NYS000152
Submitted: December 15, 2011

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel (914) 788-2055

Fred Dacimo
Vice President
Operations License Renewal

NL-11-074

July 14, 2011

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

SUBJECT: Response to Request for Additional Information (RAI)
Aging Management Programs
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

REFERENCE:

1. NRC Letter, "Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Numbers 2 and 3, License Renewal Application," dated June 15, 2011

2. Entergy letter (NL-11-032)," Response to Request for Additional Information (RAI) Aging Management Programs," dated March 28, 2011

Dear Sir or Madam:

Entergy Nuclear Operations, Inc is providing, in Attachment 1, the response to the reference 1 request for additional information (RAI). Attachment 2 provides the updated listing of regulatory commitments for license renewal.

If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-734-6710.

A128
NLR

I declare under penalty of perjury that the foregoing is true and correct. Executed on
July 14, 2011

Sincerely,

FRD/cbr

Attachment: 1. Response to Request for Additional Information (RAI), Aging Management Programs

2. IPEC List of Regulatory Commitments (Rev. 14)

cc: Mr. William Dean, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. Dave Wrona, NRC Branch Chief, Engineering Review Branch I
Mr. John Boska, NRR Senior Project Manager
Mr. Paul Eddy, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. Francis J. Murray, Jr., President and CEO NYSERDA

ATTACHMENT 1 TO NL-11-074

LICENSE RENEWAL APPLICATION
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)
AGING MANAGEMENT PROGRAMS

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

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)
AGING MANAGEMENT PROGRAMS

RAI 3.0.3.1.2-2

Background:

The response to RAI 3.0.3.1.2-1 dated March 28, 2011, proposed to manage the effects of aging for buried steel propane piping and tanks within the scope of license renewal by monitoring tank level. License renewal application (LRA) Section 2.3.3.15 states that the license renewal function of these components is to provide a pressure boundary. NUREG-1800, "Standard Review Plan for License Renewal" (SRP-LR), Rev. 1, Section A.1.2.3.4, item 2, states that a program based solely on detecting structure and component failure is not considered an effective aging management program for license renewal.

Issue:

In order to detect the effects of aging via a change in tank level, the license renewal pressure boundary function would already have had to fail (Le., leak). Consistent with the SRP-LR, this methodology should not be considered an effective aging management program.

Request:

Explain the basis for concluding that monitoring the propane tank level provides reasonable assurance that the license renewal pressure boundary function of the tank and piping is met.

Response for RAI 3.0.3.1.2-2

The carbon steel propane tanks and approximately fifty feet of carbon steel piping are in scope for license renewal due to their function of supporting 10 CFR 50.48 and Appendix R lighting requirements. There are two propane tanks supplying fuel to the one engine. They are not safety-related and do not contain environmentally hazardous materials. The direct visual inspections of buried safety-related and hazmat carbon steel piping being performed as discussed in the response to RAI 3.0.3.1.2-1 parts 1b and 1c for IP3 components will provide objective evidence of the condition of the propane piping and tanks since they are made of similar materials and are coated and exposed to similar soil conditions. These propane components have no unique characteristics that would require a specific inspection.

Observation of tank levels allows personnel to initiate corrective action to repair or replace a leaking tank, thereby providing reasonable assurance that the generator system will be available when called upon to perform its intended function. This is similar to the approach specified in NUREG-1801, Revision 2, Section XI.M41 for monitoring the integrity of fire system piping based on annual flow testing or monthly monitoring of jockey pump operation. The aging management approach for the carbon steel propane tanks and related piping is not based solely on detecting structure and component failure; but on detecting degradation such that corrective action can be effected prior to loss of system intended function. Therefore, monitoring the propane tank levels, in conjunction with opportunistic inspections of the propane piping and tanks and planned inspections of similar piping, provides reasonable assurance that the system intended function of the associated generator will be met consistent with the current licensing basis.

RAI 3.0.3.1.2-3

Background:

The response to RAI 3.0.3.1.2-1 dated March 28, 2011, revised the number and frequency of buried pipe inspections and stated the number and frequency of soil testing to determine corrosivity of the soil in the vicinity of in-scope buried pipe.

Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21(d) states, in part, that the final safety analysis report (FSAR) supplement must contain a summary description of the programs and activities for managing the effects of aging. SRP-LR 3.3.2.4, Rev. 1, states, in part, that the summary description of the programs and activities for managing the effects of aging for the period of extended operation in the FSAR Supplement should be sufficiently comprehensive such that later changes can be controlled by 10 CFR 50.59, and the description should contain information associated with the bases for determining that aging effects will be managed during the period of extended operation.

Issue:

The updated final safety analysis report (UFSAR) supplement does not reflect the planned number and frequency of buried in-scope piping inspections and soil testing to be conducted during the thirty-year period starting ten years prior to the period of extended operation.

Request:

Revise the UFSAR supplement to reflect the number and frequency of buried in-scope piping inspections and soil testing to be conducted during the 30-year period starting ten years prior to the period of extended operation,

Response for RAI 3.0.3.1.2-3

Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

A.2.1.5 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program is a new program that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

Prior to entering the period of extended operation, plant operating experience will be reviewed and multiple inspections will be completed within the past ten years. Additional periodic inspections will be performed within the first ten years of the period of extended operation.

IP2 will perform 20 direct visual inspections of buried piping during the 10 year period prior the PEO. IP2 will perform 14 direct visual inspections during each 10-year period of the PEO. Soil samples will be taken prior to the PEO and at least once every 10 years in the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each

<u>system. If test results indicate the soil is corrosive then the number of piping inspections will be increased to 20 during each 10-year period of the PEO.</u>

The Buried Piping and Tanks Inspection Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection with the following modification.

The Buried Piping and Tanks Inspection Program will be modified based on operating experience to include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. The program will classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Corrosion risk will be determined through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Inspection priority and frequency for periodic inspections of the in-scope piping and tanks will be based on the results of the risk assessment. Inspections will be performed using qualified inspection techniques with demonstrated effectiveness, Inspections will begin prior to the period of extended operation.

A.3.1.5 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program is a new program that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

Prior to entering the period of extended operation, plant operating experience will be reviewed and multiple inspections will be completed within the past ten years. Additional periodic inspections will be performed within the first ten years of the period of extended operation.

<u>IP3 will perform 14 direct visual inspections of buried piping during the 10 year period prior the PEO. IP3 will perform 16 direct visual inspections during each 10-year period of the PEO. Soil samples will be taken prior to the PEO and at least once every 10 years into the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each system. If test results indicate the soil is corrosive then the number of piping inspections will be increased to 20 during each 10-year period of the PEO.</u>

The Buried Piping and Tanks Inspection Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection with the following modification.

The Buried Piping and Tanks Inspection Program will be modified based on operating experience to include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. The program will classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Corrosion risk will be determined through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Inspection priority and frequency for periodic inspections of the in-scope piping and tanks will be based on the results of the risk assessment. Inspections will be performed using qualified

inspection techniques with demonstrated effectiveness, Inspections will begin prior to the period of extended operation.

RAI 3.0.3.1.10-3

Background:

By letter dated March 28, 2011, the applicant provided its response to RAI 3.0.3.1.10-1. Regarding its ASME Class 1 small bore socket weld inspection plan at IP2 during the extended period of operation, the applicant stated that it will perform volumetric examination of "at least ten socket welds" during each 10-year period [interval1 of the period of extended operation" in Part 1 and Part 3 of the response. However, it also stated "ten socket welds" in Part 4 of the response.

Also regarding its socket weld inspection plan at IP2, the applicant stated that it will perform volumetric examination of "ten socket welds in 2012" in Part 1 and Part 4 of the response. However, it also stated "at least ten socket welds in 2012" in Part 3 of the response,

Issue:

It is not clear to the staff whether the applicant intends to examine "ten" or "at least ten" socket welds during each 10-year interval of the period of extended operation. Based on I P2's plant specific operating experience, IP2 appears to have experienced five cases of socket weld failures. The staff's expectation is that a robust inspection program of socket welds is warranted and the inspection sampling should be sufficiently significant so that cracking, if exists, will be detected.

Request:

Justify the sampling adequacy for each 10-year period [interval] during the period of extended operation.

Response for RAI 3.0.3.1.10-3

The following supersedes the response for IP2 socket welds in the IPEC letter, NL-11-032, dated March 28, 2011.

IPEC will perform volumetric weld metal inspections on a sample of IP2 small-bore piping socket welds during the third period of the current (fourth) 10 year ISI interval. In addition, IPEC will perform twenty-five volumetric weld metal inspections of IP2 socket welds during each subsequent 10-year ISI interval. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.

The schedule for ASME Class 1 small-bore piping inspections is contained in the IP2 ISI Program. These new inspections will be added to the IP2 ISI Program, which is in the second period of the fourth ISI interval. ASME Code Section XI, IWB-2412(b)(2) specifies that when inspections are added in the second period of an ISI interval, then at least 25% of the required examinations shall be performed during the third period. Consistent with the direction in IWB-2412(b)(2), IPEC will perform seven volumetric inspections of socket welds (28% of the 25 new inspections per interval) during the third period of the fourth ISI interval, which ends in 2016. This schedule allows time for proper scheduling and contingency planning for the inspections to occur during scheduled refueling outages.

In approximately 38 years of operation, cracking has not been identified as the cause of leaks from small bore

Class 1 socket welds. Rounded or pin hole defects caused three leaks, including the May 2010 leak, and mechanical damage caused a fourth. No cause was determined for the fifth leak which occurred in 1980, over 30 years ago. Inspections of the base metal near socket welds have found no significant degradation resulting from the effects of aging. Based on this IP2 operating experience, the addition of periodic inspections of 25 socket welds during each ISI interval provides reasonable assurance that the affected welds will remain capable of performing their intended function through the period of extended operation.

Commitment #46

Include in the IP2 ISI program that IPEC will perform twenty-five volumetric weld metal inspections of small-bore Class 1 socket welds each 10-year ISI interval scheduled as specified by IWB-2412 of the ASME Section XI Code. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.

UFSAR Changes

Changes are shown with strikethroughs for ~~deletions~~ and underlines for <u>additions</u>.

A.2.1.17 Inservice Inspection – Inservice Inspection (ISI) Program

The ISI Program is an existing program based on ASME Section XI Inspection Program B (Section XI, IWA-2432), which has 10-year inspection intervals. Every 10 years the program is updated to the latest ASME Section XI code edition and addendum approved in 10 CFR 50.55a.

The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment of sign of degradation, flaw evaluation, and corrective actions.

On March 1, 2007, IP2 entered the fourth ISI interval. The ASME code edition and addenda used for the fourth interval is the 2001 Edition with 2003 addenda.

<u>IPEC will perform twenty-five volumetric weld metal inspections of small-bore Class 1 socket welds during each 10-year ISI interval scheduled as specified by IWB-2412 of the ASME Section XI Code. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.</u>

The current program ensures that the structural integrity of Class 1, 2, and 3 systems and associated supports is maintained at the level required by 10 CFR 50.55a.

A.2.1.27 One-Time Inspection – Small Bore Piping Program

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 ASME Code does not require volumetric examination of Class 1 small bore piping. The One-Time Inspection of ASME Code Class 1 Small Bore Piping Program will manage cracking through the use of volumetric examinations.

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~~ <u>butt welds. Small bore piping socket welds are periodically inspected and therefore are not included in this program.</u>

When evidence of an aging effect is revealed by a one-time inspection, evaluation of the inspection results will identify appropriate corrective actions.

The inspections will be performed prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.

RAI B.0.4-1

Background:

Pursuant to 10 CFR 54.21 (a}(3), a license renewal applicant is required to demonstrate that the effects of aging on structures and components subject to an aging management review are adequately managed so that their intended functions will be maintained consistent with the current licensing basis for the period of extended operation. Section 3.0.1 of NUREG-1800, "Standard Review Plan for Review of license Renewal Applications for Nuclear Power Plants" Revision 1 (SRP-LR), defines an aging management review as the identification of the materials, environments, aging effects, and aging management programs (AMPs) credited for managing the aging effects. In turn, SRP-LR Section A.1.2.3 defines an acceptable AMP as consisting of ten elements, including Element 10, "Operating Experience."

In addition, 10 CFR 54.21(d) requires the application to contain a FSAR supplement. This supplement must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation.

The Indian Point Nuclear Generating Units 2 and 3 license renewal application (LRA), Section B.O.4, provides a general description of how the applicant operating experience was gathered and considered in preparing the LRA. This section also states that, "Site procedures require reviews of site and relevant industry OE [operating experience] as the site continues operation through the license renewal period."

Issue:

Although LRA Section 8.0.4 states that operating experience will be reviewed in the future, it does not fully describe the details of how the applicant will use future operating experience to ensure that the AMPs will remain effective for managing the aging effects during the period of extended operation. Also, it is not clear as to which AMPs will be updated based on these operating experience reviews. In addition, the LRA does not state whether new AMPs will be developed, as necessary. Further, LRA Section B.O.4 does not provide the staff reasonable assurance that ongoing operating experience reviews will continue to inform AMP updates for license renewal.

Request:

Describe in detail the programmatic activities that will be used to continually identify aging issues, evaluate them, and, as necessary, enhance the AMPs or develop new AMPs for license renewal. In this description, address the following:

- Describe the sources of plant-specific and industry operating experience that are monitored on an ongoing basis to identify potential aging issues. Indicate whether these plant-specific sources require monitoring: corrective action program, system health reports, licensee event reports (LERs), and the results of inspections performed under the AMPs. Similarly, indicate whether these industry sources require monitoring: vendor recommendations, revisions to industry standards on which the AMPs are based, LERs from other plants, NRC Bulletins, Generic Letters, Regulatory Issue Summaries, Information Notices, Regulatory Guides, license Renewal Interim Staff Guidance, and revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." Describe the criteria used to classify a particular piece of information as aging related and outline the training provided to plant personnel so that they can adequately make such classifications.

- Describe how the identified aging issues are further evaluated to determine their potential impact on the plant aging management activities. Indicate whether the affected structures and components and their materials, environments, aging effects, aging mechanisms, and AMPs are identified and documented consistent with the methods used to prepare the LRA Describe how the results of AMP inspections are considered to adjust the frequency of future inspections, establish new inspections, and ensure an adequate depth and breadth of component, material, environment, and aging effect combinations. Describe the records of these evaluations and indicate whether they are maintained in an auditable and retrievable form.

- Describe the process and criteria used to ensure that the identified enhancements are implemented in a timely manner.

- Describe the administrative controls over these programmatic activities.

Provide a summary description of these activities for the UFSAR supplement required by 10 CFR 54.21(d). If enhancements for license renewal are necessary, also provide the updates for the UFSAR supplement.

If such an operating experience program is determined to be unnecessary, provide a detailed explanation of the bases for this determination.

Response for RAI B.0.4-1

As stated in LRA Section B.0.4, site procedures require reviews of site and relevant industry OE as the site continues operation through the license renewal period. These procedures implement two existing programs that monitor, on an ongoing basis, industry and plant-specific operating experience that includes, but is not limited to, operating experience related to the effects of aging on in-scope structures and components. These programs are the Operating Experience Program and the Corrective Action Program. The evaluations completed under these two programs ensure that aging management programs continue to be effective in managing the aging effects for which they are credited.

<u>Description of the Operating Experience Program (OEP)</u>

The OEP implements the requirements of NRC NUREG-0737, "Clarification of TMI Action Plan Requirements," Section I.C.5, and is consistent with guidance contained in INPO 10-006, Revision 1, "Operating Experience (OE) Program and Construction Experience (CE) Program Descriptions" and INPO 97-011, "Guidelines for the Use of Operating Experience." As such, the OEP monitors industry operating experience.

Sources monitored under the OEP include the following.

- NRC licensee event reports (LERs) from other plants
- NRC generic communications (Bulletins, Generic Letters, Regulatory Issue Summaries, Information Notices)
- INPO Event Report (IER) documents
- NSSS Owners group reports
- vendor bulletins
- 10CFR Part 21 reports
- operating experience from other Entergy Nuclear sites

Regulatory Guides, License Renewal Interim Staff Guidance, and revisions to industry standards are not monitored under the OEP because they are not sources of operating experience. These documents are lagging indicators typically issued in response to information provided in the OE documents discussed above.

Incoming OE items are screened by a team of OE coordinators for impact on Entergy plants. A series of team meetings, inter-site conference calls, and condition review groups are used to ensure the proper consideration of OE documents.

Further documentation in the Corrective Action Program is required when the initial OEP evaluation identifies a condition adverse to quality, a non-conformance, the potential inoperability of any structures, systems or components, degraded equipment, or equipment not performing as expected or per design. Degraded equipment includes equipment degraded due to the effects of aging.

Issues with potential plant impact require the initiation of a written OEP review. Timely determination of plant impact is ensured by assigning due dates for OEP written reviews, not to exceed 90 days. Extensions past the due date require management approval. The result of an OEP written review can include enhancement of existing aging management programs or development of new aging management programs.

Issues with no impact (or only a small probability of impact) but considered to have informational value are sent to the appropriate departmental point of contact for review.

Description of the Corrective Action Program (CAP)

The CAP implements the requirements of 10 CFR 50, Appendix B, Criterion XVI. As such, the CAP is used to monitor plant-specific operating experience and industry operating experience that is relevant to the plant.

The CAP is entered upon identification of a condition adverse to quality, a non-conformance, the potential inoperability of any structures, systems or components, degraded equipment, or equipment not performing as expected or per design. Degraded equipment includes equipment degraded due to the effects of aging. Issues addressed in the CAP must include adverse conditions and conditions adverse to quality, and can include minor problems that may be precursors to more significant events. This includes a broad range of problems and areas for improvement.

Sources monitored under the CAP include the following.

- licensee event reports (LERs)
- system health reports
- the results of inspections performed under plant programs
- results of the operating experience review program
- reports of assessments of the effectiveness of plant programs

Under the CAP, conditions are coded to enable trending for the purpose of addressing broader programmatic or process weaknesses. Site management is responsible for ensuring that trend codes are provided for conditions assigned to their department. Aging-related trend code criteria include the following.

- CA - This code is used to identify trends indicating a deviation from the licensing or design basis with respect either to design basis analysis (as the design is changed, plant aging occurs or new analysis techniques are employed) or an actual decrease in the margin between current operating parameters and the most limiting corresponding design parameter.
- EO – This code is used to identify repeat equipment or system problems due to design, aging or obsolete components/parts or for unknown reasons that are not attributed to inadequate maintenance.
- EV – This code is used to document issues concerning damage to plant buildings and structures. This includes aging issues such as roof leaks, cracks due to settling or similar problems.

Conditions are then evaluated and corrected. Evaluation includes consideration of the need for the adjustment of the frequency of future inspections, whether new or different inspections are needed, and whether the inspections include adequate depth and breadth of component, material, and environment combinations. Engineering evaluation of age-related conditions is performed by engineering personnel who are trained and qualified to perform engineering evaluations.

Extent of condition reviews evaluate related operating experience to determine the scope of corrective actions. Corrective actions can include enhancement of existing aging management programs or development of new aging management programs. For significant conditions adverse to quality, the cause of the condition is determined and corrective actions to preclude recurrence are implemented.

Timely implementation of identified enhancements is ensured through assignment of responsibility to specific site organizations for monitoring and reporting on the status of work completion. Prescribed guidelines are used to set the timeframe for implementation due dates. Designation of an enhancement as a "long term corrective action" (that is, an enhancement which cannot be implemented within this timeframe) requires approval of senior site management. Regular oversight of program enhancements that remain to be implemented is provided. A focused self-assessment of the CAP is performed on a regular basis.

Description of Elements Common to the OEP and the CAP

The administrative controls for the review of operating experience provide a formal review and approval process.

IPEC procedures for the OEP and CAP under the current licensing basis will be maintained to require review of site and industry OE as the site continues operation through the license renewal period, as stated in LRA Section B.0.4. As such, revisions to the UFSAR supplement provided in LRA Appendix A are not required.

RAI B.1.4-1

Background:

LRA Section B.1.4 states that the Boral Surveillance Program measures physical and chemical properties of sample coupons at specified intervals. Sufficiently detailed information as to the inspection and testing intervals, and how they account for plant-specific operating experience has not been provided

10 CFR 54.21(d) states, in part, that the FSAR supplement must contain a summary description of the program and the activities for managing the effects of aging. SRP-LR 3.3.2.4, Rev. 1, states that the summary description of the programs and activities for managing the effects of aging for the period of extended operation in the FSAR supplement should be sufficiently comprehensive such that later changes can be controlled by 10 CFR 50.59, and the description should contain information associated with the bases for determining that aging effects will be managed during the period of extended operation.

Issue:

The license renewal application description of the Boral Surveillance Program does not discuss the frequency of inspection and testing activities to be performed during the period of extended operation and how they will be adequate to manage the aging effects of loss of material and loss of neutron-absorbing capability. Additionally, the UFSAR supplement does not reflect the planned number and frequency of inspections and testing.

Request:

1. State how often Boral inspection and testing activities will be conducted during the period of extended operation and. if the inspection and testing interval exceeds 10 years. explain why the frequency is adequate to manage the aging effects of loss of material and loss of neutron-absorbing capability.

2. Revise the UFSAR Supplement to reflect the number and frequency of inspections and testing to be conducted during the period of extended operation.

Response for B.1.4-1

1. Boral inspection and testing activities are based on IPEC operating experience regarding the condition of the Boral and will be conducted during the period of extended operation at a frequency of at least once every 10 years.

2. LRA Section A.3.1.3 (UFSAR supplement for Boral Surveillance Program) is revised as follows.

A.3.1.3 Boral Surveillance Program

The Boral Surveillance Program is an existing program that provides assurance the Boral neutron absorbers in the spent fuel racks maintain the validity of the criticality analysis in support of the rack design. The program relies on representative coupon samples mounted in surveillance assemblies located in the spent fuel pool to monitor performance of the absorber material without disrupting the integrity of the storage system.

Surveillance assemblies are removed from the spent fuel pool on a prescribed schedule and physical and chemical properties are measured. From this data, the stability and integrity of the Boral in the storage cells are assessed.

Boral inspection and testing activities are conducted at a frequency of at least once every 10 years.

Clarification for RAI 3.1.2.2.13-1 - Steam Generator Divider Plate and RAI 3.1.2.2.16-1 - Tube-to-Tubesheet Issues.

Clarification of RAI 3.1.2.2.13-1

Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

Response for RAI 3.1.2.2.13-1 Part 2

At IP2 the original Westinghouse Model 44 steam generators were replaced with Model 44F steam generators in 2000. At IP3 the original Westinghouse Model 44 steam generators were replaced with Model 44F steam generators in 1989.

The Electric Power Research Institute (EPRI) has extensively evaluated the foreign operating experience with divider plate cracking in their reports dated June 2007, November 2008, and December 2009, and concluded that a cracked divider plate in a Westinghouse Model F SG is not a safety concern, and does not affect the design of the adjacent pressure boundary components.

The industry plans are to study the potential for divider plate crack growth and develop a resolution to the concern through the EPRI Steam Generator Management Program (SGMP) Engineering and Regulatory Technical Advisory Group. This industry-lead effort is expected to begin in 2011 and be completed within two years.

Recognizing that the EPRI SGMP resolution of this issue is under development, Entergy will inspect all IPEC steam generators to assess the condition of the divider plate assembly. The examination technique used will be capable of detecting PWSCC in the steam generator divider plate assembly ~~welds~~. The IP2 steam generator divider plate inspections will be completed within the first ten years of the PEO. The IP3 steam generator divider plate inspections will be completed prior to the end of the first refueling outage following the beginning of the PEO. (Commitment 41)

Clarification of RAI 3.1.2.2.16-1

Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

Response for RAI 3.1.2.2.16-1 Part 2

IP3 replaced its steam generators in 1989. The tube-to-tubesheet welds have been in service approximately twenty two years. If Option 1 is not implemented, IP3 will implement Option 2 that includes tube-to-tubesheet weld inspections for PWSCC. For IP3 these inspections will be performed prior to the end of ~~within~~ the first ~~2~~ refueling outage~~s~~ following the the beginning of the PEO. (Commitment 42)

Clarification for RAI 3.0.3.1.6-1 – Inaccessible Medium-Voltage Cable Program.

IPEC letter number NL-11-032 dated March 28, 2011 revised LRA Section A.2.1.22 for IP2. This letter revises LRA section A.3.1.22 for IP3 as follows.

A.3.1.22 Non-EQ Inaccessible Medium-Voltage Cable Program

The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that entails periodic inspections for water collection in cable manholes, and periodic testing of cables. In scope medium-voltage cables (cables with operating voltage from 2kV to 35kV) and low-voltage power cables (400 V to 2 kV) exposed to significant moisture ~~and voltage~~ will be tested at least once every ~~ten~~ six years to provide an indication of the condition of the conductor insulation. Test frequencies are adjusted based on test results and operating experience.

The inspection frequency for water collection is established and performed based on plant specific operating experience with cable wetting or submergence in manholes (i.e., the inspection is performed periodically based on water accumulation over time and event driven occurrences, such as heavy rain or flooding).

The program includes periodic inspections for water accumulation in manholes at least once every ~~two~~ years (annually). Inspection frequency will be increased as necessary based on evaluation of inspection results.

The Non-EQ Inaccessible Medium-Voltage Cable Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.

ATTACHMENT 2 TO NL-11-074

LICENSE RENEWAL APPLICATION
IPEC LIST OF REGULATORY COMITMENTS

Rev. 14

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

List of Regulatory Commitments

Rev. 14

The following table identifies those actions committed to by Entergy in this document.

Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.1 A.3.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection. Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using direct visual inspection.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-09-106 NL-09-111 NL-11-032	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents to the storage tanks. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit items 128, 129, 132, 491, 492, 510

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.10 A.3.1.10 B.1.11
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.11 A.3.1.11 B.1.12, Audit Item 164
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.12 A.3.1.12 B.1.13

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.15 A.3.1.15 B.1.16

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-09-018	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52
11	Delete commitment.		NL-09-056	

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of bus inspected. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to “re-torquing” connections for phase bus maintenance and bolted connection maintenance.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.21 A.3.1.21 B.1.22

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.22 A.3.1.22 B.1.23 Audit item 173
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.24 A.3.1.24 B.1.25 Audit item 173
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to 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. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.25 A.3.1.25 B.1.26

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.26 A.3.1.26 B.1.27 Audit item 173
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.27 A.3.1.27 B.1.28 Audit item 173
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.28 A.3.1.28 B.1.29
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.32 A.3.1.32 B.1.33 Audit item 173
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.34 A.3.1.34 B.1.35

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building-elevated passageway (IP2) • new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.35 A.3.1.35 B.1.36 Audit items 86, 87, 88, 417

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	• new fuel storage racks • sumps, sump screens, strainers and flow barriers Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material. Enhance the Structures Monitoring Program for IP2 and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO.		NL-08-127	Audit Item 360 Audit Item 358

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Enhance the Structures Monitoring Program to include more detailed quantitative acceptance criteria for inspections of concrete structures in accordance with ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures" prior to the period of extended operation (PEO).		NL-11-032	
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.36 A.3.1.36 B.1.37 Audit item 173
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: September 28, 2013	NL-07-039	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039	A.2.1.41 A.3.1.41

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	IP3: December 12, 2015	NL-07-039 NL-08-127	A.3.2.1.4 4.2.5
33	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 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: 1. 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. 2. Additional plant-specific 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. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. 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. (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.	IP2: September 28, 2011 IP3: December 12, 2013 Complete	NL-07-039 NL-07-153 NL-08-021 NL-10-082	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit item 146

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59l(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	April 30, 2008 Complete	NL-07-078 NL-08-074	2.1.1.3.5
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the extended period of operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the extended period of operation, to assure liner degradation is not occurring in this area. Any degradation will be evaluated for updating of the containment liner analyses as needed.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127 NL-09-018	Audit Item 27
36	Perform a one-time Inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation. A sample of leakage fluid will be analyzed to determine the composition of the fluid. If additional core samples are taken prior to the end of the first ten years of the period of extended operation, a sample of leakage fluid will be analyzed.	IP2: September 28, 2013	NL-08-127 NL-09-056 NL-09-079	Audit Item 359
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127	Audit Item 361

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RTpts or C_VUSE, updated calculations will be provided to the NRC.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-143	4.2.1
39	Deleted		NL-09-079	
40	Evaluate plant specific and appropriate industry operating experience and incorporate lessons learned in establishing appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs. Documentation of the operating experience evaluated for each new program will be available on site for NRC review prior to the period of extended operation.	IP2: September 28, 2013 IP3: December 12, 2015	NL-09-106	B.1.6 B.1.22 B.1.23 B.1.24 B.1.25 B.1.27 B.1.28 B.1.33 B.1.37 B.1.38
41	IPEC will perform an inspection of steam generators for both units to assess the condition of the divider plate assembly. The examination technique used will be capable of detecting PWSCC in the steam generator divider plate assemblies ~~associated welds~~. The IP2 steam generator divider plate inspections will be completed within the first ten years of the period of extended operation (PEO). The IP3 steam generator divider plate inspections will be completed within the first refueling outage following the beginning of the PEO.	IP2: Prior to September 28, 2023 IP3: ~~Prior to December 12, 2025~~ Prior to the end of the first refueling outage following the beginning of the PEO	NL-11-032 NL-11-074	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
42	IPEC will develop a plan for each unit to address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds. Each plan will consist of two options. Option 1 (Analysis) IPEC will perform an analytical evaluation redefining the pressure boundary in which the tube-to-tubesheet weld is no longer included and, therefore, is not required for reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted as part of a license amendment request requiring approval from the NRC. Option 2 (Inspection) IPEC will perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identifies: a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.	IP2: Prior to September 28, 2023 IP3: Prior to December 12, 2025 IP2: ~~Prior to~~ Between March 2020 and March 2024 IP3: Prior to the end of ~~Within~~ the first ~~2~~ refueling outage~~s~~ following the beginning of the PEO.	NL-11-032 NL-11-074	N/A
43	IPEC will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any.	IP2: Prior to September 28, 2023 IP3: Prior to December 12, 2025	NL-11-032	4.3.3

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
44	IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS "Design CUF" module.	Within 60 days of issuance of the renewed operating license.	NL-11-032	N/A
45	IPEC will not use the NB-3600 option of the WESTEMS program in future design calculations until the issues identified during the NRC review of the program has been resolved.	Within 60 days of issuance of the renewed operating license.	NL-11-032	N/A
46	Include in the IP2 ISI Program that IPEC will perform twenty-five volumetric weld metal inspections of ~~ten socket welds in 2012 and of at least ten~~ socket welds during each 10-year ISI interval scheduled as specified by IWB-2412 of the ASME Section XI Code during ~~period of~~ the period of extended operation. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.	IP2: Prior to September 28, 2013	NL-11-032 NL-11-074	N/A