this number was calculated.	The Thermal Power Optimization Task Report T0302 updated the feedwater nozzle CUF to <1.0 based on the associated (1.5%) power uprate. The extrapolation in LRA section 4.3.1.4 is thus no longer valid. PNPS will modify the LRA to delete this extrapolation. PNPS will perform a new feedwater nozzle fatigue analysis prior to the period of extended operation. This commitment is Item 35 of the PNPS commitments for license renewal. This requires an amendment to the LRA.	Finnin, Ron	Pace, Ray	Accepted
346	Section 4.3.3, Effects of Reactor Water Environment on Fatigue Life. Please provide more details on your implementation plan: A. How will the further refinement of the fatigue analyses be performed? Will it consider finite element analyses? B. If an aging management program is used, please include a commitment to issue for NRC approval 24 months prior to entering period of extended operation. C. Will replacement be of the same material type?	A. Further refinement of the ASME Class 1 fatigue analysis for the RPV and nozzle locations will be performed considering the predicted number of transients at each location adjusted to the end of the extended license period using refined finite element evaluation as applicable. The refined analysis will account for environmental effects as applicable using the FEN methodology described by the GALL report or other industry Codes and Standards as approved by NRC. B. License renewal Commitment 31 includes a commitment to submit the aging management program to the NRC 24 months prior to the period of extended operation if the aging management program option is chosen. C. Appropriate replacement material will be selected in accordance with PNPS design control procedures, if replacement is a chosen option.	Finnin, Ron	Pace, Ray	Open – NRC Reviewing

Item	Request	Response	Lead	Support	Category
347	Table 4.3-3, Note 1 states "No PNPS-specific value was available; used generic value from NUREG/CR-6220." a. Wrong NUREG identified - should it be NUREG-6260? b. The NUREG-6260 CUF is based on the specific plant used in that NUREG and is dependent on that plant's piping configuration. That value cannot be used for PNPS calculation. Please justify how this value applies to PNPS unless the PNPS piping configurations are same as the NUREG-6260 plant or provide a PNPS specific CUF value.	A. Yes, this is a typo, it should be NUREG-6260. B. The CUF values from NUREG-6260 were intended as typical values used to predict the magnitude of the effect of considering the reactor coolant environment on fatigue for PNPS. PNPS will amend the LRA to remove the CUFs from Table 4.3-3 that are taken from NUREG-6260. See Item 346 for PNPS's commitment to perform additional environmentally adjusted fatigue analyses prior to the period of extended operation. This response requires an amendment to the LRA.	Finnin, Ron	Pace, Ray	Accepted
349	[3.4.1-W-01] In numerous line items in Tables 3.4.2-2, 3.3.2-14-3, 9, 10, 11, 17 and 18 of the Steam and Power Conversion System, the applicant credits TLAA - Metal Fatigue to manage the aging effect of metal fatigue (cumulative fatigue damage), and indicates that the evaluation of this TLAA is addressed in Section 4.3 of the LRA. However, it appears that the write-up of the Section 4.3 does not cover the discussion for most components. Please explain the discrepancy.	Listing TLAA – metal fatigue in the tables in Section 3 indicates that the conditions for fatigue were present and that they needed to be evaluated. Associated components were subsequently evaluated in LRPD-06, TLAA - Metal Fatigue. If the evaluation found no TLAA, it was not listed in Section 4 of the LRA. For clarification, Entergy will revise the Section 3 tables to remove the TLAA – metal fatigue entries whenever there was no associated TLAA discussed in Section 4 of the LRA. This item is closed to item 506.	Finnin, Ron	Pace, Ray	Closed

Item	Request	Response	Lead	Support	Category
350	[3.4.1-W-02] Section 3.4.2.2.2 (1) of the LRA (page 3.4-4), the applicant states: "Loss of material due to general, pitting and crevice corrosion for carbon steel piping, piping components, and tanks, exposed to treated water and for carbon steel piping and components exposed to steam is an aging effect requiring management in the steam and power conversion systems at PNPS, and is managed by the Water Chemistry Control – BWR and Periodic Surveillance and Preventive Maintenance (PSPM) Programs." Please clarify the above summary, regarding the use of PSPM program. Is the use of PSPM program is in lieu of the OTI program to verify the effectiveness of the Water Chemistry Control – BWR program or some of the AEM combination will be managed by using PSPM alone.	The Section 3.4.2.2.2 (1) further evaluation discussion is referenced by Table 3.4.1 items 3.4.1-2, 3.4.1-4 and 3.4.1-6. The discussion column entry of item 3.4.1-6 indicates that the PSPM program applies to the condensate storage tanks. Although the water in these tanks would be subject to the water chemistry controls – BWR program, the PSPM program is sufficient to manage loss of material and was the only program credited for these tanks. See the response to question 3.4.1-5 (item #353) which documents that the Water Chemistry Control - BWR program should have been credited along with the PSPM program for the condensate storage tanks. This requires a supplement/amendment to the LRA.	Lingenfelter, Jacque	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
351	[3.4.1-W-03] Why is OTI program not credited for those line items in Tables 3.4.2-x and Table 3.3.2-14-x (corresponding to VIII.E-33, condensate system, VIII.C-6, extraction steam system. VIII.D2-7, feedwater system, and VIII.B2-6, main steam system) that reference item 3.4.1-4?	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.4.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control-BWR, Water Chemistry Control- Auxiliary Systems and the Water Chemistry Control- Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
352	[3.4.1-W-04] Why is OTI program not credited for those line items in Table 3.3.2-14-x (corresponding to VIII.E-7, heat exchanger components in condensate system) that reference item 3.4.1-5?	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.4.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control-BWR, Water Chemistry Control- Auxiliary Systems and the Water Chemistry Control- Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
353	[3.4.1-W-05] The applicant references GALL item VIII.E-40 (steel tank in condensate system) for the condensate storage system carbon steel tank, as listed in LRA Table 3.4.2-1, (page 3.4-28), but takes credit of PSPM to manage the aging effect of loss of material. The GALL recommends using "Water Chemistry" and "OTI" programs for this component and AEM combination. Although the PSPM, as described in PNPS LRA B1.24, has more stringent inspection requirement than OTI, it does not include controlling water chemistry to minimize component exposure to aggressive environment. Please explain why relying on PSPM alone is sufficient for meeting the GALL's recommendations to manage the aging effect of loss of material for the condensate storage system carbon steel tank. The carbon steel tank listed in Table 3.3.2-14-10, feedwater system (page 3.3-171) and Table 3.3.2-14-11, feedwater heater drains and vents system (page 3.3-178), also reference GALL item VIII.E-40. Why is OTI program not credited for these line items that reference item 3.4.1-6.	Since the condensate storage tank contains fluid that is subject to the controls of the Water Chemistry Control - BWR Program, the program applies to the tank. The LRA will be clarified to explicitly credit the Water Chemistry Control - BWR Program in addition to PSPM with managing the effects of aging for the condensate storage tank surfaces exposed to the treated water environment. Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. As stated in LRA Table 3.4.1, the One-Time Inspection Program is credited to verify effectiveness of the water chemistry control program for line items that reference item 3.4.1-6. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control-BWR, Water Chemistry Control- Auxiliary Systems and the Water Chemistry Control- Closed Cooling Water programs. This item is closed to Item 372.	Orlicek, Jack	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
354	[3.4.1-W-06] Why is OTI program not credited for those line items in Table 3.3.2-14-35 (corresponding to VIII.A-14) that reference item 3.4.1-7?	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376			
355	[3.4.1-W-07] Why is OTI program not credited for those line items in Table 3.2.2-4, HPCI System, (page 3.2-49) and Table 3.2.2-5, RCIC System, (page 3.2-62) (corresponding to VIII.E-10) that reference item 3.4.1-9?	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.4.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control-BWR, Water Chemistry Control- Auxiliary Systems and the Water Chemistry Control- Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
356	[3.4.1-W-08] Why is OTI program not credited for those line items in Table 3.3.2-5, Station Blackout Diesel, (page 3.3-90) and Table 3.3.2-6, Security Diesel Generator System, (page 3.3-102) (corresponding to VIII.G-15) that reference item 3.4.1-10?	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376.			
357	[3.4.1-W-09] Why is OTI program not credited for those line items in Table 3.4.2-2, Main Condenser and MSIV Leakage Pathway, Table 3.3.2-14-9, Extraction Steam System, Table 3.3.2-14-16, HPCI, Table 3.3.2-14-18, Main Steam System, and Table 3.3.2-14-19, Offgas and Augmented Offgas System that reference item 3.4.1-137	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control-BWR, Water Chemistry Control- Auxiliary Systems and the Water Chemistry Control- Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
358	[3.4.1-W-10] Since notes "A" and "C" were used in various Table 3.3.2-14-x line items, which reference item 3.4.1-14, why OTI program is not credited for those lines?	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
359	[3.4.1-W-11] Since note "C" was used in Table 3.3.2-14-4, Condensate Demineralizer System line items, which reference item 3.4.1-15, why OTI program is not credited for those lines?	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
360	[3.4.1-W-12] Since notes "A" and "C" were used in Table 3.4.2-14, Condensate Storage System and various Table 3.3.2-14-x line items which reference item 3.4.1-16, why OTI program is not credited for those lines?	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
361	3.4.1-W-13 Why is OTI program not credited for those line items in Table 3.4.2-14-35, Turbine Generator and Auxiliary System (corresponding to VIII.A-3) that reference item 3.4.1-18?	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376.			

Item	Request	Response	Lead	Support	Category
362	[3.4.1-W-14] Why is OTI program not credited for those line items in Table 3.4.2-14-35, Turbine Generator and Auxiliary System (corresponding to VIII.A-9 and VIII.G-3) that reference item 3.4.1-19?	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376.			

Item	Request	Response	Lead	Support	Category
363	[3.4.1-W-15] Table 3.4.1, item 3.4.1-20 for steel tanks exposed to air - outdoor. PNPS uses the System Walkdown Program to manage the aging effect of loss of material due to general, pitting, and crevice corrosion through the use of periodic visual inspections. The GALL Report recommends the AMP of Aboveground Steel Tanks Program (GALL XI. M29) to be used. While the System Walkdown Program may be an acceptable alternate for Aboveground Steel Tanks AMP for inspection, the Aboveground Steel Tanks AMP has some program attributes not addressed in the System Walkdown Program. For examples, the System Walkdown Program is silent on the preventive actions, but the Aboveground Steel Tanks AMP includes preventive measures to mitigate corrosion by protecting the external surface of steel tanks with paint or coatings in accordance with standard industry practice. Please explain how the preventive actions and detection of aging effects at inaccessible locations such as the tank bottom surface will be performed for the subject tanks using the System Walkdown AMP.	Preventive Actions: Protective coatings were applied during fabrication or installation of the subject tanks well before development of aging management programs for license renewal. The System Walkdown Program entails visual inspections of external surfaces of carbon steel tanks to identify degradation of coatings, sealants, and caulking plus indications of leakage. The site corrective action process would require evaluation and repair, if necessary, of degraded coatings or caulking. Detection of Aging Effects: The condensate storage tank is a nonsafety-related carbon steel tank that contains treated water. The tank sits on a concrete pad with a sand and oil base cushion that is designed to remove moisture from the bottom of the tank to minimize the potential for corrosion. The internals of the tank which are subjected to continuous wetting are periodically inspected for corrosion and pitting including inaccessible areas (under water) as documented in site procedure NE8.02. This same procedure also inspects exterior caulking at the base of the tank for cracking in order to prevent water accumulation under the tank. This procedure is credited in the Periodic Surveillance and Preventive Maintenance program section 4.17 and Attachment 3 of LRPD-02 for management of the external and internal surfaces of this tank. Any degradation of the internals of the tank will result in a condition report and an evaluation of the extent of the condition, which may involve ultrasonic examination to determine remaining thickness. Because the environment inside the tank is significantly	Ford, Bryan	Ivy, Ted	Open – NRC Reviewing

Item	Request	Response	Lead	Support	Category
		harsher than the environment on the underside of the tank, internal degradation would be expected long before corrosion on the outside. If degradation occurs on the inside (including the bottom), examinations of the degraded areas would require a determination of the remaining wall thickness which ensures the integrity of the tank is maintained. However, to ensure that significant degradation on the bottom of the condensate storage tank is not occurring, PNPS commits to perform a one-time ultrasonic thickness examination in accessible areas on the bottom of the condensate storage tank prior to the period of extended operation. Standard examination and sampling techniques will be utilized. This is commitment number 36 This requires an amendment to the LRA.			
364	[3.4.1-W-16] Table 3.4.1, item 3.4.1-22, for steel bolting and closure bolting exposed to air with steam or water leakage, air - outdoor (external), or air - indoor uncontrolled (external). The applicant references GALL items VIII.H-1 and H-4 for the closure bolting in various Steam and Power Conversion System, as listed in LRA Table 3.4.2-1 and 3.3.2-14-x, but takes credit for the System Walkdown Program to manage the aging effect of loss of material. The GALL Report recommends AMP XI.M18, Bolting Integrity Program, which includes a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in the EPRI report NP-5769. Please justify how the additional attributes listed in GALL AMP XI.M18 for aging management of closure bolting are addressed in the System Walkdown Program.	A Bolting Integrity Program will be developed that will address the aging management of bolting in the scope of license renewal. The Bolting Integrity Program will be implemented prior to the period of extended operation in accordance with commitment number 32. This requires an amendment to the LRA to include descriptions of the Bolting Integrity Program in Appendices A and B and to identify where the program is applicable. This item is closed to Item 373.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
365	[3.6.2.2-N-01] In LRA Table 3.6.2-1 under Cable connections (metallic parts), you have stated that no aging effects and no AMP is required. NUREG-1801, Revision 1, AMP XI.E6, "Electrical Cable Connection not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specifies that connections associated with cables within the scope of license renewal are part of this program, regardless of their associated with active or passive components. Also, refer to pages 107, 256, and 257 of NUREG-1833, "Technical Bases for Revision to the License Renewal Guidance Documents," for additional information regarding AMP XI.E6. Provide a basis document including an AMP with the ten elements for cable connections or provide a justification for why an AMP is not necessary.	The PNPS electrical AMR, AMRE-01, in section 3.4.1 states for cable connections (metallic parts), "An evaluation of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation stressors for the metallic parts of electrical cable connections identified no aging effects requiring management. • Metallic parts of electrical cable connections potentially exposed to thermal cycling and ohmic heating are those carrying significant current in power supply circuits. Typically, power cables are in a continuous run from the supply to the load. Therefore, the connections are part of an active component and not subject to aging management review. • The fast action of circuit protective devices at high currents mitigates stresses associated with electrical faults and transients. In addition, mechanical stress associated with electrical faults is not a credible aging mechanism because of the low frequency of occurrence for such faults. Therefore, electrical transients are not applicable stressors. • Metallic parts of electrical cable connections exposed to vibration are those associated with active components that cause vibration. Because they are part of an active component, they are not subject to aging management review. • Corrosive chemicals are not stored in most areas of the plant. Routine releases of corrosive chemicals to areas inside plant buildings do not occur during plant operation. Such a release, and its effects, would be an event, not an effect of aging. In addition, their location inside active components protects the metallic parts of electrical cable connections from contamination. Therefore, this stressor is not applicable.	Stroud, Mike	Das, Swapan	Open -- NRC Reviewing

Item	Request	Response	Lead	Support	Category
		• Oxidation and corrosion usually occur in the presence of moisture or contamination such as industrial pollutants and salt deposits. Enclosures or splice materials protect metal connections from moisture or contamination. Since bolted connections are considered part of an active device and are maintained by the plant Maintenance Rule program, there are no aging effects requiring management for bolted connections of cable systems. Since PNPS maintains cable connections under a current maintenance program and has no indication of an aging mechanism due to loose connections, no AMP is needed in addition to the Maintenance Rule program.			

Item	Request	Response	Lead	Support	Category
366	[3.6.2.2-N-02] In LRA Table 3.6.2-1 under high voltage insulator (SBO), you have stated that no aging effects and no AMP is required. You further stated, in Section 3.6.2.2.2 of the LRA, that PNPS is located near the seacoast where salt spray is considered. However, salt spray buildup is a short-term concern based on local weather conditions (event driven). Therefore, you have concluded that surface contamination is not an applicable aging mechanism for high voltage insulators at PNPS. NUREG 1800, Rev. 1, Standard Review Plan for Review of License Renewal Application for Nuclear Power Plant, Section 3.6.2.2.2 identified degradation of high voltage insulator in presence of salt deposits or surface contamination. Various airborne materials such as dust, salt and industrial effluent can contaminate insulator surfaces. A large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flash over. Surface contamination can be problem in areas where there are greater concentration of airborne particles such as near facilities that discharge soot or near the sea coast where salt spray is prevalent. Industry operating experience identified the potential of loss of offsite power due to salt deposition to switchyard insulators. On March 17, 1993, Crystal River Unit 3 experienced a loss of the 230 kV switchyard (normal offsite power to safety-related busses) when a light rain caused arcing across salt-laden 230 kV insulators and opened breakers in switchyard. In March 1993, the Brunswick Unit 2 switchyard experienced a flash over of some high-voltage insulators. The incident was attributed to a winter storm in the area. Since 1982, Pilgrim station has also experienced several loss of offsite power events when ocean storms deposited salt on the 345 kV switchyard causing the insulator to arc to ground. In light of	As shown by the OE (Operating Experience) cited in this question, flashover due to salt contamination of insulators is caused by events, typically storms, regardless of the age of the insulators. This is clearly not an effect of aging. Therefore, surface contamination is not an applicable aging mechanism for high-voltage insulators at PNPS. Since the condition is caused by severe weather conditions unrelated to aging, an aging management program is not appropriate to address this concern. However, while salt spray buildup is a short-term concern based on local weather conditions (event-driven), such buildup can cause problems with the offsite power supply system. Because of this operating experience, PNPS has applied Sylgard (RTV silicone) coatings to some switchyard insulators to reduce flashover. The addition of Sylgard to the insulators has reduced the likelihood of insulator flashover. System walkdowns are performed at least once per refueling cycle and are normally performed more frequently to do a visual inspection of the switchyard high-voltage insulators that are in-scope of license renewal in accordance with EN-DC-178. These walkdowns will continue to be performed into the period of extended operation. LRPD-02 will be revised as follows: The System Walkdown Program will be revised to include the visual inspection of high-voltage insulators in-scope of license renewal.	Stroud, Mike	Das, Swapan	Accepted

Item	Request	Response	Lead	Support	Category
	these industry and plant operating experiences, provide justification of why an AMP is not necessary.				
367	[3.6.2.2-N-03] In LRA, Table 3.6.2-1, under switchyard bus and connections, you have stated that no aging effects requiring management and no AMP is required. NUREG 1800, Rev. 1, Standard Review Plan for Review of License Renewal Application for Nuclear Power Plant, Section 3.6.2.2.3 identifies loss of preload is an aging effect for switchyard bus connections. Torque relaxation for bolted connection is a concern for switchyard bus connections and transmission conductor connections. An electrical connection must be designed to remain tight and maintain good conductivity through a large temperature range. Meeting this design requirement is difficult if the material specified for the bolt and the conductor are different and have different rates of thermal expansion. For example, copper or aluminum bus/conductor materials expand faster than most bolting materials. If thermal stress is added to stresses inherent at assembly, the joint members or fasteners can yield. If plastic deformation occurs during thermal loading (i.e., heatup) when the connection cools, the joint will be loose. EPRI document TR-104213, "Bolted Joint Maintenance & Application Guide," recommends inspection of bolted joints for evidence of overheating, signs of burning or discoloration, and indication of loose bolds. Provide a discussion for why torque relaxation for bolted connections of switchyard bus is not a concern for PNPS.	At PNPS, bus to bus connections are welded instead of bolted. Switchyard buses are connected by flexible connectors to insulators and active components. Since switchyard bus is typically under a constant load, thermal cycling that could cause torque relaxation is infrequent. With no connections to vibrating equipment, vibration is not an aging mechanism for switchyard bus. The switchyard connections to the startup transformer are part of the active assembly maintained by the plant maintenance program. Therefore, torque relaxation is not an aging effects requiring management for switchyard bus. In addition, thermography is performed at least once every 6 months to maintain the integrity of the connections. This program will continue into the period of extended operation.	Stroud, Mike	Das, Swapan	Closed

Item	Request	Response	Lead	Support	Category
368	[3.6.2.2-N-04] In LRA, Section 3.6.2.2.3, you have stated that PNPS does not utilize transmission conductors in the circuits for recovery of offsite power following an SBO. Describe SBO recovery paths for PNPS. Confirm that no transmission conductors are utilized in the circuits for recovery paths. Support these answers with a main one line diagram.	The preferred source of offsite power comes from the 345kV switchyard. The feed from the switchyard breakers, 352-2 and 352-3, travels by switchyard bus to the startup transformer, X4, and then travels by underground cables to the safety buses in the plant. The alternate offsite power source comes from the 23kV switchyard and travels from breaker 252 by underground cables to the shutdown transformer, X13, and then by underground cables to bus A8. From A8 the power travels by underground cables to the safety buses in the plant. Neither PNPS recovery path for offsite power uses transmission conductors. These paths are shown on Figure 2.5-1 of the LRA.	Stroud, Mike	Das, Swapan	Closed
369	[3.6.2.2-N-05] 10 CFR 54.4 (a)(3) requires, in part, that all systems, structures, and components (SSCs) relied on in safety analyses or plant evaluation to perform a function that demonstrates compliance with the commission's regulations for station black out (10 CFR 50.63) are within the scope of license renewal. What is your alternate ac (AAC) source used to meet SBO requirements? Are all SSCs (including electrical components) associated with AAC sources included in the scope of licensee renewal? If they are not, explain why not. If they are, provide an AMR for long-lived, passive SSCs associated with the AAC sources.	At PNPS, the station blackout diesel generator provides the alternate AC power source. All SSCs associated with the AAC diesel are in scope for license renewal. The LRA provides the aging management review results for long-lived, passive SSCs associated with the AAC power source in each discipline section of the LRA.	Stroud, Mike	Das, Swapan	Closed

Item	Request	Response	Lead	Support	Category
370	[3.6.2.2-N-06] Are all electrical and I&C containment penetrations EQ? If not, provide AMRs and AMPs for non-EQ electrical and I&C containment penetrations. The AMRs should include both organic (XLPE, XLPO, and SR internal conductor/pigtail insulation, etc.,) as well as inorganic material (such as cable fillers, epoxies, potting compounds, connector pins, plugs, and facial grommets).	The PNPS LRA Section 3.6.2.2 will be revised to read as follows: "Some of the penetration assemblies at PNPS are not EQ. The non-EQ penetration assemblies are subject to aging management review. The aging management review is provided in AMRE-01 and the AMP for penetration assembly pigtails is provided in the non-EQ insulated cables and connections program will manage the aging effects of the penetration assembly cables and connections. Table 3.6.2-1 includes the electrical penetration conductors and connections in the line item for electrical cables and connections not subject to 10 CFR 50.49 – EQ." The structural report for bulk commodities, AMRC-06, addresses the penetration assembly components, seals and sealing elements that form the radiological control barrier for containment in Table 3.5.2-1. This requires an amendment to the LRA.	Stroud, Mike	Das, Swapan	Accepted

Item	Request	Response	Lead	Support	Category
371	[G.3.3.1-P-01] Tables 3.3.2.14-1 through 3.3.2.14-35 address non-safety related components affecting safety related systems. However, these tables address all such systems in section 3.3, Auxiliary Systems, even though some of these systems belong to section 3.2, ESF Systems, and section 3.4, Steam and Power Conversion (S&PC) Systems. Tables 3.3.14-7, 14-16, 14-25, and 14-28 are for systems that belong to Section 3.2; and tables 3.3.14-1, 14-3, 14-5, 14-9, 14-10, 14-11, 14-17, and 14-18 are for systems that belong to Section 3.4. The Table 1 item reference also specifies Tables 3.2.1 and 3.4.1. The audit report and the SER are based on systems as defined in GALL Report sections of ESF, Auxiliary, and S&PC systems. As written in the LRA, it will make the audit report and SER confusing because the ESF systems section 3.2 write-up will include Tables from section 3.3, and the S&PC systems section 3.4 write-up will include Tables from section 3.3. Different reviewers write these sections. Please justify why the non-safety systems associated with ESF and S&PC systems were included in the Auxiliary system section.	Section 14 includes all the systems that have intended functions that meet 10 CFR 54.4(a)(2) for physical interaction. To indicate individual systems included in the aging management review for (a)(2), Table 3.3.2-14 is subdivided by system. For example, Table 3.3.2-14-1 is for the circulating water system, a system which only has components included for (a)(2). For the core spray system, Table 3.3.2-14-7 shows the components included for (a)(2) but since the system is also in scope for other reasons, Table 3.3.2-2 shows the components included for 54.4(a)(1) and (a)(3). The aging management review of the systems that have functions that met 10 CFR 54.4(a)(2) for physical interaction was done separately from the review of systems with intended functions that met 10 CFR 54.4 (a)(1) or (a)(3). The results of this review were presented separately so that they could be reviewed separately on the basis of physical proximity rather than system function. This allows a reviewer to clearly distinguish which component types in a system were included for 10 CFR 54.4(a)(2) for physical interaction. Since most of these systems are auxiliary systems they were added as part of the auxiliary systems section.	Fronabarger, Don	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
372	[G.3.3.1-P-02] Discrepancy between Table 3.3.1 line items and Tables 3.3.2-X for those line items that credit water chemistry or oil analysis program and a verification program such as one-time inspection (OTI) program. The Table 1 item is consistent with the GALL report and correctly credits the chemistry program and the OTI program or for plant-specific program also credits chemistry and OTI programs. However, the Table 2 line items that reference these Table 1 line items do not credit the OTI program. These Table 2 line items however have a footnote 'A', or 'C' which states that it is consistent with the MEAP combination in the GALL Report. Please justify why the OTI program is not credited in Table 2, even though it is credited in Table 1 and footnote 'A' implies total consistency with GALL for MEAP combination.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs.	Fronabarger, Don	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
373	[G.3.3.1-P-03] PNPS does not include Bolting Integrity Program in the LRA, however credits other programs as alternate to the bolting integrity program. The GALL Report AMP XI.M18, Bolting Integrity Program provides several recommendations in the 10-element evaluation, specifically recommendations associated with preventive actions such as selection of bolting material, use of lubricants and sealants and additional recommendations of NUREG-1339. Some of the alternate programs may be acceptable for inspection, however, they do not address the preventive actions. Please clarify how PNPS meets these recommendations when using alternate programs or please credit a Bolting Integrity Program for the various Table 2 line items as appropriate. For section 3.3, this applies to Table 3.3.1, line items 3.3.1-19, 3.3.1-27, 3.3.1-42, 3.3.1-43, 3.3.1-58, and 3.3.1-78.	A Bolting Integrity Program will be developed that will address the aging management of bolting in the scope of license renewal. A copy of the aging management program basis document for the Bolting Integrity Program will be provided for review with the LRA supplement. The Bolting Integrity Program will be implemented prior to the period of extended operation in accordance with commitment number 32. This requires an amendment to the LRA to include descriptions of the Bolting Integrity Program in Appendices A and B and to identify where the program is applicable.	Fronabarger, Don	Woods, Steve	Accepted

Item	Request	Response	Lead	Support	Category
374	[T.3.3.1-P-01] Table 3.3.1, item 3.3.1-1, for steel cranes with an aging effect of cumulative fatigue damage, the GALL recommends TLAA to be evaluated for structural girders of cranes. The discussion section states that this line item was not used in section 3.3, however steel cranes are evaluated in section 3.5. Tables 3.5.2-2 and 3.5.2-4 address cranes but for an aging effect of loss of materials. Cumulative fatigue damage of cranes is not addressed in section 3.5 or in the TLAA section 4.7 (plant specific TLAA). Also see TLAA question. Please explain where this line item is addressed in the LRA.	As defined in 10 CFR 54.3, a TLAA is a licensee calculation or analysis that, among other things, involves time-limited assumptions defined by the current operating term. There is no analysis for steel cranes at PNPS that satisfies the definition. CMAA-70 defines allowable stress range based on joint category and service class. Service class is based on load class (mean effective load factor) and number of cycles. However, the number of cycles is NOT based on 40 years of operation of this crane. The anticipated cycles for the PNPS reactor building crane are well below any of the cycle ranges given in CMAA-70. Based on realistic estimates and the historical rate of use of the cranes to date, the PNPS reactor building and turbine building cranes would take over 350 years to reach the minimum cycle range for CMAA-70. Consequently there is no TLAA associated with crane load cycles.	Finnin, Ron	Chan, Laris	Accepted

Item	Request	Response	Lead	Support	Category
375	[T.3.3.1-P-02] Table 3.3.1, item 3.3.1-5, for heat exchanger exposed to treated water > 60C (>140F), discussion states that OTI will be used as verification program for water chemistry. However, for those line items in Table 3.3.2-3 where item 3.3.1-5 is referenced, OTI program is not credited. See question G.3.3.1.2 above.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
376	[T.3.3.1-P-03] Table 3.3.1, Item 3.3.1-14 for steel components exposed to lubricating oil, GALL report recommends lubricating oil analysis program and OTI as a verification program. However, in the discussion section only the oil analysis program is credited. Section 3.3.2.2.7, item 1 states that operating experience at PNPS has confirmed the effectiveness of this program in maintaining contaminants within limits such that corrosion has not and will not affect the intended functions of these components. Please explain how PNPS can make this statement if inspection has not been performed.	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
377	[T.3.3.1-P-04] Table 3.3.1, item 3.3.1-17 for steel elements exposed treated water discussion states that OTI will be used as verification program for water chemistry. Refer to question T.3.3.1.2 and G.3.3.1.2. This applies to several line items in various Table 2's that reference item 3.3.1-17.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
378	[T.3.3.1-P-05] Table 3.3.1, item 3.3.1-18 for steel and SS diesel engine exhaust piping, in the discussion column references section 3.3.2.2.7 item 3 for further evaluation. Section 3.3.2.2.7 item 3 states that the carbon steel diesel exhaust piping and components in the fire protection system is managed by the Fire Protection Program. The Fire Protection Program uses visual inspections of diesel exhaust piping and components to manage loss of material. However, Appendix B.1.13.1 program description which identifies the system/commodities in scope for inspection does not include the inspection of the diesel exhaust piping and components. There is no enhancement identified in the program write-up to include this inspection during the period of extended operation. Please explain this discrepancy between section 3.3.2.2.7 item 3 and the AMP B.1.13.1 program description or include this inspection in the AMP as an enhancement.	Enhancements will be made to the Fire Protection program to credit existing or implement new preventive maintenance tasks for the fire pump diesel to ensure that all aging effects identified in Table 3.3.2-9 line items that apply to the fire pump diesel components are adequately managed and intended functions are maintained without crediting the detection of leakage as managing an aging effect. This requires an amendment to LRA appendices A and B.	Fronabarger, Don	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
379	[T.3.3.1-P-06] Table 3.3.1, item 3.3.1-21 for steel components exposed to lubricating oil. This is the same issue as in question T.3.3.1.3 above, except the section is 3.3.2.2.9, item 2.	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376.			
380	[T.3.3.1-P-07] Table 3.3.1, Item 3.3.1-23 for SS heat exchanger components exposed to treated water. This is the same issue as in question T.3.3.1.2 above, except the section is 3.3.2.2.10, item 2.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
381	[T.3.3.1-P-08] Table 3.3.1, item 3.3.1-24 for SS and aluminum components exposed to treated water. This is the same issue as in question T.3.3.1.2 above, except the section is 3.3.2.2.10, item 2. There are over 80 line items associated with this in different table 2s.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
382	[T.3.3.1-P-09] Table 3.3.1, item 3.3.1-26 for copper alloy components exposed to lubricating oil. This is the same issue as in question T.3.3.1.3 above, except the section is 3.3.2.2.10, item 4.	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376.			
383	[T.3.3.1-P-10] Table 3.3.1, item 3.3.1-30 for SS components exposed to sodium pentaborate solution. This is the same issue as in question T.3.3.1.2 above, except the section is 3.3.2.2.10, item 8.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
384	[T.3.3.1-P-11] Table 3.3.1, item 3.3.1.33 for SS components exposed to lubricating oil. This is the same issue as in question T.3.3.1.3 above, except the section is 3.3.2.2.12, item 2.	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these. components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376.			
385	[T.3.3.1-P-12.1] Table 3.3.1, item 3.3.1-37 for SS components exposed to treated water >60C (>140F). This line item applies to RWCU system and GALL Report recommends AMP XI.M25, BWR Reactor Water Cleanup System. The applicant states "Supplement 1 to GL 88-01 states that IGSCC inspection of RWCU piping outside of the containment isolation valves is recommended only until actions associated with GL 89-10 on motor operated valves are completed. Since PNPS has satisfactorily completed all actions requested in NRC GL 89-10, the Water Chemistry Control BWR Program is used in lieu of the BWR Reactor Water Cleanup System Program to manage this potential aging effect." However, the AMP also states that in addition to meeting this criterion, piping is made of material that is resistant to IGSCC. Please confirm what grade of stainless material is used and justify that it is resistant to IGSCC.	Original Type 304 stainless steel piping and fittings between drywell penetration X-14 and the 6" x 4" reducer downstream of MO-1201-5 were replaced with type 316L stainless steel.	Taylor, Andy	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
386	[T.3.3.1-P-12.2] Same issue as question T.3.3.1.2 above also applies here where OTI is not credited in Table 2 line items where 3.3.1-37 is referenced.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
387	[T.3.3.1-P-13] Table 3.3.1, item 3.3.1-38 for SS components exposed to treated water >60C (>140F). This is the same issue as in question T.3.3.1.2 above.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.3.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
388	[T.3.3.1-P-14] Table 3.3.1, item 3.3.1-40 for steel tank in diesel fuel oil system exposed to air-outdoor external environment. The GALL Report recommends AMP XI.M29 Aboveground Steel Tanks, however PNPS is crediting a different program, System Walkdown Program. This program is consistent with GALL Report AMP XI.M36, External Surfaces Monitoring. While the System Walkdown Program is an acceptable alternate for Aboveground Steel Tanks AMP for inspection, however, the Aboveground Steel Tanks AMP has some preventive actions associated with it that are not addressed in the System Walkdown Program. Furthermore, the GALL AMP specifies wall thickness measurement of tank bottom if it is supported on earthen or concrete foundations. Please clarify if the steel tanks are coated with protective paint or coating in accordance with industry practice, and whether sealant or caulking is applied at the interface edge between the tank and the foundation as per the GALL AMP XI.M29. Please state how the tank is supported.	No carbon steel tanks in the fuel oil system exposed to air – outdoor are included in scope for license renewal. The LRA will be amended to remove the line item in table 3.3.2-7 for carbon steel tanks exposed to air-outdoor . The discussion for line item 3.3.1-40 will be amended to state the line item is not used. This requires a supplement/amendment to the LRA.	Nichols, Bill	Chan, Laris	Accepted
389	[T.3.3.1-P-15] Table 3.3.1, item 3.3.1-43, for steel bolting and closure bolting exposed to air – indoor uncontrolled (external) or air – outdoor (External). The GALL Report recommends AMP XI.M18,Bolting Integrity program, however PNPS is crediting a different program, System Walkdown Program. PNPS indicates that the system walkdown program is similar to XI.M36, External Surfaces Monitoring Program. However, the XI.M36 AMP does not have any preventive actions, whereas the Bolting Integrity Program considers preventive action. Please justify how the preventive actions of GALL AMP XI.M18 are addressed in the system walkdown program.	A Bolting Integrity Program will be developed that will address the aging management of bolting in the scope of license renewal. The Bolting Integrity Program will be implemented prior to the period of extended operation in accordance with commitment number 32. This requires an amendment to the LRA to include descriptions of the Bolting Integrity Program in Appendices A and B and to identify where the program is applicable. This item is closed to item 373.	Fronabarger, Don	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
390	[T.3.3.1-P-16] Table 3.3.1, item 3.3.1-58, for steel external surfaces exposed to air – indoor uncontrolled (external), air outdoor (external), and condensation (external). For those line items in Table 2's where this Table 1 line item is referenced for bolting, same issue as question T.15 should be addressed. In Table 3.3.2-10, LRA page 3.3.-123, for tank in Halon system, which references line item 3.3.1-58, Fire Protection Program is credited. Please justify why the Fire Protection Program was not identified in the discussion column of Table 3.3.1, item 3.3.1-58 or supplement the LRA to include this program	A Bolting Integrity Program will be developed that will address managing the effects of aging on bolting in the scope of license renewal. The Bolting Integrity Program will be implemented prior to the period of extended operation in accordance with commitment number 32. The LRA will be clarified to include Fire Protection Program in the discussion for Item 3.3.1-58 of Table 3.3.1. The revised discussion text will read as follows: "The System Walkdown Program manages loss of material for external surfaces of steel components. For some fire protection system components, the Fire Protection Program will manage loss of material." The Note for the related line in Table 3.3.2-10 (steel halon tank exposed to air) will be changed from "B" to "E". This requires an amendment to the LRA to include descriptions of the Bolting Integrity Program in Appendices A and B and to identify where the program is applicable. This first part of this item is closed to Item 373. The Fire Protection portion of this item requires an amendment to the LRA.	Lingenfelter, Jacque	Woods, Steve	Accepted

Item	Request	Response	Lead	Support	Category

391	[T.3.3.1-P-17]
	
	Table 3.3..1, item 3.3.1-61, for elastomer fire barrier penetration seals exposed to air – outdoor or air indoor uncontrolled. PNPS credits Fire Protection Program and states in the discussion column that this line item was not used in the auxiliary systems tables. Fire barrier seals are evaluated as structural components in Section 3.5. Cracking and the change in material properties of elastomer seals are managed by the Fire Protection Program.
	
	However, in section 3.5, Table 3.5.2-6, Bulk Commodities, on pages 3.5-82, and 3.5-83, where line item 3.3.1-61 is referenced, PNPS credits the Fire Protection Program and the Structures Monitoring program. However, line item 3.3.1-61 does not credit structures monitoring program. As a matter of fact, the Structures Monitoring Program is enhanced to add guidance for inspection of elastomer seals, etc. Please clarify if both programs are credited for managing aging effects for penetration seals as stated in Table 3.5.2-6, and if so, please supplement the LRA to include the Structures Monitoring program in Table 3.3.1, item 3.3.1-61.
		In Table 3.5.2-6 on Page 3.5-82 of the LRA, the aging effects for the elastomer components penetration sealant and seismic joint filler in a protected from weather environment are cracking and change in material properties. Depending on the specific application, the Fire Protection Program or the Structures Monitoring Program will manage the effects of aging. For clarification, these component line items will be separated into individual line items as follows.
		
		Delete the following line items:
		Penetration sealant(fire rated, flood, radiation) // EN, FB, FLB, PB, SNS // Elastomer // Protected from weather // Cracking Change in material properties // Fire protection/Structures Monitoring // III.A6-12 (TP-7) // 3.5.1-44 // C
		
		Seismic joint filler // FB, SNS // Elastomer // Protected from weather // Cracking Change in material properties // Structures Monitoring, Fire Protection // VII.G-1 (A-19) // 3.3.1-61 // C
		
		Add the following line items:
		Penetration sealant (fire rated) // EN, FB, PB, SNS // Elastomer // Protected from weather // Cracking Change in material properties // Fire Protection // VII.G-1(A-19) // 3.3.1-61 // B
		
		Penetration sealant (flood, radiation) // EN, FLB, PB, SNS // Elastomer // Protected from weather// Cracking Change in material properties // Structures Monitoring // III.A6-12 (TP-7) // 3.5.1-44 // C
		
		Seismic isolation joint // FB, SNS // Elastomer // Protected from weather // Cracking Change in material properties // Fire protection // VII.G-1 (A-19) // 3.3.1-61 //
			Lingenfelter, Jacque	Chan, Laris	Accepted

Item	Request	Response	Lead	Support	Category
		D Seismic isolation joint // SNS // Elastomer // Protected from weather // Cracking Change in material properties // Structures monitoring // III.A6-12 (TP-7) // 3.5.1-44 // C This requires an amendment to the LRA.			
392	[T.3.3.1-P-18] Table 3.3.1, item 3.3.1-64 for steel piping, piping components, and piping elements exposed to fuel oil. The intent of this line is to address the diesel-driven fire pump, which is why the Fire Protection Program is recommended by the GALL Report. PNPS states that this line item was not used. Loss of material of steel components exposed to fuel oil was addressed by other items including line items 3.3.1 20 and 3.3.1 32. The Fire Protection program specifies that the diesel driven fire pump be periodically tested to ensure that the fuel supply line can perform its intended function. PNPS B.1.13.1 has not taken any exception to this test and is identified as being consistent with the GALL program. However, B.1.13.1, Fire Protection program is not credited in line item 3.3.1 20. Please clarify if PNPS has a diesel driven fire pump and if not, should an exception be taken to the GALL Report AMP. If PNPS does have a diesel driven fire pump, where in the LRA section 3.3 is it addressed and is the Fire Protection program credited.	PNPS has a diesel driven fire pump with components addressed in Table 3.3.2-9. The fuel oil supply to the diesel driven fire pump is included in Table 3.3.2-7. The line item of carbon steel piping with a fuel oil internal environment in Table 3.3.2-7 for the fuel supply line does not credit the Fire Protection Program. Although the programs credited in Table 3.3.2-7 for the fuel supply line provide an acceptable alternative approach to manage the effects of aging, in order to achieve consistency with NUREG-1801 the LRA will be revised to credit the Fire Protection Program. LRA Table 3.3.2-7 will be revised to add an additional line item to credit the Fire Protection Program to manage the fuel supply line in addition to the Diesel Fuel Monitoring Program. This will also require a change to line item 3.3.1-64 since the new line item will specify 3.3.1-64 as the Table 1 item. This requires an amendment to the LRA.	Fronabarger, Don	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
393	[T.3.3.1-P-19] Table 3.3.1, item 3.3.1-72 for steel HVAC ducting and components internal surfaces exposed to condensation (Internal). However, there is only line in Table 2 where this Table 1 line item is referenced. This line item is in Table 3.3.2-3, RBCCW system and the component is heat exchanger housing. PNPS states in the discussion column of line 3.3.1-72 that loss of material of steel component internal surfaces exposed to condensation is managed by the System Walkdown Program. The System Walkdown Program manages loss of material for external carbon steel components by visual inspection of external surfaces. For systems where internal carbon steel surfaces are exposed to the same environment as external surfaces, external surfaces condition will be representative of internal surfaces. Thus, loss of material on internal carbon steel surfaces is also managed by the System Walkdown Program. Please clarify how PNPS concluded that the internal surface of the heat exchanger is the same as the external surface in the RBCCW system.	The internal components of the heat exchanger housing have the potential for being exposed to a combination of low temperature closed cooling water and high dewpoint indoor drywell air which could result (though not expected) in condensation on the cooling coil that would be collected in the bottom of the housing. Condensation was also identified on the un-insulated external surfaces of the heat exchanger housing due to the potential of the housing surface temperature downstream of the cooling coil being less than or equal to the dew point of the surrounding air in the drywell. These environments were conservatively identified even though the expected environment would be indoor air with no condensation since the cooling water temperature is normally maintained at ~ 80°F. System Walkdown was credited because the expected environment for both the internal and external surfaces would be the same in either case.	Orlicek, Jack	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
394	[T.3.3.2-P-01] Component types filter housing and turbo charger in Table 3.3.2-9, Fire Protection - Water system and piping in Table 3.3.2-10, *Fire Protection - Halon system* reference Table 3.2.1, item 3.2.1-32. This Table 1 line item addresses steel piping and ducting components and internal surfaces exposed to air-indoor uncontrolled (internal) environment. Discussion column of item 3.2.1-32 credits System Walkdown, Periodic Surveillance and Preventive Maintenance, and One-Time Inspection programs. However, the Table 3.3.2-9 and Table 3.3.2-10 components identified above credit Fire Protection Program, which is not credited in the discussion column of item 3.2.1-32. Furthermore, the program description of LRA Appendix B.1.13.1, Fire Protection Program does not include inspection of the above identified components. Please clarify the discrepancy between the credited programs in item 3.2.1-32 and the program credited for the above identified component types. Also, please justify why the Fire Protection program description does not address inspection of these component types in these two systems or enhance the program to include these inspections.	Since it manages internal and external surfaces with the same material and environments, the System Walkdown Program described in B.1.30 is a more appropriate program for the line items in Table 3.3.2-9 that have indoor air (int) as an environment and credit the Fire Protection Program. In addition, line item 3.2.1-32 should include the Fire Protection Program since Table 3.3.2-10 includes Halon system piping internal surfaces that credit the Fire Protection Program and rollup to this line item. This requires an amendment to the LRA.	Fronabarger, Don	Burke, Steve	Accepted

Item	Request	Response	Lead	Support	Category
395	[T.3.3.2-P-02] Component types heat exchanger tubes in Table 3.3.2-4, Emergency Diesel Generator system and Table 3.3.2-9, Fire Protection - Water system are made from copper alloy and exposed to lubricating oil environment, which reference Table 3.2.1, item 3.2.1-9. PNPS only credits the Oil Analysis program. This issue is the same as in question T.3.3.1.3.	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. See response to item 376.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
396	[T.3.3.2-P-03] Component types heat exchanger tubes in Table 3.3.2-5, Station Blackout diesel Generator system, and Table 3.3.2-6, Security Diesel Generator system are made from steel and exposed to an external environment of fuel oil with an aging effect of reduction of heat transfer due to fouling, which reference Table 3.4.1, item 3.4.1-10. PNPS only credits the Oil Analysis program. This issue is the same as in question T.3.3.1.3 Also, please clarify why one of the above component type identifies footnote 'D', whereas the other identifies footnote 'E', even though they have the same MEAP combination.	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376.			
397	[T.3.3.2-P-04] Steel component types thermowell, tubing and valve body in Table 3.3.2-14-19, Off-Gas system reference Table 3.4.1, item 3.4.1-13, which credits water chemistry and one-time inspection program for verification. However the table 2 line items do not credit the verification program. This is the same issue as questions G.3.3.1.2 and T.3.3.1.2.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.4.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
398	[T.3.3.2-P-05] Stainless steel component types thermowell, tubing and valve body in Table 3.3.2-14-19, Off-Gas system reference Table 3.4.1, item 3.4.1-14, which credits water chemistry and one-time inspection program for verification. However the table 2 line items do not credit the verification program. This is the same issue as questions G.3.3.1.2 and T.3.3.1.2.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.4.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Heard, David	Closed

Item	Request	Response	Lead	Support	Category
399	[T.3.3.2-P-06] Steel component types ejector, heat exchanger shell, orifice, piping, pump casing, thermowell, and valve body in Table 3.3.2-14-19, Off-Gas system reference Table 3.4.1, item 3.4.1-2, which credits water chemistry and one-time inspection program for verification. However the table 2 line items do not credit the verification program. This is the same issue as questions G.3.3.1.2 and T.3.3.1.2.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.4.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to item 372.	Fronabarger, Don	Chan, Laris	Closed
400	[T.3.3.2-P-07] Table 3.3.2-14-27, RWCU system, steel component type heat exchanger shell, in treated water environment with an aging effect of loss of material, PNPS credits Water Chemistry Control - Closed Cooling Water program and references Table 3.3.1, line item 3.3.1-17. However, line item 3.3.1-17 addresses Water Chemistry Control - BWR program. Should line item 3.3.1-47 be referenced, which addresses the Water Chemistry Control - Closed Cooling Water for the same MEAP combination? Please supplement the LRA accordingly.	The appropriate entries for the last three columns for the line in Table 3.3.2-14-27, RWCU system, steel component type heat exchanger shell, in treated water environment with an aging effect of loss of material, are VII.C2-14 (A-25), 3.3.1-47, and D. This requires an amendment to the LRA.	Lingenfelter, Jacque	Chan, Laris	Accepted

Item	Request	Response	Lead	Support	Category
401	[T.3.3.2-P-08] Table 3.3.2-14-27, RWCU system, stainless steel component type orifice, in treated water environment with an aging effect of loss of material, references Table 3.3.1, line item 3.3.1-17. However, this line item is for steel components. Should line item 3.3.1-24 be referenced, which addresses stainless steel components for the same EAP? Please supplement the LRA accordingly.	The appropriate Table 1 item entry for the line in Table 3.3.2-14-27, RWCU system, stainless steel component type orifice, in treated water environment with an aging effect of loss of material, is 3.3.1-24. This requires an amendment to the LRA.	Lingenfelter, Jacque	Chan, Laris	Accepted
402	[3.5.2.2.1.4-H-01] Loss of material due to General, Pitting and Crevice Corrosion. Please, explain for your last statement in this section as it said: "Therefore, significant corrosion of the drywell shell is not expected". Does this mean you DO have some corrosion? If not, why significant?	As stated in Section 3.5.2.2.1.4, PNPS inspections of the drywell shell below floor level identified no evidence of corrosion of the drywell shell. The drywell shell steel has a coated surface and no degradation of this coating was identified. The statement in question is not addressing the current condition but rather the conditions expected in the future. It is difficult to say there will be absolutely no corrosion in the future, but there is reasonable assurance that corrosion, if any, will not be significant or meaningful with respect to degradation.	Ahrabli, Reza	Heard, David	Closed
403	[3.5.2.2.1.7-H-01] Stress Corrosion Cracking (SCC) becomes significant for stainless steel if a tensile stress and a corrosion environment exist. The stress may be applied external or residual (internal). Visual VT-3 examinations may be unable to detect this aging effect. Potential susceptible components at PNPS are penetration sleeves and bellows. Please identify the "Other" method of examination to detect this style of effect?	The "other" method which may be used to detect cracking is the existing Containment Leak Rate Program with augmented ultrasonic exams. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Containment Leak Rate Program is described in Appendix B.	Ahrabli, Reza	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
404	[3.5.2.2.2.1-H-01] Aging of structures not covered by Structures Monitoring Program. Do you (PNPS) have any operating experience related to this area? Please, provide the details.	As stated in Section 3.5.2.2.2.1 of the LRA, PNPS has no structures that are not covered by Structures Monitoring Program that are within the scope of license renewal and subject to aging management review.	Ahrabli, Reza	Chan, Laris	Closed
405	[3.5.2.2.2.1.8-H-01] Lock Up due to wear for Lubrite Radial beam Seats in BWR drywell and other Sliding Support Surfaces.. As indicated in this section that "...lock-up due to wear is not an aging effect requiring management at PNPS. However, Lubrite plates are including within the Structures Monitoring Program and Inservice Inspection (ISI-IWF) Programs..." Please, provide the cross reference in between these two programs.	The lubrite plates associated with the radial beam seats are inspected under the Structures Monitoring Program. The lubrite plates associated with the torus support structure are inspected by the ISI (IWF) program.	Ahrabli, Reza	Kalb, J	Closed

Item	Request	Response	Lead	Support	Category
406	[3.5.2.2.2.6-H-01] Aging Support not covered by Structures Monitoring Program. Please provide: 1. More information is needed about bolting materials used in structural applications at PNPS including Group B1.1 applications. What are the bolting materials used? What are the nominal yield strengths and upper-bound as-received yield strengths? Describe the PNPS resolution of the bolting integrity generic issue, as it relates to structural bolting. Was any structural bolting identified as potentially susceptible to cracking due to SCC? Was any structural bolting replaced as part of the resolution? 2. Describe the scope and AMR for Class MC Pressure Retaining Bolting. How is loss of preload managed?	Need clarification. What is meant by "the bolting integrity generic issue"? 1) Bolting material at PNPS consists of A325 – Type 1 conforming to ASTM-A325 and A490 Type 1 conforming to ASTM-A490, per PNPS specification C-94-ER-Q-E3. The nominal yield strength for A325 is 92 ksi and for A490 is 130 ksi. For structural bolting applications, PNPS is consistent with NUREG 1801 in managing the effects of aging with the structures monitoring program or ISI (IWF), as applicable. No PNPS bolting has been identified that is susceptible to SCC. 2) In general, PNPS manages loss of material for bolting with visual inspections. For structural bolting, the visual inspections are part of the Structures Monitoring Program. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700°F) as stated in the ASME Code, Section II, Part D, Table 4. No PNPS structural bolting operates at >700°F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for structural bolting. Other causes of loss of preload include inadequate bolted joint design and ineffective maintenance practices. Loss of preload due to these causes is prevented by incorporation of industry guidance for good bolting practices into PNPS procedures for design and maintenance of bolted joints.	Ahrabli, Reza	Kalb, J	Closed

Item	Request	Response	Lead	Support	Category
407	[3.5.1-13-H-01] In Table 3.5.2-1 on Page 3.5-51 of the LRA, for component Bellows the AMPs shown is CII-IWE, which is a plant-specific AMP. A Note C has been assigned to this AMR line item, component is different, but consistent with material, environment, aging effect, and aging management program for NUREG-1801 line item. This AMP is consistent with NUREG-1801 the GALL description. Table 1 line item 3.5.1-13 bellows. Explain how the plant-specific PNPS CII-IWE AMP is consistent with the GALL specified AMP.	Line item 3.5.1-13 addresses steel, stainless steel elements, dissimilar metal welds: torus; ventline; vent header; ventline bellows and downcomers. For PNPS ventline bellows and associated welds, this line item is consistent with the NUREG-1801 AMR results, but the PNPS CII-IWE program described in Appendix B is a plant-specific program. The Drywell to torus vent line bellows item on LRA Page 3.5-51 references line item 3.5.1-13 and correctly indicates Note "E". For the Bellows (reactor vessel and drywell) line item in Table 3.5.2-1 on Page 3.5-51 of the LRA, reference to line item 3.5.1-13 is not appropriate. The Table 3.5.2-1 line item "Bellows (reactor vessel and drywell)" and the corresponding line item in Table 2.4-1, Page 2.4-13, were inadvertently included in the LRA and should be deleted. The reactor vessel and drywell bellows perform no license renewal intended function. These components are not safety-related and are not required to demonstrate compliance with regulations identified in 10 CFR 54.4(a)(3). Failure of the bellows will not prevent satisfactory accomplishment of a safety function. Leakage, if any, through the bellows is directed to a drain system that prevents the leakage from contacting the outer surface of the drywell shell. Deleting the line items discussed above requires an amendment to the LRA.	Ahrabli, Reza	Chan, Laris	Accepted

Item	Request	Response	Lead	Support	Category
408	[3.5.1-16-H-01] In Table 3.5.2-1 on page 3.5-55 of the LRA for Primary Containment Electrical Penetration seals and sealant, the AMP shown is Structures Monitoring. The applicant is asked to verify that the CII-IWE AMP will not be used instead to manage the aging of the moisture barrier.	PNPS primary containment does not have a moisture barrier. Therefore an AMP is not required. The referenced line item on Page 3.5-55 applies only to primary containment electrical penetration seals and sealant. Table Line Item 3.5.1-16 will be updated to read: "The aging effects cited in the NUREG-1801 item are loss of sealing and leakage. Loss of sealing is a consequence of the aging effects cracking and change in material properties. For PNPS, the Containment Leak Rate program manages cracking and change in material properties for the primary containment seals and gaskets. There is no moisture barrier where the drywell steel shell becomes embedded in the drywell concrete floor." This requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted
409	[3.5.1-44-H-01] In Table 3.5.2-6 on Page 3.5-83 of the LRA, for component seals and gaskets, material rubber in a protected from weather environment; the aging effects are cracking and change in material properties. One of the aging management programs shown is the Structures Monitoring Program. The GALL line item referenced is III.A6-12 and the Table 1 reference is 3.5.1-44. The note shown is E, a different AMP than shown in GALL. However, GALL Line Item III.A6-12 and Table 1 Line Item 3.5.1-44 both specify the Structures Monitoring Program. Explain why the note shown is not A instead of E for the lower half of this AMR line item.	In Table 3.5.2-6 on Page 3.5-83 of the LRA, for component seals and gaskets, material rubber in a protected from weather environment, Note "E" was used because it applies to the top half of the line item. The LRA will be clarified to indicate that Note "A" applies to the lower half of the line item. This requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
410	[3.5.1-58-H-01] In Table 3.5.2-6 on Page 3.5-73 of the LRA, for component electrical and instrument panels and enclosures, material galvanized steel in a protected from weather environment; the aging effect is none. The GALL line item referenced is III.B3-3, which is for the following components: Support members; welds; bolted connections; support anchorage to building structure. Explain why the LRA AMR line item has a Note A shown instead of a Note C, different component with respect to the GALL line item. Or as an alternative, a letter Note A with a number note explaining that the component is different.	NUREG-1801 does not mention every type of component that may be subject to aging management review (e.g., panel is not in NUREG-1801) nor does the terminology used at a specific plant always align with that used in GALL. Consequently, matching plant components to NUREG-1801 components is often subjective. In this particular case, panels, which have no specific function other than to support and protect electrical equipment, were considered support members and Note A was applied. The use of either Note A or C has no impact on the aging management review results. Note "A" will be changed to Note "C" for component electrical and instrument panels and enclosures, material galvanized steel in a protected from weather environment in Table 3.5.2-6 on Page 3.5-73 of the LRA. No change is required to the other entries for this line item. This requires an amendment to the LRA.	Ahrabli, Reza	Das, Swapan	Accepted
411	[3.5.1-8-H-01] In Table 3.5.2-1 on Page 3.5-54 of the LRA for component Torus shell with the aging effect cracking-fatigue, the note assigned is E. Note E is consistent with NUREG-1801 material, environment, and aging effect but a different aging management program is credited. Explain why this note is E when the AMP shown for this line item is TLAA and the referenced GALL Line Item II.B1.1-4 also specifies a TLAA.	For Table 3.5.2-1 on Page 3.5-54 of the LRA for component Torus shell with the aging effect cracking-fatigue, Note "E" will be changed to Note "A". This requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
412	[3.5.1-5-H-01] LRA table 3.5.1, Item Number 3.5.1-5, has the following statement under the discussion column: "The drywell steel where the drywell shell is embedded is inspected in accordance with the Containment Inservice Inspection (IWE) Program and Structures Monitoring Program". This is an difficult inspection. Change this discussion statement to agree with LRA Section 3.5.2.2.1.4 that states: The drywell steel shell and the moisture barrier where the drywell shell becomes embedded in the drywell concrete floor are inspected in accordance with the Containment Inservice Inspection (IWE) Program and Structures Monitoring Program.	For LRA Table 3.5.1, Item 3.5.1-5, the discussion in Section 3.5.2.2.1.4, Page 3.5-9, should have the reference to moisture barrier deleted, since the PNPS drywell does not contain this commodity. For LRA Table 3.5.1, Item 3.5.1-5, the discussion column should read: "The drywell steel shell and the area where the drywell shell becomes embedded in the drywell concrete floor are inspected in accordance with the Containment Inservice Inspection (IWE) Program." The last sentence of the first paragraph in LRA Section 3.5.2.2.1.4, should read: "The drywell steel shell and the area where the drywell shell becomes embedded in the drywell concrete floor are inspected in accordance with the Containment Inservice Inspection (IWE) Program." This requires an amendment to the LRA.	Ahrabli, Reza	Pardee, R.	Accepted

Item	Request	Response	Lead	Support	Category
413	[3.5.1-9-H-01] LRA Table 3.5.1, Item Number 3.5.1-9, has the following statement under the discussion column: Not applicable. See Section 3.5.2.2.1. This should be read as Section 3.5.2.2.1.6. However, the following statement is made in LRA Section 3.5.2.2.1.6: "Fatigue TLAAs for the steel drywell, torus, and associated penetrations are evaluated and documented in Section 4.6." The components associated with LRA Table 3.5.1, Item Number 3.5.1-9 are: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers. Explain how Item number 3.5.1-9 is not applicable when a fatigue TLAA has been performed for the torus and penetrations. Explain why the vent line, vent header and vent line bellows are not listed in LRA Sections 3.5.2.2.1.6 and 4.6 as referenced in Table 3.5.1, Line Item 3.5.1-8.	Fatigue analyses have been evaluated for the torus, torus vent system, and torus penetrations. The following line will be added to Table 3.5.2-1: "Torus mechanical penetrations // PB, SSR // Carbon steel // Protected from weather // Cracking // TLAA-metal fatigue // II.B4-4(C-13) // 3.5.1-9 // A" The evaluation of the torus vent system fatigue analysis determined that it was not a TLAA. The significant contributor to fatigue of the vent system is post-LOCA chugging, a once in plant-life event. As there will still be only one design basis LOCA for the life of the plant, including the period of extended operation, this analysis is not based on a time-limited assumption and is not a TLAA. Fatigue for the vent system is event-driven and is not an age-related effect. The discussion column entry for Table 3.5.1 item 3.5.1-8 will be changed to read as follows: "Fatigue analysis is a TLAA for the torus shell. Fatigue of the vent system is event-driven and the analysis is not a TLAA. See Section 3.5.2.2.1.6." The discussion column entry for Table 3.5.1 item 3.5.1-9 will be changed to read as follows: "Fatigue analysis is a TLAA for the torus penetrations. See Section 3.5.2.2.1.6." Section 3.5.2.2.1.6 will be changed to read as follows: "TLAA are evaluated in accordance with 10 CFR 54.21(c) as documented in Section 4. Fatigue TLAAs for the torus and associated penetrations are evaluated and documented in Section 4.6." Section 3.5.2.3, Time-Limited Aging Analyses, will be changed to read as follows: "TLAA identified for structural components and commodities include fatigue analyses for the torus and torus penetrations. These	Ahrabli, Reza	Pace, Ray	Accepted

Item	Request	Response	Lead	Support	Category
		topics are discussed in Section 4.6." These changes require an amendment to the LRA.			
414	[3.5.1-12-H-01] LRA Table 3.5.1, Item Number 3.5.1-12 and 3.5.1-13, under the discussion column, does not make reference to LRA Section 3.5.2.2.1.8 for further evaluation. Explain why this link is not made to the further evaluation section. Explain the need for augmented ultrasonic exams to detect fine cracks since a CLB fatigue analysis does exist.	A link from items 3.5.1-12 and 3.5.1-13 will be added to section 3.5.2.2.1.8. Section 3.5.2.2.1.8 should state: "Cyclic loading can lead to cracking of steel and stainless steel penetration bellows, and dissimilar metal welds of BWR containments and BWR suppression pool shell and downcomers." Cracking due to cyclic loading is not expected to occur in the drywell, torus and associated penetration bellows, penetration sleeves, unbraced downcomers, and dissimilar metal welds. A review of plant operating experience did not identify cracking of the components and primary containment leakage has not been identified as a concern. Nonetheless, the Containment Leak Rate Program with augmented ultrasonic exams and Containment Inservice Inspection – IWE, will continue to be used to detect cracking. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Containment Inservice Inspection – IWE and Containment Leak Rate programs are described in Appendix B. This requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
415	[3.5.1-16-H-01] LRA Table 3.5.1, Item Number 3.5.1-16, under the discussion column, states that seals and gaskets are not included in the Containment Inservice Inspection Program at PNPS. One of the components for this item number is moisture barriers. Explain how PNPS seals the joint between the containment drywell shell and drywell concrete floor if there is no moisture barrier. Explain why the inspection of this joint is not part of the Containment Inservice Inspection Program at Pilgrim?	There is no gap to seal at the joint between the containment drywell shell and the concrete floor. Concrete grout is poured directly against the drywell shell. The installation is shown as Detail 1 on Drawing C-71. The Containment Inservice Inspection Program includes inspection of this joint. (Also see audit question #408 which addresses changes to LRA)	Ahrabli, Reza	Pardee, R.	Closed
416	[3.5.1-33-H-01] For LRA Table 3.5.1, Item Number 3.5.1-33, provide the maximum temperatures that concrete experience in Group 1-5 structures.	The maximum bulk area ambient temperatures for Groups 1-5 occurs in the drywell and is an average temperature of 148°F, reference UFSAR Table 5.2-2. For structures outside the drywell the bulk area maximum temperature is 120°F for Groups 1-5 structures as identified in Table 10.9-2 of PNPS UFSAR. Concrete within the drywell consist of the reactor pedestal, sacrificial shield wall and the drywell floor. Assurance that bulk concrete temperatures within the drywell remain below 150 degrees F is obtained through maintaining average bulk containment temperature within the limits allowed by PNPS Technical Specification Section 3.2-H (Page 3/4.2-5). Although upper elevations of the drywell may exceed 150°F, the concrete of the drywell is at lower elevations. The drywell cooling system provides cooling to ensure temperature limits are not exceeded. The highest concrete in the drywell is the sacrificial shield wall. The concrete in this wall is not load bearing.	Ahrabli, Reza	Kalb, J	Closed

Item	Request	Response	Lead	Support	Category
417	[3.5.1-34-H-01] LRA Table 3.5.1, Item Number 3.5.1-34, under the discussion column, does not make reference to LRA Section 3.5.2.2.2.4 (1) for further evaluation. Explain why this link is not made to the further evaluation section.	NUREG-1800, Item Number 3.5.1-34 indicates that further evaluation is necessary only for aggressive environments. No reference was provided to further evaluation in LRA Section 3.5.2.2.2.4 (1) since the PNPS environment is not aggressive as noted in LRA Table 3.5.1, Item Number 3.5.1-34, under the discussion column. For clarification, LRA Table 3.5.1, Line Item 3.5.1-34 discussion will be revised to add "See Section 3.5.2.2.2.4(1)". This requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted
418	[3.5.1-35-H-01] LRA Table 3.5.1, Item Number 3.5.1-35, under the discussion column, does not make reference to LRA Section 3.5.2.2.2.4 (2) for further evaluation. Explain why this link is not made to the further evaluation section.	For clarification, LRA Table 3.5.1, Item 3.5.1-35 discussion will be revised to add reference to Section 3.5.2.2.2.4(2). LRA Table 3.5.1, Item 3.5.1-35 discussion will be revised to refer to ACI 318 in lieu of ACI-301, since the provided reference to ACI should have been ACI 318 and not ACI 301. This requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
419	[3.5.1-36-H-01] LRA Table 3.5.1, Item Number 3.5.1-36, under the discussion column, does not make reference to LRA Section 3.5.2.2.2.4 (3) for further evaluation. Explain why this link is not made to the further evaluation section. The statement: "See Section 3.5.2.2.2.1 (5) for additional discussion" needs further clarification that this section is for Groups 1-5, 7-9, however it would apply to accessible Group 6 concrete. Explain why LRA Section 3.5.2.2.2.4 (3) lists cracking of concrete due to Stress Corrosion Cracking (SCC).	LRA Table 3.5.1, Line item Number 3.5.1-36 discussion will be revised to read as follows: "Reaction with aggregates is not an applicable aging mechanism for PNPS concrete components. See Section 3.5.2.2.2.1(5) (although for Groups 1-5, 7, 9 this discussion is also applicable for Group 6) and Section 3.5.2.2.2.4(3) additional discussion. Nonetheless, the Structures Monitoring Program will confirm the absence of aging effects requiring management for PNPS Group 6 concrete components." Due to an administrative oversight, the heading of LRA Section 3.5.2.2.2.4 (3) inadvertently lists cracking of concrete due to Stress Corrosion Cracking (SCC). This section heading should have begun with "Cracking Due to Expansion and Reaction with Aggregates...". Stress corrosion cracking is not discussed in the body of this section. This change requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted
420	[3.5.1-40-H-01] LRA Table 3.5.1, Item Number 3.5.1-40, under the discussion column, states: "...Plant experience has not identified reduction in concrete anchor capacity or other concrete aging mechanisms. Nonetheless, the Structures Monitoring Program will confirm absence of aging effects requiring management for PNPS concrete components." The project team cannot find an AMR line item in Table 2 for this component (Building concrete at locations of expansion and grouted anchors; grout pads for support base plates). Provide the Table 2 number, LRA page number, and component for where this AMR line item is evaluated and shown.	Building concrete at locations of expansion and grouted anchors; grout pads for support base plates are shown as "foundation" and "Reactor vessel support pedestal" in LRA Table 3.5.2-1 (page 3.5-55), "foundation" in Tables 3.5.2-2 through 3.5.2-5 (pages 3.5-59, 3.5-61, 3.5-64, and 3.5-67), and as "Equipment pads/foundations" in Table 3.5.2-6 (page 3.5-80). Further evaluation is provided in LRA section 3.5.2.2.2.6(1), page 3.5-15. For clarification, LRA Table 3.5.1, Item Number 3.5.1-40 discussion will be revised to add "See Section 3.5.2.2.2.6(1)". This requires an amendment to the LRA.	Ahrabli, Reza	Kalb, J	Accepted

Item	Request	Response	Lead	Support	Category
421	[3.5.1-50-H-01] LRA Table 3.5.1, Item Number 3.5.1-50, under the discussion column, states that loss of material is not applicable to PNPS. NUREG-1833 on Page 93 for Item TP-6 states an approved precedent exists for adding this material, environment, aging effect, and program combination to the GALL Report. As shown in RNP SER Section 3.5.2.4.3.2, galvanized steel and stainless steel in an outdoor air environment could result in loss of material due to constant wetting and drying conditions. Aluminum would also be susceptible to a similar kind of aging effect in the outdoor environment. Provide a discussion of the actual group B2 and B4 galvanized steel, aluminum, and stainless steel PNPS components which are within the scope of license renewal and exposed to an outdoor air environment. Discuss the location of these components at PNPS and how they are protected from constant wetting and drying conditions.	For LRA Table 3.5.1, Item Number 3.5.1-50, the discussion column should read: "This aging effect is managed by the Structures Monitoring Program." Components that may be considered in the B2 and B4 grouping consist of those line items in Table 3.5.2-6 with materials galvanized steel, aluminum, or stainless steel. This requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
422	[3.5.1-52-H-01] LRA Table 3.5.1, Item Number 3.5.1-52, under the discussion column, states that loss of mechanical function due to the listed mechanisms is not an aging effect. Proper design prevents distortion, overload, and fatigue due to vibratory and cyclic thermal loads. Explain how loss of mechanical function due to corrosion is not an aging effect which needs to be managed for the period of extended operation. If proper design prevents distortion, overload, and fatigue due to vibratory and cyclic thermal loads, explain if there has ever been a component failure at PNPS due to any of these conditions. Explain if there has ever been a component failure in the nuclear industry due to any of these conditions. Explain where sliding support bearing and sliding support surfaces are used in component groups B2 and B4 at PNPS and provide the environment they are exposed to.	Loss of material due to corrosion is an aging effect that can cause a loss of intended function. Loss of mechanical function would be considered a loss of intended function. Loss of mechanical function is not an aging effect, but is the result of aging effects. There have been component failures in the industry due to distortion, overload, and excessive vibration. Such failures typically result from inadequate design or events rather than the effects of aging. Failures due to cyclic thermal loads are very rare for structural supports due to their relatively low temperatures. The sliding surface material used at PNPS is lubrite, which is a corrosion resistant material. Components are inspected under ISI-IWF for torus saddle supports and Structures Monitoring Program for the lubrite components of radial beam seats. Plant operating experience has not identified failure of lubrite components used in structural applications. No current industry experience has identified failure associated with lubrite sliding surfaces. Components associated with B2 grouping are limited to the torus radial beam seats and support saddles. There are no sliding support surfaces associated with the B4 component grouping for sliding surfaces at PNPS. For clarification, LRA Table 3.5.1, Item 3.5.1-52 will be revised to read as follows: "Loss of mechanical function due to the listed mechanisms is not an aging effect. Such failures typically result from inadequate design or operating events rather than from the effects of aging. Failures due to cyclic thermal loads are rare for structural supports due to their relatively low temperatures." This requires an amendment to the LRA.	Ahrabli, Reza	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
423	[3.5.1-54-H-01] LRA Table 3.5.1, Item Number 3.5.1-54, under the discussion column, states that loss of mechanical function due to the listed mechanisms is not an aging effect. Proper design prevents distortion, overload, and fatigue due to vibratory and cyclic thermal loads. Explain how loss of mechanical function due to corrosion is not an aging effect which needs to be managed for the period of extended operation. If proper design prevents distortion, overload, and fatigue due to vibratory and cyclic thermal loads, explain if there has ever been a component failure at PNPS due to any of these conditions. Explain if there has ever been a component failure in the nuclear industry due to any of these conditions. Explain what PNPS inspects for during VT-3 visual examinations of groups B1.1, B1.2 and B1.3 components under its Inservice Inspection Program during its current license and also anticipated VT-3 visual examinations during its possible extended license.	The discussion for Item Number 3.5.1-54 was not implying that failures have not occurred, but that loss of mechanical function is not an aging effect. For license renewal, Entergy identifies a number of aging effects that can cause loss of intended function. Loss of intended function includes loss of mechanical function. The loss of function is not considered an aging effect. Aging effects that could cause loss of mechanical function for components in Item Number 3.5.1-54 are addressed elsewhere in the aging management reviews. For example, loss of material due to any mechanism is addressed in Table 3.5.2-6 under listings for component and piping supports ASME Class 1, 2, 3 and MC (Page 3.5-71), and component and piping supports (Page 3.5-72). Component failures at PNPS and in the nuclear industry have certainly occurred due to overload (typically caused by an event such as water hammer) or vibratory and cyclic thermal loads. Because of the low operating temperatures, failures due to cyclic thermal loads are extremely rare for structural commodities. Failures due to distortion or vibratory loads have also occurred due to inadequate design, but rarely if ever, due to the normal effects of aging. PNPS inspections during VT-3 visual examinations of groups B1.1, B1.2 and B1.3 components are consistent with what is required by code. For clarification, LRA Table 3.5.1, Item 3.5.1-54 will be revised to state: "Loss of mechanical function due to distortion, dirt, overload, fatigue due to vibratory, and cyclic thermal loads is not an aging effect requiring management. Such failures typically result from inadequate design or events rather than the effects of aging. Loss of material due to corrosion, which could cause loss of mechanical function, is addressed under	Ahrabli, Reza	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
		Item 3.5.1-53 for Groups B1.1, B1.2, and B1.3 support members." This requires an amendment to the LRA.			
424	Table 3.3.2-4, Emergency Diesel Generator System, for carbon steel expansion joints in an internal environment of exhaust gases credits the TLAA – fatigue for managing cracking due to fatigue. TLAA section 4.3.2, Non-Class 1 Fatigue, assumes, in general 7000 thermal cycles for piping systems, allowing a stress reduction factor of 1.0 in the stress analysis. This is a good assumption for pipe, fittings, etc., however, may not be a good assumption for expansion joints. Please confirm if the expansion joints are included in section 4.3.2, and justify that the assumption of 7000 cycles is appropriate.	PNPS included the expansion joint with the exhaust piping in Section 4.3.2 of the LRA. PNPS documentation does not identify any design code for the expansion joint separate from the exhaust piping (B31.1). Partial cycles are not a concern for the diesel exhaust system since the exhaust temperature is assumed to reach normal operating temperature with each start of the engine. The expansion joint is exposed only to the same number of full cycles to which the rest of the piping is exposed. The expansion joint is designed specifically to accommodate movement that could result from the heating and cooling of the exhaust piping; in other words, its design intent is to have better fatigue response than the rest of the piping. Therefore, PNPS assumed the piping would be more limiting than the expansion joint for the allowable number of cycles prior to requiring management of cracking due to fatigue.	Finnin, Ron	Chan, Laris	Accepted

Item	Request	Response	Lead	Support	Category
425	As part of the Thermal Power Optimization Project, GE performed another fatigue analysis. GE issued a report, GE-NE-0000-0000-1892-02, Rev. 0, March 2002, Thermal Power Optimization, Task-302 – RPV – Stress Evaluation. This report calculated new CUFs, which in some cases are different than what is shown in the LRA, Table 4.3-1, Maximum CUFs for Class 1 Components. The GE Report, Section 3.3, Results, states that feedwater nozzle CUF recalculation indicate a CUF that went from <0.8 to <1.0. Similarly, Table 3.3.1.3 fatigue summary, last column, indicates CLTP/TLTP values. Again, specific values are provided for 3 line items, however, for feedwater nozzle, only <1.0 is specified. Please justify what <1.0 means. Please provide a specific calculated value. Also, please justify why the revised TPOP CUF values were not identified in the LRA Table 4.3-1, instead of old values calculated by ALTRAN Corporation in 1994. Are there other LRA TLAA sections affected by the TPO project, such as Section 4.2, RPV Neutron Embrittlement Analysis.	a) The Pilgrim records system had not been updated to include the changes in CUF due to the 2003 TPO program in time to support LRA preparation. TPO has a small impact on CUF as detailed in GE-NE-0000-000-1898-02, Rev. 1, 3/2002. The records system has been updated and the PNPS corrective action program requires that the information be assessed for potential impact on other LRA sections. PNPS will update LRA table 4.3-1 to include the values from the TPO. In preparing the TPO stress evaluation, GE reviewed only those RPV components whose pressure, temperature, and flow conditions were more severe due to the TPO and with fatigue usage factors greater than 0.5. These CUFs were not recalculated by traditional methods, but rather were estimated by conservatively scaling the stresses, determining the code allowable number of cycles for those stresses, then determining the incremental usage factor for a group of cycles considered in the original stress report. Before the TPO, the CUF for the feedwater nozzle (Altran Report) was listed as <0.8, for the TPO this CUF increased to <1.0. No precise value was calculated. As stated in the response to Question 345, PNPS will perform a new feedwater nozzle fatigue analysis prior to the period of extended operation. b) No other sections of the LRA are affected by the TPO. The fluence values used in Section 4.2 were based on the higher power level.	Finnin, Ron	Pace, Ray	Open – NRC Reviewing

Item	Request	Response	Lead	Support	Category
426	[T.3.3.2-P-09] Table 3.3.2-4, EDG System, page 3-78, for carbon steel expansion joints, in an internal environment of exhaust gas credits TLAA-fatigue to manage the aging effect of cracking due to fatigue. Please confirm if TLAA Section 4.3.2, Non-Class 1 Fatigue, includes these expansion joints. Also, see TLAA question 8.	TLAA-metal fatigue is not an aging management program. Under the standard LRA format, TLAA-metal fatigue is inserted under the aging management program as a convenience to indicate that a TLAA for metal fatigue applies to that line item. The carbon steel expansion joints are designed per the requirements of ASME B31.1 for a limited number of thermal cycles. The evaluation of fatigue for ASME B31.1 components is discussed in Section 4.3.2. The evaluation determined that the EDG components will remain below the cycle limit for 60 years such that cracking is not expected.	Fronabarger, Don	Chan, Laris	Accepted
427	[T.3.3.2-P-10] For aging effect of cracking due to fatigue, PNPS has credited TLAA - metal fatigue as an aging management program for components in an internal environment of exhaust gas in Table 3.3.2-4, EDG Systems; however in Table 3.3.2-5, SBDG System and Table 3.3.2-6, SDG System, the Periodic Surveillance and Preventive Maintenance (PSPM) Program is credited, which includes visual or other NDE techniques to inspect exhaust system components to manage cracking. Please justify why the PSPM program is not credited for the EDG system components for managing aging effect of cracking. It is only credited for loss of material and fouling.	TLAA-metal fatigue is not an aging management program. Under the standard LRA format, TLAA-metal fatigue is inserted under the aging management program as a convenience to indicate that a TLAA for metal fatigue applies to that line item. The EDG exhaust systems are designed per the requirements of ASME B31.1 for a limited number of thermal cycles. The evaluation of fatigue for ASME B31.1 components is discussed in Section 4.3.2. The evaluation determined that the EDG components will remain below the cycle limit for 60 years such that cracking is not expected. The exhaust systems for the station blackout diesel generator and security diesel generator are not designed to a code or standard where thermal cycles are a consideration. Therefore, the Periodic Surveillance and Preventive Maintenance (PSPM) program will manage or confirm the absence of cracking due to thermal fatigue.	Lloyd, Leland	Pace, Ray	Closed

Item	Request	Response	Lead	Support	Category
428	[T.3.3.2-P-11] Table 3.3.2-9, Fire Protection - Water System, for piping, silencer and turbocharger in an internal exhaust gas environment with an aging effect of cracking due to fatigue, PNPS has credited the Fire Protection Program to manage this aging effect. The program element 6, Acceptance Criteria, is enhanced to verify that the diesel engine did not exhibit signs of degradation while it was running; such as exhaust gas leakage. Please justify how the aging effect of cracking is managed by verifying for exhaust gas leakage. If there is leakage, it implies a through-wall crack has occurred. Verifying for leakage is not an adequate aging management program for managing cracking.	The aging effect of fatigue cracking is conservatively identified for the fire pump diesel engine. If the exhaust components were designed per ASME B31.1 code, a limited number of cycles would be the threshold for susceptibility to cracking due to fatigue. Since the system is normally in standby and used primarily during testing, it is unlikely to reach any legitimate threshold to produce fatigue cracking. Furthermore, through monitoring and trending of performance data under the Fire Protection Program, cracking of system components will be identified and corrected through the corrective action program. As described in section B.1.13.1, observation of degraded performance produced corrective actions including engine replacement in 2002 prior to loss of intended function. Consequently, continued implementation of the Fire Protection Program provides reasonable assurance aging effects will be managed for the diesel fire pump exhaust subsystem. In addition, PNPS performs fire pump inspection, testing and maintenance in accordance with NFPA 25 which would also detect the presence of cracking in the exhaust system prior to loss of intended function. This item is closed to item 378.	Fronabarger, Don	Burke, Steve	Closed

Item	Request	Response	Lead	Support	Category
429	[T3.3.2-P-12] In LRA Section 3.3.2.2.7.3, PNPS states that the carbon steel diesel exhaust piping and components in the fire protection system is managed by the Fire Protection Program. The Fire Protection Program uses visual inspections of diesel exhaust piping and components to manage loss of material. If Fire Protection Program (LRA B.1.13.1) is credited for managing aging of these components, please explain why these system components are not included in the program description of the Fire Protection Program. Furthermore, no enhancement is addressed that would include these components in the Fire Protection Program.	The program description listed in Section B.1.13.1 matches the description cited in GALL section XI.M26, Fire Protection which includes the diesel driven fire pump. The exhaust piping and components are part of the fire pump. Enhancements for aging management of the exhaust subsystem are described for attributes 3-parameters monitored/inspected and 6-acceptance criteria of the program. This item is closed to item 378.	Fronabarger, Don	Burke, Steve	Closed
430	[T.3.3.2-P-13] Subsequent to question T.3.3.2.1, the applicant has credited Fire Protection Program in lieu of GALL AMP XI.M38, Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components as recommended for GALL item V.D2-16, which is referenced by the applicant for these line items. The GALL AMP XI.M38 states that visual inspection of internal surfaces of plant components is performed during maintenance or surveillance activities for visible evidence of corrosion to indicate possible loss of material. Since PNPS is using the Fire Protection Program in lieu of GALL AMP XI.M38, please explain how the Fire Protection Program performs this visual inspection. As written in the LRA, the Fire Protection Program is not adequate to manage loss of material for these components.	See the response to Item 394 that addresses items in Table 3.3.2-9. For the piping component line item in Table 3.3.2-10 that has indoor air (int) as an environment the Fire Protection Program includes a visual inspection of the external surfaces of the Halon system piping and tanks. Since external surfaces are representative of internal surfaces that are exposed to the same environment, the Fire Protection Program is adequate for managing the aging effects of components exposed to indoor air. This item is closed to item 378.	Fronabarger, Don	Burke, Steve	Closed

Item	Request	Response	Lead	Support	Category
431	[T3.2.2-P-01] Table 3.2.2, question 1 The PNPS B.1.12 Fatigue Monitoring is credited for managing the aging effect "Cracking fatigue" for components in the RHR (Table Number 3.2.2-1), ADS (Table Number 3.2.2- 3), HPIC (Table Number 3.2.2 4), RCIC (Table Number 3.2.2 5) systems. In most cases the components have been assigned Note "A" or Note "C". However, the PNPS B.1.12 Fatigue Monitoring program has exceptions to the GALL program, X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary. Therefore, Note "C" should be Note "D" and Note "A" should be Note "B" as appropriate for these components.	NUREG-1801 does not specify X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary in the AMP column for items identifying cumulative fatigue damage. NUREG-1801 identifies fatigue as a TLAA and refers to guidance in SRP Section 4.3 which in turn describes treatment of fatigue in a variety of ways depending on the component. Since NUREG-1801 does not credit the Fatigue Monitoring Program, exceptions in this program have no bearing on the selection of notes.	Lingenfelter, Jacque	Heard, David	Closed
432	[T3.2.2-P-02] Table 3.2.2, question 2 The PNPS B.1.30 System Walkdown Program is used to detect LOM for carbon steel bolting instead of GALL XI.M18 Bolting Integrity. XI.M18 invokes visual VT-1 examination for bolting less than 2 inches in diameter. It is not clear if VT 1 is used for bolting that is examined in accordance with the System Walkdown Program. What standard is used for visual inspection of bolting under the System Walkdown Program.	A Bolting Integrity Program will be developed that will address the aging management of bolting in the scope of license renewal. The Bolting Integrity Program will be implemented prior to the period of extended operation in accordance with commitment number 32. This requires an amendment to the LRA to include descriptions of the Bolting Integrity Program in Appendices A and B and to identify where the program is applicable. This item is closed to Item 373.	Fronabarger, Don	Pardee, R.	Closed

Item	Request	Response	Lead	Support	Category
433	[T3.2.2-P-03] Table 3.2.2, question 3 Stainless steel and steel components that are exposed to treated water in Table 3.2.2 do not specify one-time inspection to detect loss of material although Table 3.2.1 indicates OTI. Add OTI as AMPs for these components for consistency with Table 3.2.1 or provide a justification for not performing OTI.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.2.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Fronabarger, Don	Chan, Laris	Closed
434	[T3.2.2-P-04] Table 3.2.2, question 4 It is not clear if the System Walkdown Program provides for inspection interior surfaces of carbon steel components exposed to indoor air for LOM. Please provide details showing inspection of interior surfaces for this component.	The System Walkdown Program is not intended to inspect interior piping and component surface unless they have been exposed for inspection during maintenance and repairs. As indicated in the tables in Section 3 of the LRA, the System Walkdown Program manages aging for external surfaces of components. The program also manages loss of material from internal surfaces in situations in which internal and external material and environment combinations are the same such that external surface condition is representative of internal surface condition.	Fronabarger, Don	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
435	[T3.2.2-P-05] Table 3.2.2, question 5 Item numbers 3.2.2-4, 3.2.2-5, and 3.3.2-14-16 are stainless steel piping components (e.g. orifices, strainers). Please explain why Note "C" was assigned to these components.	The various piping components in tables 3.2.2-4, 3.2.2-5, and 3.3.2-14-16, to which Note "C" was assigned, have steam as the environment. The systems represented by these tables are all ESF systems; however, NUREG-1801 does not include the combination of stainless steel in a steam environment for any ESF component (Chapter V). Consequently, comparisons were made to steam and power conversion systems components (Chapter VIII) where the stainless steel/steam combination is addressed. Since the systems do not match, a Note "C" is applied.	Lingenfelter, Jacque	Chan, Laris	Closed
436	[T3.2.2-P-06] Table 3.2.2, question 6 Item number 3.3.2-14-16, are steel piping components (e.g. orifices, strainers). Please explain why Note "C" was assigned to these components.	The various steel piping components in table 3.3.2-14-16, to which Note "C" was assigned, have steam as the environment with the aging effect of either cracking – fatigue or loss of material. The system represented by this table is an ESF system; however, the only aging effect identified in the NUREG-1801 ESF tables (Chapter V) for a combination of steel in a steam environment, is flow accelerated corrosion. Consequently, comparisons were made to steam and power conversion systems components (Chapter VIII) where the steel/steam combination includes cracking – fatigue and loss of material as aging effects. Since the systems do not match, a Note "C" is applied.	Lingenfelter, Jacque	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
437	[T3.2.2-P-07] Table 3.2.2, question 7 SRP-LR, 3.2.2.2.8 Loss of material due General, Pitting, and Crevice Corrosion, Item 3 provides for the verification of the effectiveness of the lubricating oil program through one-time inspection of selected steel components at susceptible locations. Carbon steel components are not, specifically or through a representative component, subjected to a one-time inspection for loss of material. Add OTI as AMPs for these components for consistency with Table 3.2.1 or provide a justification for not performing OTI.	During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.	Fronabarger, Don	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
		This item is closed to Item 376.			
439	[T3.2.2-P-09] Table 3.2.2, question 9 The GALL specifies XI.M20, Open-Cycle Cooling Water System Program for carbon steel piping and PNPS credits the plant-specific Periodic Surveillance and Preventive Maintenance Program. Although the plant-specific program provides for visual and/or UT inspection as in XI.M20, it does not provide for preventive actions. What is the justification for not implementing preventive actions?	Item 3.2.1-35 specifies the Periodic Surveillance and Preventive Maintenance Program instead of XI.M20, Open-Cycle Cooling Water System Program, because the environment indicated as raw water in tables 3.2.2-6 and 3.2.2-7 is used to identify water which is untreated but is not part of the raw cooling water system. Therefore, the preventive actions from GL 89-13 that are described in NUREG-1801 XI.M20 do not apply. The remaining preventive action specified in XI.M20 is not actually an ongoing AMP element, but is the design consideration that components are constructed of appropriate materials. The site corrective action program provides reasonable assurance that if appropriate materials were not provided in the original component design, any resulting problems would be evaluated and appropriate corrective actions would be taken to address those problems.	Ivy, Ted	Chan, Laris	Closed
440	[T3.2.1-1-P-01] Table 3.2.1-1, question 1 The PNPS LRA, Section 3.2.2.2.1 indicates that cumulative fatigue damage is a TLAA evaluated in accordance with 10CFR54.21(c). However, PNPS aging management reviews do not consider cumulative fatigue damage a concern for steel or stainless steel unless system temperature exceeds 220 degrees F or 270 degrees F, respectively which is not a condition of the SRP LRA Section 3.2.2.2.1. Provide an analysis that justifies the exemption of evaluation for cumulative fatigue damage for steel or stainless steel components in systems that operate below 220 degrees F or 270 degrees F, respectively.	The use of 220 degrees (carbon steel) and 270 degrees (stainless steel) as a screening criteria below which there is no consideration of mechanical fatigue as an aging mechanism is documented in Appendix H to EPRI 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools," usually referred to as the Mechanical Tools. This document takes the screening limits of 220/270 degrees from the EPRI Fatigue Management Handbook, TR-104534. Fatigue is based on thermal cycles seen by the component, and if the component doesn't go above these temperatures it is not seeing thermal cycles large enough to contribute to fatigue.	Finnin, Ron	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
441	[T3.2.1-3-P-01] Table 3.2.1-3, -5, -6, -8, -9, -10, -14, -15, -16 -18, question 2 These item numbers specify One-Time Inspection along with another program such as Water Chemistry or Lubricating Oil Analysis. However, Table 3.2.2 components that correspond to these Table 3.2.1 items do not specify one time inspection to detect loss of material. Please change component line items to include One-Time Inspection or provide the basis for excluding OTI.	Since the One-Time Inspection (OTI) Program is applicable to each water chemistry control program, it is also applicable to each line item that credits a water chemistry control program. LRA Table 3.2.1 indicates that the One-Time Inspection Program is credited along with the water chemistry control programs for line items for which GALL recommends a one-time inspection to confirm water chemistry control. Table 2 credits the OTI program through reference to the associated Table 1 line item. During the performance of routine maintenance on components that contain lubricating oil, visual inspections of these components would identify degraded conditions that could be attributed to an ineffective Oil Analysis Program. The corrective action program at PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified as part of this program. The review of operating experience at PNPS for the last five years did not identify any condition reports that indicated an ineffective oil analysis program or that identified degraded component conditions such as corrosion or cracking in a lubricating oil environment. This review of operating experience at PNPS serves in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water	Fronabarger, Don	Chan, Laris	Closed

programs.

This item is closed to Item 372.

During the past five years, many visual inspections of components containing lubricating oil have been performed during corrective and preventive maintenance activities. The visual inspections of these components would identify degraded conditions such as corrosion or cracking that could be attributed to an ineffective Oil Analysis Program. PNPS has a low threshold for the identification of degraded conditions such that corrosion or cracking of components would be identified and entered into the corrective action program. No condition reports that identified degraded component conditions, such as corrosion or cracking in a lubricating oil environment, were initiated as a result of these inspections. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Oil Analysis Program.

This item is closed to Item 376.

Item	Request	Response	Lead	Support	Category
442	[T3.2.1-35-P-01] Table 3.2.1-35, question 3 The GALL specifies XI.M20, Open Cycle Cooling Water System Program and PNPS credits the plant specific Periodic Surveillance and Preventative Maintenance Program. Although the plant specific program provides for visual and/or UT inspection as in XI.M20, it does not provide for preventive actions. Provide justification for not adhering to XI.M20.	Item 3.2.1-35 specifies the Periodic Surveillance and Preventive Maintenance (PSPM) Program instead of XI.M20, Open-Cycle Cooling Water System Program, because the environment indicated as raw water in tables 3.2.2-6 and 3.2.2-7 is used to identify water which is untreated but is not part of the raw cooling water system. Therefore, the preventive actions from GL 89-13 that are described in NUREG-1801 XI.M20 do not apply. The remaining preventive action specified in XI.M20 is not actually an ongoing AMP element, but is the design consideration that components are constructed of appropriate materials. The site corrective action program provides reasonable assurance that if appropriate materials were not provided in the original component design, any resulting problems would be evaluated and appropriate corrective actions would be taken to address those problems.	Ivy, Ted	Chan, Laris	Closed
443	[General-P-01] In general, System Walkdown is credited for managing LOM for bolting. However, other aging effects may be active for bolting and System Walkdown does not provide for preventive actions. Aging Effects for bolting should be managed under the umbrella of a Bolting Integrity Program in accordance with GALL program XI.M18.	A Bolting Integrity Program will be developed that will address the aging management of bolting in the scope of license renewal. The Bolting Integrity Program will be implemented prior to the period of extended operation in accordance with commitment number 32. This requires an amendment to the LRA to include descriptions of the Bolting Integrity Program in Appendices A and B and to identify where the program is applicable. This item is closed to Item 373.	Fronabarger, Don	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
444	[General-P-02] Components in the SGT system that are exposed to instrument air are managed with the plant-specific Instrument Air Quality Program (PNPS AMP B.1.17). This program only monitors the air quality. However, the GALL Compressed Air Monitoring Program, XI.M24, additionally requires testing for leakage rates, inspection for corrosion, and performance testing components. What program(s) provide for these additional requirements? If these additional requirement of XI.M24 are not covered by another program, please provide justification for not including them. This comment is applicable to the IA system as well.	Through monitoring of air quality, the Instrument Air Quality Program maintains instrument air free of significant contaminants and water, thereby preventing loss of material. This approach to managing loss of material is more effective than leakage monitoring and repetitive inspection for corrosion. Performance monitoring under the maintenance rule addresses active components that would be included in performance testing. No additional aging effects were identified whose management required these other attributes of the Compressed Air Monitoring Program, XI.M24. Recent internal inspections of the air receiver tanks and moisture checks of the instrument air system have not detected significant corrosion or moisture in the system. These past inspections at PNPS serve in lieu of a one-time inspection to provide confirmation of the effectiveness of the Instrument Air Quality program in managing aging effects of components exposed to instrument air without the additional program attributes recommended by GALL XI.M24.	Nichols, Bill	Chan, Laris	Closed
445	[3.1.1-J-01] Some of the items that roll up to Item 3.1.1-2 are described in LRA Table 3.1.2-1 as in an environment of Treated Water > 220 deg F, and some are described as in Treated Water > 270 deg F. Please justify the use of two temperature ranges to describe the environments for the components that roll up to Item 3.1.1-2.	The actual environments for these components are all essentially the same regardless of the listed temperature. The environments specifying the two temperature ranges indicate that the system temperature is above the threshold value that can result in cracking due to fatigue for the specific component material. The nominal fatigue threshold for stainless steel is 270°F and for carbon steel, 220°F as stated in the EPRI Mechanical Tools (EPRI Report 1003056).	Finnin, Ron	Chan, Laris	Closed
446	[3.1.1-J-02] In-core Housings; Nozzles - Head Seal Leak-Off (N12, N13).	Drawings were available for NRC review during the site visit.	Chan, Laris	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
447	[3.1.1-J-03] In LRA Table 3.1.2-1, the Component Type ID Attachment Welds (core spray, dryer hold down pads, etc) are indicated as having the intended function of "pressure boundary." Please justify that these components provide a pressure boundary function.	The license renewal function of these components (pressure boundary) concerns the weld between the ID attachment and the vessel. Because these components are directly attached to the pressure boundary, they were conservatively given an intended function of pressure boundary. This is consistent with the treatment of vessel ID attachment welds in NUREG-1801 Sections IV.A1-12 and XI.M4.	Finnin, Ron	Chan, Laris	Closed
448	[3.1.1-J-04] LRA Table 3.1.2-1 indicates that for ID Attachment Welds, the aging effect of "Cracking-fatigue" is managed by a TLAA. Please discuss whether these components are explicitly addressed in the TLAA or bounded by the results of the TLAA. What is the specific TLAA that manages the aging effect of "Cracking-fatigue" in these components?	These attachment welds are not specifically listed in the reactor vessel stress report; however, they are bounded by the results of that report. Any vessel stress report done per ASME Section III contains CUFs only for those locations that the designer felt could be fatigue limiting. While only these limiting areas are actually calculated, the stress report covers the entire vessel. A copy of the vessel stress report (Combustion Engineering CENC-1139) was provided to the inspector.	Finnin, Ron	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
449	[3.1.1-J-05] In LRA Table 3.1.2-3, carbon steel piping and fittings and valves in a treated water environment are shown as having the aging effect of loss of material. The aging management program recommended by corresponding GALL line item Volume 1, Table 1, Item 13, is Water Chemistry and One-Time Inspection . For piping and fittings and valves with diameter >= 4" NPS, the aging management program is shown as "Water Chemistry Control - BWR" and "Inservice Inspection" in LRA Table 3.1.2-3. For piping and fittings and valves with diameter < 4" NPS, the aging management program is shown as "Water Chemistry Control - BWR" in LRA Table 3.1.2-3. The note associated with the line items in LRA Table 3.1.2-3 is Note "C". Questions: For the carbon steel piping and fittings and valves with diameter >= 4" NPS, please provide justification that Note C is the correct note to apply for these components. For carbon steel piping and fittings and valves with diameter , 4" NPS, please provide justification that Note C is the correct note to apply for these components. Also, for these components please provide justification for not performing a one-time inspection as recommended by GALL line item Volume 1, Table 1, Item 13.	As identified in the discussion column entry of Table 3.1.1 Item 13 (3.1.1-13), Water Chemistry Control – BWR is augmented by the One-Time Inspection Program to assure effectiveness of the water chemistry program. This is true wherever the water chemistry program is credited. The Water Chemistry Control – BWR and One-Time Inspection Programs, by themselves, satisfy the NUREG-1801 recommendations. The ISI Program supplements the Water Chemistry and One Time Inspection Programs, but is not necessary to satisfy the NUREG-1801 recommendations. Since the Water Chemistry Control – BWR and One-Time Inspection Programs are consistent with the NUREG-1801 programs, a Note "A" or "C" is appropriate. Since the only viable comparison for these piping and valve lines is to IV.C1-6 for isolation condenser components, Note "C" must be used. For components with diameter < 4" NPS, the answer is the same. Both Water Chemistry Control – BWR and One-Time Inspection Programs apply to these components, which is consistent with the recommendations of NUREG-1801. Since the only viable comparison for these piping and valve lines is to IV.C1-6 for isolation condenser components, Note "C" must be used.	Finnin, Ron	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
450	[3.1.1-J-06] In LRA Table 3.1.2-1, some of the components with aging effect "Loss of Material" that roll up to LRA Table 1 line item 4.1.1-14 show that aging management is provided by "Water Chemistry Control- BWR and Inservice Inspection"; others of the components with aging effect "Loss of Material" that roll up to LRA Table 1 line item 4.1.1-14 show that aging management is provided by "Water Chemistry Control - BWR." The corresponding line item in GALL – Line 14 in Volume 1, Table 1 – shows the Aging Management Programs as "Water Chemistry" and "One-Time Inspection." LRA Note 3.1.2.2.2, paragraph 3, indicates that One-Time inspection of representative samples will be used to confirm the effectiveness of the Water Chemistry Control program. Question: Please discuss the criteria for selecting the sample points for the One-Time Inspections. Will the Thermal Sleeves that roll up to LRA Table 1 line item 4.1.1-14 be specifically inspected? Or, will they be included in the population from which components are selected for one-time inspection, but not specifically inspected? Please describe how the thermal sleeves provide the intended function of "Pressure Boundary." Does "pressure boundary" - in this context - mean RPV pressure boundary.	1) As explained in Section B.1.23 of the LRA: "The elements of the program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging degradation." In addition, guidance of NUREG-1801 for XI.M32 and XI.M35 will be used to select sample points. 2) They will be included in the population from which the samples are selected. Which specific items will be inspected will be determined by applying the guidance from NUREG-1801, Section XI.M32 and XI.M35, when PNPS implements this program. 3) These components are welded to the reactor coolant pressure boundary. Consequently, these components were conservatively given an intended function of pressure boundary. Thermal sleeves are considered subject to aging management review in NUREG-1801 item IV.A1-7.	Finnin, Ron	Chan, Laris	Closed
451	[3.1.1-J-07] Please clarify the function of the component in Table 3.1.2-3 identified as "Detector (CRD)"? Is this the rod position indicator assembly, or something else?	The detectors indicated as "Detector (CRD)" are detectors for pressure and level in the scram accumulators.	Finnin, Ron	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
452	[3.1.1-J-08] Please make available during the site visit a copy of the BWRVIP recommendations related to aging management of the steam dryer.	A copy of BWRIP-139 was provided to the inspector.	Chan, Laris	Chan, Laris	Closed
453	[3.1.1-J-09] The GALL's recommended aging management program for the steam dryer is "A plant-specific aging management program is to be evaluated." In Table 3.1.2-2 the Aging Management Program identified for the steam dryer is "BWR Vessel Internals" and Note "E" is applied. Please explain why Note E (rather than Note A) is applied for this line item. The discussion of "Notes" on LRA pages 3.0-4 and 3.0-5 states that "letter designations are standard notes based on Appendix F of NEI 95-10 (Reference 3.0-3)." The reference is to NEI 95-10, Revision 6. However, review of the reference finds that Appendix F is about "Industry Guidance on Revised 54.4(a)(2) Scoping Criteria"; and Notes are discussed in Table 4.2-2 of that document. Please correct this administrative error in the LRA.	Note "E" is used rather than Note "A" because the NRC and NEI agreed to use Note "E" rather than Note "A" when GALL specifies a plant-specific program. This indicates the need for the staff to review the acceptability of the program, while Note "A" would indicate that the use of the program had already been accepted as documented in the GALL report. The appropriate reference for the LRA standard format is NEI 95-10, Revision 6, Appendix D rather than Appendix F. This requires an amendment to the LRA. This response requires an amendment to the LRA.	Finnin, Ron	Mileris, George	Accepted
454	[3.1.1-J-10] GALL item VI.A1-5 indicates that penetrations for flux monitor and for the drain line roll up to GALL, Volume 1, Table 1, Item 40. The LRA does not indicate that penetrations for the drain line and for flux monitor roll up to LRA Table 3.1.1, Item 40. Please justify why the drain line penetrations and the flux monitor penetrations are not included in the roll-up.	A portion of this question requires clarification. Table 3.1.2-1 does not include a component type specifically named "flux monitor penetration." The incore housings, which provide vessel penetrations for flux detectors, are made of stainless steel and for the aging effect of cracking, the pointer to Table 3.3.1 is item 40. The drain nozzle in Table 3.1.2-1, which presumably is the drain line penetration indicated in the question, is composed of carbon steel, so rollup to Table 3.1.1 item 40, for stainless steel components, would be inappropriate.	Finnin, Ron	Mileris, George	Closed

Item	Request	Response	Lead	Support	Category
455	[3.1.1-J-11] In LRA Table 3.1.2-1 the aging effect of cracking for CRD Stub Tubes and In-Core Housings is shown as managed by Water Chemistry Control and BWR Vessel Internals AMPS. In GALL the aging effect of cracking for these components is shown as managed by Water Chemistry Control and BWR Penetrations. Please discuss why PNPS has included these component in the BWR Vessel Internals program rather than in the BWR Penetrations program as recommended by GALL.	The PNPS BWR Penetrations Program is consistent with the NUREG-1801 Section XI.M8, which covers only SLC/DP nozzle and instrument penetrations as discussed in BWRVIP-27 and BWRVIP-49. PNPS includes the CRD stub tubes and instrument housings in the BWR Vessel Internals Program as they are covered by BWRVIP-47, Lower Plenum, which is included in NUREG-1801 program XI.M9. This is slightly inconsistent with NUREG-1801 Section IV, but PNPS felt it was better to be consistent with the programs in Section XI than the one line item in Section IV. At PNPS, both the BWR Penetrations Program and the BWR Vessel Internals Program are implemented by the same plant procedure.	Finnin, Ron	Mileris, George	Closed
456	[3.1.1-J-12] In LRA Table 3.1.2-2 the Component Type "Control rod guide tubes - tube" is in an environment of "Treated water" > 270 deg-F, and the Component Type "Control rod guide tubes - base" is in an environment of "Treated water > 482 deg-F". Please clarify what is meant by "Control rod guide tubes - base" and explain why its environment is different from the "Control rod guide tubes - tube."	The CRGT base is located near the bottom of the guide tube and supports the control rod when the drive is disconnected and removed for service. The control rod guide tube is made of stainless steel. Its environment is given as >270 °F because that is the threshold for fatigue of stainless steel per the EPRI Mechanical Tools ((1003056). The guide tube base is made of CASS and consequently its environment was quoted as >482 °F as this is the threshold for thermal embrittlement in CASS. The limiting temperature was listed for each component. Both components see the same temperatures.	Finnin, Ron	Mileris, George	Closed

Item	Request	Response	Lead	Support	Category
457	[3.1.1-J-13] In LRA Table 3.1.2-3 the only components identified as having the aging effect of Loss of Material [due to FAC] and included in the Flow Accelerated Corrosion AMP are carbon steel piping and fittings >= 4" NPS. The GALL description of the FAC AMP (XI.M17) does not limit applicability of this program based on pipe diameter. Please justify why only the large-diameter piping in Table 3.1.2-3 is included in the FAC program. Please identify the piping segments that are included in the FAC program in LRA Table 3.1.2-3.	Flow-accelerated corrosion (FAC) is not expected to be a significant aging mechanism for the majority of the reactor coolant system.(including piping and fittings <4" NPS) as the lines are either seldom used (such as, scram discharge header, core spray, HPCI, nuclear system pressure relief, PASS, RCIC, RHR, and SLC) or there is little flow while in use (CRD, NBVI, RWCU). In LRA Table 3.1.2-3, carbon steel piping segments >=4" NPS (such as feedwater piping) are included in the FAC Program. PNPS has reviewed the FAC program and determined that it includes a portion of the reactor vessel drain piping that supplies RWCU, and this is small bore - carbon steel piping. PNPS will add loss of material due to flow accelerated corrosion to the line entry for small bore piping (<4" NPS) in LRA table 3.1.2-3 (page 3.1-63). The new entry will identify Flow accelerated corrosion as a separate aging effect as done for the large bore carbon steel piping entry on page 3.1-65. The GALL comparison will be Volume 2 item IV.C1-7 which rolls up to Table 3.1.1-45. This requires an amendment to the LRA.	Finnin, Ron	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
458	[3.1.1-J-14] In LRA Table 3.1.2-2, for components with aging effect "Loss of Material" that roll up to LRA Table 1 Item 3.1.1-47, the AMP is identified as "Water Chemistry Control - BWR." However, in the GALL the aging effect of Loss of Material for these components is managed by both Water Chemistry and Inservice Inspection (IWB, IWC, and IWD). Please justify why Water Chemistry Control - BWR with no associated inspection is adequate to manage the aging effect of Loss of Material for these components.	The items in Table 3.1.2-2 that roll up to Line Item 3.1.1-47 (GALL table IV item IV.A1-6) are for loss of material due to pitting and crevice corrosion. NUREG-1801 repeatedly credits Water Chemistry Control - BWR augmented by the One-Time Inspection program to manage loss of material due to pitting and crevice corrosion (for example IV.A1-8, IV.A1-11). This program combination is adequate to manage this aging effect in that the loss of material due to pitting and crevice corrosion for the internals is no different than the loss of material due to pitting and corrosion for other stainless steel components exposed to reactor coolant. As noted in Table 3.1.1, the One-Time Inspection Program will verify effectiveness of the Water Chemistry Control - BWR Program. While ASME Code table IWB-2500-1 (Category B-N-1) does require VT-1 or VT-3 inspection of the interior attachments and core support structures, it does not require inspection of the majority of the internals. Therefore, crediting ISI for managing loss of material of the internals in general is inappropriate. The PNPS One-Time Inspection Program will incorporate the results of other inspections that are performed including ISI inspections done per ASME XI IWB-2500-1 B-N-2 and other opportunistic inspections.	Finnin, Ron	Pardee, R.	Closed

Item	Request	Response	Lead	Support	Category
459	[3.1.1-J-15] In LRA Table 3.1.1, Item Number 3.1.1-48 Discussion includes the statement, "Inservice inspection is not applicable to components < 4" NPS." ASME Section XI, Table IWB 2500-1, Examination Category B-J, requires Surface (but not Volumetric) examination for pressure retaining welds in Class 1 pipe that is < 4" NPS. Please reconcile the statement in Item 3.1.1-48 Discussion with the ASME Section XI requirements stated above.	Perhaps the statement that ISI does not apply is misleading. We should have said that PNPS does not credit ISI for aging management of piping <4". ISI typically only requires surface examinations of these components and the aging effects requiring management initiate on the ID, therefore we did not credit ISI for managing these effects. An LRA amendment is required. PNPS will amend the LRA to delete the statement "Inservice inspection is not applicable to components < 4" NPS." from the discussion in line item 3.1.1-4. This will require an amendment to the LRA.	Finnin, Ron	Pardee, R.	Accepted
460	[3.1.1-J-16] In LRA Table 3.1.1, Item Number 3.1.1-48 Discussion includes the statement, "Cracking in steel components due to thermal and mechanical loading is not directly dependent on water chemistry, so only the One-Time Inspection Program is credited." However, there are no line items in the 3.X.2 Tables where "One-Time Inspection" by itself rolls up to Item Number 3.1.1-48. Please explain the apparent inconsistency between the LRA statement and the way that the roll-ups to Item Number 3.1.1-48 are done in the LRA.	For clarification, the statement "Cracking in steel components due to thermal and mechanical loading is not directly dependent on water chemistry, so only the One-Time Inspection Program is credited" should be deleted. An LRA amendment is required. PNPS will amend the LRA to delete the statement "Cracking in steel components due to thermal and mechanical loading is not directly dependent on water chemistry, so only the One-Time Inspection Program is credited." from the discussion in line item 3.1.1-48 This will require an amendment to the LRA.	Lingenfelter, Jacque	Chan, Laris	Accepted

Item	Request	Response	Lead	Support	Category
461	[3.1.1-J-17] In GALL Volume 1, Table 1, Item 49, an augmented inspection using UT or other demonstrated acceptable inspection is recommended for BWRs with a crevice in the access hole covers. Does PNPS have a crevice in the access hole covers? Does PNPS perform an inspection of the access hole covers using UT or other demonstrated acceptable inspection techniques?	TIMELINE OF SHROUD ACCESS HOLE COVER EXAMINATIONS: - 1988 – GE issues SIL 462 - 1991 (RFO-8) - UT of both covers (for circ. flaws only) - 1993 (RFO-9) - UT of both covers (for circ. and radial flaws) - 1995 (RFO-10) - UT of zero degree cover only - 1995 (RFO-10) - VT-1 of both covers - 2001 – GE issues SIL 462 Rev.1 on 3/01 - 2003 (RFO-14) - EVT-1 of both covers - 2005 (RFO-15) - no exams - 2007 (RFO-16) - Plan to inspect at 180 degrees by VT-1 - 2009 (RFO-17) – Plan to inspect at 0 degrees by VT-1 Pilgrim will continue to inspect the access hole covers at 180 degrees and 0 degrees visually at 4 and 6 year intervals, respectively, during the current licensing period. If new BWRVIP guidance is issued on these components, PNPS will perform inspections in accordance with that guidance. Within the first 6 years of the period of extended operation and every 12 years thereafter, PNPS will inspect the access hole covers with UT methods. Alternatively, PNPS will inspect the access hole covers in accordance with BWRVIP guidelines should such guidance become available.	Pardee, Rich	Mileris, George	Accepted

Item	Request	Response	Lead	Support	Category
		This is commitment item 34.			
462	[3.1.1-J-18] RA Table 3.1.2-1 lists the ISI program as the AMP used to managing the aging effect of cracking in "Other Pressure Boundary Bolting - Upper head flange bolts and nuts - CRD flange bolting. Please identify the ASME Examination Category and Requirements that are applicable for these components.	Category B-G-1 of the ASME XI code contains the requirements for all pressure-retaining bolting >2" dia. in the ISI Program. The code requires a volumetric (ultrasonic) exam for all RPV closure studs (examined in place) and a VT-1 visual exam for all RPV closure nuts every 10 years. Category B-G-2 of the ASME XI code contains the requirements for pressure-retaining bolting <=2" dia. in the ISI Program. The code requires a VT-1 visual exam every 10 years for bolting in this category (includes CRD flange bolting, RPV head N7 & N8 nozzle flange bolting).	Pardee, Rich	Pardee, R.	Closed
463	[3.1.1-J-19] LRA Table 3.1.2-2 identifies "Thermal Aging Embrittlement of CASS" as the AMP to manage the aging effect of "reduction in fracture toughness" for three component types: "Control Rod Guide Tubes - Base", "Fuel Support Pieces - Four Lobed", and "Jet Pump Assemblies [various components]." However LRA Table B-2 says that the NUREG-1801 Program "Thermal Aging Embrittlement of CASS" is "not applicable" at PNPS. Please correct or justify this apparent inconsistency in the LRA. Also, if an LRA correction is needed, please ensure that the Notes for each of the three component line items are validated or changed to be consistent with any changes made in the LRA.	NUREG-1801 program XI.M12 "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)" applies to CASS pressure boundary components in the RCS. This program is not applicable to PNPS, as we have no CASS pressure boundary components. NUREG-1801 program XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)" applies to reactor vessel internals (non-pressure boundary) pieces made of CASS. The mentioned components above are all reactor vessel internals and are covered by this program. In some instances, the LRA refers to Thermal Aging Embrittlement of CASS Program as a shortened name for and with a hyperlink to the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program. For clarification, those instances will be revised to clearly indicate the appropriate program. This requires an amendment to the LRA.	Finnin, Ron	Mileris, George	Accepted

Item	Request	Response	Lead	Support	Category
464	[3.1.1-J-20] GALL Volume 1, Table 1, Line 52 identifies the aging effects for RCPB closure bolting as "Cracking due to SCC, loss of material due to wear, loss of pre load due to thermal effects, gasket creep and self-loosening." Only the aging effect of "Cracking" is identified in LRA Table 3.1.2-1 for component that roll up to LRA Line Item 3.1.1-52. The "Discussion" in the LRA for Line Item 3.1.1-52 provides discussion of why the other aging effects listed in GALL are not included applicable at PNPS. Question: Please provide PNPS' basis for the Discussion statement that "Industry operating experience indicates that loss of material due to wear is not a significant aging effect for this bolting." Please clarify what is meant by "not a significant aging effect." Please provide a copy of technical reference(s) supporting the LRA statement that "Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700 deg-F).	To clarify the LRA discussion in line item 3.1.1-52, the phrase "not a significant aging effect" means not an aging effect requiring management. This is consistent with the EPRI Mechanical Tools that do not consider loss of material due to wear an aging effect for bolted closures. In addition, loss of material due to wear was not identified as an area of concern in the resolution of GSI-29 for bolting. The general system bolting to which this line item applies is not routinely disassembled. Occasional thread failures due to wear mechanisms such as galling, are not age related but are event-driven conditions that are resolved when they occur. Bolting at PNPS is standard grade B7 carbon steel, or similar material, except in specialized applications where stainless steel bolting is utilized. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700°F) as stated in the ASME Code, Section II, Part D, Table 4. No PNPS bolting operates at >700°F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for the reactor coolant system. A copy of this section of the code was available during the audit.	Finnin, Ron	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
465	[3.1.1-J-21] The LRA Discussion for Line Item 3.1.1-52 includes the statement, "To address these bolting operational concerns, PNPS has taken actions to address NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants." Please identify and provide a copy of any previous, docketed correspondence in which PNPS describes its actions and commitments (if any) with regard to NUREG-1339.	GL 91-17, Generic Safety Issue 29, Bolting degradation or failure in nuclear power plants is dated 10/17/91. The GL required no response and no docketed correspondence was submitted. PNPS did review GL 91-17 in 1991 and a review summary was provided to the NRC audit team during the site visit. Partly as a result of the PNPS review of GL 91-17, Station Maintenance procedure for bolting, 3.M.4-92 was developed based on EPRI NP-5067, "Good Bolting Practices".	Chan, Laris	Brochu, Jill	Closed
466	[3.1.1-J-22] In LRA Table 3.1.2-1 a line item identifies the aging effect of "Loss of Material" for the component type "Closure flange studs, nuts, washers, and bushings." Note "H" is applied for this line item, indicating that the aging effect is not in NUREG-1801 for this component, material and environment combination. Please identify and discuss the mechanism that creates the aging effect of "Loss of Material" in these components. Please identify and describe PNPS-specific or industry experience where the aging effect of "Loss of Material" has been observed in these components. Please include a discussion of why "Loss of Material" is an aging effect applicable for these components but not for components that roll up to LRA Table Line Item 3.1.1-52.	In the Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3, EPRI, Palo Alto, CA: 2001. 1003056 (The Mechanical Tools) Appendix E, low alloy steel exposed to indoor air containing moisture (humidity) is subject to loss of material due to the aging mechanism of general corrosion. This bolting item has this material and environment combination and therefore the aging effect is applicable. In accordance with the operating experience provided in the Reactor Head Closure Studs Program, examination of 18 reactor head closure studs and visual examination of 18 nuts and 18 washers during RFO15 found no new recordable indications of loss of material. LRA Table Line Item 3.1.1-52 is based on NUREG-1801, Volume 1, Table 1 which addresses loss of material due only to wear for carbon and stainless steel bolting. Since the NUREG-1801 line item does not address any other aging mechanisms that result in loss of material, it was deemed that the line item is not applicable for loss of material due to general corrosion	Finnin, Ron	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
467	[3.1.1-J-23] LRA Table 3.1.2-3 includes a line item for Main Steamline Flow Restrictors made of CASS, in an environment of Treated Water > 482 deg-F, aging effect of Reduction in Fracture Toughness. For Class 1 piping components made of this material, in this environment and with this aging effect, the GALL recommends the AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." In lieu of the recommended AMP, PNPS proposes to use a One-Time Inspection. Questions: The GALL-recommended AMP includes screening criteria to determine which CASS components are potentially susceptible to thermal aging embrittlement and require augmented inspection. Has PNPS applied the screening criteria to the Main Steamline Flow Restrictors? If so, what were the results? Please describe what examination requirements, methods and standards will be used in PNPS's proposed One-Time Inspection of the Main Steamline Flow Restrictors. Please justify that a One-Time Inspection provides adequate aging management of the Main Steamline Flow Restrictors during the period of extended operation.	The main steam line flow restrictors are not pressure retaining components (no pressure boundary function). They are a cast piece that is inserted inside the main steam piping. The main steam piping is the pressure boundary. Consequently, the main steam flow restrictors are not a good candidate for GALL program XI.M12. a) No, PNPS has not done the screening for the main steam line flow restrictors. b) While the inspection procedure has not yet been developed, the planned inspection is a visual examination performed by inserting a camera into the main steam line. c) Reduction of Fracture Toughness (Cracking) and Loss of Material of the main steam line flow restrictors are not considered likely effects during the period of extended operation (No aging of these restrictors is identified by NUREG-1801). Loss of material will be mitigated by BWR - Water Chemistry Control. Nonetheless, PNPS has committed to do a one-time inspection to verify that these aging effects are not occurring. Since the flow restrictors are not pressure retaining components, the One-Time Inspection Program is adequate to manage the effects of aging.	Finnin, Ron	Mileris, George	Closed

Item	Request	Response	Lead	Support	Category
468	[3.1.1-J-24] LRA Item Number 3.1.1-53 Discussion states, "There are no steel components of the Class 1 reactor vessel, vessel internals or reactor coolant pressure boundary exposed to closed cycle cooling water." However, LRA Table 3.1.2-3 (page 3.1-68) includes line items for Pump cover - Thermal barrier (RR) made of CASS where the aging management programs are identified as "Water Chemistry Control - Closed Cooling Water" and "Inservice Inspection." These line items appear to be inconsistent with the Discussion in 3.1.1-53. Please explain why these line are not inconsistent with the Discussion in 3.1.1-53 or correct the inconsistency.	As stated in the question, item 3.1.1-53 refers to steel components. CASS is considered stainless steel. The material and environment combination of stainless steel in closed cycle cooling water does not appear in the RCS (Chapter IV) tables of NUREG-1801; therefore, the line item for the pump cover – thermal barrier is compared to the ESF tables of NUREG-1801.	Lingenfelter, Jacque	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
469	[3.1.1-J-25] PNPS LRA Table 3.1.2-3 includes entries for piping and fittings made of carbon steel in a environment of Air-indoor (ext). Some of these entries have an aging effect of loss of material; some of these entries have an aging effect of "none." For the entries with aging effect of "none", Note 101 is applied and states, "High component surface temperature precludes moisture accumulation that could result in corrosion." Please clarify the high temperature conditions that are mentioned in the note: What is the "high temperature" threshold? For piping that experiences significant temperature changes during operation, approximately what percentage of operation at temperature below the high temperature threshold is assumed or anticipated for those piping and fittings where the aging effect is "none"? Please discuss the methodology that PNPS uses to identify which piping is classified as having aging effect of "loss of material" and which has aging effect of "none."	The selection of the aging effect of loss of material or of no aging effect was dependent upon the temperature of the component during normal operation. Components with a temperature above the boiling point of water will preclude moisture accumulation. As a matter of convenience, the transition point was assumed at the temperature threshold of 220°F for cracking due to fatigue in steel. Although these components can be below this threshold during shutdown conditions, and some components could possibly see temperatures both above and below this threshold during normal operation, these components should rarely, if ever, be at a temperature below the local dew point. Consequently, even during shutdown conditions, moisture accumulation should be negligible. The PNPS position on loss of material on exterior surfaces of steel piping grew out of earlier license renewal application experience. Loss of material on external surfaces is normally managed by system walkdowns; however, system walkdowns don't inspect the exterior surface of insulated piping unless the insulation is removed for maintenance. There is no need to remove insulation and directly inspect pipe external surfaces as the heat that requires the insulation prevents moisture accumulation which in turn prevents loss of material. PNPS's plan is to inspect uninsulated steel piping for loss of material via system walkdowns and not remove any insulation.	Lingenfelter, Jacque	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
470	[3.1.1-J-26] PNPS LRA Table 3.1.2-3 contains two line items for "Bolting (flanges, valves, etc)" where the material is either low alloy steel or stainless steel, the environment is Air-indoor (external), and the aging effect is cracking. Please identify the mechanism that causes this aging effect in these components. Please justify that the inservice inspection program provides aging management of these components adequate to ensure that they continue to perform their intended function during the period of extended operation. Please clarify whether PNPS will be developing a bolting integrity program modeled on Section XI.M18 to include these components.	Table 3.1.1 item number 3.1.1-52 specifies the aging effect of cracking due to stress corrosion cracking for carbon and stainless steel reactor coolant system pressure boundary closure bolting. Inservice inspection of bolting components is specified in GALL XI.M18, Bolting Integrity, for management of cracking and loss of material of pressure retaining bolting inspected in accordance with ASME Section XI. Therefore, inservice inspection is acceptable for managing cracking in reactor coolant pressure boundary bolting. However, a Bolting Integrity Program that credits inservice inspections will be developed that will address the aging management of bolting in the scope of license renewal. This requires an amendment to the LRA to include descriptions of the Bolting Integrity Program in Appendices A and B and to identify where the program is applicable. This item is closed to Item 373.	Finnin, Ron	Chan, Laris	Accepted
471	[3.1.1-J-27] In LRA Table 3.1.2-3, MEAP combination Bolting, Stainless steel, Air-indoor, Cracking-fatigue, TLAA – the notes are "A, 105." Please explain why note 105 is applicable to this line item.	The aging effect of cracking due to fatigue depends on the thermal and mechanical loading of the component and is effectively independent of the environment at the surface of the component. The tables in NUREG-1801, Volume 2, Chapter IV (outside of Subsection A1) include components with an air environment and an aging effect of cracking due to fatigue. While one of these lines could have been used as a substitution, the choice of a line within the corresponding system table (Table IV.C1 in this case) was preferred. Plant specific Note 105 explains that the difference in environments is acceptable for the evaluation of cracking due to fatigue.	Lingenfelter, Jacque	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
472	[3.1.1-J-28] In LRA Table 3.1.2-1, MEAP combinations "Closure flange studs" or "Other pressure boundary bolting," Low alloy steel, Air-indoor, Cracking-fatigue, TLAA – the notes are "C, 105." Please explain why note 105 is applicable to these line items.	The aging effect of cracking due to fatigue depends on the thermal and mechanical loading of the component and is effectively independent of the environment at the surface of the component. The tables in NUREG-1801, Volume 2, Chapter IV (outside of Subsection A1) include components with an air environment and an aging effect of cracking due to fatigue. While one of these lines could have been used as a substitution, the choice of a line within the corresponding system table (Table IV.A1 in this case) was preferred. Plant specific Note 105 explains that the difference in environments is acceptable for the evaluation of cracking due to fatigue.	Lingenfelter, Jacque	Mileris, George	Closed

Item	Request	Response	Lead	Support	Category
473	[3.1.1-J-29] In LRA Table 3.1.2-1, the following components are identified as having the aging effect of "cracking," and Note H is applied: Dome (Bottom Head); Dome (Upper Closure Head); Flanges (Shell closure flange and Upper head closure flange); Vessel Shell (Beltline shell); Vessel shell (Intermediate nozzle shell, lower shell, upper shell); Nozzles (Main steam). Table 3-1 in BWRVIP-74-A (Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal) addresses various potential age related mechanisms and indicates the components to which the mechanisms apply. Except for the mechanism of "fatigue" which applies to some of the components listed in the paragraph above, there is no mechanism in Table 3-1 of BWRVIP-74-A that causes cracking and that BWRVIP-74-A identifies as applicable for the components listed above. Question: Please provide a discussion of the methodology that PNPS used to determine that the aging effect of "cracking" is applicable for the components listed in the first paragraph, above. Please identify the mechanism(s) that cause cracking in these components. Please explain how or whether PNPS incorporated the information contained in BWRVIP-74-A into its determination that cracking is an aging effect applicable for these components. Please discuss the plant-specific or industry experience reviewed by PNPS in making the determination that cracking is an aging effect applicable for these components.	The cracking referred to in these entries is stress corrosion cracking of the stainless steel cladding. This was not entered based on BWRVIP-74, but was based on the mechanical tools and industry operating experience. NUREG-1801 also specifies cracking due to SCC as an aging effect for many stainless steel material entries. Note that for entries such as Nozzle, Drain (N11) which is unclad carbon steel there is no cracking entry other than cracking-fatigue.	Finnin, Ron	Mileris, George	Closed

Item	Request	Response	Lead	Support	Category
474	[3.1.1-J-30] In LRA Table 3.1.2-1, the component Stabilizer Pads (part of Supports - Stabilizer pads, support skirt) is identified as having an aging effect of "loss of material" and the AMP is Inservice Inspection. Questions: What is the mechanism that causes the aging effect of loss of material? Please describe the Inservice Inspection for the Stabilizer pads: What is the examination frequency? Examination requirement? Examination method? Acceptance standard? Are there any currently approved relief requests applicable for this component?	The entry in table 3.1.2-1 is for both the support skirt and the stabilizer pads. The support skirt was conservatively considered susceptible to loss of material as it remains below 220 °F. The stabilizer pads are located on the sides of the vessel, and are typically greater than 220 °F. Consistent with other LRA components, these pads should not be subject to loss of material. The LRA will be clarified to indicate that the loss of material entry applies only to the support skirt. This requires an amendment to the LRA. The stabilizer pads are inspected per ASME Section XI Table IWB-2500-1 category B-K. The code (footnote 7 to Table IWB-2500-1 category B-K) allows surface examination from an accessible side of the weld. At PNPS the top side of the weld is accessible and PNPS performs magnetic particle testing of the top side of each bracket weld in every 10 year interval. PNPS meets the code requirements and therefore has no relief request for these inspections.	Finnin, Ron	Mileris, George	Accepted

Item	Request	Response	Lead	Support	Category
475	[TLAA-H-01] The applicant is requested to provide the design codes for the liner plate, torus down comer/vent header and torus-attached piping, and SRV piping for review.	[1] The design code for the drywell liner plate is ASME Code, Section III. The code includes Code Case 1330-1 and Code Case 1177-5, and the latest edition as of June 9, 1967. [Reference Chicago Bridge and Iron (CB&I) document 9-8014]. For the torus shell, the design code is ASME Code, Section III. The code includes Code Case 1330-1 and Code Case 1177-5, and the latest edition as of June 9, 1967. It was later evaluated to the requirements of ASME Section III Division I with addenda through Summer 1977 and Code Case N-197 as part of the Mark 1 Torus Program. [Reference Teledyne Engineering Services (TES) document TR-5310-1]. [2] The original design code for the torus downcomer/vent header is ANSI B31.1, 1967 edition. It was later evaluated to the requirements of ASME Section III Division I with addenda through Summer 1977 and Code Case N-197 as part of the Mark 1 Torus Program. [Reference TES document TR-5310-1]. [3] The original design code for the torus attached piping is ANSI B31.1, 1967 edition. It was later evaluated to the requirements of ASME Section III, 1977 edition, with Addenda through Summer 1977 as part of the Mark 1 Torus Program. Pipe support analysis was performed to Section III Subsection NF [Reference TES document TR-5310-2]. [4] The original design code for the SRV piping is ANSI B31.1, 1967 edition. It was later evaluated to the first anchor from the torus to the requirements of ASME Section III, 1977 edition, with addenda through Summer 1977 as part of the Mark 1 Torus Program. [Reference TES document TR-5310-2]. The SRV/DL piping was analyzed for higher discharge flow as part of the Thermal Power Optimization (TPO) Program to the same design code.	Chan, Laris	Mileris, George	Closed

Item	Request	Response	Lead	Support	Category
476	[TLAA-H-02] The applicant is requested to provide a statement indicating that the estimate of the total number of 60-year SRV actuations used in the design fatigue analysis remains valid and conservative, based on the actual SRV actuations counted through 2005.	PNPS has tracked SRV actuations from 1992 to 2005. A total of 14 actuations have been recorded on valve A, and 13 each on valves B, C and D. Using the 14 actuations in this thirteen year period, the projected actuations for the rest of 60 years are 31 lifts. The number of lifts in the first 21 years of plant life (1972 – 1993) were not recorded. These lifts were more frequent in the early years, so PNPS estimated these 21 years at 5 times the recorded rate. This yields 120 lifts in the first 21 years. Combining the early period, the recorded period, and the projected period, there will be an estimated 165 lifts in 60 years. PNPS plant specific analysis (Teledyne Engineering Services document TR-5310-2) states that the SRV penetrations are qualified for 7500 cycles of maximum load Based on this, the projected CUF for 60 years is calculated as 0.022.	Chan, Laris	Mileris, George	Closed

Item	Request	Response	Lead	Support	Category
477	[TLAA-H-03] Please provide Fatigue Analysis of the SRV discharge piping and Fatigue analysis of other Torus attached piping.	Teledyne Engineering Services document TR-5310-2 documents stress evaluations for the SRV piping for various load combinations, but does not include a fatigue analysis. (The fatigue analysis of the SRV piping along with all the other torus attached piping.) (TAP is bounded by MPR-751, the GE Mark 1 containment program. MPR-751 concluded that for all plants and piping systems considered, in all cases the fatigue usage factors for an assumed 40-year plant life was less than 0.5. In a worst-case scenario, extending plant life for an additional 20 years would produce usage factors below 0.75. Since this is less than 1.0, the fatigue criteria are satisfied. The MPR-751 generic fatigue analysis is thus protected for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii) A PNPS/plant specific analysis addresses the SRV discharge piping and its supports, as well as the main vent penetration through which the SRV discharge enters the torus. This analysis states that the SRV penetrations are qualified for 7500 cycles of maximum load while the SRVs are expected to see less than 50 cycles at maximum load and less than 4500 cycles a partial load. The report concludes "Since the 7500 cycles of maximum load bounds both of these by such a large margin and since no other significant loads are imposed on the line, the penetration was assumed acceptable for fatigue without further evaluation." Increasing the 40 year cycles by 1.5 for the period of extended operation would still be only 75 maximum load cycles and 6750 low load cycles for a total of 6850 mixed load cycles, less than the 7500 maximum load cycles permitted. The fatigue analysis for torus penetrations thus remains valid for the period of extended operation in accordance	Finnin, Ron	Chan, Laris	Closed

with 10 CFR 54.21(c)(1)(i).

The PNPS plant-specific analysis (TR-5310-2) references the generic GE Mark 1 Containment program for other torus attached piping. The results of the generic GE Mark 1 containment program (based on 40 years of operation) were that 92% of the TAP would have cumulative usage factors of less than 0.3, and that 100% would have usage factors less than 0.5. Conservatively multiplying the CUFs by 1.5 shows that for 60 years of operation, 92% of the TAP would have CUFs below 0.45, and 100% would have CUFs below 0.75. These calculations have thus been projected through the period of extended operation in accordance with 10 CFR 50.21(c)(ii).

Item	Request	Response	Lead	Support	Category
490	What is the operating history for buried pipes in terms of the number of inspections and any leaks and their cause, (internal or external caused leaks)? Have any buried pipes been replaced due to corrosion or coating problems? If the phased array UT technique is used, how will it be qualified and how will the operators be qualified?	In the past 5 years there has been limited experience with the inspection of buried piping at PNPS. This experience has occurred mainly on the fire water underground distribution system. This system is approximately 35 years old and consists of cement lined malleable iron pipe with mechanical joints. There has been no history of significant leaks other than during two instances, one in 2001 and one in 2005. In the first event the 8" underground line down stream of 8-L-22 failed. The probable cause of failure was most likely induced by minor fabrication anomalies compounded by marginal installation techniques. When this piping was examined it was found to be overall in very good condition externally except for a small area of surface corrosion, attributed to marginal installation techniques. In the second event the 8" underground pipe failed in the area of the N2 tank adjacent to the EDG building. Due to congestion and the presence of the tank, which was installed subsequent to the installation of the piping, it was not possible to dig up the piping to examine it and determine the cause of the failure but may be related to the installation of the tank. In addition to these two instances there have been a number of valves excavated during maintenance which found the valves and piping to be in remarkably good condition. From an additional historical perspective, the salt service water (SSW) system at PNPS has experienced leaks on the buried inlet (screenhouse to auxiliary bays) piping as a result of internal corrosion. The original piping material was rubber lined carbon steel wrapped with reinforced fiberglass wrapping and coal tar saturated felt and heavy Kraft paper. The leaks were determined to be the result of the degraded rubber lining being in contact with sea water. These pipes have	Ivy, Ted	Kalb, J	Closed

since been replaced with unlined Titanium wrapped with the same external coating as the original pipe. This pipe replacement occurred in 1995 and 1997. In addition, the SSW buried discharge piping (also rubber lined carbon steel with external pipe wrapping, same as inlet piping) from the auxiliary bays to the discharge canal also experienced severe internal corrosion due to failure of the rubber lining. Two 40' lengths of 22" diameter pipes (one on each loop) were replaced in 1999 as a result of the failed rubber lining and internal corrosion. These spools were replaced with carbon steel coated internally and externally with an epoxy coating. The piping that was removed was examined after its wrapping was removed and its external surface was found to be in good condition. Since that time, the entire length of both SSW buried discharge loops have been lined internally with cured-in-place pipe linings, "B" Loop in 2001 and "A" Loop in 2003.

The phased array inspection technique, was provided merely as an example of a potential future examination technique. It and other remote techniques will potentially be able to assess the condition of extensive portions of buried piping without the need for excavation. This exception was taken to allow the potential use of this technique or others in lieu of excavating piping in order to provide a more effective assessment of overall piping condition while eliminating the potential for damaging the piping during excavation. Since a superior inspection technique is not yet available, specifics regarding qualification of the process and technicians are not available.

Item	Request	Response	Lead	Support	Category
494	Five line items in Table 3.3.2-14-1 (LRA pages 3.3-134 through 137) reference Table 3.4.1 item 3.4.1-8 and credit PSPM Program to manage the aging effect of LOM for steel piping, piping components, and piping elements exposed to raw water. Please identify the specific components in the Circulating Water System that are represented by these Table 2 line items and provide procedures under which PSPM will be implemented to manage the aging effect of LOM due to general, pitting, crevice, MIC, and fouling.	The circulating water system consists primarily of two circulating water pumps and associated piping and valves as shown primarily on M211. The review to determine the 10 CFR 54.4(a)(2) components used a spaces approach that identified all component types and material combinations in the system that were in scope but did not list individual component numbers. As identified in LRA Table 2.3.3.14-B, the only areas of the turbine building that were excluded were the components inside the main condensers and the only portions of the intake structure that were excluded were the intake structure hypochlorite pump room and chlorination area. The components included bolting, circulating water pump casings, the above ground piping, tubing, thermowells, the condenser inlet outlet and cross connect valves, expansion joints and the associated vent, drain, and instrument valve bodies. The water box scavenging system shown on M211 is no longer in use, but the portions that still form a pressure boundary for the water boxes are included. As identified on M212 Sheet 1, the residual chlorine sample pump is no longer used, but portions of the system were included that still form the pressure boundary. As indicated in Attachment 3 of LRPD-02, Aging Management Program Evaluation Report (AMPER), procedures do not exist for the inspection of these components, and a complete listing of components that will be included in the procedures is not available. As stated in LRA Appendix B and Commitment 21, program activity implementing documents will be enhanced prior to the period of extended operation to incorporate the attributes of this inspection described in the AMPER. This will assure	Ivy, Ted	Gaedtke, Joe	Closed

Item	Request	Response	Lead	Support	Category
		that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.			
495	Four line items in Table 3.3.2-14-1 (LRA pages 3.3-134 and 135), PNPS claimed that Circulating Water System components of piping and tanks which are made of plastic, have no aging effect under condensation external and raw water internal environments. What kind of plastic material are they. Why are they not subject to aging effect?	Some of the circulating water system piping in scope for [Maintenance Rule 10 CFR 50.65] (a)(2) shown on the piping & instrument diagrams is piping codes JE and JF. Pipe class JE is fiberglass reinforced plastic. As identified in the PNPS Specification for Piping M300, piping code JF allows the use of PVC piping. Per Note 3 on M211, some of the piping is PVC. The 55 gallon drum shown on M212 Sheet 1 which is the tank in this line item is also PVC. Aging effects were identified for (a)(2) components included in AMRM-30 using the Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3, EPRI, Palo Alto, CA: 2001, 1003056 (The Mechanical Tools). In accordance with the Mechanical Tools, Section 2.1.8 of Appendix A, PVC and thermoplastics are relatively unaffected by water or humidity. The components in question are installed indoors and contain raw water. Therefore, based on the Mechanical Tools and industry operating experience, this piping has no aging effects requiring management in raw water or condensation environments.	Ivy, Ted	Gaedtke, Joe	Closed

Item	Request	Response	Lead	Support	Category
496	Four line items in Table 3.3.2-14-1 with note F(LRA page 3.3-133), the applicant proposed to manage cracking and change in material properties of the elastomer for condenser expansion joint exposed to raw water and condensation in external environment using AMP of Periodic Surveillance and Preventive Maintenance (PSPM). Please provide technical justification as why PSPM alone is sufficient to manage the aging effects of cracking and change in a material properties.	As indicated in Attachment 3 of LRPD-02, Aging Management Program Evaluation Report (AMPER), inspections will be performed to determine the surface condition and flexibility of the circulating water expansion joints. As indicated in the AMPER, a representative sample of the expansion joints will be visually inspected and manually flexed every 5 years to verify no significant cracking or other abnormalities while flexing elastomer components. A visual inspection and physical manipulation of this component ensures that the elastomer is not cracking and that the material properties of flexibility are still adequate for the expansion joint to maintain its pressure boundary and not affect safety-related components. Industry operating experience for components of this type has shown that the frequency of inspection should be adequate to manage these aging effects.	Ivy, Ted	Gaedtke, Joe	Closed
497	Three line items in Table 3.3.2-14-1 (LRA pages 3.3-134, 135, and 136), the applicant proposed to manage LOM of copper alloy >15% Zn for piping, strainer housing and valve body exposed to condensation external environment using AMP of System Walkdown. Please provide technical justification as why System Walkdown alone is sufficient to manage the aging effect of LOM. Do you consider the aging effect of loss of material due to selective leaching for these line items.	While these components are managed by the selective leaching program for the internal surface, the selective leaching program is not credited with the management of loss of material for external surfaces that are only wetted by condensation. If these components were to experience selective leaching, the aging effect will occur on and be identified by the Selective Leaching Program for the internal surface that is exposed to raw water before any significant selective leaching is experienced on the external surface that is wetted only by periodic condensation. This is due to the minimal amount of electrolyte that is present in a periodic condensation environment. Therefore, the System Walkdown Program alone is expected to be an adequate program for the external surfaces of these components.	Ivy, Ted	Gaedtke, Joe	Closed

Item	Request	Response	Lead	Support	Category
498	Eleven line items in Table 3.3.2-14-9 with note G (Extraction Steam System, the applicant proposed to manage cracking, LOM, and cracking-fatigue of nickel alloy for expansion joint exposed to treated water using water chemistry control BWR and TLAA metal fatigue. Two line items related to TLAA metal fatigue will be lumped to Question 3.4.1-W-01 for discussion. For the other 9 line items, please provide technical justification as why Water Chemistry Control BWR alone is sufficient to manage the aging effects of cracking and LOM.	As can be seen in section 4.24.2 of LRPD-02, Aging Management Program Evaluation Report (AMPER), the water chemistry control-BWR program includes periodic monitoring and control of known detrimental contaminants such as chlorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. As identified in Attachment 2 of the AMPER, a One-Time Inspection Program will be completed to verify the effectiveness of the water chemistry control-BWR program to manage the aging effects of loss of material and cracking. Therefore, the combination of these two programs is sufficient to manage the aging effects of cracking and loss of material for nickel alloy components exposed to treated water. This requires an amendment to the chemistry program descriptions in LRA Appendices A and B to clearly indicate that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - BWR, Water Chemistry Control - Auxiliary Systems and the Water Chemistry Control - Closed Cooling Water programs. This item is closed to Item 372.	Ivy, Ted	Gaedtke, Joe	Closed

Item	Request	Response	Lead	Support	Category
499	[T.3.3.2.14] In Table 3.3..2-9, Fire Protection - Water System, PNPS credits LRA AMP B.1.13.1, Fire Protection Program to manage loss of material and fouling of gray iron and copper ally >15% Zn heat exchanger shell and tubes. However, the Fire Protection program description does not include these components nor has the program been enhanced to include these components. Please clarify how the Fire Protection Program will manage these aging effects for these components.	In accordance with AMP B.1.13.1, procedures will be enhanced (attributes 3 and 6) to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant (jacket water), or exhaust gas leakage. Through monitoring and trending of performance data, specifically jacket cooling water, fouling and loss of material for the fire pump diesel jacket water heat exchanger will be identified and corrected through the corrective action program. As described in operating experience for AMP B.1.13.1, observation of degraded performance produced corrective actions including engine replacement in 2002 prior to loss of intended function. Consequently, continued implementation of the Fire Protection Program provides reasonable assurance aging effects will be managed for the diesel fire pump jacket water heat exchanger. In addition, PNPS performs fire pump inspection, testing and maintenance in accordance with NFPA 25 which would also detect the presence of aging effects in the jacket water system prior to loss of intended function. This item is closed to item 378.	Ivy, Ted	Burke, Steve	Closed

Item	Request	Response	Lead	Support	Category
500	[T.3.3.2.15] In the LRA, PNPS has indicated "None-None" for AE/AMP combination in several Table 2's in section 3.3, for plastic components in various environments. Please identify what kind(s) of plastic material is (are) used at PNPS.	At PNPS piping codes JE, JF, JG and HT are plastic or fiberglass. As identified in the PNPS Specification for Piping M300, pipe class JE is fiberglass reinforced plastic, piping code JF allows the use of polyvinyl chloride (PVC) piping, and class HT piping is PVC. Per note 3 on M211, some of the pipe code JG is PVC. Some specific components are also identified as plastic in the LRA that are not included in the piping class summary sheets which required component specific reviews to identify the material. For instance some components such as the tank shown on M212 sheet 1 is identified on the drawing as a 55 gallon PVC drum and some piping like the piping on M273 sheet 3 is identified on the drawing as chlorinated polyvinyl chloride (CPVC). The fuel oil system table 3.3.2-7 also identifies a plastic filter housing used on the station blackout diesel fuel oil filter X-176. These are plastic bowls at the bottom of the filter housing that collect water and sediment. The exact type of plastic is not known but was selected for use by the original manufacturer in this application. In addition, similar to all the plastic materials described above it is not exposed to direct sunlight and was designed to be used with fuel oil. Therefore, as stated in the EPRI Mechanical Tools none of these components is expected to experience aging effects that require management in the environments to which they are exposed.	Ivy, Ted	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
501	[T.3.3.2.16] In some Table 2's, PNPS has stated "None-None" for AE/AMP combination for stainless steel bolting in an air-outdoor environment, however, in Tables 3.3.2-5 and 3.3.2-9, PNPS identified loss of material as an aging effect for the same material/environment combination and credited the system walkdown program to manage this aging effect. In an outdoor environment, stainless steel material could be susceptible to loss of material. Please clarify this discrepancy.	The only table that did not identify loss of material for stainless steel bolting in an air-outdoor environment was Table 3.3.2-7 for the fuel oil system. Loss of material is an aging effect requiring management that should have been identified for the stainless steel bolting with an environment of air-outdoor. This aging effect is managed by the System Walkdown Program. This requires an amendment to the LRA.	Ivy, Ted	Chan, Laris	Accepted
502	T.3.3.2.17 In Table 3.3.2-14-21, PNPS has credited the Water Chemistry Control - Auxiliary Systems program to manage the aging effect of loss of material for components in the potable and sanitary water system. However, the program description and the scope of the program only address stator cooling water chemistry. The only element where potable and sanitary water is mentioned is in the element for detection of aging effects. Please justify why potable and sanitary water is not identified in the program description and scope of work or supplement the program to include it.	The "Scope of Program" section of B.1.32.1 of the LRA states city water is taken from the Town of Plymouth water main and distributed throughout the potable and sanitary water system at town water pressure. City water is monitored and treated by the Town of Plymouth to meet the regulations of the Commonwealth of Massachusetts. As stated in the "Detection of Aging Effects" section of B.1.32.1 of the LRA, verification that the water monitoring and treatment by the Town of Plymouth is effective will occur under the One-Time Inspection Program, which entails inspections to verify the effectiveness of water chemistry control programs to ensure that significant degradation is not occurring and component intended function is maintained during the period of extended operation. Therefore potable and sanitary water is included in the program	Ivy, Ted	Chan, Laris	Closed

Item	Request	Response	Lead	Support	Category
503	Question 4.3-1: Identify which components/commodity groups in AMR Tables 3.1.2-1, -2, and -3 were designed to ASME Section III. Clarify which components/commodity groups received an ASME Section III CUF calculation, and identify which commodity group listing in LRA Table 4.3-1 provides the applicable CUF result. If no CUF calculation was performed, justify the basis for exclusion and propose an acceptable AMP to manage the aging effect "cracking fatigue" in accordance with the criterion in 10 CFR 54.21(c)(1)(iii). If an exclusion from performing a CUF calculation is based on an ASME Section III, provide the paragraph in the Code.	This response addresses Question 504 and Question 505.	Finnin, Ron	Pace, Ray	Open – Plant Action
504	Question 4.3-2: Identify which components in AMR Tables 3.1.2-1, -2, and -3 were designed in accordance with the ASME B31.1 Code. Clarify whether the commodity groups were evaluated for an allowable stress reduction assessment based on the 7000 thermal cycles in accordance with the B31.1 Code. Identify whether: (1) the allowable stress reduction analysis remains bounded under 10 CFR 54.21(c)(1)(i), (2) the allowable stress range needs to be reduced in accordance with the stress reduction criteria in the B31.1 Code to comply with 10 CFR 54.21(c)(1)(ii), or (3) the aging effect "cracking - fatigue" needs to be managed for the period of extended (EPO) operation in accordance with 10 CFR 54.21(c)(1)(iii) and propose an acceptable AMP to manage the aging effect.	Answered in Question 503.	Finnin, Ron	Pace, Ray	Closed

Item	Request	Response	Lead	Support	Category
505	Question 4.3-3: For non-piping components/commodity groups in LRA Tables 3.1.2-1, -2, and -3 that were not designed to ASME Section III or AMSE B31.1, identify which design code applies to the particular commodity group and clarify whether the design code required a metal fatigue analysis. If a metal fatigue analysis was required, summarize what type of metal fatigue calculation was required to be performed and discuss how: (1) the analysis remains bounding under 10 CFR 54.21(c)(1)(i), (2) has been projected to the expiration of the EPO and remains acceptable pursuant to 10 CFR 54.21(c)(1)(ii), or (3) whether an AMP needs to be proposed to manage the aging effect of "cracking - fatigue" for the EPO and state which AMP will be used to manage the aging effect. If a metal fatigue analysis was not performed and "cracking -fatigue" needs to be manage for the EPO, propose an acceptable AMP for the management of the aging effect in accordance with the criterion in 10 CFR 54.21(c)(1)(iii).	Answered in Question 503.	Finnin, Ron	Pace, Ray	Closed

Item	Request	Response	Lead	Support	Category
506	Question 4.3-4: For non-piping components/commodity groups in LRA Tables 3.2.2-X, 3.3.2-X and 3.4.2-X, identify which design code applies to the particular commodity group and clarify whether the design code required a metal fatigue analysis. If a metal fatigue analysis was required, summarize what type of metal fatigue calculation was required to be performed and discuss how: (1) the analysis remains bounding under 10 CFR 54.21(c)(1)(i), (2) has been projected to the expiration of the EPO and remains acceptable pursuant to 10 CFR 54.21(c)(1)(ii), or (3) whether an AMP needs to be proposed to manage the aging effect of "cracking - fatigue" for the EPO and state which AMP will be used to manage the aging effect. If a metal fatigue analysis was not performed and "cracking -fatigue" needs to be manage for the EPO, propose an acceptable AMP for the management of the aging effect in accordance with the criterion in 10 CFR 54.21(c)(1)(iii).		Finnin, Ron	Pace, Ray	Open – Plant Action

Item	Request	Response	Lead	Support	Category
507	Question 4.3-5: The application states that, while not mandatory, the design of the RPV internal components is in accordance with the intent of ASME Section III. Please clarify from both a regulatory and technical point of view what is meant by designed in accordance with the "intent ASME Section III." Identify which Edition of ASME Section III is being referred to with respect to the design of the RPV internals.	The statement that the reactor vessel internals were built to the intent of ASME section XI came from the FSAR. GE made this statement in many of the FSARs for BWRs of Pilgrim's vintage. This statement means that the design of the reactor internals was better than commercial grade quality. Materials, wall thickness, construction techniques (including welding) were what would have been used for an ASME component. However, analyses and testing were not performed or documented as required for a component designed "in accordance with" the ASME code. As no specific code was adhered to, no specific code year was specified; however, as the internals were designed as part of the plant design it can be assumed the same code year (1965) was used for general guidance. LRA Section 4.3.1.2 will be revised to delete the statement that the internals are designed to the intent of the ASME code as follows: "4.3.1.2 Reactor Vessel Internals A review of the design basis document reveals that the only internals component for which there is a fatigue analysis is the core shroud stabilizer (tie rods), the result of a repair to structurally replace circumferential shroud welds surrounding the core. This analysis is a TLAA. The maximum CUF identified for the shroud for 40 years of operation is 0.33. The CUF is included in Section 4.3.1. The Fatigue Monitoring Program ensures the fatigue analyses remain valid by monitoring the actual numbers of cycles and evaluating them against the design values for numbers of allowable cycles. Time-limited aging analyses (fatigue analyses) for the core	Finnin, Ron	Pace, Ray	Open – NRC Reviewing

Item	Request	Response	Lead	Support	Category
		shroud stabilizer will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i) or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii)." This requires an amendment to the LRA.			
508	Question 4.3-6: The first full paragraph on page 4.3-2 states that fracture mechanics analyses or flaw growth analyses are TLAAs for PNPS if the analyses are based on time-limited assumptions. Identify all fracture mechanics or flaw growth safety assessments that meet the criteria for TLAAs in 10 CFR 54.3. If any exist, amend Section 4.0 of the LRA to include them as TLAAs for the application and evaluate them in accordance with the requirements of 10 CFR 54.21(c)(1). Include enough technical information to justify acceptability of the fracture mechanics or flaw growth analyses. Any fracture mechanics or flaw growth analyses that meet these TLAA criteria will be evaluated by the NRC's technical staff in the Division of Component Integrity, Office of Nuclear Reactor Regulation.	PNPS identified no fracture mechanics (flaw growth) analyses that were TLAA. The results of the PNPS review of these analyses are located in Section 2.4 of PNPS document LRPD-06, -Limited Aging Analyses – Mechanical Fatigue. Three flaw growth analyses were found (the CRD nozzle to end cap weld, the Reactor Recirculation nozzle thermal sleeves, and Reactor Recirculation nozzle N2F). None of these analyses were TLAA.	Finnin, Ron	Pace, Ray	Open – NRC Reviewing

Item	Request	Response	Lead	Support	Category
509	{3.6.2.2-N-07} In LRA Section 3.6.2.2, you have stated that mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. Wear has not been apparent during routine inspections. If left unmanaged for the period of extended operation, surface rust would not cause a loss of intended function and thus, is not a significant concern. Provide a technical justification of why loss of material due to mechanical wear caused by wind blowing of supported transmission conductors is not an aging effect requiring management for high-voltage insulators. Also, provide a technical justification of why surface rust would not cause a loss of intended function and is not a significant concern for high-voltage insulators if left unmanaged for the period of extended operation.	Loss of material due to mechanical wear is an aging effect for strain and suspension insulators if they are subject to significant movement. A possible cause for movement of the insulators is wind blowing the supported transmission conductor, allowing the conductor to swing from side to side. Although this mechanism is possible, industry experience has shown transmission conductors do not normally swing and that when they do, due to a substantial wind, they do not continue to swing for very long once the wind has subsided. PNPS has no transmission conductors supported by high-voltage insulators in-scope of license renewal and therefore loss of material due to wear of high-voltage insulators is not an aging effect requiring management for the period of extended operation. Various airborne materials such as dust, salt and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and in most areas washed away by rain, while the glazed and coated insulator surfaces at PNPS aids in contamination removal. PNPS applied Slygard (RTV silicone) coatings to some switchyard insulators to reduce flashover. Surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as near facilities that discharge soot. PNPS is not located near any facilities that produce airborne particles such as soot. Therefore, surface contamination is not an applicable aging mechanism for high-voltage insulators at PNPS. LRA Section 3.6.2.2.2 has a typo in the fourth paragraph. The paragraph should read as follows: "Mechanical wear is an aging effect for strain and suspension insulators in that they are subject to	Stroud, Mike	Das, Swapan	Accepted

Item	Request	Response	Lead	Support	Category
		movement. Wear has not been apparent during routine inspections. If left unmanaged for the period of extended operation, surface contamination would not cause a loss of intended function and thus, is not a significant concern." This requires an amendment to the LRA.			
510	[3.6.2.2-N-08] Various airborne materials such as dust and industrial effluent can contaminate insulator surfaces. A large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover. Explain why surface contamination such as dust and industrial effluent is not a significant aging effect requiring management for high-voltage insulators at PNPS.	Since various airborne materials such as dust, salt and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and in most areas washed away by rain, while the glazed and coated insulator surfaces at PNPS aids in contamination removal. PNPS applied Slygard (RTV silicone) coatings to some switchyard insulators to reduce flashover. Surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as near facilities that discharge soot. PNPS is not located near any facilities that produce airborne particles such as dust or soot. Therefore, surface contamination is not an applicable aging mechanism for high-voltage insulators at PNPS.	Stroud, Mike	Das, Swapan	Closed

Item	Request	Response	Lead	Support	Category
511	[3.6.2.2-N-09] Provide a technical justification of why increased resistance of switchyard bus connections due to oxidation is not an aging effect requiring management.	A potential mechanism contributing to aging of switchyard bus connections is surface oxidation, which can lead to increased contact or connection resistance. Connection surface oxidation is not significant for switchyard bus connections at PNPS sine the switchyard bus connections are welded. Therefore, no aging effects due to surface oxidation are required to be managed for the period of extended operation. The connections to active devices are inspected under the Maintenance Rule program. In addition, thermography is performed at least once every 6 months to maintain the integrity of the connections. This program will continue into the period of extended operation.	Stroud, Mike	Das, Swapan	Closed

Item	Request	Response	Lead	Support	Category
512	[3.1.1-13] LRA Table 3.1.1, Item Number 48, is applicable for Class 1 piping, fittings and branch lines <NPS 4" exposed to reactor coolant. The GALL Report indicates that the aging effects of cracking due to thermal and mechanical loading apply for both carbon steel and stainless steel components. However, no Class 1 piping components made of carbon steel are rolled up to this line item. Please explain why no carbon steel piping components are rolled up to this line. Are there no Class 1 carbon steel piping components <NPS 4" at PNPS? If there are Class 1 carbon steel piping components <NPS 4" at PNPS, then please justify why they are not rolled up to line item 3.1.1-48.	As stated in PNPS AMRM-33, "cracking due to flaw growth is managed by the inspection requirements for Class 1 components in accordance with ASME Section XI, Subsection IWB. Because inservice inspection per ASME Section XI is required in accordance with 10 CFR 50.55a, cracking due to flaw growth is not identified on the tables in Attachment 1." Cracking due to flaw growth is considered equivalent to the NUREG-1801 entry of cracking due to thermal and mechanical loading. The ISI Program applies to Class 1 carbon steel piping components at PNPS. The LRA will be clarified to show that cracking is an aging effect requiring management for Class 1 carbon steel piping components <NPS 4" at PNPS and that the appropriate aging management programs include the ISI Program and the One-Time Inspection Program. The discussion column for Item 3.1.1-48 will be revised to be consistent with this change. The credited aging management programs will be the same as those listed for the NUREG-1801 line items corresponding to LRA Table 3.1.1, Item 48. This requires an amendment to the LRA.	Finnin, Ron	Kalb, J	Accepted

Item	Request	Response	Lead	Support	Category
513	As a follow-up to question T3.2.1-35-P-01 (Item 442) one of the line items that rolls up to Item 3.2.1-35 only credits the Containment Leak Rate program for managing the aging effect of loss of material. In accordance with GALL XI.S4 this program by itself does not detect that aging degradation has initiated. Please explain how the use of the Containment Leak Rate program is acceptable by itself to manage aging effects.	The Periodic Surveillance and Preventive Maintenance (PSPM) Program is more appropriate to manage loss of material for piping and valve body in a raw water internal environment in Table 3.2.2-7. The LRA will be revised to credit this program instead of Containment Leak Rate Program to manage the aging effect of loss of material. In addition, the discussion in Item 3.2.1-35 of Table 3.2.1 will be revised to read as follows: "The Periodic Surveillance and Preventive Maintenance Program manages the loss of material for steel components exposed to raw water." This requires an amendment to the LRA to revise Table 3.2.2-7, 3.2.1 and Appendix B	Ivy, Ted	Heard, David	Accepted

Item	Request	Response	Lead	Support	Category
514	[3.1.1-32] LRA Table Items 3.1.1-14, 3.1.1-15 and 3.1.1-47 all include discussions saying that aging of the components rolling up to those lines will be by Water Chemistry augmented by the One Time Inspection Program. Attachment 2 of LPRD-02, Revision 02, provides a list of AMRM's affected by the One-Time Inspection Activities. However, Attachment 2 does not include AMRM-31 (Reactor Pressure Vessel) or AMRM-32 (Reactor Vessel Internals) in the list of affected AMRM's. Please provide an explanation of why AMRM-31 and AMRM-32 are not included in Attachment 2 of LRPD-02, Revision 02. How will PNPS ensure that appropriate one-time inspections are performed for the RPV and RVI components where such inspections are credited for Aging Management during the period of extended operation?	Throughout the application, the One-Time Inspection (OTI) Program has been treated as a support program for the water chemistry program for the purposes of verifying water chemistry program effectiveness. The One-Time Inspection Program has not been treated as an aging management program directly applicable to the systems that credit water chemistry for aging management. This treatment was considered appropriate since the verification of water chemistry program effectiveness will be one integrated task that verifies effectiveness of the program for all systems that credit water chemistry; the water chemistry program effectiveness will not be verified separately for each system. For the cases where the One-Time Inspection Program addresses component specific inspections, it is listed in the LRA as an aging management program directly applicable to the components. The first row of Attachment 2 of LRPD-02 identifies the activities of the One-Time Inspection Program that will verify water chemistry program effectiveness for all systems that credit water chemistry. This line applies to the water chemistry programs, including Water Chemistry Control – BWR, which in turn applies to many of the systems listed in the application. The reactor pressure vessel and reactor vessel internals components credit the Water Chemistry Control – BWR program, so this line applies to AMRM-31 and AMRM-32. The remaining lines of Attachment 2 of LRPD-02 identify activities of the One-Time Inspection Program that address component specific inspections. Applicable systems are identified for these inspections	Finnin, Ron	Kalb, J	Accepted

Item	Request	Response	Lead	Support	Category
515	LRA Table 4.3-1 provides the limiting 40-year cumulative usage factors (CUFs) for the RPV, RPV internal components, and reactor coolant pressure boundary (RCPB) piping that were designed to ASME Section III. With the exception of the CUF values for RPV feedwater nozzles, PNPS has accepted the TLAA metal fatigue CUF analyses and stated that the 40-year CUF conclusion remains valid for the period of extended operation (EPO) in accordance with 10 CFR 54.21(c)(1)(i) or that the effect of "cracking - fatigue" will be managed for the EPO. The last paragraph on Page 11 of LRPD-06 states that "more than half of the design basis transients defined in the UFSAR projections show that the allowable limit, as defined by the RPV cyclic load analysis, will be exceeded before the end of the period of extended operations." The paragraph further states that "A detailed analysis beyond the scope of this report would be required to re-evaluated the CUFs if the transient limits are in fact exceeded," and that "The existing cycle monitoring program will monitor the cycles and require corrective action upon approaching a limit." Please explain how the 40-year CUF conclusion will remain valid for the EPO when PNPS Report No. LRPD-06 implies that the CUFs should be recalculated and projected out 60 years. Please take in account the fact that Draft Commitment 31 requires corrective action when the CUFs exceed 1.0, and not when the implementation of AMP B.1.12, "Fatigue Monitoring Program" determines that the actual transient cycles will approach the number of design transient cycles that are allowed in the design basis. If the CUFs should have been projected and recalculated for 60-years, as indicated in LRPD-06, provide a commitment when the 60-year CUFs values for the RCPB components will be provided to the NRC for review and approval under either 10 CFR 54.21(c)(1)(ii) or (iii). The response to this question may require amendment of Commitment	LRPD-06 was not intended to imply that the CUFs should be projected out to 60 years in accordance with 10 CFR 54.21(c)(1)(ii). CUFs in Table 4.3-1 are based on assumed numbers of transient cycles, not on a number of years. These CUFs are not necessarily 40-year limiting values. As long as the cycles are not exceeded, the CUFs do not need to be recalculated. While some of the numbers of cycles projected for 60 years in Table 4.3-2 exceed the design basis assumptions for numbers of cycles, the Fatigue Monitoring Program assures that the analyses will be revised to increase the allowable number of cycles before exceeding the design basis assumptions. While LRPD-06 projects numbers that exceed the design basis assumptions, the projections are conservative and the actual numbers of cycles may not exceed the design basis assumptions on the numbers of cycles. CUFs will require recalculation IF the numbers of actual transients approach the design basis values. Because the CUFs in Table 4.3-1, with the exception of the feedwater nozzle, are well below 1, the allowable numbers of cycles can be increased through reanalysis assuming higher numbers of cycles.	Finnin, Ron	Pace, Ray	Open – NRC Reviewing

Item	Request	Response	Lead	Support	Category
	31 and/or UFSAR Supplement Summary Description A.2.2.2.1, "Class 1 Metal Fatigue." This item goes with item 425.				
516	The TPO project documented the results of reactor vessel fatigue usage factors of limiting components in table 3-2 in GE report GE-NE-0000-0000-1898-02, Rev.0 March 2002. In the summary Table, it states that for CRD nozzle – stub tube, the existing PNPS CUF value was 0.8, and is now changed to 0.870 for TPO. However, the LRA Table 4.3.1, which identifies class 1 CUF values, the CRD nozzle value of 0.8 was not identified. Please justify why this value was not included in the LRA.		Finnin, Ron	Pace, Ray	Open – Plant Action

Item	Request	Response	Lead	Support	Category
517	Question 4.3-8: PNPS provided the project team with the stress analyses and cumulative usage factor calculations for the PNPS recirculation replacement piping systems and core shroud stabilizers in the following documents: • DC23A4084 & 23A4084, Rev.1, Pilgrim Recirculation Piping Replacement, □June 27, 1985. • GE Report 25A5685, Revision 1, Stress Report - Shroud Stabilizers Vessel, □June 19, 1995. • GE Report GENE-771-79-1194, Revision 2, Shroud Repair Hardware Stress □Analysis , June 19, 1995. LRA Table 4.3-1 lists that the limiting 40-year CUF for the recirculation piping is 0.110 and that the limiting 40 year CUF for the core shroud stabilizers is 0.330. The limiting 40 year CUF values provided in these reports for these components are 0.923 and 0.008, respectively. These values do not correlate to the 40-year CUF values provided in LRA Table 4.3-1. Explain why the 40-year CUF values in these design basis documents differ from the 40-year values provided in LRA Table 4.3-1 . If these design basis document do not constitute the most current design basis CUF bases for the replacement recirculation piping system and core shroud stabilizers, clarify which documents do contain the latest design basis CUF calculations for these component commodity groups. Should this be the case, this question will remain open until the staff can review the appropriate design basis calculations for these component commodity groups.		Finnin, Ron	Pace, Ray	Open – Plant Action

Item	Request	Response	Lead	Support	Category
518	3.1.1-34: LRA Table 3.1.2-1 includes three AMR results lines related to bolting. Two of these lines ("incore housing bolting" and "other pressure boundary bolting") identify the aging effect of cracking (not due to fatigue) and the aging management program is Inservice Inspection. GALL AMP XI.M18 (Bolting Integrity) refers to ASME Section XI requirements for detection of aging effects. However, for high strength bolting (> 150 ksi), the GALL AMP states that for bolting size greater than 1-inch nominal diameter a volumetric examination comparable to that of ASME Section XI Examination Category B-G-1 is required in addition to the visual examination required by Examination Category B-G-2 (for pressure retaining bolting 2" and less in diameter). Sufficient information has not been found in the LRA or in other documents reviewed to determine whether the incore housing bolting and other pressure boundary bolting in Table 3.1.2-1 can be excluded from the augmented examination. Question: For the components described as "incore housing bolting" and "other pressure boundary bolting" in LRA Table 3.1.2-1, please provide the following information. 1) Is the yield strength of these components greater or less than 150 ksi? 2) Is the diameter of these components greater than 1", and less than or equal to 2"? 3) If any of these components have yield strength greater than 150 ksi and diameter between 1" and 2", will PNPS perform the augmented volumetric inspection as recommended in the GALL report? Alternatively, if such components are used at PNPS and PNPS does not propose to perform		Cox, Alan	Lach, David	Open – Plant Action

Item	Request	Response	Lead	Support	Category
	the augmented volumetric inspection, please provide a plant-specific basis to waive the augmented requirement of the GALL AMP.				