IPRenewal NPEmails

From: Green, Kimberly
Sent: Thursday, December 02, 2010 5:47 PM
To: STROUD, MICHAEL D
Cc: IPRenewal NPEmails; Holston, William; Ng, Ching; Yee, On; Doutt, Clifford
Subject: Draft RAIs
Attachments: Draft RAIs on GALL Rev.2.doc

Mike,

Attached are draft RAIs. Please review and let me know if you need a telephone conference call to discuss them. The purpose of the call would be to obtain any clarification on the draft RAI.

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Hearing Identifier: IndianPointUnits2and3NonPublic_EX
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Subject: Draft RAIs
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From: Green, Kimberly

Created By: Kimberly.Green@nrc.gov

Recipients:
"IPRenewal NPEmails" <IPRenewal.NPEmails@nrc.gov>
Tracking Status: None
"Holston, William" <William.Holston@nrc.gov>
Tracking Status: None
"Ng, Ching" <Ching.Ng@nrc.gov>
Tracking Status: None
"Yee, On" <On.Yee@nrc.gov>
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"Doutt, Clifford" <Clifford.Doutt@nrc.gov>
Tracking Status: None
"STROUD, MICHAEL D" <MSTROUD@entergy.com>
Tracking Status: None

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Options
Priority: Standard
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D-RAI 3.0.3.1.2-1

Background

In light of Operating Experience (OE) that has occurred coincident with and after the staff evaluation of the Indian Point License Renewal Application (LRA) and issuance of the Safety Evaluation Report (SER), the staff is concerned about the continued susceptibility to failure of buried (i.e., piping in direct contact with soil) and/or underground piping (i.e., piping not in direct contact with soil, but located below grade in a vault, pipe chase, or other structure where it is exposed to air and where access is limited) that is within the scope of 10 CFR 54.4 and subject to aging management for license renewal. The staff reviewed the LRA, SER and a letter dated July 27, 2009 from the applicant addressing buried pipe program modifications as a result of recent site operating experience. Based on the review of these documents subsequent to the recent industry OE, the staff does not have enough information to evaluate how Indian Point is implementing changes to their program based on the industry experience.

Issue

1. The LRA and supplemental material did not contain enough specifics on the planned inspections for the staff to determine if the inspections would be adequate to manage the aging effect for all types/materials of in-scope buried pipes (e.g., safety/code class and potential to release materials detrimental to the environment (e.g., diesel fuel and radioisotopes that exceed Environmental Protection Agency (EPA) drinking water standards)).
2. The staff believes that buried coated steel piping is more susceptible to potential failure if it is not protected by a cathodic protection system unless soil resistivity is greater than 20,000 ohm-cm.
3. The LRA and supplemental material did not contain enough specifics for the staff to understand the general condition of the backfill used in the vicinity of buried in-scope piping.
4. In a letter dated July 27, 2009, the applicant stated that it will employ qualified inspection methods with demonstrated effectiveness for detection of aging effects during the period of extended operation. The staff acknowledges that where examining buried pipe from the exterior surface is not possible due to plant configuration (e.g., the piping is located underneath foundations) it is reasonable to substitute a volumetric examination from the interior of the pipe provided the surface is properly prepared. However, beyond ultrasonic techniques, the staff is not aware of another reliable volumetric inspection methodology that is suitable for inspecting buried in scope piping. This is particularly true, in light of industry experience, with guided wave ultrasonic technology.
5. Based on a review of the LRA and UFSAR, it is not clear to the staff what in-scope systems (if any) have underground piping or if such piping will receive inspections consistent with the program described in LRA AMP B.1.11 External Surfaces Monitoring Program.

Request

1. Respond to the following:
    a. Describe how many in-scope buried piping segments for each material, code/safety-related piping, and potential to release materials detrimental to the environment category will be inspected.
    b. For the 45 planned inspections prior to the period of extended operation:

i. How many will consist of an excavated direct visual inspection of the external surfaces of the buried pipe?
ii. What length of piping will be excavated and have a direct visual inspection conducted?

c. Understanding that the total number of inspections performed will be informed by plant-specific and industry operating experience, what minimum number of inspections of buried in-scope piping is planned during the 40 – 50 and 50 – 60 year operating periods? When describing the minimum number of planned inspections, differentiate between material, code/safety-related piping, and potential to release materials detrimental to the environment category piping inspection quantities of buried in-scope piping.

d. What specific inspections will be performed for the IP3 security generator propane tank and at what frequency?

2. Respond to the following:

a. Confirm at IP2 that the service water system and at IP3 that the service water suction piping are the only in-scope steel piping systems currently protected by a cathodic protection (CP) system.

b. For those systems that are protected by a CP system: (a) Has annual NACE survey testing been conducted, and if so, for how many years? (b) Have the output of the beds been trended, and if so, what are the results of the trending? (c) What is the availability of the cathodic protection system?

c. For buried in-scope steel piping systems that are not cathodically protected:

i. Justify why this piping will continue to meet or exceed the minimum design wall thickness throughout the period of extended operation, assuming that no coatings are applied to the piping, or
ii. Justify why the number of the planned inspections of this piping is sufficient to reasonably assure that this piping will continue to meet or exceed the minimum design wall thickness throughout the period of extended operation.

3. Respond to the following:

a. Provide details on any further excavations conducted since July 2009 that provide insight on the extent of condition of the quality of the backfill in the vicinity of buried pipes.

b. If there is no further information on the condition of the quality of backfill, justify why the planned inspections are adequate to detect potential degradation as a result of coating damage, particularly in steel buried pipe systems that are not protected by a CP system.

4. Respond to the following:

a. In absence of a qualified method, and until such time that one is demonstrated to be effective, what alternative inspection methods will Entergy employ when excavated direct visual examinations are not possible due to plant configuration.

b. Justify why the methods identified in response to request 4a will be effective at providing reasonable assurance that the buried in-scope piping systems will meet their current licensing basis function.

c. If a volumetric examination method is used, what percentage of interior axial length of the pipe will be inspected?

5. For in-scope <u>underground</u> piping, respond to the following:

a. State what systems have underground piping and indicate the corresponding length of piping

b. State how often and what quantity of underground piping for each system will be inspected by AMP, and indicate which AMP will be used.

D-RAI 3.0.3.1.6-1

Background

NUREG-1801, Rev. 1, "Generic Aging Lessons Learned," (the GALL Report) addresses inaccessible medium voltage cables in Aging Management Program (AMP) XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The purpose of this program is to provide reasonable assurance that the intended functions of inaccessible medium voltage cables (2 kV to 35 kV), that are not subject to environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized, will be maintained consistent with the current licensing basis. The scope of the program applies to inaccessible (in conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installations) medium-voltage cables within the scope of license renewal that are subject to significant moisture simultaneously with significant voltage.

The application of AMP XI.E3 to medium voltage cables was based on the operating experience available at the time Revision 1 of the GALL Report was developed. However, recently identified industry operating experience indicates that the presence of water or moisture can be a contributing factor in inaccessible power cables failures at lower service voltages (480 V to 2 kV). Applicable operating experience was identified in licensee responses to Generic Letter (GL) 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," which included failures of power cable operating at service voltages of less than 2 kV where water was considered a contributing factor.

Recently identified industry operating experience provided by NRC licensees in response to GL 2007-01 has shown: (a) that there is an increasing trend of cable failures with length in service beginning in the 6th through 10th years of operation and, (b) that moisture intrusion is the predominant factor contributing to cable failure. The staff has determined, based on the review of the cable failure distribution, that an annual inspection of manholes and a cable test frequency of at least every 6 years is a conservative approach to ensuring the operability of power cables and, therefore, should be considered.

In addition, recently identified industry operating experience has shown that some NRC licensees may experience cable manhole water intrusion events, such as flooding or heavy rain, that subjects cables within the scope of program for GALL Report XI.E3 to significant moisture. The staff has determined that event driven inspections of cable manholes, in addition to a 1 year periodic inspection frequency, is a conservative approach and, therefore, should be considered.

Issue

The staff has concluded, based on recently identified industry operating experience concerning the failure of inaccessible low voltage power cables (480 V to 2 kV) in the presence of significant moisture, that these cables can potentially experience age related degradation. The staff noted that the applicant's Inaccessible Medium-Voltage Cables Program does not address inaccessible low voltage power cables [400 V (nominally 480 V) to 2 kV inclusive]. In addition, more frequent cable test and cable manhole inspection frequencies (e.g., from 10 and two years to six and one year, respectively) should be evaluated to ensure that the Non-EQ Inaccessible Medium Voltage Cable program test and inspection frequencies reflect industry and plant-

specific operating experience and that test and inspection frequencies may be increased based on future industry and plant-specific operating experience.

Request

Provide a summary of your evaluation of recently identified industry operating experience and any plant-specific operating experience concerning inaccessible low voltage power cable failures within the scope of license renewal (not subject to 10 CFR 50.49 environmental qualification requirements), and how this operating experience applies to the need for additional aging management activities at your plant for such cables.

1. Explain how Entergy will manage the effects of aging on inaccessible low voltage power cables within the scope of license renewal and subject to aging management review; with consideration of recently identified industry operating experience and any plant-specific operating experience. The discussion should include assessment of your aging management program description, program elements (i.e., Scope of Program, Parameters Monitored/Inspected, Detection of Aging Effects, and Corrective Actions), and FSAR summary description to demonstrate reasonable assurance that the intended functions of inaccessible low voltage power cables subject to adverse localized environments will be maintained consistent with the current licensing basis through the period of extended operation.

2. Provide an evaluation showing that the proposed Non-EQ Inaccessible Medium-Voltage Cable program test and inspection frequencies, including event-driven inspections, incorporate recent industry and plant-specific operating experience for both inaccessible low and medium voltage cable.

3. In Commitment 40, Entergy committed to evaluate plant-specific and industry operating experience prior to entering the period of extended operation. Explain how the proposed Inaccessible Medium Voltage Program will continue to ensure that future industry and plant-specific operating experience will be incorporated into the program such that inspection and test frequencies may be increased based on test and inspection results.

D-RAI 3.1.2.2.13-1

Background

SRP-LR Section 3.1.2.2.13 identifies that cracking due to primary water stress corrosion cracking (PWSCC) could occur in PWR components made of nickel alloy and steel with nickel alloy cladding, including reactor coolant pressure boundary components and penetrations inside the RCS such as pressurizer heater sheathes and sleeves, nozzles, and other internal components. GALL Report Volume 2 Item IV.D1-06 recommends Chapter XI.M2, "Water Chemistry," for PWR primary water to manage the aging effect of cracking in the nickel alloy steam generator (SG) divider plate exposed to reactor coolant.

LRA Table 3.1.1, item 3.1.1-81, credits the Water Chemistry Control – Primary and Secondary Program to manage cracking due to primary stress corrosion cracking in nickel-alloy steam generator primary channel head divider plate exposed to reactor coolant in the steam generators, and LRA Table 3.1.1, Item 82, indicates that the SG primary side divider plates are composed of nickel alloy.

Unit 2 FSAR Section 4.2.2.3 and Table 4.2-1 describe the construction materials for the replacement Model 44F steam generators. The staff noted that there is no information about the construction materials of the divider plate assembly for the Unit 2 steam generators.

Unit 3 FSAR Section 4.2.2 and Table 4.2-1 describe the construction materials for the replacement Model 44F steam generators. The staff noted that there is no information about the construction materials of the divider plate assembly for the Unit 3 steam generators.

Issue

In some foreign steam generators with a similar design to that of Indian Point Units 2 and 3 steam generators, extensive cracking due to PWSCC has been identified in SG divider plate assemblies made with Alloy 600, even with proper primary water chemistry. Specifically, cracks have been detected in the stub runner, very close to the tubesheet/stub runner weld and with depths of almost a third of the divider plate thickness. Therefore, the staff noted that the Water Chemistry Control – Primary and Secondary Program may not be effective in managing the aging effect of cracking due to PWSCC in SG divider plate assemblies.

Although these SG divider plate assembly cracks may not have a significant safety impact in and of themselves, such cracks could affect adjacent items that are part of the reactor coolant pressure boundary, such as the tubesheet and the channel head, if they propagate to the boundary with these items. For the tubesheet, PWSCC cracks in the divider plate could propagate to the tubesheet cladding with possible consequences to the integrity of the tube-to-tubesheet welds. For the channel head, the PWSCC cracks in the divider plate could propagate to the SG triple point and potentially affect the pressure boundary of the SG channel head.

Request

1. Discuss the materials of construction of the Units 2 and 3 SG divider plate assemblies, including the welds within these assemblies and to the channel head and to the tubesheet.

2. If any constitutive/weld material of the SG divider plate assemblies is susceptible to cracking (e.g., Alloy 600 or the associated Alloy 600 weld materials), explain how Entergy plans to manage PWSCC of the SG divider plate assemblies to prevent the propagation of cracks into other items that are part of the RCPB, whereby it challenges the integrity of the adjacent items.

D-RAI 3.1.2.2.16-1

Background

SRP-LR Section 3.1.2.2.16 identifies that cracking due to primary water stress corrosion cracking (PWSCC) could occur on the primary coolant side of PWR steel steam generator (SG) tube-to-tube sheet welds made or clad with nickel alloy. The GALL Report recommends ASME Section XI ISI and control of water chemistry to manage this aging effect and recommends no further aging management review for PWSCC of nickel alloy if the applicant complies with applicable NRC Orders and provides a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines. In GALL Report Revision 1, Volume 2, this aging effect is addressed in item IV.D2-4, applicable only to once-through SGs, but not to recirculating SGs.

The staff noted that ASME Code Section XI does not require any inspection of the tube-to-tubesheet welds. In addition, there are no NRC Orders or bulletins requiring examination of this weld. However, the staff's concern is that, if the tubesheet cladding is Alloy 600 or the associated Alloy 600 weld materials, the tube-to-tubesheet weld region may have insufficient Chromium content to prevent initiation of PWSCC. Similarly, this concern applies to SG tubes made from Alloy 690TT. Consequently, such a PWSCC crack initiated in this region, close to a tube, could propagate into/through the weld, causing a failure of the weld and of the reactor coolant pressure boundary, for both recirculating and once-through steam generators.

In LRA Table 3.1.1, item 3.1.1-35, the applicant stated that the corresponding GALL Report line applies to once-through steam generators and was used as a comparison for the steam generator tubesheets. The applicant further stated that for the steel with nickel alloy clad steam generator tubesheets, cracking is managed by the Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs.

In LRA Section 2.3.1.4, the applicant described that the Unit 2 replacement Westinghouse Model 44 steam generator tubes are fabricated from Alloy 600TT and the Unit 3 replacement Westinghouse Model 44 steam generator tubes are fabricated from Alloy 690TT. The applicant also described that the tubesheet surfaces in contact with reactor coolant are clad with Inconel, and the tube-to-tube sheet joints are welded.

Issue

Unless the NRC has approved a redefinition of the pressure boundary in which the autogenous tube-to-tubesheet weld is no longer included, or the tubesheet cladding and welds are not susceptible to PWSCC, the staff considers that the effectiveness of the primary water chemistry program should be verified to ensure PWSCC cracking is not occurring. Moreover, it is not clear to the staff how the Steam Generator Integrity Program is able to manage PWSCC of the tubesheet cladding, including the tube-to-tubesheet welds.

Request

1a. For Unit 2 SGs, clarify whether the tube-to-tubesheet welds are included in the reactor coolant pressure boundary or alternate repair criteria have been permanently approved.

1b. If the SGs do not have permanently approved alternate repair criteria, justify how your Steam Generator Integrity Program is capable to manage PWSCC in tube-to-tubesheet welds, or provide a plant-specific AMP that will complement the primary water chemistry program, in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds.

2. For Unit 3 SGs tube-to-tubesheet welds, justify how your Steam Generator Integrity Program is capable to manage PWSCC in tube-to-tubesheet welds, or provide either a plant-specific AMP that will complement the primary water chemistry program, in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds, or a rationale for why such a program is not needed.

D-RAI RCS-3

Background

In LRA Section 4.3.3 and Commitment 33 (as amended by the letter dated January 22, 2008) the applicant discussed the methodology used to determine the locations that required environmentally-assisted fatigue analyses consistent with NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The staff recognized that, in LRA Tables 4.3-13 and 4.3-14, there are eight plant-specific locations listed based on the six generic components identified in NUREG/CR-6260. The applicant also discussed in LRA Tables 4.3-13 and 4.3-14 that the surge line nozzle in the RCS piping is bounded by the surge line piping to safe end weld at the pressurizer nozzle. LRA Section 4.3.3 and Commitment 33 were amended as follow:

> At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3, IPEC will implement one or more of the following:
>
> > (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following.
> >
> > For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3) with existing fatigue analysis valid for the period of extended operation, use the existing CUF.
> >
> > More plant-specific limiting locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component.

Representative CUF values from other plants, adjusted to or enveloping the IPEC plant-specific external loads may be used if demonstrated applicable to IPEC.

An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.

Issue

GALL AMP X.M1 states the impact of the reactor coolant environment on a sample of critical components should include the locations identified in NUREG/CR-6260, as a minimum, and that additional locations may be needed. The staff identified two concerns regarding the applicant's environmentally-assisted fatigue analyses. First, item (1) of above LRA section and Commitment 33 indicated that more limiting plant-specific locations may be evaluated. However, it is only one of the *options* that may be taken. Furthermore, the limiting locations *may* be added and the staff is concerned whether the applicant is committed to verify that the plant-specific locations per NUREG/CR-6260 are bounding for the generic NUREG/CR-6260 components. Second, the staff noted that the applicant's plant-specific configuration may contain locations that should be analyzed for the effects of reactor coolant environment, that are more limiting than those identified in NUREG/CR-6260. This may include locations that are limiting or bounding for a particular plant-specific configuration or that have calculated CUF values that are greater when compared to the locations identified in NUREG/CR-6260.

Request

1. Confirm and justify that the plant-specific locations listed in LRA Tables 4.3-13 and 4.3-14 are bounding for the generic NUREG/CR-6260 components.

2. Confirm and justify that the locations selected for environmentally-assisted fatigue analyses in LRA Tables 4.3-13 and 4.3-14 consist of the most limiting locations *for the plant* (beyond the generic components identified in the NUREG/CR-6260 guidance). If these locations are not bounding, clarify which locations require an environmentally-assisted fatigue analysis and the actions that will be taken for these additional locations. If the limiting locations identified consist of nickel alloy, state whether the methodology used to perform environmentally-assisted fatigue calculation for nickel alloy is consistent with NUREG/CR-6909. If not, justify the method chosen.