Entergy

**Entergy Nuclear Northeast**
Indian Point Energy Center
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Fred Dacimo
Site Vice President
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October 11, 2007

Re: Indian Point Units 2 & 3
Docket Nos. 50-247 & 50-286
NL-07-124

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

SUBJECT: Entergy Nuclear Operations Inc.
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
**Supplement to License Renewal Application (LRA)**

REFERENCES:

1. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application" (NL-07-039)
2. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application Boundary Drawings (NL-07-040)
3. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application Environmental Report References (NL-07-041)

Dear Sir or Madam:

In the referenced letters, Entergy Nuclear Operations, Inc. applied for renewal of the Indian Point Energy Center operating license. The purpose of this letter is to provide the responses to the questions raised by the NRC team during the Aging Management Program audit.

Attachment I provides the subject responses to the NRC team audit questions.

This letter contains no new commitments. If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-734-6710.

A128
NRR

I declare under penalty of perjury that the foregoing is true and correct. Executed on October 11, 2007.

Victoria J. Williams
VICTORIA J. WILLIAMS
NOTARY PUBLIC - STATE OF NEW YORK
NO. 01WI6046851
QUALIFIED IN PUTNAM COUNTY
MY COMMISSION EXPIRES 08-21-2010

Sincerely,

Patrick W. Conroy for
Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Attachment:

I. Questions and Answers from the NRC Team Audit - Aging Management Programs

cc: Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. Bo M. Pham, NRC Environmental Project Manager
Mr. John Boska, NRR Senior Project Manager
Mr. Paul Eddy, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. Paul D. Tonko, President, New York State Energy, Research, & Development Authority

# ATTACHMENT I TO NL-07-124

Questions and Answers from the NRC Team Audit - Aging Management Programs

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 and 50-286

# NRC AMP Audit - All Items

| Item | Request | Response |
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| 1 | Section 3.6-1<br><br>Describe SBO restoration paths for IP2/IP3. Included appropriate drawings for discussion. | The single line schematics (FSAR Figures 8.2-1 and 8.2-2) were provided for review.<br><br>As stated in the IPEC LRA, Section 2.5, Page 2.5-2, "The offsite power sources required to support SBO recovery actions are the offsite sources that supply the station auxiliary transformers. Specifically, the offsite power recovery path includes the station auxiliary transformers, the 138KV switchyard circuit breakers supplying the station auxiliary transformers, the circuit breaker-to-transformer and transformer-to-onsite electrical distribution interconnections, and the associated control circuits and structures."<br><br>Based on IP2 UFSAR Section 8.1.2.1, "10 CFR 50 Appendix A General Design Criterion 17 - Electric Power Systems," IP2 is supplied with normal, standby, and emergency power sources. Offsite (standby) power required during plant startup, shutdown, and after a turbine trip is supplied from the Buchanan Substation by the Con Edison 138 kV system feeders and the 13.8 kV system feeders. The 138 kV feeder is the preferred standby power source and is connected to the 6.9 kV buses through the station auxiliary transformer. The 13.8 kV feeder is the alternate standby power and is connected to the 6.9 kV buses through the GT autotransformer. The Buchanan 13.8 kV system is available for immediate manual connection to the auxiliary buses. The 480 volt engineered safety feature buses are connected to the 6.9 kV buses through station service transformers. LRA Figure 2.5-2 shows the 6.9kV source for Busses 5 and 6 as the 138kV/6.9kV station auxiliary transformer, which is shown connected to two separate 138kV transmission conductors through Breaker F2 and through Breaker BT 4-5. Figure 2.5-2 will be revised to show the 138 kV feeder connection via the station auxiliary transformer and the 13.8 kV feeder connection via the GT autotransformer. The GT autotransformer is connected to the alternate feed from the Buchanan 13.8 kV substation via breaker F2-3. Because breaker BT 4-5 is a connection to IP3 and not a boundary or interface point between the plant and transmission system, Figure 2.5-2 will be revised to show 13.8 kV Breaker F2-3 instead of BT 4-5. Breaker F2-3 is the interface between the plant and the interconnected grid at the Buchanan substation 13.8 kV bus. Figure 2.5-2 will be revised to show motor operated disconnect F3A instead of breaker F2, because breaker F2 is an integral component in the Buchanan substation. F3A is the interface between the plant and the interconnected grid at the Buchanan substation as shown on interface agreement drawings with Con Edison.<br><br>Based on IP3 UFSAR Section 8.2.1, "Network Interconnection", and 8.2.3, " Emergency Power - Sources Description," IP3 is supplied with normal, standby, and emergency power sources. Offsite (standby) power required during plant startup, shutdown and after a turbine trip is supplied from the Buchanan Substation by the Con Edison 138 kV system feeders and the 13.8 kV system feeders. The 138 kV feeder is the preferred standby power source and is connected to the 6.9 kV buses through the station auxiliary transformer. The 13.8 kV feeder is the alternate standby power and is connected to the 6.9 kV buses through the GT autotransformer. The Buchanan 13.8 kV system is available for immediate manual connection to the auxiliary buses. The 480 volt engineered safety feature buses are connected to the 6.9 kV buses through station service transformers. LRA Figure 2.5-3 shows the 6.9kV source for Busses 5 and 6 as the 138kV/6.9kV station auxiliary transformer, which is shown connected to two separate 138kV transmission conductors through Breaker BT2-6 and through Breaker BT5-6. Figure 2.5-3 will be revised to show the 138 kV feeder connection via the station auxiliary transforme, and the 13.8 kV feeder connection via the GT autotransformer. The GT autotransformer is connected to the alternate feed from the Buchanan 13.8 kV substation via breaker F3-1. Because breaker BT 5-6 is a connection to IP2 and not a boundary or interface point between the plant and transmission system, Figure 2.5-3 will be revised to show Breaker F3-1 instead of Breaker BT 5-6. Breaker F3-1 is the interface between the plant and interconnected grid at the Buchanan substation 13.8 kV bus. Breaker BT 2-6 is the interface between the plant and interconnected grid at the Buchanan substation as shown on the interface agreement drawings with Con Edison<br><br>Information to be incorporated into the LRA. |
| 2 | Section 3.6-2 | The only high voltage direct burial insulated cable (>35 kV) is part of the IP2 SBO |

| Item | Request | Response |
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| | High voltage direct burial insulated cable (>35 kV) may be exposed to condensation and wetting in inaccessible location, such as conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installation. When an energized high voltage cable is exposed to wet conditions for which it is not designed, water tree or a decrease in dielectric strength of the conductor insulation can occur. This can potentially lead to electrical failure. Provide a manufacturer certification that 138 kV direct burial insulated transmission cable is qualified for continuous submerge condition or provide an AMP to ensure that water tree aging effect will not degrade the cable intended function during the period of extended operation. | recovery path. The cable is a portion of the 138 kV path from the Station Aux Transformer to breaker F2 as shown in LRA Figure 2.5-2. This is a lead sheathed solid dielectric insulated cable. The lead sheath prevents moisture in submerged cables from contacting the insulation, so water trees will not be formed. Therefore, there is no aging effect that requires management.<br><br>The specification for the 138 kV 750 MCM solid dielectric cable states the cable is supplied with a moisture barrier. Radial water sealing is achieved by a corrosion resistant lead sheath. Longitudinal water sealing is achieved by using a water swelling material applied under the lead sheath. The cable passed longitudinal water penetration tests as specified in the applicable AEIC specification. The cable is installed in a pipe-type system, which originally contained an oil-filled cable system. The replacement cable was installed in the same route.<br><br>This cable was designed with a thick layer of lead over the cable insulation with an overall jacket over the lead and insulation. The construction of this cable differs from the typical medium voltage cable design of insulation with an overall jacket. This type of cable is used in transmission substation networks to maximize the life of the cable, which is mainly associated with the good characteristics in moisture environments, and the dielectric constant requirements of a 138 kV feeder cable. The AEIC CS7 specification is for lead sheath power (69 kV to 138 kV) cables designed to be installed in wet environments for extended periods. The insulation system for this cable is a cross-linked polyethylene (XLPE). The lead sheath combined with the overall jacket provides a virtually impenetrable barrier against hostile environments – liquids, fire hydrocarbons, acids, caustic, sewage, etc.<br><br>The license renewal electrical handbook states lead sheath cables prevent the effects of moisture on the cable insulation.. A lead sheathed cable is comparable to a submarine cable.<br><br>Based on the above, the aging effects caused by moisture and voltage stress is not applicable to this cable. This 138 kV underground cable, which is part of the IP2 offsite power path, does not have any aging effects that require management; therefore, this cable is not included in the scope of the Non-EQ Inaccessible Medium-Voltage Cable program. |
| 20 | AMP B.1.3-1 (Boraflex Monitoring)<br><br>According to GALL, the applicant's Boraflex Monitoring Program, according to manufacture's recommendations, should assure that no unexpected degradation occurs that would compromise the criticality analysis.<br><br>What are the manufacturer's recommendations for IP-2 AND IP-3? | The boraflex manufacturer was Brand Industrial Services Corporation who no longer supports the product. The recommendations for management of boraflex at IP2 are derived from industry experience and responses to NRC GL 96-04, Boraflex Degradation in Spent Fuel Pool Storage Racks.<br><br>Boraflex is not used for criticality control of the IP3 spent fuel pool. |
| 21 | AMP B.1.3-2 (Boraflex Monitoring)<br><br>What is the justification for IPEC selection of areal density measurement over GALL specification for measuring gap formation by blackness testing. | Areal density testing provides a direct measurement of in-rack performance of boraflex panels through measurement of gaps, erosion, and general thinning. Blackness testing provides only an indication of neutron absorber presence and does not quantitatively measure the Boron-10 areal density of neutron absorber in each rack. Therefore, areal density along with the monitoring of silica levels in the spent fuel pool provides adequate detection of boraflex degradation. |
| 24 | AMP B.1.5-3 (Boric Acid Corrosion)<br><br>Discuss how the applicant responded to the NRC' s order and bulletins listed below; explain how these responses have been used to update the component list location and visual inspection within the scope of the Boric Acid Corrosion Program.<br><br>NRC Bulletin 2002-01 dated March 29 and May 16, 2002<br>NRC RAI on Bulletin 2002-01 dated January 17, 2003<br><br>NRC Bulletin 2003-02 dated September 19, 2003<br>NRC Order EA 03 009, dated March 3, April 11 and April 18, 2003 | IPEC responses to the referenced NRC generic communications are contained in the letters referenced below. Copies of the letters were available on site for review or in ADAMS.<br><br>Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity"<br>This bulletin was issued to alert licensees of the significant corrosion of the Davis Besse reactor vessel head which resulted from through-wall CRDM nozzle leakage. Licensees were required to review their GL 88-05 boric acid inspection programs to ensure effectiveness in detecting corrosion at RCS locations where Alloy 600 could crack and result in accumulation of wet boron. In response to this bulletin, both IP2 and IP3 committed to review their boric acid corrosion prevention programs as originally required by GL 88-05. Procedures 2PT-R156, "RCS Boric Acid Leakage and Corrosion Inspection", 3-PT-R114A, "Reactor Vessel and Closure Head Boric Acid Leakage and Corrosion Inspection", and 3-PT-R114, "RCS Boric Acid Leakage and Corrosion Inspection" were revised to include inspection for signs of leakage or boron deposits detected during bare metal visual inspections of the reactor vessel |

| Item | Request | Response |
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| | NRC Bulletin 2004 - 01, dated May 28, 2004 | head near the CRDM nozzles. The procedures also warn that signs of possible RCS leakage may include boron or rust on containment radiation monitor filters, FCU cooling fins, and some parts of containment. Refer to the following letters for bulletin response specifics.<br>NL-02-050/IPN-02-023, "Submittal of 15 Day Response to NRC Bulletin 2002-01"<br>NL-02-074/IPN-02-039, "Submittal of 60 Day Response to NRC Bulletin 2002-01"<br>NL-02-099/IPN-02-060, "Supplement to 15 Day Response for NRC Bulletin 2002-01"<br><br>NRC RAI on Bulletin 2002-01<br>This RAI further outlined the requirements of a comprehensive boric acid corrosion control program.<br>Refer to the following letter for response specifics.<br>NL-03-020, "Response to Request for Additional Information Regarding the 60-day Response to NRC Bulletin 2002-01"<br><br>NRC Bulletin 2003-02<br>This bulletin informed facilities that current methods of inspecting the reactor pressure vessel (RPV) lower heads may need to be supplemented with bare-metal visual inspections in order to detect reactor coolant pressure boundary leakage. The bulletin also requested licensees provide the NRC with information related to inspections that have been performed to verify the integrity of the RPV lower head penetrations. IP2 and IP3 reported that bare metal visual inspection of lower head penetrations revealed no evidence of pressure boundary leakage. Procedures 2-PT-R204, "Visual Inspection of Reactor Vessel Bottom Mounted Instrumentation Penetrations for Leakage" and 3-PT-R204, "Visual Inspection of Reactor Vessel Bottom Mounted Instrumentation Penetrations for Leakage" were developed to meet the requirements of this bulletin. Refer to the following letters from the NRC acknowledging completion of the bulletin requirements.<br>COR-05-02835, "Indian Point Unit 2 – Response to NRC Bulleting 2003-02, " Leakage From Reactor Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity""<br>COR-05-02892, "Indian Point Unit 3 – Response to NRC Bulleting 2003-02, " Leakage From Reactor Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity""<br><br>First Revised Order EA-03-009<br>This order extended the region of the CRDM considered susceptible to PWSCC and required both visual and volumetric examination of all nozzles on a prescribed frequency. IPEC meets the requirements of this order. Refer to the following letter regarding the IPEC response to EA-03-009.<br>NL-04-026, "Answer to February 20, 2004 Revised NRC Order Regarding Interim Requirements for Reactor Pressure Vessel Heads<br><br>Bulletin 2004-01<br>This bulletin requests that each PWR facility provide a description of their Alloy 82/182/600 materials used for pressurizer heater and steam space penetrations and inspection plans for future refueling outages. Neither IP2 nor IP3 pressurizers contain Alloy 82/182/600 components. Refer to the following letter regarding the IPEC response to bulletin 2004-01.<br>NL-04-090, "Response to NRC Bulletin 2004-01 Regarding Inspection of Alloy 82/182/600 Materials Used In Pressurizer Penetrations and Steam Space Piping Connections" |
| 25 | AMP B.1.7-1 (Containment Leak Rate)<br><br>The applicant indicates that this AMP is consistent with GALL AMP XI.S4, without exception or enhancement. GALL Vol.2, Rev. 1, AMP XI.S4, Scope of Program, states "Leakage testing for containment isolation valves (normally performed under Type C tests), if not included under this program, is included under LRT programs for systems containing the isolation valves."<br><br>Is Entergy crediting 10 CFR Part 50, Appendix J, Type C containment isolation valve leak rate testing during the license renewal period? | The Containment Leak Rate Program includes Type A, Type B, and Type C tests of primary containment pressure-retaining components as described in 10 CFR Part 50, Appendix J.<br><br>Thus, IP2 and IP3 are crediting 10 CFR Part 50, Appendix J, Type C containment isolation valve leak rate testing during the period of extended operation. |
| 26 | AMP B.1.8-1 (Containment Inservice ) | Entergy performed an element-by-element comparison, available on-site, of IPEC AMP B.1.8, Containment Inservice Inspection, to NUREG-1801 AMPs XI.S1, ASME |

| Item | Request | Response |
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| | The intent of the staff in writing GALL Vol. 2 Chapter XI, was to enable an applicant to take credit for an existing mandated inspection program with minimal effort (i.e., simply identify and explain exceptions and enhancements). Entergy has identified AMP B.1.8 - Containment Inservice Inspection as being plant-specific. The staff reviewed LRA Appendix B.1.8 and concluded that the 10-element evaluation does not identify any differences from GALL AMPs XI.S1 and XI.S2. Entergy is requested to document an element-by-element comparison of AMP B.1.8 to GALL AMPs XI.S1 and XI.S2, identifying and explaining all exceptions and enhancements to the GALL AMPs. | Section XI, Subsection IWE, and XI.S2, ASME Section XI, Subsection IWL. The comparison identifies and explains exceptions to the ten elements of the NUREG-1801 AMPs. IPEC AMP B.1.8, Containment Inservice Inspection does not require enhancement to satisfy the recommendations of NUREG-1801 AMPs XI.S1 and XI.S2.<br><br>Results of comparison to be incorporated into the LRA. |
| 27 | AMP B.1.8-2 (Containment Inservice)<br><br>The IP 2 and 3 containments have a somewhat unique design feature: thermal insulation on the steel liner plate, at the lower elevations of the cylindrical containment wall. In both UFSARs, this insulation is credited with limiting the liner temperature increase to 80 degrees F during a design basis accident. Both UFSARs state that the insulation is removable, to permit periodic inspection of the containment liner plate.<br><br>(1) Identify the AMP and describe the specific inspections performed, to ensure that this insulation will continue to perform its intended function.<br><br>(2) Describe the plant-specific operating experience related to removal of this insulation and inspection of the containment liner plate normally covered by the insulation. How does the condition of the normally insulated liner plate surface compare to the condition of the normally uncovered liner plate surface? Has augmented inspection, per Category E-C, been necessary? | (1) As shown in LRA Table 3.5.2-1, line item "liner plate insulation jacket", there is no aging effect requiring management for liner plate thermal insulation, therefore there is no AMP.<br><br>(2) IP2 and IP3 have approximately 20% of the liner inaccessible due to the insulation at the lower elevations of the containment. At the 46' Elevation, a caulking sealant, used as a moisture barrier, is installed at the junction of the bottom edges of the insulation panels and the floor to prevent moisture from reaching the steel liner. When performing a visual examination of the liner, the insulation covering portions of the containment liner is not removed. The IWE examination includes inspection of the moisture barrier to ensure that it has not degraded. IP2 and IP3 will remove insulation during the required IWE examinations if insulation removal is required to meet the requirements in Table 2500-1.<br><br>During the IWE first interval for IP2, corrosion was discovered on the liner during the first period (April 2000) containment inservice inspection. The corrosion existed in the portion of the liner where it is abutted by the fill slab that covers the base mat liner. A number of inspections, investigations, and evaluations were performed to determine the acceptability of the liner to perform its design function. The inspection found several areas where the moisture barrier was missing or not properly bonded between the floor slab and insulation. The degradation of the moisture barrier raised a concern relative to the condition of the liner. In order to address these concerns, IP2 selected nine (9) panels of the liner insulation for removal to facilitate augmented inspection, per Category E-C. During the removal and re-installation of these insulation panels, the opening covers are re-sealed with the caulking sealant in order to re-establish the moisture barrier.<br><br>When the insulation was removed, minor corrosion (light rust) was noted. Thickness readings were taken with no significant wall loss detected. As a result of three consecutive inspections of the nine (9) panel areas, the containment liner plate in these areas was found dry and the corrosion inactive, and the liner plate was well within the required containment liner thickness. In conclusion, the IP2 VC liner will perform its' intended function and is within acceptance limits for continued operation. This augmented exam was completed during the last IP2 Containment ISI Interval. |
| 28 | AMP B.1.8-3 (Containment Inservice)<br><br>Identify all augmented inspections required by IWE or IWL that are being implemented during the current inspection intervals. For each case, describe the initial finding that necessitated augmented inspection. | Neither IP2 nor IP3 have any augmented inspections required by IWE or IWL during the current inspection intervals. |
| 29 | AMP B.1.8-4 (Containment Inservice)<br><br>Entergy does not credit GALL AMP XI.S8 for license renewal. Confirm that Level I containment protective coatings are not credited for liner plate corrosion prevention/mitigation in the current design bases for IP 2 and 3. | The liner plates of IP2 and IP3 containment are provided with appropriate protective coatings. However, the Level I containment protective coatings are not credited for liner plate corrosion prevention/mitigation in the current design bases for IP2 and IP3. |
| 30 | AMP B.1.8-5 (Containment Inservice)<br>TLAA 4.6-1 | (a) Describe in greater detail the event that resulted in the permanent liner plate deformation. |

| Item | Request | Response |
|---|---|---|
| | In its review of TLAA Section 4.6, the staff noted that in 1973 a significant permanent deformation of the IP Unit 2 liner plate occurred at the penetration for feedwater line #22. The operating experience element of AMP B.1.8 does not discuss this existing condition nor the results of periodic inspections conducted under the Containment ISI Program.<br><br>(a) Describe in greater detail the event that resulted in the permanent liner plate deformation. When specifically did it occur? What was identified as the root cause? How was this corrected?<br><br>(b) Discuss the history of ISI of the permanently deformed liner plate, from 1973 to the present. | Following a reactor trip from approximately 7% power, a break occurred in the feedwater line to Steam Generator No. 22 just inside containment near the feedwater line penetration. An area of the containment liner adjacent to the feedwater line break was slightly bulged, apparently as a result of steam and water impingement.<br><br>The feedwater line incident report NL-74-A07, dated January 14, 1974, from William J. Cahill, Jr., Vice President Indian Point to John F. O'Leary, Director of Licensing Atomic Energy Commission will be available on site for staff review.<br><br>When specifically did it occur?<br><br>November 13, 1973<br><br>What was identified as the root cause?<br><br>The bulging of the containment liner in the vicinity of the steam generator No. 22 feedwater line at the penetration was caused by the impingement of steam and water on the liner.<br><br>How was this corrected?<br><br>The containment building was pressurized to push the bulged liner back in place. The liner moved 5/8 of an inch during pressurization to 15 psig and no further during pressurization to 47 psig. This led to the conclusion that the liner made contact with the concrete after the 5/8 inch shift and that the extent of the deformation was not as great as originally suspected.<br><br>Numerous modifications were made to prevent water hammers in feedwater lines and improve piping and liner ability to withstand such forces. These included adding an additional 18 feet of insulation above the pipe break area completely around the inside of containment (an additional 8 feet in the vicinity of the steam and feedwater lines), changing the piping layout to steam generator No. 22 inside containment, installing additional pipe supports, and installing "J Tubes" on the feedwater ring inside the steam generators to delay the draining of the feedwater rings which allowed a steam/water interface to develop.<br><br>(b) General visual examinations were conducted under the Containment Inservice Inspection Program between June, 2004 and November 2004 for all accessible areas of the containment liner, including penetrations and airlocks, in accordance with Table IWE-2500-1, Category E-A, Item E1.11.<br><br>Minor surface corrosion and/or coating deterioration were observed on the penetrations. This is general surface corrosion that has not resulted in any significant loss of material.<br><br>The containment leak rate test at IP2 in 2006 was completed satisfactorily. |
| 31 | AMP B.1.9-1 (Diesel Fuel Monitoring)<br><br>Provide a more detailed description of past and present fuel oil monitoring activities at the Indian Point site, including surveillance and maintenance procedures implemented to mitigate corrosion and verify the effectiveness of the Diesel Fuel Monitoring aging management program. Provide the frequency for the maintenance activities. | The Diesel Fuel Monitoring Program currently includes sampling activities and analysis on the following tanks in accordance with technical specifications on fuel oil purity and the applicable guidelines of ASTM Standards D1796 (water and sediment by centrifuge), D2276 (particulate gravimetrically), and D4057 (sampling).<br>•EDG fuel oil storage tanks (21/22/23-FOST, EDG-31/32/33-FO-STNK) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/80 days<br>•EDG fuel oil day tanks (21/22/23-FODT, EDG-31/32/33-FO-DTNK) Viscosity, Water and Sediment only (D1796) Tested 1/month<br>•Gas turbine fuel oil storage tanks (GT2/3-FOT, GT1-FOT-11/12) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/80 days<br>•Diesel fire pump fuel oil storage tank (DFPFOT) (IP2) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/184 days<br>•Security diesel fuel oil day tank (SDDT) (IP2) Viscosity, Water and Sediment only (D1796) Tested 1/month<br>•Appendix R fuel oil storage tank (ARDG-FO-ST) (IP3) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/184 days<br>•Appendix R fuel oil day tank (ARDG-FO-DT) (IP3) Viscosity, Water and Sediment only (D1796) Tested 1/month<br>•Diesel fire pump fuel oil storage tank (FP-T-3) (IP3) Properties of #2D Diesel fuel per ASTM D975, particulates per D2276, Tested 1/184 days<br><br>The specific fuel oil monitoring activities are accomplished in accordance with the technical specifications and procedure 0-CY-1810. |

| Item | Request | Response |
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| | | The EDG fuel oil storage tanks, EDG fuel oil day tanks, GT1 gas turbine fuel oil storage tanks, GT2/3 gas turbine fuel oil storage tanks, diesel fire pump fuel oil storage tanks, security diesel fuel storage tank, and IP3 Appendix R fuel oil day tank, are periodically sampled, near the bottom, once per month to determine water content. Reference the following procedures which were provided on site for review:<br>(Ref. Attachment 4, 0-CY-1500; Attachment 1, 0-CY-1810)<br>(IP2 Ref. Section 4.3, 2-CY-1560)<br><br>The EDG and GT2/3 fuel oil storage tanks are drained, cleaned and inspected every ten years to detect potential degradation and confirm the absence of aging effects. Reference the following procedures which were available on site for review:<br>(IP2 Ref. Section 4, 2-GNR-009-ELC; GT2/3-FOT*001)<br>(IP3 Ref. Section 4, GNR-024-ELC)<br><br>Thickness measurements were performed once on the IP3 EDG fuel oil storage tanks (31 and 32) to verify that significant degradation was not occurring. The Above Ground Steel Tanks Program includes the use of NDE techniques (UT) for the GT2/3 fuel oil storage tank once every ten years during visual inspections. Reference the following procedures which were provided on site for review:<br>(IP3 Ref. Section 4, GNR-024-ELC),<br>( PM task GT2/3-FOT*001) |
| 32 | AMP B.1.9-2 (Diesel Fuel Monitoring)<br><br>The LRA is silent on the use of tank coatings. Are the internal surfaces of any of the fuel oil storage tanks within the scope of license renewal coated or lined? If so, describe how the aging of the coating or lining is managed. | The only tanks known to have an internal coating are the security diesel fuel oil day tank (SDDT) and two EDG fuel oil storage tanks (EDG-31/32-FO-STNK). The coating in tanks is not credited to prevent aging effects that could result from the fuel oil environment. The EDG fuel oil storage tanks are inspected on a 10 year frequency in accordance with 3-GNR-024-ELC. Step 4.4.1.30 requires an inspection of the internal of the tank for any physical defects which would include defects in the coatings. The SDDT tank is nonsafety-related tank that is not inspected due to its small size (10 gallons). Degradation of the coating would be detected by sampling of the fuel oil in the tank for particulates.<br><br>Any coating degradation will be evaluated under the corrective action program. |
| 33 | AMP B.1.9-3 (Diesel Fuel Monitoring)<br><br>LRA AMP B.1.9 states that the program is being enhanced to include cleaning and inspection of the GT1 fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank once every ten years. Provide a more detailed description of past and present fuel oil monitoring activities related to these tanks. | The GT-1 tanks are monitored in accordance with technical specifications on fuel oil purity and the guidelines of ASTM Standards D1796 (water and sediment by centrifuge), D2276 (particulate gravimetrically), and D4057 (sampling). In addition the GT1 gas turbine fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank are periodically sampled, near the bottom, to determine water content. The frequencies and acceptance criteria are provided in the references below which were available on site for review.<br>(Ref. Attachment 4, 0-CY-1500; Attachment 1, 0-CY-1810). |
| 34 | AMP B.1.9-4 (Diesel Fuel Monitoring)<br><br>The LRA states that IPEC does not add biocides to diesel fuel oil storage tanks as recommended in GALL, to prevent biological breakdown of the diesel fuel. Rather, the existing processes for minimizing water contamination of the fuel and reviewing site and industry operating experience appear to be credited. While these processes may be effective in determining the existence of biological contamination, they do not appear to meet the intent of GALL for preventing and minimizing the accumulation of biological activity. Also, the LRA does not address an apparent exception to NUREG 1801, Element 7, regarding the addition of biocide to fuel oil when the presence of biological activity is confirmed. Please clarify. | At IPEC the evidence of microbiological activity, if any, is evaluated under the corrective action program. If the evaluation determines a need to use biocides based on additional sampling and monitoring, this will be handled in the corrective action program. However, the site does not immediately introduce biocides on the detection of microbiological activity based on ASTM Special Technical Publication 1005.<br><br>The following is a summary of points from ASTM Special Technical Publication 1005, Distillate Fuel: Contamination, Storage and Handling. Copy of document provided on site for review.<br><br>"The mere detection of viable microorganisms in hydrocarbon fuels or oils is not evidence of a significant microbial involvement. Distribution of the microorganisms is unlikely to be homogeneous, and obtaining a representative sample can be difficult or impossible. In contrast to this uncertainty (that microbes are homogeneously distributed) the appearance of corrosivity in stored petroleum products is good presumptive evidence that sulfate-reducing bacteria are at work." "As a first step in preventing the adverse effects of microbial growth in practical situations, water should be eliminated from storage and handling systems. As a last resort the use of a biocide may be necessary. The new problems that are introduced, as the result of using a biocide should be carefully considered."<br><br>IPEC does take exception to Element 2 in that biocides are not currently used at IPEC, However, this is not considered an exception to GALL in element 7 since biocides will be used if evaluation under the correction action program deems them necessary to correct the condition. Procedures 2-CY-1560 section 4.5 and 3-CY-2615 section 4.1 allow the addition of biocides for IP2 and IP3 if needed. |

| Item | Request | Response |
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| 35 | AMP B.1.9-5 (Diesel Fuel Monitoring)<br><br>Describe how the quality of initial fuel oil purchases and deliveries is ensured. | Purchase specifications for fuel oil have specific technical requirements that the fuel be ASTM 2D fuel oil meeting the specifications of ASTM D975 in order to ensure it meets quality standards for delivery. |
| 36 | AMP B.1.9-6 (Diesel Fuel Monitoring)<br><br>The LRA states that thickness measurements of storage tank bottom surfaces are performed to verify that significant degradation is not occurring. Provide the procedures used to perform this surveillance and describe the acceptance criteria and basis for minimum wall thickness. Also provide a technical basis for the specified 10 year surveillance frequencies. | The only fuel oil tanks with procedures or tasks requiring NDE of the tank bottom are the IP3 EDG storage tanks and the GT2/3 storage tank. These inspections are described in procedure GNR-024-GLC and PM task GT2/3-FOT*001 which are available on site for review. The minimum acceptable thickness for each tank bottom when inspected is based upon a component specific engineering evaluation. Wall thickness will be acceptable if greater than the minimum wall thickness for the specific component. A copy of PM task was provided for review.<br><br>The basis for the 10 year wall thickness inspection frequency is to perform the inspections in conjunction with other 10 year inspections and cleanings which is consistent with the recommended frequency in Reg. Guide 1.137 and meets New York State regulations for fuel oil storage tanks. Past visual inspections of fuel oil storage tanks have not detected significant degradation that would lead to a need for an increased inspection frequency. |
| 37 | AMP B.1.9-7 (Diesel Fuel Monitoring)<br><br>Provide the schedule for implementation of the enhancements to this AMP. | As specified in the IPEC commitment list for Commitment 7, the implementation schedule for the enhancements to this program are<br>IP2:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 |
| 38 | AMP B.1.11-1 (External Surfaces Monitoring)<br><br>Give details of surfaces included in the external Surface Monitoring Program accessible only when the insulation is removed. | The surfaces included in the program are the external surfaces of carbon steel, stainless steel, copper alloy, cast iron, and aluminum components that are normally insulated. Surfaces that are insulated are inspected when the external surface is exposed, e.g., during maintenance. Routine maintenance occurs at such intervals that there is 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. |
| 39 | AMP B.1.12-1 (Fatigue Monitoring)<br><br>The LRA states in the Program Description:<br><br>The program ensures the validity of analyses that explicitly analyzed a specified number of fatigue transients by assuring that the actual effective number of transients does not exceed the analyzed number of transients.<br><br>(a) Please describe the method used to determine the actual effective number of transients.<br><br>(b) Which component(s) will this methodology be applied to? | (a) IP2 and IP3: Site data is reviewed by a cognizant engineer to determine transients that have occurred since the last review. The engineer then updates the list of total transients to date. Transients reviewed include those listed in Table 4.3-1 (IP2) and 4.3-2(IP3) of the LRA and Table 4.1-8 of the UFSAR. Procedures 2-PT-2Y015, Thermal Cycle Monitoring Program and 3PT-M051, Plant Operation Information was available for review on-site and provide further details.<br><br>As described in the enhancement to the Fatigue Monitoring Program, IP3 will complete a review of existing fatigue analyses of record and enhance the fatigue monitoring program to include additional transient cycles similar to what has been done for IP2. This enhancement to the IP3 identification and tracking of transients is identified in Commitment 6.<br><br>(b) Determination of actual numbers of transients is independent of specific components. The method is applied to transients. Different components are affected by different transients. The basis for the IP2 design cycles is described in WCAP-12191, Revision 3, "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for Indian Point 2". WCAP-12191 was available for review on-site. |
| 40 | AMP B.1.12-2 (Fatigue Monitoring)<br><br>The LRA states in the Exception Section that " The IPEC program updates fatigue usage calculations when the number of actual cycles approach the analyzed number of cycles."<br><br>What are the action or alarm limits that will trigger the corrective action. | IP2: Alert cycles are defined as the number of cycles which may accumulate in two monitoring periods. If the number of analyzed cycles is exceeded using alert cycles, a condition report is generated to ensure that corrective actions are taken prior to exceeding the analyzed number of cycles. The number of alert cycles is calculated by taking the cycles accumulated during the period, multiplying them by 2, and adding them to the total accumulated cycles to date. If this projection remains below the total number of analyzed cycles, no further action is required.<br><br>IP3: The current fatigue monitoring program does not have action or alarm limits. The cognizant engineer and the reviewing supervisors determine if a condition report is required. Plant operation is not allowed if the analyzed number of a particular transient is exceeded unless appropriate engineering evaluation under the corrective action program has determined it acceptable. |

| Item | Request | Response |
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| | | This item has been closed to question #119. |
| 41 | AMP B.1.12-3 (Fatigue Monitoring)<br><br>Under Enhancement Section: For IP3, the applicant proposes to "revise appropriate procedures to include all the transients identified."<br><br>(a) Please list all applicable transients.<br><br>(b) Why does this enhancement not apply to IP2? | (a) LRA Table 4.3-2 reflects the transients monitored by the IP3 fatigue monitoring program. IP3 has not expanded the program beyond UFSAR Table 4.1-8. IP3 will complete a review of existing fatigue analyses of record and enhance the fatigue monitoring program to include additional transient cycles similar to what has been done for IP2. This enhancement to the IP3 identification and tracking of transients is identified in Commitment 6.<br><br>(b) IP2 has performed a detailed review of required transients as documented in WCAP-12191, Revision 3, "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for Indian Point 2". WCAP-12191 is available for review on-site. |
| 42 | AMP B.1.12-4 (Fatigue Monitoring)<br><br>The LRA states in the Operating Experience that the Fatigue Monitoring Program includes re evaluation of usage factors as appropriate.<br><br>(a) What factors/conditions would warrant a re-evaluation.<br><br>(b) Under what circumstances that IP2 charging nozzles were re-evaluated? Please describe the re-evaluations process for IP2 charging nozzles. | (a) Cumulative usage factors (CUF) are re-evaluated when the actual number of cycles approaches the design limit as shown in UFSAR Tables 4.1-8 for IP2 and IP3. Refer to the response to Audit Question AMP B.1.12-2.<br><br>(b) The original IP2 design did not include a fatigue analysis for charging nozzles. Westinghouse noted the transient in letter IPP-90-752 dated September 1990. The IP2 charging nozzle transient cycle history was updated along with other analyzed transients in the development of WCAP-12191, Revision 3, "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Final Report for Indian Point 2". |
| 43 | AMP B.1.15-1 (Flow-Accelerated Corrosion)<br><br>The LRA states that the incidents of wall thinning were detected in the vent chamber drain and high pressure turbine drain components during 3R13 in March 2005 and in a steam trap pipe during 2R17 in May 2006. These incidents resulted in replacements of the affected components during the respective outages. Describe if the piping and the affected components were included in the FAC program prior to these inspections and if the affected components were replaced with the like for like materials or with a FAC resistant material such as chrome-moly. Also substantiate the response with actual thickness data, i.e., the nominal thickness, minimum acceptable thickness and the measured thickness at these affected locations. | The piping and affected components were included in the FAC program prior to these inspections. As the wall thinning of these components was discovered during the outage, they were replaced with like for like materials. Subsequent to these outages, the Wet Steam Pipe Replacement Project has and will replace piping found to be worn by past FAC inspections with FAC resistant materials. The High Pressure Turbine Drain piping downstream of the control valves was replaced with chrome moly during 3R14. The Vent Chamber Drain piping is to be replaced with chrome moly piping. The replacement is to be performed in three phases. Phase 1 included the "A" train and was completed during 3R14. Phase 2, to be performed during 3R15 will include the "B" Train, and Phase 3 to be performed during 3R16 will include the common "A" and "B" Train piping.<br><br>Actual thickness data of vent chamber drain, high pressure turbine drain and steam trap components are provided below.<br><br>Unit 3<br>Vent chamber drain piping -<br>3" diameter, schedule 40<br>Nominal wall thickness 0.216"<br>Minimum acceptable thickness 0.123"<br>Minimum thickness required for 2 more years of service after 3R13 0.135"<br>Minimum measured thickness 0.052"<br><br>High pressure turbine drain piping –<br>2" diameter, schedule 80<br>Nominal wall thickness 0.218"<br>Minimum acceptable thickness is 0.083"<br>Minimum thickness required for 2 more years of service after 3R13 0.116"<br>Minimum measured thickness is 0.085".<br><br>High pressure turbine drain piping –<br>¾" diameter, schedule 80<br>Nominal wall thickness 0.154"<br>Minimum acceptable thickness 0.046"<br>Minimum thickness required for 2 more years of service after 3R13 0.059"<br>Minimum measured thickness 0.059"<br><br>Unit 2<br>Steam trap piping –<br>1" diameter, schedule 80<br>Nominal wall thickness 0.179"<br>Minimum acceptable thickness 0.054"<br>Minimum thickness required for 2 more years of service after 2R17 0.072" |

| Item | Request | Response |
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| | | Minimum measured thickness 0.063" |
| 44 | AMP B.1.15-2 (Flow-Accelerated Corrosion)<br><br>The LRA states that operating experience for IP2 and IP3 was accounted for in the most recent updates of the respective CHECWORKS FAC models. The LRA further states that the CHECWORKS models were updated using the inspection data from the outage inspections and the FAC wear rate changes due to the recent power uprates. Provide a time line when these models were updated and inspection data from which outages was utilized in the updates. Has IP ever experienced situations in which the model predicted wear rates may have been lower than the actual wear rates measured during FAC inspections? If yes, describe how were these nonconservative wear rate predictions handled and what has been done to correct the model? | Timeline for CHECWORKS update –<br><br>Unit 2<br><br>CHECWORKS Model update completed 3/23/2005 incorporating the wear rate changes due to the power uprate.<br>CHECWORKS Model update completed 9/12/2006 incorporating 2R17 inspection data.<br><br>Unit 3<br><br>CHECWORKS Model update completed 3/23/2005 incorporating the wear rate changes due to the power uprate.<br>CHECWORKS Model update completed 10/25/2005 incorporating 3R13 inspection data.<br><br>CHECWORKS Predicted wear rates –<br><br>Indian Point has adopted EPRI recommendations and modeled plant piping using realistic operating conditions. Therefore, there are instances where the model predicted wear rate is less than the actual wear rates measured during FAC inspections. This results in a Pass 2 analysis Line Correction Factor (LCF) greater than 1.0, indicating the CHECWORKS algorithm is under-predicting the wear rates. In cases where the wear rate is higher than predicted and remaining service hours are low, these components are selected for inspection, thereby targeting the "worst" components first and expanding the inspection scope to other components that are also likely worn. The increase in inspections provides assurance the components are suitable for continued service, and additional inspection data as input to the model.<br><br>Once the components have been inspected, a trended wear rate approach (from section 4.7 of EPRI NSAC 202L) is used to schedule the next time to inspect the components, with safety factors for conservatism.<br><br>The CHECWORKS model is corrected every outage with the latest chemistry, operating, and inspection data. Through the Pass 2 Wear Rate Analysis process in CHECWORKS, predicted wear rates are adjusted to coincide with measured wear rates. In the case where the model predicted wear rate is less than the actual wear rate, the predicted wear rates are increased (multiplied by the LCF) to match the inspection data. Over time, this approach aligns CHECWORKS predictions to actual conditions in the plant. |
| 45 | AMP B.1.15-3 (Flow-Accelerated Corrosion)<br><br>Provide a few examples of modifications and/or improvements to the FAC program at Indian Point in the past five years. What were the specific reasons (e.g., lessons learned, plant operating experience, industry experience or other (define)) for those changes and how have the changes made the FAC program more effective with respect to the management of aging? | 1. Update of CHECWORKS version from 1.0G to SFA<br>CHECWORKS FAC Version 1.0 was released by EPRI in 1993. In 2000, in recognition of the fact that CHECWORKS would not function under future Windows operating systems, EPRI began development of the successor code, CHECWORKS SFA 2.0 (and later CHECWORKS SFA 2.1 and 2).<br>The reason for the conversion is twofold.<br>The first was to stay current with industry trends. With the release of CHECWORKS SFA, EPRI will discontinue support of the CHECWORKS 1.0 software. To benefit from any future changes or improvements to the CHECWORKS software, the database must be compatible with CHECWORKS SFA.<br>The second intention of the conversion was to improve the accessibility to the CHECWORKS database. Conversion to CHECWORKS SFA creates a model with the ability to import and export data (not possible in version 1.0), enabling us to more accurately and efficiently compile program information such as outage inspection scopes.<br><br>2. Implementation of FAC Manager software<br><br>Use of FAC Manager software was implemented at IPEC. Industry experience using this software has been positive. The software allows us to efficiently manage FAC related activities. For example, FAC Manager performs all the non safety-related wall thinning calculations (100+ calculations per outage) using the Entergy Engineering Standard "Pipe Wall Thinning Structural Evaluation" ENN-CS-S-008. This software decreases the probability of calculation error associated with manual calculations resulting in less errors and omissions. |

Other benefits include:
It provides a consistent approach at all facilities benefiting shared resource personnel.
All FAC related data is consolidated in one place, saving time and minimizing errors due to referencing several data sources.
Multi-user / site capability allows analysis from other sites, utilizing resources and expertise from across the fleet.

3. Updating CHECWORKS Model to include power uprate

Power uprate changed feedwater and steam flow rates, and temperatures, which in turn changed local chemistry values. All of these factors affect wear rates due to FAC. The pre-uprate CHECWORKS model did not address the changes resulting from the Appendix K and stretch power uprate. The update of the CHECWORKS model reflects all plant power level changes (the original power level, Appendix K uprate and stretch power Uprate).
Historical (pre-uprate and Appendix K uprate) operating conditions remain within the model, associated with the applicable operating cycles. This ensures that the model's predictions of total current and future wear will be as accurate as possible because the predictions will be based on both historical and current operating conditions.

4. Development of fleet FAC procedure EN-DC-315

To support the Entergy standardization effort, a fleet-wide FAC procedure was developed to standardize the FAC program at all the Entergy Nuclear sites. A common corporate procedure provides a consistent approach to managing FAC. This enables more efficient use of shared resources, and facilitates the effective use of knowledge/expertise and operating experience across the fleet.

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**46** — AMP B.1.15-4 (Flow-Accelerated Corrosion)

If the thickness measurements during FAC inspection indicate degradation or wall thinning beyond the predicted minimum wall thickness, how would the sample size be adjusted under Indian Point's FAC Program to address the detected degradation? Include actual inspection data and examples to substantiate the response.

[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 is performed to bound the extent of thinning.
[2] When inspections of components detect significant wall thinning, the sample size for that line is 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.

Vent Chamber Drain (VCD) pipe thinning during 3R13
3R13 inspection of a VCD elbow immediately downstream of MSR-31A PCV-7008 found wall thinning less than the minimum acceptable wall thickness, requiring replacement of the elbow. Based on the results of this exam, a sample expansion was performed to determine the extent of condition for this pipe thinning.
The expansion included corresponding components on the other moisture separator reheaters with a configuration similar to that of the elbow displaying the thinning. Four additional inspections were performed. These inspections also found wall thinning less than the minimum acceptable wall thickness, requiring replacement of these components.
The sample expansion was continued until no additional components were detected with significant wear. Four additional inspections were performed downstream of the worn elbows. The results of this expansion did not find significant wear and the sample expansion was terminated.
The vent chamber drain lines on Unit 2 were replaced with FAC-resistant materials, and were not considered in this sample expansion.

Reheater Drain pipe thinning during 3R14

A leak in the reheater drain system was detected during cycle 14. A review of both Unit 2 and Unit 3 FAC programs was performed to determine if similar locations to this leak have been inspected for wall thinning and determine if additional inspections were required.
A review of the Unit 2 FAC inspection history found that all similar locations had been recently inspected or replaced. No additional inspections were recommended.
A review of the Unit 3 FAC inspection history found some similar locations that did

| Item | Request | Response |
|---|---|---|
| | | not have recent inspections and were recommended for inspection. A total of 9 inspections were added on the A and B trains at locations similar to the leak.<br><br>As a result of these inspections, two elbows were found to have wall thinning and were replaced during 3R14. Review of the sample expansion developed for the initial leak determined that the wall thinning was bounded by this expansion. All similar locations have been identified and scheduled for inspection during 3R14. Inspection of the remaining 7 components found them acceptable for continued service, and will continue to be monitored in the FAC Program. |
| 47 | AMP B.1.15-5 (Flow-Accelerated Corrosion)<br><br>How is the industry experience utilized in the FAC Program at Indian Point? How does IP gets feedback from other plants? Are there any unique differences between the FAC Programs of IP2 and IP3? If wall thinning or degradation is observed during FAC inspection of one unit, are the corresponding components on the other unit inspected for similar degradations? | Industry experience is reviewed in accordance with the corporate procedure EN-OE-100 Operating Experience Program and is implemented in conjunction with the corrective action program. Details on the review and actions to be taken are provided in this procedure. A site OE coordinator screens incoming operating experience for site applicability. This includes operating experience within the Entergy corporation and the industry. In addition, other utilities participate in QA audits of programs where they provide their unique experience.<br><br>Industry experience is evaluated, and if applicable to IPEC is incorporated into the FAC inspection scope. Feedback from other plants is obtained from attendance at CHECWORKS users group (CHUG) meetings where industry OE is exchanged during the formal presentations as well as an information exchange session where each utility describes issues encountered since the last meeting. Another source of OE is FACnet. It is a communications tool used by FAC personnel to ask questions, share ideas, and exchange information via email.<br><br>The only previous differences between the Unit 2 and Unit 3 FAC Programs were dealing with how the data was stored and how specific component evaluations were performed. With the implementation of the corporate FAC procedure and the use of FAC Manager, the Unit 2 and Unit 3 FAC programs are now very similar.<br><br>When thinning or degradation is observed during FAC inspection of one unit, the corresponding components on the other unit are evaluated for similar degradation. Examples are provided in the response to AMP B.1.15 Question # 46, where the extent of condition review evaluates the other unit for similar degradations |
| 48 | AMP B.1.15-6 (Flow-Accelerated Corrosion)<br><br>The LRA states that the FAC Program for IP2 was audited in 2004 and that the audit team determined that the program was effective and in compliance with ASME code, EPRI standards, and INPO guidelines and NRC regulations.<br><br>(a) Which organization performed this audit and what was the purpose of this audit? Was a similar audit performed on IP3 FAC Program?<br><br>(b) Explain which specific documents of the stated organizations were used in the audit to establish program compliance.<br><br>(c) Which specific elements of the Indian Point FAC Program and what specific documentation pertaining to the program was reviewed by the audit team to establish that the program was effective? | (a) This was an internal QA department audit with assistance from an outside utility and the purpose was to confirm that several IPEC Unit 2 programs including FAC were in compliance with the requirements of the NRC Regulations, Codes, Industry Standards, IPEC Unit 2 Technical Specifications, Final Safety Analysis Reports and commitments. A similar audit was recently performed for Unit 3 in the spring of 2007 and documented in audit report QA-08-2007-IP-1. This audit determined that the program was satisfactory with no findings. There have also been QA surveillances performed of the IP3 and IP2 programs in 2005 and 2006.<br>(b) QA audits are performed in accordance with corporate nuclear management manual procedure EN-QV-109 Audit Process. The following specific documents of the organizations stated in the question were reviewed as part of the audit:<br><br>NRC Generic Letters 89-08 & 90-05, NUREG-1344, ANSI B31.1, EPRI Report TR-10611, NSAC 202L-R2, INPO SOER's 87-3 & 82-11.<br><br>(c) The following features of the FAC program were reviewed: procedures, FAC inspections, industry experience, wall thinning analysis and calculations, and corporate and IPEC commitments. Though this inspection was not an inspection of the FAC program elements described in NUREG-1801, it did review portions of the program that encompass elements of B.1.15. These elements would be Scope, Preventive Actions, Parameters Monitored, Detection of Aging Effects, Monitoring and Trending, Acceptance Criteria, and Operating Experience. Examples of documents reviewed include ENN-DC-315 rev. 0, ENN-NDE-9.05, EPRI Technical Report NSAC-202L-R2, IP-CALC-04-01727 and IP-CALC-04-01620, and IP-CALC-04-01713, Revision 0 |
| 49 | AMP B.1.15-7 (Flow-Accelerated Corrosion)<br><br>The LRA includes operating experience items which pertain to inspections during 3R13 and 2R17 outages for IP3 and IP2 respectively. Both items are recent (March 2005 and May 2006 respectively) items. Provide more examples of inspection results to demonstrate that the FAC program at Indian Point is effective in managing | Identification of degradation and corrective action prior to loss of intended function provide assurance that the FAC Program is effective for managing aging effects due to flow accelerated corrosion. Corrective actions are addressed by the wet steam replacement project. This project is a multi-year task to replace FAC susceptible piping with FAC resistant material. Replacement materials include stainless steel, chrome-moly and carbon steel pipe with a stainless steel liner.<br><br>The following are more examples of inspection results to demonstrate that the FAC program is effective in managing the effects of aging. |

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| | the aging effect. | Wall thinning was found on the LP extraction steam lines to the Unit 2 22 feedwater heaters that are located inside the condenser neck. As part of the wet steam pipe replacement project, these lines are being replaced with FAC-resistant chrome moly material. The 22C feedwater heater extraction steam lines were replaced during 2R17 (2006) and the 22A and 22B feedwater heaters extraction steam lines are to be replaced during 2R18 with chrome moly material. Inspections performed for Unit 3 32 feedwater heater extraction line found these components acceptable for continued service and will not require replacement.<br><br>Wall thinning was found on two 35 extraction steam elbows during 3R14 FAC inspections. As part of the wet steam pipe replacement project, these lines are being replaced with FAC-resistant chrome moly material during 3R15. The 25 extraction steam line for Unit 2 was replaced entirely with stainless steel and chrome moly material.<br><br>Wall thinning was found on the steam lines from the preseparators to the 35 extraction steam header at Unit 3 during 3R12 FAC inspections. As part of the wet steam pipe replacement project these lines were replaced with carbon steel piping with a stainless steel cladding during 3R13 (2005). The 25 extraction steam line for Unit 2 was replaced entirely with stainless steel and chrome moly material.<br><br>Additional pipe replacements by the Wet Steam Pipe Replacement Project include:<br><br>3R14, 2007<br>Due to wear found in FAC inspections, approximately 700' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant chrome moly piping. In addition, the carbon steel discharge piping from the High Pressure Turbine Drain Main Steam flow control valves (9 lines totaling approximately 50 feet of pipe) to the condenser were replaced due to wall thinning observed during FAC examinations.<br><br>2R16, 2004<br>Due to wear found in FAC inspections, approximately 200' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant chrome moly piping. Also replaced was approximately 10' of carbon steel MSR drain piping downstream of LCV-1105A to the 26 FWHs with FAC resistant chrome moly.<br><br>3R12, 2003<br>Due to wear found in FAC inspections, the carbon steel North to South Main Steam Trap header was replaced with FAC resistant chrome moly piping; the 33 Feedwater Heater Operating vent carbon steel piping was replaced with FAC resistant chrome moly.<br><br>2R15, 2002<br>Due to wear found in FAC inspections, approximately 150' of carbon steel extraction steam piping to FWH23A was replaced with FAC resistant chrome moly, and approximately 200' of carbon steel Feedwater Heater 23 A, B and C operating vent piping was replaced with FAC resistant chrome moly.<br><br>3R11, 2001<br>Due to wear found in FAC inspections, approximately 40' of carbon steel extraction steam piping to the 35A and 35B FWH was replaced with FAC resistant chrome moly piping, and the carbon steel 36 FWH operating vents were replaced with FAC resistant chrome moly pipe. In addition 9 extraction steam traps carbon steel piping was replaced with FAC resistant chrome moly piping.<br><br>2R14, 2000<br>Due to wear found in FAC inspections, approximately 1700' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant stainless steel, and approximately 115' of carbon steel 25 FWH extraction steam piping was replaced with FAC resistant stainless steel. |
| 50 | AMP B.1.16-1 (Flux Thimble Tube Inspection)<br><br>LRA AMP B.1.16, "Program Description" states: " An NDE methodology, such as eddy current testing (ECT), or other similar inspection method is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88 09, Thimble Tube Thinning in Westinghouse Reactors." | Consistent with the program description described in GALL, other applicant-justified and NRC-accepted inspection methods may be used. However, only eddy current testing is used to monitor thinning of flux thimble tubes at IP2 and IP3. The program description in LRA Sections A.2.1.15, A.3.1.15, and B.1.16 will be revised to state that eddy current testing is the NDE method used by the Flux Thimble Tube Inspection Program. The phrase "or similar inspection method" will be removed.<br><br>Clarification to be incorporated into the LRA. |

| Item | Request | Response |
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| | Discuss what other similar inspection method is used for monitoring the wear of flux thimble tubes for IP2 and IP3. How does this method compare with the ECT, as recommended in GALL? | |
| 51 | AMP B.1.16-2 (Flux Thimble Tube Inspection)<br><br>LRA AMP B.1.6 includes three enhancements to be implemented prior to the period of extended operation for GALL consistency in program elements "Monitoring and Trending," "Acceptance Criteria," and "Corrective Actions."<br><br>a.GALL "Monitoring and Trending" recommends: " The wall thickness measurements will be trended and wear rates will be calculated. Examination frequency will be based upon wear predictions that have been technically justified as providing conservative estimates of flux thimble tube wear. The interval between inspections will be established such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection. The examination frequency may be adjusted based on plant specific wear projections. Re baselining of the examination frequency should be justified using plant specific wear rate data unless prior plant specific NRC acceptance for the re baselining was received. If design changes are made to use more wear resistant thimble tube materials (e.g., chrome plated stainless steel) sufficient inspections will be conducted at an adequate inspection frequency, as described above, for the new materials." Discuss how the stated enhancement in the LRA satisfies the GALL for both IP2 and IP3.<br><br>b. GALL "Accptance Criteria" recommends: " Appropriate acceptance criteria such as percent through wall wear will be established. The acceptance criteria will be technically justified to provide an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained. The acceptance criteria will include allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies, as applicable, to the inspection methodology chosen for use in the program. Acceptance criteria different from those previously documented in NRC acceptance letters for the applicant=s response to Bulletin 88 09 and amendments thereto should be justified." Discuss how the stated enhancement in the LRA satisfies the GALL for both IP2 and IP3.<br><br>c. GALL "Corrective Actions" recommends: "Flux thimble tube wall thickness which do not meet the established acceptance criteria must be isolated, capped, plugged, withdrawn, replaced, or otherwise removed from service in a manner that ensures the integrity of the reactor coolant system pressure boundary is maintained. Analyses may allow repositioning of flux thimble tubes that are approaching the acceptance criteria limit. Repositioning of a tube exposes a different portion of the tube to the discontinuity that is causing the wear." Discuss how the stated enhancement in the LRA satisfies the GALL for both IP2 and IP3. | a. For IP2, the measurements from the last performance will be trended with the next scheduled wear rate measurement. While IP2 compares measured values in practice, the enhancement to Element 5 will formalize the process. For IP3, wear measurements are trended per Attachment 1, Section 6.0 of procedure THI-002-RVI where each tube inspection is recorded on datasheets and a permanent strip chart recording is made at the time of the inspection. Inspection results are recorded on a table in listed in THI-002-RVI. Wear rates and examination frequencies are calculated per RE-ICI-910625 which states that 80% wear would occur during cycle 24 for IP2. Wear rates and examination frequencies are calculated per IP-CALC-07-0038 which requires an eddy current inspection prior to 3R16 for IP3. Changing the baseline of the exam frequency has not occurred and the flux thimble tube design has not changed. Therefore, existing activities are consistent with the Flux Thimble Tube Monitoring Program attribute "Monitoring and Trending" with the enhancement to better formalize the process.<br><br>b. IP2 and IP3 have established acceptance criterion of 80% through wall (thimble tube wall thickness is not less than 20% of initial wall thickness). Tubes with 80% through wall wear shall be replaced or isolated. Thimble tubes with wear exceeding 40% through wall but projected to remain under 80% by the next inspection may be repositioned after engineering evaluation. Thimble tubes with wear projected to exceed 80% by the next inspection will be repositioned, replaced, or isolated. This is conservatively based on WCAP-12866 recommendations which include potential inaccuracies. IPEC responses in April 1989 to Bulletin 88-09 cited acceptance criteria of 50% for IP2 and 60% for IP3. As recommended by the Bulletin, the Westinghouse Owners Group completed WCAP 12866 in 1991 which determined that a thimble can safely remain in service with up to 80% (includes conservatism) through wall loss. The results of the WCAP were adopted by IPEC in 1991. As described above, existing activities are consistent with the Flux Thimble Tube Monitoring attribute "Acceptance Criteria". The enhancement is intended to formalize these activities.<br><br>c. Flux thimble tubes are isolated, capped, plugged, withdrawn, repositioned, or replaced when wall thickness is less than the minimum required.<br><br>IP2: During the Spring 2006 IP2 outage, all flux thimble tubes were repositioned by approximately two inches as part of a seal table modification. Nine flux thimble tubes have been capped.<br><br>IP3: Two flux thimbles have been capped as recommended by calculation IP-CALC-07-0038.<br><br>These existing activities are consistent with the Flux Thimble Tube Monitoring Program attribute "Corrective Actions". The enhancement is intended to formalize these activities. |

| Item | Request | Response |
|---|---|---|
| 52 | AMP B.1.17-1 (Heat Exchanger Monitoring)<br><br>The staff compared the enhancements to the Scope of Program with the specific AMR line items in LRA Sections 3.2 and 3.3 that credit AMP B.1.17 - Heat Exchanger Monitoring. A total of 14 AMR line item entries were located, all identified only as "Heat Exchanger - Tubes". These occurred under the following systems:<br><br>Table 3.2.2-1-IP2 RHR (1 line item)<br>Table 3.2.2-1-IP3 RHR (1 line item)<br>Table 3.2.2-4-IP2 Safety Injection (1 line item)<br>Table 3.2.2-4-IP3 Safety Injection (1 line item)<br>Table 3.3.2-2-IP3 Service Water (1 line item)<br>Table 3.3.2-3-IP2 Component Cooling Water (2 line items)<br>Table 3.3.2-3-IP3 Component Cooling Water (2 line items)<br>Table 3.3.2-6-IP2 Chemical & Volume Control (2 line items)<br>Table 3.3.2-6-IP3 Chemical & Volume Control (2 line items)<br>Table 3.3.2-16-IP2 SBO/App. R Diesel Generator (1 line item)<br><br>The staff could not correlate the scope of program, including the enhancements, with the AMR table entries; and requests the following clarifications:<br><br>(a) Identify the specific component inspections currently included in the existing program that are credited for license renewal.<br><br>(b) Correlate the 14 AMR table entries identified above with the specific component inspections included in the enhanced program. | (a) This program is only credited to manage the aging effect of loss of material due to wear. The existing site eddy current heat exchanger inspection program includes safety-related and nonsafety-related heat exchangers. Eddy current inspections of Generic Letter 89-13 safety-related heat exchangers cooled by service water are included as part of the Service Water Integrity Program. The existing heat exchanger eddy current inspections on IP2 and IP3 are detailed in Appendix 1 and 2 of procedure IP3-RPT-UNSPEC-03499. The only heat exchangers currently included in the existing program are the IP3 instrument air heat exchangers SWN CLC 31/32 HTX that were inadvertently listed as needing to be added to the program as part of the enhancement. The existing program will be continued into the period of extended operation with enhancements.<br><br>(b) Table 3.2.2-1-IP2 RHR / RHR heat exchangers (IP2 – 21/22RRHX)<br><br>Table 3.2.2-1-IP3 RHR / RHR heat exchangers (IP3 - ACAHRS1/2)<br><br>Table 3.2.2-4-IP2 Safety Injection / safety injection pump lube oil heat exchangers (IP2 - CCW-HTEX-WCLR-1009/1010/1011)<br><br>Table 3.2.2-4-IP3 Safety Injection / safety injection pump lube oil heat exchangers (IP3 - SISP31/32/33 OC HTX),<br><br>Table 3.3.2-2-IP3 Service Water /The line item in Table 3.3.2.2 IP3 Service Water refers to the IP3 instrument air heat exchangers SWN CLC 31/32 HTX. The inclusion of this heat exchanger as part of the enhancement is an error since these heat exchangers are in the existing eddy current inspection program.<br><br>Table 3.3.2-3-IP2 Component Cooling Water / spent fuel pit heat exchangers (21SFPHX), secondary system steam generator sample coolers (21/22/23/24 SGSC), waste gas compressor heat exchangers (21/22 WGCSWC)<br><br>Table 3.3.2-3-IP3 Component Cooling Water / spent fuel pit heat exchangers (ACAHSF1), secondary system steam generator sample coolers (SGBDS-31/32/32/34HX), waste gas compressor heat exchangers (WD-WGC-31/32HTX)<br><br>Table 3.3.2-6-IP2 Chemical & Volume Control / non-regenerative heat exchangers (IP2 - 21NRHX), charging pump seal water heat exchangers (IP2 - 21SWHX), charging pump fluid drive coolers (IP2 – 21/22/23CHPFCA), charging pump crankcase oil cooler (IP2 - 21/22/23CHPFCB)<br><br>Table 3.3.2-6-IP3 Chemical & Volume Control / non-regenerative heat exchangers (IP3 – CSAHNRT), charging pump seal water heat exchangers (IP3 - CSAHSW1), charging pump fluid drive coolers (IP3 - CHRG PP31/32/33 CASING HTX), charging pump crankcase oil cooler (IP3 - CHRG PP31/32/33 CRANK HTX)<br><br>Table 3.3.2-16-IP2 SBO/App. R Diesel Generator / SBO/Appendix R diesel jacket water heat exchanger (ARDG-JWHX)<br><br>Information to be incorporated into the LRA.<br><br>The charging pump crankcase oil coolers were inadvertently omitted from the scope of heat exchangers to be included in the program and the IP3 instrument air heat exchangers SWN CLC 31/32 HTX are already included in the existing program and should not be part of the enhancement |
| 53 | AMP B.1.17-2 (Heat Exchanger Monitoring)<br><br>The staff noted that all AMR table entries identify " Loss of Material - Wear" as the aging effect being managed. Is this wear induced by flow through and/or over the heat exchanger tubes? Does the wear result from abrasive fluid at high velocity or from flow-induced vibration of the tubes? | The wear that is identified by this aging effect is wear (fretting) on the outside of the tubes due to contact between the tubes and the tube support plates. It is not expected that this will occur but is conservatively identified as an aging effect requiring management. The wear could be caused by vibration of the tube as a result of high flows or excessive clearance between the tube and tube support plate. Wear resulting from abrasive fluid at high velocity is not expected in the heat exchangers included in this program due to the controlled water chemistry of the process fluids on the shell and tube sides. |
| 54 | AMP B.1.17-3 (Heat Exchanger Monitoring)<br><br>Under "Parameters Monitored or Inspected", an " enhancement" to the existing program is to specify visual inspection where non-destructive examination, such as eddy current testing, is not | All of the heat exchangers in the existing eddy current inspection program are large enough such that eddy current inspection can be performed. Visual inspection of the ID of heat exchanger tubes in the existing program is not routinely performed. Some of the new heat exchangers added by the enhancement are small enough such that eddy current inspection may not be possible necessitating visual inspection. |

| Item | Request | Response |
|---|---|---|
| | possible. In the existing program, what is currently done if eddy current testing is not possible? | |
| 55 | AMP B.1.17-4 (Heat Exchanger Monitoring)<br><br>Describe the details of the visual inspection techniques to be employed. Does this include remote visual inspection of the inside of the tubes? What specific acceptance criteria are applied to visual inspection? Compare this to the acceptance criteria applied to eddy current testing. | Depending on the size of the heat exchanger, tube configuration, and tube size, a remote visual inspection of the tubes may be required if eddy current examination of the tubes is impractical. Remote visual inspection may be performed by means of a fiberscope inserted through the tubes, or on the tube exterior from the shell side. As specified in the enhancement for the acceptance criteria attribute, appropriate procedures will be revised to establish acceptance criteria for heat exchangers visually inspected to include no unacceptable signs of degradation. This is identified as commitment #10. The eddy current tests have a minimum acceptable tube wall thickness acceptance criterion, which is determined by engineering evaluation on a heat exchanger-specific basis. |
| 56 | AMP B.1.17-5 (Heat Exchanger Monitoring)<br><br>Do any of the heat exchangers included in the scope of this AMP come under the jurisdiction of ASME Code Section III and Section XI? If yes, identify the specific heat exchangers and discuss how the Section XI requirements for inspection are satisfied by this AMP. | This AMP manages the aging effect of loss of material due to wear for the tubes in the heat exchangers listed under the enhancement for the scope of the program. The tubes in the other heat exchangers currently in this program are eddy current tested to detect loss of material. Some heat exchangers are classified as ISI Class 1, 2, and 3 and are subject to the requirements of ASME Section XI inservice inspection and repair / replacement requirements associated with the pressure boundary. Repairs or modifications to heat exchangers will comply with the design code(s) of record (ASME Section III and/or ASME Section VIII, as applicable). The heat exchanger monitoring program does not implement any of these repair/ replacement or inspection activities. |
| 57 | AMP B.1.18-1 (Inservice Inspection)<br><br>LRA AMP B.1.18, Program Description states: The Inservice Inspection (ISI) Program is an existing program that encompasses ASME Section XI, Subsections IWA, IWB, IWC, IWD and IWF requirements at GALL AMP XI.M1 imposes requirements for Subsections IWB, IWC, and IWD for Class 1, 2, and 3 pressure retaining components and their integral attachments. Subsection IWA describes general requirements associated with Subsections IWB, IWC, and IWD. GALL AMP XI.S3 covers Inservice inspection of Class 1, 2, 3 and MC component supports for ASME piping and components addressed in Section XI, Subsection IWF. The staff notes that the 10 element evaluation for the Subsection IWF inspection is not explicitly addressed in LRA AMP B.1.18.<br><br>(a) Provide a detailed 10 element evaluation of the Subsection IWF inspection for Class 1, 2, 3 and MC component supports and discuss any exceptions or enhancements when assessed against the recommendations in GALL AMP XI.S3, AASME Section XI, Subsection IWF. Specifically, discuss the inspection methods, their frequencies, sampling methods for each class of supports, acceptance criteria, and operating experience findings and their corrective measures.<br><br>(b) The attributes of AMP B.1.18 and GALL AMP XI. M1 are mostly identical and consistent, except AMP B.1.18 also includes the GALL AMP XI.S3 for supports. Explain why Entergy categorizes AMP B.1.18 to be plant specific. | (a) Entergy described the Inservice Inspection (AMP B.1.18) Program as a plant-specific program rather than comparing to the corresponding NUREG-1801 programs (XI.M1 and XI.S3) because the NUREG-1801 programs contain many ASME Section XI table and section numbers which change with different editions of the code. Because of this, comparison with the NUREG-1801 programs generates many exceptions and explanations which detract from the objective of the comparison. The CLB requires that IPEC follow the version of ASME Section XI referenced in 10CFR50.55(a) and approved for use at IPEC. As this is the case, the Inservice Inspection Program is presented as a plant-specific program so it can be judged on its own merit without the distraction of numerous explanations of exceptions due to differing code editions.<br><br>Since the Inservice Inspection Program is a plant-specific program, comparison of the 10 elements with NUREG-1801 program XI.S3 is not appropriate. Therefore, in the program basis document (IP-RPT-06-LRD02, available for on-site review) the attributes of the program are compared to the ten elements of an aging management program for license renewal as described in NUREG-1800, Table A.1-1. Additional information clarifying specific attributes of the IWF portion of the ISI program is provided below.<br><br>Inspection methods, frequencies and sampling methods - The ISI Program manages loss of material for ASME Class MC and Class 1, 2, and 3 piping and component supports, anchorages, and base plates by visual examination of components using NDE techniques, frequencies, and sample sizes in accordance with 10 CFR 50.55(a).<br><br>Class 1 piping supports - visual (VT-3) - 25% of class 1.<br>Class 2 piping supports - visual (VT-3) - 15% of class 2.<br>Class 3 piping Supports - visual (VT-3) - 10% of class 3.<br><br>For Class 1, 2 and 3 piping supports, the total percentage sample shall be comprised of supports from each system where the individual sample sizes are proportional to the total number of nonexempt supports of each type and function within each system.<br><br>Supports Other than Piping Supports (Class 1, 2, & 3 and MC) - visual (VT-3) - 100% of the supports. For multiple components other than piping, within a system of similar design, function, and service, the supports of only one of the multiple components are required to be examined.<br><br>Acceptance Criteria - Acceptance standards for examination evaluations, repair procedures, inservice test requirements, and replacements for ASME Class MC and Class 1, 2, and 3 piping and component supports are in accordance with 10 CFR 50.55(a). The following conditions are unacceptable: |

| Item | Request | Response |
|---|---|---|
| | | (i) deformations or structural degradations of fasteners, springs, clamps, or other support items;<br>(ii) missing, detached, or loosened support items;<br>(iii) arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces;<br>(iv) improper hot or cold positions of spring supports and constant load supports;<br>(v) misalignment of supports;<br>(vi) improper clearances of guides and stops.<br><br>Identification of unacceptable conditions triggers an expansion of the inspection scope, and reexamination of the supports requiring corrective actions during the next inspection period in accordance with the code. Repair and replacement criteria and procedures are also in accordance with the code.<br><br>Operating Experience - ISI examinations at IP2 and IP3 were conducted during 2004 and 2005. Results found to be outside of acceptable limits were either repaired, evaluated for acceptance as is, or replacement activities were initiated. Identification of degradation and performance of corrective action prior to loss of intended function are indications that the program is effective for managing aging effects. A self-assessment of the ISI program was completed in October 2004. Review of scope for 2R16 (2004) and 3R13 (2005) verified that the proper inspection percentages had been planned for both outages. A follow-up assessment was held for IP2 in March 2006 to ensure that all inspection activities required to close out the third 10-year ISI interval were scheduled for 2R17 (2006). Confirmation of compliance to program requirements provides assurance that the program will remain effective for managing loss of material of components. QA surveillances in 2005 and 2006 revealed no issues or findings that could impact effectiveness of the program.<br><br>(b) See response to (a). |
| 58 | AMP B.1.18-2 (Inservice Inspection)<br><br>LRA AMP B.1.18, "Scope of Program" states: " The ISI Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel. Both IP2 and IP3 use ASME Code Case N 481 as approved in Regulatory Guide 1.147 for managing the effects of loss of fracture toughness due to thermal aging embrittlement of CASS pump casing pressure retaining welds. ASME Code Case N 481 has been incorporated in later editions of the code and IP2 will not reference Code Case N 481 in the 4th interval."<br><br>Explain why a discussion of this specific code case is included. | The Inservice Inspection Program uses nondestructive examination (NDE) techniques to manage reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel.<br><br>Since Code Case N-481 has been approved in Regulatory Guide 1.147, it is part of the ASME code and need not be mentioned separately. Therefore, sentences referencing code case N-481 in LRA AMPs B.1.18 and B.1.37 will be removed from the LRA.<br><br>Clarification to be incorporated into the LRA. |
| 59 | AMP B.1.18-3 (Inservice Inspection)<br><br>LRA AMP B.1.18, "Detection of Aging Effects" states: "The ISI Program will be revised to provide periodic inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump supports." What has been the plant specific operating experience with the degradation of the lubrite plates? | Neither IP2 nor IP3 has plant-specific operating experience with degradation of the Lubrite sliding supports used in the steam generator and reactor coolant pump sliding supports.<br><br>As discussed in EPRI Report 1002950, Aging Effects for Structures and Structural Components (Structural Tools) Revision 1, Lubrite material resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high radiation, and requires no maintenance. An extensive search of industry operating experience did not identify any instances of Lubrite plate degradation or failure to perform its intended function. Consequently, there are no known aging effects that would lead to a loss of intended function.<br><br>Nevertheless, as described in LRA AMP B.1.18, the ISI Program will confirm by visual inspection the absence of aging effects for the Lubrite used in the steam generator and reactor coolant pump sliding supports through the period of extended operation.<br><br>Clarification to be incorporated into the LRA.<br>Commitment # 11. |
| 60 | AMP B.1.18-4 (Inservice Inspection) | The ISI program will continue to be implemented in full compliance with the |

| Item | Request | Response |
|---|---|---|
| | LRA AMP B.1.18, "Detection of Aging Effects" states: "Both IP2 and IP3 have adopted risk informed inservice inspection (RI ISI) as an alternative to current ASME Section XI inspection requirements for Class 1, Category B F and B J welds pursuant to 10 CFR 50.55a(a)(3)(i). The RI ISI was developed in accordance with the EPRI methodology contained in EPRI TR 112657, Rev. B A, "Revised Risk Informed Inservice Inspection Evaluation Procedure." The risk informed inspection locations are identified as Category R A."<br><br>During the license renewal period, will the ISI program be implemented in full compliance with the requirements of 10 CFR 50.55a in effect at the beginning of each new 10 year inspection interval? | requirements of 10 CFR 50.55a in effect at the beginning of each new 10 year inspection interval.<br><br>Letters detailing RI-ISI for IP2 and IP3 category B-F and B-J welds and NRC acceptance letters were provided to the auditor for review.<br><br>Since use of RI-ISI at IP2 and IP3 has been approved pursuant to 10 CFR 50.55a(a)(3)(i), RI-ISI need not be mentioned separately. Therefore, reference to RI-ISI will be deleted from LRA AMP B.1.18.<br><br>Clarification to be incorporated into the LRA. |
| 61 | AMP B.1.18-5 (Inservice Inspection)<br><br>LRA AMP B.1.18, "Monitoring and Trending" states: "ISI results are recorded every operating cycle and provided to the NRC after each refueling outage via Owner's Activity Reports. These reports include scope of inspection and significant inspection results. They are prepared and submitted in accordance with NRC accepted ASME Section XI Code Case N 532 1 as approved by RG 1.147."<br><br>During the license renewal period, will the ISI program be implemented in full compliance with the requirements of 10 CFR 50.55a in effect at the beginning of each new 10 year inspection interval? | ISI results are recorded every operating cycle and provided to the NRC after each refueling outage via Owner's Activity Reports. These reports include scope of inspection and significant inspection results.<br><br>The ISI program will continue to be implemented in full compliance with the requirements of 10 CFR 50.55a in effect at the beginning of each new 10 year inspection interval.<br><br>Since Code Case N-532-1 has been approved in Regulatory Guide 1.147, it is part of the ASME code and need not be mentioned separately. Therefore, the sentence referencing code case N-532-1 in LRA AMP B.1.18 will be removed from the LRA.<br><br>Clarification to be incorporated into the LRA. |
| 62 | AMP B.1.19-1 (Masonry Walls)<br><br>The applicant has identified an enhancement to the Scope of Program, as follows: "Revise applicable procedures to specify that the IP1 intake structure is included in the program." The LR intended function of the IP1 intake structure relates to protection of Appendix R equipment, in accordance with 10 CFR 54.4(a)(3). The intent of the GALL Masonry Wall AMP (XI.S5) is to ensure that a previously documented seismic qualification basis, in accordance with IE Bulletin 80-11, remains valid through implementation of the guidance provided in IN 87-67. Has a documented seismic qualification basis, in accordance with IE Bulletin 80-11, been developed for the masonry components of the IP1 intake structure? If so, provide the documentation at the audit. If not, then this AMP cannot be credited to manage aging for the extended period of operation. | IE Bulletin 80-11, Masonry Wall Design, addressed the potential for problems with the structural adequacy of concrete masonry walls in proximity to or with attachments to safety-related piping or equipment. There are no masonry walls in IP1 intake structures which meet the classification of IE Bulletin 80-11. Thus, no seismic qualification basis in accordance with IE Bulletin 80-11 has been developed for masonry components of IP1 intake structure.<br><br>IP1 intake structure houses components required for the alternate safe shutdown system, which is credited in the Appendix R safe shutdown analysis. Accordingly, the structure has license renewal intended function for 10 CFR 54.4(a)(3) since it provides support for equipment credited for regulations associated with fire protection (10CFR 50.48).<br><br>The scope of the GALL Masonry Wall AMP (XI.S5) states: "The scope includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4."<br><br>Consistent with scope of GALL Masonry Wall AMP (XI.S5), and as described in license renewal application B.1.19, Indian Point Energy Center (IPEC) Masonry Wall Program is an existing program that manages aging effects of all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. Included components are 10 CFR 50.48-required masonry walls.<br><br>The IPEC Masonry Wall Program, with enhancement, assures the effects of aging are managed such that IP1 intake structure will continue to perform its intended function through the period of extended operation. |
| 63 | AMP B.1.22-1 (Bolted Cable Connections)<br><br>GALL AMP XI.E6 states that testing may include thermography, contact resistance testing, and other appropriate testing methods. In AMP B.1.22, under Detection of Aging Effect element, | Visual inspection is an alternative technique to thermography or measuring connection resistance of bolted connections that are covered with heat shrink tape, sleeving, insulating boots, etc. where the only alterative to visual inspection is destructive examination. This is the same philosophy applied to bolted connections in metal-enclosed bus. |

| Item | Request | Response |
|---|---|---|
| | you have stated that inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual based on plant configuration and industry guidance. Explain how visual inspection can detect loosening of bolted cable connections. | AMP B.1.22 is a plant specific program proposed instead of a program that is consistent with GALL XI.E6. Element 4, "Detection of Aging Effects," can be revised as follows to clarify this statement.<br><br>A representative sample of electrical connections within the scope of license renewal, and subject to aging management review will be inspected or tested prior to the period of extended operation to verify there are no aging effects requiring management during the period of extended operation. The factors considered for sample selection will be application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selected will be documented. Inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual based on plant configuration and industry guidance. Visual inspection should be used instead of destructive examination when other methods cannot be used. The one-time inspection or testing provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective.<br><br>Clarification to be incorporated into the LRA.<br>Commitment # 14. |
| 64 | AMP B.1.24-1 (Instrumention Circuits Test Review)<br><br>GALL AMP XI.E2 states that this program applies to high-range-radiation and neutron flux monitoring instrumentation cables in addition to other cables used in high voltage, low level signal application that are sensitive to reduction IR. In AMP B.1.24, you only mention about neutron monitoring system cables.<br><br>(a) Explain why high range monitoring cables are not included in the AMP B.1.24.<br><br>(b) List other cables used in high voltage, low level signal application. Explain why these cables were not included in the scope of AMP B.1.24. | (a)Although not explicitly listed, the high range radiation monitoring cables were included in AMP B.1.24. The aging management review included neutron monitoring circuits and high range radiation monitoring circuits. Reference Attachment 3 of the electrical AMR report. The program description for AMP B.1.24 uses the phrase (i.e., neutron flux monitoring instrumentation). Since this was meant to be an example, the term "e.g." would have been a more appropriate choice than "i.e.".<br><br>(b)During the IPA, the only high instrument voltage circuits with low signal values that were not subject to aging management review were the incore detectors and area radiation monitors. The nonsafety-related incore detectors and the area radiation monitors do not perform a license renewal intended function per 10 CFR 54.4(a)(1), (2), or (3). Therefore, the incore detectors and the area radiation monitors are not included in the scope of the B.1.24 (XI.E2) aging management program.<br><br>A change will be made to LRA Section B.1.24 for clarification. The recommended change is as follows.<br><br>The Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture; (i.e., neutron flux monitoring instrumentation and high range radiation monitors); can be maintained consistent with the current licensing basis through the period of extended operation. Most sensitive instrumentation circuit cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results will be performed once every ten years, with the first review occurring before the period of extended operation.<br><br>For sensitive instrumentation circuit cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurring before the period of extended operation. 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 he intended functions of the cables can be maintained consistent with the current licensing basis through the period of extended operation. This program will consider the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR 109619.<br><br>Clarification to be incorporated into the LRA. |
| 65 | AMP B.1.25-1 (Insulated Cables and Connections)<br><br>You have stated that a representative sample of accessible insulated cables and connections | This program addresses cables and connections under the premise that a large portion of cables and connections are accessible. This program sample consists of all accessible cables and connections in localized adverse environments. If an unacceptable condition or situation is identified for a cable or connection during this |

| Item | Request | Response |
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| | within the scope of license renewal will be visually inspected. Describe the technical basis for sampling and action taken if a degradation was found on a representative sample. | visual inspection, the corrective action process will be used for resolution. As part of the corrective action process a determination will be made as to whether the same condition or situation is applicable to other cables or connections.<br><br>The program description for B.1.25 will be revised as follows.<br><br>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. The program sample consists of all accessible cables and connections in localized adverse environments.<br><br>Clarification to be incorporated into the LRA. |
| 66 | AMP B.1.26-1 (Oil Analysis)<br><br>LRA references a June 2006 evaluation of oil analysis practices among Entergy Northeast sites. Provide documentation describing this evaluation (e.g., report) and describe how the evaluation impacted oil analysis practices at Indian Point. | The evaluation report was provided during the on-site audit. Based on the report results, oil analysis frequencies were evaluated with recommended actions. The evaluation resulted in changes to the frequencies of some oil analyses. However, these changes did not affect components in the scope of license renewal that credited the Oil Analysis Program for managing the effects of aging. |
| 67 | AMP B.1.26-2 (Oil Analysis)<br><br>Describe the process for reviewing oil analysis test results and how these reviews ensure that unusual trends are identified and alert levels have not been reached or exceeded. | The results of oil analyses are reviewed by the predictive maintenance group to determine if oil is suitable for continued use until the next scheduled sampling or scheduled oil change. Oil analysis data sheets are provided by an offsite vendor with current and historical analysis results. The data is reviewed to evaluate unusual trends. When degraded conditions are indicated, the predictive maintenance group will take appropriate actions to check the validity of the data and issue a condition report with recommended corrective actions. |
| 68 | AMP B.1.26-3 (Oil Analysis)<br><br>The LRA states that the lubricating oil analysis program is consistent with the program described in GALL, but also identifies six elements as requiring enhancement to achieve this consistency. Provide a more detailed description of past and present lubricating oil monitoring activities at the Indian Point site and the schedule for implementation of enhancements to this AMP. | The enhancements identified for the Oil Analysis Program are not necessary to achieve consistency with the program described in the GALL report. As indicated in LRA Section B.1.26, two of the four enhancements involve adding nonsafety-related components to the program that are not covered in the existing program. The remaining two enhancements involve formalizing in procedures actions that are being informally performed under the existing program. As indicated in the LRA, the existing lubricating oil monitoring activities are essentially the same as those specified in the GALL report. A matrix outlining sampled components and frequencies will be available for review during the on-site audit. Additionally, past oil analysis data sheets will also be available showing historic test results.<br><br>Enhancements will be implemented prior to the period of extended operation. |
| 69 | AMP B.1.26-4 (Oil Analysis)<br><br>In its description of the exception to NUREG 1801 Element 3, Parameters Monitored or Inspected, the LRA states that flash point has little significance with respect to the effects of aging. Because flash point identifies the presence of volatile and flammable materials, an abnormally low flash point can be indicative of fuel contamination. Provide a technical justification for this exception. | As stated in LRA Section B.1.26 exception note 1, fuel dilution testing is performed in lieu of flash point testing for lubricating oil systems potentially exposed to hydrocarbons. While it is important from an industrial safety perspective to monitor flash point, it is not related to managing the effects of aging. Analyses of filter residue or particle count, viscosity, total acid/base (neutralization number), water content, fuel dilution, and metals content provide sufficient information to verify the oil is suitable for continued use. IPEC performs a fuel dilution test in lieu of flash point testing on emergency diesel generators and IP3 Appendix R diesel generator lubricating oils. There could be two factors that affect the flash point of the oil; the addition of fuel that would lower the flash point or the addition of water that would raise the flash point. The fuel dilution test determines the percent by volume of fuel and the water content test determines the percent by volume of water. By determining the percent by volume of both fuel and water, the analysis can determine the expected change in flashpoint. For oil systems not associated with internal combustion engines, lubricating oil flash point change is unlikely. |
| 70 | AMP B.1.27-1 (One-Time Inspection)<br><br>GALL recommends that the applicant should schedule the inspection no earlier than ten years prior to the period of extended operation. The LRA states that the inspection will be performed prior to the period of extended operation. The statement should be revised to imply that the inspection will be performed with in the 10 years period prior to the period of extended operation. | For Indian Point Energy Center Unit 2 (IP2), the facility operating license (DPR-26) expires at midnight September 28, 2013. For Indian Point Energy Center Unit 3 (IP3), the facility operating license (DPR-64) expires at midnight December 12, 2015. Since the commitment is being made within the ten years prior to the period of extended operation, the statement that the inspection will be performed prior to the period of extended operation is appropriate and need not be changed. |

| Item | Request | Response |
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| 71 | AMP B.1.27-2 (One-Time Inspection)<br><br>The LRA states that the representative sample size will be based on Chapter 4 of EPRI document 107514, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation. Justify how this sampling technique with 90% confidence level provides an effective aging management program with adequate assurance that the applicable components will continue to perform their intended functions through the period of extended operation. | Consistent with NUREG-1801, XI.M32 each inspection activity includes a representative sample of the material and environment population, and, where practical, focuses on the components most susceptible to aging due to time in service and severity of operating conditions. Also, the program provides for increasing the inspection sample size and locations if aging effects are detected.<br><br>Since an initial random sample size provides 90% confidence that 90% of the population does not experience degradation, and the inspection focuses on the most susceptible locations whenever practical, a higher confidence level is achieved. Therefore, the One-Time Inspection Program provides adequate assurance that the applicable components will continue to perform their intended function through the period of extended operation. |
| 72 | AMP B.1.27-3 (One-Time Inspection)<br><br>What is the specific scope of AMP B.1.27 One Time Inspection that will be implemented to verify the effectiveness of each of the following AMPs: B.1.9, B.1.26, B.1.39, and B.1.40? | B.1.9 Diesel Fuel Monitoring - A representative sample of susceptible components of each material and environment crediting the diesel fuel monitoring program for aging management will be inspected using combinations of nondestructive examinations (including VT-1, ultrasonic, and surface techniques) performed by qualified personnel following procedures that are consistent with Section XI of ASME B&PV Code and 10CFR50, Appendix B to verify the absence of significant corrosion or fouling.<br><br>B.1.26 Oil Analysis - A representative sample of susceptible components of each material and environment crediting the oil analysis program for aging management will be inspected using combinations of nondestructive examinations (including VT-1, ultrasonic, and surface techniques) performed by qualified personnel following procedures that are consistent with Section XI of ASME B&PV Code and 10CFR50, Appendix B to verify the absence of significant corrosion or fouling.<br><br>B.1.39, B.1.40 and B.1.41 Water Chemistry Programs -<br>A representative sample of susceptible components of each material and environment crediting a water chemistry program for aging management will be inspected using combinations of nondestructive examinations (including VT-1, ultrasonic, and surface techniques) performed by qualified personnel following procedures that are consistent with Section XI of ASME B&PV Code and 10CFR50, Appendix B to verify the absence of significant cracking, corrosion or fouling. |
| 73 | AMP B.1.28-1 (One-Time Small Bore Piping)<br><br>According to GALL, AMP XI.M35, this program is applicable only to plants that have not experienced cracking of ASME Code Class 1 small-bore piping resulting from stress corrosion or thermal and mechanical loading. Justify that both IP2 and IP3 meet this criteria. | Inspections performed to date at IP2 and IP3 have not found cracking of ASME Code Class 1 small-bore piping. |
| 74 | AMP B.1.28-2 (One-Time Small Bore Piping)<br><br>In the Scope section of XI.M35, GALL states that the One-Time Inspection program for ASME Code Class 1 small-bore piping includes locations that are susceptible to cracking. The GALL also states that guidelines for identifying piping susceptible to potential effects of thermal stratification or turbulent penetration are provided in EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001.<br><br>(a) Will this new program to be implemented by Indian Point follow the guidelines of EPRI Report 1000701 for identifying the susceptible locations for inspection?<br><br>(b) If Indian Point One-Time Inspection Program will not utilize the guidelines of the above EPRI Report, what criteria will be used for identification of susceptible locations? Also justify that this criteria will be equivalent to the EPRI guidelines. | (a) As stated in LRA Section B.1.28, the One-Time Inspection – Small Bore Piping program will be consistent with NUREG-1801 XI.M35. The program will include a sample selected based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations. EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001, or subsequent revisions of this industry guidance, will be followed for identifying susceptible locations for inspection.<br>(b) See response to (a). |

| Item | Request | Response |
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| 75 | AMP B.1.29-1 (PSPM)<br><br>What codes and standards are used to implement the Periodic Surveillance and Preventive Maintenance Program? What acceptance criteria are used during the implementation of this program and where are the acceptance criteria defined? | As shown in LRA Section B.1.29, many of the Periodic Surveillance and Preventive Maintenance Program activities include visual or other non-destructive examinations of structures, systems, and components. These examinations are performed in accordance with approved procedures consistent with manufacturers' recommendations. The acceptance criteria, which are specified in the program document, will be included in plant procedures. |
| 76 | AMP B.1.29-2 (PSPM)<br><br>The program description for the Periodic Surveillance and preventive Maintenance program implies that this AMP will be used to manage loss of material for carbon steel components of the cranes, crane rails, and girders. GALL includes AMP XI.M23, Inspection of Heavy Load and Light Load Handling Systems, to manage these components. Describe if the activities of the Indian Point AMP B.1.29 are consistent with the recommendations of the GALL AMP XI.M23. Provide a justification for the activities that are not consistent. | Reactor building crane structural steel girders used in load handling are inspected under the Periodic Surveillance and Preventive Maintenance (PSPM) Program identified in Section B.1.29 of the application. This program will include visual inspections of the crane rails and girders consistent with XI.M23 to manage loss of material. The acceptance criteria in the PSPM Program are "No significant corrosion or wear." The XI.M23 acceptance criteria states, "Any significant visual indication of loss of material due to corrosion or wear is evaluated according to applicable industry standards and good industry practice." PSPM monitoring effectiveness and degrading trends are documented in accordance with 10CFR50 Appendix B. Therefore the aging management activities for crane rails and girders under the above two programs will be consistent with the attributes described for the program in NUREG-1801 XI.M23 during the period of extended operation. |
| 77 | AMP B.1.29-3 (PSPM)<br><br>The program description for the Periodic Surveillance and preventive Maintenance program implies that this AMP will be used to manage loss of material for internal surfaces of piping, valves, ducting and other piping components. GALL includes AMP XI.M38, Inspection of Internal surfaces in miscellaneous Piping and Ducting Components, to manage these components. Describe if the activities of the Indian Point AMP B.1.29 are consistent with the recommendations of the GALL AMP XI.M38. Provide a justification for the activities that are not consistent. | The XI.M38 program consists of visual inspections of the internal surfaces of steel piping, piping components, ducting, and other components exposed to environments such as condensation and indoor air that are not covered by other aging management programs.<br>The PSPM program performs internal visual inspections during maintenance activities. These inspections provide timely detection of degradation by confirming the integrity of the internal component surface. Visual inspections are performed by personnel qualified in accordance with site procedures. Inspection intervals are dependent on component material and environment. Acceptance criteria include no significant loss of material or fouling. Unacceptable conditions and degrading trends are documented in accordance with 10CFR50 Appendix B.<br>Aging management activities for internal steel piping, piping components, and ducting included in the Periodic Surveillance and Preventive Maintenance program as shown in Attachment 2 of IP-RPT-06-LRD-07 are consistent with the attributes described for the program in NUREG-1801 XI.M38. |
| 78 | AMP B.1.29-4 (PSPM)<br><br>In the "Evaluation" section of the AMP, the LRA states that the representative sample size will be based on Chapter 4 of EPRI document 107514, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation. Justify how this sampling technique with 90% confidence level provides an effective aging management program with adequate assurance that the applicable components will continue to perform their intended functions through the period of extended operation. | The representative sample size used for the Periodic Surveillance and Preventive Maintenance (PSPM) Program is consistent with the sample size discussion for the One-time Inspection Program per NUREG-1801, XI.M32. Periodic inspection activities include a representative sample of the material and environment population, and, where practical, focus on the components most susceptible to aging due to time in service and severity of operating conditions. To assure the representative sample size provides 90% confidence that 90% of the population does not experience degradation, the inspections focus on the most susceptible locations whenever practical, and the program provides for increasing the inspection sample size and locations if aging effects are detected.<br><br>With a combination of proven statistical sampling, focus on susceptible location, and a mechanism for increasing the sample size, the PSPM program provides more than adequate assurance that the applicable components will continue to perform their intended function through the period of extended operation. |
| 79 | AMP B.1.29-5 (PSPM)<br><br>The program description for the Periodic Surveillance and preventive Maintenance program implies that this AMP will be used to manage loss of material for external surfaces of steel components. GALL includes AMP XI.M36, External Surfaces Monitoring, to manage these components. Describe if the activities of the Indian Point AMP B.1.29 are consistent with the recommendations of the GALL AMP XI.M36. Provide a justification for the activities that are not consistent. | The Periodic Surveillance and Preventive Maintenance Program manages the aging effects of cracking, change in material properties, and fouling on external surfaces. Management of loss of material on external surfaces of some select carbon steel surfaces is also managed by the PSPM program.<br><br>Aging management activities for external surface monitoring of steel piping, piping components included in the Periodic Surveillance and Preventive Maintenance program as shown in Attachment 2 of IP-RPT-06-LRD-07 are consistent with the attributes described for the program in NUREG-1801 XI.M36. |

| Item | Request | Response |
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| 80 | AMP B.1.29-6 (PSPM)<br><br>Explain how is the "Monitoring and Trending" (element 5 of Evaluation Basis) accomplished in implementing Indian Point AMP B.1.29. | Systems within the scope of the PSPM program are monitored through system engineering activities per site procedures. Results from monitoring activities are evaluated against acceptance criteria and trends are developed by comparing current results to previous results to predict degradation rates. These predictions are used to confirm that loss of component intended function will not occur prior to the next scheduled inspection. Trend data from these activities is used to revise inspection frequencies per the site preventive maintenance processes.<br><br>All degrading trends will be documented per the IPEC Corrective Action Program in accordance with 10CFR50 Appendix B. |
| 81 | AMP B.1.30-1 (Reactor Head Closure Studs)<br><br>Discuss additional information (e.g., results of testing on the actual stud and nut material) to substantiate that the maximum tensile strength of the reactor closure studs and nuts is less than 170 ksi. | Results of testing shown on available test reports for the actual reactor head closure stud and nut material showed an average measured tensile strength value for each heat number < 170ksi.<br><br>Documentation of available test results were provided for on-site review. |
| 82 | AMP B.1.30-2 (Reactor Head Closure Studs)<br><br>LRA AMP B.1.30, "Program Description" states: " The NUREG 1801 program, Section XI.M3, Reactor Head Closure Studs is based on ASME Code Edition 2001 including the 2002 and 2003 Addenda. The IPEC ISI program is based on ASME Code Edition 1989, no Addenda with inspection of reactor head closure studs based on the 1998 Edition through the 2000 Addenda. The 1998 Edition through the 2000 Addenda allows surface or volumetric examination when closure studs are removed which is consistent with the requirements of NUREG 1801, Section XI.M3." The staff notes that the GALL AMP XI.M3 program element "Detection of Aging Effects" requires both surface and volumetric examination of studs when removed. Provide an explanation why this is not considered as an exception to the GALL program. | The following passage of NUREG-1801AMP XI.M3 program element "Detection of Aging Effects" appears to be incorrect because ASME Section XI, Code Edition 2001 including the 2002 and 2003 addenda allows surface or volumetric examination when closure studs are removed.<br><br>NUREG-1801, Section XI.M3 states, "Components are examined and tested as specified in Table IWB-2500-1. Examination category B-G-1, for pressure-retaining bolting greater than 2 in. diameter in reactor vessels specifies volumetric examination of studs in place, from the top of the nut to the bottom of the flange hole, and surface and volumetric examination of studs when removed."<br><br>It appears that the phrase "surface and volumetric examination of studs when removed" should have been changed to "surface or volumetric examination of studs when removed" when the ASME code version cited in NUREG-1801 was changed.<br><br>Since the IPEC program is consistent with Table IWB-2500-1 examination category B-G-1 in ASME Code Edition 2001 including the 2002 and 2003 Addenda it is consistent with NUREG-1801. |
| 83 | AMP B.1.31-1 (Reactor Vessel Head Penetration Inspection)<br><br>LRA AMP B.1.31, "Program Description" states: " This program was developed in response to NRC Order EA 03 009. The ASME Section XI, Subsection IWB Inservice Inspection and Water Chemistry Control Programs are used in conjunction with this program to manage cracking of the reactor vessel head penetrations. Detection of cracking is accomplished through implementation of a combination of bare metal visual examination (external surface of head) and non visual examination (underside of head) techniques. Procedures are developed to perform reactor vessel head bare metal inspections and calculations of the susceptibility ranking of the plant."<br><br>(a) What are the susceptibility ranks [or the effective degradation years (EDY)] for both IP2 and IP3?<br><br>(b) Has Entergy requested relaxation of the requirements in the revised Order EA 03 009 for either IP unit? If yes, discuss the technical bases for the relaxation requests.<br><br>(c) Discuss in detail the implementation of NRC Order EA 03 009 for both IP2 and IP3, with respect to detection of aging effects. | (a) At the last refueling outage (Spring, 06), IP2 calculated EDY corresponding to the moderate susceptibility category. At the last refueling outage (Spring, 07), IP3 calculated EDY corresponding to the high susceptibility category. IPEC will update the IP2 EDY calculations prior to the next refueling outages as required by the Order.<br><br>(b) A relaxation request was granted to perform a BMV examination of no less than 95 percent of the RPV head surface rather than 100 percent because a small area is partially obscured by a reflective metal insulation (RMI) support ring located downslope from the outermost RPV head penetrations. (Ref. COR-04-0244, COR-05-0530)<br><br>A relaxation request was granted wherein the inspection coverage NDE, using ultrasonic testing (UT) techniques, of head penetration nozzles is limited by a threaded section that is for some penetrations less than the 1 inch below the lower boundary limit. IPEC performs ultrasonic testing (UT) from the inside surface of each RPV head penetration nozzle from 2 inches above the J-groove weld and extending down the nozzle to at least the top of the threaded region or further down the threaded region to the extent allowed by technology and geometry. (Ref. COR-06-00111, COR-06-00373)<br><br>(c) IPEC has fully implemented the requirements of EA-03-009 with approved relaxation requests. The aging effect managed is PWSCC, which typically initiates in the penetration nozzle or in the nozzle J-groove attachment weld. Every two refueling outages for IP2 and every refueling outage for IP3, BMV examination of at least 95% of the reactor head surface including those areas upslope and downslope of the insulation and ventilation shroud support ring is performed to identify and document evidence of boric acid deposits and head surface degradation. A 360 degree visual inspection around each of the reactor head penetrations is performed to identify and document evidence of boric acid deposits at the annulus between the penetration and the vessel head . Visual inspections of |

| Item | Request | Response |
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| | (d) How is this AMP coordinated with the Boric Acid Corrosion Prevention Program (AMP B.1.5)? | pressure retaining components above the reactor vessel head are performed. Every two refueling outages for IP2 and every refueling outage for IP3, examinations consisting of eddy current testing and ultrasonic test are performed on the wetted surfaces on the ID side of penetration nozzles.<br><br>As described in outage inspection reports, no indications of reactor pressure vessel upper head degradation or primary reactor coolant boundary leakage at the reactor vessel head penetrations has been discovered.<br><br>(d) The Boric Acid Corrosion Control Program complements the Reactor Vessel Head Penetration Inspection Program by performing a visual inspection of the reactor vessel head at locations specified by procedures 2-PT-R156, "Boric Acid Leakage and Corrosion Inspection" and 3-PT-114A, "Reactor Vessel and Closure Head Boric Acid Leakage and Corrosion Inspection". Corporate procedure EN-DC-319, "Inspection and Evaluation of Boric Acid Leaks" provides general guidance for both head penetration inspections and other boric acid leak detection. Inspection for boric acid corrosion is coordinated with reactor vessel disassembly and other inspections required by EA-03-009 as directed by implementing procedures and outage scheduling.<br><br>COR-04-0244, COR-05-0530, COR-06-00111, COR-06-00373 were provided. |
| 84 | AMP B.1.34-1 (Service Water Integrity)<br><br>Since this aging management program (AMP) may include non safety related components, such as piping, it typically has a broader scope than the GL 89 13 program. Describe the difference in scope between the Indian Point site GL 89-13 program and this (AMP) and, if applicable, describe how the implementation of GL 89-13 recommendations was extended to bound systems and components within the scope of this AMP. | The GL 89-13 program includes safety-related components that are cooled by the service water systems (heat exchangers) as well as the safety-related components that supply the cooling water for heat removal (i.e., pumps, piping, valves, etc.). The Service Water Integrity Program scope includes all GL 89-13 program components, as well as, additional components in the scope of license renewal that contain service water regardless of their safety classification. The service water systems at IPEC supply both safety-related and nonsafety-related loads. The nonsafety-related components and loads included in the Service Water Integrity Program consist of main turbine auxiliary cooling loads such as turbine lube oil coolers, stator water coolers, seal oil coolers, and hydrogen coolers as well as other loads such as turbine hall closed cooling water heat exchangers In addition, the GL 89-13 and Service Water Integrity programs do not include components that contain raw water not supplied by the service water systems such as the circulating water and traveling screen wash water systems.<br><br>The types of components and their materials included in the GL 89-13 program and the Service Water Integrity Program are the same. As such, the methodology of periodic inspection and maintenance applies for both. GL 89-13 is not extended to nonsafety-related heat exchangers that are included in the Service Water Integrity Program. Periodic inspections are sufficient to manage aging effects of the nonsafety-related heat exchangers since they do not have a license renewal component intended function of heat transfer. The Service Water Integrity Program includes activities, such as chemical treatment using biocides and chlorine, which apply to the service water system as a whole. Periodic visual inspections and inspections using non-destructive examination (NDE) techniques are used to manage loss of material in SW components regardless of safety classification. The GL 89-13 program includes inspections of some nonsafety-related components in the service water system, such that the inclusion of these additional components in the Service Water Integrity program is reasonable. |
| 85 | AMP B.1.36-1 (Stuctures Monitoring)<br><br>From the applicant's description of the B.1.36 AMP "Structures Monitoring" in LRA Appendix B, the staff cannot identify the complete scope of the program. Very significant enhancements to the " Scope of Program" are identified. However, there is no description of the scope of the existing structures monitoring program, and there is no explanation why such major enhancements to the program scope are needed for license renewal. The staff reviewed Section 2.4 of the LRA, to better understand the intended functions of the structures that are being added to the scope. While almost all of the added structures serve a license renewal intended function for 10 CFR 54.4(a)(3), about half (11) of these structures also serve license renewal intended functions for 10 CFR 54.4(a)(1) and/or 10 CFR 54.4(a)(2). In | a) The following structures and their structural components are inspected as part of the existing structures monitoring program (Ref. Aging Management Program Evaluation Report IP-RPT-06-LRD08, section 3.3).<br><br>• auxiliary feedwater pump building (IP2/3)<br>• boric acid evaporator building (IP2)<br>• city water meter house<br>• condensate storage tanks foundation (IP2)<br>• containment building (also known as vapor containment (IP2/3)<br>• control building (IP2/3)<br>• electrical tunnel (IP2/3)<br>• emergency diesel generator building (IP2/3)<br>• fan house (IP2/3)<br>• fuel storage building (IP2/3)<br>• gas turbine generator No. 1, 2 and 3 enclosures<br>• gas turbine generator No. 2 and 3 fuel tank foundations<br>• intake structure (also known as screenwell structure) (IP1/2/3)<br>• power conversion equipment building (IP3)<br>• primary auxiliary building (IP2/3) |

| Item | Request | Response |
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| | accordance with NRC guidance (RG 1.160) and industry guidance (NEI 93-01) these structures would be expected to be included in the current existing program.<br><br>(a) Describe the structures and structural components inspected as part of the existing structures monitoring program.<br><br>(b) Explain why eleven (11) structures listed in the "Scope of Program" enhancement have intended functions for 10 CFR 54.4(a)(1) and/or 10 CFR 54.4(a)(2). | • primary water storage tank foundation (IP2)<br>• radiation monitoring enclosure (IP2)<br>• refueling water storage tank foundation (IP2)<br>• superheater building (IP1)<br>• transformer switchyard support structures (IP3)<br>• transmission towers (SBO recovery path) and foundations (IP2/3)<br>• turbine building (IP1/2/3) and heater bays (IP2/3)<br>• utility tunnel (IP1)<br><br>b)<br>City Water Storage Tank Foundation<br>The foundation supports the in-scope city water storage tank and meter house. The tank is in-scope because it provides a source of water for the auxiliary feedwater system for both IP2 and IP3 and supplies emergency water for safety injection, residual heat removal, and charging pumps.<br>The city water storage tank foundation has intended function for 10 CFR 54.4(a)(2).<br>Condensate Storage Tank Foundation (IP3)<br>The condensate storage tank foundation supports the condensate storage tank. The foundation has intended functions for 10 CFR 54.4(a)(1) and (a)(2).<br>Containment Access Facility and Annex (IP3)<br>The containment access facility and annex is located adjacent to the primary auxiliary building (PAB). The containment access facility and annex is Class III except for the structural steel portion interfacing with the primary auxiliary building (PAB), which is seismic Class I. The structure has intended function for 10 CFR 54.4(a)(2).<br>Discharge Canal<br>The discharge canal carries the safety-related service water system discharge to the river. Three backup service water pumps, which provide cooling water from the discharge canal in the unlikely event that the service water intake structure is damaged, are supported on a slab spanning the walls of the canal. The portion of the discharge canal wall that is adjacent to the service water pipe chase is seismic Class I and is part of the ultimate heat sink. The structure has intended functions for 10 CFR 54.4(a)(1) and (a)(2).<br>Primary Water Storage Tank Foundation (IP3)<br>The primary water storage tank foundation provides the main support for the 165,000 gallon primary water storage tank. The tank supplies demineralized water for the primary water makeup system. The primary water storage tank foundation is a Seismic Class I reinforced concrete spread footing supporting the primary water storage tank. The structure has intended functions for 10 CFR 54.4(a)(2).<br>Refueling Water Storage Tank Foundation (IP3)<br>The refueling water storage tank foundation provides the main support for the 350,000 gallon refueling water storage tank. The tank supplies borated water to the refueling canal, safety injection pumps, the residual heat removal pumps, and the containment spray pumps for the loss-of-coolant accident. The structure has intended functions for 10 CFR 54.4(a)(1).<br>Service Water Pipe Chase (IP3)<br>The service water pipe chase provides protection of service water lines that span across the discharge canal. The structure provides protection of the service water valves and associated piping. This structure has intended functions for 10 CFR 54.4 (a)(1) and (a)(2).<br>Service Water Valve Pit (IP3)<br>Service water valve pit for each intake structure is provided for protection of service water components. This structure has intended functions for 10 CFR 54.4 (a)(1) and (a)(2).<br><br>Superheater Stack (IP1)<br>The superheater building is adjacent to but physically separated from the control building. The superheater stack is located on top of the Unit 1 superheater building. The exterior walls are masonry or metal siding. The superheater building was originally classified as seismic Class III, but it is utilized by Unit 2 in a safety function and is now classified as seismic Class I. This structure has intended functions for 10 CFR 54.4(a)(1) and (a)(2).<br>Waste Holdup Tank Pit (IP2)<br>The waste holdup tank pit houses the waste holdup tank, which serves as the collection point for all liquid radwaste. This structure is conservatively credited for performing the following intended functions for 10 CFR 54.4(a)(2).<br>Provide functional support to nonsafety-related components whose failure could result in potential offsite releases.<br>Waste Holdup Tank Pit (IP3)<br>The waste holdup tank pit (WHTP) is two adjacent underground structures joined together to form a single structure. It is adjacent to the primary water storage tank and the radioactive machine shop. The structure houses waste holdup tanks No. |

| Item | Request | Response |
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| | | 31, 32 and 33 each in their own separate. The structure has the following intended functions for 10 CFR 54.4(a)(2).<br><br>Provide functional support to nonsafety-related components whose failure could result in potential offsite releases |
| 86 | AMP B.1.36-2 (Structures Monitoring)<br><br>The second enhancement to AMP B.1.36 under " Scope of Program" indicates that "procedures will be revised to clarify that in addition to structural steel and concrete", 13 commodities "are inspected for each structure, as applicable." The staff notes that the specific commodities listed would be expected to be included in the current existing program if they are safety-related or important to safety. The staff is unclear what commodities are currently being inspected in the existing program.<br><br>(a) Describe the structural commodities inspected as part of the existing structures monitoring program.<br><br>(b) Explain why the 13 commodities are identified as an enhancement to the "Scope of Program." | (a) The structural commodities inspected as part of the existing structures monitoring program include structural steel (beam, columns, end connections), support steel (instruments racks, base plates, etc.), concrete surfaces, instrument racks . Individual inspection checklists are provided in the program procedures for each commodity.<br>(Ref. ENN-DC-150, Section 5.5 and Attachments 9.2 and 9.4)<br><br>(b) While many of the listed commodities are routinely inspected as part of the current structures monitoring program (AMP B.1.36), they are not explicitly identified in the program procedures. Thus, the purpose of the enhancements is to ensure these items (including their anchorages) are identified explicitly in the program. For example, the existing SMP includes inspection of concrete damage due to vibrating equipment, which addresses equipment pads and foundation identified in the enhancement (Ref. ENN-DC-150, Section 5.7 [2] and Attachment 9.4).<br><br>In LRA Section B.1.36.2 and in Commitemnt 25, add "(include their anchorages)" in paragrapgh discussing the enhancemnts to SMP for IP2 and IP3.<br><br>Clarification to be incorporated into the LRA. |
| 87 | AMP B.1.36-3 (Structures Monitoring)<br><br>An enhancement to AMP B.1.36 under " Detection of Aging Effects" is to monitor groundwater for aggressiveness to concrete. Sulfates, pH and chlorides will be monitored. Ground water testing is to be conducted at least every five (5) years, by taking samples from a well that is representative of groundwater surrounding below-grade site structures<br><br>(a) Describe past and present groundwater monitoring activities at the Indian Point site, including the sulfates, pH and chlorides readings obtained; and the location(s) where test samples were/are taken relative to the safety-related and important-to-safety embedded concrete foundations.<br><br>(b) Explain the technical basis for concluding that testing a single well every five (5) years is sufficient to ensure that safety-related and important-to-safety embedded concrete foundations are not exposed to aggressive groundwater. | a) There is sufficient number of analytical results to ensure that the ground water is being properly monitored. Large numbers of groundwater wells located adjacent to the structures have been sampled and were analyzed for sulfate and chloride at a contract laboratory, with pH having been determined at the time of sample collection. The data indicates that the ground water is non-aggressive (pH>5.5, Chloride <500 ppm and Sulfate <1500 ppm). Several samples taken along the facility waterfront and adjacent to the discharge canal were noted to have higher than normal levels of chloride. Given the location of samples, these higher than normal levels are believed to be due to the salinity of the brackish Hudson River water at the Indian Point location of the river. In all cases pH results are >5.5 and sulfate concentration < 1500 mg/L. Ground water samples will continue to be obtained on a quarterly basis for one calendar year in order to fully characterize these parameters (Chloride, Sulfate, and pH) for the groundwater at IPEC to account for any seasonal variation. The selected sample locations will provide representative sample of the ground water in the vicinity of the structures. A review of the several hundred ground water pH values collected in late 2005 to present reveal that the ground water had a pH of >5.5 in all cases except four. In those four cases pH was found to be <5.5 SU. All four of these low pH samples were obtained from the same sample point on the same day. To date all subsequent samples taken from this sample point were found to have a pH >5.5 SU.<br><br>There is sufficient number of monitoring wells being sampled at various locations to ensure monitoring the ground water. And, the results are being properly evaluated in order to characterize the ground water across the site (in vicinity of the safety-related structures). The sample data and well map are available on site for review.<br><br>b) A sample frequency of 5 years in a limited number of wells adjacent to safety structures and those falling under 10 CFR 54.4 (a)(1) and 10 CFR 54.4 (a)(2) would be sufficient to confirm non-aggressive nature of the ground water. The large sample population for the initial characterization, the diverse locations from which the samples were obtained and the seasonality of sample collections contribute to our confidence in the understanding of the nature of the ground water. Additionally, we would not normally expect to see the ground water conditions change unless an extraordinary event occurred such as a major withdrawals (such as significant pumping out the ground water) or injections of water on the Site or in the vicinity of the Site. Finally, the three structural inspections performed in five year intervals showed no major change in structural integrity from inspection to inspection. |
| 88 | AMP B.1.36-4 (Structures Monitoring)<br><br>In LRA Appendix B, Table B-2, the applicant indicates that "This program [GALL AMP XI.S7] is not credited for aging management. The Structures Monitoring Program manages the | (a) The water control structures at Indian Point Energy Center (IPEC) which have an intended function for license renewal and are included (or will be included) in the scope of AMP B.1.36 (Structures Monitoring) are intake structure (including intake structure enclosure) and discharge canal. The discharge canal is not explicitly specified in the structures monitoring procedures. An enhancement identified for AMP B.1.36 will explicitly specify the discharge canal. (Ref. LRA section 2.4.2 and |

| Item | Request | Response |
|---|---|---|
| | effects of aging on the water control structures at IPEC." GALL AMP XI.S7 offers this option, provided all the attributes of GALL AMP XI.S7 are incorporated in the applicant's Structures Monitoring Program.<br><br>(a) Identify the specific water control structures that have an intended function for license renewal, and are included in the scope of AMP B.1.36.<br><br>(b) Describe the attributes of AMP B.1.36 that pertain to aging management of water control structures.<br><br>(c) Explain how these attributes of AMP B.1.36 encompass the attributes of GALL AMP XI.S7, without exception. | B.1.36)<br><br>(b) AMP B.1.36 (Structures Monitoring Program) is an existing program that performs inspections in accordance with 10 CFR 50.65 (Maintenance Rule) as addressed in Regulatory Guide 1.160 and NUMARC 93-01. Periodic inspections are used to monitor the condition of water control structures and structural components to ensure there is no loss of intended function. If established criteria as specified in maintenance rule scoping documents are exceeded the affected system is monitored in accordance with a 10 CFR 50.65 (a)(I) action plan.<br><br>The parameters monitored or inspected were selected based on information included in industry codes, standards and guidelines, and also consider industry and plant-specific operating experience.<br><br>Inspections of steel and concrete portion of accessible water control structures are performed at five-year intervals and inspections of normally inaccessible areas are performed using special tools or inspection of adjacent areas when possible. More frequent inspections may be performed based on past inspection results, industry experience, or exposure to a significant event.<br><br>Inspection methods, inspection schedule, and inspector qualifications ensure that aging degradation will be detected and quantified before loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are based on information provided in industry codes, standards and guidelines, and also consider industry and plant-specific operating experience.<br><br>The acceptance criteria were selected to ensure that the need for corrective actions is identified before loss of intended functions. Acceptance criteria were established considering information provided in industry codes, standards, and guidelines including<br>NE1 96-03, ACI 201.1 R-92, and ACI 349R-85. Industry and plant-specific operating experience was also considered. IPEC applies requirements of 10 CFR Part 50 Appendix B to the Structures Monitoring Program through use of the IPEC corrective action program.<br><br>( c) The Structures Monitoring Program (AMP B 1.36) is consistent with the program described in NUREG-1801, Section XI.S6, Structures Monitoring Program with enhancements listed in LRA section B.1.36. The SMP attributes are consistent with the XI.S7 program attributes that are applicable to the in-scope IPEC water control structures.<br><br>1) Scope – The scope of the GALL XI.S7 program applicable to IPEC is the intake structure and discharge canal. There are no earthen structures at IPEC in the scope of license renewal. The intake structure is included in the scope of the Structures Monitoring Program. The discharge canal will be explicitly added to the program as an enhancement to AMP B.1.36. (Ref. LRA section 2.4.2 and B.1.36)<br><br>2) Preventive actions – The GALL XI.S7 program includes no preventive actions. AMP B.1.36 is consistent with preventive actions.<br><br>3) Parameters Monitored – The aging effect requiring management for concrete structural components of the intake structure is loss of material which is consistent with GALL Volume 2 item III.A6-7. The parameters monitored from the GALL XI.S7 program applicable to loss of material are consistent with those monitored by the Structures Monitoring Program. The guidance for inspections of concrete in Section C.2 of RG 1.127 is consistent with the guidance in ACI 349.3 used in the Structures Monitoring Program. Based on the above discussion, the parameters monitored include loss of material, cracking, movement (settlements and deflections).<br>Since there are no earthen structures at IPEC in scope of the license renewal, GALL XI.S7 attributes applicable to earthen structures are not applicable for IPEC water control structures.<br>4) Detection of Aging – GALL XI.S7 identifies visual inspection methods as the primary method used to detect aging. The Structures Monitoring similarly uses visual inspection methods as the primary method used to detect aging in concrete structural components. GALL XI.S7 identifies inspection intervals of five years. The Structures Monitoring Program identifies similar inspection intervals of five years for accessible areas and opportunistic inspections for buried components. Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason.<br><br>5) Monitoring and Trending – Monitoring is by periodic inspection for both the GALL |

| Item | Request | Response |
|---|---|---|
| | | XI.S7 and Structures Monitoring Programs.<br><br>6) Acceptance Criteria – Acceptance criteria in NUREG-1801, XI.S7 says plant-specific acceptance criteria based on Chapter 5 of ACI 349.3R-96 are acceptable. Appropriate guidance is provided in the Structures Monitoring Program to ensure corrective measures are identified prior to loss of intended function. The guidance in the Structures Monitoring Program includes reference to ACI 349.3R-96. XI.S7 acceptance criteria related to earthen structures are not applicable.<br><br>7-9) The corrective actions, confirmation process and administrative control attributes of the Structures Monitoring Program and the GALL XI.S7 program are consistent.<br><br>10) Operating Experience – The operating experience relevant to the effectiveness of the Structures Monitoring Program is presented in Appendix B of the application and is consistent with the operating experience described in GALL XI.S7.<br><br>Therefore, the attributes of the NUREG-1801 XI.S7, Water Control Structures, aging management program pertaining to the intake structure are incorporated within the AMP B.1.36 (Structures Monitoring Program).<br><br>The following is added to commitemnt 25: "Enhance the Structures Monitoring Progrm for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years, or earlier if determined to be necessary.<br><br>Information to be incorporated into the LRA. |
| 89 | AMP B.1.36-5 (Structures Monitoring)<br><br>What is Entergy's schedule for implementing the enhancements to AMP B.1.36? | Enhancements to the Structures Monitoring Program (AMP B.1.36) will be implemented prior to the period of extended operation.<br>See Commitment #25 |
| 90 | AMP B.1.39-1 (Water Chemistry-Auxiliary System)<br><br>Describe past and present surveillance tests, sampling, and analysis activities for managing the effects of aging on components within the scope of this AMP. | Recent monthly tests of stator cooling water samples have been within specification. Monthly stator cooling water analysis will continue per the requirements of procedure 0-CY-2510, "Closed Cooling Water Chemistry Specifications and Frequencies"<br><br>The LRA credits both the Water Chemistry Control – Auxiliary Systems and Periodic Surveillance and Preventative Maintenance (PSPM) programs to manage loss of material for the NaOH tank. Since thickness measurements are performed every five years under the PSPM Program, use of the water chemistry control – auxiliary systems is not required. Therefore, IP-RPT-06-LRD07 and the LRA will be revised to remove the Water Chemistry Control – Auxiliary Systems Program as an aging management program for the NaOH tank.<br><br>Auxiliary steam supply is cross-connected so that IP2 or IP3 can support the steam requirements of either unit from the main steam systems. Components in the house service boiler systems subject to aging management review are exposed to main steam during normal operation and are managed by the Water Chemistry Control – Primary and Secondary Program and not the Water Chemistry Control – Auxiliary Systems Program as stated in the LRA. Therefore, IP-RPT-06-LRD07 and the LRA will be revised to remove the Water Chemistry Control – Auxiliary Systems Program as an aging management program for the house service boiler systems. Water chemistry parameters for house service boiler components are maintained per EPRI guideline TR-102134, "Pressurized Water Reactor Secondary Chemistry Guidelines". Recent test of secondary water chemistry parameters have been within specification or corrective actions have been performed to return parameters to acceptable levels per prescribed action levels. Parameters are maintained per the requirements of Procedure 0-CY-2410, "Secondary Chemistry Specifications". Recent chemistry data was available for review.<br><br>Information to be incorporated into the LRA. |
| 91 | AMP B.1.39-2 (Water Chemistry-Auxiliary Systems)<br><br>Describe the procedures used to perform surveillance activities and the basis for acceptance criteria and sample / test frequencies. | Stator cooling water systems are high purity systems in which poor oxygen control can cause an increase in copper corrosion products. Based on this experience, stator cooling water is monitored monthly for conductivity and copper. Refer to Procedure 0-CY-2510, Closed Cooling Water Chemistry Specifications and Frequencies and 2-SOP-26.7, Generator Stator Cooling Water System for more information. |

| Item | Request | Response |
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| | | The LRA credits both the Water Chemistry Control – Auxiliary Systems and Periodic Surveillance and Preventative Maintenance (PSPM) programs to manage loss of material for the NaOH tank. Since thickness measurements are performed every five years under the PSPM program, use of the Water Chemistry Control – Auxiliary Systems Program is not required. Therefore, IP-RPT-06-LRD07 and the LRA will be revised to remove the Water Chemistry Control – Auxiliary Systems Program as an aging management program for the NaOH tank.<br><br>Auxiliary steam supply is cross-connected so that IP2 or IP3 can support the steam requirements of either unit from the main steam systems. Components in the house service boiler systems subject to aging management review are exposed to main steam during normal operation and are more appropriately managed by the Water Chemistry Control – Primary and Secondary Program and not the Water Chemistry Control – Auxiliary Systems Program as stated in the LRA. Therefore, IP-RPT-06-LRD07 and the LRA will be revised to remove the Water Chemistry Control – Auxiliary Systems Program as an aging management program for the house service boiler systems. Water chemistry parameters for house service boiler components are maintained per EPRI guideline TR-102134, "Pressurized Water Reactor Secondary Chemistry Guidelines". Parameters are maintained per the requirements of Procedure 0-CY-2410, "Secondary Chemistry Specifications" available for review during the audit.<br><br>Information to be incorporated into the LRA. |
| 92 | AMP B.1.40-1 (Water Chemistry-Closed Cooling)<br><br>The LRA takes an exception to the GALL recommendation for detection of aging effects through performance and functional testing. As a result, this program credits preventive measures to manage the effects of aging. Provide objective evidence (e.g., plant specific operating experience) which demonstrates that the existing preventive measures will adequately manage the effects of aging in the closed cooling water system components that are within the scope of license renewal. | A recent QA audit found that closed cooling water chemistry parameters are maintained within industry guidelines and a recent routine inspection of components in a closed cooling water system found no evidence of active corrosion.<br><br>LRA section B.1.27, One-Time Inspection, describes inspections planned to verify effectiveness of the water chemistry control programs to ensure that significant degradation is not occurring and component intended function is maintained during the period of extended operation. The results of these inspections will provide objective evidence to demonstrate that the existing preventive measures will adequately manage the effects of aging in the closed cooling water system components that are within the scope of license renewal. |
| 93 | AMP B.1.40-2 (Water Chemistry-Closed Cooling)<br><br>The LRA states that in June 2003, CCW corrosion inhibitor (molybdate concentration) was found to be out of specification and that corrective actions were taken to restore the molybdate concentration to specification. However, the LRA does not indicate if surveillance practices (e.g., sampling) were also modified as a result of this occurrence. Provide a description of past and present surveillance activities and, if applicable, provide a justification if the surveillance practices or frequencies were not revised as a result of this event. | The IP2 CCW system Molybdate is administratively controlled within the 400-800 ppm range to ensure it remains within the 200-1000 ppm range recommended in the EPRI Closed Cooling Water Guidelines (EPRI TR 1007820). In accordance with EPRI TR-1007820, site procedures contain two action levels. 1) If the Molybdate level falls below 200 ppm the system should be restored to above 200 ppm within 90 days. 2) If the Molybdate level falls below 160 ppm the system should be restored to above 200 ppm within 30 days. If these actions are not accomplished, an engineering evaluation must be performed to determine the impact of the condition on the long-term reliability of the system.<br><br>On 3/21/03, a 113 ppm Molybdenum concentration (which correlates to an ~188 ppm Molybdate concentration) was observed. Subsequently, on 4/15/2003, a 131 ppm concentration was observed. The low concentration occurred due to dilution when water was added to the system to compensate for leaks and work activities. Leaks were repaired, Molybdate was added to the system to restore the concentration to the normal range, and the normal monthly sample frequency was temporarily increased (two samples were taken the next week) to verify that the concentration remained within the normal range. The concentration on 4/22/03 was 418 ppm and the concentration on 4/23/03 was 425 ppm, indicating that proper control had been restored.<br><br>A few weeks later (5/14/2002), a 395 ppm concentration was observed. While this value does not require action per the EPRI guidelines, it is outside the administrative control range, so Molybdate was again added. Since that time, monthly samples (June 2003 to August 2007) have shown that the IP2 CCW Molybdate concentration has remained above the action level threshold and, except for one reading of 377 ppm in May 2006, has remained within the 400-800 ppm administrative control range.<br><br>As sustained Molybdate concentrations below 160 ppm could initiate system material degradation, EPRI TR 1007820 and site procedures direct that an engineering evaluation be performed to determine the impact of the condition on the long-term reliability of the system if the condition persists for more than 30 days |

| Item | Request | Response |
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| | | after the first sample below 160 ppm. Since the Molybdate concentration in the IP2 CCW system was returned to 418 ppm seven days after the sample below 160 ppm and has remained above the threshold since that time, evaluation of the impact of the condition on long-term reliability is not necessary and increased sampling is not warranted. Sample results since June 2003 have confirmed the adequacy of the established sampling frequency. |
| 94 | AMP B.1.40-3 (Water Chemistry-Closed Cooling)<br><br>The LRA states: "Continuous program improvement provides assurance that the program will remain effective for managing loss of material of components." However, the LRA only cites one QA audit observation to support this conclusion. Provide additional information to support this conclusion. | In addition to the QA audit of the plant chemistry program in August 2003 that was mentioned in the LRA, similar audits in June 2005 and September 2006 support the conclusion that continuous program improvement provides assurance that the Water Chemistry Control - Closed Cooling Water Program will remain effective for managing loss of material of components.<br><br>The June 2005 audit concluded that the program is effective in implementing applicable regulations, industry standards and the quality assurance program manual. Strengths were noted in the areas of leadership, accountability, training, and review of industry operating experience.<br><br>The September 2006 audit concluded that closed cooling water systems are treated and controlled to industry guidelines. Improvements were noted in the use of the condition reporting process and strengths were noted in the area of chemistry data trending. |
| 95 | AMP B.1.40-4 (Water Chemistry-Closed Cooling)<br><br>The exception to GALL, Element 5, Monitoring and Trending, states that visual inspections are not performed. Provide a technical justification for not performing visual inspections recommended in GALL. | The Water Chemistry Control – Closed Cooling Water Program is a preventive program which does not include inspections. EPRI report TR-1007820 refers to inspections performed in conjunction with maintenance activities, which are not treated as part of this program. In addition, LRA Section B.1.27, One-Time Inspection, describes inspections planned to verify effectiveness of the water chemistry control programs to ensure that significant degradation is not occurring and component intended function is maintained during the period of extended operation. |
| 96 | AMP B.1.40-5 (Water Chemistry-Closed Cooling)<br><br>GALL, Element 2, preventive actions, states that system corrosion inhibitor concentrations should be maintained within limits specified in EPRI TR 107396. Since this element is not identified in the exception, it is assumed that the IP program is consistent with NUREG 1801. Describe the basis for specified corrosion inhibitor concentration limits. | The IP Water Chemistry Control – Closed Cooling Water Program will be consistent with NUREG-1801. The program maintains system corrosion inhibitor concentrations within specified guidelines of EPRI Report TR-1007820, Rev. 1 to minimize corrosion and SCC. EPRI TR-1007820 supersedes TR-107396 referenced in NUREG-1801. |
| 97 | AMP B.1.40-6 (Water Chemistry-Closed Cooling)<br><br>For each program attribute having an exception to GALL, provide a detailed, line by line, comparison of the criteria recommended in GALL (e.g., EPRI TR 107396) against the criteria / industry standard (e.g., EPRI TR 1007820) that have been implemented. | The Water Chemistry Control – Closed Cooling Water Program is based on EPRI guidelines for closed cooling water issued as EPRI TR-1007820, 'Closed Cycle Cooling Water Chemistry,' Rev. 1, dated April 2004. This guideline supersedes EPRI TR-107396, 'Closed Cycle Cooling Water Chemistry Guideline,' Revision 0, issued November 1997, referenced in NUREG-1801. Revision 1 of the EPRI guideline is significantly more directive than Revision 0 and incorporates action levels with established thresholds for specific actions required. Revision 1 specifically establishes recommended monitoring frequencies and clearly identifies expected control parameter values.<br>The LRA indicates that Water Chemistry Control – Closed Cooling Water Program attributes 3, 4, 5, and 6 have an exception to GALL. In all four cases, the exception is due to the fact that NUREG-1801 recommends the use of performance and functional testing to ensure acceptable function of the CCCW systems, while the IPEC Water Chemistry Control – Closed Cooling Water Program does not include performance and functional testing. The exception is the same regardless which revision of the EPRI guideline is used because neither revision of the EPRI guideline recommends that equipment performance and functional testing should be part of a water chemistry program. Rather, the EPRI reports state (Section 5.7 in EPRI report TR-107396 and Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. |
| 98 | AMP B.1.41-1 (Water Chemistry-Primary & Secondary)<br><br>It is noted that Indian Point AMP B.1.41, Water Chemistry Control - Primary and Secondary, is | The Revision 4 changes to TR-105714 consider the most recent operating experience and laboratory data. It reflects increased emphasis on plant-specific optimization of primary water chemistry to address individual plant circumstances and the impact of the Nuclear Energy Institute (NEI) steam generator initiative, NEI |

| Item | Request | Response |
|---|---|---|
| | based on the guidelines provided in EPRI TR-105714, Revision 5 and EPRI TR-102134, Revision 6. The corresponding GALL AMP XI.M2, Water Chemistry, is based on the guidelines provided in Revision 3 of EPRI TR-105714 and TR-102134. Provide details of the specific changes to these documents after Revision 3. Include a justification as to how the adoption of the later revisions impact the effectiveness of the AMP to manage aging effects. | 97-06, which requires utilities to meet the intent of the EPRI guidelines. TR-105714, Rev. 5 clearly distinguishes between prescriptive requirements and non-prescriptive guidance.<br><br>Revision 4 of TR-102134 was issued in November 1996 and provided an increased depth of detail regarding the corrosion mechanisms affecting steam generators and the balance of plant, and also provided additional guidance on how to integrate these and other concerns into the plant-specific optimization process. Revision 5 provides additional details regarding plant-specific optimization and clarifies which portions of the EPRI guidelines are mandatory under NEI 97-06. Revision 6 provided further details regarding how to best integrate these guidelines into a plant-specific chemistry program while still ensuring compliance with NEI 97-06 and NEI 03-08.<br><br>IPEC and other utilities provide input as well as review the recommendations and changes made to EPRI guidelines. Based on guideline review against the current chemistry program, manufacturer recommendations, and associated station documents, changes are made to chemistry controlling procedures which are subject to the safety review process (10 CFR 50.59 process).<br>Consequently, the Water Chemistry Control – Primary and Secondary Program based on current EPRI guidelines is made more effective at managing aging effects through proactive implementation of later revisions of the EPRI guidelines. |
| 99 | AMP B.1.41-2 (Water Chemistry-Primary & Secondary)<br><br>The LRA Section B.1.41 lists an enhancement to Attribute 3, Parameters Monitored or Inspected and Attribute 6, Acceptance Criteria, which requires revision of appropriate IP2 procedures to test sulfates monthly in the RWST with a limit of < 150 ppb. Why is this enhancement only applicable to IP2 and does not apply to IP3? | Consistent with EPRI TR-105714, Rev. 5 recommendations, IP3 currently monitors RWST sulfates monthly with a limit of < 150 ppb. IP2 has not incorporated this recommendation and an enhancement is required. Thus, the enhancement does not apply to IP3. |
| 100 | AMP B.1.41-3 (Water Chemistry-Primary & Secondary)<br><br>The LRA Section B.1.41, under Operating Experience, states that a QA audit of the primary and secondary plant chemistry program was conducted in August 2003 and this audit noted that monitoring and processing requirements for primary and secondary water chemistry complied with both IP2 and IP3 technical specifications, implementing procedures, and the IP3 Technical Requirements Manual (TRM).<br><br>(a) Why is there no statement about compliance with IP2 Technical Requirements Manual?<br><br>(b) The specific QA audit described above was in August 2003. How frequently are these QA audits performed? | a) While chemistry requirements are currently included in the IP2 Technical Requirements Manual, the QA audit in August 2003 was performed during the improved technical specification project and updating the TRM for both units. At the time of the audit, the IP2 TRM was not updated with chemistry requirements.<br><br>b) QA audits of the chemistry department are performed every 2 years. An additional audit was performed in 2006 to adjust the two year cycle to even number years for scheduling purposes. Both 2005 and 2006 audit reports were provided during the audit. |
| 103 | Please provide 2006 Fire Water System Flow Test. | 2006 Fire Water System Flow Test provided. |
| 104 | Provide Approval Package for SA0-703 rev 25. | Approval package per EN-DC-128 provided for SAO-703, rev 25. |
| 105 | Are the IP3 foam tanks required for compliance with 10 CFR 50.48. Why is the enhancement for foam tank inspection only applicable to IP3? | The foam tanks for IP2 and IP3 are not required to comply with the requirements of 10 CFR 50.48. The IP3 foam tanks (FOAM TANK 1/2/3/4) were conservatively included as components subject to aging management review during consideration of non-safety related components that may affect safety related components. Further review revealed that since the tanks are located on concrete slabs on lower elevations of the turbine buildings and are not pressurized, failure of the foam tanks would not affect safety related equipment. Therefore, neither the IP2 nor the IP3 foam tanks (or their drain line components) are subject to aging management review. Consequently, the enhancement requiring internal inspection of the IP3 foam tanks is not required. |

| Item | Request | Response |
|---|---|---|
| | | The LRA will be revised to delete the enhancement specifying internal inspection of the IP3 foam tanks in Sections A.3.1.13 and B.1.14. LRA table 3.3.2-19-11-IP2 and 3.3.2-19-20-IP3 will be revised to remove line items for components with the environment of fire protection foam.<br><br>Clarification to be incorporated into the LRA. |
| 106 | The enhancement for element 4 of the Fire Protection Program that applies to sprinkler head requirements per NFPA 25 states the nozzles are inspected. NFPA requires the nozzle to be tested or replaced. Inspections do not meet the Code requirements. | The term "inspection per NFPA standards" as listed in the Fire Protection Program enhancement to Element 4 will be replaced by "tested or replaced per NFPA standards" to more clearly reflect the requirements of NFPA.<br><br>Clarification to be incorporated into the LRA. |
| 107 | B.1.1: The gas turbine fuel storage tanks were repaired following the discovery of pitting in April 2002 using a weld overlay. What was the regulatory basis for this repair (e.g., Code repair, approved code case, relief request) and how will it be handled for the period of extended operation? | This repair of pitting in the tank bottom was made in accordance with API Standard 653 second edition, December 1999 "Tank Inspection, Repair, Alteration, and Reconstruction". This is a nonsafety-related tank. The GT 2/3 fuel oil storage tank has a repetitive task for an internal inspection, and UT cleaning that is scheduled on a 10 year frequency as described in the Above Ground Steel Tanks Program. |
| 108 | B.1.2: Does IP2 and IP3 have a bolting expert as recommended in the EPRI documents? | EPRI TR-104213, Bolted Joint Maintenance & Applications Guide, recommends providing an on-site bolting coordinator who has the technical ability and authority to focus on both programmatic issues and day-to-day resolution of problems. IPEC Maintenance provides the functions of the bolting coordinator consistent with the guidance of EPRI TR-104213. |
| 109 | B.1.5: Have you observed boric acid leakage from Conoseal flanges? | Both IP2 and IP3 have experienced periodic Conoseal leakage during the past few cycles of operation. The most recent leaks occurred at penetration #95 during the current IP2 fuel cycle while the most recent leak at IP3 was detected during the Spring 07 refueling outage. As a result of these leaks, both IP2 and IP3 have implemented a modification to the Conoseal flanges to minimize the probability of future leakage. All of the recent leaks (with the exception of the current leak at penetration #95) have been eliminated and the affected areas of the reactor vessel head have been cleaned and examined for signs of material degradation. None of these leaks have resulted in any detectable degradation of either (IP2 and IP3) reactor vessel head. |
| 110 | B.1.6: Do you have any buried tanks in scope for license renewal? If so, please identify them.<br><br>Has IP2 or IP3 had to replace any buried piping or had to replace or repair any sections of buried pipe? | The following tanks are buried and in scope for license renewal and included in the Buried Piping and Tanks Inspection Program.<br><br>IP2 Fuel Oil Storage Tanks (21/22/23 FOST)<br>GT1 Fuel Oil Storage North and South Storage Tanks<br>IP2 Security Diesel Fuel Tank<br>IP3 Appendix R Fuel Oil Storage Tank (EDG-33-FO-STNK)<br>IP3 Security Propane Fuel Tanks (2 of them)<br>IP3 Fuel Oil Storage tanks (EDG-31/32/33-FO-STNK)<br><br>A review of site condition reports back to 2000 revealed that there have been two underground piping leaks that occurred on the auxiliary steam supply cross connect line between Unit 2 and Unit 3. The first leak occurred in 2002 and CR-IP3-2002-04267 was written for this leak. The leak was repaired via the work control process. The second leak occurred in April 2007 and is documented in CR-IP3-2007-01852. This line has been excavated and replaced. The cause of the failure was determined to be advanced corrosion of the pipe due to moisture intrusion. This was caused by the pipe coating breaking down and insulation that was not sufficient for the task. After replacement, the pipe was reinsulated using a special high temperature application moisture resistant material, that was designed to prevent this type of corrosion in the future. This piping is nonsafety-related and not in the scope of license renewal. Copies of the condition reports were provided. No other buried piping repair or replacement was identified during review of operating experience. |
| 111 | Provide Fire Protection System Impairment Summary. | Provided the fire protection system impairment summary as of 6-10-07. |
| 123 | AMP B.1.23 (Non-EQ Inaccessible Medium-Voltage Cable)<br><br>Why are cables for service water pump motors | The Indian Point service water cables are safety-related, but are 480 VAC. As stated in the Sandia report 96-0344, DOE Cable AMG, water treeing is a degradation phenomenon that has been documented for medium-voltage electrical cable with certain extruded polyethylene insulations and EPR insulations. Water |

| Item | Request | Response |
|---|---|---|
| | not included in the B.1.23 AMP? | treeing has historically been more prevalent in higher voltage cables; proportionately few occurrences have been noted for cables operated below 15 kV. This is likely due to the comparatively high electric field density and voltage gradient required for significant treeing to occur. However, water treeing in medium-voltage cable operated below 15 kV has been documented. The formation and growth of trees varies directly with operating voltage; treeing is much less severe in 4-kV cables than those operated at 13 or 33 kV. Due to the low dielectric stress, water trees do not occur in low-voltage cables. Jackets and semiconducting shields may substantially reduce the ingress of moisture and ion migration, thereby reducing the rate of tree formation and propagation. New materials using ion scavengers may be effective at further reducing water tree growth. The DOE AMG typically defines medium voltage as 4 kV to 13.8 kV, but conservatively defines the lower value as 2 kV. NUREG-1801 and the license renewal electrical handbook uses the lower value of 2 kV.<br><br>The longer a medium voltage cable is energized, the greater the likelihood that moisture will affect the service life of the cable. Degradation of insulation materials due to "water treeing" is a potential aging mechanism for underground medium voltage cables that are energized greater than 25% of the time and subject to moisture. Cables in underground duct banks or conduits are considered underground cables subject to moisture for the Indian Point IPA.<br><br>All of the Indian Point safety-related power cables are 480 VAC, so there are no medium voltage circuits that are safety-related. The 480 VAC cables are not subject to water treeing; therefore, there are no aging effects requiring management by the Non-EQ Inaccessible Medium-Voltage Cable AMP (B.1.23). The cables included in the B.1.23 AMP are in scope for 10 CFR 54.4(a)(3) |
| 124 | AMP B.1.20 (Metal-Enclosed Bus Inspection)<br><br>The LRA program description only discusses visual inspections, but the enhancements to the existing plant program discuss visually inspecting bolted connections every 5 years, or every 10 years if using thermography. In site document for the AMP evaluation, items 3(b), 4(b), and 6(b) discuss only using visual inspections. The existing site procedure for the 480 VAC bus uses micro-ohm checks.<br><br>Why is only visual inspection discussed? Why are the other methods in GALL XI.E4 not discussed? Provide additional discussion for the other inspection methods addressed in GALL, or provide the basis for not including the other methods. | As indicated in LRA Section B.1.20, the "Metal-Enclosed Bus Inspection Program" is consistent with the inspection methods described in NUREG-1801. The program description in LRA Section B.1.20 will be clarified to describe the alternate tests and inspections discussed in NUREG-1801, Section XI.E4. Visual inspections will continue to be used for bolted connections as appropriate.<br><br>The site AMP evaluation report will also be clarified as discussed for LRA B.1.20. The program description, and Items 4(b), and 6(b) will be modified to address the inspection methods besides visual that are discussed in NUREG-1801, Section XI.E4. Item 3(b) does not require a change, since this item is consistent with NUREG-1801. The inspection methods used in the existing site procedures will be reflected in the site AMP evaluation report.<br><br>Clarification to be incorporated into the LRA. |
| 125 | AMP B.1.20 (Metal-Enclosed Bus Inspection)<br><br>The site document for the AMP operating experience discusses items found in the bus IP3 480 V Switchgear. Provide additional details for this incident and explain why this incident was not detrimental to the System function. | The site operating experience review report listed operating experience obtained from the condition report system. The issue at IP2 in 2006 was found during the performance of the non-safety related 6.9 kV Bus 4 PM. Degradation was found on the load side of the heater drain pump motor cables. The damage to the cable jacket/insulation was due to vibration of a support plate, and the cable degradation was repaired. The degradation was minimal, and the function of this cable was not affected. This CR was associated with 6.9 kV switchgear, which is not associated with the metal enclosed bus. This OE is an example of a design issue or a maintenance issue.<br><br>The issue at IP3 in 2003 was found during the performance of the safety-related 480 V Bus 5A PM. A switchgear separation barrier plate was found lying loose in the back of the switchgear cabinet. Also, a piece of cable approximately 10 inches long was found lying in the bottom of the switchgear cabinet. These were maintenance issues and the actions were to remove the section of cable, and attach the plate based on the design configuration. |
| 126 | Please provide copies of recent self assessments of the Inservice Inspection Program. | Provided copies of QA-08-2005-IP-1, "IPEC Unit 3 Engineering Programs Audit," 5/5/2005; LO-WPOLO-2004-00051, "ISI Snapshot Assessment for IPEC," 10/19/2004; and LO-WPOLO-2005-00046, "ISI Snapshot Assessment for IP2," 04/28/2005. |
| 127 | B.1.9: In section 4.5 of LRD07 under program description it states that thickness measurements | The program description provides a general description of what the program will do after all enhancements are implemented. This is in accordance with NEI 95-10 |

| Item | Request | Response |
|---|---|---|
| | of storage tank bottom surfaces verify degradation is not occurring. This implies that measurements are being currently being performed. Does this need to be revised to say after enhancements are completed? | Appendix D for application format and NUREG-1800 Table 3.3-2 which provides guidance for what a program description should include. Enhancements and exceptions are not discussed in this section of the document but are presented in each of the elements that have the exceptions and enhancements. |
| 128 | B.1.9: In section 4.5 of LRD07 section B.2.a GALL says periodic draining of water collected at the bottom of tanks minimizes amount of water. How is this addressed in B.1.9? What procedures perform this draining or water removal at IPEC? | Procedure 0-CY-1810 covers the monitoring of all diesel fuel oil on site and has a specification of "none detectable" for the tank bottom sample. When water has been detected, it has been removed in the past by direction of a supervisor. The sampler itself has been utilized in the past to remove water while obtaining a sample. Chemistry procedure 0-CY-3340 OPERATION OF THE GORMAN-RUPP TANKLEENOR could be utilized if larger amounts of water were encountered. 0-CY-1810 will be enhanced to include direction to remove water from the tank bottom if detected. In addition the revision will direct the sample be taken near the tank bottom for water detection.<br><br>Information to be incorporated into the LRA. |
| 129 | B.1.9: In section 4.5 of LRD07 section B.2.a in the section that discusses sampling of the fuel oil tanks near the bottom to determine water content it refers to procedure 0-CY-1500 attachment 4. This procedure does not appear to discuss sampling near the bottom of the tanks. Why is this procedure a reference and if so should it discuss sampling location? | This procedure attachment provides the location of the sample points for unit 1, 2 and 3 components. It includes the sample locations for the following fuel oil storage tanks:<br>IP2 EDG Day tanks (21/22/23), IP2 Fire protection diesel fuel tank, GT1 Fuel Oil South and North tanks, GT2&3 Fuel Oil Tank, IP3 EDG fuel oil day tanks (31/32/33), IP3 Fire Pump Fuel oil tank and the IP3 Appendix R Fuel Oil Day tank.<br><br>All of the sample points that are identified for these tanks in procedure 0-CY-1500 are taken at locations that are near or on the bottom of the tank such that there is no need to discuss the sampling location in this procedure to ensure a sample is taken near the bottom. |
| 130 | B.1.9: In section 4.5 of LRD07 section B.3.a GALL says ASTM D1796 and D2709 are used for determination of water and sediment. IPEC only uses ASTM D1796 and not D2709. Why is this acceptable? | As stated in the last three sentences of B.3.b of section 4.5 of IP-RPT-06-LRD-07, ASTM standards D1796 and D2709 are standards for the determination of water and sediment for different viscosities of fuel oil. ASTM standard D1796 is the appropriate standard for the ASTM-2D fuel oil used at IPEC. ASTM standard D2709 (water and sediment by centrifuge for lower viscosities) is not applicable for the fuel oil used at IPEC. |
| 131 | B.1.9: In section 4.5 of LRD07 section B.6.a GALL says ASTM D 6217 and modified D2276 are used. IPEC only uses ASTM D2276 and not D6217. Why is this acceptable? | It is acceptable to not use ASTM D6217 because use of ASTM D2276 is a more conservative method to measure the same parameter. ASTM D6217 is a laboratory method for middle distillate fuel particulate distillation. This method uses a smaller volume of sample passing over the filter membrane. As referenced in ASTM D6217, "Test Method D5452 and its predecessor Test Method D2276 were developed for aviation fuels and used 1 gal or 5 L of fuel sample. Using 1 gal of a middle distillate fuel, which can contain greater particulate levels, often required excessive time<br>to complete the filtration. The D6217 test method used about a quarter of the volume used in the D2276 method." Both of the methods use the same filter size of .8 microns. The difference in filtering a larger volume for a longer time using the ASTM D-2276 method is actually more conservative.<br>LRA Section B.1.9, second paragraph of exception to Element 6 will be revised as follows.<br>For determination of particulates, NUREG-1801 recommends use of modified ASTM Standards D2276 Method A and D6217. Determination of particulates is according to ASTM Standard D2276.<br>LRA Section B.1.9, exception note 4, will be revised as follows.<br>Determination of particulates is according to ASTM Standard D2276 which conducts particulate analysis using a 0.8 micron filter, rather than the 3.0 micron filter specified in NUREG-1801. Use of a filter with a smaller pore size results in a larger sample of particulates since smaller particles are retained. Thus, use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter specified in NUREG-1801. ASTM D6217 applies to middle distillate fuel using a smaller volume of sample passing over the 0.8 micron filter. Since ASTM D2276 determines particulates with a larger volume passing through the filter for a longer time than the D6217 method, use of D2276 only is more conservative.<br><br>Clarification to be incorporated into the LRA. |
| 132 | B.1.9: Procedure 2-CY-1560 for IP2 has as section 4.5 that has a step to add chemicals to the fuel oil storage tanks if determined necessary | There is not an IP3 procedure directing when to add biocide to the IP3 fuel oil tanks. Prior to integration of the units, the procedure already existed at Unit 2. Procedure integration focused on the type of chemicals to be added; it did not |

| Item | Request | Response |
|---|---|---|
| | by Chemistry. There does not appear to be a similar step in any IP3 procedure but there is a procedure 3-CY-2615 for adding chemicals to fuel oil tanks. Does this exist in an IP3 procedure and if not why the difference? | explicitly evaluate the method or timing of the chemical addition.<br>An enhancement will be added to combine the direction from 3-CY-2615 and 2-CY-1560 into a 0-CY series procedure for the addition of chemicals including biocide on both units.<br><br>Information to be incorporated into the LRA. |
| 133 | B.1.20: (Metal Enclosed Bus)<br><br>The site document for the AMP evaluation references a site procedure for performing 480VAC metal enclosed bus inspections. One of the steps discusses "re-torquing" connections. Why is re-torquing acceptable? | The aging management program evaluation report for the "Metal Enclosed Bus Inspection Program, which is described in LRA Section B.1.20, does not require "re-torquing" connections. The plant staff acknowledged that the practice of "re-torquing" connections is not a good practice, and was not intended to be performed. "Re-torquing" connections is not recommended in EPRI documents for phase bus maintenance and bolted connection maintenance. The plant will process a change to the site procedure to remove the reference to "re-torquing" connections. |
| 148 | Service Water Integrity<br>Inspector requested a copy of EN-DC-184 referred to in SEP-SW-001 in section 1.1 | At the time SEP-SW-001 was being developed, a corporate procedure (EN-DC-184) was also being drafted to apply to all 10 Entergy plants. EN-DC-184 would have included all the requirements that SEP-SW-001 presently provides. However, some plants had issues with the corporate procedure, and it has not yet been finalized or approved. It should be noted that the corporate procedure drafted at the time SEP-SW-001 was originally issued would not have added any additional requirements to the IPEC SW program, such that SEP-SW-001 was and is being correctly and effectively implemented at this time.<br><br>Procedure SEP-SW-001 states that the site procedure aligns with the corporate procedure EN-DC-184. This is an incorrect statement since there is no corporate procedure for service water programs. Since there is no impact on the site program from this discrepancy, this error will be corrected during the next procedure review and revision.<br><br>A copy of rev. 1 to SEP-SW-001 and the IPEC response letters to Generic Letter 89-13 were provided to the inspector. |
| 149 | Impairment summary for fire protection systems (6-10-2007) indicates that the "Utility tunnel HP fire header has less than minimum wall thickness and header isolation". What is the relationship to the HP fire water system and the root cause? (See enhancement regarding wall thickness evaluations) (See B.1.14 Operation Experience section RE: No evidence of loss) | The utility tunnel HP fire header is presently isolated as the result of discovery of piping section(s) that have degraded below minimum allowable wall thickness. The loop segmentation capabilities of the HP fire water loop enable the required fire protection water supplies to safety-related and safe-shutdown related plant areas to be maintained, despite the isolation of the utility tunnel header.<br><br>The degradation of carbon steel piping within the utility tunnel (city water and fire protection headers) was determined to be caused by chronic in-leakage of ground water into the tunnel, causing external corrosion of the city water and fire protection piping.<br><br>Engineering evaluations have been developed and work orders planned to address the cause by sealing the leaking penetrations/openings into the utility tunnel, thereby minimizing further water intrusion and contact with piping surfaces.<br><br>In addition, the city water piping will be encapsulated with a proprietary piping wrap and coating restoration system that will restore the structural and hydraulic integrity of the city water piping, and provide an exterior surface that will be resistant to corrosion.<br><br>A similar modification is being evaluated for restoration and protection of the Fire Protection piping in the utility tunnel. The sealing of the utility tunnel wall and ceiling penetrations as described above will eliminate the water intrusion and source of the exterior corrosion. The installation of the modification to seal the utility tunnel wall and ceiling penetrations is scheduled for completion during 2007.<br><br>The Fire Water System Program manages aging effects for components exposed to treated water (fire water) on internal surfaces. The external surface of fire water components is managed by the External Surfaces Monitoring program. Since the loss of material described in this operating experience was on the external surface and caused by water intrusion, this operating experience is not applicable for the Fire Water System Program. |
| 150 | The exception to NUREG-1801 for B.1.13 regarding the frequency of functional testing of Halon (IP2) and CO2 (IP3) from 6-months to 18 and 24 months respectively does not provide the | The current functional testing frequencies of the IP2 cable spreading room Halon system and the IP3 cable spreading room, IP3 480V switchgear room and IP3 Diesel Generator Building CO2 systems is as follows: |

| Item | Request | Response |
|---|---|---|
| | station/system specific operating history. What is the engineering basis and justification for these specific systems? | IP2 cable spreading room Halon system - once per 18 months<br><br>IP3 cable spreading room, IP3 480V switchgear room and IP3 Diesel generator building CO2 systems - once per 24 months with the exercising of fire dampers which form the boundary of the protected enclosures at once per 12 months.<br><br>A review of past performed functional testing of these systems has indicated no adverse indications of material degradation that requires adjustment of the testing frequencies. (ref. PT-EM19, 3-PT-2Y004 and 3-PT-2Y005). The condition reporting database was similarly reviewed and revealed no adverse indications of material degradation. |
| 151 | What is the original licensing basis for the functional testing frequency of CO2 and Halon systems at IP2 and IP3? | The original licensing basis for the functional testing frequency of CO2 and Halon systems at IP2 and IP3 are as follows:<br><br>IP2<br><br>The cable spreading room Halon system was installed as part of the plant modifications to improve the fire protection program resulting from reviews against BTP APCSB 9.5-1, Appendix A. Limiting conditions for operation and surveillance requirement were subsequently developed for this system and approved by the NRC under Amendment 64 to the FOL (ref. SER dated October 31, 1980). The functional test frequency was once per 18 months. This frequency is currently maintained in the administrative procedure SAO-703.<br><br>IP3<br><br>The cable spreading room, 480V switchgear room and Diesel generator building CO2 systems were installed as part of the plant modifications to improve the fire protection program resulting from reviews against BTP APCSB 9.5-1, Appendix A. Limiting conditions for operation and surveillance requirement were subsequently developed for these systems and approved by the NRC under Amendment 45 to the FOL (ref. SER dated November 18, 1982). The functional test frequency was once per 18 months.<br><br>A change to the functional testing frequency for these systems was subsequently proposed and approved by the NRC under Amendment 146 to the FOL (ref. SER dated April 20, 1994) to accommodate operation within a 24 month operating cycle. The functional test frequency was changed to once per 24 months with the exercising of fire dampers which form the boundary of the protected enclosures at once per 12 months. These frequencies are currently maintained in the IP3 TRM (Ref. TRO 3.7.A.7 |
| 152 | What is the justification for excluding the firewater jockey/ maintenance pumps from the scope of the HP fire water systems (B.1.14)?<br><br>These are not identified in :<br>SAO-703, rev25 (IP2) A.1<br>Section 3.7.A.1.7 and 3.7.A.1.8 of the IP3 TRM<br>AP-64.1 Rev. 2 Appendix R SSCs | The fire water jockey/maintenance pumps support standby operation of the fire water system and are conservatively included in the scope of license renewal and subject to aging management review. The Fire Water System Program manages component aging effects. However, the jockey/maintenance pumps are not required for operation of the fire water system to comply with 10 CFR 50.48 and Appendix R. Therefore, prescribed testing per SAO-703, TRM and AP-64.1 is not required. |
| 153 | A "cross-connect" of the HP fire water system exists between Units 1, 2, and 3 individual fire water supply systems. Has credit been taken for the use of this capability per the CLB? (B.1.14) | IP2 and IP3 maintain independent fire protection systems and the "cross connect" is not considered for compliance with IP2 or IP3 fire protection requirements. |
| 154 | B.1.11 (External Surfaces Monitoring)<br>Under attribute "Parameters Monitored and Inspected", examples of parameters inspected are provided and a reference is made to the systems walkdown procedure attachment 9.1. The guidelines in the attachment do not appear to cover attributes of coating degradaton and corrosion/material wastage. Clarify if these attributes are reviewed during system walkdowns. It is noted that the enhancement will revise guidance documents to require periodic inspection of systems in scope and subjet to an AMR. Will the revision include inclusion of these attributes? | Attachment 9.1 includes a line item of paint and preservation which would encompass coating degradation and corrosion/material wastage since if the paint is intact and the equipment properly preserved coating degradation and corrosion/material wastage would not be present. Attachment 9.1 also includes a statement at the beginning that the guidelines are not all inclusive. This is also documented in attachment 9.2 which is a checklist that identifies paint and preservation as potential items of concern. As stated in section 1.0 of EN-DC-178 a system walkdown is a detailed look at system material condition which would include the attributes of coating degradation and corrosion/material wastage regardless of it being specifically identified as an inspection item. |

| Item | Request | Response |
|---|---|---|
| 155 | B.1.11 (External Surfaces Monitoring)<br>Under the attribute "Detection of Aging Effects" a list of components and environments is given for those AMMs where visual inspection of the external surfaces is credited for internal surfaces. In two cases, the internal environment is given as indoor air, but the external environment is given as air-indoor or air-outdoor. Explain why this is acceptable? | The use of the condition of external surfaces to provide an indication of the condition of internal surfaces is acceptable when the external environment is outdoor air because the external environment is much more aggressive. Therefore, if visual inspections of the external surface are not experiencing loss of material, the internal surface is assured to be in good condition due to the milder internal environment. |
| 156 | B.1.15 (FAC): The program description provided for AMP B.1.15 in the LRA states that the program is based on the guiddelins of EPRI NSAC-202L-R2. the review of Indian Point Procedure EN-DC-315, rev. 0 Rlow Accelerated Corrosion Program provided during the site audit, references "ltatest" revison of this document which is revision 3. Since the guidelines provided in two revisions of NSAC-202L are different, address which hrevison of the document is applicable to Indian Point FAC Program. If Indian Point utilizes Rev. 3 of the NSAC document, the LRA should list this as an exception and include a justification for the use of the later revision to establish consistency with GALL Report. | Indian Point utilizes Revision 3 of NSAC 202L. As indicated in NSAC 202L, Revision 3, the new revision of EPRI guidelines incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that became available since Revision 2 was published. The updated recommendations refine and enhance those of previous revisions without contradicting existing plant FAC programs. An exception to GALL was not taken since implementing the elements of Revision 3 guidelines did not create program deviations from the guidelines in Revision 2 and the requirements specified in GALL are being met with Revision 3 of NSAC-202L. A review of the FAC program elements affected by Revision 3 changes is provided as follows showing the changes had minimal impact on the program.<br><br>Element (1), Scope of Program – The differences of Section 4.2, Identifying Susceptible Systems, between Revision 2 and Revision 3 are mostly editorial. The guidance of prioritizing the system for evaluation in Section 4.2.3 of Revision 2 is addressed in Section 4.9 of Revision 3. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3. Guidance for using plant experience and industry experience in selecting inspection locations was added in Revision 3. The basis for sample expansion was clarified in Revision 3. Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection. This is more compatible with the schedule of the implementation of FAC program during outages.<br><br>Element (4), Detection of Aging Effects – Clarification of the inspection techniques of UT and RT was added in Section 4.5.1 of Revision 3. There are no changes of the guidance for UT grid. Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. This is beyond the level of detail provided in Revision 2 and in the GALL report. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and of Revision 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles was enhanced in Section 4.5.2 of Revision 3. Also, Section 4.5.4 was added for use of RT to inspect large-bore piping, Section 4.5.5 was added for inspection of turbine cross-around piping, and Section 4.5.6 was added for inspection of valves |
| 157 | Fire Barriers<br><br>What is the current frequency of inspection for fire barrier penetrations and what is the % sample to be inspected? | All accessible fire barrier penetration seals are visually inspected at least once every seven operating cycles (approximately 15% per 24 months operating cycle). During each inspection interval, at least 10% of each type of seal is inspected. |
| 158 | Fire Barriers<br><br>Fire separation barrier inspections (2-PI-Q001 Rev. 8) acceptance criteria does not include a specific failure mode of HEMYC fire barrier wrap identified in GL 2006-03. Specifically the potential shrinkage of the outer layer fabric (Refrasil) that could expose the interior layors of Kawool . Is this guidance (GL 2006-03) incorporated into the barrier inspection program and specifically where? | The failure mode cited in Generic Letter 2006-03 specifically the potential shrinkage of the outer covering, exposing the interior surfaces or layers to the fire, relate to the performance and response of a Hemyc fire barrier wrap under fire conditions which were installed in accordance with vendor requirements. These requirements were similarly used during the installation of the Hemyc fire barrier wrap at IP2 and IP3.<br><br>Periodic test 2-PI-Q001 ensures through a visual inspection that the material condition of the wrap is satisfactory (i.e., the wrap is not missing, punctured or torn, the wrap is not oil soaked or shows evidence of other chemical contamination and that it is properly banded as required), thereby consistent with the initial pre-fire condition. |
| 159 | B.1.23<br>a) Item 3(b) of the site AMP evaluation document references an EPRI document instead of listing examples of types of tests that could be | LRA Section B.1.23 and the site AMP evaluation document state this program is consistent with NUREG-1801, XI.E3 without exceptions or enhancements.<br><br>a) The AMP evaluation document for the Non-EQ Inaccessible Medium-Voltage |

| Item | Request | Response |
|---|---|---|
| | performed similar to those provided in GALL. Provide information so a determination can be made for consistency of the EPRI document and the GALL example programs.<br><br>B) Item 4(b) of the site AMP evaluation document states that an engineering evaluation will be perfomed to determine the proper frequency for manhole inspection. Provide information for how this will use OE to justify the frequency. | Cable, Item 3(b) will be clarified to provide examples of tests.<br><br>Current<br>"The specific type of test performed will be determined prior to the initial test. The test will 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."<br><br>Proposed<br>The specific type of test 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, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed.<br><br>b) The AMP evaluation document for the Non-EQ Inaccessible Medium-Voltage Cable, Item 4(b) will be modified to clarify the use of site OE for the frequency of manhole inspections.<br><br>Current<br>Inspections will be based on actual plant experience with water accumulation in manholes and the frequency of inspection will be adjusted based on the results of an engineering evaluation, but an inspection will occur at least once every two years, with the first inspection for license renewal occurring prior to the period of extended operation.<br><br>Proposed<br>Inspections will be based on actual plant experience with water accumulation in manholes. Based on water accumulation discovered during inspections, the frequency of inspection will be adjusted based on the results of corrective action process evaluations. The inspections will occur at least once every two years, with the first inspection for license renewal occurring prior to the period of extended operation |
| 160 | B.1.10<br><br>During the discussion of the EQ program with the Indian Point owner, the process of incorporating OE into the program was discussed. Other than the information provided in the site OE report, is there any additional OE associated with effectiveness of the EQ program. | In January 2006, during an EQ program enhancement project it was discovered that an IP3 EQ file did not identify or address qualifications of pigtail extension cables. A CR was initiated to capture EQ documentation deficiency, which was not an environmental qualification deficiency. The EQ program enhancement project was initiated to correct this type of historical discrepancy. The applicable test reports were obtained, and were evaluated. The applicable test reports met IP3's environmental parameter requirements, so these cables were considered qualified. Therefore, there was no operational concern. An extent of condition review was not required because of the EQ program enhancement project.<br><br>In July 2004, it was identified that the EQ program replacements for AOV components and the AOV program replacements could be redundant. Some of the AOV components are EQ, but not all. It was identified there was an inconsistency in the philosophy for these repetitive tasks. Also, there was an inconsistency on which tasks were routed for EQ program review. To address the extent of condition, corrective actions were to review the AOV replacement scope to ensure all EQ components that will be replaced under the AOV program repetitive tasks are documented.<br><br>To ensure that Indian Point EQ Program stays current with the industry and that the industry operating experience (OE) is addressed, participation in several industry based working and assessment groups is maintained. The industry groups are comprised of utility operators worldwide, but the majority are in the US and Canada. Many topics and issues relating to equipment qualification are currently being pursued by these groups. Specific issues include the NRC's EQ Task Action Plan (active interaction with the NRC staff, NEI and the Group), Cost-Saving Measures related to EQ activities (e.g., revised source term, file/documentation management, staffing), SOV qualification (generally and with respect to specific designs (extended qualified life valves (NS-2 Group-sponsored testing)), cable qualification (e.g., aging, submergence, and similarity), issues arising from ongoing NRC inspections, qualification of High Range Radiation Monitors, issues arising from ongoing NRC Routine, Team and Special inspections, qualification of specific equipment types (splices, penetrations, transmitters, etc.) as identified by the Group, and integration of equipment qualification considerations into license renewal. Participation in these organizations also provides a source of regulatory and reference documents, component information, engineering analyses, and |

| Item | Request | Response |
|---|---|---|
| | | materials data from many different manufacturers and utilities. |
| 161 | B.1.13<br>The RCP lube oil tanks collection system includes a passive flame arrestor(s) to prevent flashback. The RCP lube oil collection system is inspected every 24 months and every 31 days for inventory. (SAO-703 Rev. 25) (IP2/ 2-PT-R201)<br>Is this component included in the scope of the fire protection program (AMR) due to credit provided to FP SSC's? (10 CFR 54.4(a)(3)) & 10 CFR 50.48) | The RCP oil collection system flame arrestors are subject to aging management review with aging effects managed by the Fire Protection Program. The flame arrestors are included in the component type "piping" in Table 3.3.2-12-IP2 and 3.3.2-12-IP3. |
| 165 | B.1.26 Oil Analysis<br>Provide a technical basis for the oil sampling frequency. | Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of defration to fail, fault discovery, and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.<br><br>A copy of the template bases for medium voltage motors, low voltage motors, and horizontal pumps and procedure EN-DC-335 were provided during the audit. |
| 166 | B.1.26 Oil Analysis<br>NUREG-1801 Acceptance Criteria for XI.M39 states that water and particulate concentration is determined in accordance with industry standards. What industry standards form the basis for acceptance criteria at IP2 and IP3? | The Oil Analysis Program is designed to function as a screening tool to help identify adverse lube oil conditions or trends. The screening process is supplemented with detailed analysis in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951 and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturer's recommendations. |
| 167 | Diesel Fuel Monitoring<br>Provide frequency at which biological activity and/or particulate contamination concentrations are monitored for each fuel oil storage tank in scope of license renewal. Include basis for each frequency. If an industry standard is referenced in your response, provide a copy of that standard. (electronic version preferred if available) | Response provided in the revised response to question 31. |
| 168 | Diesel fuel Monitoring<br>Provide ASTM Special Technical Publication 1005 referenced in response to Q 34.<br>(Electronic version perferred if available.) | Copy of publication provided |
| 169 | Diesel Fuel Monitoring<br>Provide ASTM D975.<br>(Electronic version preffered if available.) | Provided copy of 1985 version of standard. |
| 170 | Oil Analysis<br>What is the technical bases for the oil analysis frequencies at IPEC. | Oil analysis frequencies for equipment at IPEC are based on Entergy Templates, which have technical bases justifications in the templates. Procedure EN-DC-335, "PM Bases Template", references EPRI PM bases TR-106857 Volume 1 thru 39 and EPRI guide for determining PM task intervals TR-103147 in developing this procedure. Each template has a failure location and cause, progression of defraction to fail, fault discovery and task objective. Each component type uses these subjects to conclude to a frequency to mitigate failure.<br><br>A printout of the template bases for medium voltage motors, low voltage motors and horizontal pumps were provided to the inspector, along with procedure EN-DC-335. |
| 171 | Please include a statement about inspection techniques utilized to the description of the One-Time Inspection Program in LRA Section B.1.27. | The One-Time Inspection program description in LRA Sections A.2.1.26, A.3.1.26 and B.1.27 will be clarified by addition of the following statement. "The inspections will be nondestructive examinations (including visual, ultrasonic, and/or surface techniques)."<br><br>Clarification to be incorporated into the LRA. |
| 172 | In the list of One-Time Inspection Program | For several one-time inspection activities, the term "components" was used to |

| Item | Request | Response |
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| | activities, listed in the program description in Section B.1.27 of the LRA, some activities do not specify the types of components to be inspected. Please include the types of components to be inspected under these activities. | describe piping, piping elements, and other components within the system that are of the material and environment to be inspected.<br><br>For these one-time inspection activities, the application will be clarified by replacing "components" with "piping, piping elements and components."<br><br>Clarification to be incorporated into the LRA. |
| 173 | Please confirm in the commitment list and LRA Appendix A that new programs will be implemented consistent with the corresponding program described in NUREG-1801. | The commitment list and LRA Appendix A will be clarified to state that new programs will be implemented consistent with the corresponding program described in NUREG-1801. The new programs are Buried Piping and Tanks Inspection, Non-EQ Inaccessible Medium-Voltage Cable, Non-EQ Instrumentation Circuits Test Review, Non-EQ Insulated Cables and Connections, One-Time Inspection, One-Time Inspection – Small Bore Piping, Selective Leaching, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS), and Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS).<br><br>Clarification to be incorporated into the LRA.<br>Commitment # 3, 15, 16, 17, 19, 20, 23, 26, and 27. |
| 174 | The program description provided for AMP B.1.28 in the LRA states that the One-Time Inspection – Small Bore Piping Program is a new program applicable to small bore ASME Code Class 1 piping less than 4 inches nominal pipe size (NPS 4"), which includes pipe, fittings, and branch connections. The LRA also states that the Indian Point's new program will be consistent with NUREG-1801 Program XI.M35, One-Time Inspection of ASME Code Class 1 Small-Bore Piping. However, NUREG-1801, Section XI.M35, states that the program is applicable to small-bore ASME Code Class 1 piping and systems less than or equal to 4 inches nominal pipe size (i.e., sizes up to and including 4 inch size). If Indian Point intends to exclude 4" size from AMP B.1.28, this should be treated as an exception to GALL and a justification included in the LRA to establish consistency with the GALL report. | The NUREG-1801 Program Description for Program XI.M35 indicates that a One-Time Inspection Of ASME Code Class 1 Small-Bore Piping is needed because the ASME code does not include a volumetric examination of piping "less than or equal to NPS 4" to detect cracking resulting from thermal and mechanical loading or intergranular stress corrosion. However, according to ASME Code, a volumetric examination is already required for piping equal to NPS 4".<br><br>Also, NUREG-1801 Item IV.C2-1 is the only PWR line item which applies the One-Time Inspection of ASME Code Class 1 Small Bore Piping Program (XI.M35). This line item is for Class 1 piping "less than NPS 4".<br><br>Therefore, Entergy concludes that it is not the intent of GALL for Program XI.M35 to include NPS 4" pipe. Therefore, the IPEC One-Time Inspection – Small Bore Piping Program includes only small bore Class 1 piping < NPS 4", which is consistent with GALL. |
| 175 | Commitment letter NL-07039 for oil analysis states the oil analysis program will be enhanced to formalize trending of preliminary oil screen results as well as data provided from independent laboratories. The FSAR Supplement A.2.1.25 for oil analysis states that appropriate procedures will be revised to formalize trending.<br>The commitment letter and the FSAR Supplement should state the same answer. | LRA Sections A.2.1.25 for IP2, A.3.1.25 for IP3, and B.1.26 will be revised to agree with Commitment 18 listed in commitment letter NL-07039. The last two enhancements listed in Section A.2.1.25 and the last two enhancements listed in Section A.3.1.25 will be revised to read as follows. "Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Formalize trending of preliminary oil screening results as well as data provided from independent laboratories."<br><br>Clarification to be incorporated into the LRA. |
| 176 | In the list of Periodic Surveillance and Preventive Maintenance Program activities, some activities do not specify the types of components to be inspected. Please clarify the types of components to be inspected in these activities.<br><br>Also, some activities do not indicate whether the internal or external surfaces are to be inspected. Please clarify. | For several Periodic Surveillance and Preventive Maintenance Program activities, the term "components" was used to describe piping, piping elements, and other components within the system that are to be inspected. For these Periodic Surveillance and Preventive Maintenance Program activities, the application will be clarified by replacing "components" with "piping, piping elements and components."<br><br>The LRA will be clarified to show that the internal surfaces of piping, piping elements, and components are inspected by the Periodic Surveillance and Preventive Maintenance Program for the following items shown in the program description of Section B.1.29.<br><br>Recirculation pump cooler housing<br>Station air containment penetration piping<br>Portable blowers and flexible trunks stored for emergency ventilation use<br>EDG exhaust gas piping<br>EDG air intake and aftercooler<br>EDG starting air<br>EDG cooling water makeup<br>IP2 fuel oil cooler |

| Item | Request | Response |
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| | | IP3 Appendix R radiator, aftercooler, starting air, and crankcase exhaust<br>Auxiliary feedwater<br>Control room HVAC<br><br>IP2 Nonsafety-related affecting safety-related<br>River water service system<br>Waste disposal system<br>Water treatment plant<br><br>IP3 Nonsafety-related affecting safety-related<br>Chlorination system<br>Circulating water system<br>EDG system<br>Floor drain system<br>Gaseous waste disposal system<br>Instrument air system<br>Liquid waste disposal system<br>Nuclear equipment drain system<br>River water system<br>Station air system<br>Secondary plant sampling system<br><br>Clarification to be incorporated into the LRA. |