From: Bo Pham
To: <dtyner@entergy.com>,"MICHAEL D STROUD" <MSTROUD@entergy.com>
Date: 10/10/2007 9:40:20 AM
Subject: Fwd: Indian Point AMR Pre-Audit Questions
cc: "Kimberly Green" <KJG1@nrc.gov>,<IPNonPublicHearingFile@nrc.gov>

Mike & Donna,

Please find attached the revision to the AMR questions for our 10/22 audit. Thanks.

Bo Pham
Project Manager
Division of License Renewal
U.S. Nuclear Regulatory Commission
301-415-8450
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>>> Peter Wen 10/10/07 9:25 AM >>>
Bo,

Inadvertently, we transmitted the wrong file to you on Sunday, 10/7/2007. Please find the AMR pre-audit questions in the "attachment," which include all six sections of AMR questions (i.e., from AMR 3.1 thru 3.6). Please re-transmit this set of questions to the applicant. Thanks.

Sorry for the inconvenience.

Peter

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From: Bo Pham

Created By: BMP@nrc.gov

Recipients
"Kimberly Green" <KJG1@nrc.gov>
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Peter

3.1-1-Subudhi	In LRA Tables 3.1.2-3 and 3.1.2-4, Entergy credits Water Chemistry Control – Primary and Secondary AMP to manage fouling in SG and HX tubes in three line items for each IP unit. The LRA marks generic note H for these line items for tubes exposed to treated or treated borated water, indicating that there is no NUREG-1801 (or GALL) line item for the component, material and environment combination. Describe how the Water Chemistry Control – Primary and Secondary AMP will prevent fouling in SG and HX tubes in the RCS and what method(s) would confirm that this aging effect is not occurring in these components and thus ensure the effectiveness of the this AMP.
3.1-2-Subudhi	a) In LRA Section 3.1.2.2.1 and the discussion in LRA Table 3.1.1, item number 3.1.1-1, Entergy indicates that the reactor vessels at IP2/3 are not supported by support skirts and therefore, cumulative fatigue damage (as a TLAA) for support skirts is not applicable to IP2/3 reactor vessels. However, the corresponding Table 2 line item indicates that the reactor vessels are supported on support pads, which are usually welded to the underside of the coolant nozzles and rests on steel base plates atop a support structure attached to the concrete foundation. Discuss how the fatigue cracking of support pad attachment welds is managed for IP2/3 reactor vessels. b) In LRA Section 3.1.2.2.1, Entergy states that no fatigue analysis was required for the pressurizer support skirts since the Inservice Inspection Program will manage the cracking due to fatigue. Please discuss how IP2/3 ISI program will adequately manage the cracking due to fatigue for the period of extended operation. Specifically, include in the discussion the inspection methods, frequency, acceptance criteria, and past operating experience on the pressurizer support skirts at IP2/3. c) LRA Table 3.1.1, item 3.1.1-7 addresses cracking due to fatigue (as a TLAA) for support skirts, attachment welds, and pressurizer relief tank (PRT) components (in addition to RCPB closure bolting and studs, SG components, piping external surfaces and bolting) in the RCS, made out of carbon or stainless steel. In LRA Table 3.1.2-3, Entergy indicates a TLAA line item referring to Table 3.1.1-7 for the RCS components. The corresponding GALL Table 2-item IV.C2-10 (R-18) references RCS components for this TLAA, which includes piping and pipe components external surfaces and bolting. LRA Table 2 line items associated with this TLAA do not include the support skirts and/or attachment welds for RCS components (e.g., RCP, SG, PRT) other than the pressurizer and PRT components. Clarify if these components (except RV attachment weld and pressurizer support skirts) are within the scope of LR for IP2/3. If such components are within the scope of the license renewal, then provide technical justification why these components are not subject to cracking due to fatigue for IP2/3 and included in the Table 2 items of the RCS.
3.1-3-Subudhi	In LRA Table 1 item 3.1.1-17, Entergy states in its discussion, “The nozzles are not controlling for the TLAA evaluations.” This Table 1 item

refers to a TLAA for the loss of fracture toughness due to neutron irradiation embrittlement in the vessel beltline region. Demonstrate why the materials of the nozzles are not controlling for the TLAA evaluations.

3.1-4-Subudhi In LRA Table 1 item 3.1.1-21 and LRA Section 3.1.2.2.5, Entergy states, “SA508-Cl 2 forgings clad with stainless steel using a high-heat input welding process were not used in the IP2 or IP3 vessels.” This line item is identified as not applicable to IP2/3. Describe the quantitative criteria that define “high-heat input welding process” and compare it to the welding parameters used for deposition of the SS cladding in the IP2 and IP3 vessels.

3.1-5-Subudhi In LRA Section 3.1.2.2.7, item 2 Entergy states that the Water Chemistry Control – Primary and Secondary and Thermal Aging Embrittlement of CASS AMPs manage cracking due to SCC in CASS RCS piping components. Entergy also states that the ISI program for some components supplements these AMPs. In LRA Table 3.1.2-3, only the CASS pipe fittings credit the ISI program in addition to Water Chemistry Control – Primary and Secondary and Thermal Aging Embrittlement of CASS AMPs. Discuss the criteria that require the IP2/3 ISI program for certain RCS components to be added as supplement to Water Chemistry Control – Primary and Secondary and Thermal Aging Embrittlement of CASS AMPs.

3.1-6-Subudhi In LRA Section 3.1.2.2.9, Entergy states that stress relaxation in stainless steel and nickel alloy reactor vessel internals screws, bolts, tie rods, and hold-down springs are not applicable since these components operate at a temperature that is $\leq$ 700^{o}F in accordance with ASME Code, Section II, Part D, Table 4. Provide specific details of the materials of these IP2/3 RVI components and their operating temperature conditions in comparison to the Code threshold temperatures.

3.1-7-Subudhi In LRA Table 3.1.2-1, Entergy credits Water Chemistry Control – Primary and Secondary and Nickel Alloy Inspection AMPs to manage cracking in nickel alloy vessel internal attachment core support lugs (pads). This line item also references Table 1 item 3.1.1-31 and Table 2 item IV.A2-12 (R-88), which require the ISI program along with Water Chemistry Control – Primary and Secondary and Nickel Alloy Inspection AMPs. Clarify this discrepancy.

3.1-8-Subudhi In LRA Section 3.1.2.2.14, Entergy credits visual inspections under SG Integrity AMP to manage wall thinning due to FAC that could occur in carbon steel FW rings and supports, as noted in NRC IN 91-19 at San Onofre 2/3. Although the description of the SG Integrity AMP includes other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue, no details are found in the LRA about how the inspection methods and their evaluation are performed with regard to loss of material in carbon steel FW inlet ring and supports in the IP2/3 SGs. Discuss the type of visual inspections that could detect the wall thinning of these SG components, the acceptance criteria and operating experience associated with these activities at IP2/3.

3.1-9-Subudhi	In LRA Section 3.1.2.2.16, Entergy credits Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs for managing cracking in carbon steel with Ni-alloy clad in steam generator tubesheet primary side. The Table 2 line item in LRA Table 3.1.2-4 references Table 1 item 3.1.1-35 and GALL item IV.D2-4 (R-35); both line items specify the implementation of applicable plant commitments to (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines. LRA Section A.2.1.34, which documents the UFSAR updates for the SG Integrity AMP, does not contain this commitment. Explain why this is not specifically documented in LRA Section A.2.1.34 as a LR commitment.
3.1-10-Subudhi	In LRA Table 1 item 3.1.1-52, Entergy provides an explanation why cracking due to SCC, loss of material due to wear, loss of preload due to thermal effects, gasket creep, and self-loosening are not applicable to IP2/3 CS and SS RCPB pump valve closure bolting, and those in high pressure and high temperature environment. In fact, there were no Table 2 line items addressing these aging effects in both LRA Tables 3.1.2-3 and -4. GALL Table 2 items IV.C2-7, and IV.D1-1 and -2 for cracking, and items IV.C2-8 and IV.D1-10 for loss of preload due to thermal effects, gasket creep, and self-loosening credits the bolting integrity AMP for managing these aging effects. Moreover, loss of material due to corrosion in bolts exposed to indoor air environment is managed by the bolting integrity AMP [LRA Table 1 item 3.1.2-23, and LRA Table 2 item V.E-4 (EP-25)]. Note that IP2/3 Bolting Integrity AMP is consistent with GALL AMP XI.M18, Bolting Integrity Program and based on the LRA, the IP2/3 Bolting Integrity AMP manages all the above-mentioned aging effects. Provide technical justification for the following: a. Applied stress for SS closure bolting applications at IP2/3 is much less than 100ksi. Basis for a threshold of 100ksi in the bolting materials at IP2/3 when cracking of bolting due to SCC is not an aging effect requiring aging management. b. Loss of material due to wear is not a <u>significant</u> aging effect for the bolting based on industry experience. Event driven conditions such as galling are not aging-related degradation. c. Loss of preload due to stress relaxation is not an applicable aging effect. Note that temperature condition is one of many factors (e.g., vibration, thermal cycles) that may cause loosening of bolts even in a benign thermal environment.
3.1-11-Subudhi	In LRA Table 3.1.1, item 3.1.1-62, Entergy states that cracking due to cyclic loading is addresses as cracking due to fatigue (presumably, as a TLAA). Entergy also states that the ISI program manages the cracking of SS piping >4" NPS. However, no Table 2 line item addresses cracking due to cyclic loading for SS and CS with SS clad piping in the RCS (i.e., hot leg, cold leg, surge line, and spray line) exposed to reactor coolant as required by 10CFR54.21(a). The GALL item 3.1.1-62 addresses cracking

due to cyclic loading and recommends ISI program to monitor the cracking in the piping and pipe fittings. This is required in addition to the establishment of the cumulative usage factors due to fatigue (or cyclic) loadings in accordance with 10CFR54.21(c). Provide technical justification for not including these Table 2 line items in the LRA Table 3.1.2-3 for RCS components.

3.1-12-Subudhi In LRA Table 3.1.1, item 3.1.1-64, Entergy states, "The Inservice Inspection and Water Chemistry Control – Primary and Secondary Programs manage cracking in steel with stainless steel or nickel alloy clad components. Cracking of stainless steel components is addressed in other lines." Identify which other lines address cracking of stainless steel components in the pressurizer exposed to treated borated water.

3.1-13-Subudhi In LRA Table 3.1.1, item 3.1.1-65, Entergy addresses cracking due to PWSCC in Ni-alloy RV upper head penetration nozzles, instrument tubes, and head vent pipe, and welds exposed to treated borated water. GALL recommends ISI, water chemistry control and Ni-alloy penetration nozzles (XI.M11A) AMPs, while Entergy credits water chemistry control and Ni-alloy inspection program.

The IP2/3 AMP B.1.31 corresponds to the GALL AMP XI.M11A and manages PWSCC of Ni-based penetrations exposed to treated borated water. The Ni-Alloy inspection program (LRA B.1.21) manages Ni-alloy components that are not covered by the RVH penetration inspection (B.1.31) and SG integrity (B.1.35) AMPs.

a. Provide technical justification for not crediting the GALL-recommended ISI, water chemistry control and Ni-alloy penetration nozzles (XI.M11A) AMPs to manage cracking due to PWSCC in Ni-alloy RV upper head penetration nozzles, instrument tubes, and head vent pipe, and welds exposed to treated borated water.

b. Discuss how the water chemistry control – primary and secondary and the Ni-alloy inspection AMPs would manage cracking in Ni-alloy nozzle safe end and welds (inlet/outlet safe ends and closure head vent), as indicated in LRA Table 2 items referencing Table 1 item 3.1.1-65. Note that the Table 2 item IV.A2-18 (R-90) referenced for these line items in LRA Table 3.1.2-1 also recommends ISI, water chemistry control, and Ni-alloy penetration nozzles (XI.M11A) AMPs, consistent with GALL Table 1 item 3.1.1-65.

3.1-14-Subudhi In LRA Table 3.1.1, item 3.1.1-66, Entergy states, "This line was not used. Erosion at manways and handholes is the result of damage from leaking joints that have not been corrected. At IPEC leaks are fixed as soon as practical. If damage due to erosion has occurred, it would also be repaired." Based on this, Entergy has not included this line item in the LRA Table 3.1.2-4. GALL recommends ISI program (Class 2: which requires visual inspections during pressure testing) to manage loss of material due to erosion in carbon steel steam generator secondary manways and handholes (cover only) exposed to air with leaking secondary-side water and/or steam. Provide technical justification how Entergy ensures the preventive (that detect the damage due to erosion) and corrective measures (that repair the leakage) for leaking joints and thus, would manage loss of material due to erosion in these SG components.

3.1-15-Subudhi In LRA Table 3.1.1, item 3.1.1-68, Entergy states, "The Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs manage cracking in most stainless steel and steel with stainless steel clad Class 1 components. For some components not subject to the Inservice Inspection Program, the Water Chemistry Control – Primary and Secondary Program manages cracking. The pressurizer spray head coupling and locking bar supports flow distribution within the pressurizer and are not part of the pressure boundary. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program." LRA Table 3.1.2-3 line item referring to these components and the Table 1 item 3.1.1-68 [Table 2 item IV.C2-20 (R-217)] indicates that the water chemistry control AMP would manage the cracking. This is inconsistent with GALL recommendations as well as Entergy's statement in the Table 1 item 3.1.1-68. Clarify this discrepancy.

3.1-16-Subudhi In LRA Table 3.1.1, item 3.1.1-69, Entergy states, "The Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs manage cracking in stainless steel nozzles and penetrations. Nickel alloy used for such applications is compared to other lines." Identify which other lines applicable to Ni-alloy components exposed to reactor coolant and manage cracking due to SCC and PWSCC.

3.1-17-Subudhi In LRA Table 3.1.1, item 3.1.1-74, Entergy states, "Consistent with NUREG-1801 for some components. The Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs manage cracking and loss of material of stainless steel and nickel alloy steam generator components exposed to secondary feedwater and steam. For some components, loss of material is managed by the Water Chemistry Control – Primary and Secondary Program. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program." LRA Table 3.1.2-4 line item referring to secondary handhole cover RTD well as well as boss for IP3 and the Table 1 item 3.1.1-70 [Table 2 items IV.D1-14 (RP-14) and IV.D1-15 (RP-15)] indicates that the water chemistry control AMP would manage the cracking. This is inconsistent with GALL recommendations as well as Entergy's statement in the Table 1 item 3.1.1-74.

a. GALL Table 2 items IV.D1-14 (RP-14) and IV.D1-15 (RP-15) recommend SG integrity and water chemistry control AMPs. Justify why for some components the one-time inspection AMP is credited instead of GALL-recommended SG integrity AMP in LRA Table 1 item 3.1.1-74, specifically to manage cracking in the secondary handhole cover RTD well for IP3.

b. Clarify why the plant-specific note 104 is not indicated for secondary handhole cover RTD well and boss for IP3 to manage cracking of secondary handhole cover RTD well and loss of material in secondary handhole cover RTD boss. The note would ensure that one-time inspection AMP is applicable to these two Table 2 line items.

c. Since both IP2 and IP3 steam generators are Westinghouse Model 44F, explain why LRA Table 3.1.2-4-IP2 does not include line items for secondary handhole cover RTD well and boss, similar to LRA Table 3.1.2-4-IP3.

3.1-18-Subudhi In LRA Table 3.1.1, item 3.1.1-84, Entergy states, "The Water Chemistry Control – Primary and Secondary Program manages cracking in one nickel alloy steam generator component exposed to secondary feedwater or steam. The One-Time Inspection Program will be used to verify the effectiveness of the water chemistry program." LRA Table 3.1.2-4 line item referring to secondary handhole cover RTD boss cracking for IP3 and the Table 1 item 3.1.1-84 [Table 2 item IV.D2-9 (R-36)] indicates that the water chemistry control and one-time inspection AMPs would manage the cracking. Since both IP2 and IP3 steam generators are Westinghouse Model 44F, explain why LRA Table 3.1.2-4-IP2 does not include the line item for secondary handhole cover RTD boss, similar to LRA Table 3.1.2-4-IP3.

3.1-19-Subudhi In LRA Table 3.3.1, item 3.3.1-8, Entergy states, "Stainless steel components of some heat exchangers to which this NUREG-1801 line item applies, including the regenerative heat exchanger, are in the reactor coolant systems in series 3.1.2-x tables. The Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs manage cracking of stainless steel heat exchanger bonnets and shells exposed to treated borated water. The Water Chemistry Control – Primary and Secondary Program manages cracking of stainless steel heat exchanger tubes. The program is augmented by the One-Time Inspection Program which will verify the absence of cracking in similar material environment combinations since the regenerative heat exchanger cannot be inspected internally." In LRA Table 3.1.2-3, Entergy credits water chemistry control – primary and secondary AMP to manage cracking in stainless steel HX tubes exposed to treated borated water and references Table 1 item 3.3.1-8. Clarify why the plant-specific note 314 that verifies effectiveness of the Water Chemistry Control – Primary and Secondary Program, is not indicated for HX tubes to manage cracking.

3.1-20-Subudhi In LRA Table 3.4.1, line items 3.4.1-14 (for cracking) and 3.4.1-16 (for loss of material), Entergy states that consistent with NUREG-1801, Water Chemistry Control – Primary and Secondary Program manages cracking and loss of material in stainless steel components exposed to treated water. The One-Time Inspection Program is used to verify the effectiveness of the water chemistry program. In LRA Table 3.1.2-4, Entergy credits water chemistry control – primary and secondary AMP to manage cracking and loss of material in stainless steel piping, tubes and valves exposed to treated water and references Table 1 items 3.4.1-14 and 3.4.1-16. Plant-specific notes for the steam and power conversion system do not include one that verifies the effectiveness of the Water Chemistry Control – Primary and Secondary Program for managing cracking and loss of material. Discuss how Entergy intends to verify the effectiveness of the Water Chemistry Control – Primary and Secondary Program for managing cracking and loss of material in SS components exposed to treated water.

3.2-1-Wen Numerous line items in Tables 3.2.2-1-IP2 and 3.2.2-1-IP3 (RHR System) credit TLAA- Metal Fatigue to manage the aging effect of metal fatigue (cumulative fatigue damage). These line items also indicate that the evaluation of the TLAA is addressed in Section 4.3 of the LRA. However, it appears that the writeup in Section 4.3 does not cover the discussion for most components, such as flex hose, flow elements, thermowell, tubing, and valve bodies. Please explain the discrepancy.

3.2-2-Wen While IP3 has two line items in Table 3.2.2-2 (Containment Spray System) and Table 3.2.2-4 (Safety Injection Systems), which correspond to GALL V.D1-26, Piping, Piping Components and Piping Elements. These line items reference Table 1 item 3.2.1-4. Please explain why IP2 does not have similar items.

3.2-3-Wen Both IP2 and IP3 have two line items in Table 3.2.2-5 (Containment Penetrations System) reference Table 1 item 3.2.1-8. Describe how One-Time Inspection will be performed on these components. Specifically, please discuss the parameters to be monitored and the inspection techniques that will be utilized. Please also justify why One-Time Inspection Program alone is sufficient to manage the aging effect of loss of material due to pitting and crevice corrosion.

3.2-4-Wen The “Discussion Column” of LRA Table 1 Item 3.2.1-24 states that loss of preload is a design-driven effect and this aging effect needs not be considered. Thus, no associated Table 2 line items were included in the IP LRA.

Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications, however, loss of preload could also due to other effects such as gasket creep and self-loosening.

Please justify why other effects are not applicable. In addition, loss of preload in bolting is listed as an aging effect in the GALL Report, which credits the Bolting Integrity Program for managing this effect. Please justify why the applicant’s Bolting Integrity Program (B.1.2) did not take exception to the GALL Report, given that loss of preload is not considered an aging effect in IP.

3.2-5-Wen The “Discussion Column” of LRA Table 1 Items 3.2.1-25 and 26, state that these two line items are not applicable. Does IP has bearing and lube oil coolers and associated piping that are considered part of the ESF systems? What are the operating temperatures for these components. If

	these components were not included in the ESF system, where were they being addressed at?
3.2-6-Wen	The “Discussion Column” of LRA Table 1 Items 3.2.1-32, states that “The Fire Protection and Periodic Surveillance and Preventive Maintenance Programs manage loss of carbon steel components by periodic visual inspection of component internal surfaces.” Please elaborate how “Fire Protection Program” would manage loss of material and explain why the associated Table 2 line items didn’t credit this? Please also compare the heat exchanger (housing) inspection frequency difference between the “Periodic Surveillance and Preventive Maintenance Program,” proposed by IP and “External Surfaces Monitoring,” recommended by the GALL Report.
3.2-7-Wen	Regarding Table 1 Items 3.2.1-37: please explain why “Periodic Surveillance and Preventive Maintenance Program” is equivalent to GALL recommended AMP (Open-Cycle Cooling Water System) for managing aging effect of loss of material for containment sump piping and valve body (GALL Report item (V.A-19)).
3.2-8-Wen	The “Discussion Column” of LRA Table 1 Items 3.2.1-50 states that this line item is consistent with the GALL Report. Explain why no associated Table 2 line items is liked to this Table 1 line item?
3.2-9-Wen	IP2 and IP3 both have two line items of bolting (one in RHR system and the other in Containment Spray system) that reference Table 1 line item 3.2.1-57. These bolting have “pressure boundary” intended function. Please explain why “Bolting Integrity Program” is not credited for these bolting?
3.3-1-Morante	LRA Table 1 item 3.3.1-1: How is SRP 4.7 generic guidance implemented to address cumulative fatigue damage of "steel cranes-structural girders?
3.3-2-Morante	LRA Table 1 item 3.3.1-5 states that the only stainless steel heat exchanger components exposed to treated water in the auxiliary systems are in the steam generator secondary side sample coolers, which are addressed in other lines. Where and how is this addressed?
3.3-3-Morante	LRA Table 1 item 3.3.1-6: Does the diesel exhaust piping have an intended function for LR? Define. Is it subject to aging management under any credited AMP?
3.3-4-Morante	LRA Table 1 item 3.3.1-8: Confirm that the Inservice Inspection Program mentioned in the first paragraph is credited for managing cracking due to SCC for the regenerative heat exchanger components, consistent with the reactor coolant systems in series 3.1.2-x tables. Correct the second paragraph to be consistent with this.

3.3-5-Morante	LRA Table 1 items 3.3.1-10, -41: Compare the bolting used in IP 2/3 auxiliary systems to the high-strength bolting addressed by this GALL Table 1 line item. Are the IP 2/3 bolts replaced during maintenance?
3.3-6-Morante	LRA Table 1 item 3.3.1-15,-16: LRA Section 3.3.2.2.7 item 1 states "Steel piping components and tanks of the reactor coolant pump oil collection system are not continuously exposed to a lubricating oil environment that is maintained by the Oil Analysis Program. Therefore this program is not credited for managing loss of material on these components. Instead these components are managed by the One-Time Inspection Program. This program will use visual or volumetric NDE techniques to inspect a representative sample of the internal surfaces to assure there is no significant corrosion." The OTI program is NOT a program that manages aging. It confirms the absence of degradation. If degradation is found, then an aging management program needs to be developed. Revise the LRA accordingly and identify what actions will be taken if degradation is discovered by the OTI.
3.3-7-Morante	LRA Table 1 item 3.3.1-42: Does IP 2/3 have bolting exposed to air with steam or water leakage in Auxiliary Systems? If yes, why is this line item not used?
3.3-8-Morante	LRA Table 1 item 3.3.1-45: How is loss of preload currently managed at IP 2/3, if not by the existing Bolting Integrity Program? Describe the IP 2/3 operating experience with loss of bolt pre-load. How is the absence of loss of bolt pre-load confirmed?
3.3-9-Morante	LRA Table 1 items 3.3.1-46, 47, 50, 51 and 52 state that the One-Time Inspection Program for Water Chemistry will use visual inspections or non-destructive examinations of representative samples to verify that the Water Chemistry Control – Auxiliary Systems and Water Chemistry Control – Closed Cooling Water Programs have been effective at managing aging effects. Explain why Table 2 line items that reference Table 1 items 3.3.1-46, 47, 50, 51 and 52 do not refer to OTI.
3.3-10-Morante	LRA Table 1 item 3.3.1-53: Compare the Periodic Surveillance and Preventive Maintenance Program, which is credited to manage loss of material for carbon steel station air system components exposed internally to condensation, to the GALL- recommended Compressed Air Monitoring Program.
3.3-11-Morante	LRA Table 1 item 3.3.1-54: GALL recommends a periodic monitoring program (Compressed Air Monitoring) for this line item. Explain why confirmation of the lack of degradation is sufficient for IP 2/3.
3.3-12-Morante	LRA Table 1 item 3.3.1-72: Identify and describe the applications of the External Surfaces Monitoring Program to manage loss of material for internal surfaces exposed to condensation. How is the environment determined to be the "same"?

3.3-3-Morante	LRA Table 1 item 3.3.1-79: Explain the differences between those components that require the Service Water Integrity AMP and those components that only require OTI confirmation of lack of degradation. The material, environment, and function appear to be the same in both cases.
3.3-14-Morante	In accordance with Table 1 item 3.3.1-87, the Boraflex Monitoring Program, supplemented by the Water Chemistry Control – Primary and Secondary Program, manages the degradation of Boraflex. LRA Table 3.3.2-1-IP2/3 credits Water Chemistry Control for managing loss of material and cracking and Boraflex Monitoring for change in material properties. Confirm that the Boraflex Monitoring Program, supplemented by the Water Chemistry Control – Primary and Secondary Program manages all three Table 2 items addressing loss of material, cracking and change in material properties.
3.3-15-Morante	In accordance with LRA Table 1 item 3.3.1-13, the Boral Surveillance Program, supplemented by the Water Chemistry Control – Primary and Secondary Program, manages the degradation of Boral including the reduction of neutron-absorbing capacity. Confirm that the Table 3.3.2-1-IP2/3 line item also includes the aging effect reduction of neutron-absorbing capacity.
3.3-16-Morante	In LRA Table 3.3.2-2-IP2/3 one line item for Cu alloy (>15% Zn) HX tubes exposed to treated water (ext), Service Water Integrity manages loss of material due to wear. Explain how the Service Water Integrity AMP manages components exposed to treated water.
3.3-17-Morante	In LRA Table 3.3.2-3-IP2/3 for Cu alloy (>15% Zn) HX tubes exposed to treated water (ext), there are two line items, one credits HX Monitoring and the other Service Water Integrity, to manage the same aging effect (loss of material due to wear). Explain the difference.
3.3-18-Morante	LRA Table 1 items 3.3.1-7and -8 indicate that the water chemistry program is augmented by the One-Time Inspection Program, which will verify the absence of cracking. . Explain why Table 2 line items in Table 3.3.2-6-IP2/3 and for other systems referring to these Table 1 items do not credit OTI.
3.3-19-Morante	Provide technical justification why One-Time Inspection is not credited for verifying the effectiveness of the Oil Analysis AMP to manage cracking in stainless steel components exposed to lubricating oil, as listed in LRA Tables 3.3.2.14-IP2, 3.3.2.14-IP3, and 3.3.2.16-IP3.
3.3-20-Morante	LRA Tables 3.3.2-11-IP2, -IP3, 3.3.2-14-IP2, -IP3, 3.3.2-15-IP2, -IP3, and 3.3.2-16-IP2, -IP3 all identify the aging effect “cracking-fatigue” associated with the environment “exhaust gas (int.)”. The components are all parts of exhaust systems for diesel generators. Three different approaches are identified for aging management: Fire Protection AMP in Tables 3.3.2-11-IP2, -IP3; Periodic Surveillance and Preventive Maintenance AMP in Tables 3.3.2-15-IP2, -IP3 and 3.3.2-

	16-IP3; TLAA-Metal Fatigue in Tables 3.3.2-14-IP2, -IP3 and 3.3.2-16-IP2. Describe the physical behavior that results in cracking due to fatigue, and the basis for the selected approach to managing this aging effect, for each of these 8 systems. Identify where in the LRA the applicable TLAAs are described. Also identify the associated TLAA documents that will be available for audit.
3.3-21-Morante	In the series of LRA Tables 3.3.2-19-xx-IP2 and 3.3.2-19-xx-IP3, there are numerous line items (over 100) that specify “cracking-fatigue” as the aging effect and “TLAA-metal fatigue” as the aging management program. The components are mostly piping and valve bodies, but also include tubing, filter housing, heater housing, strainer housing, steam trap, flex joint, sight glass, thermowell, and flow element. Identify where in the LRA the applicable TLAAs are described. Also identify the associated TLAA documents that will be available for audit.
3.4-1-Arora	The GALL Report (NUREG-1801) includes the Steam Turbine System and Extraction Steam System as part of the steam and power conversion system. Why are these two systems not included in the scope description of Steam and power conversion System, Section 3.4, included in Indian Point license renewal application?
3.4-2-Arora	LRA Section 3.4.2.1, Materials, Environment, Aging Effects Requiring management and Aging Management Programs includes the list of AMPs applicable to each system covered under Section 3.4, Steam and Power Conversion Systems. It is observed that One-Time Inspection AMP is missing from the AMP lists provided for the Main Steam, Main Feedwater and Steam Generator Blowdown Systems. Since the GALL Report (NUREG-1801) recommends that One-Time Inspection Program is to be used to verify the effectiveness of Water Chemistry Control Program used by Indian Point in these systems, the list should have included One-Time Inspection along with the other AMPs to complete the list. Explain if Indian Point has a justification for not including One-Time Inspection Program in the lists of applicable programs.
3.4-3-Arora	LRA Tables 3.4.2-1-IP2 and 3.4.2-1-IP3 (Main Steam System) include several items pertaining to carbon steel and stainless steel piping, piping components, and elements that are exposed to indoor air environment. Does this piping (and piping components and elements) have bare surface exposed to the indoor air or is this piping insulated? If the piping has insulation, it’s not directly exposed to the indoor air and the applicable line items will required to be revised.
3.4-4-Arora	In LRA Tables 3.4.2-X and 3.3.2-19-X, for several line items pertaining to carbon steel piping, piping components, and piping elements, Indian Point has utilized the GALL Report line item 3.4.1-29 for managing flow-accelerated corrosion. The “Aging Effect Requiring Management” columns in these tables indicate “loss of material” as the Aging Effect. To be consistent with the terminology used in GALL Table 4, Item 29, the “Aging Effect/Mechanism” should state “Wall thinning due to flow-accelerated corrosion” as the aging effect. All pertinent line items in the IP

tables pertaining to the Flow-Accelerated Corrosion Program need to be corrected. Some examples of the IP2/IP3 tables to which this change applies are: 3.4.2-1-IP2, 3.4.2-1-IP3, 3.4.2-2-IP2, 3.4.2-2-IP3, 3.4.2-3-IP2, 3.4.2-3-IP3, 3.4.2-4-IP2, 3.4.2-4-IP3, and several 3.3.2-19-X tables.

3.4-5-Arora

Each LRA Table 3.4.2-1-IP2 and 3.4.2-1-IP3, Main Steam System, includes one line item pertaining to carbon steel piping externally exposed to “indoor air” with the aging effect listed as “none” and Table 1 item listed as “3.4.1-28” with notes “I & 401” in the last column. Note “I” implies that the aging effect in NUREG-1801 for this component, material, and environment combination is not applicable and Note “401” implies that these components remain at high temperature during normal operation which precludes moisture condensation and the resulting corrosion. The next line item in these Tables is for the carbon steel pipe with internal exposure to “indoor air” with the aging effect listed as “loss of material” and Table 1 item listed as “3.2.1-32” and Note “E” in the last column. Note “E” implies that a different management program is credited for this line item. The aging management program included in these Tables for the second line item is “External Surfaces Monitoring.” The aging management program used in GALL Report for line 3.2.1-32 is “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.”

The following three questions apply to the situation described above:

a. Do these two line items described above represent the same piping, one line covering the internal and the other the external environment? Describe the function of this piping in the main steam system.

b. What kind of indoor air is flowing through the piping that the high temperature stated in Note 401 is maintained in the piping? How the absence of corrosion is ascertained when the system cools down, e.g., during the plant shut down, refueling outages, and start up mode prior to attaining the normal operation high temperature mentioned in the Note?

c. Explain how the “External Surfaces Monitoring” Program stated in the Table is used by IP to monitor the loss of material on the “internal” surface of the subject piping?

3.4-6-Arora

Each LRA Table 3.4.2-1-IP2 and 3.4.2-1-IP3, Main Steam System, includes one line item pertaining to carbon steel bolting externally exposed to “indoor air” with the aging effect listed as “none” and Table 1 item listed as “3.4.1-22” with notes “I & 401” in the last column. Note “I” implies that the aging effect in NUREG-1801 for this component, material, and environment combination is not applicable and Note “401” implies that these components remain at high temperature during normal operation which precludes moisture condensation and the resulting corrosion.

The following questions apply to the situation described above:

a. Which component or equipment in the main steam system these bolts are installed on? Describe how the high temperature as stated in Note “401” is maintained during the normal operation. Also explain how the absence of corrosion is ascertained when the system piping and the equipment on which this bolting is installed cools down, e.g., during the plant shut down, refueling outages, and the start up mode prior to attaining the normal operation high temperature mentioned in the Note.

b. The GALL line item 3.4.1-22, as stated in the above tables, recommends the “Bolting Integrity Program” to manage the loss of material due to general, pitting and crevice corrosion in addition to loss of preload due to thermal effects and gasket creep and self loosening for the stated component, material, and environment combination. Explain how these aging effects are not applicable to the bolting in question. If IP is managing this aging effect/mechanism under the other programs, please identify such programs.

3.4-7-Arora	In LRA Table 3.4.1, Item 3.4.1-11 states in the discussion column that this line item is consistent with NUREG-1801. IP plans to use “Buried Piping and Tanks Inspection” Program to manage “loss of material” aging effect as recommended by the GALL. The GALL Report recommends, under “Further Evaluation Recommended,” that detection of aging effects and operating experience are to be further evaluated. Describe the operating experience that IP has in the area of handling buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil and how this plant specific and industry operating experience is planned to be evaluated and utilized in the developing this “new” program.
3.4-8-Arora	LRA Table 3.4.1, Item 3.4.1-30, which pertains to steel piping, piping components, and piping elements, exposed to air outdoor (internal) or condensation (internal), has been used by IP for the condensate storage tanks for Units 2 and 3. The vapor space of these tanks is nitrogen blanketed per the discussion provided in the table for this line item. The specific “Note 402” applied to these tanks states that the tank vapor space is conservatively assumed to be condensation. The GALL recommends steel tanks to be managed for “loss of material due to general, pitting and crevice corrosion” under line item number 3.4.1-6. Explain if IP’s aging management program for these steel tanks follows the recommendations of the GALL line item 3.4.1-6 also in addition to those of line item 3.4.1-30.
3.5-1-Morante	Confirm that all component type/aging effect combinations that credit the SMP for aging management in Tables 3.5.2-1 thru -4 are included in the scope of the SMP and are inspected for the designated aging effect. Identify the document(s) available for audit that includes this information.
3.5-2-Morante	Why is Note E specified for Table 3.5.2- 1 and 3.5.2-4 line items that reference IWE, IWL, and IWF as the aging management program?

3.5-3-Morante	In Tables 3.5.2-1 thru -4, why are the "Table 1 Item" and "NUREG-1801 Vol. 2 Item" columns blank for all cases where the "Note" column specifies "I, 501"? All of these Table 2 line items have applicable entries for these 2 columns. The implication by leaving them blank is that GALL does not address them. This is not the case. The applicant has taken exception to the GALL "Aging Effects Requiring Management". Revise the 3.5.2 Tables accordingly.
3.5-4-Morante	Plant Specific Note 501 states "The IPEC environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation." The Table 2 line items indicate "None" for the aging effects. Does the identified AMP confirm the absence of loss of material, cracking, and change in material properties? Revise the note accordingly.
3.5-5-Morante	Plant Specific Note 502 states "Loss of insulating characteristics due to insulation degradation is not an aging effect requiring management for insulation material. Insulation products, which are made from fiberglass fiber, calcium silicate, stainless steel, and similar materials, in an air – indoor uncontrolled environment do not experience aging effects that would significantly degrade their ability to insulate as designed. A review of site operating experience identified no aging effects for insulation used at IPEC." Discuss moisture/humidity effects on the insulating characteristics of the insulation material. Discuss the containment internal environment, in the area where the containment insulation is attached. Is the insulation exposed to moisture/humidity? How is this potential aging effect managed?
3.5-6-Morante	For Table 1 items 3.5.1-57 and 3.5.1-41, confirm there are no HVAC components that are vibration-isolation mounted in the IP 2/3 LR scope.
3.5-7-Morante	In reference to Table 1 item 3.5.1-54, confirm that the IWF program at IP 2/3 currently inspects for loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads, and that IWF will continue to inspect for this condition during the LR period.
3.5-8-Morante	In reference to Table 1 item 3.5.1-51, are the nominal yield strengths or the actual yield strengths below 150 ksi? Identify the document(s) available for audit that confirms the actual bolt material strengths.
3.5-9-Morante	In reference to Table 1 item 3.5.1-48, describe the materials of construction for all water control structures in the IP 2/3 LR scope. Are there earthen intake and discharge canals? Does Entergy conduct 5-year underwater inspections of these structures?
3.5-10-Morante	In reference to Table 1 item 3.5.1-34, are any water control structures in the IP 2/3 LR scope exposed to raw service water (ultimate heat sink)? How is increase in porosity and permeability, cracking, and loss of material due to aggressive chemical attack managed for these

structures? Does Entergy conduct 5-year underwater inspections of these structures?

3.5-11-Morante	In reference to Table 1 item 3.5.1-32, why is SMP not credited for accessible areas? Does IP 2/3 meet the criteria in ACI 201.2R-77? If not, how are inaccessible areas managed for aging?
3.5-12-Morante	In reference to Table 1 item 3.5.1-31, why is SMP not credited for accessible areas? Does IP 2/3 meet the groundwater criteria for a non-aggressive environment? Does IP 2/3 have a program for sampling of below-grade concrete for signs of degradation? Provide the details of the program.
3.5-13-Morante	In reference to Table 1 items 3.5.1-23,-24,-26,-27, why is the phrase "except Group 6" included here, considering that the SMP is being credited for managing aging of Group 6 structures?
3.5-14-Morante	In reference to Table 1 item 3.5.1-26, is IP 2/3 located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) ? If so, why is freeze-thaw not applicable?
3.5-15-Morante	In reference to Table 1 item 3.5.1-6, IWE should be credited instead of IWL. Please correct.
3.6-1-Nguyen	Provide an AMR for long-lived components and structures for the revised secondary SBO recovery path. This path is from the switchyard circuit breakers to onsite electrical distribution system including the associated control circuits and structures.
3.6-2-Nguyen	In LRA, Table 3.6.2-1, under Transmission conductors and connections for SBO recovery, you have stated that no aging effects requiring management and no AMP is required. You have also stated that the IPEC transmission conductors subject to AMR were bounded by the Ontario Hydro test. NUREG 1800, Rev. 1, Section 3.6.2.2.3 identifies loss of conductor strength due to corrosion is the aging effect of high voltage transmission conductor. Explain in detail how the test conducted by Ontario Hydro study is valid for your plant. Include plant specific acceptance criteria for transmission conductor strength in your response.
3.6-3-Nguyen	In LRA, Table 3.6.2-1, under 138 kV direct buried insulated transmission cable, you have stated that no aging effect requiring management and no AMP is required. You also states through Note 602 that based on vendor information, this transmission cable is not subject to water treeing, since it is designed for continuously wet conditions. Address the following: a. How is positive oil pressure maintained in the pot heads to prevent any moisture intrusion? b. How is the property of the oil in the pot head maintained to the manufacturer's specifications?

c. Provide details of periodic visual inspections and walk down performed and proposal for monitoring for oil leakage including checking tightness of the pothead bolted connections.

d. Provide manufacturer specifications that this cable is qualified for continuously wet conditions.